

OIL & GAS PIPELINES

IN NONTECHNICAL LANGUAGE

OIL & GAS PIPELINES

IN NONTECHNICAL LANGUAGE

THOMAS O. MIESNER AND WILLIAM L. LEFFLER

Disclaimer

The recommendations, advice, descriptions, and the methods in this book are presented solely for educational purposes. The authors and publisher assume no liability whatsoever for any loss or damage that results from the use of any of the material in this book. Use of the material in this book is solely at the risk of the user.

Copyright © 2006 by
PennWell Corporation
1421 South Sheridan Road
Tulsa, Oklahoma 74112-6600 USA

800.752.9764
+1.918.831.9421
sales@pennwell.com
www.pennwellbooks.com
www.pennwell.com

Director: Mary McGee
Managing Editor: Marla Patterson
Production / Operations Manager: Traci Huntsman
Production Manager: Robin Remaley
Production Editor: Amethyst Hensley
Cover Designer: Charles Thomas
Book Designer: Robin Remaley

Library of Congress Cataloging-in-Publication Data Available on Request

Thomas O. Miesner and Leffler, William L.
Oil and Gas Pipelines in Nontechnical Language
Includes index
ISBN 1-59370-058-X

All rights reserved. No part of this book may be reproduced, stored in a retrieval system, or transcribed in any form or by any means, electronic or mechanical, including photocopying and recording, without the prior written permission of the publisher.

Printed in the United States of America
1 2 3 4 5 10 09 08 07 06

This book is dedicated to pipeliners, from the early entrepreneurs in Pennsylvania and Baku to the modern-day technicians. The efforts of these people have supplied us with crude oil, natural gas, gasoline, jet, diesel, and home-heating fuels virtually continuously for more than 100 years.

Contents

Acknowledgments	xvii
1 How Pipelines Differ	1
Crude Oil Pipelines	3
Refined Products Pipelines	4
Natural Gas Pipelines	5
Pipeline Customers	6
2 The First Leg	9
Creating Nostalgia	9
Enter Competition	12
Oily Beginnings	12
Gaseous Progress	14
Endeavor and Technology	16
Disturbed Interests	18
The Russians	19
Separate Ways	21
Expansion	22
The Great Offshore	23
Diversity	26
Shifting Sands	27
References	28
3 How Pipelines Work	29
The Physics of Fluid Flow	29
Municipal Water Systems	31
Friction Losses, Pipe Lengths, and Flow Rates	32
Splitting flows	34

Hydraulic Properties of Hydrocarbon Fluids	35
Measures and dimensions	35
Density	37
Viscosity	39
Pour point	41
Vapor pressure and evaporation	41
Pressure	44
Compressibility	44
Why gases behave that way	45
Hydraulics	47
Basic Flow Principles and Equations	47
The First Law of Thermodynamics	47
Bernoulli's equation	48
Flow characteristics	49
Friction loss	50
Elevation loss (or gain)	51
Flow rates and capacities	54
Conclusion	55
4 Oil Pipeline Operations	57
Crude Oil Lines—a Brief Review	57
Refined Products Lines—a Brief Review	58
Field Operations to Central Control Room	59
Crude oil receipt and delivery field operations	59
Refined products receipt and delivery field operations	62
Central Control Room Operations	63
Planning and scheduling operations	65
The scheduler's role	66
The controller's role	68
Hydraulic concepts—practical applications in mainline operations	72
The Control Room	79
Routine operations	80
Abnormal operations	84
Operator Training	85
References	86
5 Natural Gas Pipeline Operations	87
Natural Gas Lines—a Brief Review	88
Gathering lines	89
Gas processing plants	90
Receipts from LNG facilities	92
Pipeline hubs	93

From Field Operations to Central Control Room Operations . . .	94
Natural gas field operations	94
Natural gas delivery operations	99
Central Control Rooms	100
Planning and scheduling operations	101
Monitoring and controlling the pipeline	103
Hydraulic concepts—optimizing line operation	104
Routine operations	105
Quality control	106
Abnormal operations	106
Operator Training	107
References	107
6 Petrochemical and LPG Pipeline Operations	109
Definitions	109
Product Characteristics	110
C4 products	110
C3 products	111
C2 products	111
Compressibility	112
Leak Detection	112
Measurement	113
Quality	113
Commissioning and Decommissioning	114
Freezing temperatures	114
Storage	115
Hydraulics	117
Addendum—Supercritical Fluids	118
7 Offshore Pipelines	121
Line Design	122
Installing Subsea Pipelines	124
The boon and bane of buoyancy	124
Laying pipe	125
S-lay	125
J-lay	126
Reel barge	128
Tow-in	130
Bottom Conditions	131

Risers	131
Attached risers.	131
Pull tubes	132
Steel catenary riser	132
Top-tensioned risers	134
Riser tower.	135
Flexible risers	136
ROVs	136

8 SCADA, Controls, and Leak Detection. 139

SCADA	140
Design and Control	141
Human versus computer decision making	141
Local or central control	142
Manual or automated	143
Communications	143
Human machine interface.	146
Real-time operating data	147
Configuration tool.	150
Application interface	150
Historic database	150
Amount of data to gather	151
Update frequency	151
Update process	152
Corrupted data	152
Indicators, alarms, and alarm filtering.	153
SCADA performance	155
Data sharing	156
Reports and logs	156
Security	157
SCADA in summary	157
Local SCADA.	158
Leak Detection	158
Leaks and releases.	159
Leak detection systems.	160
Leak detection methods.	162
Internal systems	163
External systems	167
Conclusion.	168

9	Maintenance	169
	What Causes Releases?	170
	Equipment damage	171
	Corrosion	173
	Mechanical failures	174
	Natural hazards	176
	Other causes of failures	180
	How to Prevent Damage	180
	Equipment damage	180
	Corrosion	184
	Mechanical failures	186
	Natural hazards	186
	Other causes of failure	187
	Finding Potential Problems before They Become Failures	187
	Internal inspection devices	187
	Hydrostatic testing	190
	Electrical surveys	192
	Direct assessment	196
	Risk and Pipeline Safety	197
	Consequences	198
	Probabilities	198
	Framework for considering risk	198
	Data	202
	Integrity Management Plan	203
	Repairs	204
	Replacing the pipe	204
	Reinforcing the pipe	206
	Grinding to reduce stress concentrations	207
	Deposited weld metal	208
	Coating repairs	208
	Other Maintenance Activities	209
	Line lowering	209
	ROW maintenance	209
	Cathodic maintenance	210
	Maintenance pigging	210
	References	212

10	Investment Decisions	213
	Why Are They Built?	213
	Who Decides to Build?	214
	How Is the Decision Made?	216
	Demand and supply	216
	Economics	218
	Ownership Changes.	224
	Master Limited Partnerships	225
	Determining the Purchase and Sales Price	226
	Economic value	226
	Comparable sales	227
	Highest and best use.	227
	Reconstruction cost new	227
	Book value	228
11	Major Components and How They Work	229
	Pipe.	229
	Manufacturing methods	230
	Properties of pipe	231
	Nonferrous pipe	232
	Coatings.	232
	Fusion bond epoxy	233
	Coal tar.	234
	Plastics.	234
	Tapes.	234
	Shrink sleeves.	235
	Concrete coating.	236
	Fittings and Flanges.	236
	Fittings.	236
	Flanges.	238
	Valves	238
	Gate valves.	239
	Ball valves	240
	Plug valves.	240
	Check valves.	243
	Globe valves.	244
	Pressure relief valves	245
	Actuators.	246
	Pumps and Compressors.	247
	Positive displacement pumps and compressors.	247
	Centrifugal compressors and pumps.	252

Prime Movers	257
Engines	258
Electric motors.	259
Turbines	259
Variable Speed Devices	260
Mechanical VSDs	260
Electrical variable frequency drives	260
Meters	261
Positive displacement meters.	261
Turbine meters.	262
Orifice meters	263
Ultrasonic meters	264
Coriolis meters	265
Provers	265
Pipe provers.	265
Master meters	266
Other Components	267
References	267

I2 Engineering and Design 269

Safety Considerations.	270
Route Selection.	270
Line Size, Wall Thickness, and Looping	271
Engineering aspects of friction loss	271
Systems Curves.	275
Fittings, Flanges, and Valves.	276
Wall Thickness and Grade of Pipe	276
Looping	278
Pump, Compressor, and Prime Mover Selection.	279
Pump selection.	279
Compressor selection.	282
Prime mover selection	283
Flow and Pressure Control	284
Natural gas	285
Oil	285
Number of Stations	286
Station Location	287
Storage	289
Location of oil storage	289
Number and size of oil tanks	290
Location of natural gas storage	291
Natural gas storage management	291

Operating storage	292
Seasonal storage	292
Station Design and Layout.	293
Compressor and pump stations	293
Delivery stations	295
Storage fields and tank farms.	295
Ancillary station equipment	296
Additional Design Considerations	297
Crossings.	297
Block valves	298
Conclusion.	298
13 Construction	299
Permitting.	300
Contracting and Procurement	300
ROW and Land Acquisition.	301
Inspection.	302
Staking the Line.	302
Pipeline Construction Spreads	303
Preparing the ROW.	303
Stringing	304
Welding	305
Weld Inspection	308
Trenching	309
Lowering In	310
Backfilling	312
Bends, Crossings, and Tie-Ins	312
Bends.	313
Crossings.	314
Tie-ins	315
Quality Control.	316
Cleaning and Sizing.	316
Hydrostatic Testing	317
Commissioning	317
Station Construction	317
Cleanup and Restoration.	318
Handoff for Operations.	318
Documentation.	319
14 Satisfying Stakeholders	321
Introduction.	322
Stakeholders	322
Owners.	323

Customers 324

Landowners and neighbors 324

Governments 325

Nongovernmental organizations 326

Interested citizens 326

Industry 327

Suppliers and contractors 327

Competitors 327

Employees 327

Media 328

Balancing Needs and Wants 329

 Safety 329

 Supply 332

 Other wants 332

Conclusion 333

References 333

Appendix: Abbreviations and Acronyms 335

Index 339

Acknowledgments

Many people contributed to this book by sharing their knowledge, either teaching us or allowing us to learn by observation. Others took a keen interest in this project, and freely lent their expertise. It is impossible to thank each one by name, but there are some groups and specific people that deserve individual mention.

Larry Clynch, Richard Tennille, and Nick Mavris were early teachers and mentors for one of us at Continental Pipe Line Company. Over a career, field operators and technicians, control room operators, senior operators, schedulers, and directors provided protection from making mistakes that came during our learning years, or they allowed “safe” mistakes that helped the knowledge process. Our experience has been that almost everyone we encountered in the pipeline industry willingly shared their successes and failures, providing us further opportunities to learn.

When we started this book, we did not intend to have a chapter on chemical pipeline operations, but Paul Davis volunteered to write the chapter for us. He helped us understand the critical nature of the lighter hydrocarbons, and deserves early mention among those helping with the book.

We wrote chapter 3 first because it established the basic knowledge for the rest of the book. David Vanderpool provided extensive help during several revisions of that chapter, suggesting analogies and better ways to explain the topic. John Anderson and Wayne Swafford checked chapter 3 from a natural gas perspective.

We originally contemplated only one chapter on operations, but we quickly discovered natural gas and oil each deserved individual chapters. Their unique properties make operations quite different, a theme repeated throughout the book. Butch Kincaid, Ross Sinclair, Larry Hoelscher, Dwayne Burton, Ron Hales, Tim Roehrick, and Albert Horelica, Jr. each took the time to patiently explain to persons with mostly oily experience the mysteries of natural gas operations. That included several control room visits and a tour

through Albert's spotlessly clean compressor station, where his father had worked before him. John Bartos and Rick Ykema added in-depth knowledge to compressors and compressor operations for chapter 11.

Being involved with a complete replacement of SCADA and leak detection systems is something no one should have to do more than once in a career. Despite that, as we wrote the book, Galen Stanley took extra time to help us better conceptualize leak detection and its relationship to SCADA as we tried to put knowledge into words. Luis Gamboa assisted with local SCADA, and Richard Parker and Kevin Rittie reviewed the entire chapter.

John Keifner lent his knowledge and experience to chapter 9, providing valuable critique. Peter Nicholson provided insight regarding corrosion and cathodic issues, helping keep that section of chapter 9 consistent with current practices.

David Vanderpool returned to review chapter 12, as did Dave Dean, who also reviewed chapter 13. They both suggested valuable additions and clarifications for the chapters they reviewed.

Denise Hamshere and Marty Matheson spent extensive time improving our notion of stakeholders and the subtle and effective impact they have on project permitting processes. George Tenley reviewed the chapter, providing analogies to make better points, and Michele Joy and Peter Lidiack provided comments and clarifications for chapter 14.

To all these people, we express our thanks. Nonetheless, and as always, we had the last word, so we carry the burden of interpreting correctly what they offered.

Finally, we thank our families, particularly our wives, for the patience, understanding, encouragement, and love they provided during this effort. As any well-married author will attest, those four gifts are the prerequisites of timely book completion.

T.O.M.
W.L.L.

1

How Pipelines Differ

The difference between a violin and a viola is that a viola burns longer.

—**Victor Borge (1909–2000)**

This is quite a three-pipe problem.

—**Sir Arthur Conan Doyle (1859–1930)**

If some veteran natural gas pipeline operators moved over to an oil pipeline, they would scratch their heads in wonderment about the different variables, controls, customer requirements, and alarm bells.

But aside from operations, oil and natural gas pipelines look essentially the same, perform the same service, and obey the same laws of physics. They are installed in largely the same manner and face the same regulatory and social dilemmas. But that does not mean they all use the same nomenclature.

Such differences in nomenclatures can occur concerning natural gas pipelines versus oil pipelines, and crude oil pipelines versus refined products pipelines. Making life easier, operations of some types of pipelines are more or less indistinguishable from oil pipelines operations. These include chemical liquids pipelines, natural gas liquids (NGL) pipelines, and liquefied petroleum gas (LPG) pipelines. On the other side, pipelines that move anhydrous ammonia, carbon dioxide, and gaseous chemicals like ethylene operate much like natural gas pipelines.

The pipeline industry further subdivides crude oil pipelines into the following categories:

- Crude oil gathering lines
- Crude oil main lines

Somewhat parallel, natural gas pipelines fall into these categories:

- Natural gas gathering lines
- Natural gas transmission lines
- Local distribution lines

Both the liquid and natural gas pipeline value chains begin in the oil patch, where oil and gas are extracted from underground reservoirs, sometimes as mixed streams, sometimes separately. If the stream at the wellhead is a mixture, field separators at the well sites segregate it into oil and gas, and the two commodities are treated separately from that point (fig. 1–1).

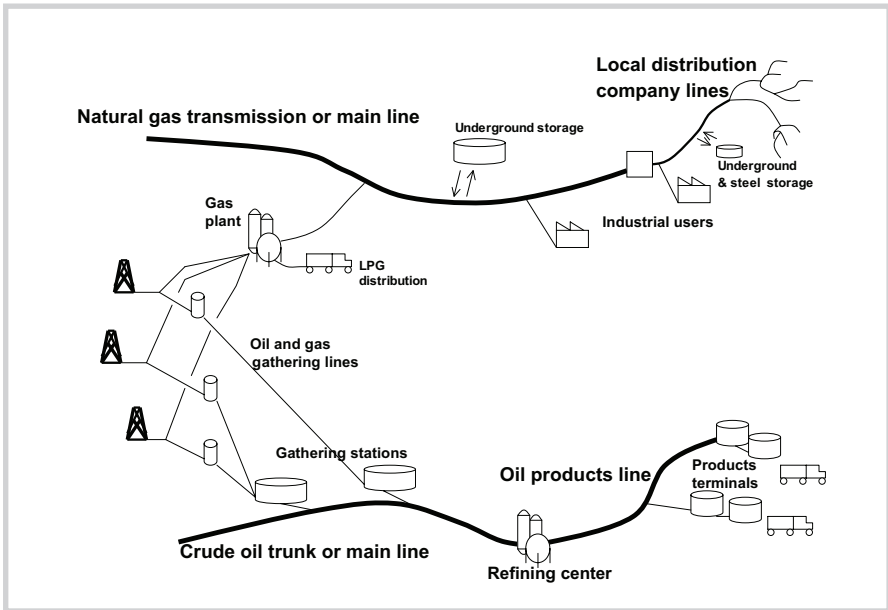


Fig. 1–1. Oil and natural gas value chain

Crude Oil Pipelines

Crude oil gathering lines are normally made from 2-inch (in.) to 12-in. pipe. They originate at the production field tank battery (fig. 1–2), a collection of smaller tanks, for transport by truck or pipeline to a gathering station (a collection of larger storage tanks).



Fig. 1–2. Crude oil tank battery at a well site (Courtesy Miesner, LLC)

The gathering station aggregates crude from many sources, including deliveries by tank truck. It is normally adjacent to a crude oil mainline and has a pump station to inject the crude oil into the main line. Gathering stations may be located at the beginning of a main line or along the route. Main lines are generally 8-in. or more in diameter.

When a gathering station is located along a main line, often called a trunk line, the crude oil can be injected into the continuous flow of crude oil as it goes past. If the crude oil is sufficiently different from that flow, the pipeline can be stopped upstream of the gathering station. A volume of crude can be pumped in as a separate batch. The batch is then tracked as it moves down the pipeline and is delivered to separate customers or into segregated tanks at the destination.

Besides gathering stations, main lines receive crude oil from other main lines, regional storage facilities, and marine off-loading facilities. Conversely, main lines deliver to the same list of facilities plus, most importantly, refineries.

Refined Products Pipelines

The refined products pipeline value chain begins at refineries and ends at petroleum products terminals. This is a collection of large tanks located along the pipeline near consumers (fig. 1–3).



Fig. 1–3. Oil product tanks at a pipeline terminal (Courtesy Explorer Pipeline Company)

Products move down the pipeline in batches. Sometimes the entire flow of the pipeline is diverted into a terminal tank, while at other times only a slipstream moves into the tank.

From the terminal, the petroleum products move to retail outlets or commercial and industrial consumers in tank trucks or in tank cars.

The network at either end of a product pipeline can vary. The Yellowstone Pipeline originates in Billings, Montana, where it receives batches of product from only three refineries. The pipeline moves the product to terminals across Montana. Yellowstone is the single source for those terminals.

Explorer Pipeline begins on the U.S. Gulf Coast, where it receives batches of product from a dozen or more refineries and other pipelines. When it reaches Dallas, Tulsa, St. Louis, and Chicago, Explorer competes with other pipelines coming into the area. It also competes with other refineries in the area.

Natural Gas Pipelines

Gathering lines receive natural gas at well sites, often moving it to gas plants for further processing (fig. 1–4). Sometimes, depending on gas quality and contaminants, the natural gas is injected directly into gas transmission lines without processing. The contents of the natural gas, particularly contaminants, determine whether the natural gas stream needs extensive processing at gas plants.



Fig. 1–4. Natural gas processing plant (Courtesy ConocoPhillips)

Facilities at gas plants usually remove acid gases and the NGLs. The acid gases include hydrogen sulfide and carbon dioxide, gases having the potential to corrode the facilities of both the pipeline and the consumer. Hydrogen sulfide is also toxic and is a pollutant. The NGL could include natural gasoline, butanes, propane, and sometimes ethane.

If a natural gas stream has a heavy content of NGLs, at least the natural gasoline and some of the butane has to be removed to avoid condensation in the gas transmission lines. Condensation causes operational challenges, as further discussed in chapter 5. Upon removal, the NGLs have various markets and moves from the gas plant in tank cars, trucks, or their own pipelines.

Compressor stations at gas plants or gathering systems boost the pressure of the natural gas to move or inject the gas into the main line. Sometimes compression is not needed because the natural gas is already at a high enough

pressure coming out of the ground to force it into the main line or transmission line. Natural gas is always injected into transmission lines as other gas goes by. Since the gas is more or less fungible (interchangeable), batching is not required. As natural gas enters the main line, commercial adjustments can be made for the energy content of the injected natural gas. This might be done if it is higher or lower than the typical 1,000–1,050 British thermal units (BTUs) per standard cubic foot (scf).

Natural gas transmission lines transport natural gas to the local distribution companies (LDCs) for further movement to homes and businesses. Increasingly, natural gas transmission lines deliver directly to large end users like industrial plants, businesses, commercial sites, and power generation plants, bypassing LDCs. Sometimes, instead of going directly to consumers, natural gas is stored for future use. The storage can consist of aboveground steel tanks, underground caverns, aquifers, or old, depleted oil or gas fields.

The management of daily and seasonal storage is an essential service provided by the main lines to the producers, the shippers, and the LDCs.

Pipeline Customers

Crude oil pipelines sell transportation to shippers, which could be refiners, crude oil producers and traders, or other intermediaries. The customers for refined products pipelines include refiners, traders, and commercial and industrial consumers such as airlines, power companies, government agencies, and railroads.

Natural gas transmission companies have the same generic customers as crude oil pipelines, such as producers and traders. Instead of refiners, however, they have LDCs and large-volume consumers.

In the United States, LDCs normally have an exclusive right to serve a particular area. They purchase natural gas and then provide transportation of the natural gas to residential, commercial, and industrial consumers, charging one fee for the service and the natural gas. In some markets, the resellers have a corporate affiliation with the LDC. In most cases in the United States, the natural gas transmission lines never actually own the natural gas. They simply transport the natural gas for a fee, just like railroads transport other commodities without owning them.

So natural gas is transported “as is” from the wellhead all the way to consumers, with the exception of some minor processing at gas plants. In contrast, oil goes through major transformation at refineries before it is suitable for consumption by its various customers. Because of that, oil products pipelines carry multiple products. This adds even more contrast to the operating complexities of the two types of pipelines, oil and gas, as will become abundantly clear in coming chapters.

2

The First Leg

All I really need to know I learned in kindergarten.

—Robert Fulghum (1937–)

Some historians would start a review of pipeline progress by citing the Chinese experience. A few thousand years ago, they used hollowed bamboo with mud seals to move water—and some say natural gas—for short but unspecified distances. And there might be allusions to the fresh water and toilet facilities of Crete's King Minas in the second century B.C. But all that ancient lore is more about plumbing than pipelining, and while it may be interesting, it is not all that useful.

The real history of oil and gas pipelining begins two centuries ago, and relevant remnants of the experience still abound in today's commerce.

Creating Nostalgia

In 1806 in London, the London and Westminster Gas Light and Coke Company (LWGL&C) began laying the first gas mains ever placed under a public street. LWGL&C had commercialized the process that transformed coal into gas that would burn with enough incandescence to light the streets from lamp posts every 50 feet (ft) or so. The city government

gave permission to dig from Haymarket to St. James Street, lay pipes made of sheet lead, and charge the city for municipal lighting. Thus the legal protocol for future municipal franchises was established.

This *unnatural gas* (not the methane eventually tapped in underground reservoirs) assumed the name *manufactured gas* and sometimes *town gas*. Manufactured gas consisted of a mixture of mostly methane, ethylene, carbon monoxide, and carbon dioxide. The ethylene gave it sufficient luminescence that the lamp lights needed no mantle to burn brightly, an advantage over natural gas, which contains almost no ethylene.

Only a few years later, the Baltimore City Council received a petition from some entrepreneurial Marylanders for a similar franchise. In 1817 they granted the Gas Light Company of Baltimore a contract. Its goal was “to open a street or streets for the purpose of laying pipes for trying the experiment and estimating the expense at which he could contract with the Council for lighting the city.”¹

Gaslights captured the imagination of cities around America in succeeding decades, arriving in subsequent years in the following cities:

- 1825 New York City
- 1829 Boston
- 1832 Louisville
- 1835 New Orleans
- 1836 Philadelphia
- 1843 Cincinnati
- 1846 St. Louis
- 1854 San Francisco
- 1867 Los Angeles
- 1872 Minneapolis
- 1873 Seattle

Evidence of gaslight districts survives in many of these cities (fig. 2–1).

The gaslight companies built plants that gasified coal and sometimes oil, wood, and even cottonseed and corn cobs. They located these plants close to their target customers, the street lamp districts, followed quickly by residential and commercial lighting customers. For the distribution systems, some fashioned pipelines initially of hollowed, wooden log segments (fig. 2–2), with inside diameters as large as 8 in. Lengths ran from 2 ft to 8 ft. By the 1820s, British-designed cast-iron pipe arrived to replace logs.



Fig. 2-1. Gas light, circa 1892. The light fixture hanging in the W. J. Murphy Grocery Store in Rawlings Cross, Newfoundland, used locally manufactured gas, undoubtedly supplied through a town gas distribution system. (Courtesy Centre for Newfoundland Studies)



Fig. 2-2. Segment of hollowed log used as a gas pipeline joint (Courtesy Midwest Energy Association; photo by Tom Miesner)

Enter Competition

In 1821, a Fredonia, New York blacksmith, William Aaron Hart, created a new industry. He pounded a few lengths of pipe into the ground in the vicinity of some strangely ignitable gas bubbling from a running creek bed. He then fashioned a floating, open-bottomed box next to his well and captured the gas as it surfaced. Finally, he ran hollowed log pipes to a Lake Erie lighthouse a half mile away and then to the nearby town. With the lighthouse beacon and chandeliers of the theater in town thus lit up, Hart had created the natural gas pipeline industry. The quiet competition between natural gas and manufactured gas continued in America for another 130 years.

Oily Beginnings

While the Fredonia smithy may have drilled the first natural gas well, Americans usually give all the credit to Col. Edwin Drake for drilling the first so-called well. He found oil in Titusville, Pennsylvania in 1859 and single-handedly instigated the petroleum industry's own version of the cosmic Big Bang. After that it expanded inexorably at remarkable speed, with no seeming bounds. In only a few decades, the "Big Bang" of oil and gas operations swirled across the oceans, creating new orbits of activity as markets sucked up this new energy source for heating and lighting.

Of modest proportions at the beginning, oil producers like Drake first loaded their product, crude oil, into barrels. Whatever barrels were handy—wine, whiskey, fish, nails, or salt pork barrels—were pressed into service. Shortly, a phalanx of coopers arrived at the oilfields to manufacture a new supply.

Along with them came teamsters with horse-drawn rigs to haul the loaded barrels to the nearest railhead or river landing, as the oil made its way to refineries and markets. The roads they traveled were generally poor, if they existed at all. Weather sometimes made the shortest passage from the wellhead impossible. A dilemma arose concerning what to do with the blessedly continuous production of oil when the roads became hopelessly mired.

The conceptual leap in the oil business from piping to pipelining, from plumbing to transportation, started haphazardly in 1862. J. L. Hutchings attempted to demonstrate his newly patented rotary pump. He began by laying a 2-in. cast-iron pipe over the hill from the historic Tarr Farm oil field near Oil Creek, Pennsylvania, to a nearby refinery. His pump performed well, but the

pipeline was a disaster. He had soldered the pipe joints with lead, but at the first increase in pressure, the connections leaked so badly none of the pumped oil reached the refinery. Disillusioned and broke, he exited the scene.

Not long after, the next step took place in nearby Pithole, a town that must have been named by someone with an interesting sense of humor. A consortium of oilmen and venturers led by Samuel Van Syckel, called the Oil Transportation Association (OTA), placed a 2-in. wrought iron pipeline over a 6-mile (mi) track from an oil field to the railroad station at Oil Creek (fig. 2-3). The pipe had threaded joints to deter leaks. Borrowing from the railroads, the OTA built a telegraph line along the right-of-way (ROW) to communicate the complicated bookkeeping of multiple shippers.



Fig. 2-3. Early Pennsylvania pipeline (Courtesy Drake Well Museum)

Three steam-driven pumps provided the power to deliver a remarkable 1,900 barrels per day (bpd), for which Van Syckel charged \$1 per barrel (bbl). He undercut the teamsters by \$4–\$5/bbl. Riding on his success, Van Syckel built a parallel line and dropped the charge on both to 50¢/bbl and still made money.

Van Syckel’s achievement did not go unnoticed. Pipelines sprouted like kudzu along the hills of Pennsylvania.

Gaseous Progress

Oilmen muttered in frustration when the first fluids from their wells were gas. They were only mildly annoyed if an oil/gas mixture appeared. For the most part, they considered natural gas a waste product. What they did not use to raise steam for their steam engines they typically burned on-site in a flare (fig. 2–4).

However, not everyone rejected as valueless the energy content of natural gas. The Rochester Gas Light Company (RGLC) saw an opportunity to displace the manufactured gas in its distribution system with natural gas from a well 25 mi away. The company laid a wooden pipeline to tap it but struggled for some time with the conversion from one type of gas to another. The lower luminescence of natural gas was bad for the lighting business, and its higher heating content meant replacing burner tips throughout the system. Still, shutting down the gasification works justified the switch.

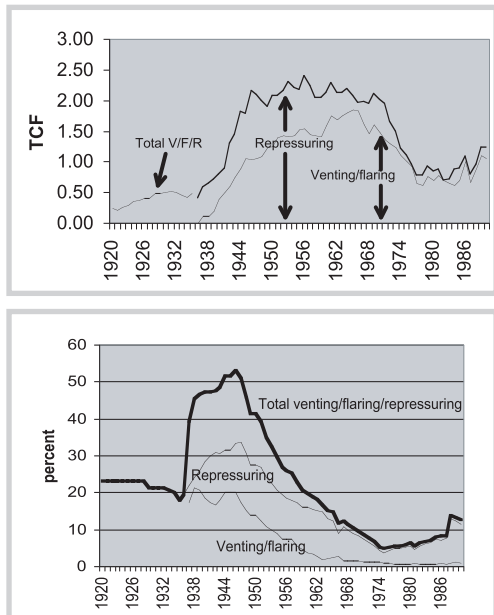


Fig. 2–4. U. S. natural gas volumes and their disposition. It was not until the middle of the 20th century that oilmen realized that pumping the gas back into the reservoir, called repressuring, would return the energy necessary to drive even more oil out. As late as 1935, 20% of the natural gas in the United States was flared.

With RGLC as their role model, producers began to market gas from gas wells and even the so-called associated gas that arrived at the surface mixed with the crude oil. Natural gas had to be separated anyway from crude oil at the wellhead before the crude oil was transportable and marketable. By the 1880s, Pittsburgh, by then a city with heavy industry, became the central focus for natural gas marketing and pipeline construction. Five hundred miles of pipelines brought natural gas from the oil and gas fields of western Pennsylvania. They fed 200 thousand cubic feet per day (Mcf/d) of gas to various industries. These included 10 iron and steel mills, six glass-making factories [including the original Pittsburgh Plate Glass (now PPG) facility], and every brewery in town, including the legendary Pittsburgh Brewing Company. (The latter made Iron City beer.) In addition, producers supplied gas to the Simpson Natural Gas Crematory.

Meanwhile in 1879, the Tidewater Pipeline Company completed the first crude oil trunk line from western Pennsylvania. This was a 115-mi run to the Philadelphia and Reading Railroad depot at Williamsport (fig. 2–5). From there the crude oil moved by tank car to New York and other tidewater refineries along the Atlantic. This heroic effort represented no small achievement of civil engineering and human output. Compared to anything previous, as it crossed the Allegheny Mountains, it covered longer distances and higher altitudes by a factor of 10. Eight years later, Tidewater extended the line to Bayonne, New Jersey, eliminating the railroad haul altogether.

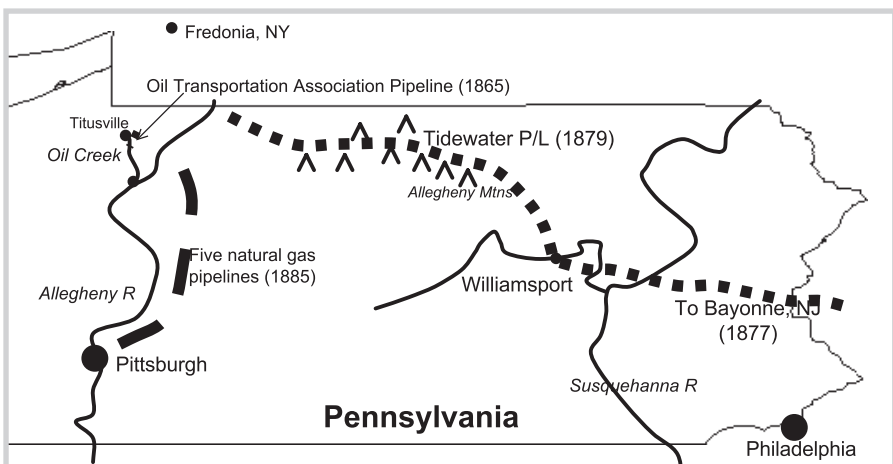


Fig. 2–5. Map of western Pennsylvania pipelines, 1865–1885

Endeavor and Technology

Ingenuity and sweaty human endeavor are better words than technology to describe pipeline development in the early years. Cast-iron pipes replaced the wooden logs soon enough, allowing experimentation with threaded joints. And as so often is the case, sometimes the simplest idea proved a bonanza. In 1880, Solomon Dresser, an unsuccessful oil driller, developed a threaded coupling with a rubber O-ring that effectively and cheaply sealed oil and gas pipeline connections and made installation easier. (Dresser went on to found the company that became at its peak Dresser Industries, before Halliburton absorbed and broke it up.) For the next 40 years, Dresser's design remained the pipeline industry's favorite coupling.

Most Pennsylvania crude oils have high wax contents. In the winter, the wax could accumulate on pipeline walls and plug the flow, especially in small-diameter lines. Shorter lines could be disassembled and swabbed to remove the wax, but some of the longer lines were just shut down until summer. Shade-tree mechanics tried numerous devices to keep the lines clear, such as pushing wood or leather balls through the lines. Usually they disintegrated before getting to the end of the line.

Pigs?

How did the devices used to clean pipelines (and now detect mechanical flaws of the lines) get the name pig? An expert in the field, Andrew Marwood of the Pipeline Engineering Company, offers two possibilities:

- PIG, a pipeline injected gadget.
- In the early days of pipelining, as the leather balls used to swab pipelines moved down the line, they squealed—like a pig.

Marwood suggests that both undocumented possibilities may be more a myth of mirth than a matter of fact.

One anonymous and unheralded pipeline builder, or *pipeliner*, fashioned a scraper from a long bolt, with sheet metal and leather washers the size of the inner diameter. The pumper inserted the assembly in the line and pushed it through with a column of oil behind it. Thus the first successful *pig* was put in play.

Pipeline designers, and certainly the installers, always looked for lighter weight but stronger pipeline materials. Iron and steel plate could be formed into cylindrical shapes and welded along the seam, but the process was expensive and often unreliable.

In 1885, the Mannesman brothers, Reinhard and Max, of Germany devised a machine that could make pipe with no seams at all. They took a red hot billet (cylinder of steel) and pushed it around a mandrel using a set of

rollers that simultaneously turned it and shoved it. The mandrel acted like a piston, hollowing out the cylinder. Then they pushed it through another mill and mandrel combination to thin down the walls and create a long tube that they could polish up a little and sell as 40-ft pipe.

With little design change, the Mannesman brothers' brilliant insight has lasted 130 years as a method for producing medium-diameter pipe with thin walls and high strength—three good ideas in a row.

Still, screwing together joints of threaded pipe required intensive physical labor (fig. 2–6), even after large machines were developed to handle the chore. After three or four decades watching its crews manhandle threaded joints, in 1911 the Philadelphia and Suburban Gas Company finally allowed them to weld the joints together using oxyacetylene torches.



Fig. 2–6. A pipeline gang installing threaded pipe, circa 1890. The crews used long tongs to grip and turn the pipe. (Courtesy API and the Behring Center of the Smithsonian Institute)

There were other instances of empirical discovery. Pipeline owners and operators quickly learned by observation what the extremes of Pennsylvania weather could do to heavy, screwed-together cast-iron pipe laid out on the ground in more or less a straight line. In the cold of winter, the cast-iron pipe contracted, pulling threaded joints apart or otherwise cracking. Oil poured out.

In the heat of the summer, the lines expanded and bent themselves into serpentine shapes, knocking over mailboxes, telegraph poles, and small trees, and spilling out oil. By the 1880s, burying pipelines a few feet below the surface became standard practice, with expansion loops along the way.

Two modest inventions outside the pipeline business helped move it along more briskly. In 1885 Robert Bunsen devised a burner that could effectively mix air and natural gas to produce an efficient flame. For this he achieved the same type of immortality later enjoyed by Roy Jacuzzi. Not so lucky in this regard, but just as innovative, Carl Auer von Welsbach in Germany developed a practical gas mantle, which he patented in 1885. It enabled effective substitution of natural gas for manufactured gas lighting.

Disturbed Interests

With any innovation, some people champion it, some ignore it, and others treat it as a threat. The teamsters were only the first to find pipeliners a threat. From the beginning, they had performed the essential duty of hauling the loaded barrels of oil to market. But the Brotherhood of Pennsylvania Oil Haulers, a notoriously tight clique, earned five times the average wage of other union workers. They quickly saw the reality of a 5-mi pipeline that could pump 1,000 bpd—it would replace 300 teamsters working 10-hour days.

With that prospect, from the beginning the teamsters vandalized one installation after another as the pipeline industry emerged. After J. L. Hutchings' first pipeline failed mechanically, he had no chance to modify it. The teamsters smashed his pumps and tore up his line with chains and pickaxes. Soon after, they dragged the Oil Transportation Association's line out of the ground as soon as it was laid. Armed confrontations with killings of cinematic proportions ensued. Eventually the rule of law prevailed, and the 3,000 teamsters left Pennsylvania or gained employment hauling pipe joints for new lines.

As confidence in the integrity and efficiency of pipelines grew, in the 1870s they spread beyond the railroad depots towards the population centers along the Atlantic Coast. The long-haul business of the railroads was threatened. Most railroads tried to stop the expansion by refusing to allow oil pipelines to cross their tracks. In one instance, the Pennsylvania Railroad refused to give ROW under its rail bed to the Columbia Conduit Company. The pipeline company then finessed the railroad company by building a terminal on either side of a railroad street crossing. They loaded tank wagons with the temporarily interrupted crude oil, hauled it across the tracks, and unloaded it to resume its pipeline journey.

In some cases, the railroad conflicts became as physical as those with the teamsters. Railroad crews ripped up pipelines adjacent to their tracks with chains attached to locomotives. Armed guards hired by the pipeline companies knocked heads with gangs of railroad thugs.

Resolution eventually came from the top. John D. Rockefeller's Standard Oil Company played one railroad against another and against rival oil companies while he built and acquired a network of pipelines and refineries. By 1880 he had bullied his way into a monopolistic position downstream of the oil-producing sector, which by then spread from Pennsylvania to Ohio and West Virginia. He dictated both oil prices and railroad tariffs, but he did effect an end to violence in the local communities.

In 1906 the U.S. government undermined Rockefeller's control through pipeline and refinery ownership. It enacted the Hepburn Act, which deemed all interstate oil pipelines to be regulated common carriers. That mandated open access to the lines by all shippers and regulated the tariffs. Shortly after, Rockefeller's grip on the oil business was totally loosened by a historic 1911 U.S. Supreme Court decision that broke the Standard Oil Company into 33 autonomous companies, including 13 pipeline companies.

The Russians

Not all the excitement of pipelining in the 19th century happened in Pennsylvania. The Azerbaijanis claim that their first oil well preceded Colonel Drake's by 13 years. Even more preemptive is a description of a hand-dug oil well 35 meters (m) deep that was drilled in 1594 in Balakan in the district of Baku.² Whatever the truth, by 1885 oil production was gushing from a mother lode in Balakhan, not the easiest place in the world to get to or

from. Some 10,000 peasants were hauling oil from the oil fields to Baku on the Caspian Sea for refining and transport up the rivers to the Russian heartland. They used whatever containers they could find, which mostly consisted of wineskins, but also included wooden barrels, which were in scarce supply because of the lack of trees. In this parallel world, they too built a 10-km pipeline with pipe imported from America, fighting off coopers and oil transportation companies the whole time, and began deliveries to Baku in 1879.

Transportation to Baku was only the small prize. The industry pressed the Russian government to build a pipeline from there to the Black Sea, some 530 mi away (fig. 2–7). That would give them access to a warm-water port, and by ship to the rest of the world through the Bosphorus Strait. It took the government 10 years of bureaucratic mulling—even without an environmental assessment—and 10 years of construction to build it. The 8-in. line, with its 16 pumping stations, started up in 1906. It featured a suspension bridge crossing over the Kura River, threaded pipe imported from America, and red lead paint for corrosion protection. The line delivered 10–15 Mbpd of kerosene. This was enough to allow Marcus Samuels, the major supporter, to break the stranglehold the Standard Oil Company had on the Asian kerosene market. He thus jumpstarted his new company, Shell Transport and Trading.



Fig. 2–7. Pipeline route from Baku (solid line) to a warm-water port on the Black Sea

Separate Ways

By 1907, the pipeline industry had sorted itself into several distinct business models:

- Oil-producing companies, or consortiums of them, built or acquired their own crude oil pipelines to assure physical access to the refining sector, even though they were common carriers.
- Independent companies built and ran crude oil trunk lines, selling transportation as common carriers.
- Independent companies built crude oil gathering lines and acted as *consolidators*, or buyers and sellers of crude oil.
- Most oil products pipelines were built and owned by oil companies or consortiums to gain cheaper access to markets as common carriers.
- Most natural gas pipelines were built and owned by natural gas merchants, who purchased gas at the wellhead and sold it to LDCs. Few natural gas lines were owned by producers.
- Natural gas distribution companies bought gas from the natural gas pipeline companies. Many also merged at some point with the local electricity generating and distributing companies.

These business models persisted in the United States through the century, except for natural gas. In the period 1915–1935, the most important natural gas distribution companies and some gas pipelines were consolidated into a cozy cartel of holding companies. That ended abruptly with the enactment of several pieces of federal legislation in the 1930s that forced disintegration.

The last of these laws, the Natural Gas Act of 1938, reinforced the earlier model of merchant ownership of natural gas pipelines. The pipeline companies bought from the producers, transported the natural gas, and sold it to the LDCs, but now all at regulated prices. However, in the 1970s, a wave of deregulation broke over the oil and gas industry. A new set of rules separated participation in the transportation function and the merchant function into arm's length corporate control.

New business models resulted that included:

- Pipeline companies that only sold natural gas transportation (plus storage and other related services)
- A myriad of buyers and sellers of natural gas and its transportation, which included producers, LDCs, and traders
- Oil products pipelines that catered to a large sector of buyers, sellers, and traders

Large integrated oil companies reassessed their strategic priorities toward the end of the 20th century, especially in the context of environmental exposure. As a result, they have been steadily divesting themselves of oil pipeline assets. Coincidentally, at the same time in the United States, certain tax-favored structures, including master limited partnerships, have emerged as ready buyers.

Expansion

In the first one-third of the 20th century, U.S. pipelines expanded exponentially during a golden age (fig. 2–8) in which a happy confluence took place. While electricity replaced kerosene for lighting, gasoline demand for automobiles kept refineries gainfully occupied. At the same time, the giant natural gas fields in the Southwest, including the Panhandle Field in North Texas and the Hugoton Field in Kansas, Oklahoma, and Texas, came on stream. These fields required access to markets in the Northeast. Later, the giant oil fields of the Middle East, Venezuela, Africa, and Russia called for connections to the sea, or in the case of Siberia, access to markets 2,000 mi–3,000 mi away.

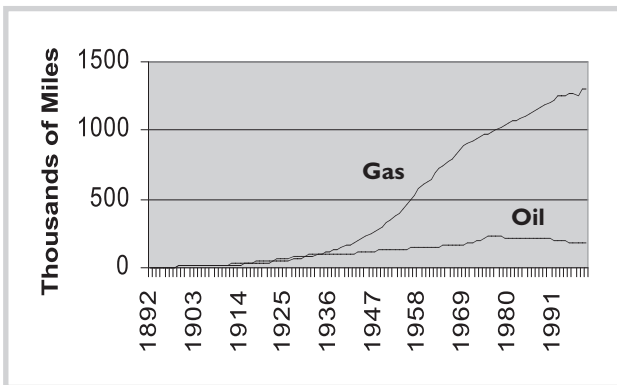


Fig. 2–8. Growth of U. S. pipeline mileage. At the end of the 20th century, there were about 160,000 mi of oil pipelines, 300,000 mi of natural gas main lines, and 1,900,000 mi of natural gas distribution lines in place.

Meanwhile technological advances bloomed in the pipeline sector:

- Seamless pipe replaced other forms.
- Electric welded seams replaced threaded joints.
- Pipeline lengths and diameters doubled and tripled, and line pressures increased.
- Steam-driven pumps and compressors gave way to gasoline- or diesel-driven pumps, or compressors powered by natural gas.
- Tractors and trucks replaced mules and horses.
- Ditching machines replaced picks and shovels.
- Coated steel extended pipeline life.
- The causes of cathodic corrosion were identified and remedied.
- Electric control boards monitored throughput, pressures, and leak detection.
- Telephone lines provided communications.

This litany of gadgets, devices, and technologies underpinned the growth of pipelines for 50 years, until Kerr McGee found oil underneath its platform in the Gulf of Mexico in 1947. Then a new set of techniques had to be developed to connect offshore oil and gas to onshore transportation.

The Great Offshore

Already pipelines had spanned rivers, clinging to railroad bridges or their own structures. As early as 1887, the Benson Pipeline crossed under New York Harbor from the mainland, a total of 5 mi, to deliver oil to Staten Island from western Pennsylvania. (Ruptures from dragging anchors made operations an incessant headache, but the development of diving techniques kept the line functional.)

In 1900 a gas main was laid under the Mississippi River by “pulling” a pipeline across the 2,100-ft span and sinking it. At its deepest point it reached 120 ft.

In the same way, some offshore pipelines could be pulled by tow boats to their destinations and lowered. But as distances increased beyond 10 mi and depths exceeded 500 ft, new ideas and equipment were needed. At first the offshore drilling companies and the construction companies like Santa Fe and McDermott built large barges with long extensions off their sterns. These would let the pipeline slip off as it was welded, joint by joint. Surprisingly enough, the welded pipe could bend sufficiently to extend down to the seabed without buckling as the barge made its way to the offshore platform.

The real proving ground for laying offshore pipelines was the North Sea, hardly ever as calm as an average Gulf of Mexico day. The discovery of the world-class Forties Field and the Brent Field begged for pipeline connections to the huge oil and gas reserves. Starting in the 1970s, new pipe-laying vessels began to appear. Some mimicked drilling vessels by adopting semi-submersible hulls with flooded, submerged pontoons that gave them stability even in a rolling sea (fig. 2–9).



Fig. 2–9. Pipe-laying vessel. Vessels like this one can lay pipe in water depths as great as 10,000 ft. (Courtesy Heerema Marine Contractors)

In the 1970s, Algeria had accumulated enormous natural gas reserves, while Italy had a burgeoning demand for fuel. Connecting the two required one of two things:

- Converting the gas to liquid in multibillion dollar plants and shipping it to market in special LNG tankers
- Building a pipeline connecting the two countries

While the Mediterranean Sea may normally be placid, the crossing from Tunisia to Italy via Sicily (fig. 2–10) was unprecedented in scope in 1974. The contract winning company, Saipem, built a special vessel, the *Castoro 5*. This pipe-laying vessel laid the first leg, a 10-in. line, across the 900-ft deep Messina Straits between Sicily and the Italian coast. On the other side of Sicily, they laid a 16-in. line in the 1,400-ft deep Sicily Channel to Tunisia (with connections to Algeria). That changed the state of the art, and improved the pipeline industry's depth capabilities by an order of magnitude.

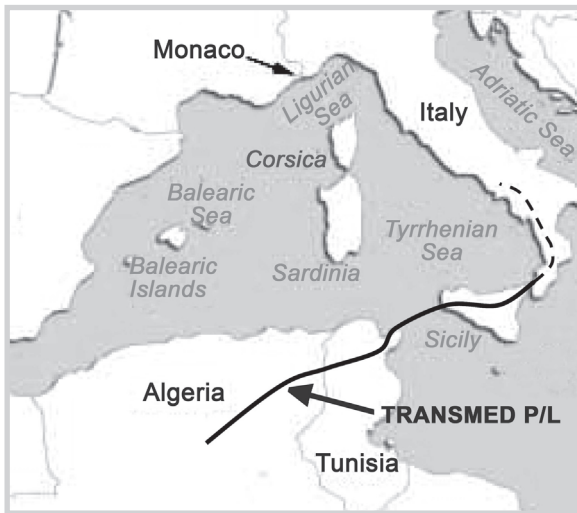


Fig. 2–10. The Sicilian connection. In 1974, the subsea pipeline had to cross a 900-ft trench to connect Sicily to the Italian mainland and a 1,400-ft channel to North Africa.

For 20 years, design improvements reduced weather-related downtime, catastrophic buckling of the pipe, and other hazards. By the 1990s, giant vessels were laying oil and gas pipelines, plus electrical and hydraulic umbilicals to communicate between wellheads and production platforms in almost 10,000 ft of water.

Diversity

Pipeline operators learned to extend their crude oil and natural gas transportation technology to other commodities. In 1893, Lewis Emery and the flamboyant Captain Jacob Jay Vandergrift built a refined products line from their refinery to a railhead in Wilkes-Barre, Pennsylvania. Cynics predicted that the various fuels moving in batches down the line would be hopelessly mixed. As the first consignment arrived at the depot, they found about 50 ft of the liquid column had commingled. That meant that only about 12 bbl out of a batch of 15,000 bbl–20,000 bbl had to be downgraded at a loss of less than 1¢/gallon (gal).

Some pipelines have seen service in both crude oil and natural gas service. During World War II, Nazi submarines devastated the seaborne oil traffic between the U.S. Gulf Coast and the East Coast. To circumvent this hazard, the government's Petroleum Administration for War, in cooperation with the largest U.S. oil companies, built a 24-in. crude oil line from Texas to Philadelphia. This line, called the Big Inch Line, was built in 13 months. A few months later, they completed a parallel 20-in. products line to Linden, New Jersey, called the Little Big Inch Line. The saga of the efforts to put these lines in place required a triumph over bureaucracy during wartime allocation of materials, as well as project execution described in superlatives.

Ironically, after the war, Texas Eastern Transmission Company purchased the lines and converted them to natural gas service. Then seeking another more lucrative opportunity in 1955, they converted the Little Big Inch Line to use in petroleum products service.

In 1958, Texas Eastern began sending test shipments of propane through the Little Big Inch. Regular shipments of large batches of propane started by the end of the year. In 1960 Willbros Corporation, a premier pipeline construction company, finished the Mid-America Pipeline. This was the first long-distance (2,175-mi) LPG pipeline, running from Houston to Selkirk, New York.

Broadening the diversity of oil and gas pipeline technology even more, by the end of the 1960s, pipelines from West Texas to the U.S. Gulf Coast carried *raw make*. These mixtures of the natural gas liquids (ethane, propane, butanes, and natural gasoline) moved to separation facilities near the markets. There they were fractionated into the four individual hydrocarbon products and sold as chemical feedstocks. In 1953, Gulf Oil started the first ethylene pipeline system, a hydrant operation that distributed the petrochemical to plants along the U.S. Gulf Coast. In 1983, Willbros completed a 550-mi carbon dioxide (CO₂) line for Shell Oil Company. This line extended from Cortez, New Mexico, where large volumes of CO₂ were found in natural reservoirs, to oilfield enhancement projects in Midland, Texas.

Shifting Sands

The 20th century saw step-change advances in pipeline technology as the industry moved from small-diameter pipes largely screwed together to large-diameter, high-pressure welded pipelines. Now pipelines are ubiquitous in economically developed countries, carrying a large share of the energy needed to fuel their citizen's life styles.

However, both public and national oil companies still struggle, as they have since the Baku pipeline, with access to ports and markets across international borders. Notorious examples of political disasters have weighed heavily in planning and negotiations.

- The pipeline system through the Levant was built in 1932, 1942, and 1952 from western Iraq through Syria, Palestine, and Israel to the Mediterranean. It was held hostage from time to time by the transit countries, sometimes for decades or longer for complex political and economic reasons.
- The Tapline was built in 1950 from Saudi Arabia through Jordan, Lebanon, and Syria. It was closed down numerous times for political disagreements and because of armed conflict.
- The Transneft pipeline system was built by the USSR's central government from central Russia to consumers in its satellite countries. The USSR's breakup has resulted in an uneven privatization of this pipeline system. Transneft has been unable to separate badly needed pipeline debottlenecking incentives from government-mandated oil-production incentives.
- The TransMed pipeline experienced protracted negotiations between two national companies and three governments in the run up to construction. The conflict was not about the pipeline but over the price of the gas in it.
- The Alyeska Pipeline, though not international, had as its alternative a route through Canada. Ten years of negotiations between the North Slope oil producers (BP, Exxon, and Arco) and the U.S. government over environmental, security, and economic interests were ended only by an international oil crisis in 1973.
- The owners of huge natural gas reserves on the Alaskan North Slope have wrangled with regulators and legislators for more than two decades about the route of a proposed natural gas pipeline through Canada to the lower 48 states.

Energy forecasts continue to predict growing needs for oil and natural gas and therefore new and expanded pipelines to carry them. However, even with technological advances, significant challenges remain. The Alyeska Pipeline experience reflects the more urgent and pervasive issue that presented itself to the pipeline industry: the pipeline industry's relationship with society. All over the world, pipeline executives now spend a majority of their days ensuring that their companies deliver not just molecules of oil and gas, but safety, environmental protection, and general well-being.

The franchise that pipelines have had that gives them certain rights of property use and revenue collection is now framed in terms of the numerous stakeholders involved. It does not just concern the pipeline owners, shippers, and landowners, but also involves interest groups concerned with the collective welfare of individuals. To qualify for the right to lay a new line, or indeed to continue to use an existing one, pipeline companies now have to demonstrate the balance of benefits against the inevitable costs to society. The benefits weighed are both economic and noneconomic in nature.

References

1. Miller, J. *Rembrandt Peale, 1778–1860: A Life in the Arts*, Philadelphia: Philadelphia Historical Society, 1985, p. 125.
2. Aliyev, N. "The History of Oil in Azerbaijan," summer 1994. Retrieved May 6, 2004, from: http://www.azer.com/aiweb/categories/magazine/22_folder/22_articles/22_historyofoil.html

3

How Pipelines Work

Order and simplification are the first steps toward the mastery of a subject—the actual enemy is the unknown.

—Thomas Mann (1875–1955)

The operation of a pipeline seems simple enough: pump fluid in one end and take it out the other. While the principles dictating the behavior of fluids in pipelines are rather intuitive, the calculations involved can be fairly complex. The general physical principles governing natural gas and oil pipelines are the same, but natural gas is many times more compressible than oil. This is an important factor when it comes to understanding the differences between oil and natural gas pipelines. The first part of this chapter demonstrates these laws of physics using water line examples. The second part moves to hydrocarbons—their properties and measurement, and the laws associated with them. The chapter concludes with an introduction to hydraulics.

The Physics of Fluid Flow

Pipelines move fluids and for now, one can think of fluids as either oil or natural gas. Though it seems obvious, fluids contained in pipelines and storage vessels conform to the shape of those vessels, which is one of the principle characteristics of fluids.

In the next paragraph are five statements that may seem increasingly outlandish, but by reading the rest of the chapter, one might get completely comfortable with them.

Pressure makes fluids move. Pressure is a reflection of energy added to pipelines by pumps, compressors, or gravity. The pressure in a shutdown (nonflowing) pipeline along a level route is the same along its entire length. For a shutdown line along a route with elevation changes, the pressure is higher in the valleys and lower at the hilltops. But start this line flowing, and the pressure is almost always lower as the fluid moves along.

Fluids always move from a point of higher energy (in pipelines energy is normally measured as pressure) to one of lower energy, unless something like a closed valve stops them. When energy is added to a pipeline by a pump or a compressor, pressure builds. If one opens any point, flow starts.

A fluid would seem to be slippery by its nature, and yet friction must still be considered. Friction between the inside wall of the pipe and the moving fluid, as well as internal friction between the molecules of the fluid, resist flow and must be overcome with energy. Gravity adds or subtracts pressure depending on elevation differences. Friction generates heat, which is another way of saying it converts pressure energy to heat energy. This heat energy is transferred to the fluid or the surrounding environment. Figure 3-1 shows a simple example of a level pipeline. The compressor station at the origin adds pressure that is then consumed by friction and lost as a motive force (fig. 3-1).

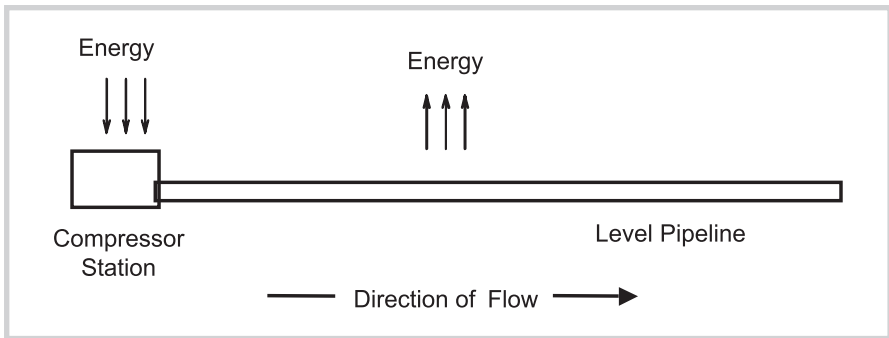


Fig. 3-1. Fluid flow along a level line

The equation for the pressure at any point along this level line is:

$$\text{Pressure at any point} = \text{Pressure at origin} - \text{Pressure loss due to friction}$$

Add in the element of elevation and the equation becomes:

$$\text{Pressure at any point} = \text{Pressure at origin} - \text{Pressure loss due to friction} \pm \text{Pressure due to elevation differences}$$

Figure 3-2 shows a line with elevation changes.

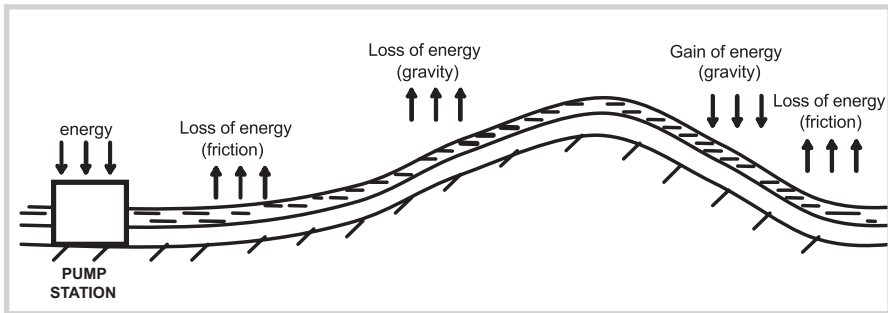


Fig. 3–2. Fluid flow along a line with elevation changes

Municipal Water Systems

Municipal water systems illustrate the forces of gravity and pressure. The water tower, a huge water tank on a hill or on a standpipe, is a familiar sight in most towns. Water moves from the tank, through the mains, and around town by energy from gravity, sometimes assisted by pumps located in carefully selected locations. Of course, the built-up energy of the water in the tank came from the pump that initially pushed the water up there.

At any faucet, the pressure from the elevated tank or pump is higher inside the faucet than the atmospheric pressure outside the faucet. When the faucet opens, water gushes out as the fluid seeks the lower pressure in the sink.

A water system is sometimes called a *hydrant system*. Water can come in from several receiving inputs and can leave the system from several thousand output points. That is okay because water is water, and the source of the water does not make any difference to the consumer. Natural gas pipelines normally operate as hydrant systems. Natural gas enters and leaves the systems at multiple points. It is all the same and consumers do not care where it originates.

The water system in a house also provides another example—the *batch system*. When someone turns on a hot water faucet, chances are, if they are not in South Texas in the summertime, cool water comes from the faucet for a while. The water in the piping between the hot water heater and the faucet had previously reached temperature equilibrium with its cool surroundings. But in a short while, hot water from the heater moves down the line, pushing out the cool water. The flow from the faucet turns warm, then hot. In this case, the characteristic of the fluid does make a difference to the user. A batch of cold water precedes a batch of hot water, with just a little mixture of (warm)

interface between them. The pipeline industry's batch system is a pipeline system in which different products (gasoline, diesel, and jet fuel) move in batches within the same pipe.

Friction Losses, Pipe Lengths, and Flow Rates

Pushing the domestic water system analogy along, one could consider the lowly garden hose. A 50-ft length of hose attached to a spigot delivers a certain amount of water through the nozzle. A 100-ft length delivers less. The reason is due to friction loss. As water flows along, water molecules rub against the walls of hose and each other, generating friction and dissipating energy, thus losing pressure. The longer the hose, the more friction and the more pressure drop. This might not call for a booster pump to reach a backyard sprinkler, but it certainly does for the Alaska Pipeline as it moves crude oil 1,000 mi from the North Slope to Valdez. Friction is one of the two main reasons for compressor and pump stations. (The other is gravity.)

Most people have a spray nozzle (valve) at the end of their garden hose. It allows them to stop the flow without turning off the spigot. With the nozzle shut, the pressure at the spigot is the same as the pressure at the nozzle. Since the hose is not flowing, all the pressure in the hose is static pressure (versus dynamic pressure). There is no friction loss since there is no flow. Each molecule is pushing against both its upstream and downstream neighbor equally hard, and the one at the very end is pushing against the spray nozzle. None move. When the nozzle opens, the molecule right next to the nozzle suddenly has only the air outside the hose to push against it. It leaps out, setting up a chain reaction and allowing flow. Since there is now flow, there is also friction loss. (If the nozzle is lying on the ground, there is a slight offset to the pressure loss due to friction, as the water runs downhill.)

As the nozzle opens, a number of things happen:

- The plastic garden hose had already expanded as the pressure built when the nozzle was shut. When the nozzle reopens, the pressure drops, the hose contracts, and with less space in the hose, extra water surges out of the nozzle.
- A pressure wave moves quickly from the nozzle back through the hose. Molecules in the hose go successively from stationary to moving in a short time, demanding energy and causing friction.
- Eventually (within a few tenths of a second) the flow settles down to a constant rate.

As the nozzle is closed:

- The flow decreases and the friction losses decrease.
- A pressure wave moves from the nozzle back. If one closes the nozzle quickly, the pressure wave may be large enough to make the hose surge or “jump.”
- The pressure equalizes (increases) in the hose, which expands.

With this simple garden hose example, steady state occurs quickly. In complex liquids lines, moving thousands of tons of liquid, pressure surges can be powerful.

The air compressor and air tank are useful in demonstrating an important difference between gas and liquids. An empty air tank in a garage is the same temperature as the garage. If one turns on the air compressor and pumps up the air tank, there will be more air in the tank, and it will feel hotter. The compressor forced air molecules closer together, and they cannot move around as much. The energy that used to cause them to bump around had to go somewhere. It turned into heat—an important concept in natural gas compressor operations. By the way, the opposite is also true. Reducing the pressure absorbs heat (see the First Law of Thermodynamics, explained later in this chapter).

Another familiar example, the balloon, demonstrates the power of compressibility. Consider what occurs if a person fills a balloon with water, holds the end closed, lays it on a table, and lets go of the end. The water gushes out. If the person fills an identical balloon with air, lays it on the table, and releases the end, the balloon will fly off the table and around the room. The escaping air releases more energy than the escaping water because the air had been compressed.

In terms of the garden hose analogies, a nozzle usually has a number of settings, allowing different amounts of water to escape in different patterns. (Of course, some people use their thumbs instead.) If a pattern allows more water to come out, the flow rate, and consequently the pressure loss as the water moves to the nozzle, is higher. Combined with the much larger Bernoulli effect (discussed later in this chapter), that causes the water not to shoot out very far.

Conversely, closing down the opening causes a pinch point and significant friction loss. This reduces the flow rate upstream of the pinch point and increases the velocity downstream of the pinch point. The higher speed stream squirts much farther.

Thus:

- Friction causes resistance to flow.
- Faster flow rates produce more friction than slower rates.
- Changing pressures causes the conduit to expand or contract.
- The size and pattern of the opening determine the pressure loss and therefore the velocity through the opening.
- As the flow starts or stops, the pressure is different than at steady state.
- Starting or stopping suddenly causes pressure surges.
- Changing one variable, pressure or flow rate, can change the other, and changing the length changes both.

Splitting flows

An additional analogy may be found inside the house. When someone takes a shower and another person in the house unconscionably flushes a toilet, some of the water previously going to the shower goes to the toilet (fig. 3–3). A sudden reduction in water flow in the shower occurs. To the chagrin of the person in the shower, sometimes the cold water flow drops more than the hot water flow, and the shower changes momentarily to scalding.

When valves are open in more than one location, various laws of physics redistribute flow in a way that balances pressures and flow rates. Where the water flows split, the following equations apply:

$$\begin{aligned} \text{Pressure at split} &= \text{Pressure at shower} \\ &+ \text{Pressure loss between shower and split} \end{aligned}$$

$$\begin{aligned} \text{Pressure at split} &= \text{Pressure at toilet} \\ &+ \text{Pressure loss between toilet and split} \end{aligned}$$

That is the basic lesson in the physics of flow, but it only covers half the fun of hydraulics. The second part consists of the laws of fluid mechanics, most of which were developed by the great minds of the 17th, 18th, and 19th centuries. But before that comes the properties of fluids. Water has been used as an example thus far, and oil and natural gas follow the same laws of physics. But the difference in properties will dictate the dissimilarity of their flow behavior.

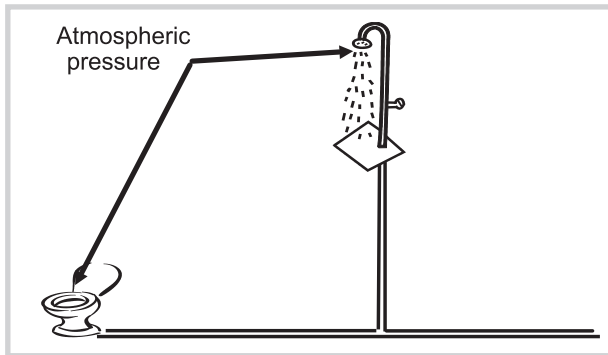


Fig. 3–3. Shower and toilet example. Pressures are equal at the split.

Hydraulic Properties of Hydrocarbon Fluids

Many different types of molecules make up fluids transported in oil pipelines. Natural gas pipelines carry relatively few different types. The properties of these fluids, especially oil because it is composed of more different types of molecules, vary enormously. Some of the more important concerning pipeline operators include:

- Density
- Viscosity
- Vapor pressure
- Compressibility

To make life unnecessarily complicated, these properties are measured by more than one set of standards.

Measures and dimensions

Two basic ways of measuring have evolved over the years: the metric system and the English system. Both are used in hydraulics. Length and time are easy enough to understand. In the English system, lengths come in inches, feet, yards, and miles. The more logical metric system uses the meter as the basic measure, and divides it into centimeters and millimeters, as well as the larger kilometers. Time is blessedly expressed in both systems in the familiar seconds, minutes, and hours.

The third important set of dimensions in hydraulics, force and mass, is a bit more difficult. In general people tend to confuse the terms *weight* and *mass* or *force* and *pressure*, and it usually does not matter...unless they happen to be working on pipeline hydraulics.

A short explanation of Newton's Second Law may be useful at this point. Back in 1666, Sir Isaac Newton (1642–1727) said, in somewhat more effusive prose, of course:

$$F = Ma$$

where

F is force,
M is mass, and
a is acceleration.

One important force is gravity, which acts on the mass of every body. Any body, of course, has some mass, independent of whether it is on Earth or is floating in a space craft. Mass is a measurement of any amount of matter.

Mass times the acceleration due to gravity gives weight, a downward force. The acceleration is 32 ft/sec², which is due to the Earth's gravity. That is, given a free fall drop with no wind resistance, an object will increase its speed by 32 ft/sec for every second it drops. That applies at or near the Earth's surface where pipeline work is done, so the acceleration due to gravity is essentially a constant for pipeline work. (A hundred miles up or down, it would be different.)

The dimensions of force, mass, and acceleration annoyingly come in several standards. Two are most popular: the U.S. Customary System (USC), which was formerly the British Gravitational System, and the International System of Units (SI).

In the USC, the common dimension of weight is the pound (lb). Mass is normally expressed in *slugs*, which is 1 lb divided by the acceleration due to gravity. (This should not be confused with the use of *slug* later in this book to mean a small accumulation of liquid in a gas pipeline.)

Using SI units, the measure of mass is the gram (g) or kilogram (kg), and the unit of force is appropriately called the newton (N).

Density

Strictly speaking, *density* is the quantity of a fluid expressed in terms of mass per unit volume. Ironically, after all the tedious development of nomenclature, engineers almost always use the terms pound and kilogram when they refer to mass. So the density of water, for example, is universally referred to as about 62 lb/cubic foot (cf) in USC units. In SI units, it is 1 kg/liter (L), which gives a clue how the size of the liter was originally picked.

Density can be expressed as pounds per cubic foot, as in the water example, but more commonly, especially for pipeline work, relative density, or *specific gravity*, is used:

$$\text{Specific gravity} = \text{Density of fluid} / \text{Density of reference material}$$

For liquids the reference material is water; for gases the reference material is air. As examples:

- Gasoline that has a specific gravity of 0.69 has 69% of the mass of the same volume of water.
- Natural gas that has a specific gravity of 0.67 has 67% of the mass of the same volume of air.

Temperature and pressure both affect density. If one raises the temperature, molecules move faster. They jump around a little more and push against each other harder, taking up more space, decreasing density. Compressing gas forces more gas into the same space, increasing its density.

All commercial oil transactions are corrected for changing temperatures. This is accomplished by first measuring volume under ambient conditions, then recalculating the volume that would exist under standard conditions. While oil may be essentially noncompressible at the same temperature, 1 gallon (gal) of gasoline at 1°F is denser and has more contained energy than 1 gal of gasoline at 100°F. Consequently, it is worth more. One cubic foot of natural gas at 1,000 pounds per square inch (psi) pressure has more mass and energy than 1 cf of natural gas at 10 psi. Commercial transactions always have corrections for temperatures for oil and temperatures and pressures for gas. For buying and selling, each party uses the same pressure and temperature for the transaction. Common practice is to convert to 60°F and atmospheric pressure.

Natural gas sales are also adjusted for energy content, measured in British thermal units (BTUs) or *therms*. One BTU is the quantity of heat necessary to raise the temperature of 1 lb of water 1°F (from 58.5°F to 59.5°F) under standard pressure of 30 in. of mercury at or near its point of maximum density. One therm is equal to 100,000 BTUs.

Some organizations involved with these conventions include the American Petroleum Institute (API), American Gas Association (AGA), and the American Society for Testing and Materials (ASTM), now ASTM International. They have developed extensive tables for the conversion of natural gas and petroleum liquids to standard conditions in support of commercial transactions.

Engineering calculations, in contrast to commercial adjustments, must account for actual operating conditions, not the accountant's standardized measures. The crude oil in the Interprovincial Pipeline from Canada to Minnesota is denser than the crude in the Caño Limón pipeline in the tropics of Columbia. This is true even though both crudes have nearly the same (standard) density.

API gravity. In the early part of the 20th century, the petroleum industry, through the API, developed its own measure of density for liquids, a measure called *API gravity*. It is a function of specific gravity and is calculated as:

$$\text{API gravity} = \frac{141.5}{\text{Specific gravity}} - 131.5$$

API gravity was developed as an aid to laboratory workers. It increased the scale on the hydrometers used to measure fluid density, allowing those reading gauges in the field (*gaugers*) to better see their measurements. Nobody remembers anymore where the 141.5 and 131.5 came from (not even the API!). Furthermore, the advance of instrumentation makes this old trick no longer necessary. But using API gravity has become a tradition in the oil industry.

API gravity is expressed in degrees API (°API). Gasoline with a specific gravity of 0.69 has an API gravity of 73.6°API. Diesel fuel, a heavier liquid, has a gravity of about 32.0°API (fig. 3–4).

There are several important things to remember about API gravity:

- The higher the API gravity, the lighter the material.
- Natural gas measurements generally use specific gravity, not API gravity.
- Water has a gravity of 10°API.
- API gravity is just another measure of fluid density and is used only in the oil and gas industry. It has no other special meaning.

The density of a fluid has a direct impact on the amount of energy required to move the fluid to a higher elevation, and therefore the pressures in a pipeline. Denser (heavier) fluids require higher pressures to push them uphill; they gain more pressure as they go downhill.

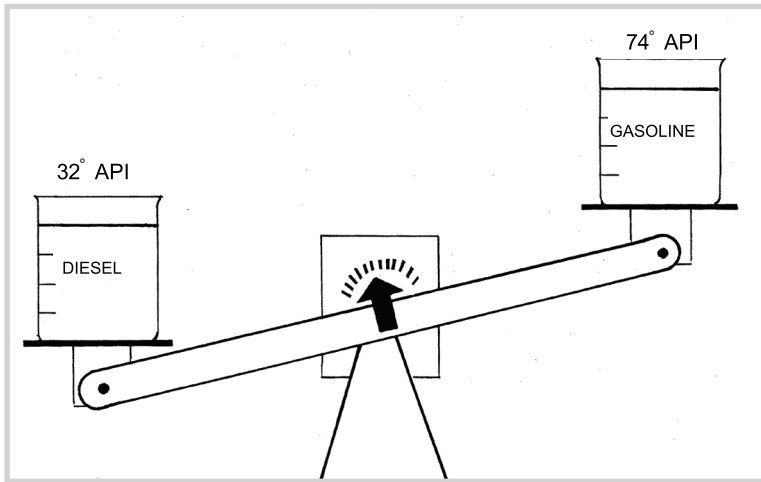


Fig. 3–4. Density differences. The lower the °API, the heavier the material.

Viscosity

Physicists attest that molecules tend to attract each other. It is what keeps the world together. Big, complicated molecules, the kind that make up petroleum fluids, tend to get tangled up with each other. This attraction and tangling combine to cause internal resistance to flow called *viscosity*. Imagine pouring spaghetti from a pot of hot water into a strainer. The long pieces tangle as they plop in the strainer. Now think about that spaghetti if it were cut up into ¼-in. pieces. It would flow better.

As another culinary analogy, one could knock over a glass of milk and a jar of honey on the same table. The milk would run off the table onto the floor. The honey would hardly flow at all. This is because the honey molecules—complicated, branched organics—intertwine so much they stick to each other (and anything around them). Milk has a lower viscosity than honey.

The higher the viscosity, the more energy it takes to move the fluid because of the internal resistance resulting from molecular action.

Viscosity is expressed in one of two ways by names that are easy to misuse:

- **Absolute viscosity.** This is sometimes confusingly called dynamic viscosity, and it is a measure of the force to move a liquid at a constant velocity through a tube or pipe.
- **Kinematic viscosity.** This is the ratio of absolute viscosity to fluid density. (Kinematics is the branch of mechanics that deals with motion.)

$$\text{Kinematic viscosity} = \text{Absolute viscosity} / \text{Specific gravity}$$

Absolute viscosity is measured in centipoises, named after Jean Louis Poiseuille (1797–1869), who developed the concept. Centipoise is pronounced “centi pwaz.” (*Poiseuille*, however, is essentially unpronounceable.)

Kinematic viscosity is measured in centistokes, after the much more sensibly named George Stokes (1819–1903). His law of viscosity became the basis for modern hydrodynamics.

Measuring absolute viscosity in a laboratory involves timing how long it takes for a given volume of fluid, at one of various specified temperatures, to pass through the capillary tube in a viscometer.

The amount of energy required to move fluids depends to a large extent on their viscosity. Higher viscosity fluids have more resistance to flow, requiring more energy to push them along. In general, lower API gravity fluids (the heavier ones) are more viscous; higher API gravity fluids (the lighter ones) are less viscous and flow more easily (fig. 3–5).

This relationship between viscosity and gravity is only a chemical idiosyncrasy of petroleum. Viscosity does not depend on density. Water, for example, is denser than nearly all crude oils but it is much less viscous.

Viscosity could be calculated for each type of molecule in a mixture and the blend viscosity predicted through a complex equation. It is usually much easier and more accurate to simply get a sample of the material, test it at several temperatures, and then draw graphs of viscosity versus temperature. From charts like these, engineers read viscosities as needed to accommodate design temperatures.

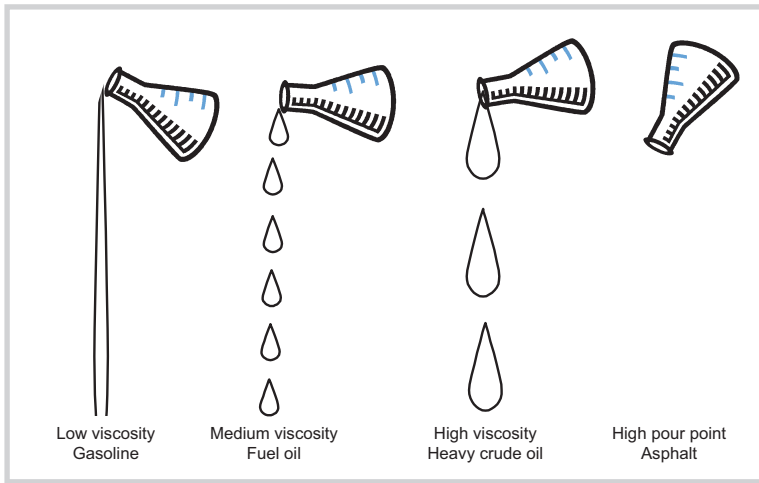


Fig. 3–5. Viscosities of various fluids

Pour point

As temperatures drop, liquids can reach their pour point and cease to flow. Some highly viscous liquids have to be heated or have a pour point depressant added to allow them to move at ambient temperatures. People in Bemidji, Minnesota speak about diesel engines that will not start in the winter unless they have diesel fuel spiked with kerosene or with a *pour point depressant*. (Alternatively, they heat their cars using the electric circuit conveniently provided by the city fathers at the parking meter!)

Pour point is related to viscosity, but it is a different concept. Clearly, engineers must consider pour point when designing pipelines and storage facilities in cold climates. It would be embarrassing to put a high pour point crude oil into a large storage tank in the fall and not be able to remove it until the summer.

Vapor pressure and evaporation

Most liquids eventually evaporate if left standing in an open container. Some evaporate faster than others, and pressures and temperatures can affect the rate.

One can consider a can of soda as an example. It is a fluid that is liquid (mostly water) with gas (carbon dioxide) dissolved in it. The gas gives the soda its fizz; the liquid, its body and taste.

As long as the can is sealed, the pressure inside keeps most of the carbon dioxide dissolved in the liquid. When someone pops the top, the dissolved gas is exposed to lower pressures and begins to escape the can. Left on the counter for a few hours, all the gas leaves the soda can and dissipates into the atmosphere. An imperceptible amount of the liquid also leaves the can in the same period as it evaporates. If the temperature of the liquid in the can is raised, it evaporates faster.

As a fluid, the soda conforms to the shape of the can. Without a container, the gas takes no discernible shape. If the container of liquid is kept closed, the space above the liquid, if any, remains filled with the vapors of that liquid. The pressure in that container of vapor/liquid is called the *saturated vapor pressure* of the mixture and is higher than the atmospheric pressure. Another way to grasp the concept is to consider vapor pressure a measure of how much pressure is needed to keep any more liquid (or dissolved gas in the case of soda) from vaporizing.

The fizzy can of soda with the carbon dioxide has a saturated vapor pressure about equal to the vapor pressure of carbon dioxide. (The true vapor pressure can be calculated through a set of equations combining the vapor pressure of each ingredient in its proportionate amount, but carbon dioxide has, by far, the largest effect.) After the carbon dioxide leaves, the vapor pressure of the flat soda is lower, reflecting primarily the vapor pressure of the water left in the mixture.

Saturation vapor pressure is also dependent on temperature. If one raises a liquid's temperature, the saturation vapor pressure increases.

The propane tank under an outdoor grill contains both vapor and liquid. As gas (vapor) is fed to the grill, more of the liquid vaporizes and maintains the pressure in the tank. When the last of the liquid evaporates, the pressure in the tank begins to drop. The amount of gas going to the burners declines to nothing as the vapor pressure approaches atmospheric pressure.

Thus:

- Fluids, both gases and liquids, conform to the shape of their containers.
- The rate at which fluids leave an open container depends on temperature, the surrounding pressure, and the vapor pressure of the fluid.
- Temperature and pressure help determine if a fluid stays as a liquid or turns to gas.
- Higher vapor pressure means more volatility.

Evaporation is different from boiling. As mentioned before, molecules of a liquid have a sticky affinity for each other. But the molecules at the surface are in less contact with other molecules than molecules further down. So they have fewer molecules with which to adhere. Molecules in a liquid state have their own energy, and some at the surface have enough to escape to the vapor form, albeit slowly. Of course different liquids have molecules of different energy levels, and that is why they evaporate at different rates. Every type of liquid has a unique vapor pressure and evaporation rate.

The higher the temperature, the more energy molecules have, and the faster the liquids evaporate. When temperature reaches the boiling point, something different happens. Molecules anywhere in the liquid can vaporize, rise to the surface, and leave the liquid. Bubbles always seem to form at the bottom of a pot of boiling water. This is because it is where the heat enters the pot.

Vapor pressure is an important consideration in both natural gas and oil pipelines for different reasons. Natural gas pipelines transport primarily one type of molecule—methane. However, other molecules such as ethane, butane, propane, and water are often present in small percentages. When the combination of natural gas pipeline operating temperatures and pressures exceeds the vapor pressure of these heavier molecules, they turn to liquid. This blocks the flow and damages compressors and other equipment.

For oil lines, when line pressure drops below the vapor pressure of the fluid, bubbles form. As the liquid/bubble mixture passes through pumps, pressure increases, and the bubbles suddenly collapse back into liquids. The sudden collapse, called *cavitation*, can damage the pump. If the line pressure drops below the liquid's vapor pressure, some vaporizes, leaving a combination of liquid and vapor. The vapor can expand as it passes through meters and other equipment, causing them to operate faster than design speed and damaging them.

Another phenomenon in an oil pipeline, called *pulling apart the pipe*, happens when the pressure in the pipeline drops below the vapor pressure of the oil in the line. (That could happen where a pipeline goes over the top of a tall hill, as the fluids begin to rush down the other side due to gravity.) When a pipeline *pulls apart*, it is slack. While nothing bad happens physically to the pipeline, the measurement process is all messed up. More volume comes out the end than goes in the beginning. Traditional oil pipeline leak detection systems compare volume input versus volume output. The characteristics of an oil line operating in a slack condition looks much the same as a leak to the operator.

Pressure

Pressures are measured in pounds per square inch, psi, in USC units, and in pascals, Pa, in SI units. This book uses pounds per square inch for pressure measurements.

Pressure can be shown as absolute pressure (psia) or gauge pressure (psig). Since pressure gauges are calibrated to atmospheric pressures:

$$\text{Absolute pressure} = \text{Gauge pressure} + \text{Atmospheric pressure}$$

The standard atmospheric pressure is 14.7 psi at sea level, but ambient pressures change with the weather, and pressures differ from valleys to mountaintops.

In the petroleum industry, the vapor pressure of a liquid is measured in *pounds Reid Vapor Pressure*, abbreviated lbs RVP, or sometimes just RVP. The apparatus to measure RVP was designed by a fellow named (naturally) Reid. It calibrates the RVP to 100°F and an ambient pressure of 760 millimeters (mm) of mercury. The ASTM publishes a rigorous procedure using the apparatus to determine the vapor pressure. One should keep in mind that RVP is not equal to gauge pressure or absolute pressure.

Compressibility

Density, viscosity, and vapor pressure are each important components for oil pipelines, but compressibility is less important (until the subject of leak detection comes up). As before, gas pipelines contain a limited number of different kinds of simpler, smaller molecules. Density and viscosity vary with pressure, and compressibility is an important consideration for gas.

All materials, whether solid, liquid, or gas, compress or expand. Steel beams in skyscrapers actually compress a small amount because of the weight they carry, and engineers design accordingly. Steel pipelines stretch (this is called *strain* by engineers) and get slightly larger in diameter as pipeline pressures increase. They return to their original diameter when the line is depressurized—as long as they are not stretched too much, thus exceeding their *elastic limit*.

Liquid molecules are always in contact with their neighbors. Compressing them requires effort since it involves molecular forces. In contrast, gas molecules at normal pressures have relatively large spaces between them and their neighbors. The gas molecules literally fly around knocking into each other. Compressing them only requires reducing the space between them.

Compressibility is the measure of how much work it takes to force a given mass into a smaller space. Every material has a specific *bulk modulus*, which is defined as:

$$\text{Bulk modulus} = \text{Change in pressure} / \text{Change in volume} / \text{Volume}$$

When calculating bulk modulus, pressure is expressed in terms of pounds per square inch, while volume is in terms of barrels or cubic feet. The volume dimensions cancel each other out in the calculation, so the units of bulk modulus become psi. The bulk modulus of water is about 312,000 psi, gasoline is about 190,000 psi, and steel is about 29,000,000 psi. Without going into any more details, these values show, not surprisingly, that more force is required to compress steel than water. Gasoline compresses more than water at the same pressure.

Why gases behave that way

About the time Newton made his intellectual breakthroughs in motion and gravity, Robert Boyle (1627–1691) earned the title of “Father of Modern Chemistry.” In 1662 he discovered rules of gas behavior that came to be known as Boyle’s Law. A century later, Jacques Charles (1746–1823) added to the knowledge about gases in 1787 with his own gas laws.

Joseph Louis Gay-Lussac (1778–1850) added a third law around 1801 to complete the picture. These three remarkable and universal relationships apply not just to some gases, but to all gases. They do, however, have a caveat: the gas must be an ideal gas. (Definitions of an ideal gas are somewhat pedantic. For example: an ideal gas is one that obeys the Ideal Gas Law and the Ideal Gas Law describes the pressure, temperature, and volumes of an ideal gas.) Since no gas is ideal, a correction factor is needed, which is called the Z factor. (Physicists denote it as *n*.) It accounts for the attraction and repulsion occurring between the gas atoms, causing them not to always obey the Ideal Gas Law. Since attraction and repulsion partly depend upon how close the atoms are packed together, the Z factor varies according to the pressure.

Where P, V, and T are the absolute pressure, volume, and temperature of a gas, Boyle’s Law says:

$$V_1/V_2 = P_2/P_1$$

That is, the change in the volume of a gas is inversely proportional to the change in its pressure, and vice versa. For the same amount of gas, raising the pressure decreases the volume as long as the temperature stays constant.

Then along came Charles' Law, which says:

$$V_1/V_2 = T_1/T_2$$

That is, the change in volume of a gas is proportional to the change in its temperature. For the same amount of gas, raising the temperature raises the volume, as long as the pressure remains constant.

Finally, Gay-Lussac's Law says:

$$P_1/P_2 = T_1/T_2$$

That is, for a given volume of gas, the temperature will vary in proportion to the pressure. For the same amount of gas, raising the temperature raises the pressure as long as the volume remains constant.

The important thing to remember about these laws is that pressures, temperatures, and volumes of any gas are intimately and rigorously related to each other. These three equations, along with the Z factor, are combined to produce *equations of state*. Equations of state are aimed at modeling and predicting how the three factors interrelate in specific applications. They are important during pipeline design and engineering, and for pipeline operations and leak detection modeling.

There is a practical operating point to remember about compressibility. As fluids are compressed, they absorb potential (pressure) energy. Their temperatures rise, and they can lose heat to their environment. As they decompress, they release this potential energy in the form of kinetic energy, and absorb heat. Oil, being practically noncompressible, cannot absorb very much potential energy (and does not release much heat energy). When a molecule of oil bumps against its neighbor, the neighbor quickly bumps against its neighbor, sending a pressure wave down the line. This phenomenon causes "water hammer" in home water systems. Gas, being fairly compressible, readily absorbs and dampens pressure waves.

The compressibility of gas makes it more forgiving of pressure surges. However, as in the balloon example, when gas lines leak, they can release a tremendous amount of potential energy very quickly. Such leaks can tear pipes and throw soil and debris, and they create a distinctive roar. Again, compressibility is one of the key differences between gas and liquids. (This is a statement that will be repeated frequently throughout this text.)

So, these four hydraulic properties—density, viscosity, vapor pressure, and compressibility—are fundamental to the design and operations of natural gas and oil pipelines. Equations of state, mentioned earlier, use these properties

to predict fluid behavior. Literally thousands of charts and graphs have been developed through calculations and experimentation to represent fluid behavior over the range of conditions pipelines encounter. The next section discusses how these properties are used to analyze, predict, and control pipeline operations.

Hydraulics

Hydraulics is the engineering approach to fluid mechanics. In the 1860s, practical entrepreneurs built small and short pipelines. The hydraulic principles had been discovered well before the beginning of the gas and oil pipeline era, but early pipeline builders and operators were generally technologically challenged. Much of their engineering acumen came from trial and error rather than formal technical training. In the early part of the 20th century, practical experimentation merged with theory and empirical research. Nowadays, pipeline hydraulics mixes theory, experimentation, and practical experience.

Basic Flow Principles and Equations

Most of what needs to be known about hydraulics comes from the laws of thermodynamics and Bernoulli's Principle.

The First Law of Thermodynamics

This principle is also commonly called the Law of Conservation of Mass and Energy. It states that matter or its energy equivalent cannot be created or destroyed. It can only remain as it is or change from one form to another. This notion had been around for some time when, in mid-1800s, James Prescott Joule (1818–1889) demonstrated the law through a series of experiments. (Thus the unit of energy in the metric system is called the joule.)

The First Law is fundamental to pipeline hydraulics. The force of compressors and pumps puts energy into fluids, pushing them along or uphill against the force of gravity. Friction converts part of that energy to heat energy as the fluids move through the pipe. When fluids run from the top of the hill to the bottom, the force of gravity helps pull them down. Keeping track of these energy flows allows pipeline engineers to design and operate pipelines.

Bernoulli's equation

Another critical law regarding the behavior of fluids is Bernoulli's Principle. In the 18th century, while trying to determine how to measure blood pressure, Daniel Bernoulli (1700–1782) inserted a straw into a pipe. He noted that the height to which the liquid in the straw rose was directly related to the speed of the fluid in the pipe. With faster flow, the liquid level in the straw dropped; with slower flow, it rose. The principle has broad application, especially to pipelines. After more experimentation and analysis, Bernoulli hatched the relationships thereafter known as the Bernoulli Principle. In its purest form, it states:

$$\text{Static pressure} + \text{Dynamic pressure} = \text{Constant}$$

Static pressure is the potential energy (pressure) exerted at the bottom of a standing column of fluid. Dynamic pressure is the kinetic energy of the fluid, or the energy it has because it is moving. The amount of this energy depends on the velocity and density of the fluid.

Figure 3–6 demonstrates Bernoulli's Principle. The lower velocity of flow in sections A and C results in lower dynamic pressure than in section B. Thus the static pressure (as measured by the liquid in the vertical section of pipe) is higher in sections A and C than section B. Note the velocities are different, but the flow rates in mass per unit time are the same in each section.

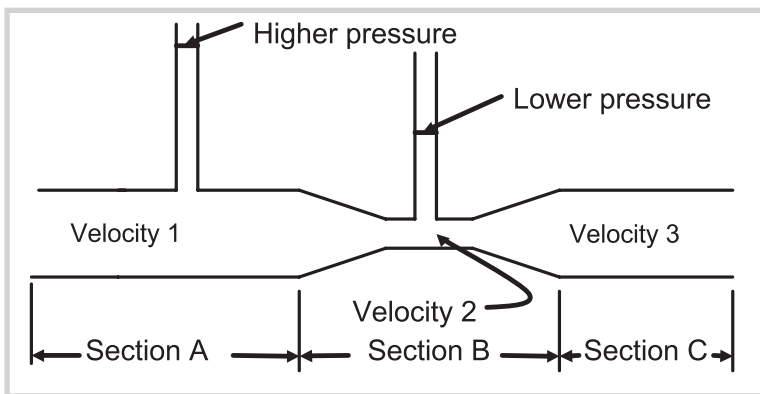


Fig. 3–6. Bernoulli's Principle. $\text{Velocity } 1 = \text{velocity } 3$; $\text{velocity } 2 > \text{velocity } 1$.

Based on this principle, Bernoulli developed several equations to explain the behavior and flow of ideal fluids in ideal situations. These equations became the basis of more practical equations developed over time and through experience. Curiously, as experience accumulated over the last 100 years,

engineers found some equations are more convenient for predicting results for larger diameter pipe. Others are more convenient for smaller diameter pipe, while some are unique to the fluids. Not much space in this book is devoted to flow equations, but it is important to know a bit about:

- Flow characteristics
- Friction loss
- Elevation loss (or gain)
- Flow rates

Flow characteristics

Fluid flow through pipelines is either laminar, transitional turbulent, or fully turbulent. Knowing which of these is happening is important, because it affects pressure loss calculations.

Laminar flow is pleasantly smooth, streamlined flow. Each molecule moves along in a straight line. It is pushed by the molecule behind and pushes the molecule ahead, never bothering its neighbor to the left, right, top, or bottom. It is called laminar because the molecules move in layers over each other. Imagine a small brook with the water peacefully babbling along. When the water looks smooth and clear over the rocks it is in laminar flow. In laminar flow, the layers move at different speeds. Those near the center of the pipe moving the fastest, and those at the wall (theoretically) are not moving at all (fig. 3-7).

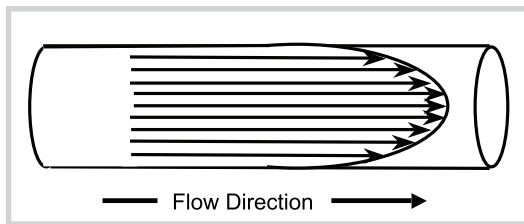


Fig. 3-7. Laminar flow profile

Ironically, the benignly sounding laminar flow also causes much more mixing at the interface between fluids with different properties, a critical consideration for oil pipelines.

In turbulent flow, the molecules bounce around, moving laterally (perpendicular to the flow) as well as longitudinally along the pipe (fig. 3-8).

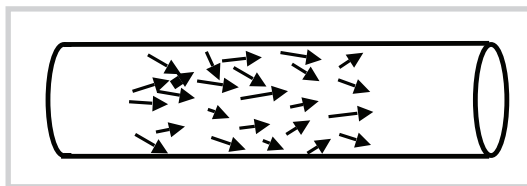


Fig. 3–8. Turbulent flow profile

The lateral movement is caused by the molecules colliding with the sides of the pipe and with each other. The inside of steel pipe may look smooth, but to molecules, even a little unevenness makes a big difference. If shoved against the side by their neighbors, they bounce off the wall. Look at a flag flapping in the wind. On a windy day, the velocity of the air moving over the two sides of the flag is fast enough that it is in turbulent flow, causing eddy currents and consequently flapping.

Sir Osborne Reynolds (1842–1912) is widely credited with discovering laminar flow around 1880. He injected dye into a stream of fluid and found that at lower flow rates, the flow remained streamlined. At higher velocities the flow went from streamlined to turbulent. In 1882 he published a paper regarding this topic and introduced a number called, not surprisingly, the Reynolds number. The size of the Reynolds number predicts whether flow is laminar or fully turbulent. Reynolds numbers appear prominently in pressure loss equations.

Friction loss

For long-distance pipelines, friction loss is the major factor requiring pump or compressor stations. Friction loss is caused by the molecules rubbing against each other and against the pipe wall. It is dictated by several factors:

- Viscosity
- Density
- Velocity (a function of pipe diameter and flow rate)
- Pipe length
- Roughness of the inside of the pipe

Most pipelines operate with turbulent flow. The unpredictable nature of the molecules bouncing around in turbulent flow makes modeling the behavior of individual molecules difficult. But modeling the aggregate behavior of all the molecules is easier. Over the years, hydraulic engineers

have devised short cuts to calculate friction and pressure loss. (As in the garden hose examples, friction loss is energy loss and that translates to pressure loss.) Charts and graphs, based on fine-tuned experimentation, have given practical and acceptable results. All have used the factors mentioned. Computer models, using the same information as the charts and graphs, also have improved modeling speed and accuracy.

There is an important difference between natural gas and liquids when it comes to friction loss, which depends on viscosity, density, and velocity. For a liquid, each of these properties is essentially constant in the same pipeline at the same temperature with the same fluid. So pressure friction loss per mile is the same for each mile.

This is not the case for natural gas. As the natural gas moves along the line, pressure is eaten up by friction. The natural gas farther downstream of the compressor is at a lower pressure than the gas near the compressor (assuming the same elevation). Since natural gas is compressible, this loss of pressure allows the natural gas to expand. This in turn decreases density, increases velocity, and therefore increases friction loss. Natural gas pipeline modelers take care to include this phenomenon as they calculate pressure loss due to friction.

Elevation loss (or gain)

As mentioned earlier, pressure declines as fluids move uphill and increases as they flow downhill. But how much will they decline or increase? That depends on the weight of the fluid and the height of the hill. The heavier the fluid, the more pressure it takes to push it up the hill. Higher hills require more pressure than lower ones.

Another water example is a cube of water with dimensions of 1 ft on all sides, which weighs 62.4 lb (fig. 3–9).

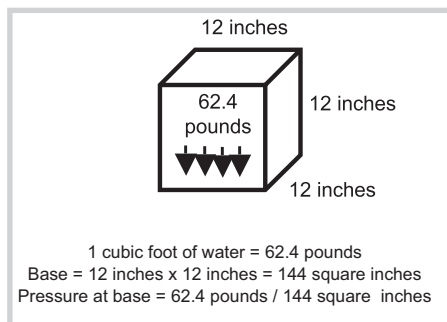


Fig. 3–9. Pressure from a cube of water

The entire 62.4 lb, as a column, is pushing down on a 12-in. \times 12-in. square (144 in.²).

The pressure at the bottom of the cube is:

$$62.4 \text{ lb}/144 \text{ in.}^2 = 0.433 \text{ lb/in.}^2$$

If the 12-in. square column of water is 100 ft tall, the pressure at the bottom is:

$$0.433 \text{ psi/ft} \times 100 \text{ ft} = 43.3 \text{ psi}$$

The pressure at the bottom of the column is 43.3 psi greater than the pressure at the top of the column.

This is where expressing density as specific gravity really comes in handy. As mentioned, gasoline has a specific gravity of 0.69. The pressure at the bottom of a column (or pipeline) of gasoline 100 ft high is:

$$43.3 \text{ psi} \times 0.69 = 29.88 \text{ psi}$$

Diesel fuel is more dense than gasoline (it has a higher specific gravity and a lower API gravity). It requires more pressure to pump it up the same hill. Both gasoline and diesel are less dense than water (fig. 3–10).

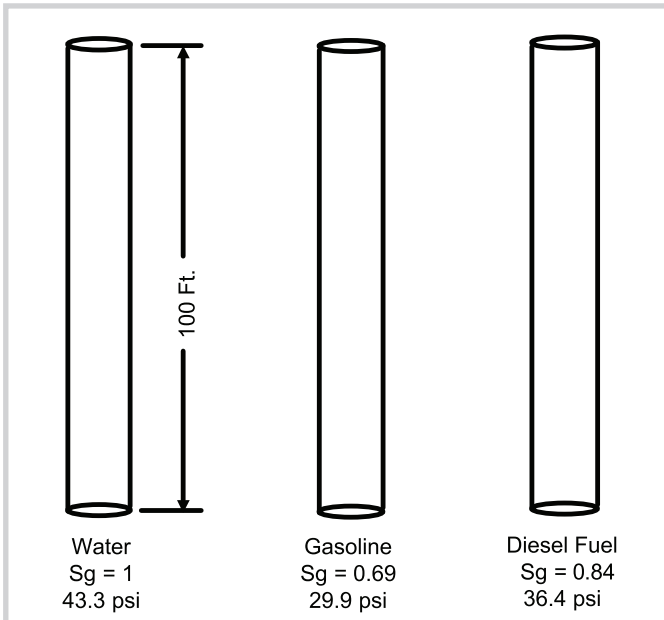


Fig. 3–10. Pressures at the bottom of columns of fluids. More dense fluids exert more pressure.

Gas works the same way but with an important difference. Remember, liquids are essentially not compressible, so their density does not depend (very much) on pressure. Each successive cubic foot of water up the column weighs the same as the one under it. Again, not so for gas. Since gas is compressible, each successive cubic foot of gas up the column is less dense than the one below. It weighs less than the one underneath. How this situation is handled is covered in chapter 5.

Pressure caused by gravity depends on the height of the column of fluid, not the geometry of the column (fig. 3–11).

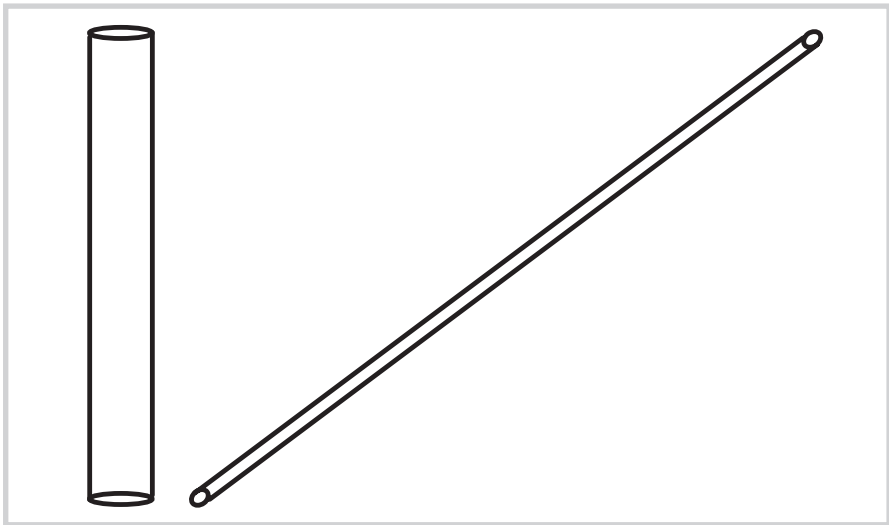


Fig. 3–11. Pressure at the bottom of two pipes. Pressure due to gravity at the bottom of both pipes is the same. Total force at the bottom (pressure \times area) is greater for the larger diameter pipe because of greater area of the base.

It may seem the pressure should be higher at the bottom of the slanted pipe on the left because there is a longer column, but it is the same at the bottom of both pipes. The force exerted is greater for the pipe on the left because the pressure is exerted over a greater area at the bottom. However the force per square inch, the pressure, remains the same in both pipes.

Another way to measure pressure is *feet of head*, or the height in feet of a column of fluid that produces the amount of pressure. In figure 3–10, 43.3 psi is equal to 100 ft of head of water, and 29.9 psi is equal to 100 ft of head of gasoline. This measure is used for oil lines but not for gas lines and is covered more in chapter 4.

Flow rates and capacities

The flow rate of a pipeline is simply the volume that can or does flow past a given point in a set amount of time. The generic flow rate equation is:

$$\text{Mass} = \text{Density} \times \text{Area} \times \text{Velocity} \times \text{Time}$$

The amount of mass going past a point in a given amount of time is equal to the density of the material times the cross-sectional area, times the velocity the material is traveling, times the amount of time. There are many different ways flow is measured, but each is a form of this equation. Mass is often converted to volume.

Oil flow rates are normally measured in barrels per hour (bbl/hr, or bph), cubic meters per hour (m³/hr), or tonnes per hour (t/hr). The flow rates in gas lines are measured in cubic feet or cubic meters per hour.

Since liquids are essentially incompressible over a reasonable time, the flow into an oil line should equal the flow out; if not, there is a problem. Again, this is not true for gas. A gas line can be filled with gas at low pressure, and more can be forced into it all day long, up to its maximum operating pressure, with no gas coming out. The amount it takes to “fill up” a gas line is called *line pack*.

Flow rates come in two varieties: the current flow rate and the ultimate capacity. Natural gas lines serving cities must have sufficient capacity to serve the town on the coldest day of winter, as well as the local gas-fired power plants on the hottest day of summer. They normally flow well below their ultimate capacity in the off-season.

The input into gas lines is more uniform than the output. Gas wells produce into gas lines at a relatively constant rate. At the other end, consumers generally use more gas during the day than at night. Over a 24-hr period, demand on gas pipelines can go from trough to peak. Gas storage and line pack are used to help level off this imbalance. Weekly and seasonal demands can vary 50%, and storage and compression capacity usually handle these variations.

Oil lines operate at more constant flow rates, since oil is relatively easy to store in inventory in tanks at each end and along the way.

Conclusion

This chapter discussed physics of fluid flow and the hydraulic properties of hydrocarbon fluids, and introduced how these concepts are used. The next three chapters, on oil pipeline operations, gas pipeline operations, and chemical pipeline operations, apply this knowledge. Oil and gas are similar in many ways, but the differences are important enough to warrant covering them in two different chapters. Chemical pipeline operations fall somewhere in between. This will cover some engaging stuff!

4

Oil Pipeline Operations

Energy and persistence conquer all things.

—Benjamin Franklin (1706–1790)

Oil pipelines move millions of barrels of crude oil and refined products each day all over the world. In the United States, they move 17% of all freight, dry or wet, at 2% of the total freight bill.¹ But oil pipelines differ from gas pipelines, as established in the last two chapters, in ways profoundly important to operations. This chapter deals only with oil pipeline operations—both crude oil and refined products lines. It covers local field operations and central control room operations. It extends the hydraulic concepts to oil operations and finishes with the sometimes distasteful subject of abnormal operations.

Crude Oil Pipelines—a Brief Review

Crude oil pipelines gather the crude from wells and move it to refineries, trade centers, or export ports, and from trade centers and import ports to refineries. The ultimate destination is always a refinery. Crude oil pipelines are comprised of gathering lines and main lines. The names do not always indicate the size. Some gathering lines in high-production areas are larger than some main lines in smaller and older production areas. But one crude oil pipeline operates more or less the same as the next.

Many pipelines receive crude oils of differing qualities along their routes. These crude oils are either commingled in the line or segregated and batched. This will depend on the costs of segregation and the specific crude oil's value in the refining business. Some refineries are designed to process only specific qualities of crude oil. Inadvertently running other types can severely disrupt operations or damage the equipment. Those refineries may demand specifically segregated crude oil be delivered to them. Other refineries can tolerate a mixture of various quality crude oils. In those cases, pipelines may track the qualities of the various crude oils mixed in the line and delivered using *quality banks*. This complex accounting procedure allows the pipelines to give shippers monetary adjustments for quality disparities between receipts and deliveries. Quality banks are discussed in more detail later in this chapter.

Refined Products Lines—a Brief Review

Products lines move refined products such as gasoline, jet fuel, and diesel fuel from refineries, trade centers, or seaport to markets. Such end points could be truck-loading facilities, trade centers, and export facilities. Most operate as batched systems, but some are dedicated to a specific product. *Dedicated lines* move only one product, such as jet fuel going to airports or fuel going to power plants. Most of them are just a few miles long and originate from tanks at an oil products terminal or seaport. They simply complete the journey that started on a multiproduct system.

The quality of products, even those with similar names, adds a level of complexity to products pipelines. For example, gasoline generally comes in at least three grades: regular, midgrade, and premium. In some locales, for each of the three grades, environmental regulations require different specifications at points along the route of the line. This forces the pipeline to manage six, nine, or even more grades, each with its own specifications. On the one hand, these regulations require more tanks to handle the different products and increase the complexity and cost of operations. On the other hand, batches of any single grade with the same quality specifications from different refiners are often commingled into a single batch of fungible products. This simplifies operations and improves efficiency.

Field Operations to Central Control Room

Pipeline operations and maintenance were once performed exclusively in the field. Accounting and record keeping may have been conducted at a central administrative office. However, almost everything else, such as starting and stopping pumps, opening and closing valves, reading meters, servicing equipment, and completing repairs had to be performed manually along the line. The operations and maintenance functions largely blurred. Many times the same people did both. As communication technology and automation evolved, so did the concept of remote operations. Remote operations allow workers to perform operating functions from a location removed from the physical location of the equipment.

Some operations are still carried out in field locations, but in recent decades, control operations have been largely concentrated in a central control room. Maintenance functions, out of necessity, continue to be carried out in the field at the equipment's location. This has led to the present distinction between operations and maintenance:

- Operations keep the fluids flowing in the line.
- Maintenance keeps the line and equipment in good operating condition.

This book covers operations and maintenance in separate chapters. They are different functions, even if performed by the same person or organization. Today operations and maintenance activities mostly vary by the level of automation, not by the physical activity. Starting a compressor in Russia is the same as starting a compressor in Indonesia. This chapter and the next three chapters are concerned with operations. Chapter 9 covers maintenance.

Crude oil receipt and delivery field operations

Crude oil, when it comes from the ground, brings with it some trash, such as sand, as well as water and gases. Production streams are generally routed through processing equipment, removing most of the solid materials and the water, and separating the oil and natural gas. This chapter deals with oil's subsequent journey.

After leaving the processing equipment, crude oil enters *lease tanks*. Receiving pipelines publish shipper guidelines listing crude oil quality specifications. The processing equipment should ensure the crude oil is of sufficient

quality to be *merchantable*. Often the crude oil waits in the tank until a gauger checks its quality. Other times it enters the pipeline through automated equipment.

In manual operations, gaugers measure and test the oil to determine if it meets or exceeds the pipeline's specifications. The measurement procedure works a lot like using a dipstick to check the oil in an engine. The gauger climbs to the top of the tank, opens a hatch, and drops the end of a special tape measure to the bottom (fig. 4-1).



Fig. 4-1. Gauging a crude oil tank. The gauger reads the tape, much like reading the dipstick in a car.

The gauger withdraws the tape and reads the height of the liquid. Every tank has been previously *strapped*. When it was built, careful measurements were taken to determine the volume corresponding to the heights. This measurement was codified in a table or, these days, stored in a computer. The gauger either looks up the measured height in a book or keys it into the computer to find the volume in the tank. This determines *gross volume* (uncorrected) and is only the first step.

The gauger then checks the temperature of the crude oil and takes a sample. This sample is *ground out* using a centrifuge to force the heavier sediment and water to the bottom. This test determines the amount of *basic sediment and water* (BS&W) present in the oil—one of the pipeline’s specifications. The gauger corrects the volume to 60°F using tables in the manual. The amount of BS&W is subtracted, yielding the total corrected amount of merchantable oil in the tank. If the tank has too much BS&W, the gauger may reject the tank, requiring the crude oil owner to clean the tank or run the crude oil through the processing equipment again.

If the quality is acceptable, the gauger *runs the tank*, either by opening valves, allowing gravity flow, or by starting a pump to move the oil. The pump is connected to a timer, flow switch, or float switch that will stop the flow at the appropriate point. The gauger then goes on to another tank or tank battery while the oil drains.

Later the gauger returns to measure the crude oil remaining in the tank. The difference between the opening and closing gauges (both adjusted for BS&W and corrected to 60°F) is the amount of crude oil that went into the line. The gauger uses all this information to write a receipt ticket. Copies will go to the producer, the pipeline, and sometimes other interested parties, such as a government agency or other royalty owners. (One party’s delivery is another’s receipt. In this case, the producer is the deliverer and the pipeline is the recipient. So the gauger writes out a receipt ticket on behalf of the pipeline.)

For automatic operations, the oil is measured and tested by *lease automatic custody transfer* (LACT, or sometimes ACT) units. ACTs are skid mounted and built to be easily installed and later moved to a new location as production falls (fig. 4–2).

The ACT measures the crude and takes small samples on a set schedule. It also adjusts for temperature or has a chart that records the temperature for later calculations. From time to time a gauger comes by, takes the sample, and grinds it out to determine BS&W. The gauger uses the temperature and BS&W information to write a receipt ticket, just as in the case of manual operations.

Sometimes the amount of crude being produced at a location does not justify the capital costs of building a pipeline to the lease. In these cases, the crude is picked up by trucks and hauled to a central area connected to a pipeline, where it is delivered into tanks and held until the pipeline is ready to move it out. The measurement process of the truck movement at both ends works the same.

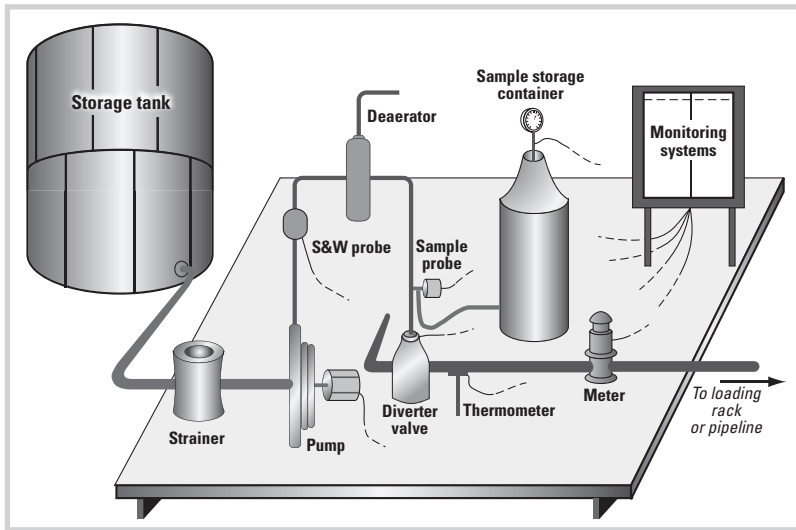


Fig. 4–2. Automatic custody transfer unit

Crude oil delivery operations work the same way as receipt operations. The crude oil is delivered to a refinery or another pipeline or tank farm. The same measurements, sampling, and ticketing apply. Typically, the volumes are larger, and a mainline pipeline meter is used rather than manual measurements or ACTs.

Refined products receipt and delivery field operations

Refined products start their journey at refineries and move to other pipelines or to truck-loading terminals or bulk plants for further distribution by truck, rail, or dedicated pipeline. The mechanics of receipt and delivery operations for products are similar to crude oil (except for correcting for BS&W). In addition, products pipelines establish and closely monitor numerous other quality specifications for the products, including:

- Gravity
- Octane number
- Cetane number
- Vapor pressure
- Flash point
- Color
- Sulfur content
- Particulates content

If any batches do not meet specifications, the shipper must correct the situation before the pipeline accepts the products. Sometimes testing is done as the product is received by the pipeline. At other times, especially for sensitive products such as jet fuel, the pipeline may insist on testing the contents of an entire tank before accepting any of the product from that tank.

At their destination, products are delivered from the pipeline into a delivery facility. As they leave the pipeline, they are tested again to insure the pipeline has maintained product quality while in its custody. Depending on the level of automation at the delivery facility, either operators at the site or central control room operators position valves to direct the products to the correct tanks. They will switch between meters and sample and test the quality of material delivered. Receipt and delivery tickets are written at the receiving and delivering locations to account for the products.

Central Control Room Operations

In the 1860s, the OTA provided the first real-time, end-to-end communications system along a pipeline. It built a telegraph along the route of a 2-in. wrought iron pipeline over a 6-mi track from an oil field to the railroad station at Oil Creek, Pennsylvania. The telegraph line was used to communicate the complex bookkeeping of multiple shippers. This innovation began the trend toward central control room operations.

As technology developed, the telephone complemented the telegraph, and motors replaced the manual handles on valves. Dispatchers sat in central control rooms and communicated by phone (or telegraph). Still, operations continued to be people-intensive. Operators located in the field told the dispatchers what was happening. The dispatchers then told the operators when to open or close valves, start and stop pumps and engines, read meters, and perform other operations. Dispatchers were like orchestra conductors, telling the operators what to do but depending on the operators to do it.

As automation took over, central control rooms became the nerve centers of the pipelines, and the roles of dispatchers and operators merged into the controller's job. Now controllers read conditions from displays, decide what to do, and send out digital commands to remote pumps, valves, and the like (fig. 4-3). They depend heavily on communications technology and electronic controls to do the work formerly done manually by operators and over the telephone by dispatchers. And from down the hall, the schedulers feed them the plans to implement.



Fig. 4–3. Oil pipeline controller at work. Each display shows different aspects of pipeline operation. (Courtesy Explorer Pipeline Company)

The functions of the central control room include:

- Planning and scheduling operations
 - Forecasting available capacity
 - Receiving shipper nominations
 - Developing pump, receipt, and delivery schedules
 - Making adjustments to the plans as needed
 - Communicating the plans and adjustments

- Monitoring and controlling the pipeline
 - Understanding the operating scenario
 - Operating equipment (pumps, valves, motors, and meters, etc.)
 - Monitoring line and equipment parameters
 - Making routine adjustments
 - Communicating line operations
 - Responding to calls from third parties

- Responding to and correcting abnormal operations
 - Detecting abnormal operations and conditions
 - Responding to abnormal and emergency situations
 - Keeping all parties informed as needed
 - Dealing with nonroutine communications
- Maintaining the control equipment

Planning and scheduling operations

Operations planning and scheduling includes all the steps from very detailed planning of multiproduct, multishipper refined products operations to limited overview for commingled crude oil lines. Planning and scheduling tools vary from simple paper systems to sophisticated computer modeling. No matter the approach or tool, the objective is the same—safe, efficient, on-time, low-cost, high-quality movement of the oil.

Batching. In multiproduct lines, the different grades of products move end to end in successive batches. Figure 4–4 shows the order of a typical batch sequence in a refined products line.

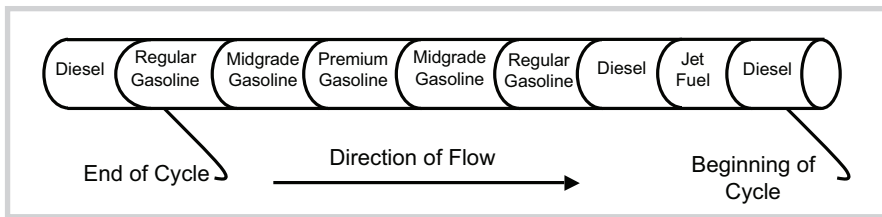


Fig. 4–4. Typical refined product batch sequence. Similar products follow each other in sequential order.

Most refined products pipelines begin a new cycle on a set time frame, such as every 5, 7, or 10 days.

Crude oil lines that operate as batched systems are a bit less formal but follow a set sequence when possible. The most similar grades are grouped next to each other to minimize contamination and downgrading (fig. 4–5).

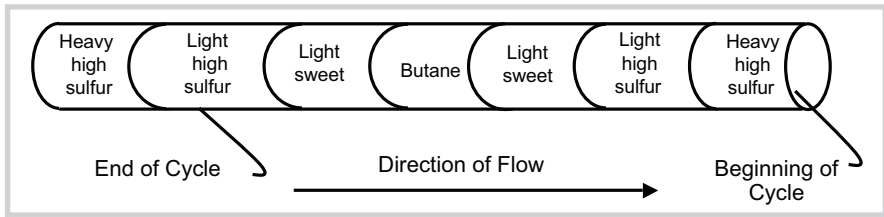


Fig. 4–5. Typical crude oil batch sequence

Some, but not many, crude oil lines move butane as a segregated batch. When they can, they buffer either side of the butane with small quantities of condensate as a way to reduce mixing the butane and the crude oil. Butane is sometimes pumped directly into the crude as a diluent. However, crude oil purchasers want to receive the quality they pay for and are not happy when producers spuriously add lower valued materials, such as butane, to their crude oil. It often falls to the pipeline company to police quality for the purchasers.

Where one product or type of crude butts up against the next, some mixing inevitably and regrettably occurs. This volume of mixed fluids is called *transmix* or *interface material*, a subject dealt with later in this chapter.

The scheduler's role

Toward the end of the month, pipeline schedulers receive *nominations* from shippers for the next month. The nominations define how much of each type of oil the shippers want to move. Schedulers add up all shipper nominations to arrive at a total. They communicate with maintenance people to understand any maintenance work planned for the line that may reduce the effective throughput capability.

The projected available capacity for the month is compared to total nominations to insure all volume can be handled. If the nominations can be accommodated, the scheduler calculates how much should be moved each day. If the line is overnominated (does not have enough capacity to handle the nominations), the bad news goes back to the shippers. They may elect to reduce their nominations. If the revised nominations still exceed capacity, the pipeline institutes a prorated delivery plan. Shippers are allowed to move a reduced amount consistent with available capacity. Each pipeline has its own method of allocating capacity in prorated situations.

If a scheduler is comfortable that there is enough capacity to handle demand, the shippers' nominations are divided into amounts consistent with the length of the cycles, and an hour-by-hour schedule is built. (The scheduler of a pipeline operating on a 10-day cycle divides the monthly nominations into thirds and plans for one-third in each cycle.) The schedule is then transmitted either in paper or via electronic format to pipeline control room operators and shippers.

The scheduler's work does not end there. Periodically over the month (it varies by pipeline and situation), the schedule is updated to reflect reality as it unfolds. Refineries experience problems, reducing the amount of crude oil they consume or the amount of refined products they produce. Operating or maintenance problems arise, changing pipeline throughput capacity. Product demand at the terminal end is higher or lower than forecasted. A scheduler takes all these changes into consideration and makes adjustments to the schedule to keep from running out or delivering too much. Immediate adjustments frequently need to be made on weekends and during graveyard or swing shifts, so scheduling is a continuous job.

Transit time. As part of dealing with line capacity and demands, a scheduler must also consider *transit time*, the interval from the time the oil is put into the line until it arrives at the destination. Transit times can be on the order of a day or two for high-volume lines delivering to close locations or several weeks for low-volume lines delivering to distant locations. Colonial Pipeline serving the U.S. East Coast from the U.S. Gulf Coast is about 1,500 mi long. It has a transit time to the end of 18–21 days, depending on how much product is demanded.

For example, one could consider a location 1,000 mi from the input point, projected to need 5,000 bpd of regular gasoline, with a transit time of 10 days. If demand suddenly rises to 7,000 bpd or falls to 4,000 bpd, the oil destined to arrive 10 days later is just entering the line. It may be too little or too much to supply the demand. The answer might seem to be to overschedule, or err on the high side, to assure meeting demand, because running out is not good.

But could having too much be bad? A scheduler could *lock up* the line. For example, a scheduler may call for more of a certain grade into the line than can be received along the line. In that case (fig. 4–6) the controller will eventually have to either slow down or stop the line, which throws the deliveries to all other points into confusion. Then shortages occur at other destinations for other products.

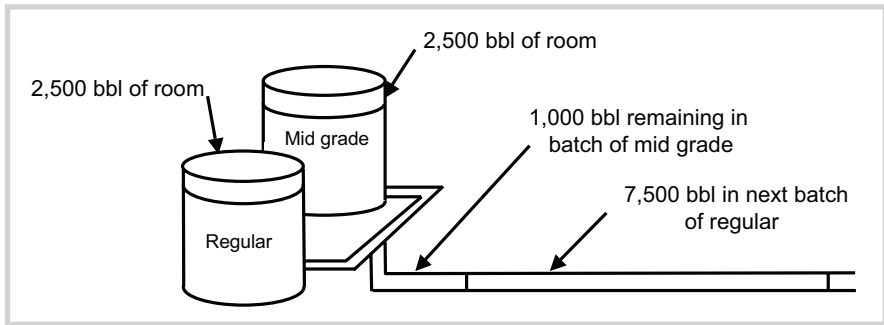


Fig. 4–6. Locking up the line. There is enough room in the midgrade tank, but the regular tank only has 2,500 bbl of room to hold the 7,500-bbl batch headed its way.

A few schedulers liken their jobs to distilling fine whiskey, trying to guess what the market will be in 7 to 10 years when it has aged properly. But most of them take a more sober and serious view of their challenge. In any event, scheduling is a constant juggling act.

The controller's role

Following a refined product batch from the refinery tank to the products terminal tank gives a good idea of the controller's job. For example, one could start with the end of the previous cycle that delivered regular gasoline. (Fig. 4–3 showed a batch sequence.) Figure 4–7 shows a simple pipeline layout with two refineries and two products terminals.

The batch of regular gasoline is being pumped from Refinery A's tanks. The controllers want to switch to pumping diesel fuel from Refinery B's tanks to begin a new cycle. They send electronic commands that open the valves on the diesel fuel tank at Refinery B and start the booster pump. (In a less-automated or more sovereign setup, the controllers would call the pumpers at Refinery B and ask them to open the valve and start the pump.)

Once flow starts from Refinery B, the controllers send commands to stop the booster pump at Refinery A and to close the regular gasoline valve at Refinery A. The controllers must perform these functions quickly to minimize mixing between the gasoline and diesel, but not so quickly that they starve the mainline pump station.

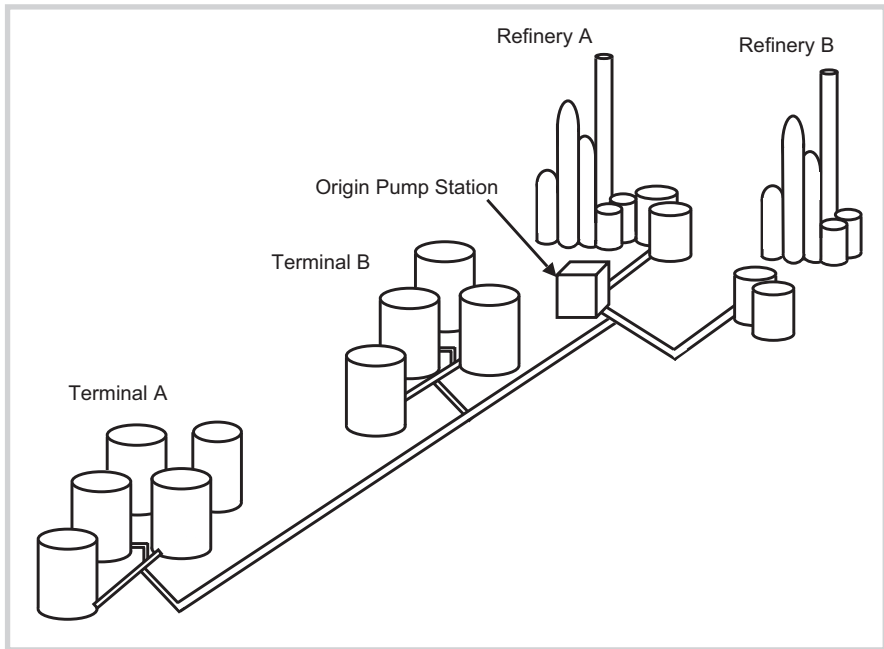


Fig. 4–7. Refinery to terminal tanks

However, controllers have to stop and consider another important issue: What was in the line between Refinery B and the pipeline station when they started the movement? Hopefully it was diesel. But how would it have gotten into the line if the last product pumped from Refinery B was gasoline?

For the answer, the controllers look at their orders. Earlier they knew the next product from Refinery B would be diesel fuel. So, as they finished pumping gasoline, they pushed it out with a little diesel fuel leaving the line between the refinery and the pipeline origination station filled with diesel. (They may do the same thing to the line from Refinery A to the origination pump station. This would ensure it is laid down with the right material when it is time to pump from Refinery A again.)

When the controllers start the present cycle, diesel, and not gasoline, is in the line between the refinery tank and the pump station. This illustrates how controllers must look ahead to make provisions for the right product to be in the line. How well controllers make the switch between products is a major determinant of how much interface they generate. It takes a special type of person to pay attention to all the details required to successfully control thousands of tons of liquid charging down the line.

Most oil pipelines have multiple pump stations. Many times not all the stations are needed. Sometimes stations are shut down and isolated from the pipeline, allowing the oil to flow past. When restarting a station that has been shut down, controllers need to know what product that station last pumped, because some of that product is still in the pump station. Perhaps gasoline is going past, and the pump station had been isolated with diesel fuel in the station piping. In this case, starting the station pumps the diesel fuel into the gasoline, contaminating it.

Following the batch down the line. For example, one could assume the diesel batch is 10,000 bbl, with 5,000 bbl destined for Terminal B and the balance to Terminal A. The controller tracks the interface between the gasoline and diesel as it moves down the line. The controller knows the amount of line fill between the origin pump station and Terminal B and knows how much of the batch has been pumped. Some pipeline companies continue to track the location of the interface with simple paper and pencil calculations, and some use sophisticated tracking software. Many use a *densitometer* or a *gravitometer*. Gravitometers are located at a known distance from the delivery location. They measure the different densities of gasoline and diesel as the stream goes by and display the differences on a screen in the control room.

When the outstation gravitometer (i.e., out from the destination) detects the gravity difference, the controllers know exactly how many barrels must be displaced for the interface to reach the delivery location (fig. 4–8).

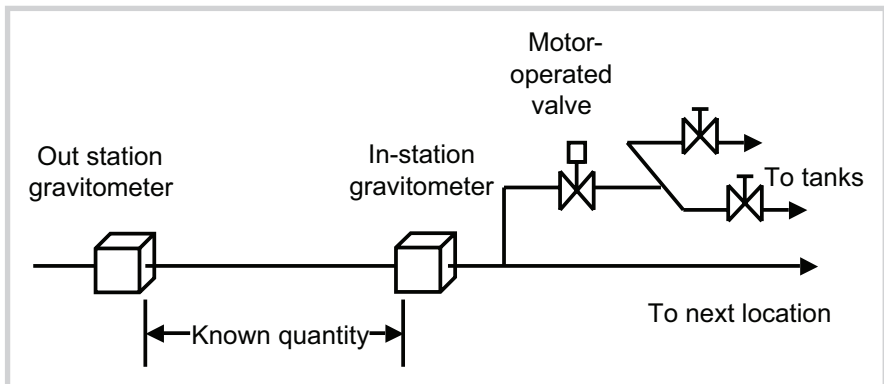


Fig. 4–8. Station gravitometers. The outstation gravitometer serves as a batch arrival “early warning.”

Based on pump rate, they calculate the time the interface will arrive. The in-station gravitometer allows the controller to confirm precisely when the interface arrives.

The product, in this case diesel, can be delivered into Terminal B back in figure 4–7 at full mainline rate or it can be *stripped* into the terminal. For a full line rate delivery, the entire stream is directed into the terminal, and the downstream line has to be shut down. Alternatively, a *strip* involves removing only part of the product as it goes by, allowing the downstream line to continue to run, and in this example continue to deliver into Terminal A. Line hydraulics, product needs, power costs, and personal preference all influence which of these delivery methods is used.

At delivery locations along the line, *heart cuts* are normally made. The interface is allowed to go well past the delivery location before the terminal starts receiving product. The receipt ends before the trailing interface arrives, taking the heart out of the batch, insuring quality integrity. Of course, the batch remaining in the pipeline gets “shorter” and slows down as product is delivered out.

At the delivery point, the lines from the pipeline to the various tanks need the same consideration as those at the refinery input end. They have to have the right product in the right lines to ensure product integrity.

Minimizing transmix. Note that Terminal A in figure 4–7 has one more tank than Terminal B. This tank receives the transmix. Transmix is normally pumped past intermediate terminals to the end of the line. Not all transmix goes into the transmix tank.

- The transmix from the gas to diesel interface does not meet quality specifications for either product and has to go in a transmix tank. From there it is transported, probably by truck or rail, to a reprocessor, who separates it into gasoline and diesel.
- The interface material between two grades of gasoline normally meets the quality specification for the lower grade and is simply added to that tank.
- Interface between regular and midgrade gasoline goes in the regular tank; between midgrade and premium, it goes into the midgrade tanks.
- Interface between diesel fuel and jet fuel goes into the diesel tank.

Making an overrun, that is, erring on the high side, of the cut from, say, midgrade to regular is not too big a deal. It simply results in more of the higher value product being downgraded a few cents per gallon. But mistakes in making cuts between diesel and gasoline can render an entire 100,000-bbl tank off spec. Gasoline in diesel can result in a dangerously low diesel flash point. Diesel in gasoline gives an end point too high for efficient combustion.

For this reason some pipelines still have a person physically at the receipt location to monitor the incoming product and decide when to make the switch between tanks. The person at the terminal samples the incoming stream, testing gravity and looking at its color to help get the timing right. As technology continues to improve, this additional testing is becoming unnecessary.

While this example uses products, crude oil batching is done in a very similar manner. The interface is more forgiving, since the crude oil is going to be processed in a refinery anyway.

Still, crude oil quality is very important, since each crude oil type has its own price and results in different refined product yields. For this reason, some crude oil lines have a quality bank, which product lines do not need. Quality banks (gravity and sulfur are the main ones) attempt to compensate shippers whose crude oil is downgraded from commingling as other types of crudes oils are pumped into the line.

Pipelines keep track of volumes and quality by shipper. Periodically they invoice those who input lower quality crude oil than the average of the stream inputs and pay those who put in higher quality crude oil. The reverse happens when the crude oil is taken out. Those who are delivered lower quality than the average are paid, and those receiving higher quality are invoiced. Quality banks require occasional renegotiation of the unit values of the adjustments as the market for crude oils of different qualities changes. The changes sometimes get contentious due to the different values refineries put on the various crude oils.

Hydraulic concepts—practical applications in mainline operations

This section puts the hydraulic concepts covered already into operating context. It also slips in a few new ideas.

Crude oil and refined products main lines, also called trunk lines, are the autobahns of oil pipelines. They have limited entry and exit points, and minimum batch sizes are required to enter. Main lines begin with origin pumping stations where pumps add energy in the form of pressure. Along the way, additional pumping stations boost the pressure to add back that which was eaten up by friction loss between the stations. Intermediate or booster stations are also needed to push oil up higher elevations. Crude oil or refined products enter the pipeline or are delivered out to various destinations along the route. An explanation of how this gets reflected and managed in the hydraulics is presented next.

Hydraulic gradient. As explained in chapter 3 concerning oil lines, friction loss per mile for the same liquid at the same flow rate and temperature in the same size line is constant. Figure 4–9 shows a hydraulic gradient for a main line with one pump station, pumping liquid across a flat terrain, with receipts into one tank 50 mi away. The origin station is pumping at 1,000 psi. The hydraulic gradient is the line sloping from the 1,000-psi mark to the tank. It represents the pressure at any mileage point along the line.

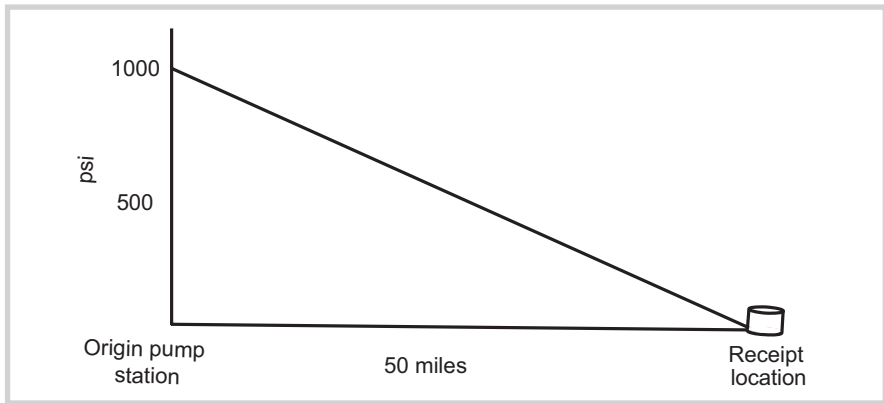


Fig. 4–9. Hydraulic gradient. The gradient's slope represents pressure loss per mile.

The slope of the hydraulic gradient represents the amount of pressure loss per mile. It is straight, since in this simple example, the same amount of pressure is lost to friction each mile. In this example, the pressure loss per mile is almost 20 psi ($1,000 \text{ psi}/50 \text{ mi} = 20 \text{ psi/mi}$).

Notice the pressure at the tank is not quite zero. If the tank were completely empty, the pressure would be zero, but in this case, there is some oil in the tank. Thus the incoming oil has to exert enough pressure to push the oil already in the tank out of its way (in this case up). Suppose the oil in the tank is diesel fuel with a specific gravity of 0.82 and the tank has 20 ft of oil. The pressure needed to get into the tank can be calculated based on the material presented in chapter 3:

$$\begin{aligned} \text{Pressure of equivalent height of water} &\times \text{Specific gravity} \\ &= \text{Pressure of diesel fuel} \end{aligned}$$

$$0.433 \text{ psi} \times 20 \text{ ft} \times 0.82 = 7.10 \text{ psi}$$

The pressure needed to enter the tank is often expressed in *feet of head*; in this case, it is 20 ft of head in diesel.

What happens as the tank fills up? The column of liquid in the tank gets taller, requiring more pressure for the diesel fuel to push its way into the tank. But the origin pump is still discharging at only 1,000 psi. So the flow rate slows slightly, reducing the friction loss.

What happens to the gradient if an offtake or input point is added to figure 4–9 between the origin station and the receipt station? Figure 4–10 shows the hydraulic gradient for this situation, and figure 4–11 shows the piping.

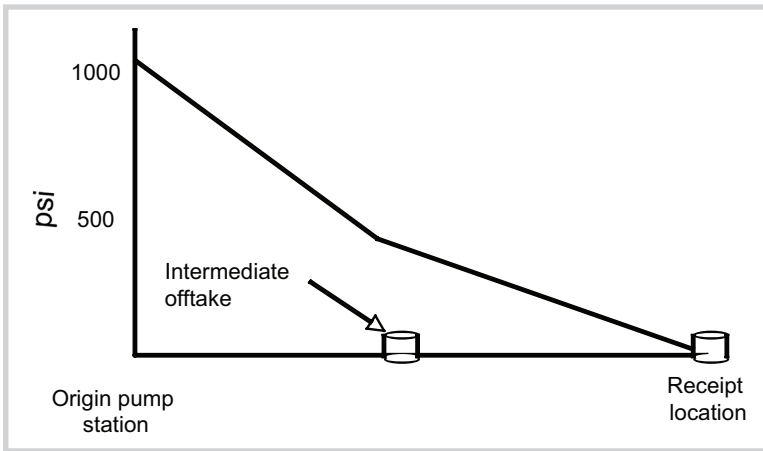


Fig. 4–10. Hydraulic gradient with an intermediate offtake point

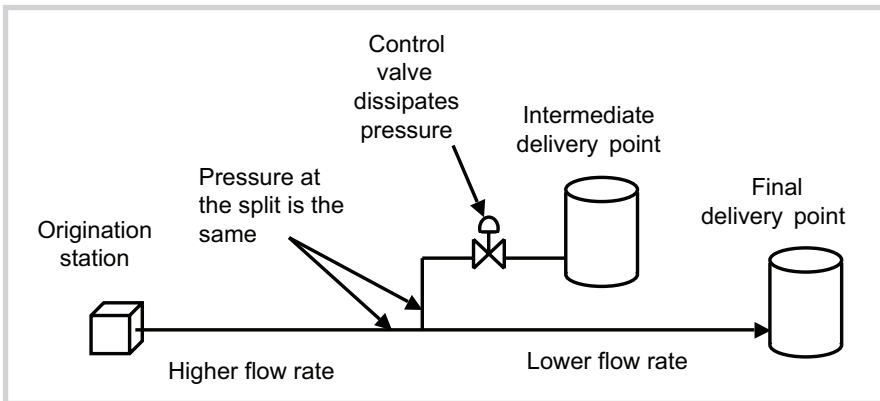


Fig. 4–11. Piping at the offtake point. The control valve throttles pressure between the line and offtake point, controlling flow into the tank and keeping line pressure high enough to move the remaining oil along.

Since some of the flow is diverted from the line, the flow rate downstream of the offtake point is slower than upstream. Past the offtake point in a pipeline, the pressure loss per mile is less than upstream, because the flow rate and the friction loss are less.

The pressure in the line at the intermediate offtake point in figure 4–9 is much higher than the pressure needed to push the liquid into the tank. (The hydraulic gradient at that point is higher than the top of the tank.) Recall from the shower and toilet example in chapter 3 the pressures at the split must be equal. However, diverting the stream at full pressure could damage the receiving terminal's tanks or create an explosive situation. To avoid that, the terminal has a control valve at the offtake point to dissipate pressure between the main line and the tank. It pinches down on the flow, causing a lot of friction loss and pressure drop into the terminal lines. But it keeps the pressure in the main line high enough to push the remaining liquid to the end of the line. The controller decides how much to pinch down the control valve based on how much is destined for that terminal.

In the case of an intermediate *injection* into an oil pipeline, the oil coming in must have enough pressure from an injection pump to force the liquid into the line. That makes the flow rate downstream of the injection higher. The pressure loss and therefore the slope of the line are greater downstream—the opposite of figure 4–9.

Besides offtakes and inputs, another situation creates unusual hydraulic gradients—two or more materials in the same line (fig. 4–12).

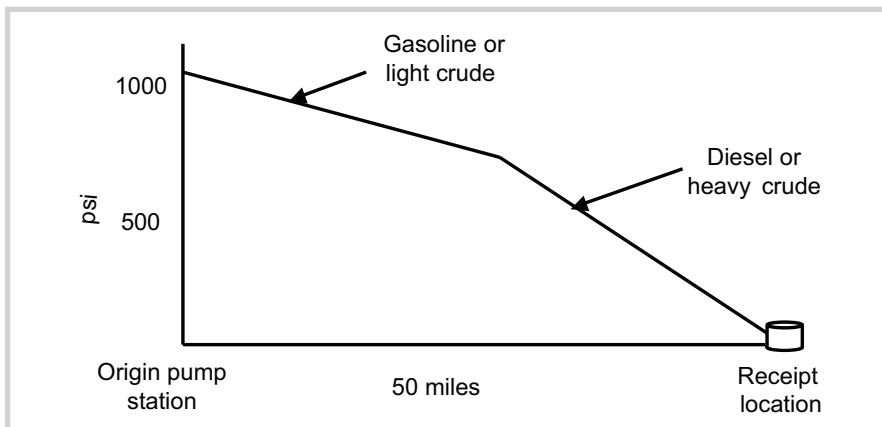


Fig. 4–12. Hydraulic gradient with two different types of oil in the line

Figure 4–12 uses the same logistics as figure 4–10, but with two different liquids in the line. The heavier material has the steeper gradient. Its higher density and viscosity gives it a higher pressure loss per mile. The lighter material is less viscous and loses less pressure to friction per mile. As the interface between the gasoline and diesel travels down the line, the *line fill* switches from the heavier fluid to the lighter. The flow rate slowly increases until it reaches maximum rate when the line is totally filled with gasoline.

Line profile. The level terrain made the previous figures easy, believe it or not. What if a hill or mountain range gets in the way? *Line profiles* are used with hydraulic gradients to understand these situations. Line profiles start with a scale drawing of the elevations along the route (fig. 4–13).

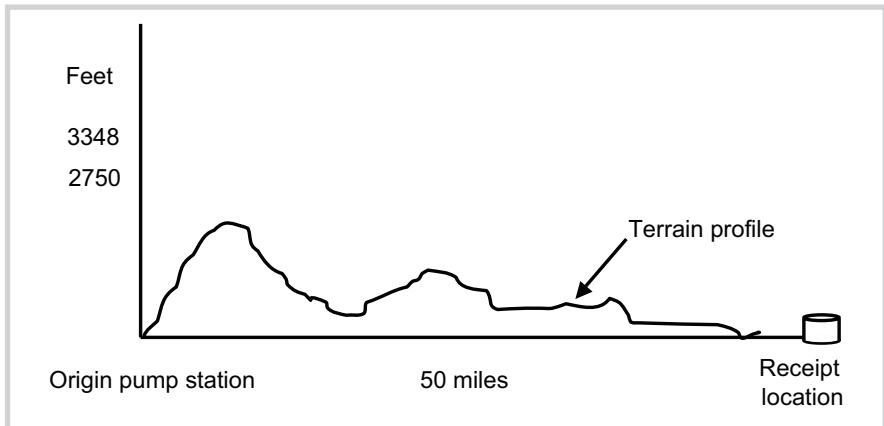


Fig. 4–13. Line profile. Profiles are developed from topographical maps or line surveys.

The information that needs to be added to make this drawing useful to oil pipeline controllers is the *maximum allowable operating pressure* (MAOP) of the pipeline and the gradient. (Up to this point in the discussion, both were shown in psi.)

Maximum allowable operating pressure. The highest pressure allowed at any point along a pipeline is the MAOP. This measure is a function of the diameter of the pipe, its wall thickness, the type of material, and a safety factor. The calculation is covered in chapter 12. But trying to add an MAOP line measured in pounds per square inch to the line profile measured in feet causes a pause. Fortunately, the discussion of pressure given in chapter 3 gives the solution.

As mentioned previously, a column of water 1 ft high exerts a pressure of 0.433 psi. Therefore, the force measured as 1 psi is equal to the force exerted by a column of water 2.31 ft high.

$$1 \text{ psi} / 0.433 \text{ psi/ft} = 2.31 \text{ ft of head of water}$$

Specific gravity, which relates weights of solids and liquids to the weight of water, now comes in handy. To convert 1 psi into feet of head of diesel fuel, one simply divides 2.31 ft of water by diesel fuel's specific gravity of 0.84.

$$2.31 \text{ psi for water} / 0.84 \text{ specific gravity} = 2.75 \text{ ft of head of diesel fuel}$$

The calculations to convert an MAOP of 1,000 psi to feet of head of diesel and gasoline follow:

$$\text{Diesel: } 1,000 \text{ psi} \times 2.31 \text{ ft/psi} / 0.84 = 2,750 \text{ ft of head}$$

$$\text{Gasoline: } 1,000 \text{ psi} \times 2.31 \text{ ft/psi} / 0.69 = 3,348 \text{ ft of head}$$

Figure 4–14 adds both these lines to figure 4–13.

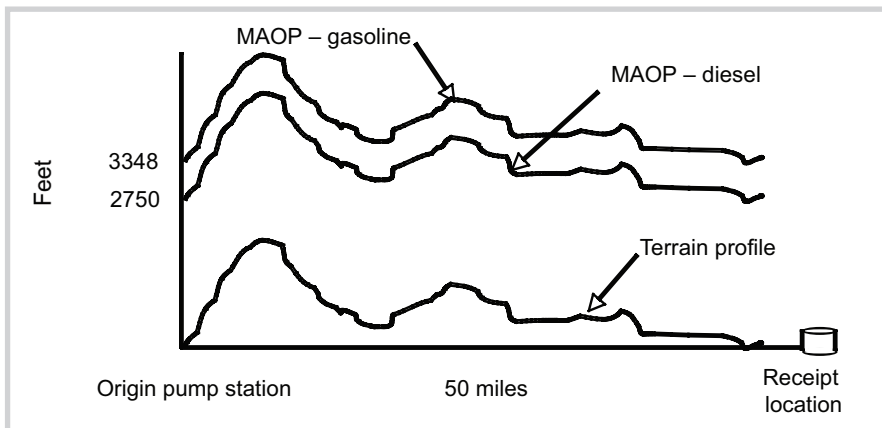


Fig. 4–14. Line profile with MAOP. The different MAOPs for gasoline and diesel are expressed in feet of head.

It may seem a little confusing at this point, but the MAOP is really the difference between the elevation of the line profile and the lines marked MAOP. But for display purposes, as will be evident in a few lines, calling the top lines MAOP is more useful.

Of course, the MAOP is in reality the same all the way along the line even though it appears to be a lot higher at the top of the hill than at the bottom. The MAOP is the same in psi for all liquids being moved on the line. It is different in feet of head for different specific gravity liquids.

Combining the concepts. The line profile, hydraulic gradient, and MAOP line are combined in figure 4–15. The hydraulic gradient has to be converted to feet of head in the same way as the MAOP. In this example, the conversion factor has to be the specific gravity of diesel in order to show that the initial discharge pressure (1,000 psi) is no higher than the MAOP of any product in the line. So the hydraulic gradient (with the scale shown in feet of head) starts at:

$$1,000 \text{ psi} \times 2.31 \text{ ft of head for water}/0.84 = 2,750 \text{ ft}$$

(Extra credit is granted to anyone who looks at the graph and realizes that the pump station is discharging at maximum rate if the material in the line is diesel, but it is not discharging at maximum rate if the material is gasoline.)

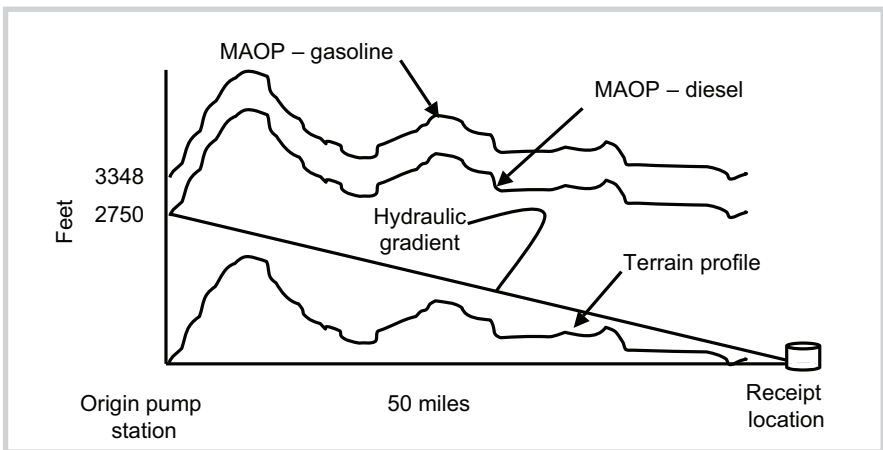


Fig. 4–15. Line profile with MAOP and hydraulic gradient

Fortunately, in this example, the hydraulic gradient lies between the line profile and the MAOPs over the whole 50 mi. If there were a hill along the way that rose higher than the hydraulic gradient, the line pressure at that point would be lower than necessary to keep the line from being pulled apart. (Remember, the line pressure at the top of a hill is lower than at the previous bottom because of gravity.) In that case, a pump station would have been put in before the hill to raise the hydraulic gradient, boosting the pressure at the top.

So the challenge is to keep the hydraulic gradient between the line profile and the MAOP line. Dropping below the line profile causes the line to be *pulled apart*. Exceeding MAOP risks a line rupture.

This section is worth rereading. Understanding hydraulic gradients and line profiles is critical to operating oil pipelines. It is also fundamental to designing lines. This example will reappear in chapter 12, “Engineering and Design.”

The Control Room

The control room is the nerve center of the pipeline (fig. 4–16).



Fig. 4–16. Oil pipeline control room (Photo by Tom Miesner)

The job of the pipeline controllers is blending the customers’ needs based on the schedule with the realities of line operations. Most of the time, a controller’s job is quite routine and predictable, but once in a while something happens to make life exciting. Some controllers liken their jobs to white water rafting—long periods of serene drifting interrupted by moments of sheer terror.

Routine operations

Controllers continually review the operating scenarios as they evolve. They send commands to meters, motors, and valves, causing them to open, close, start, and stop. These actions in turn begin and end receipts and deliveries, increase or decrease pressures and rates, and protect oil quality. They monitor the line and think ahead to anticipate problems. They also receive phone calls and e-mails alerting them to problems. Such problems might include the following:

- One refinery had a problem and will not be able to use all the crude oil headed its way.
- Another had a critical gasoline production unit taken down for maintenance, so the midgrade gasoline will not be ready as scheduled.
- An excavator wants to dig near the line and called the toll-free number on the marker to ask the pipeline company to come to the site to locate the line before they dig.
- One of the mainline motors at a pump station had a bearing failure and must be taken out of service for two weeks.

Operators handle these problems as they come up. Ultimately they have to make a decision, but they may seek guidance from the other parties involved.

The next six figures are examples of screens used by operators as they monitor and operate the pipeline. Figure 4–17 is a schematic of a refined products origination station.

Note that each item is named. Many control rooms have push buttons or switches corresponding to the names. Controllers use these switches to activate the devices. More modern control rooms use point and click screens. Controllers point to a valve, click on it with the mouse, and a dialogue box comes up on the screen. They can click on the start button or the stop button. The dialogue box may also have information about the pump, pressures, temperatures, rpm, and other aspects of pipeline operation.

Figure 4–18 is a screen for a booster station on the same line. It is much less complex but works the same way: push the button or point and click.

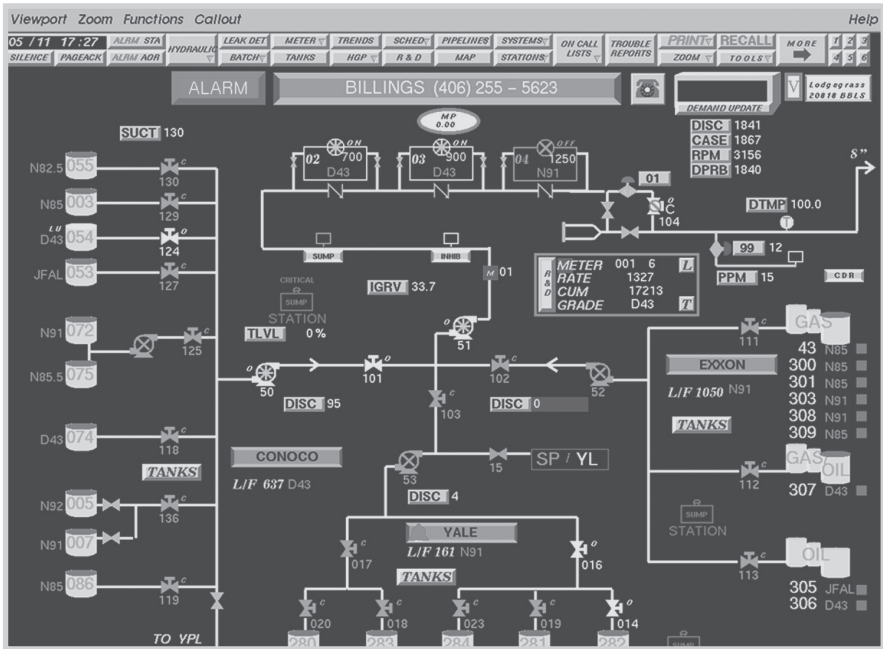


Fig. 4-17. Origination station display

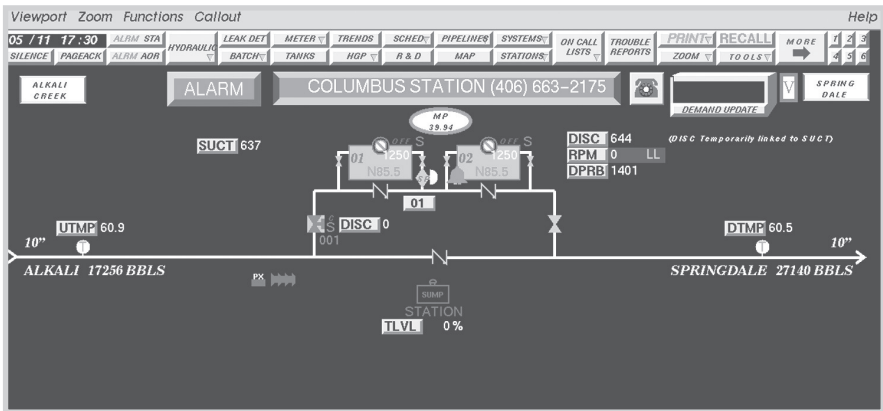


Fig. 4-18. Booster station display

Figure 4-19 is a screen from a receipt station. The controller points and clicks to switch the path to the right tank. From the information on the screen, the controller understands flow rates and tank levels.

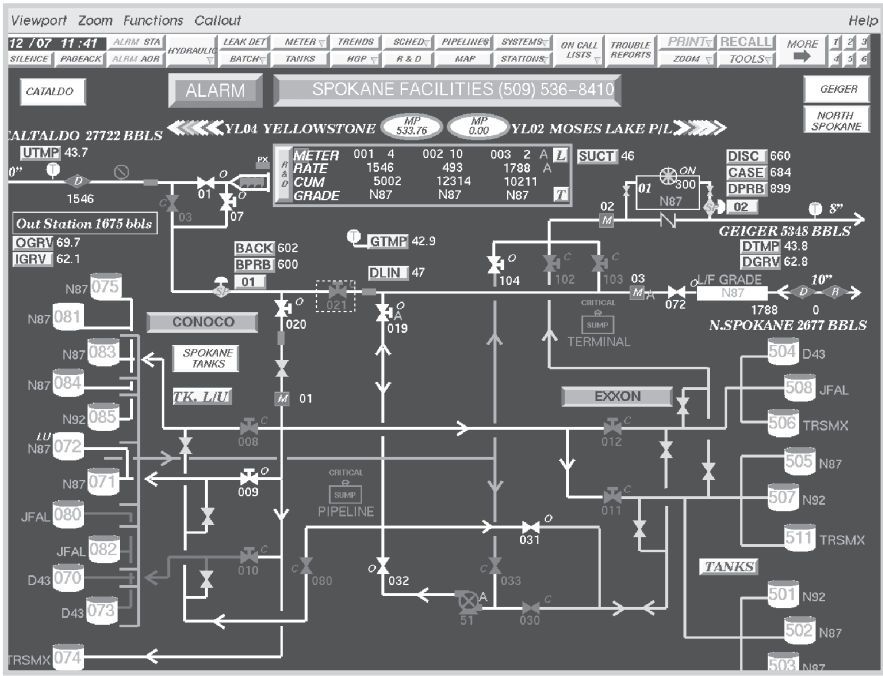


Fig. 4–19. Receipt station display

Some screens contain information but cannot be used for controls. Figure 4–20 shows the receipt and delivery schedule. From this screen, the controller knows what is going where, when it is happening, and what should happen next.

YELLOWSTONE SYSTEM RECEIPT AND DELIVERY SCHEDULE												
Segment	Station	Meter	Tank ID	Batch ID	Grade	Target Size	Batch Size	Meter Cum. Volume	Batch Remaining	Time Remaining Target	Flow Rate	
L10	BILLINGS	MTR-0001	0308	CN-2146	N91	1200	3000	1042	1958	0000:04	000:52	2398
L10	ALKALI	MTR-0001		BN-1143	D43	0	17000	0	17000		No Flow	0
L10	BOZEMAN	MTR-0001		CN-3063	D43	0	13000	0	13000		No Flow	0
L10	HELENA	MTR-0001	0036	CN-2143	N85.5	0	2745	2538	207	0000:05	000:05	2253
L10	MISSOULA	MTR-0001		CN-1138	N87	0	42000	86	41914		No Flow	0
L04	TOMFALLS	MTR-0001	0091	EX-1100	N87	29800	35000	12796	22204	0010:36	013:51	1570
L04	SPOKANE	MTR-0001	0075	CN-1098	N87	0	42000	35705	6295		003:57	1588
L01	SPOKANE	MTR-0003		???-1635	N87	0	0	2031	-2031		Compleat	1764
L01	NSPOKANE	MTR-0001		???-1330	N87	0	0	2039	-2039		Compleat	1768
L01	HILLYARD	MTR-0002		???-0612	N87	0	0	0	0		Compleat	0
L01	HILLYARD	MTR-0003		???-0870	N87	0	0	9	-9		Compleat	0
L02	SPOKANE	MTR-0002		CN-5098	D43	0	10000	82	9918		018:28	537
L02	GEIGER	MTR-0001		???-0044	JFAL	0	0	1	-1		Compleat	0
L02	FAIRCHLD	MTR-0001		???-0018	N87	0	0	2	-2		Compleat	0
L02	FAIRCHLD	MTR-0002		CN-5085	N87	0	0	2	-2		Compleat	0
L02	MOSES-LK	MTR-0001	0027	CN-5094	N92	0	4000	3381	619		001:11	521
L03	HELENA	MTR-0002		CN-4044	D43	0	22000	0	22000		No Flow	0
L03	GT-FALLS	MTR-0001		CN-4042	D43	0	9000	7990	1010		No Flow	0
L91	TOMFALLS	MQR-0001		???-000564		0	0	*****	142307		No Flow	0

Fig. 4–20. Receipt and delivery display

Figure 4–21 is a hydraulic summary of the line. Knowing pressures and pump rates is critical to operations. Most controllers have this screen up at all times.

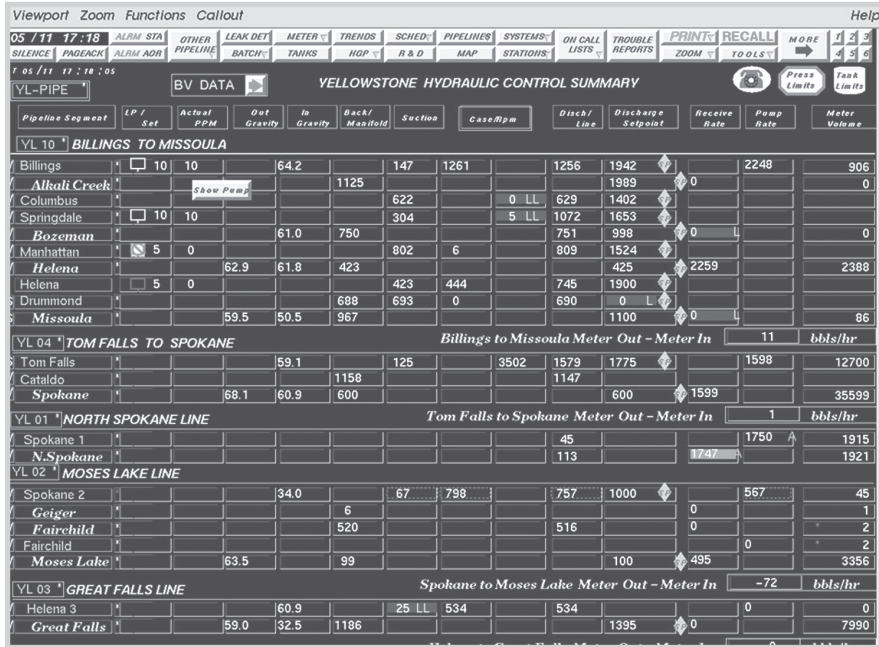


Fig. 4–21. Hydraulic summary

The line profile and hydraulic gradient are shown on figure 4–22. Note the different slopes of the gradient indicating different pressure loss. The MAOP line leaps up in certain locations, indicating a higher pressure rated pipe.

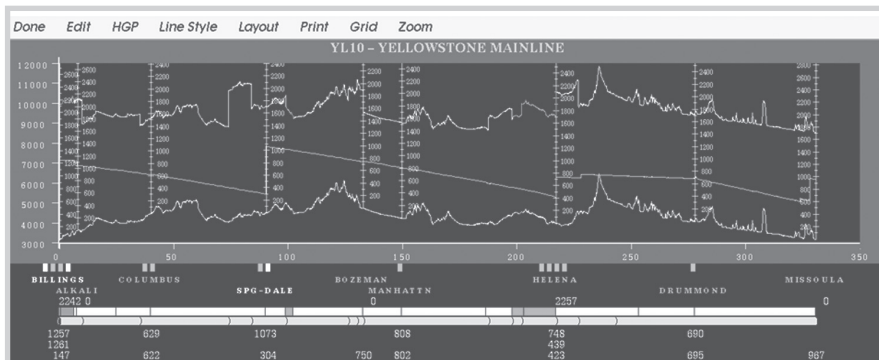


Fig. 4–22. Line profile and hydraulic gradient

Abnormal operations

A chapter on operations would not be complete without addressing the topic of abnormal operations, a concept that is not always as ominous as it sounds. The U.S. Office of Pipeline Safety offers the following definition:

Abnormal operation. The manual required by paragraph (a) of this section must include procedures for the following to provide safety when operating design limits have been exceeded:

- (1) *Responding to, investigating, and correcting the cause of:*
 - (i) *Unintended closure of valves or shutdowns;*
 - (ii) *Increase or decrease in pressure or flow rate outside normal operating limits;*
 - (iii) *Loss of communications;*
 - (iv) *Operation of any safety device;*
 - (v) *Any other malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property.²*

Abnormal operations do not always mean an emergency exists, but in some cases, it might. And that makes it part of the controller's job description to quickly and thoughtfully understand what happened and the nature of its consequences, and respond accordingly.

Unintended closures of valves or shutdowns. Sometimes valves are inadvertently closed or other devices accidentally operated incorrectly, shutting down the line when no problem exists. A valve closing unexpectedly can also indicate something terrible has happened, such as a leak. In either case, false alarm or real problem, controllers must be trained to overreact, not underreact. A plausible explanation for the shutdown must be found quickly, or restarting the line is risky.

Increase or decrease in pressure or flow rate outside normal operating limits. Unexpected pressure or flow rate problems often indicate a leak. If a break occurs in the section of line close to and downstream of the pump station, the line friction loss goes down, because the pump is pushing over a shorter distance. This means flow rate in that section of line goes up. The pump tries to push more oil faster. Since the flow rate in the section upstream of the pump does not increase, the line is in danger of being pulled apart. The pump shuts down because of low suction pressure or high flow rate.

If the break happens relatively far from the pump station, close to the downstream station, the pressure loss at the pump's discharge does not drop. This is because the flow is over nearly the same length of line. However,

the pump downstream, at the next station, is starved, since less (or no) oil is coming to it. It goes down, again, on low suction pressure. In both cases, low suction pressure indicates a major line break.

Loss of communications. Communications concerns supplying accurate data about line operations and allowing controllers to remotely control the lines. It is one of the keys to central control rooms. Without the ability to see or control, the controller is reduced back to the dispatcher role, calling to ask questions and telling field operators what to do. That might have worked in the old days when each station was manned, but it may not be possible today due to limited field operating forces. Detailed plans tell controllers what to do in the event of communication loss and involve quickly reestablishing communications or shutting down the line.

Operation of any safety device. Safety devices are installed as a fail-safe protection, just like the backup parachute carried by sky divers. Ideally they never function. But when they do, it means something went wrong. When a skydiver's primary chute fails, he does not say, "Oh well, my backup parachute saved me." Before the next jump, he finds out what happened to the primary chute and corrects it to assure it does not happen again. If operation of safety devices becomes normal and expected, controllers are desensitized to what could go wrong. They could begin to depend on safety devices to handle problems. Operators constantly remind themselves that safety device activation should never be thought of as normal operation.

Operator Training

The job of a controller is a bit like air traffic controller and pilot built into one. It requires a unique combination of skills. A controller needs the ability to understand complex systems stretching over many miles, where one action influences another. This must be coupled with the ability to quickly respond to emergency situations.

On-the-job training plays a large role in controller training. It is effective in teaching operators how to handle the routine operations of their particular line. However, since abnormal operations happen infrequently, on-the-job training is not as useful in preparing operators to handle these less-common situations. Instead, simulations, drills, discussions, and playback of previous problems play a more effective role in preparing operators to respond. Most companies have extensive training programs for their controllers before they are ever allowed to operate "solo."

References

1. Rabinow, R. A. *The Liquid Pipeline Industry in the United States: Where It's Been, Where It Is Going*. Report prepared for the Association of Oil Pipe Lines, 2004, p. 1.
2. Code of Federal Regulations 195.402(d), p. 183. Retrieved August 13, 2005, from: http://a.257.g.akamaitech.net/7/257/2422/12feb20041500/edocket.access.gpo.gov/cfr_2004/octqtr/pdf/49cfr195.402.pdf

5

Natural Gas Pipeline Operations

Not I, not I, but the wind that blows through me!

—D. H. Lawrence (1885–1930)

Almost every energy analyst who has the temerity to forecast the future says that natural gas demand will grow substantially in the coming decades. Indeed, natural gas is the darling of the energy business. Environmentalists think it the least offensive of the fossil fuels because of its clean-burning characteristics and smaller impact on carbon dioxide accumulation in the atmosphere. Entrepreneurial companies see opportunities to expand markets by tapping abundant but remote natural gas resources and shipping them to consuming countries in the form of LNG. To accommodate these bright outlooks, existing pipelines must be expanded, and new ones must be built to keep pace with expanding volumes.

This chapter deals with natural gas pipelines, covers gathering and transmission lines, and touches on local distribution lines briefly. It covers local field operations and central control room operations, extends the hydraulic concepts to natural gas, and finishes with a discussion of abnormal operations.

There is one important note regarding natural gas safety. Most people think natural gas has a distinctive odor. In fact, it is odorless. The distinctively sharp smell comes from ethyl- or methyl-mercaptan. One of these odorants is added as the gas gets close to the point of consumption so the public can easily detect a leak.

Natural Gas Lines—a Brief Review

Like oil pipelines, natural gas pipelines are composed of gathering lines and main lines. However, there is an added component—local distribution lines. The natural gas value chain can become complex (fig. 5-1).

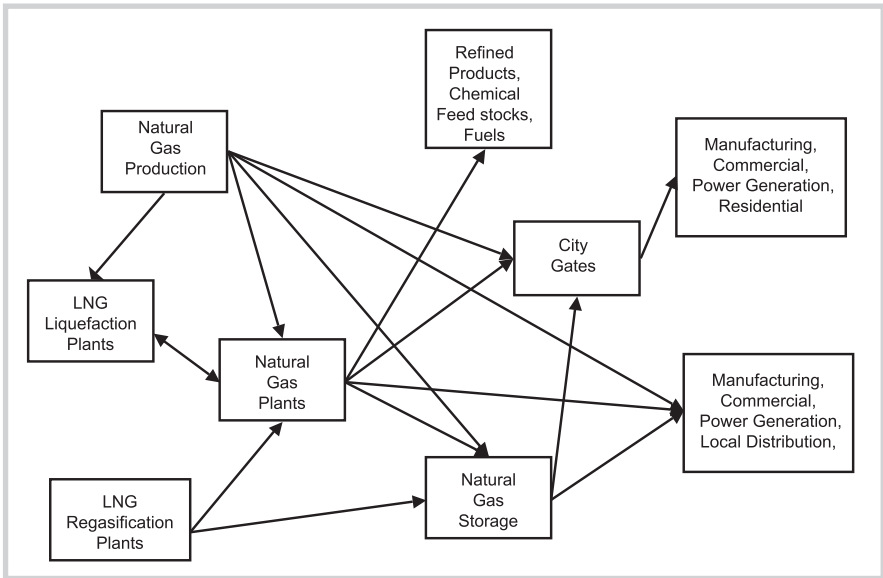


Fig. 5-1. *Natural gas value chain*

On the upstream end, natural gas gathering pipelines extend from natural gas production to gas plants, transmission lines, and NGL liquefaction plants. On the downstream end, natural gas transmission pipelines transport for shippers who sell to large end users and local distribution companies. But sometimes they also deliver to NGL liquefaction plants or gas storage. In addition they may receive from NGL liquefaction plants and gas storage.

Also on the downstream side natural gas local distribution pipelines sell to many of the same customers as those served by natural gas transmission pipelines shippers. They receive from natural gas transmission pipelines, NGL liquefaction plants, and gas storage. NGL pipelines extend from gas plants to refineries, chemical plants, and directly to bulk fuel distribution plants.

The distinction between natural gas transmission pipelines and local distribution pipelines is not so much physical as it is historical. It has more to do with the past events, regulations, traditional customers, line size, and operating pressures than hydraulics and operating principles.

The focus of this book is on large-volume natural gas deliveries, regardless of the ownership structure. Thus it stops at the city gate and does not discuss small-diameter, low-pressure lines to individual homes and businesses.

Gathering lines

Just as crude oil gathering lines collect crude oil from producing areas, gas gathering lines collect *raw gas* from the same locations. The stream of fluids coming from producing wells contains a mixture of hydrocarbon molecules and contaminants. Some gas, called *associated gas*, is produced from wells in association with crude oil. Other gas, called *nonassociated gas*, comes from wells producing only gas and no crude oil. (This has to do with the geologic history of the formation holding the gas or oil, but that is the topic of another book.) In either case, to varying degrees, depending on the production field, water, solids (like sand) and crude oil are separated from the gas near the well site.

Various processing schemes, such as two-phase, three-phase, four-phase, horizontal, and vertical separators, are combined to accommodate the particular well and operating characteristics. These separators split the gas from the liquid and other contaminants. The liquid stream was discussed in chapter 4.

At this point the gas is *raw gas*, a mixture of relatively smaller hydrocarbon molecules. (In contrast, crude oil is a mixture of relatively larger molecules.) Methane, the predominant constituent of natural gas, is the simplest of these molecules found in natural gas. Raw gas also contains some water vapor and often minor amounts of the so-called raw gas liquids, such as ethane, propane, butanes, and natural gasoline (fig. 5–2).

Some of the vapors contained in the raw gas stream, particularly water, condense into liquids as they cool off and reach their dew point, forming *hydrates*. Hydrates are slushy and sometimes crystallized complexes of water and methane. What causes the vapors to cool? Gas from the well is flowing at a high pressure that is reduced down to lower operating levels. As explained in chapter 3, as the gas pressure reduces, the gas expands. As the gas expands, it absorbs energy, reducing the temperature. To prevent hydrate formation, heaters are often placed at the transition points to insure temperatures are kept above the dew point.

The raw gas stream exits the separation process and is measured into gathering lines. Lines from the well to separators are normally called flow lines. Gathering lines start at the outlet of the separators, or if the natural gas is suitable enough, directly from the well sites. These lines move the gas to gas processing plants or to the main lines.

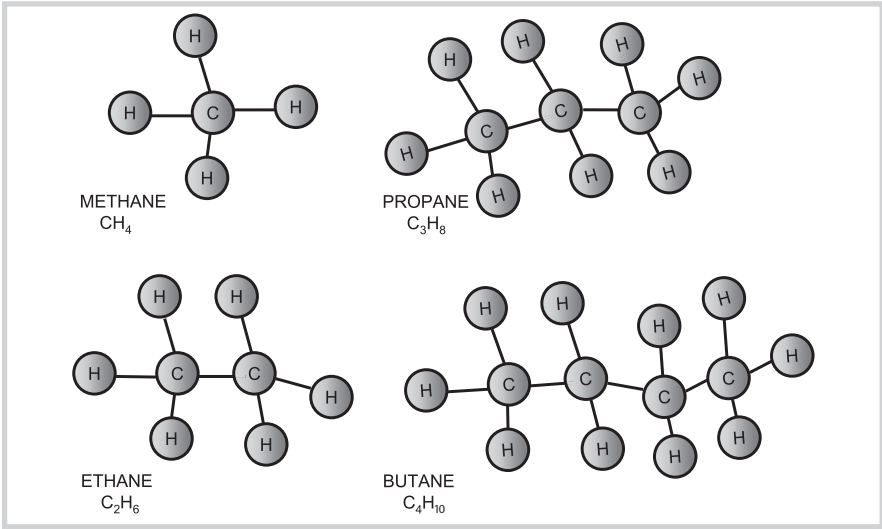


Fig. 5–2. Molecular structure of common light hydrocarbons

Gas processing plants

Some gas wells produce *dry gas*, which is essentially methane with very little heavier hydrocarbons. If it has no other contaminants, the gas can enter transmission lines without additional processing. However in many cases, raw gas is processed in processing plants (fig. 5–3), where most of the larger, heavier hydrocarbons shown in figure 5–2 are removed.



Fig. 5–3. Natural gas processing plant. The various towers each remove a specific type of hydrocarbon molecule from the stream. (Photo courtesy Miesner, LLC)

There are three reasons for removing the heavier hydrocarbons—two operational and one economic.

Slug flow and corrosion. Heavier hydrocarbon molecules and water have higher dew points than natural gas (methane). If they are not removed from the natural gas, they can cool and condense into liquids as they move along the pipeline. These liquids collect in low spots, restricting and eventually completely blocking gas flow. Pressure from gas wells upstream of the blockage builds, finally forcing the slug of liquid over the next hill and on to the next low point. This results in *slug flow* and inefficient pipeline operation. Water collecting in low spots is also a major cause of pipeline internal corrosion and can freeze in cold weather, completely blocking flow (fig. 5–4).

Even after processing, some liquids may fall out of the natural gas stream later. Thus lines are designed with intentional low spots, called *drips*, to capture and safely remove accumulations of liquids before they cause problems.

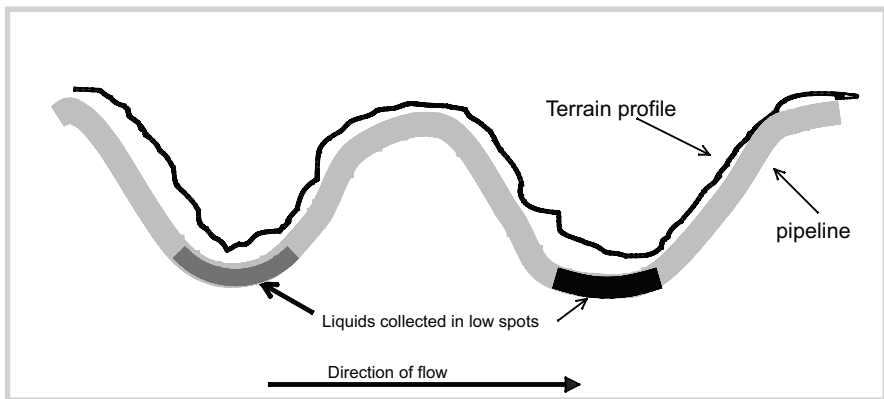


Fig. 5–4. Liquids collected in a low spot. Liquids condense and collect in low spots, temporarily blocking flow. Pressure builds upstream of the low spot, eventually pushing the liquid over the downstream hill, resulting in slug flow.

BTU content. For operating and safety reasons, natural gas appliances such as furnaces, water heaters, and washers and dryers are designed to operate in certain BTU ranges. The standard is usually about 1,050 BTU/scf. Ethane, propane, butane, and natural gasoline have successively higher BTU contents than this. The gas may have to be processed to extract higher BTU components, particularly the butane and natural gasoline. The energy content of ethane is closer to methane and can be left in the gas.

Economic value. In addition to the practical operating reasons for gas plants, there is an economic reason. Under most market conditions, propane, butane, and natural gasoline are worth more than methane. Thus gas plant construction and separation of these hydrocarbons can be commercially viable. At times, the conditions reverse and propane is left in the gas stream, and sometimes is even injected. This can cause conflict between natural gas sellers wanting top dollar for their BTUs and natural gas pipeline operators wanting consistent natural gas quality. Natural gas pipeline controllers closely monitor incoming gas streams for BTU and heavier hydrocarbon content. High-volume receipt points may have gas chromatographs to monitor gas quality (fig. 5–5).

Receipts from LNG facilities

In the last few decades, LNG has become an important part of the natural gas value chain in Europe and East Asia. More recently, LNG imports by the United States have been accelerating. LNG and its impact on natural gas pipelines merit mention.

What is LNG? It is methane, the same colorless, odorless, hydrocarbon molecule in current natural gas pipelines. However, it has been cooled to -260°F (or -162°C) in an LNG plant, where it turns from a gas to a liquid. In liquid form, natural gas takes up about 1/600th of the volume it had in its gaseous state. The smaller volume makes it economically feasible to load it on specially designed tankers for ocean transportation from producing countries to consuming countries.

LNG import terminals temporarily store the LNG until it is regasified, warmed back up to normal pipeline temperatures, and delivered into transmission lines as a vapor. At first blush, handling LNG in a natural gas line would seem to present no liquids problems. After all, when LNG is created at its origin, the gas has to be cooled to -260°F to get it into the liquid state. In the process, long before that temperature is reached, the ethane, propane, butane and heavier molecules liquefy and could easily have been removed from the natural gas stream. But LNG often comes from *stranded gas*, a term that implies the gas production is located in some remote place, far from energy markets. If that is true, the market for NGL may be equally isolated. The owner of the LNG operation may be interested in leaving the NGL in the LNG as a means of transporting it cheaply to a market or increasing its BTU content. Some LNG can even be *spiked* with extra propane and butanes because the destination market pays a premium for the liquids. In this case, the liquids-laden LNG may pose the same liquids problems covered earlier. For this reason, LNG specifications and quality are receiving considerable attention.

12:00:00 MONTH/DATE/YEAR	
CURRENT	STREAM I
BTU	1036.7
SCV	0.5871
%NIT	0.336
%CO2	0.894
%METHANE	95.61
%ETHANE	2.308
%PROPANE	0.5
% I-BUTANE	0.113
% N-BUTANE	0.115
%NEO PENTANE	0
% I-PENTANE	0.041
% N-PENTANE	0.027
%C6 PLUS	0.054
% HEXANE	0.027
%HEPTANE	0.027
NEOC5 + IC5	0.041
UNNORMALIZED TOTAL	100.6801
HOURLY	
BTU	1036
SGV	0.5863
%NIT	0.331
%CO2	0.89
DAILY	
BTU	1030.1
SGV	0.5831
%NIT	0.329
%CO2	0.91

Fig. 5–5. Typical gas quality readings from a gas chromatograph

Pipeline hubs

The ability to receive from and deliver to other pipelines is important for supply flexibility and reliability. Over time regional *pipeline hubs* have developed, locations where a number of pipelines interconnect. Examples include the Henry Hub in the United States, the National Balancing Point (NBP) in the United Kingdom, Zeebrugge in Belgium, and Baumgarten in Austria.

From Field Operations to Central Control Room Operations

Like oil pipelines, natural gas pipeline operations and maintenance activities were once exclusively a matter of field operations. They evolved along the same path as oil pipelines. Central control rooms are taking over operating tasks, while maintenance continues to be carried out in the field. The third component, administrative and regulatory oversight, is growing for natural gas pipelines, just as for oil pipelines. This requires more people to keep up with the regulations and document compliance.

As explained before:

- Operations keep the natural gas flowing through the lines.
- Maintenance keeps the line and equipment in good operating condition.

With some exceptions, the maintenance of natural gas and maintenance of oil pipelines are essentially the same and are described in chapter 9.

Natural gas field operations

Field operators are still critical to the success of natural gas pipelines. They measure gas, including the critical quality testing component of measurement, and they interact with landowners, contractors, and city and state officials. They make operating decisions regarding compression and other operating variables and serve as valuable “eyes and ears” for central control room controllers. These same persons often contribute to operating, maintenance, administrative, and regulatory activities. In the words of one natural gas field operating supervisor, “We do everything that needs doing, including cleaning the bathrooms.”

Measurement. One of the most important roles of field operators is measurement. The difference between liquids and gases has already been mentioned. (Both conform to the shape of their container, but gas expands to fill the container and more easily escapes if it is not contained.) This difference makes gas measurement different from liquid measurement. The most common gas measurement technique is the *orifice meter* (fig. 5–6). However, other metering techniques such as turbine meters and ultrasonic meters are also used.



Fig. 5–6. Orifice meter run. An orifice plate is located in the pipe to the left of the box containing a paper chart. Note the white lines coming from the orifice plate to measure pressure. (Photo courtesy Miesner, LLC)

Based on Bernoulli's Principle (chapter 3), orifice meters consist of an orifice plate of known size and configuration. They have sensors to measure line temperature, line pressure, and differential pressure between upstream and downstream of the orifice plate. The orifice plate contains a hole smaller than the inside diameter of the line, so the gas velocity increases as it passes through the orifice plate. Since the gas is going faster, the pressure has to decrease. Using information such as differential pressure across the orifice plate, line pressure, temperature, pipe diameter, and orifice plate configuration, gas quantities can be calculated. Temperatures, line pressures, and differential pressures can fluctuate significantly, even over short time periods. In high-volume locations, the data are recorded by computer modules, called *flow computers*. In smaller volume locations, these variables are captured on circular paper charts (fig. 5–7).

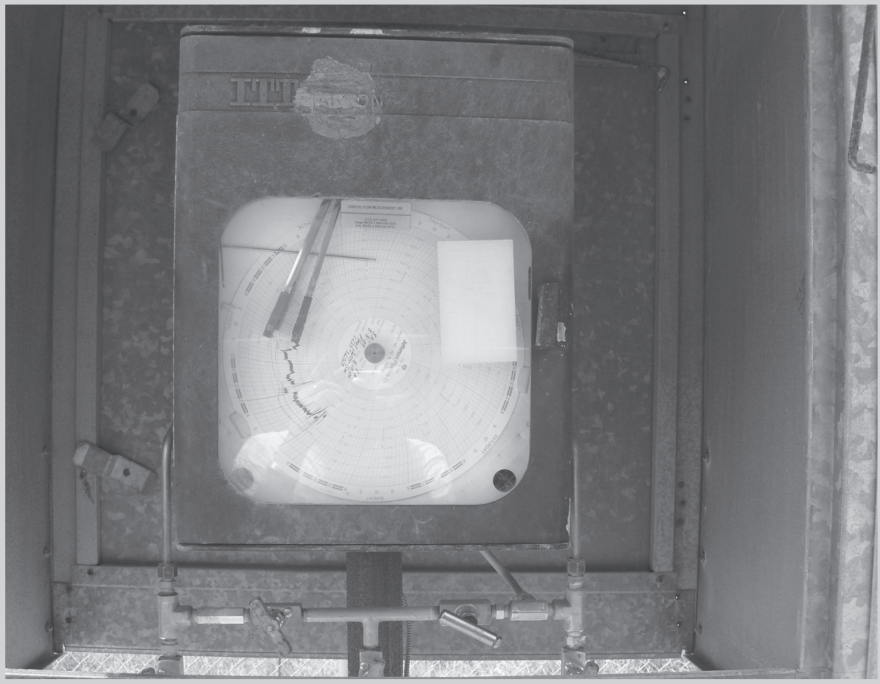


Fig. 5–7. Orifice meter paper three-pen chart recorder. The three pens record pressure, temperature, and differential pressure. (Photo courtesy Miesner, LLC)

In the case of manual operations, the field operator looks at these charts and estimates average values over the time frame for the three variables. The field operator plugs these values into a formula (or handheld computer) and calculates quantities. The operator then replaces the old charts with new charts for the next time period. Operators normally retain the old charts for some time period for documentation purposes.

In the case of flow computers, the meter run looks the same, but the box containing the circular charts is replaced by a box containing the flow computer. Flow computer outputs can be linked into SCADA systems, described in chapter 8, for line control and remote reading of measured quantities.

Besides quantity, quality is important. The raw gas stream is sampled to determine the distribution of methane, ethane, propane, butane, heavier hydrocarbons, and contaminants in the stream. Sampling is accomplished either manually, by drawing a sample into a small pressure bottle for testing in a lab, or automatically, with a gas chromatograph. These analyses determine the energy content (BTUs) of the gas. Contaminants such as carbon dioxide, oxygen, and nitrogen are accounted for in the payment calculations. When

contaminant concentrations reach certain levels, the pipeline company may refuse to continue accepting the natural gas, shutting down production. More discussion on contaminant levels will be given in the section on central control rooms.

There is one more note regarding metering. To ensure accuracy of measurements, the pressure and temperature gauges are calibrated on a predetermined schedule and also when problems are suspected. Calibration is accomplished by field technicians. They compare pressure and temperature readings of the field instruments to reference instruments with known accuracy, or against deadweight testers that produce a known pressure. Adjustments, either manual or electronic, reestablish field instrument accuracy as needed.

Managing stakeholder relations. Field operators are the main contact point for stakeholders along the route. They work with landowners, understanding and addressing their concerns, and help train local emergency response personnel. They advise local officials on siting issues, and work with excavators, helping them determine pipeline locations important to safe digging.

Gathering station operations. The gas produced from some wells has enough pressure to enter the gathering line directly without further compression. Sometimes compressors are added to boost the pressure to overcome the other gathering line's pressure (as stated earlier, pressures at line splits are equal). These compressor stations can be operated remotely from a central control room by the production field operators or operated manually by pipeline field personnel. They can also be operated by a combination of local operations and remote monitoring. Remote and local manual operations both accomplish the same tasks. They open and close valves, start and stop compressors, read instruments, respond to alarms, and modify operations to assure safety and efficiency.

The equipment needed for remote operations is normally more expensive than that needed for manual local operations, but labor costs are normally less. Decisions regarding local versus remote operations are made based primarily on economics and safety.

Compressor station operations. Origination compressor stations like pump stations are located at the beginning of the line. Figure 5-8 shows the outside of an origination station and figure 5-9 is a partial view of the engines and compressors inside the compressor building.

Further along the line, booster stations add more energy, giving the gas a boost as it travels along its journey (fig. 5-10).



Fig. 5–8. Origination gas compressor station. Several gathering lines from onshore and one from offshore enter this mainline origination compression station. The natural gas is aggregated into a common suction header, and a combination of the seven reciprocating compressors, driven by natural gas–fired reciprocating engines, add pressure to the gas before it is discharged into a 30-in. natural gas main line. (Courtesy Williams Gas Pipeline; photo by Tom Miesner)



Fig. 5–9. Inside of a origination station with reciprocating compressors. From a catwalk about 10 ft from the floor in the compressor station (shown in fig. 5–10), five cylinders of the V-10 engine are visible. (Courtesy Williams Gas Pipeline; photo by Tom Miesner)

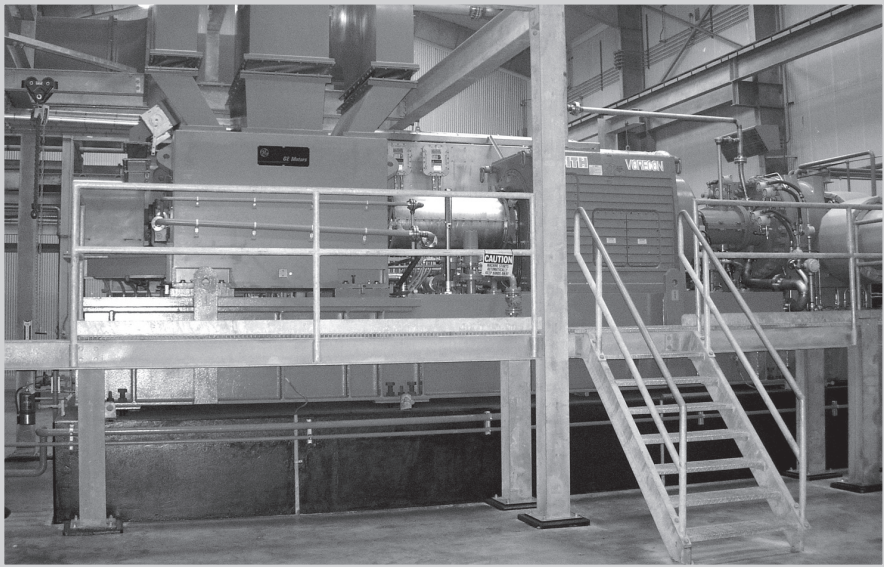


Fig. 5–10. Inside a booster station with turbine compressors. Electric motors (versus gas-driven engines) are often used in stations to meet emission standards. In addition, the station may be insulated for noise reduction. The electric motor is on the left, with a variable speed drive and the compressor connected to it in that order. (Courtesy Williams Gas Pipeline; photo by Tom Miesner)

Engines, like car engines, require cooling and lubrication. Cars have radiators and motor oil providing these functions. Compressor stations have cooling and lubricating systems for the same purposes. Compressor cooling systems sometimes cool discharge gas also. (As explained earlier, compression adds energy to press molecules closer together, increasing both temperature and pressure.) Control equipment monitors station discharge temperatures to insure they are not too high. An important function of station operators is dealing with this ancillary equipment to keep the station operating.

Natural gas delivery operations

One entity's receipt is another's delivery, so it should not be surprising that delivery operations have the same operating practices and equipment as receipt operations. That calls for a few more words about city gates.

City gates. At city gates or town border stations (fig. 5–11), transmission lines deliver natural gas to LDCs. At that point, pressure regulators reduce pressures down to those allowed in the distribution systems. Also, there are metering facilities, quality monitors, and odorization facilities. Sometimes heaters are required to warm the gas that cools as a result of the pressure reduction at the station.



Fig. 5-11. City gate station to a town along the route (Photo courtesy Miesner, LLC)

It would not make sense to have two metering stations, one for the transmission company and one for the LCD. Thus the two companies normally agree who will install and operate the equipment. The information from the one metering station is transmitted back to both control rooms. Several transmission companies may supply an LDC through different city gates, and large markets have a number of city gates.

Flow control and pressure control. Deliveries to large industrial or commercial consumers are either *flow controlled* or *pressure controlled*. Flow controlled delivery limits customers to a maximum withdrawal rate. Pressure control delivery allows customers to withdraw as much as they need as long as the delivery pressure remains above a minimum level. Even with flow control, pressure control may also be in effect to guard against low pressures on the line.

Central Control Rooms

Natural gas pipeline control rooms look much like oil pipeline control rooms, and they use the same communication and control technologies (fig. 5-12).



Fig. 5–12. Natural gas control room. (Courtesy Williams Gas Pipeline; photo by Tom Miesner)

The primary difference between oil pipeline control rooms and natural gas pipeline control rooms is not what they do but how they do it. As with oil pipelines, central control room functions are:

- Planning and scheduling operations
- Monitoring and controlling the pipeline
- Responding to and correcting abnormal operations
- Maintaining the control equipment

The description of each of these items in chapter 4 also applies to natural gas.

Planning and scheduling operations

Just like oil pipelines, natural gas pipeline schedulers match supply to demand. They work with estimates or forecasts (normally called nominations) from the shippers, doing their best to keep everything in balance. Natural gas schedulers work with only one product, natural gas, not the multitude handled by oil pipeline schedulers. They do not worry about batch arrival time or ensuring the right types of refined products are available in the

proper sequence. But natural gas schedulers work with hundreds of receipt and delivery points and rapidly changing supply and demand. Load demand forecasts show the estimated demand by area (fig. 5–13).

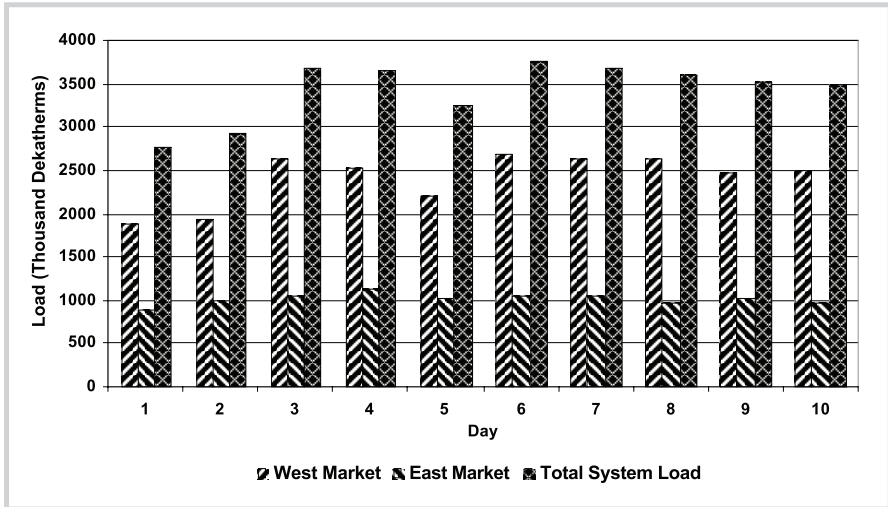


Fig. 5–13. Typical summary load demand forecast for a natural gas pipeline. Note the fluctuation in demand during this 10-day period. It is normal to update supply and demand forecasts several times during the day.

Schedulers handle fluctuations by cutting back supply, filling or withdrawing from storage or *packing* and *unpacking* the line. Packing involves putting more into the line than is taken out. Unpacking naturally is the reverse. Line pack can swing as much as 30% and provides a valuable operating cushion.

Natural gas pipelines normally receive from and deliver to each other directly without going through storage. Receiving pipelines (particularly LDCs) often work off the pressure of the delivering pipeline. Low pressure from the delivering pipeline affects the receiving pipeline immediately. High pressure at the receiving pipeline causes the delivering pipeline problems. Balancing supply, demand, and pressures among hundreds of receipt and delivery points requires constant attention. Demand is sensitive to time of day, day of the week, weather, and even sunshine and cloudiness. While schedulers adjust the supplies to meet overall demand on an hourly, daily, weekly, and monthly basis, controllers adjust ongoing line operations to accommodate needs as they happen.

Each receipt and delivery point must be tracked to account for ownership. This task normally falls to an accounting group, which works closely with the schedulers, controllers, and measurement people to ensure accurate accounting.

Companies employ individual practices, programs, and procedures to effectively schedule and account for natural gas moved on their systems. As with oil lines, natural gas controllers implement these schedules.

Monitoring and controlling the pipeline

In the words of one natural gas controller, “Our job is to safely manage line operations, ensuring pressures are low enough so suppliers can get their gas into the line but high enough customers have enough pressure to withdraw their needs, all at the lowest cost possible.” To do this controllers use the SCADA and control systems covered in chapter 8 to monitor flow rate, pressures, and gas quality at hundreds of receipt and delivery points along the line (fig. 5–14).



Fig. 5–14. Natural gas systems summary screens. The controller carefully considers the response to a message in the center of the middle screen. (Courtesy Kinder Morgan Gas Pipeline; photo by Tom Miesner)

On their SCADA screens each little symbol represents a receipt point, delivery point, compressor station, or storage field. A controller can click on points with his mouse to drill down for more detailed information, such as information about a particular group of delivery locations (fig. 5–15).

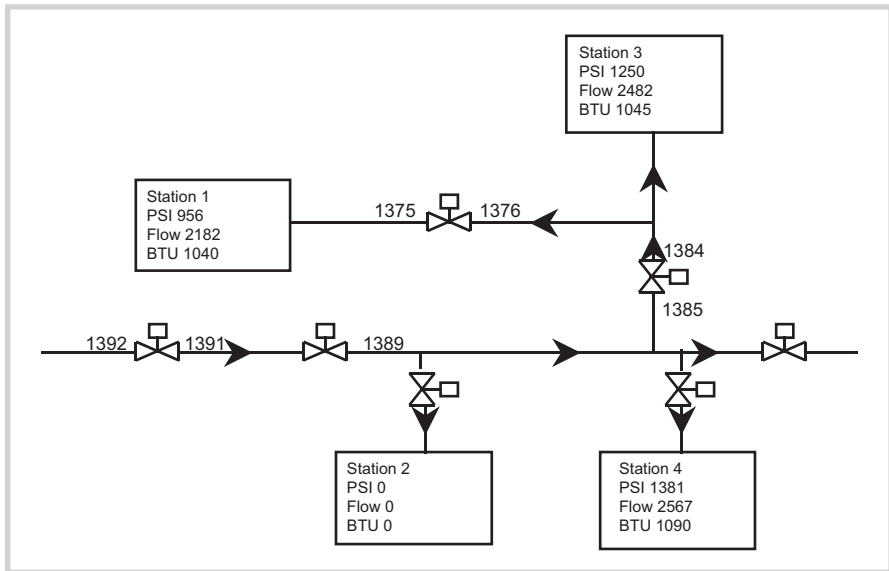


Fig. 5–15. Screen showing individual delivery location information. In this case, natural gas is flowing to stations 1, 3, and 4.

Natural gas controllers interact with their lines in the same manner as oil controllers. Older control consoles have push buttons or switches corresponding to each piece of control equipment. Controllers use these switches to operate the devices to accomplish what they want to do. More modern control rooms use point and click screens. The controller can point to a valve, click on it with the mouse, and a dialogue box comes up on the screen. The controller can click on the start button to start and on the stop button to stop. The dialogue box may also have information about the compressors, pressures, temperatures, rpm, and other information.

Hydraulic concepts—optimizing line operation

Hydraulic gradients, line profiles, batch tracking reports, and feet of head are all important for oil pipelines, but they are nowhere to be found in natural gas control rooms. However, MAOP is just as important for natural gas as for oil lines. Exceeding MAOP eats into the operating safety margin, and exceeding MAOP by too much can stress and eventually weaken the pipe. Pipeline controllers study discharge pressures, flow rates, and line pack, optimizing line operations by bringing more or less compression on line. They can send natural gas to storage or withdraw it, always keeping every location on the line below MAOP.

For some pipelines, controllers decide which compressors to start or stop. On other lines, controllers tell the control system how much station horsepower is desired. The station computer then decides which compressors to run, based on a priority list programmed into the computer by local station operators.

Routine operations

Natural gas pipeline operators want pipeline pressures as high as safely allowable, since higher pressures translate to less friction loss per unit of gas and more efficient operations. (For oil lines it is the opposite, as described in chapter 3.) Producers and others delivering into the pipeline want pipeline pressures as low as possible. This enables them to input maximum gas quantities with as little compression on their side of the delivery valve as possible, saving them money. LDCs and others receiving gas are generally aligned with the natural gas pipelines, wanting high delivery pressures, enabling them to operate with as little compression as possible.

Pipeline controllers communicate with and balance the needs of these different groups, making frequent decisions regarding compressor configuration and line pressures. They also manage the day-to-day input and output upsets. When a major gas plant unexpectedly shuts down, curtailing supply, controllers examine the situation and adjust line operations to compensate. They may decide to withdraw gas from storage, stop delivering into storage, or simply take some compression off line on the supply end, allowing the line to unpack. (The same amount delivers out, but less comes into the line.) Perhaps a cold front comes a few hours earlier than anticipated, thus increasing demand unexpectedly. Controllers will have to compensate again, using a combination of the same mechanisms—storage, compression, or line pack.

Sometimes controllers access computer modeling programs to assist with decisions about compressor selection and other line operations. Generally, for large transmission lines, the models have limited reliability because of the hundreds of receipt and delivery points, each with its own set of constraints and constantly changing conditions. At most natural gas pipelines, controller experience and intuition have more to do with safe and efficient operation than computer models.

Quality control

Natural gas controllers play an important quality role. They monitor receipts to ensure gas quality is within specifications. At major receipt points, gas chromatographs monitor the line, displaying line quality as shown earlier (fig. 5-5).

Control systems sound alarms when properties of the incoming stream exceed preset limits (high or low), and operators take corrective action. While it is a last resort, they may shut down receipt points that violate pipeline specifications.

Abnormal operations

Abnormal operations for a natural gas pipeline are not much different from abnormal operations for an oil pipeline. They may be planned or unplanned. Planned abnormal operations normally happen during planned maintenance activities, such as:

- Running internal inspection devices
- Lowering, reconditioning, or welding on the line while in service
- Performing pressure tests

These situations are carefully planned and monitored. Still they are abnormal because they happen infrequently. Controllers are usually briefed and retrained to respond to these situations very close to the time they occur, so the details are fresh in their minds. More on this is covered in the chapter on maintenance.

Unplanned or unexpected abnormal operations can cover a wide range of situations. Some of them are:

- Loss of data in the control center
- Inability for the control center to control equipment
- Unintended shutdown of the line
- Unintended activation or deactivation of any device (motor, valve, etc.)
- Operation of a safety device

These are all covered in chapter 4, but one important difference that deserves treatment concerns leaks and how they are detected.

Unlike oil leaks, natural gas leaking from pipelines is essentially invisible. Large leaks are found quickly because the rapidly decompressing gas causes a crater and makes a roaring noise. For large leaks, the control system senses a pressure drop and signals an alarm, and controllers shut down the line and close valves along the route. This allows only the natural gas between the two closest valves (one upstream and one downstream of the leak) to escape.

Smaller leaks are more difficult to detect. Chapter 8 covers leak detection, discussing the challenges line pack presents to finding small natural gas leaks. (Gas differs from liquids in that due to compressibility, volumes in do not necessarily equal volumes out.) Leaking natural gas kills the surrounding vegetation, a clear sign of potential trouble to the alert operator patrolling the line on the ground, or the line flier patrolling from the air. Ground patrols also employ gas “sniffers” designed to detect small levels of natural gas. Some emerging technologies detect leaking hydrocarbons from airplanes and by satellite.

Operator Training

As with oil pipeline controllers, on-the-job training has played a large role in how pipeline field and central control room operators have been trained. This training is effective in teaching operators how to handle routine operations. However, since abnormal operations happen infrequently, on-the-job training has limited usefulness in preparing operators to handle these situations. Instead, simulations, drills, discussions, and playback of previous problems play a more effective role in preparing operators to respond.

References

For more background information, see Raymond, M. S. and W. L. Leffler. *Oil and Gas Production in Nontechnical Language*. Tulsa, OK: PennWell, 2005.

6

Petrochemical and LPG Pipeline Operations

*Sometimes I've believed as many as
six impossible things before breakfast.*

—**Lewis Carroll (1832–1898)**

Crude oil and refined products are essentially incompressible liquids. Natural gas is very compressible. Petrochemicals and LPG are somewhere in between, which calls for a separate treatise for these products.

Of course the design, construction, and operational aspects of petrochemical and LPG pipelines are similar to oil and gas pipelines. This chapter focuses on aspects of petrochemical and LPG pipelines that are unique.

Definitions

For the purposes of this chapter, LPG has a broader definition than the one at the hardware store, where liquefied propane is for sale in pressurized containers that go under a gas grill. In this chapter, LPG includes ethane, propane, butanes, and sometimes combinations of these three hydrocarbons. These are the natural gas liquids that can be extracted from natural gas at natural gas processing plants. They can also be produced at refineries.

Petrochemicals can include hundreds of complex chemicals, but this chapter deals with only several of the basic building block petrochemicals. These are ethylene, propylene, butadienes, and butylenes. (Strictly speaking, as chemists usually do, butane

comes in two forms, called isomers. Each has its own properties, including vapor pressure and specific gravity. The same is true for butylenes, which come in three isomers, and butadienes, which come in two.)

The LPGs and petrochemicals form a nice package because they behave more like each other than oil or gas.

Product Characteristics

The chemical structure of the petrochemicals and LPGs consists of molecules that have two, three, or four carbon atoms, called C2, C3, and C4 for short. (Chemists and chemical engineers write them C₂, C₃, and C₄.) A natural gas molecule has one carbon atom, while gasoline and crude oil are composed of molecules having five or more carbon atoms. The number of carbon atoms greatly influences a product's physical characteristics.

C4 products

Table 6-1 shows that C4 products—butanes, butylenes, and butadienes—have vapor pressures ranging from 37 psia to 72 psia. (Vapor pressure is the lowest pressure that still keeps a liquid from vaporizing. This was discussed in more detail in chapter 3.) Such moderate vapor pressure makes it more practical to transport these products in the liquid state, including via pipeline, tank car, or truck. The savings in pipeline diameter (moving liquid rather than the equivalent mass as vapor) more than offset maintaining the higher pressures. The typical C4 pipeline pressures range from 100 psi up to about 1,000 psi. As long as the pipeline pressure is maintained above vapor pressure, the C4 products behave much as refined products do. They are only slightly more compressible. An increase in pressure from 100 psi to 1,100 psi increases the density of a C4 product by only 1.5% to 2.0%.

Table 6-1. Characteristics of petrochemicals and LPGs

	Chemical formula	Vapor pressure	Critical point	
		psia	temp °F	psia
Methane	CH ₄	See Note	-117	666
Ethylene	C ₂ H ₄	See Note	48.5	731
Ethane	C ₂ H ₆	See Note	90	706
Propane	C ₃ H ₈	189	206	616
Propylene	C ₃ H ₆	228	197	669
Butanes	C ₄ H ₁₀	52-72	~306	~551
Butadienes	C ₄ H ₆	637-59	~305	~628
Butylenes	C ₄ H ₈	46-63	~194	~584

Note: The standard for vapor pressure is to measure it at 100°F. Methane, ethane, and ethylene each have critical temperatures less than 100°F. Thus, at 100°F these products are always vapor, and cannot be in the liquid state no matter what the pressure. Their vapor pressures are therefore undefined.

C3 products

The C3 products, propane and propylene, have vapor pressures of about 190 psia. Even at these elevated levels, these products are also transported as liquids. Typical C3 pipeline pressures range from 300 psi up to about 1,400 psi. Again, with pressure above C3 vapor pressures, these products behave as liquids do. They are more compressible than C4 products. An increase in pressure from 300 psi to 1,300 psi increases the density of a C3 product by 2.0% to 3.5%.

C2 products

The C2 products, ethane and ethylene, diverge from the pattern because the pipelines operate in or near the *supercritical state*. This is an arcane concept from a remote corner of thermodynamics (see “Critical Information”).

The critical temperature for ethylene is only 48.5°F, and the critical pressure is 731 psi. Ethylene pipelines generally operate above these levels, with ethylene in the supercritical stage, except in places with obviously cold climates like Canada. As the pressure of a supercritical fluid is increased, it behaves more like a liquid. Typical ethylene pipeline pressures range from 800 to 2,100 psi. An increase in pressure from 900 to 1,200 psi will increase the density of ethylene by 61%. A further increase from 1,200 to 1,900 psi results in only an 18% increase. Still, at the lower end of these ranges, ethylene behaves more like a gas (it is more compressible). At the higher end, it behaves more like a liquid.

Ethane pipelines usually operate just below the critical temperature (90°F) but above the critical pressure (706 psi). They may occasionally wander into the supercritical stage.

Critical Information

All things vaporize, given a high enough temperature. It is tempting to say that all things liquefy or solidify, given a high enough pressure. But this is not so. Every substance has a critical temperature above which it will not liquefy, no matter how high the pressure. Combining the critical temperature with a critical pressure gives the critical point. Above that point, it is not possible to tell the liquid phase from the vapor phase. A fluid in this state is called a supercritical fluid. It behaves neither like a liquid (it is compressible) nor a gas (it does not follow Boyle’s or Charles’ laws whereby volumes, pressures, and temperatures all changing in proportion to each other).

Below the critical temperature, the fluid could be a vapor, a liquid, or a combination, depending on the pressure and temperature combination. Engineers use phase diagrams for chemicals like ethylene and ethane that show the pressure-temperature combinations and the corresponding phases—liquid, vapor, or a combination. Even more on this at the end of the chapter.

Compressibility

Just like natural gas, the compressibility of petrochemicals and LPGs requires considerations for these pipeline operations different from oil pipelines. The flow rate into one of these pipelines does not have to exactly match the flow rate out. The difference in the two flows is always related to pressure increases or decreases. The longer and larger diameter the pipeline, and therefore the more volume it contains, the more compressibility cushion is built in. This is especially true for the C2 products. An ethane or ethylene pipeline that is 50 mi long can flow for hours with a 25% difference between flow in and flow out.

Compressibility also means that, like natural gas lines, pressure waves do not move down the C2 pipelines as quickly as they do in liquids lines. It may take several hours to produce desired changes in pipeline conditions. To use the example of the 50-mi C2 pipeline, perhaps a customer at the end plans to increase receipts. The operators may have to begin packing the pipeline with additional flow a few hours before increasing the delivery rate. Otherwise, once the increased delivery has begun, there may not be enough additional flow capacity to raise the pipeline pressure and flow rate.

With less compressibility, the C3 and C4 products do not provide nearly as much cushion, but they can tolerate some flow imbalance for a short time.

Leak Detection

Many pipelines use online pressure and flow monitoring to detect leaks. In these systems, a computer algorithm compares actual pipeline operating conditions to calculated conditions. Discrepancies beyond a certain threshold are potential leaks. These systems work well for crude oil and refined products. They can also work for C3 and C4 products with appropriate modeling to account for the minimal compressibility. This kind of leak detection, which is mostly about measuring volumes or masses, is more difficult to adapt to a C2 product pipeline. The problem is not just that the product compresses, but that the compressibility factor changes as pressure and temperature change.

Measurement

Petrochemical shippers and customers are keenly interested in knowing how many pounds of their feedstocks the pipeline has received and delivered to them. LPG shippers are more likely to want their information in gallons or barrels, corrected to standard pressures and temperatures. In either case, because of compressibility, tracking the impact of temperature, pressure, and composition variations for petrochemicals and LPGs is more critical than for crude oil and refined products pipelines.

For either volume or mass measurements, orifice and turbine meters are both widely used to measure flow. Both normally use a flow computer for accuracy corrections. For volume measurements, the flow computer takes the volume signal from the meter (the *primary element*) and continually corrects it using pressure and temperature readings. If the composition of the fluid is subject to some variation, a densitometer may also have to be used to adjust the volume.

Mass measurement starts with the volume signal from an orifice or a turbine meter and a density signal from a densitometer. The flow computer multiplies these two signals together to calculate the mass flow. Some shippers of high purity products like ethylene and polymer grade propylene forego the densitometer. They allow the flow computer to calculate density using only pressure and temperature measurements.

Quality

Managing the quality of the fluids is more critical for petrochemicals than any other pipeline product. Crude oil, refined products, and LPG quality issues can affect volume measurements and product accounting. They might require some downgrading of product and loss of product value. Even for LPGs, small amounts of butanes can be blended off to propane or propane off to ethane.

But for some petrochemicals, quality issues can affect the integrity of a customer's processes. In many cases, a petrochemical company's processes run right off the pipeline. Small changes in product quality can cause an upset in a chemical plant's process or ruin the acceptability of its products. In some cases this can result in shutting down the process. Because of these quality concerns, petrochemical pipelines are almost always dedicated to a single product.

Ethylene and polymer grade propylene, in particular, are the most quality-stringent petrochemicals. These products are typically 99.9% pure. The most common contaminants are methane, ethane, and propane, which together make up almost all of the 0.1% impurity. Other impurities such as water, oxygen, carbon dioxide, carbon monoxide, and acetylene are typically in the 1 or 2 parts per million (ppm) range. These impurities can cause problems in the customer's plant if they reach concentrations of 5 ppm or greater.

To provide such fine quality control, pipelines use continuous, on-stream analyzers—usually gas chromatographs—installed at strategic locations to monitor product quality. In the event these devices detect off-specification product in the pipeline, the operators immediately notify the shippers and the customers. They work to determine the origin of the contaminants. Sometimes a customer can blend the bad product with another supply. Other times the pipeline has to be flushed with the off-spec material diverted to be flared or to be cleaned up.

Commissioning and Decommissioning

Commissioning a petrochemical or LPG pipeline presents special quality integrity issues. Careful effort is taken to dry the pipeline before introducing product. Petrochemical plants commonly require that petrochemical products have dew points of -70°F to -80°F . (Dew points are the temperatures at which water droplets start to form from any water vapor in the product. And almost all commercially traded petrochemicals and LPGs have some small amount of water vapor entrained in the C2 vapors or dissolved in the C3 or C4 liquids.) LPG product specifications generally call for dew points no higher than -40°F . To achieve these inordinately challenging levels of dryness, at commissioning a pipeline must be meticulously cleaned so that no moisture-retaining rust, scale, or sludge remains.

Specifications for oxygen content also call for painstaking preparation. Usually, purging a pipeline with nitrogen drives out the oxygen.

Freezing temperatures

As product is first introduced into a pipeline, the product source is at high pressure, but the pipeline may be at low pressure. As the product enters the lower pressure line, it will expand, absorbing heat in the process, causing the product temperature to drop, often precipitously. In short, pressure letdown causes falling temperatures.

Introducing C2 products can drop temperatures lower than -120°F . With C3 products, temperatures can drop to the -40°F range. Pipelines are normally made with carbon steel that is only rated for temperatures of -20°F . To ensure that the pipeline is not chilled below its rated temperature on initial fill, either some back pressure has to be maintained or heat has to be added at the input.

Sometimes a pipeline has to be decommissioned, which involves removal of the product so the pipeline can be repaired or maintained. With petrochemical and LPG vapor pressures of 35 psia or greater, the product cannot be emptied into conventional storage tanks or vacuum trucks. In many cases, the product in the pipeline can be displaced to customer's or shipper's facilities with nitrogen, with only a modicum of interface involved. Sometimes the entire product in the pipeline cannot easily be handled and has to be flared or burned as fuel.

Flaring can encounter the same low temperatures as commissioning, as the pressure drops and the fluid expands. The piping leading up to an ethylene flare is often covered with frost to within inches of the flame. Flare systems usually use stainless steel pipe due to its low-temperature ratings.

Storage

Petrochemicals and LPG pipelines and storage facilities operate together as a system. Storage sites provide the cushions—well beyond the compressibility—that balance day-to-day pipeline supply with pipeline demand.

Petrochemical and LPG pipeline operations require large quantities of product (100,000 bbl to 1,000,000 bbl) to be stored at high pressures. But the elevated pressures necessary to keep the products in the liquid state demand heavy steel structures. Construction costs forced the pipelines to look for a cheaper alternative.

A number of places around the world are endowed with huge underground accumulations of salt—the same chemical found in a kitchen salt shaker. The U.S. Gulf Coast is the best known of these locations. These massive formations known as *salt domes* are some 300 ft to 5,000 ft below the surface. Huge spaces, or caverns, can be hollowed out of these salt domes to provide storage for liquids and gases (fig. 6-1).

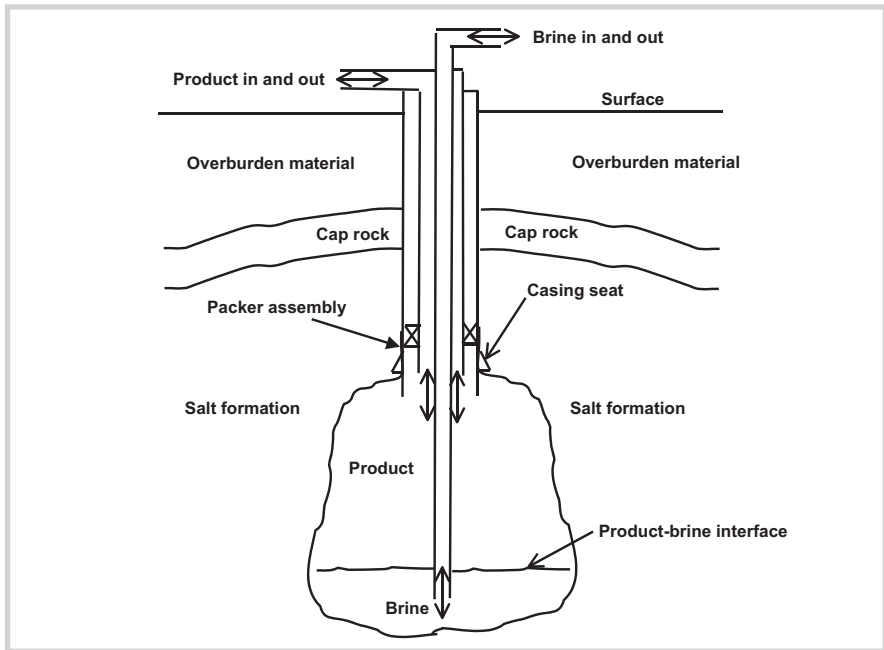


Fig. 6–1. Salt dome storage. This cavern is a wet system. (Courtesy Carl Brassow)

To create a cavern in a salt dome for use as a storage facility, a well is drilled to the right depth in the dome. After that, a cavern is leached out by pumping fresh water down a pipe into the dome. As fresh water is pumped down the pipe to dissolve the salt, the pipe's depth is varied to produce the cavern's desired shape. Salt-laden water, or brine, is displaced up another pipe as more fresh water is pumped in.

When the cavern is large enough, an LPG or petrochemical is pumped down the inlet pipe, displacing resident brine back to the surface where it is stored in lined pits. Pressure is maintained high enough to keep the product liquid, or in the case of C₂, above the critical point. The product will float on top of the brine, just as any other hydrocarbon does. At all times the cavern has to be filled with one or both liquids to insure that it will not implode.

To withdraw the product, brine is pumped from a nearby pit into the bottom of the cavern, forcing the product up the other pipe to the surface. Brine is used for this operation rather than fresh water. The brine already has all the salt it can hold, and the cavern will not be further enlarged beyond its engineering design. Fresh water would dissolve more salt and make the cavern larger, perhaps beyond safe design specifications.

The cavern just explained is called a *wet system*, because it always operates with brine to control the amount of fluid in the cavern. There are also *dry systems*, which are leached out just like wet systems but do not use brine to control the fluids. The difference has to do with the vapor pressure of the material stored and the external pressure on the cavern walls. The pressure inside the cavern must be greater than the external pressure from the *overburden*, or the rock and soil above the cavern. This prevents the cavern from *imploding*, or falling in on itself. The vapor pressures of the materials dealt with in this chapter are usually not high enough to offset the external pressure on the cavern walls. Thus they must be kept in a liquid state at all times. This results in the need for brine to displace them and maintain internal pressure at a safe level. The vapor pressure of natural gas, on the other hand, is usually high enough to offset the external pressure. Thus natural gas caverns can be operated as dry systems, although enough *cushion gas* must be left in the cavern at all times to maintain safe internal pressures. Wet systems also work for natural gas storage, but dry systems keep out the salty brine, a major cause of corrosion.

Salt dome caverns typically range in capacity from 100,000 bbl to several million bbl of storage. The U.S. government uses caverns to store nearly 1 billion bbl of readily accessible crude oil as part of its Strategic Petroleum Reserve (SPR) on the U.S. Gulf Coast.

In other parts of the world, rock formations provide the same capability. Rock caverns have to be mined using heavy equipment lowered in pieces down a shaft. Because of their size, mined rock caverns are still cheaper than aboveground steel storage, but they cost more than the construction costs of salt dome caverns.

Hydraulics

Hydraulics for most petrochemical and LPG pipelines are very similar to hydraulics for crude oil and refined products. The C3 and C4 products are pumped as liquids. They may even be batched on crude oil or refined products lines. Their pressure drop per mile is typically less than the pressure drop for an equivalent volume of crude oil or refined products, since they have lower viscosities. Their vapor pressures are many times higher than oil, but as long as the line pressure stays above their vapor pressures, the line will not be pulled apart. This is similar to other liquids.

As always, C2s are a little different, even with hydraulics. Just like with natural gas, running C2 pipelines at higher pressures results in lower, cheaper energy consumption:

- C2s run as supercritical fluids—their densities change rapidly with pressure changes.
- The objective is to move a given mass, not volume.
- Friction is a function of velocity.
- The higher the pressure, the higher the density.
- Mass = volume × density. Therefore, for a given mass, the higher the density, the lower the volume. Thus, higher pressures give lower volumes, lower velocity, and lower friction losses.

So, pipeline designers prefer higher pressures to minimize friction and unnecessarily expensive line losses.

Addendum—Supercritical Fluids

The subject of critical temperatures and supercritical fluids is elusively hard to understand. But for engineers dealing with ethylene pipelines, the notion is essential to their planning and design. One more layer of understanding is peeled back here for ethylene.

Figure 6–2 shows a phase diagram for ethylene with the following features:

- Pressures are on the vertical scale.
- Enthalpy, or in simplest terms, energy content, is on the horizontal scale. (For this exercise, understanding enthalpy is not very important to the points yet to be made.)
- Constant temperature lines are shown more or less vertically.
- There is an envelope in the middle where both liquid and vapor exist.
- The left side of the chart has conditions in which the ethylene is all liquid—very low temperatures—no matter how low the pressure.
- The right side has conditions that result in all vapor—very high temperatures—no matter how high the pressure.

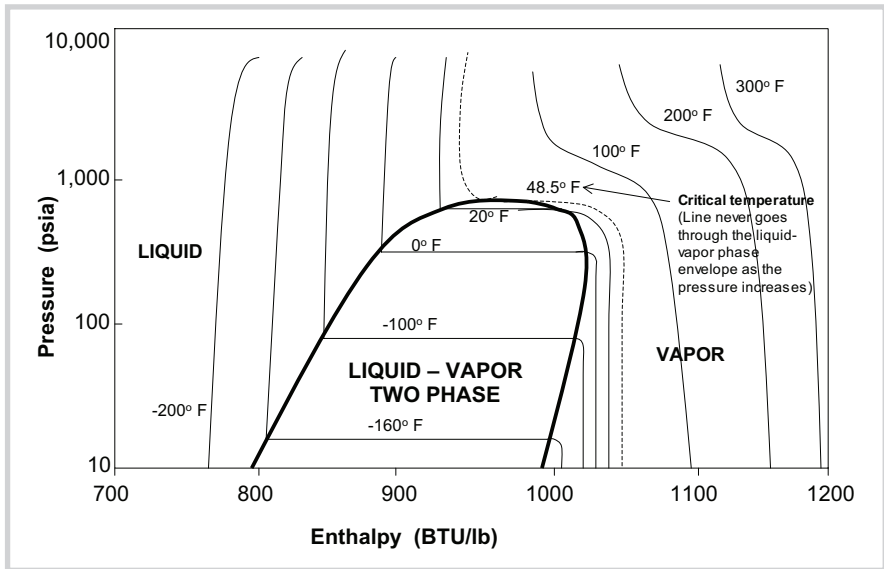


Fig. 6–2. Ethylene phase diagram

There are some noteworthy dynamics of this chart:

- Some temperature lines pass through the liquid-vapor envelope.
- Some temperatures lines do not.
- The dividing line is the *critical temperature*, 48.5°F. *Since this line does not pass through the liquid-vapor envelope, no matter how high the pressure, the ethylene does not liquefy.*

Finally, as the fluid's temperature and pressure get higher than both the critical temperature and the critical pressure, right at the top of the envelope, it becomes *supercritical*. As mentioned before, it behaves as neither a liquid (it is compressible) nor a vapor (it does not follow Boyle's and Charles' laws of pressure, temperature, and volume changes).



Offshore Pipelines

O me, why have they not buried me deep enough?
—**Alfred, Lord Tennyson (1809–1892)**

Pipelines that connect offshore oil and gas production platforms to onshore facilities present another level of complexity to installation and operation. Further, the pipelines that connect subsea wells to the platforms have their own set of critical concerns. After all, it is not possible to send a technician or a welder to a site under 10,000 ft of water to make a connection or fix a leak.

The offshore pipeline industry has its own jargon, which is evident in figure 7–1.

- *Wet trees* refers to the apparatus at the top of a subsea well that has valves, gauges, and connection flanges and is operated and serviced remotely from a nearby platform.
- *Dry trees* are equivalent to wet trees but are located on the production platform, where they can be operated and serviced directly by platform personnel. Onshore these are sometimes called Christmas trees because of their shapes and the legendary seasonal decorations put on them.
- *Jumpers* connect wellheads to manifolds. Onshore these connections would normally be installed by pipe fitters. In the offshore industry, more elaborate installation equipment, of the type used for subsea pipelines, is required.

- *Manifolds* are lengths of large-diameter pipe that have multiple flanges for inlet connections, and one for an outlet to another larger pipe or a riser.
- *Risers* are pipes connecting a tree, a pipeline, or a manifold, all on the sea floor, to the top of a production platform.
- *Subsea pipelines* take oil and gas that has been processed, separated, and treated on the platform to onshore facilities.
- *Production platforms* receive, separate, process, and ship oil and gas. The platforms can be fixed to the bottom on tall structures or can be floating platforms that are anchored to the bottom with chains or wire.

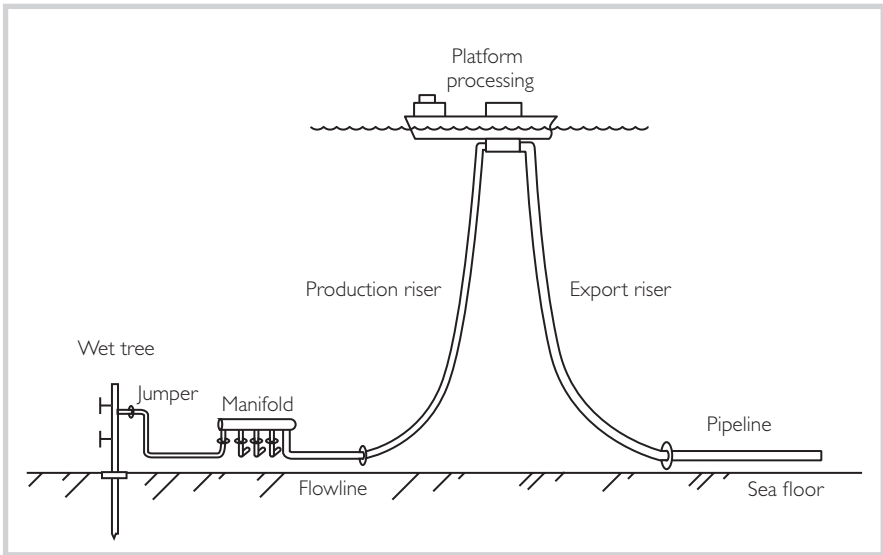


Fig. 7-1. Connections from the offshore wellhead to the onshore facilities (Source:W. L. Leffler, R.A. Pattarozzi, and G. Sterling. *Deepwater Petroleum Exploration and Production: A Nontechnical Guide*, Tulsa, PennWell, 2003.)

Line Design

The further downstream from the wellhead, as more streams commingle in manifolds, the larger the diameter of the lines becomes. Lines, of course, are sized to handle the expected pressure and fluid flow. Jumper diameters can be as small as 4 in., but 6-in. to 12-in. pipes are common. Subsea pipelines generally range from 12 in. to 30 in. To deal with the pressure both inside and outside the pipeline, wall thicknesses of the pipe range from $\frac{3}{4}$ in. to 2 in.

of steel. (At the extreme end of the subsea spectrum—deepwater operations in 10,000 ft of water—the pressure on the *outside* of a pipeline is 4,200 psi. The pressure *inside* the pipeline needed to lift oil to sea level has to be even higher to achieve the 10,000-ft lift, plus account for the friction in the pipe.)

The temperature of water in the deep ocean hovers around 30°F to 35°F. The water rapidly sucks heat out of the fluids in a bare steel pipe. The freezing cold environment can cause hydrates to form in a gas line or can cause paraffins (waxy hydrocarbons) to plate the walls of an oil line. Either way, the line can plug, making a very bad day for the production crew on the platform, hundreds or even thousands of feet above. To avoid this disaster, most lines are coated with an insulating material. (Pigging and injection of antiplugging chemicals at the wellhead can provide a complementary antidote to plugging.)

As an alternative to externally applied insulation, *pipe-in-pipe* works very well. For this technique, a 12-in. line is enclosed in an 18-in. pipe, for example. The annular space between the two lines is filled with a high-quality insulating material, providing an effect much like a thermos bottle. Insulated lines sometimes get roughed up during installation, tearing the insulation and exposing the lines to cold spots and possible plugging problems. The pipe-in-pipe eliminates this hazard.

Although the lion's share of pipelines and flow lines consists of steel pipe, there is an alternative. This is a flexible pipe that is fabricated from helically wound metallic wires interspersed with thermoplastic layers. Each layer has a specific function (fig. 7-2). These *flexibles*, as they are called, have excellent bending characteristics and are often used where steel pipe would be too rigid.

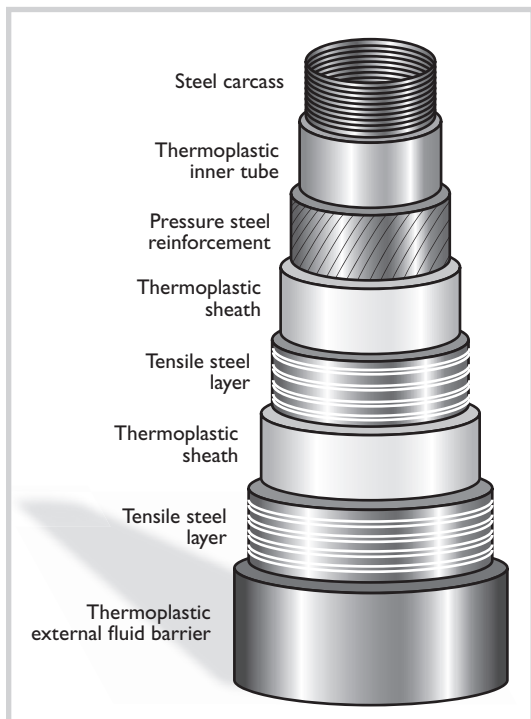


Fig. 7-2. Flexible pipe and its various layers (Source: Leffler, Pattarozzi, and Sterling. Deepwater Petroleum Exploration and Production, 2003.)

Installing Subsea Pipelines

The boon and bane of buoyancy

During the installation of a pipeline, as the pipe reaches from the stern of a lay barge to the seabed, the entire vertical load of the pipe weighs on the barge. For example, one could consider a 24-in. steel pipeline with 1-in. thick walls. One foot of that line weighs about 250 lb on the barge deck. In the water, it weighs only 50 lb, if it is filled with air and not water. The buoyancy effect provides the counteracting upward 200-lb force. Suppose a barge was laying that pipe in 3,000 ft of water. It has to support more than 150,000 lb of weight off its stern (fig. 7–3). (Actually, it will have to support more than this, because the trajectory from the lay barge to the touchdown point of the pipe is more than the water depth.) If the line suddenly flooded with water because it buckled or some other catastrophe occurred, the load on the system would jump to more than 750,000 lb. That sudden increase could cause the loss of the pipeline or damage to the lay barge. Even worse, as the water depth increases, in 10,000 ft of water the barge would be in peril if it had no quick-disconnect capability. For that reason, the laying procedure includes careful and continuous monitoring of the configuration of the outstretched pipeline to ensure structural integrity.

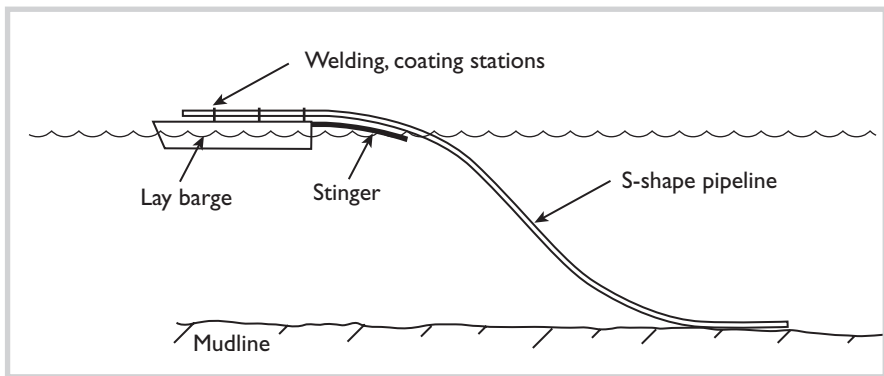


Fig. 7–3. The S-lay process and shape (Source: Leffler, Pattarozzi, and Sterling. *Deepwater Petroleum Exploration and Production*, 2003.)

Ironically, once on the sea floor, a pipeline needs more net *downward* force to keep it from drifting. Oil, so much heavier than air, adds to the weight of the steel pipe. Gas, however, does not provide the extra weight of oil. Depending on the line size, extra ballasting might be needed to hold the line in place. In shallow water, the most cost-efficient way to add weight is coating the pipe with concrete. In deeper water, the pipe wall thickness required to resist hydrostatic pressure is often enough to provide the needed weight.

Laying pipe

Jumpers, being short and typically weighing 10 to 20 tons, are generally prefabricated. They are lowered into place using cranes or winches on the deck of the construction vessel and assisted by a remotely operated vehicle (ROV). In addition, ROVs provide reconnaissance for selecting routes, surveillance during the laying, and aid in connecting various pieces when they are in place. More information on ROVs follows at the end of the chapter.

Flow lines and pipelines extend for miles and require special pipeline-laying vessels. Laying miles of pipe in thousands of feet of water starts by welding together pipe lengths of 40 ft to 240 ft. Contrary to casual perceptions, a long section of steel pipe is quite flexible. While a 40-ft length may seem totally rigid, 5,000 ft of unsupported 24-in. pipe droops like a fly rod with a 10-lb trout on the hook. Even more remarkable, to continue the angler's analogy, the same pipe can be wound around a reel for transport and later unwound during installation. To take advantage of flexibility and buoyancy, pipeline laying comes in four self-descriptive configurations: S-lay, J-lay, reel barge, and tow-in.

S-lay

An S-lay vessel has on its deck several welding stations where the crew welds together 40-ft or 80-ft lengths of insulated pipe in a dry environment away from wind and rain. The pipe, either for a flowline or a pipeline, is eased off the stern as the vessel moves forward. It curves downward through the water as it leaves until it reaches the *touchdown point*. After touchdown, as more pipe is played out, the pipe assumes the nominal S-shape shown in figure 7-3.

To control the pipe curvature as it leaves the barge, a *stinger*, a long steel structure attached to the stern of the barge, supports the pipe. Some stingers extend out 300 ft. Some barges have articulated stingers with controllable hinges that change the shape of the stinger, managing the trajectory of the pipeline. That gives S-lay barge vessels flexibility to operate in a variety of water depths, shallow to deep.

The double-curvature S-shape requires careful control of the lay barge position relative to the touchdown point. The barge must hold the pipe at the right level of tension, otherwise the curvature can become severe enough for the pipeline to buckle, a disastrous event. Tensioning rollers and controlled forward thrust provide the appropriate tensile load.

The assembly line process of feeding, welding, coating, and laying is supported with loads of pipe arriving on transport barges as the work progresses. S-lay barges can lay as much as 4 mi/day of pipeline. The S-lay process is good to at least 6,500 ft of water.

Figure 7–4 shows a world-class S-lay vessel getting ready for a job. This vessel, the *Solitaire*, owned by Allseas, is 300 m long, excluding the stinger, and can accommodate 420 people. It has two pipe transfer cranes, two double-jointing plants where 40-ft pieces are joined, seven welding stations, one quality control station, and two coating stations. It has the capacity to hold up to 580 tons of tension on the pipeline, and to lay pipe from 2 in. to 60 in. It can carry an inventory of 15,000 tons of pipe, which allows it to lay miles of pipeline before being restocked.



Fig. 7–4. Pipe-laying vessel *Solitaire* (Courtesy Allseas)

J-lay

To avoid some of the difficulties of S-laying tensile load, forward thrust J-lay barges drop the pipe down almost vertically until it reaches touchdown. After that, the pipe assumes the nominal J-shape shown in figure 7–5. J-lay barges have a tall tower on the stern or over the side where lengths of pipe are stacked, joined, welded, and coated before they slip into the sea. The tall towers mean that, realistically, only one welding station can be used, so the pipe arrives on transport barges in long, prewelded lengths up to 240 ft.

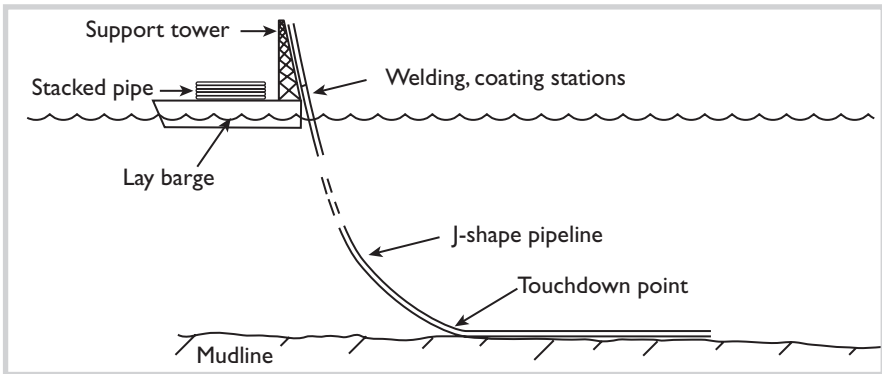


Fig. 7-5. The J-lay process and shape (Source: Leffler, Pattarozzi, and Sterling. Deepwater Petroleum Exploration and Production, 2003.)

With the simpler pipeline shape, the J-lay process can be used in deeper water than the S-lay process. During the pipe-laying procedure, the pipeline can tolerate more motion from barge movements and underwater currents that could lead to buckling. Figure 7-6 shows a J-lay process working from a large crane vessel.



Fig. 7-6. J-lay barge (Courtesy Heerema Marine Contractors)

Reel barge

Once they realized they could wind pipe around a reel like fishing line, pipeliners began to transport it and deliver it over the stern of lay vessels that way. Some reels unwind horizontally, some vertically (fig. 7–7). The horizontal reels lay pipe with an S-lay configuration. Vertical reels most commonly do J-lay but can also S-lay.

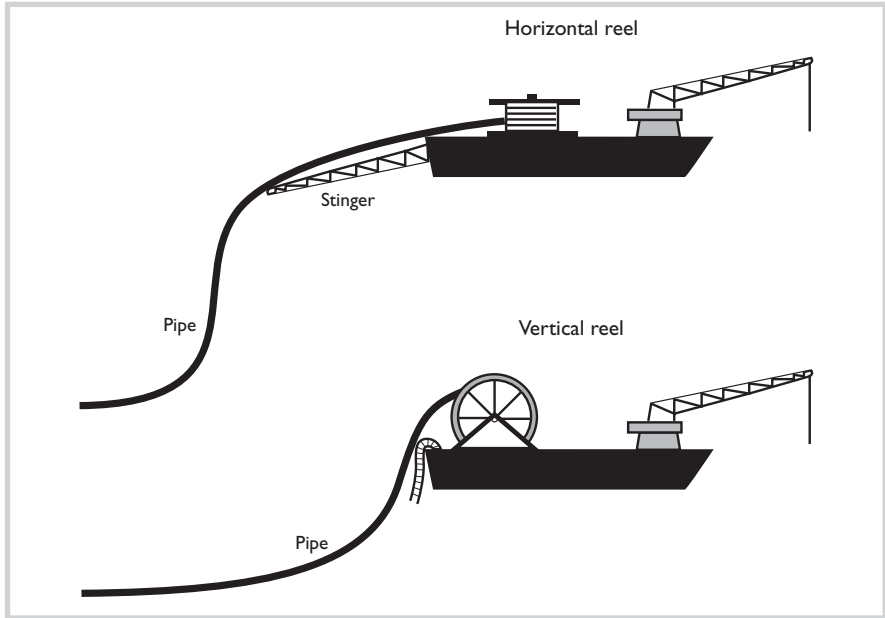


Fig. 7–7. Horizontal and vertical reel barges (Source: Leffler, Pattarozzi, and Sterling. Deepwater Petroleum Exploration and Production, 2003.)

Most of the welding and coating for reeled pipe takes place onshore, where costs are much lower. The onshore operation requires long sections of property adjoining good dockage. There the reel barge prepares to load up with the prewelded pipe stretched out onshore. Figure 7–8 shows the Global Industries' reel barge, *Hercules*, laying pipe in the Gulf of Mexico.

The length of pipe that a reel can handle depends on the pipe diameter. More than 30,000 ft of 6-in. pipe, the type used for some flowline applications, can fit on a reel. In many cases, that is sufficient for a barge to lay several flowlines. Pipe up to 18 in. in diameter has been successfully reeled, but at much smaller lengths. Some lay barges have cranes that can lift loaded reels off transport barges and return the empties. Others have to make the round trip to shore to do the exchange, a time-consuming interruption if the pipeline or flowline is not near the supply depot.



Fig. 7-8. Reel barge laying pipe (Courtesy Global Contractors)

Tow-in

There are four basic variations of the towed pipeline method, as shown in figure 7–9. For the *surface tow* approach, the pipeline has some buoyancy modules added so that it floats at the surface. Because of the length involved, two tug or towboats are required to control the pipe as it is being taken to location. Once on site, the buoyancy modules are (carefully) removed or flooded, and the pipeline settles to the sea floor.

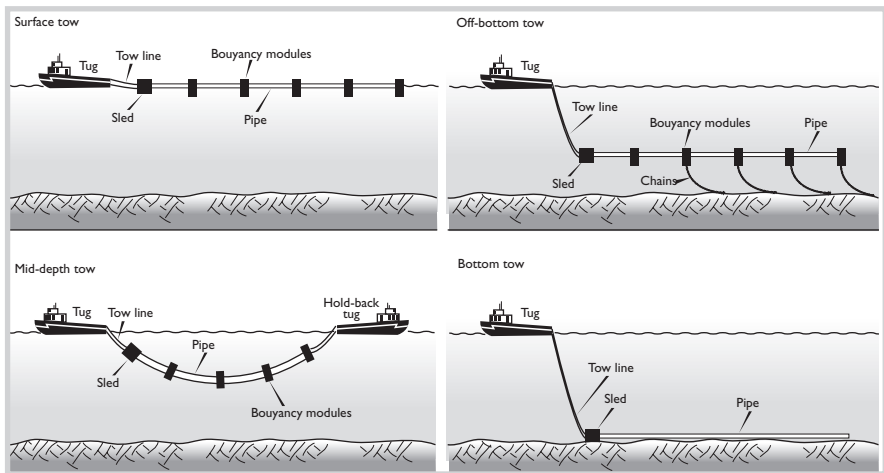


Fig. 7–9. Variations on tow-in installations (Source: Leffler, Pattarozzi, and Sterling. *Deepwater Petroleum Exploration and Production*, 2003.)

The *mid-depth tow* also requires some buoyancy modules, but fewer of them. Both the depth of submergence and the shape of the pipeline are controlled by the forward speed of the tow. In this case, the pipeline settles to the bottom on its own when the forward progression ceases.

The third case, *off-bottom tow*, involves both buoyancy modules and added weight in the form of chains. The chains cause the pipeline to sink to near the bottom, but as the chain links pile up on the sea floor, their weight reduces, and the buoyancy holds the pipe at a given distance above bottom. Again, once on location, the buoyancy is removed, and the line settles to the sea floor.

The last variation is *bottom tow*. In this case, the pipeline is allowed, or caused, to sink to the bottom, and then towed along the sea floor. This alternate is used primarily for soft and flat bottoms, and in shallow water.

In all of these approaches, the ends of the pipelines are configured with termination structures, often called sleds. This allows one end to be connected

to a subsea manifold and the other to the host platform riser system, using the previously discussed jumper method.

All of these methods have been used, and are ways to do much work onshore and thus limit exposure to offshore weather conditions. However, long tow distances also have weather-related, shipping, and other associated risks.

Bottom Conditions

To pipeline engineers, the ideal subsea terrain has a continuous flat seabed of soft clay or mud. In many deepwater areas, they find that, but not always. The terrain of the ocean floor varies as much as onshore terrain, with gullies, outcrops, ravines, hills, and escarpments. The precursor to any pipeline or flowline installation is a survey by depth-finding sonar and even an ROV to establish the safest and most economical route. Even small undulations of the seabed cause worry. As the pipeline passes over an extended dip in the surface, it has an *unsupported span*, where the pipeline does not rest firmly on (or perhaps does not even touch) the bottom. Bottom currents can lead to serious vibrations in long unsupported spans.

Strong currents can find the gaps prime targets for scouring even longer expanses, making the pipeline more vulnerable. ROVs search for these unsupported spans. Additional weights or screw-type anchors can be added to push the line down, or at least hold it steady. Alternatively, the spans can be outfitted with vortex-shedding strakes to prevent vibration from occurring.

Risers

To and from the production platform, production and export risers take six different forms. These are: attached risers, pull tube risers, steel catenary risers, top-tensioned risers, flexible riser configurations, and tower risers.

Attached risers

Fixed platforms often have the risers clamped to the outside structure, as the left side of figure 7–10 shows. The riser is prebuilt in sections. The sea bottom end of the riser is attached to the nearby inbound flowline or outbound pipeline, then assembled piece-by-piece and inserted into preplaced clamps on the structure. ROVs with electrohydraulic tools make the connections, or divers do the work.

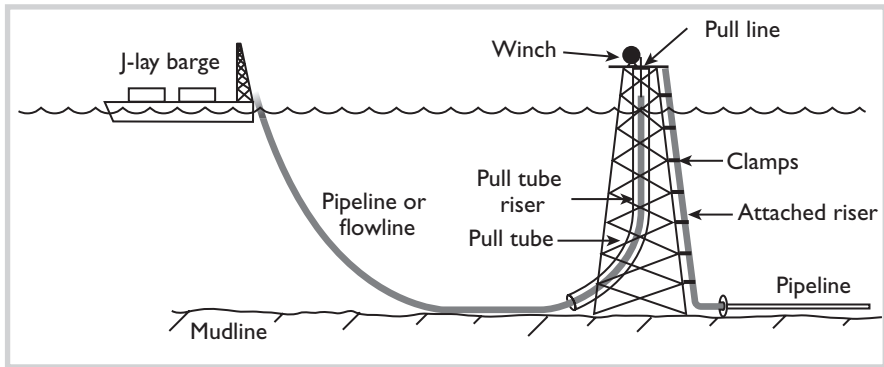


Fig. 7–10. Attached and pull tube risers (Source: Leffler, Pattarozzi, and Sterling. *Deepwater Petroleum Exploration and Production, 2003.*)

Pull tubes

In this installation, shown on the left side of figure 7–10, a flowline or a pipeline becomes the riser as it is literally dragged up through a tube in the center of the structure. The pull tube, a few inches wider than the flowline or pipeline, is generally preinstalled in the structure. A flowline or pipeline laid on the seabed floor is attached to a wire rope threaded through the pull tube. The wire rope is winched up the pull tube to the topsides, at which point the flowline or pipeline inside the tube becomes the riser. This procedure works best, of course, when the pipe is pulled directly from the lay barge and fed into the pull tube.

Steel catenary riser

Some of the world's most graceful bridges, including the Golden Gate in San Francisco and the Verrazano Narrows in New York, exhibit a classic geometric shape. The cables that are strung from the end towers and support the bridge deck form a *catenary*, a perfect geometric shape. Another imposing and classic catenary, this time inverted, is the Gateway Arch in St Louis, Missouri. Designed by Eero Saarinen, it towers 630 ft above the Mississippi River. The steel catenary riser shown schematically in figure 7–11 has a similar, albeit abbreviated, shape from the seabed to the production platform. As with the bridge cables, the more tension on the riser, the less sag in the system, and in the case of risers, the further out the touchdown point is.

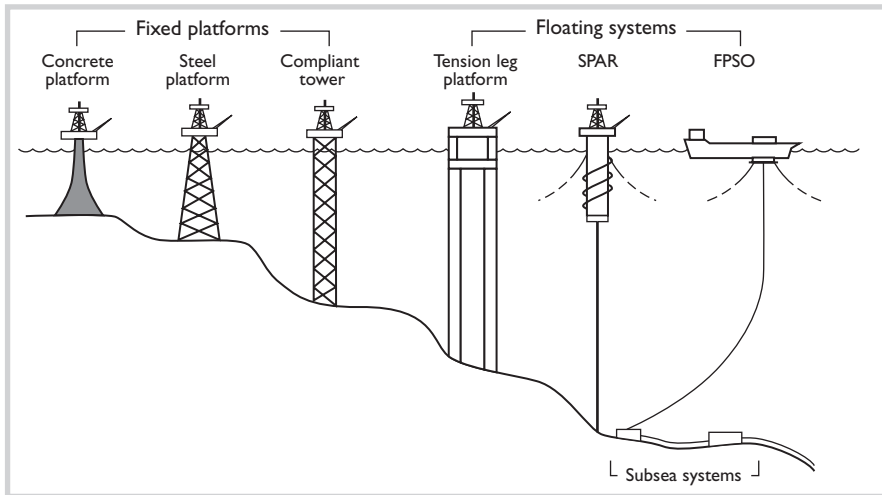


Fig. 7-11. Fixed and floating platforms (Source: Leffler, Pattarozzi, and Sterling. *Deepwater Petroleum Exploration and Production*, 2003.)

Steel catenary risers are an elegant solution to the riser challenge of connecting to floating production platforms in deepwater environments. In contrast to fixed production platforms, floating platforms move with the wave and current action of the sea (fig. 7-11). They bob, sway, and roll like any other seagoing vessel. Even though catenary risers may be made of steel, they are long enough to tolerate the extensive movement of the floating platforms without endangering their connections to the platform equipment. However, during severe storms, some floating platforms disconnect from the risers for the duration of the bad weather.

Some types of platforms move more than others. As a broad generality, from the least to the most, they are:

- **Compliant tower.** This is the tall “erector-set” type of structure that sways with currents.
- **Spar.** This is a buoyant structure that is mostly submerged but has facilities above sea level to receive, process, and ship oil and gas.
- **Tension leg platform (TLP).** This is a buoyant structure that is literally held down in the water below where it would normally float by wire tethers anchored on the sea floor.
- **Floating production system (FPS) and floating production, shipping, and off-loading (FPSO) vessels.** These are semi-permanently anchored at sea during the life of an oil or gas field and receive oil and transship it unprocessed (FSO) or processed (FPSO) to shuttle tankers or a pipeline.

Excessive motion can cause metal fatigue at two vulnerable spots: near the touchdown point (where the pipeline meets the sea floor), and at or near the top support. Because of the wide variation of conditions these platforms present to pipeline connections, the lengths of the risers and the design of the connections differ widely, as follows.

Top-tensioned risers

For some TLP and spar applications, top-tensioned risers provide a good solution. In this application, the flowline or pipeline terminates at the sea floor beneath the platform. A straight riser is run down from the platform and terminates at an L connection with the incoming or outgoing pipe (fig. 7–12).

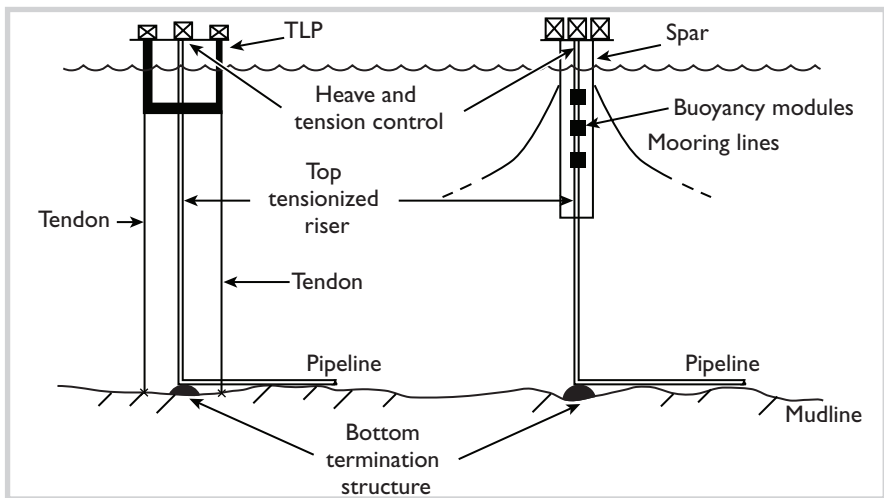


Fig. 7–12. Top-tensioned risers on held-down, floating platforms. (Source: Leffler, Pattarozzi, and Sterling. *Deepwater Petroleum Exploration and Production*, 2003.)

The riser is fixed to the sea floor, and the TLP or spar is free to move laterally under the influence of winds, waves, and currents. Thus there is vertical displacement between the top of the riser and the point where it connects to the TLP or spar. To accommodate this motion within allowable stresses in the riser, a hardware device known as a motion compensator is integrated into the top-tensioning system. An almost constant tension is maintained on the riser by the expansion-contraction action of a telescoping

connector. For spars, a simpler approach is often employed, using buoyancy cans around the outside diameter of the riser, which also mitigate vertical movement (fig. 7–13).

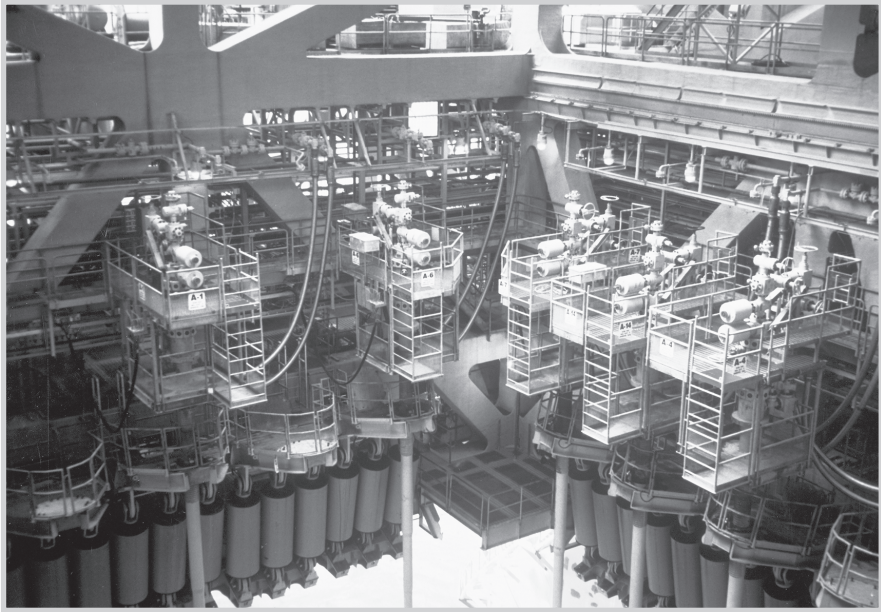


Fig. 7–13. Riser connections at a floating platform (Source: Leffler, Pattarozzi, and Sterling. Deepwater Petroleum Exploration and Production, 2003.)

On the topsides of the platform, the top-tensioned riser is connected to the processing facilities by flexible pipe to further alleviate vertical motion.

Riser tower

Some deepwater designs use riser towers. In a typical application, three steel column towers, each 4,200 ft tall, are anchored to the sea floor in 4,430 ft of water. The towers each accommodate four production risers, four gas lift risers, two water injection risers, and two service line risers. The tower is topped with a buoyancy tank, 130 ft long and from 15 ft to 26 ft in diameter. The upward force generated by the buoyancy tank holds the tower vertically stable.

Flowlines connect from the subsea wells to the tower base, and flexible lines from the nearby FPSO connect to the various risers at the tower top.

Flexible risers

Because of their bending characteristics, flexible risers are most appropriate for floating systems that experience significant vertical and/or horizontal movement. Besides the usual, free-hanging catenary riser, any of several flexible riser configurations can be used. Figure 7–14 shows four: lazy S, steep S, steep wave, and lazy wave. The specific selection depends on the expected motions of the production vessel and available installation equipment. All configurations involve providing buoyancy modules or cans at selected locations on the flexible pipe to force a given shape. They all have the net effect of reducing the stress and wear and tear on the pipe at both the touchdown point and at the platform connection.

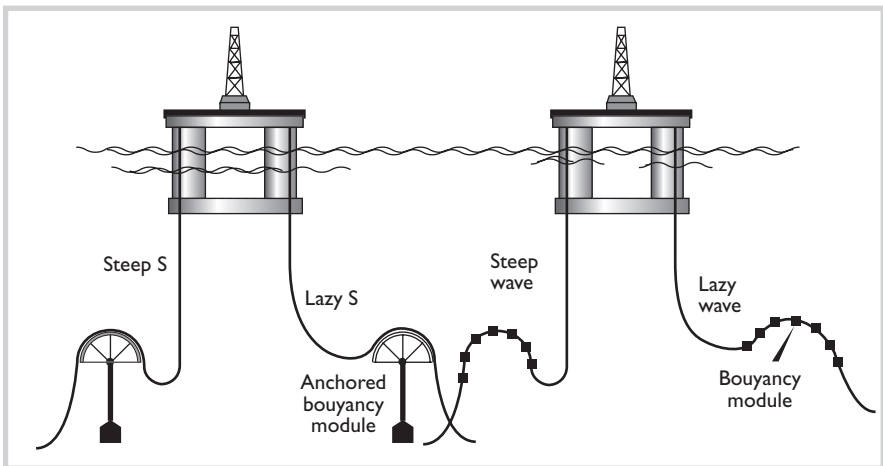


Fig. 7–14. Some flexible riser configurations (Source: Leffler, Pattarozzi, and Sterling. *Deepwater Petroleum Exploration and Production*, 2003.)

ROVs

In an undersea world where depths often exceed the levels at which divers can operate, surveillance, construction, and maintenance still have to take place. ROVs of various special designs now provide these on-site services. The most widely used ROVs do maintenance and installation (fig. 7–15).

A typical ROV has an umbilical cord back to a drilling vessel or a workboat. Through this line the ROV receives power and operating instructions. It uses this cord to send back images from its television cameras, and perhaps data from

connections to subsea modules. Facilities on the sea floor have ROV-friendly connections that allow relatively easy connection or access. An ROV carries its own tool kit and has hydraulic or electric arms to deploy various devices.

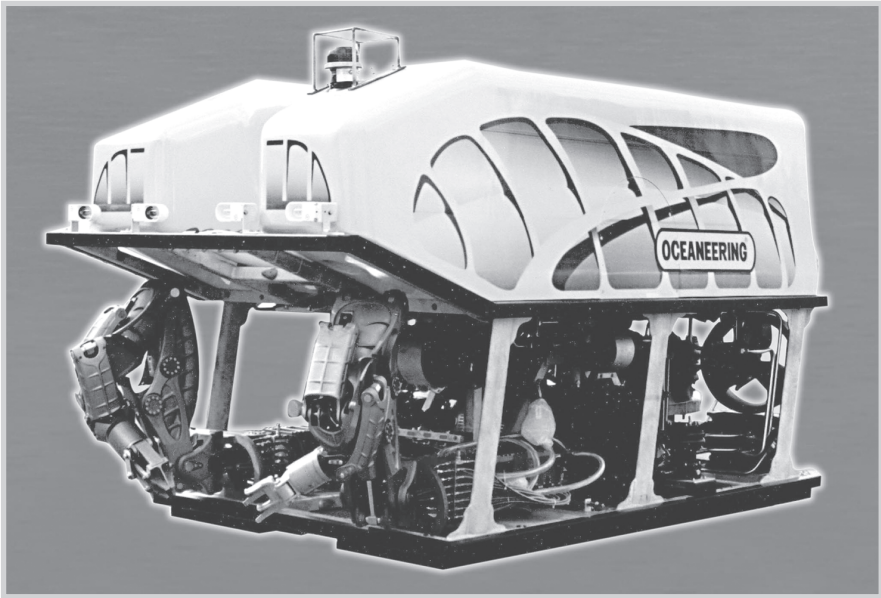


Fig. 7–15. Remotely operated vehicle (Source: Leffler, Pattarozzi, and Sterling. Deepwater Petroleum Exploration and Production, 2003.)

As an example, the ROV in figure 7–16 makes the connection of a subsea pipeline to a platform riser by grabbing, winching, and bolting. Controllers aboard a workboat watch the operation on the televised images, which unfortunately are in two dimensions, and are murky at best. Operators who grew up with video games make good candidates for ROV controllers.

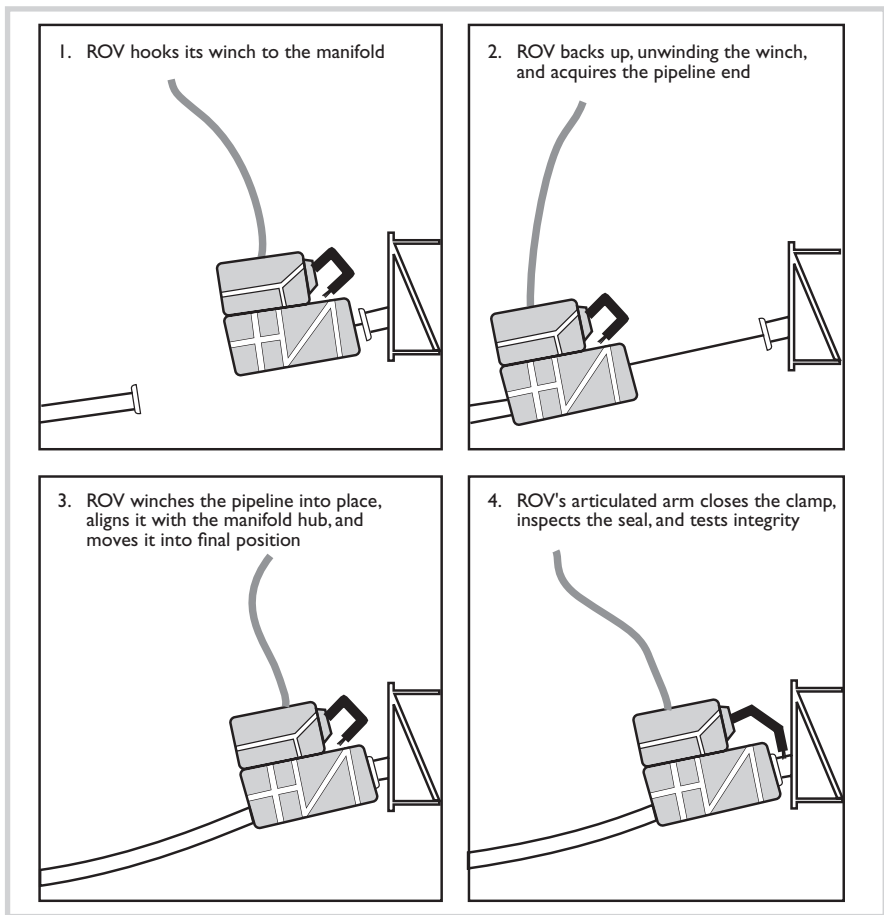


Fig. 7-16. Sequence of an ROV attaching a pipeline to a subsea manifold (Source: Leffler, Pattarozzi, and Sterling. Deepwater Petroleum Exploration and Production, 2003.)

8

SCADA, Controls, and Leak Detection

As a rule, what is out of sight disturbs men more than what they can see.

—Julius Caesar (100–44 B.C.)

On the walls of a conference room on the 15th floor hang topographical maps, pipeline layouts with storage and junctions, and schematics of flows. However, this time the flow represents data, not fluids. A group assembles around the conference table—mechanical, electrical, and civil engineers, computing and communications specialists, instrument vendors, and operations people. Their task is to create the eyes, ears, and hands of a pipeline about to be constructed.

At a different pipeline company, in the same city, another group with similar pedigrees also has gathered. They are struggling to infuse the latest technology into an existing 10-year-old pipeline control system.

In both cases, the task groups are guided by a complex set of rules that are unique to their company and are sometimes unwritten. They are generally referred to as the pipeline company's *control philosophy*. (The use of that term would, of course, make Plato, Descartes, Yogi Berra, and other great philosophers turn over in whatever habitat they occupy.) The end result, after months of effort by the team, will be all the tools the operators need to run the pipeline—the controls, SCADA, and important parts of leak detection systems.

SCADA

As explained previously, SCADA is the acronym for supervisory control and data acquisition. SCADA should perhaps have been named DAASC, for data acquisition and supervisory control, since acquisition almost always has to happen before control. But SCADA has a better two-syllable ring to it, and has become entrenched.

SCADA systems are not unique to pipelines. They are used to monitor and control processes in chemical plants, oil refineries, water distribution systems, auto manufacturing, electrical transmission, and other industries. SCADA suppliers build basic systems but customize them to suit the idiosyncrasies of each sector.

Pipelines have two peculiarities that set their SCADA systems apart from most other industries. First, pipelines start at one point and extend to another, perhaps thousands of miles away. When something unexpected happens, controllers, the people that operate the system, cannot just “walk over and take a look” as they can in a plant. The geographic location of every point on the pipeline, and the event the controllers are looking at, may be far removed from their location. That gives a level of uncertainty and complexity that makes the communication part of pipeline SCADA critical to successful operation.

Second, pipelines sometimes face regulations and standards imposed by geographically and jurisdictionally overlapping regulatory bodies. Given these factors, the control system philosophies of any two pipelines can be quite different.

What SCADA systems include varies. Some say it is only the supervisory software monitoring and controlling the pipeline. They would not include all the other instruments, gauges, transmitters, switches, actuators, computers, displays, databases, software, and communications necessary for the SCADA system to do its job. Others (who did not help write this book) say it includes the full range of instruments, from the field location to computer displays in the central control room. Whatever the scope includes, all the pieces work to monitor and control the pipeline.

The schematic in figure 8–1 shows the basic hardware and communication links of a typical SCADA system. Each piece of hardware has the appropriate operating systems, application software, and databases.

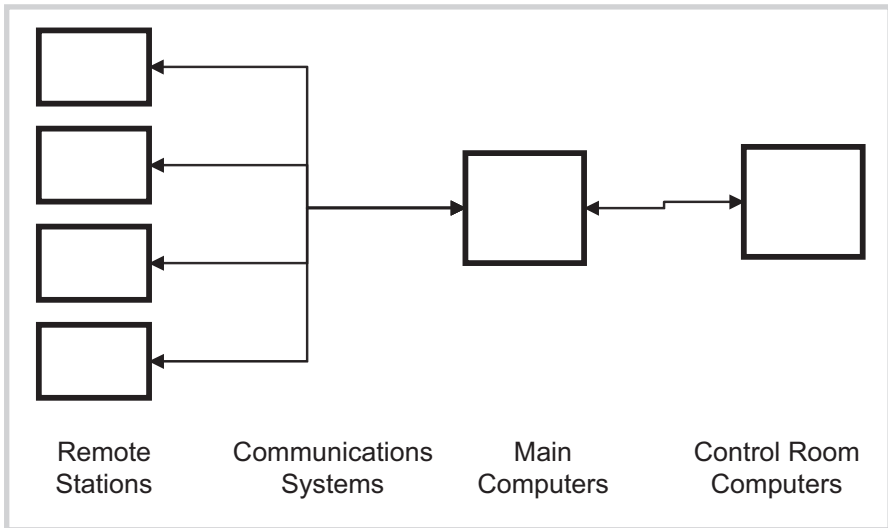


Fig. 8-1. Basic SCADA system schematic

Design and Control

Step one in designing a control system should be defining the intent, or what it is supposed to do. With control systems, as with many things—marriage, back surgery, political appointments—the ideal seldom happens. Part of the reason is that very few control systems are designed completely from scratch. Many are burdened with systems, applications, and processes already in place, or stubborn old ideas. Control system designers are blessed with (or sometimes burdened by) their unique sets of experiences, viewpoints, and needs.

Human versus computer decision making

Pipelines started well before the advent of computers. Obviously, humans made all the decisions. But now control system designers have to decide how much of the decision making should be done automatically and how much should be left up to the controllers.

Machines can make decisions quickly and consistently based on the information given to them. They do not “think” broadly about the information. Humans can introduce intuition, judgment, and feelings. That, of course, is sometimes a positive and sometimes a negative.

Some operating decisions are simple and routine and easily made by computers. Other decisions are more complex. This might include whether or not to shut down the pipeline when a leak is suspected or selecting the optimum compressor configuration to meet a specific delivery schedule. Like most other things, decision philosophies vary widely among companies. As control systems become more sophisticated, decisions are increasingly being handed to computers and other control devices. This is a struggle for some controllers as they are asked to trust equipment to make critical decisions such as switching between gasoline and diesel. A trust-enabling and important key is to have a reliable system with override capability that easily responds to manually entered data corrections. No one wants a batch tracking solution that simply shuts down a pipeline on loss of data or is extremely cumbersome to adjust. That leads to controllers continuing to track batches manually on paper “just to make sure.”

Local or central control

With these decisions made, the next question is to decide where the control decisions will be made. This will be either in a local station, in a central control room, or some combination of the two.

Local control and central control each have advantages and disadvantages. Central control better enables understanding of what is happening in each pipeline segment, station, and storage facility, facilitating pipeline optimization. One central controller making the decisions instead of several local controllers requires less verbal communication between controllers. One central controller can take into account all variables along the pipeline. But central control requires more electronic communications between local stations and the central control room, since the central controller needs to see what is happening at each station. A central control philosophy normally has lower personnel costs, but higher equipment and communication costs, than a local operations philosophy.

At the same time, controllers are unable to perform in the central control room when communications are lost. Robust backup systems in place make this situation rare, but when it happens, the controller cannot know what is happening on the pipeline. The controller thus cannot send control commands to change pipeline operations. Absent anything else, the pipeline continues to operate in the same mode as when communications were lost, a precarious situation. The controller must quickly decide whether to call out field operators to operate the stations or wait until communications are restored.

A solution might seem to be to set up the local station controls to immediately shut the pipeline down when communications are lost. But when a pipeline shuts down, particularly for an emergency or uncontrolled pipeline situation, bad things can occur. For example, in an emergency shutdown, an oil pipeline may become slack (some of the liquid turns to vapors), and most oil pipeline leak detection systems require a packed pipeline. When the pipeline is slack, most leak detection systems do not function until the pipeline is repacked after the pipeline is restarted. Emergency shutdowns can also cause pressure surges that damage the pipeline or equipment. In the case where a natural gas pipeline is suddenly shut down, downstream customer supply problems may be imminent.

Most pipelines have a combination of local and central control, with the more routine unit selection and emergency shutdown decisions made locally, and the decisions that affect the entire pipeline made centrally.

Manual or automated

The early pipelines started out all manually operated. Valves were opened and closed by hand. Engines were started or stopped manually. Now it is possible to automate most of the functions. Recall the distinction between dispatching and control. Manually operated equipment can be dispatched remotely but must be controlled locally. In contrast, automated equipment can be controlled either locally or remotely. Highly automated locations are still sometimes operated from either a local control room or a local controller walking out and pushing a button. How much and which pieces of equipment to automate are important philosophical decisions that impact overall control design.

Those valves not automated with motor operators can still provide status signals to local or central control with simple position switches. Some advanced systems use the valve position to verify that a flow path is open prior to closing valves. (The first law of oil pipelines is, “Open a valve before closing a valve.”)

Communications

The OTA built a telegraph line along the ROW of their 6-mi wrought iron crude oil pipeline running from their 1860s field to the railroad station at Oil Creek, Pennsylvania. That established the importance of communications to pipeline operations. The telegraph line was built to help the complicated bookkeeping of multiple shippers. However, operating personnel quickly learned the line was also useful to track and coordinate pipeline operations.

Pipeline companies eventually connected phones to their privately owned telegraph lines. Local station operators used these phones to coordinate pipeline operations. The privately owned phone lines have been replaced by public communication systems in countries with well-developed infrastructures. Some pipeline owners use the Internet for communications and control.

Many pipelines pass through less-developed areas where the public telephone systems are notoriously unreliable. They may use satellites as their primary communications system, with a landline backup over wires, by microwave, or even using fiber optics lines.

Design. Communications systems are seldom simple. Both the primary and backup systems may use a combination of approaches (fig. 8–2).

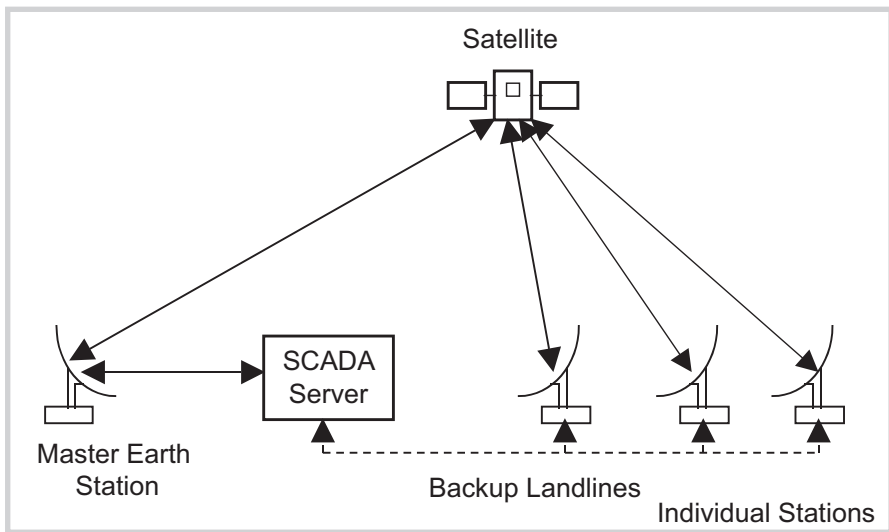


Fig. 8–2. *Satellite communications with backup landlines*

A remote delivery location with one meter may not warrant the cost of a satellite dish, so it may communicate by cell phone, or it might be radio-powered by a solar cell.

Stations with satellite dishes communicate with a satellite in geosynchronous Earth orbit (fig. 8–3). (It stays above one point on Earth.)



Fig. 8–3. Block valve with satellite communications (Courtesy Miesner, LLC)

The ground connection is a master Earth station owned by either a communication company or the pipeline. From this master station, the data are transmitted over a dedicated line to the SCADA server in the central control room. Commands from controllers travel this route in reverse.

Where they can, the local stations have a commercial phone line installed and connected to a modem. In the event of a satellite outage, modems in the central control room call the modems at each station. The modems may stay connected to large stations, while for small booster or meter stations, the modem may poll stations sequentially.

The same satellite may be used by various companies for different types of data, from pipeline operating pressures to credit card verification. The data are kept separate and sent to the right address by routers. (With some irony, satellite companies manage their satellites from control rooms that look remarkably like pipeline control rooms.)

There is a broad range of options—leased lines, microwave, radio, dedicated phone lines, the Internet, and local area and wide area networks. The key is to find a robust, secure system that works for the location and control system in question. Most systems are a combination of technologies.

Redundancy. Adding redundancy to a SCADA system eliminates single points of failure. If one piece of equipment fails, another takes its place; if one communication path falters, another assumes the load.

Some control rooms even have backup control rooms, usually located in a different city. If a Category Five hurricane is forecasted to make landfall in Houston, Texas, pipeline companies may fly their Houston controllers to an alternative control room temporarily to operate the lines from there.

Redundancy is aimed at reliability, but it also adds complexity. More equipment means more software to switch from primary to backup operation. As systems become more complicated, a change to one component of the system may more easily and inadvertently affect another component. Many companies use a careful *management of change process* to insure system reliability.

Human-machine interface

The human-machine interface (HMI) is the link between the controller and the control system, providing visualization and access to controls. It includes computers, screens, keyboards, and mice, usually located on the controller's console (fig. 8-4).



Fig. 8-4. Human-machine interface. This picture only shows two displays, but the controller consoles typically have four to six. (Photo by Tom Miesner)

Controllers can choose the specific information they want on each screen based on what is happening at the time. They can look at displays, screens, or screen shots, all three of which sound like the same thing. However, there are differences:

- Displays are the physical device on which information is displayed.
- Screens are the pages of information displayed on the display.
- Screen shots are pictures of the screen at a point in time.

Screens are the visual information link between controller and pipeline. Easy-to-read screens with a high level of *information density* (lots of information on one screen) are helpful. They allow the operator to quickly grasp current operating conditions to effectively monitor and control the pipeline. Operators can display a variety of screens but typically have a few critical favorites.

Screens are arranged in a hierarchical view. Controllers use buttons on the page to navigate through other screens, just like Web pages. With a click of a mouse on an icon, they can start and stop pumps and open and close valves. Over the years, the HMI has come a long way from the old mimic boards, station schematics on the wall indicating the status of pumps and valves with lights.

Screens are designed and built as part of the SCADA installation process. Over time, the screens are modified and updated as the equipment changes. If a new valve is added to a station, it must be added to the display, and the proper communication path installed. Adding a new compressor station requires building new screens and rebuilding existing screens to accommodate the station.

From the main SCADA server, the computers driving the HMI receive data that they turn into information and display for the controllers. Conversely, when controllers decide to issue a command to open a valve or start a compressor, the HMI receives the instructions through a switch, keyboard, or mouse. The instruction is sent on for action. In addition to displaying information and processing commands, the HMI may accept views from other applications and have graphing and trending capabilities.

Real-time operating data

Real-time operating data reveal what is happening to the pipeline in the present. (Strictly speaking, the data reveal what is happening within a few seconds of the present, or the time it takes for a signal to travel from a remote

location to a display.) Operating data are the important variables associated with pipeline operations—pressures, flow rates, position of valves, and the like. Having operating data in real-time availability is critical to allow controllers to see and respond to changing conditions and to keep the pipeline operating at peak safety and efficiency.

Operating data fit into three categories:

- **Parameter values.** These are numbers generated by instruments measuring something—pressures, temperatures, flow rates, etc.
- **Device status.** Rather than a numeric value, these signals give the state of being of a device. For example, a valve may be open, closed, or in transition; an engine driving a compressor is off, on, starting, or stopping. (To some technical people, status has a different definition. It means the quality of the data, whether they have good data or bad data. In this book, status means the state of being of the device.)
- **Other nonparametric data.** This includes alphanumeric labels for batches, names of operators who initiate commands, and names of commands.

An instrument or device can have both status and value. The status of an orifice meter may be “in use” or “on,” and the meter may register the value 100 Mcf per hour. To monitor and control a natural gas pipeline, the operations coordinator needs both the status and the value.

Points. The notion of points covers a lot. The origin and destination of data going to and coming from a device are points. For example, the incoming motor-operated valve at Explorer Pipeline’s Greenville, Texas delivery facility can have five different points. Two are command points (open and close) and three are status points (open, closed, and in transition). The valve itself is one point, with a *point tag* or a *point name*. The data concerning this valve are transmitted from the *origin point* (the valve) to a *destination point*. The latter is the place in the computer where it is captured and stored.

It should be obvious by now the care pipeline companies must exercise to keep all this straight. Pipeline control systems have hundreds to thousands of points. A *points database* or system administrator keeps track of all the points. Devices are listed on the points database and commonly shown on a *process and instrumentation diagram* (P&ID) for easier reference. During SCADA installation, technicians carefully check to make sure all points are listed and connected properly at each end. In the Explorer Greenville valve example, the point list is used to ensure the valve that shows up as the Greenville incoming motor-operated valve is really that particular valve. With carelessly installed crossed connections, the controller may open the wrong valve or no valve at all.

Following original construction, a points database is continually updated. If a new natural gas delivery point is added, the points must be correctly added to the points database, and all devices tested and connected correctly. If any of these points become confused or supply bad data, information can be misinterpreted or incorrect pieces of equipment can be started and stopped. Because of the potential consequences of errors in the points database, access is strictly restricted.

Events. An important function of the control system is detecting, displaying, and recording *events*. These are defined as changes to the pipeline or actions taken by an operator or by the SCADA system.

Examples of changes to the pipeline are:

- Crude oil pumps begin to inject 150 barrels per hour (bph) into the pipeline.
- A gas plant ceases delivery to the pipeline, causing a loss of 150 Mcf per day.
- A compressor starts and increases pressure to 250 psi.
- A natural gas customer begins to withdraw an additional 10 Mcf per hour.
- A contractor ruptures a pipeline, causing a pressure drop.

Examples of operator-generated events are commands to:

- Start compressor to increase flow rate
- Open a valve to begin a delivery
- Shut down a pump to reduce rate
- Place a remote device in maintenance mode

Examples of system-generated events are:

- An automatic system initiates a wide shutdown sequence.
- Files download to a tape backup device.
- A system device, like a printer or operator station, goes offline or comes back online.

Events can be very interrelated. An operator event, such as starting a pump, results in system events, flow and pressure increasing. Automatically shutting down the entire system results in many events. Events may also trigger alarms. All this information is displayed to the controllers on a screen or hard copy so they can take action as needed.

Configuration tool

Any database needs to be configured for the specific application. The real-time database is no exception. Like a spreadsheet, the real-time database starts as a blank page, with rows and columns waiting for data. The users configure the spreadsheet or the real-time database by writing instructions, or commands in the case of the SCADA database. The users write equations in the case of the spreadsheet, using functions and macros. The functions and macros available to the programmer for writing instructions and commands are what make up the configuration tool. The easier and more intuitive the tools, the better users like the spreadsheet, or SCADA database.

Developing, updating, and maintaining a SCADA system calls for, at minimum, a graphics editing program to build the screen graphics and a *database configuration tool*. Like a spreadsheet, the easier and more intuitive the tools provided by the vendor, the better the developer and probably the SCADA users like it.

Application interface

Other applications use data stored in the real-time database. That calls for an interface or hook to allow data to go from the real-time database to the application. For example, the leak detection process needs pressures and flow rates; the corporate accounting system needs meter readings for invoicing purposes.

These hooks are analogous to the interface that allows customers to download their personal banking data from a bank's server to the money management software on their own computer. The customer does not see the hook but cares a great deal about whether or not the interface works well.

Like banking data, the SCADA interface has to be secure. Any time an application accesses the real-time database, the interface must protect the real-time database from outside intrusion.

Historic database

From the real-time operating database, some operating data are archived in a historic database. What use does this historic data have? Changes happening over time may not be spotted using only real-time values, but may be when trends are examined, leading to better understanding and optimization of the pipeline. Logs documenting controller commands are also a valuable tool for troubleshooting problems and understanding controller performance.

There have been many changes in databases over the last half century. They first evolved from paper to mechanical charting. They then progressed to punch cards, magnetic tapes, disks, and finally to massive storage units. Accessibility has increased at every stage.

Only some of the data from the real-time database is transferred to the historic database. Again, the control philosophy dictates which information (and how much of it) will be transferred. Pressures may be read quite frequently but only changes (and when the change occurs) might be stored. Each piece of data included in the historic database is *time stamped* to show the exact time it was generated. This is a critical piece of information about the data when troubleshooting or diagnosing problems.

Historic databases provide a cornucopia of training information. With the right applications, this information can be played back. This could allow a trainee to see exactly what a more experienced controller did in a particular situation and what happened as a result. The events surrounding a pipeline leak can be analyzed to prevent future leaks or improve response time.

Amount of data to gather

Early pipeline dispatchers had only rudimentary real-time information about the pipeline they were operating. Was the equipment running? Was fluid coming out the other end? About how much was pumped over a period of time? If less was coming out one end than going in the other, they found out why.

Modern pipelines operate with much more information. Some is vital, while other information falls into the “nice to know” category. More information can result in better operation, but presenting too much information to a controller can be confusing.

Update frequency

The SCADA system receives data from thousands of devices. The data travel for most of the trip along a common route (a satellite channel, a fiber optic strand, or a phone line.) Some values can change rapidly and frequently, but *status* typically does not. SCADA manages all of this information to ensure it is available on the frequency needed and does not become garbled in the process.

To handle the job of gathering all this data in an orderly fashion, an established protocol dictates how often and when the data are gathered. The frequency and manner falls into one of three categories:

- Polling (also called scanning)
- Report by exception
- Fixed-interval reporting

During a *poll* or scan, the central system asks a device for data. *Scan tables* establish how frequently the devices are polled. Pressures may be reported quite often; meter readings from a natural gas delivery point may be collected only once per day. The scan tables refer back to the point database for data origin and destination.

For *report by exception*, a device reports only a change in value or status. If a pump turns off, it alerts the control system. But as long as it is running, it does not report its status. Some method of periodic integrity checking is usually implemented for report by exception to ensure data changes are not lost.

Fixed interval reporting is self-evident. A device reports its data on some regular basis. (Some say fixed-interval reporting is simply another example of report by exception—if the set time has not elapsed, the device does not report.)

Update process

The control philosophy establishes how and how often data are received from each point. The update process acts as traffic control for the polling, exception reporting, and fixed-interval reporting. If devices do not respond when scanned, or do not report at their appointed time, the update process initiates a diagnosis. If it cannot determine the problem, it feeds that information to the alarm process, which either generates logs for future action or notifies the controller.

The update process continually performs checks of data validity by comparing selected incoming data to past data for the same device or to preset data.

Corrupted data

What happens when some of the data coming into the control system does not make sense in the overall context of the other data? It is rare to have corrupted data, but missing, incorrect, or old data can happen due to

communication failures or failures in the field devices or network. There are two extremes concerning a controller's response when data appear to be corrupted. The controller could assume it is incorrect and simply ignore it, or the controller could immediately shut down the pipeline until the problem is located and resolved.

The usual response lies somewhere between these two options. Corrupted data may be an indication of an abnormal situation. SCADA systems contain validity-checking routines that attempt to determine if the data are good or bad. The bad data are excluded from the system and an alarm or warning is generated. Controllers call out technicians to locate and troubleshoot the problem. In any event, controllers cannot ignore seemingly bad data, because the information may in reality be accurate, and a problem may exist.

Indicators, alarms, and alarm filtering

Indicators display information that show what is happening on the pipeline. They can be lights, numbers, colored lines, animation, and sometimes audio cues (a bell ringing when an event is complete).

When indicators go beyond prescribed limits, they can become *alarms*, which are visual or audio alerts to a controller that an upset condition exists. Alarms are vital, but they can confuse and frustrate controllers if they are not designed properly.

An alarm philosophy drives the *alarm filtering strategy*. Which conditions justify an audible alarm versus just an indication (perhaps one that blinks)? Which alarms should automatically shut down the station or pipeline? Since upset conditions normally trigger many alarms, how should these be filtered so the controllers get the information they need without overloading them with alarms?

Like the blinking seat belt light in a car, frequent alarms can become invisible. Controllers may not pay attention to an alarm when they should. Controllers are normally required to physically acknowledge alarms as a way to ensure they are aware of the alarm.

The alarm process examines data as they come into the real-time database, comparing them to other pieces of data from the pipeline and to preset limits. If the alarm process detects a potential problem, it could create an alarm immediately. Alternately, it could pause and double-check the data validity from the next scan, just to make sure before issuing an alarm that there was not a data glitch.

Alarms are prioritized by the alarm process. A visual alarm (a blinking light, a message on a screen), an audible alarm, or both may be issued. The process also records details about the alarm, such as when the alarm was created and when the controller acknowledged it. Most alarm systems require the operator to acknowledge alarms by clicking a mouse or pressing a button. The alarm stays on until it is cleared. Some alarms can be cleared by the controller, while others require higher levels of supervision. Alarms can also come from applications like leak detection.

Alarms can be triggered by data at the local station level or by individual units within the local station. Station alarms usually refer to the inlet or outlet conditions at a station. These include:

- **High station discharge pressure.** A pressure sensor is located on the pipeline just before the pipeline crosses the station boundary. It monitors pressure, shutting down compressors or pumps if the station pressure exceeds a preset limit, protecting the pipeline from too much pressure.
- **Incomplete station sequence.** Stations are designed to follow a prescribed sequence during start up. A device with a timer tracks the sequences at the station. If the sequence does not occur at the rate and in the order dictated, the device generates an incomplete sequence signal or alarm.
- **High station sump level.** Some stations have sumps, small buried tanks used to drain down station piping or pump units for oil pipelines and for catching liquids for natural gas pipelines. A float switch located in the sump tank sends an alarm when the fluid level reaches a critically high level.
- **High station manifold.** A pressure sensor monitors pressure in metering stations, shutting down the station if readings reach a preset limit. This protects the typically lower pressure-rated metering equipment in the station.

Unit alarms usually refer to individual pieces of equipment. These include:

- **High unit pressure.** Similar to the high station discharge switch, a high pressure sensor is located on the discharge of each pump or compressor. It protects the pump or compressor from too much pressure in the event one of the valves associated with that piece of equipment is accidentally closed.

- **Low pump suction pressure.** Pumps must be supplied with a minimum amount of pressure at the suction to prevent damage to the pump. A pressure sensor located upstream of the pump monitors pressure to ensure the required amount of pressure is present, shutting down the unit when the pressure drops too low.
- **High unit bearing temperature.** The temperature of the bearings on the motor, pump, compressor, engine, and turbine are monitored by a sensing device located on the bearing housing. It shuts the units down if a predetermined temperature is reached.
- **High motor winding temperature.** The temperature monitor located on the motor windings is similar to the bearing alarm. It protects the motor from getting too hot.
- **High unit temperature.** A sensor monitors the temperature of the fluid in the unit, shutting down the unit before the temperature reaches a dangerous level.
- **High unit vibration.** Vibration sensors located on compressors, pumps, motors, engines, or turbines shut down the unit if vibration becomes excessive.

These are hardly exhaustive lists. The exact configuration and types of alarms depend on the specific pipeline and the operating philosophy of the owner.

SCADA performance

Pipelines operate continuously, so their SCADA systems must be available at all times. Performance metrics indicate system reliability and areas needing attention. Metrics include:

- **Update time.** This is the time from a change of state of a field device until that change of state is displayed on the control console displays.
- **Scan time.** This is the time required to access or poll all devices.
- **Communications latency.** This is the transmission time for data to move from the remote device to the host system.
- **Screen update time.** This is the time from the request for a new screen until that screen is shown on the display. (This is a bit different from update time, since this metric is system dependent as it uses data already available in the system.)

- **Command processing time.** This refers to the time from when the HMI accepts a command until that command is processed or received by the field device.
- **Historic data access time.** This is the time from a request for historic data until the data appear on the display.
- **System utilization.** This refers to the time the computing system resources are available at different SCADA load levels. (This is a measure of the surplus capacity to handle processing problems or large processing loads.)
- **System availability.** This is the time all components of the system are available for use. (This could be a percentage of the total time elapsed while the system is functioning as intended—all components are running and available with no redundancy called in to play. It could also be the percentage of time the overall system is available for use even if some components or processes have failed. In this case, redundant components been called in to use or the failed process is not critical.)

Data sharing

Who should be allowed to access the data? Few people outside the control room need real-time operating data, but many people are interested in recent historic data. Receipt and delivery data, schedules, forecasts, flow rates, and capacities are commercially important. Pipeline companies share this information both inside the pipeline organization and with their customers. In some cases, pipeline companies are precluded by law from sharing some of the information, because it might benefit one customer at the expense of another.

Reports and logs

Reports and logs relate closely to data sharing. SCADA systems generate various reports automatically and distribute them electronically or in paper form within the pipeline company and to customers. Within the pipeline company, various groups can request that ad hoc reports be generated. The data sharing philosophy greatly impacts the decisions around report generation and distribution.

Logs are a bit different. Logs capture events and commands and are an important part of the historic database for troubleshooting, optimizing processes, and training. They are routinely generated by the SCADA system

and (normally) distributed only to those involved with operations. However, when an accident occurs, logs are of great interest to all types of constituencies, both within the pipeline company and outside of it.

Security

Security, and as it relates to SCADA, *cybersecurity*, is of importance from a safety and a commercial perspective. Restricting system access requires the use of firewalls, passwords, encryption, intruder detection, and secure protocols. Control rooms, computer rooms, compressor stations, and other company facilities are sometimes secured with live guards.

Security, like the other design decisions, must be carefully considered to insure the solutions provided are appropriate for the type and magnitude of threat.

SCADA in summary

Adding in the various components discussed in the previous sections to figure 8–1 results in a more complete SCADA schematic (fig. 8–5).

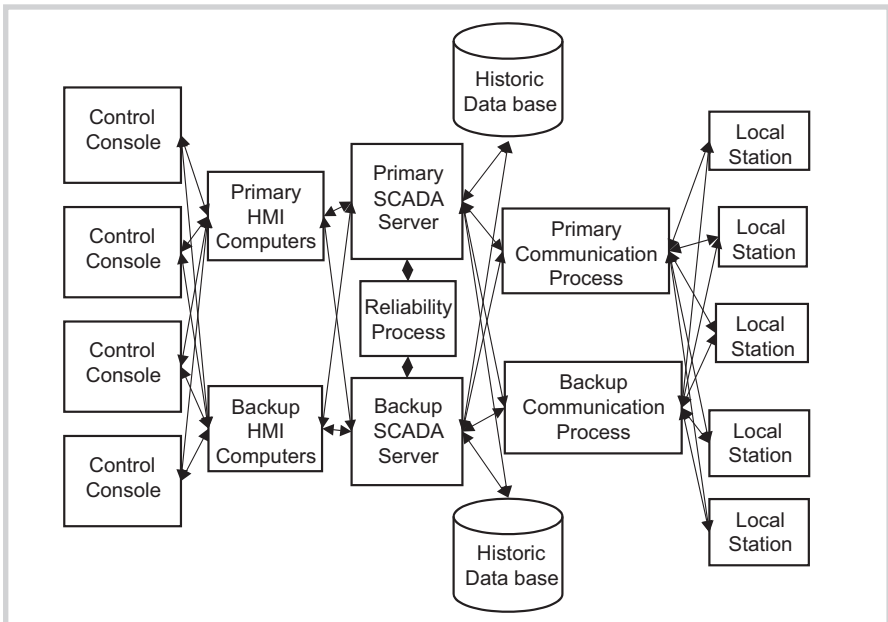


Fig. 8–5. SCADA schematic

Local SCADA

One more SCADA topic should be addressed before moving to leak detection. Individual pump, compressor, or meter stations may have local station SCADA, but that does not mean they are not controlled centrally. Local SCADA is often included as a convenience for station operators or maintenance people, providing them an easy way to open and close valves and start and stop equipment. Many times local station SCADA is manufactured by different vendors and has only one display and a keyboard to view equipment status, input data, and issue commands (fig. 8–6).



Fig. 8–6. Local station SCADA (Courtesy Williams Gas Pipeline; photo by Tom Miesner)

Leak Detection

Leak detection systems are closely connected to SCADA systems and controls. The first requirement of leak detection systems is that they quickly detect leaks. They should also identify the location, size, and rate of the leak. Finally, they should operate with a minimum number of false alarms. Any system that generates a large number of false alarms is effectively useless.

Leaks and releases

Leaks can be lethal, disruptive, expensive, embarrassing, or, in the best possible outcome, just spectacular. Leak size is normally expressed in terms of the release rate and the total amount released. Leaks can also be thought of in terms of the size of the hole in the pipe. Large leaks are normally called *ruptures*, and small leaks are called *pin holes*. Release rate and the total amount released are dependent on the size of the hole, the size of the pipe, and the pipeline pressure.

Large leaks allow sudden and rapid release of pressure (and therefore energy) and can blow a crater into the ground. Gas leaks may continue howling out of a hole in a pipe for some time, stirring up dust and debris. Oil leaks may continue to flow out of a pipe for some time just because of gravity. Oil leaks generally do not howl like natural gas leaks.

Natural gas leaks release methane into the air. Methane has a high vapor pressure, so it dissipates into the air quickly. If something ignites the gas cloud before it dissipates, the explosion and fire can be extensive and fatal. If the gas is not ignited, and the leak is underground, there may be a crater or hole in the ground at the leak site, but usually little lasting damage.

Oil pipelines carry a mix of hydrocarbons, and most are heavier than air and have relatively low vapor pressures. If an initial crater is formed, some components vaporize into the air but most remain as liquids. If ignited, the vapors burn. If not, they conform to their container, which in this case is the ground around the leak site. They either pool or follow the contour of the ground, sometimes flowing down streams for great distances and polluting surface water. Some of the liquids can percolate through the ground, reaching the water table and contaminating aquifers. Oil leaks in subsea pipelines and river crossings can quickly rise to the surface, contaminating everything in the vicinity. Some of the higher vapor pressure liquids such as propane may create low-lying, toxic, explosive clouds that can cause serious threat to human life.

In the extreme, natural gas leaks are greater safety hazards, while oil leaks present longer-lasting environmental problems with extensive cleanup costs.

Leak detection systems

Covering the subject of leak detection systems can start with the criteria for judging the system performance:

- Sensitivity
- Accuracy
- Reliability
- Robustness

While most people in the industry accept these four criteria, the appropriate levels are still fluid. The varying sizes, configurations, existing instrumentation, and routes of natural gas and oil pipelines make consensus difficult.

Sensitivity. Leak detection sensitivity has to do with leak rate and time to detection. *Leak rate* is sometimes measured as percent of flow rate. A 1% leak in a pipeline pumping 2,500 bph is 25 bbl in an hour or 600 bbl in a day. Alternatively, a *true* rate or *absolute* rate, as in 100 Mcf per hour, might be used. The standard varies from pipeline to pipeline and even between leak detection vendors.

In general, the time required to detect larger leaks is shorter than for smaller leaks. A leak detection specification might be that it is “able to detect a leak of 1% of nominal hourly flow rate within 15 minutes.”

Sensitivity is dependent on a number of factors, including line pack and quality of instrumentation. Some leak detection systems rely largely on the control system instruments for data and are only as sensitive as the instruments on which they rely. A high level of sensitivity dictates more instruments and increasingly sensitive instruments. (API Standard 1149 provides a method to determine maximum leak detection sensitivity given defined instrumentation.)

Line pack is the amount of material in the pipeline at current operating pressure. The line pack of a long, large diameter natural gas pipeline can be quite different at low and high operating pressures. A small leak has an almost negligible impact on volumes in and out. It makes a very small impact on pressures, making detection with SCADA-based leak detection systems difficult.

For example, consider a 12-in. diameter pipeline with 0.2 in. of wall thickness, 100 mi long, which is filled with gasoline. It will have a line pack of approximately 69,000 bbl. Granted, the volume is practically incompressible, but still, the gasoline compresses, and the pipe diameter gets a little larger

with increasing pressure. For each 10 psi change in pressure, the line pack in this example changes by 6.7 bbl. Hydraulically this means the pipeline could lose 6.7 bbl while showing only a 10 psi pressure drop when operating at 1,200 psi.

Leak detection modelers deal with line pack uncertainty by dividing the pipeline into short segments and modeling these sections independently. In the oil example, monitoring a shorter segment, say 10 mi (10% of the original length), means the pipeline loses only 0.67 bbl for each 10 psi pressure loss. However, using shorter control sections means more instrumentation. Pressure and temperature at each end of the segment must be known and compared to calculated values.

Leak detection sensitivity improves as the time interval increases. It is much easier to locate a small leak over a 15-hour period than over a 15-minute period, because the amount lost is 60 times larger.

Accuracy. Accuracy is the ability to determine the location of the leak, its rate, and the volume of product lost.

Location is clearly important during the initial response effort. An accurate leak location allows emergency personnel to arrive at the site quickly and contain the leak to protect the public and to begin mitigation or cleanup efforts.

Location is also important to allow response planning. Oil leaks near streams, rivers, or water supplies require a different response than those that are not. Natural gas leaks upstream of a delivery point may disrupt supply of gas to a community. Location accuracy is expressed in terms of the distance between the actual and projected leak location. Accuracy on the order of a mile may be acceptable for some rural areas, but not for small leaks in congested areas.

Leak rate and magnitude enable emergency responders to arrive with the right equipment to stop the leak and anticipate the best cleanup. Rate and magnitude also help local emergency response officials decide whether or not to evacuate the area. The total volume of oil lost can become an important number during liquid recovery efforts. However, this is best calculated as the pipeline is refilled after repair operations are complete.

Other aspects of accuracy are repeatability (the ability of an instrument to return the same reading under the same set of conditions) and precision (the smallest change that can be seen in the output of the instrument). As with sensitivity, system accuracy depends on the integrity of instruments such as meters and pressure gauges.

Reliability. The reliability of a system concerns whether or not a leak really exists when the system indicates that there is one. Pipelines regularly experience transient conditions, sporadic pressure and flow changes that interrupt steady state operations. Starting and stopping compressors or pumps, opening and closing valves, and other operating situations cause short-term transient pressure waves. Leak detection systems based on pressure changes can be fooled by these normal transient waves. Reliability requires filtering transient conditions so that alarms are generated only when leaks really exist. Otherwise operators may be desensitized to real alarms when they happen.

Unfortunately, reliability and sensitivity can work against each other. Increased sensitivity allows detection of small changes, but it also can cause decreased reliability—more false alarms. A filtering technique may ignore all fluctuations below a certain threshold. Setting this level too high can result in decreased false alarms but also decreased sensitivity.

Robustness. The leak detection system has to be able to work under less-than-ideal situations and changing conditions. The minimum level of sensitivity, accuracy, and reliability the system can sustain under these conditions determines how robust it is. Poor data acquisition and communication system performance are never good excuses for leaving a leak undetected too long. (They may be the reason but are not a valid excuse.)

Leak detection methods

Pipeline leaks are discovered in a variety of ways. Many are detected by the leak detection systems discussed in this section. Others are first discovered visually by contractors or company employees performing routine aerial or ground patrol. Natural gas pipelines are routinely monitored for leaks by use of portable instruments carried along the route. The final and least desirable method is having the leak discovered by people who live or travel along the pipeline route.

Software-based systems that use operating data retrieved by the SCADA system are classified as *internal systems*. They employ monitoring instrumentation already connected to the pipeline. Supplemental instruments may be added to achieve increased sensitivity, accuracy, reliability, or robustness.

External systems use sensors that may or may not be physically connected to the pipe. Some sensors are located in the ditch with the pipe, involving fiber optics or tubing, for example. Other sensors are portable and are transported along the pipe, such as vapor detectors or side-scanning sonar.

Internal systems

Internal leak detection systems utilize data from field sensors that monitor pressure, temperature, flow rate, viscosity, density, and velocity. These parameters are used in algorithms (mathematical equations) designed to simulate pipeline operation. The actual operations of the pipeline are compared to the simulated values. A significant difference between the modeled and actual operating conditions indicates a probable leak. This type of software-based leak detection is commonly called *computational pipeline monitoring* (CPM). Rudimentary versions of this type of model compare one value, such as pressure or flow, to preset thresholds or limits. Advanced systems perform extensive analysis of multiple variables with dynamic (changing) thresholds. Numerous kinds of computational schemes are used in the industry.

Parameter deviation. While pipeline flow rates and pressures may not always be constant, they should fit into a predictable envelop or range of values. Natural gas pipelines normally operate over a larger range of pressures and flows than oil pipelines because of compressibility and variations in demand. For example, residential customer daytime demands for natural gas are higher than nighttime demands, creating significantly different flow rates over a 24-hour period. In contrast, oil pipelines are more or less insensitive to the time of day, since they have large storage tanks between the pipeline and the customer.

Parameter deviation establishes thresholds at the high and low values of pressure and flow ranges and issues an alarm when readings cross these preset thresholds. Parameter deviation works best when the pipeline is in steady state. They may be disabled or the thresholds widened during startup, shutdown, or other transient situations to avoid false alarms.

Rate of change. Conditions are not supposed to change too quickly on pipelines. Sudden changes in flow and pressure can indicate a problem. The primary item affecting flow rates in operating pipelines is friction loss. Sometimes nothing else has changed to impact friction loss per mile (density, viscosity, and pipe diameter), but flow rate goes up quickly at the upstream end. This probably means there is less total friction loss, which could occur if some oil or natural gas was escaping before it reached the next station.

Another indication of a problem is a rapid drop in pressure, even if it is still within preset limits. The SCADA system or leak detection system monitors flow and pressure and issues an alarm when pressures change more quickly than with normal operations. Rate of change can easily detect large leaks in both natural gas and oil pipelines, but not small ones.

Line balance methods. The next several methods compare the amount of natural gas or oil coming out of the pipeline versus the amount put in. The sensitivity of these methods is impacted primarily by uncertainty in line pack and metering (including instrument sensitivity levels).

$$\text{Sensitivity} < \text{Uncertainty in line pack} + \text{Uncertainty in metering}$$

Equations of state use pressure, temperature, and fluid properties such as density to calculate volumes and flow rates. Line pack uncertainty is introduced by differences between the properties used in the equations of state for the natural gas or oil in the pipeline and their actual pressures, temperatures, and properties. Metering uncertainty is caused by the combined inaccuracy of all measuring instruments.

Line balance. This method has been in use for many years. It compares the amount pumped into the pipeline to the amount delivered out of the pipeline. Readings from the receiving meter are compared at the beginning and end of each hour. The difference gives an hourly total received. This number is compared to an equivalent number at the delivery end. An imbalance between the two numbers larger than a predetermined limit indicates a leak.

There is no compensation for change in line pack, so the pipeline balance sensitivity is limited, especially for natural gas pipelines. Even for liquid pipelines, it may take quite some time to discover a small leak using line balance.

Line balance is simple and was done manually for years for oil pipelines. At the beginning of each hour the volumes pumped in and those pumped out for the previous hour were phoned in to the dispatch center. The dispatcher manually recorded and compared the numbers. In addition to hourly readings, daily, weekly, and monthly comparisons were done in search of leaks or metering problems. Even after the advent of computers, it took a while for the dispatchers to rely on them and quit writing down the numbers.

Volume balance. Volume balance takes line balance one step further by compensating for changes in line pack. The data needed to adjust for line pack changes include average pressures, temperatures, and compressibility. (The bulk modulus is used for liquids, and the compressibility factor for natural gas pipelines.) These adjustments improve sensitivity. Unlike line balance, it is difficult to perform volume balance manually due to the increased complexity of the line pack calculations.

Modified volume balance. Sensitivity is improved with modified volume balance over volume balance by using the *dynamic bulk modulus*. This is a calculation that takes into account the amount of each product in the pipeline.

For natural gas pipelines, the bulk modulus is fairly constant, so modified volume balance does not help much. For oil pipelines, particularly those moving a variety of crude oils or refined products, using the actual value improves sensitivity compared to using a representative or average value.

Compensated mass balance. Temperature changes have a large impact on line pack volume. Natural gas may leave the compressor station in excess of 100°F and then rapidly cool to the ground temperature. Modified volume balance only compensates for temperature loss as an average between the input temperature and the output temperature. Compensated mass balance segments the pipeline based on the location of available instruments. It models the temperature and pressure along the pipeline between measurement locations. These values are used to adjust line pack, yielding a more accurate number and improving sensitivity of leak detection.

Real-time transient modeling. Line balance methods discussed in the preceding sections work best when the pipeline is in steady state condition—the pipeline is flowing smoothly with no changes. Pipelines are quite frequently not in steady state flow, so the leak detection must be desensitized to accommodate transient conditions.

Real-time transient models compensate for the pressure waves generated by compressors and pumps starting and stopping, and valves opening and closing. Real-time transient models are used in conjunction with the previously described models, calculating more accurately the variation in line pack and improving leak detection capabilities.

The use of real-time transient models requires significant data processing capabilities and frequent data polling. These models require extensive information about the configuration of the specific pipeline. This includes length, diameter, wall thickness, route elevations, and the pumps, compressors, and valves, along with their locations. In addition, they use the properties of the fluids, such as compressibility, bulk modulus, gravity, and viscosity. In many cases, additional instruments are added to the pipeline in support of a real-time transient model. The model must be updated each time a physical change is made to the pipeline.

The model is calibrated to allow some difference between calculated and actual values. The difference allowed determines sensitivity.

The dependence of transient models on quality of data calls for careful attention to equipment operations, maintenance, and calibration. If an orifice meter suddenly starts to malfunction, the model should be smart enough

to understand what has happened and compensate. It should recognize the difference between the orifice meter malfunction and a leak.

Acoustic/negative pressure wave. When a leak occurs, there is a sudden reduction in pressure right inside the pipe as the first molecules move through the new opening. Almost immediately the next molecules take their place and squeeze through the opening. That creates a pressure wave traveling away from the leak site toward both ends of the pipe.

Instruments located along the pipe detect the wave front as it passes. Signals from instruments feed back to a processor that compares when the waves arrive. The processor calculates the leak location based on this timing.

Waves in oil pipelines travel quickly, allowing rapid detection; waves in natural gas pipelines are slower. As with other methods, large leaks are easier to detect and locate than small leaks. If there are many small transient events, the pressure wave for a small leak may be filtered out along with them.

Statistical analysis. This is a hybrid form of leak detection often used in conjunction with other leak detection methods. Statistical techniques look for abnormal imbalances. By “training” the system during various normal situations, the statistical systems have an advantage when attempting to minimize false alarms.

Shut-in pressure test. This category can be used in conjunction with other methods as a way to verify small leaks. If a potential leak is indicated, the pipeline is shut down and segmented by closing valves along the route. The pressure in each individual section is monitored. A pressure drop in a segment indicates a potential leak. During shut-in tests, the temperature must be monitored and its impact on line pack considered.

This method is simple, and no mathematical formulas are required. Only the pressure (corrected for changing temperature) is monitored. However, it has some drawbacks. First, the pipeline must be shut down to allow shut-in monitoring. This can cause supply problems if customers downstream are dependent on the pipeline for supply. Second, special instrumentation may be required to accurately measure temperature and pressure. At least one pressure and temperature sensor must be located in each segment. Third, the valves at the end of the segment must seal completely to keep the monitored section from leaking into another section. Finally, this method cannot calculate leak location. These issues make pipeline companies reluctant to use this approach as a primary leak detection method in cross-country pipelines. It may be used as a backup and verification strategy. Still, a high level of sensitivity is achieved when this technique is properly implemented.

Tuning. Models must be tuned and maintained to achieve the best sensitivity without false leak alarms. Tuning is a detailed and painstaking process. The model starts as a theoretical mathematical description for the operation of the pipeline. Theory does not necessarily agree with reality, so pipeline tuners make small changes to the model in an attempt to make it match actual pipeline operation as closely as possible. Tuning takes patience and detailed knowledge about the model and the pipeline.

This is a good place to again point out a key difference between leak detection systems for oil pipelines and for natural gas pipelines, whether SCADA-based or internal. Both depend on the same laws of physics and employ the same concepts to operate the pipeline and detect leaks. Because natural gas is much more compressible than oil, gas transient changes travel slower and may dissipate quickly, making natural gas pipelines more forgiving of pressure surges. Also, compressibility introduces more line pack uncertainties. That makes the time to detect a gas leak longer than an oil leak of essentially the same size.

External systems

External leak detection systems employ special equipment not normally connected to the pipeline.

Electrical cable sensors. Cables coated with a specialty chemical are buried directly in the ditch close to the pipeline. When a leak occurs, the hydrocarbons from the leak contact the cables, changing the properties of the chemical coating. This in turn affects the electrical resistance or capacitance of the cable, indicating a leak. Unfortunately, any external hydrocarbon, natural or spilled, will trigger alarms. Also, the sensors generally have to be replaced after an alarm.

Fiber optic sensors. These sensors are also buried in the ditch directly with the pipe. Three different fiber optics technologies exist for detection of leaks. One depends on temperature change caused by escaping liquid or natural gas. The escaping fluid lowers the temperature of the surrounding area and the nearby fiber, indicating a leak.

A second technology depends on the escaping liquid to induce very small curvatures, called microbends, in the fiber. These can be detected and located with an *optical time domain reflectometer*. One other technique uses chemical changes in the fiber optic cable caused by the presence of hydrocarbons.

Vapor and soil monitoring. These two approaches place leak detection devices in select locations along the pipeline or vapor-gathering tubes along the pipeline. Both monitor the surrounding soil for hydrocarbon vapors caused by leaks. Vapor samples are gathered from the tubes and hoses and analyzed for the presence of hydrocarbon vapors.

Optical. There are active and passive optical methods. Some techniques use either a laser or a broadband device to generate an energy source above the pipeline. Any natural gas particles will absorb or scatter the energy. Sensors detect the absorption or scattering to indicate a leak. Another passive optical technique uses thermal imaging to look for differences in temperature caused by leaks.

New leak detection technologies are constantly emerging, so, once again, this is hardly an exhaustive list.

Conclusion

Clearly, SCADA and leak detection require large investments. The level of commitment to each is motivated by different but overlapping factors. Many SCADA features are productivity items that generate return from more efficient (probably less labor-intensive) operations. They also allow delivery of important commercial information to shippers, suppliers, and customers.

Leak detection has a large element of profitability—reducing lost product, cleanup costs, and associated fines and penalties. It is also imperative for environmental and civic reasons that pipeline companies quickly detect, locate, and respond to leaks of all sizes.

But, as the Bard said, “Therein lies the rub.” Large leaks are relatively easy to detect with current systems and are more damaging than smaller leaks. Smaller leaks are more difficult to detect and require more sensitive and costly leak detection systems. Detecting small leaks quickly before they become large leaks makes intuitive sense. However, the prevailing view, though based on somewhat sketchy information, seems to indicate small leaks either remain small leaks or turn quickly into large leaks. That presents a dilemma to pipeline companies when deciding how much to invest in small leak detection. As a consequence, it is possible some leak detection investment decisions are made just to “take the high ground” morally.

9

Maintenance

Energy is the essence of life. Every day you decide how you are going to use it by knowing what you want and what it takes to reach that goal, and by maintaining focus.

—Oprah Winfrey (1954–)

For pipeline companies, maintenance is about understanding the condition of the asset. They perform necessary inspections, correct potentially unsafe conditions before they cause failures, and repair failures after they occur. Still, even though maintenance and operations are two different functions, the same people often perform them.

Pipeline maintenance has evolved over time. It started out as “fixing components when they break,” just as a driver changes a tire when it blows out. As technology improved, the industry began to appreciate the value of avoiding failures and their associated costs. Public expectations heightened. The definition of maintenance broadened to include preventive maintenance—replacing components before they break—based on the average life expectancy and visual inspections of components. Similarly, more attentive drivers change their tires when they look worn or the tread depth is below a certain level, but certainly before the tire experiences a blowout.

Nowadays, the concept of maintenance in the pipeline industry also includes predictive maintenance. This goes beyond maintenance based only on component life expectancy and elementary inspections. Maintenance plans now use sophisticated data collection and interpretation technologies to prioritize maintenance activities. Pipeline companies, just like car owners, rely on computerized analysis to determine what is happening “under the hood.”

Pipeline assets can conveniently be divided into the components inside the pump stations, compressor stations, and meter stations, and those outside. Equipment inside the stations is maintained much like equipment in manufacturing plants. Other books cover the topic of maintaining plant equipment. This chapter focuses only on maintaining pipelines outside the station. It covers releases, what causes them, how to prevent them, and how to find potential problems before they become failures. It also discusses how to allocate resources to repair the most critical potential problems, and finally, how to repair problems if they occur.

What Causes Releases?

The U.S. Department of Transportation’s Pipeline and Hazardous Materials Safety Administration (PHMSA) tracks and reports releases from U.S. pipelines. Industry associations, specifically the Association of Oil Pipe Lines (AOPL), API, Interstate Natural Gas Association of American (INGAA), the AGA, and the American Society of Mechanical Engineers (ASME) also track and report releases. The Conservation of Clean Air and Water in Europe (CONCAWE) also periodically reports pipeline releases and their causes. Based on these consolidated reports, the leading causes of pipeline releases are:

- Equipment damage from excavators and agricultural activities
- Corrosion (external and internal) and stress corrosion cracking
- Mechanical failures from manufacturing and construction defects
- Natural hazards such as ground movement, weather, lightning, and currents
- Miscellaneous problems, including operating errors and equipment failures

Advocates of the need for enhanced pipeline safety and pipeline industry representatives sometimes disagree about which of these is “the leading cause.” However, this list covers almost all the pipeline releases.

There is one special case not listed previously that deserves mention. Sometimes people try tapping into a pipeline to steal its contents, often with disastrous results. Protecting against theft is a security issue and is not dealt with in this book.

Equipment damage

Pipelines often coexist with other underground utilities, packed into the same ditch. Excavation activities of any kind pose significant risks to buried pipelines. Such activities could include utility construction or maintenance, construction of buildings, roads, railroads, parking lots, and other aboveground and underground facilities. Assuring that existing pipelines are not adversely affected by such activities requires planning and care. Work crews maintaining buried utilities or installing new facilities that are adjacent to or across pipelines sometimes inadvertently damage them. Even pipeline contractors working on the line sometimes hit and rupture or damage it.

Heavy construction equipment near the pipeline may puncture the pipeline, causing an immediate release. However, it may only gouge the line, removing metal and creating a weak spot that may fail later. Equipment scraping a pipe generates heat that can change its metallurgy, making it brittle and susceptible to cracking. Coating is easily damaged by excavation activities, leading to *corrosion hot spots*, discussed later in this chapter. Figure 9–1 shows the location of an Olympic Pipeline rupture on June 10, 1999, near Bellingham, Washington, which killed three people.

The U.S. National Transportation Safety Board (NTSB) found one of the five contributing factors to this accident was damage to the pipe by a contractor working on a water treatment plant five years prior to the rupture.¹ Figure 9–2 is a sketch from the same NTSB report showing pipeline damage.

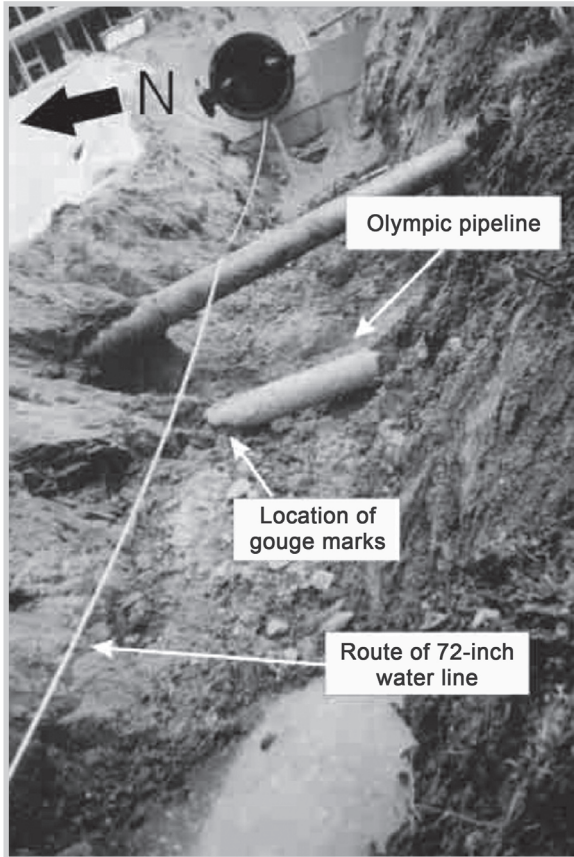


Fig. 9-1. Olympic Pipeline rupture location (Source: National Transportation Safety Board)

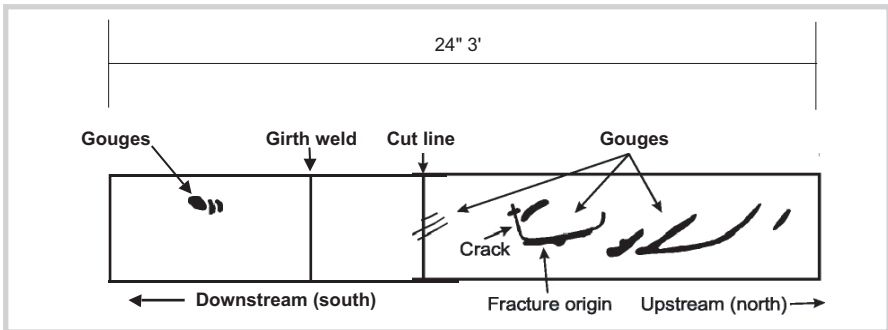


Fig. 9-2. Drawing of gouges in pipe from NTSB report. This is a top view, looking down on the pipe. Note the gouges and the fracture origin point. The cut line is where the pipe was cut following the accident. (Source: National Transportation Safety Board)

Corrosion

Almost all oil and natural gas main lines are steel. They will corrode (rust) if not protected. Properly protected, steel maintains its original properties indefinitely, but a pipeline can leak or rupture if too much metal is removed by corrosion from even a small area. There are several different types of corrosion. The type most common to pipelines is *galvanic corrosion*, which is similar to what makes flashlight batteries work. A battery supplies electric current when its zinc outer shell, the negative post of the battery (the anode), is consumed by a corrosion-like chemical reaction. The zinc metal changes to a zinc compound, and in the process, gives up electrons (electricity). The electric circuit is completed as electrons flow through the flashlight bulb and back to the positive post of the battery (the cathode).

Iron in steel accounts for 99% of the composition of pipe. Iron can be consumed in the same manner as zinc if exposed to the soil environment. Electrons flow from the pipe into the surrounding soil, migrating to other underground structures or distant parts of the same pipeline that are more positively charged. The circuit is completed by some form of electrical continuity, such as a metallic connection between the structures. The iron atoms lose electrons, becoming positively charged ions. They bond with the negatively charged molecules in the vicinity to create nonmetallic compounds that lack the strength and toughness of steel. In other words, the iron rusts, and the rust flakes off, reducing the wall thickness. The same thing can happen inside the pipe if oil and gas pipelines contain water, carbon dioxide, or other contaminants.

Corrosion of the outside and inside pipe wall is known as *external corrosion* and *internal corrosion*, respectively. Both can be influenced by microorganisms such as bacteria, fungus, and algae living on the surface of the pipe. *Microbial influence corrosion* (MIC), under certain conditions, can significantly accelerate the corrosion rate, resulting in severe pits (fig. 9-3).



Fig. 9–3. Severe microbial corrosion (Source: National Transportation Safety Board)

Mechanical failures

Mechanical defects are divided into two categories: manufacturing flaws and construction flaws.

Manufacturing flaws. Pipe materials manufactured prior to about 1970, while strong and generally serviceable, tend to be more susceptible to defects than pipe materials made in more recent times. Some pipe materials were produced with longitudinal seams made by low-frequency-current electric resistance welding (ERW). Among other materials, these have shown a propensity to failures involving the longitudinal weld seam. Pipe metallurgy, the subject of complex engineering knowledge, determines the properties of the pipe. These include the susceptibility of the pipe to brittleness and cracking, especially at cold temperatures.

Manufacturing processes, covered in chapter 11, have improved steadily over the years from the first cast-iron pipe made in Middenville, New Jersey in 1834. Improvements in pipe metallurgy and better methods for welding the longitudinal seam have all but eliminated manufacturing defects in modern pipe.

Construction flaws. There are several primary construction-related defects. These include poorly fabricated girth (circumferential) welds in the field, improper handling of the pipe during transportation and construction, and coating damage during construction. Examples of girth weld defects include mismatched alignment of the two pipe ends, incomplete penetration of the weld, lack of fusion, slag inclusion, porosity, and cracks. Improper handling and field bending of pipe sometimes causes buckles, wrinkle bends, and wall thinning.

Pipelines are coated with insulating materials to stop current flow and corrosion. Proper handling of the coated pipe during installation, or even repair, insures integrity. When damage occurs, it must be repaired to avoid concentrated current flow resulting in a corrosion hot spot.

Improper handling prior to reaching the construction site can also cause problems, as shown in figure 9–4.

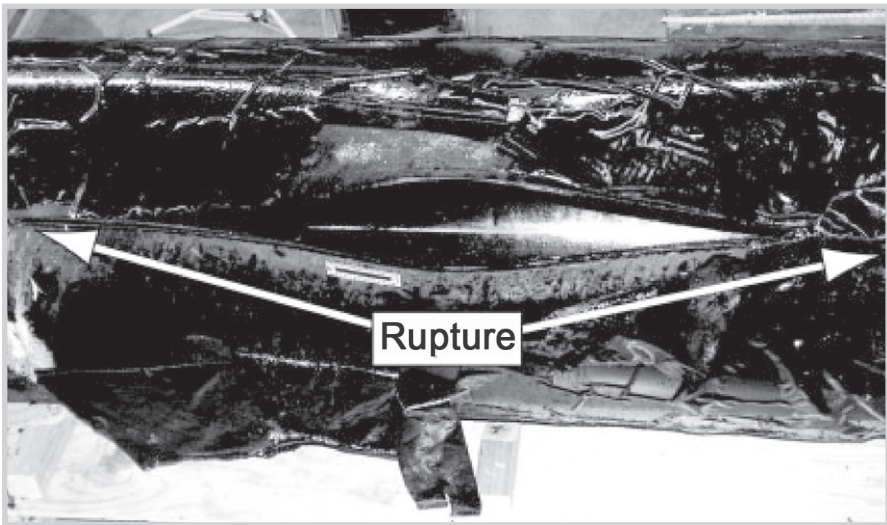


Fig. 9–4. Longitudinal seam split caused by improper loading of the pipe for transportation (Source: National Transportation Safety Board)

A fatigue crack initiated along the seam of the longitudinal weld during transit. It grew with pressure cycle stresses until the crack reached a critical size, at which time the pipe ruptured.² How does fatigue cracking during transportation begin? Improperly loading pipe can result in concentrations of stress that vary as the loaded railcars bounce up and down along the trip from pipe manufacturer to construction site. Bouncing flexes the pipe. By itself, this would not necessarily damage the pipe. However, if the pipe is

improperly loaded, the seam weld crown (the very top of the seam weld) may inadvertently be loaded face down and bear the entire weight of the pipe. The top of the seam weld is subjected to stress as it bounces along, which can initiate a fatigue crack. The phenomenon is similar to bending a wire coat hanger back and forth until it develops a crack and fails.

Chapter 13 covers construction in more detail. Additional information regarding the evolution of manufacturing and construction techniques can be found in the report, “Oil Pipeline Characteristics and Risk Factors: Illustrations from the Decade of Construction.”³

Natural hazards

Buried pipelines are susceptible to damage from earth movement caused by seismic activity. They are also susceptible to landslides, soil activity (shrinking, swelling, subsiding, or settling), scouring, and erosion (fig. 9–5).⁴

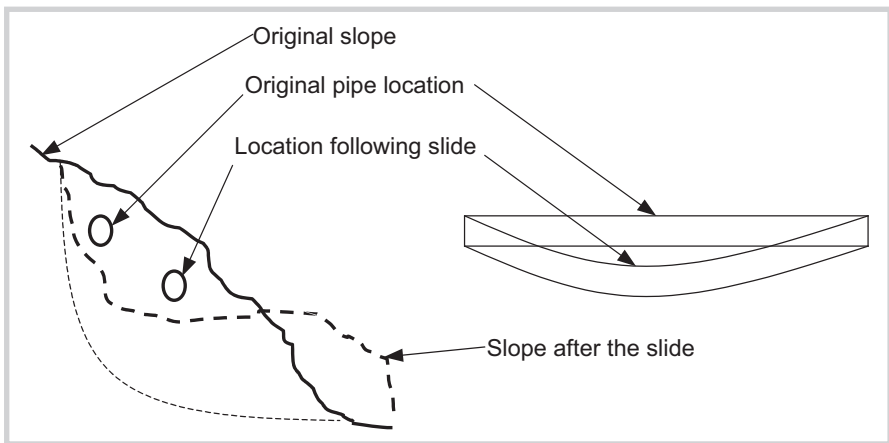


Fig. 9–5. Pipeline movements during a landslide. The force of the slide bends the pipe, causing it to stretch.

The amount of pipeline elongation is overemphasized in figure 9–5 to dramatize potential problems from land movement. Sometimes the pipeline fails during the landslide. At other times, stresses may build up and eventually rupture the pipeline, unless the pipe operator takes corrective action to relieve pipeline stresses. Sometimes the earth beneath the pipeline washes away, and the soil above the line pushes on it (fig. 9–6).



Fig. 9–6. Natural gas pipeline exposed by erosion (Courtesy Miesner, LLC)

Eventually the force may become large enough to break the line unless the pipeline operator takes corrective action.

Buried river and stream crossings and subsea pipelines are sometimes exposed by erosion. Once exposed, the flowing water presses on the pipe. Swift currents pushing against exposed pipelines increase pipeline stress and can damage and even rupture the pipeline. One of the more spectacular flooding examples occurred during October 1994 in the San Jacinto River, near Houston, Texas. Flooding ruptured 8 pipelines and undermined 29 others. The NTSB estimated more than 35,000 bbl of petroleum or petroleum products were released from the ruptured lines. Part of the spills ignited from an unknown source, causing a spectacular display of fire on the river.⁵

Sometimes riverbeds or stream bottoms wash out, exposing the pipe (fig. 9–7). When heavy rains fill a drainage ditch to overflowing, stresses can build up in the pipeline, potentially causing failures. Debris may also wash down the drainage ditch and snag on the exposed pipe, causing it to rupture.



Fig. 9–7. Natural gas pipeline exposed in a drainage ditch (Courtesy Miesner, LLC)

Lightning is another source of natural damage. Lightning is more apt to damage aboveground facilities, particularly storage tanks. At a crude oil export terminal near the Russian town of Novorossiisk, at the end of the CPC Pipeline from the Tengiz oilfield, this threat is taken seriously. They installed 16 giant lightning arrester towers as a precaution against lightning.⁶ Still, there have been cases in which the lightning grounded through a hole in the coating and caused a leak in a buried line.

Damage from seismic activity along fault lines can occur when the sections of soil shear or move differentially to each other. Earthquakes sometimes temporarily liquefy the earth around pipelines, causing differential settling. Periodic and seasonal swings in rainfall can cause soil shrinking, swelling, subsiding, or settling. These can precipitate buckles and subsequent cracks in pipelines (figs. 9–8 and 9–9).

Aseismic faulting occurs when one type of soil moves more or less than a nearby soil type. This type of faulting can be observed where streets and sidewalks change elevation abruptly. Around a pipeline, it can impart extreme stress and cause failure.



*Fig. 9–8. Pipeline buckle caused by differential settlement through a landfill
(Source: National Transportation Safety Board)*



*Fig. 9–9. Crack caused by buckling (Source: National
Transportation Safety Board)*

Other causes of failures

Of all releases, 20% to 30% can be categorized as “miscellaneous” causes of failure. Two of the leading causes in this group are operating problems and equipment malfunction. In many cases, these two only exacerbate a previous condition, because they stress a previously weakened piece of pipe or component beyond its limits.

How to Prevent Damage

Eliminating defects and relieving excessive stresses prevent pipeline failures. This section addresses each of the causes of failure and discusses some methods to prevent them.

Equipment damage

Equipment damage is a concern of pipeline companies, owners of other types of underground utilities, legislatures, regulators, emergency response officials, and contractors. In the United States, Common Ground Alliance (CGA) is an organization comprised of members of each of the groups listed above. These members work to promote the safety of underground utilities. The following sections draw heavily on a report by CGA.⁷

Planning and design. With knowledge of the locations of pipelines, construction projects can be designed to minimize the need to dig around pipelines. This is one of the best ways to avoid pipeline accidents caused by equipment. When a project involves excavation, the designers attempt to locate all underground utilities in the area. The underground utilities should be clearly shown on project plans. Designers and utility operators should meet to plan the best ways to work around the lines. Including excavators early in the planning process sensitizes them to the requirement to dig safely.

One-call centers. One-call centers are clearing houses for excavators to learn about all underground utilities in a specific geographic area. Designers and excavators should contact the center giving them the location of their projects. (It is equally important for homeowners to call their local utilities or a one-call center before beginning a “backyard project.”) The center then consults maps and databases and contacts the companies owning the underground facilities close to the excavation location. Most states in the United States have at least one such call center. Fortunately, the CGA has fostered better cooperation between various involved parties and the offices of the area’s jurisdictions.

Locating and marking. If a pipeline is contacted by a one-call center, it checks its records to see how close the excavation is to its lines. If it is close enough, the pipeline company sends someone out to locate and place markers along the line. Pipeline owners also regularly clear their ROWs and mark the pipeline routes on an ongoing basis (fig. 9–10). These permanent markers (fig. 9–11) allow landowners and excavators to determine the pipeline location so they can avoid it.



Fig. 9–10. Cleared and marked ROW (Courtesy Miesner, LLC)



Fig. 9–11. Typical ROW marker (Courtesy Miesner, LLC)

Pipeline employees or contractors use their maps, line finders, and probes to locate and stake the exact location of pipelines prior to the start of excavation projects. For particularly confined excavation sites or where the location of lines is uncertain, lines are excavated manually to find the exact location prior to mechanical excavation. Hand digging costs more than mechanical excavation, but it can avoid costly accidents. Many pipeline operators require the presence of their own inspectors during any excavation work near their lines. Excavators and pipeline operators normally work together to plan their activities and allow proper inspection and monitoring.

Excavation. Prior to excavation, representatives from the excavator and pipeline operator meet to agree on the excavation plan and confirm line locations. A *tolerance zone*, equal to the width of the pipeline plus a short distance on each side, is established. (Common Ground Alliance's *Best Practices* suggests at least 18 in. on each side.) No mechanical excavation is allowed within this tolerance zone. *Spotters*, construction company employees assigned to monitor the excavation, warn the equipment operator of dangers not easily seen. Pipeline operators monitor their own contractors digging near the line as vigilantly as they monitor excavators working for others.

Maps. Accurate maps sometimes make physically locating the line during initial project design unnecessary. Supplying pipeline location coordinates directly to project designers for inclusion on the drawings makes their work easier and improves safety. Even with the most accurate maps, pipeline operators, designers, and excavators often visit the proposed construction site prior to final design approval to verify locations.

Regulations and compliance. Appropriate regulations and compliance are important factors in avoiding equipment damage. Excavation regulations tend to vary from country to country, and often within a country as the result of differing requirements within local jurisdictions. In general, regulations requiring one-call systems and establishing tough fines for excavators who do not use the centers or who damage underground utilities tend to reduce pipeline accidents.

Public education. Chapter 14 discusses the many stakeholders who ought to be knowledgeable about pipelines in order to reduce the risk of pipeline accidents. These stakeholders include landowners, residents, excavators, utility operators, legislatures, regulators, and emergency response personnel. Pipeline companies conduct education programs, informing those living and working around the line about how to protect it and how to

recognize and respond to emergencies. Informed landowners are a valuable first line of defense for the pipeline operators. Beyond that, in the event an accident happens, trained emergency response personnel are essential.

Monitoring the route. Pipeline operators regularly patrol the route from the air as well as from the ground. These patrols look for excavation near the line and indications, such as stakes, markers, and vegetation clearing, that excavation is likely. At the same time, the patrols look for other signs of potential problems. These could include signs of small releases, encroachments, erosion, exposed pipe, marker condition, overgrown vegetation, earth movements, and general ROW conditions. The ROWs are normally kept clear of large vegetation to allow the aerial patrols better visibility. When aerial patrols identify a concern, pipeline employees are dispatched to investigate in more detail. Technologies are improving route monitoring, including surveillance by satellite, sonar mounted on airplanes, and fiber optic cables installed along the ROW.

Leak detection also calls for line monitoring, especially for small leaks. Large releases are normally located by leak detection systems or direct observation, since they attract attention. Small releases are difficult to detect. Oil releases cause wet spots, stains, or dead vegetation that may be spotted by aerial patrols. Natural gas, with a vapor pressure above atmospheric pressure, escapes into the surrounding air, often in small enough concentrations that it is not even ignitable. Such small leaks are difficult for aerial patrols to spot. Thus many natural gas pipelines have someone periodically walk the route with gas detection equipment looking for small leaks, particularly in sensitive areas such as those with high population concentrations.

Reporting and evaluation. The final step in reducing equipment damage is reporting and analyzing data about previous incidents. This allows pipeline companies to understand the root causes and take actions to reduce the likelihood of future damage. Collecting the information in a consistent format and providing it to one organization for analysis is the best way to learn about damage and how to avoid it. Industry associations and governmental agencies normally pick up this task. Whoever analyzes this information should include representatives from all stakeholders in a two-way communications format. Stakeholders can be educated about equipment damage and their role in preventing it. They can also offer valuable insight into improvement techniques.

Corrosion

Most pipeline corrosion is caused by current flow—electrons leaving the iron in the steel—especially in moist environments. Swamps and wet areas allow electrons to flow more easily than deserts and dry areas. Stopping the flow of electrons stops corrosion. Insulating coatings, such as coal tar enamel, and more recently, fusion-bonded epoxy, are applied to the outside pipe wall to stop current flow and can last more than 50 years. (There is more discussion of coatings in chapter 11.) They can effectively protect the pipe from current flow, but even a tiny hole in the coating (sometimes called a *holiday*) can concentrate current flow, creating an area of accelerated corrosion. That calls for care during the construction process, critical to avoiding holes in the coating.

Another alternative to stop corrosion is to reverse the flow of electrons, making them flow towards the pipe. This is called *cathodic protection* and is accomplished in two ways—by *sacrificial* or *impressed current* (fig. 9–12).

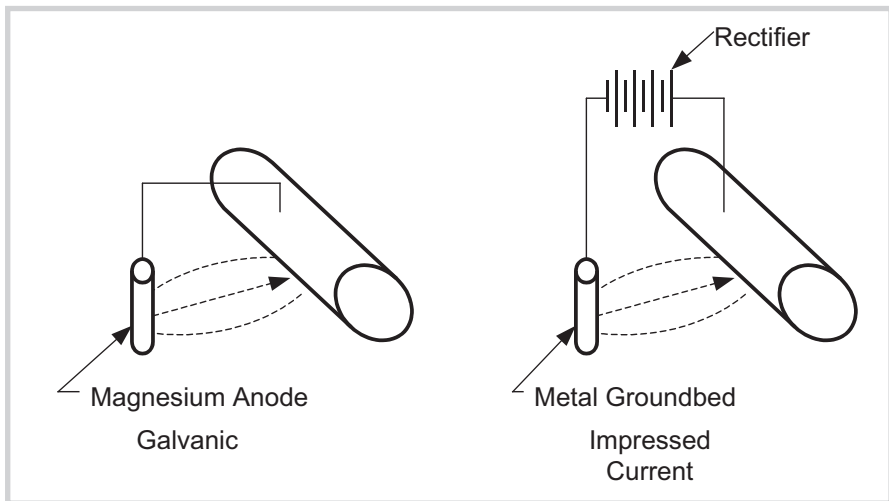


Fig. 9–12. Galvanic and impressed current cathodic protection

Sacrificial protection, the original method, involves burying a metal with a higher electrochemical potential than iron (often magnesium) in selected locations along the line. These *anodes* are connected to the line with insulated wires. Electrons flow from the sacrificial anode to the pipe (which becomes the cathode), preventing corrosion.

Impressed current involves connecting a *rectifier* (essentially a transformer that converts alternating current to direct current) to the line. The rectifier actually impresses current onto the pipeline, causing electrons to flow towards the pipe rather than away from it (something like recharging a battery). This prevents oxidation. Where do the electrons come from? As with galvanic protection, anode *groundbeds* are also buried along the line. They can be made of cast iron or other suitable material. The anodes are connected to the positive terminal of the rectifier. The negative terminal of the rectifier is connected to the pipe, completing the electrical circuit. Soil type and coating quality determine the number of rectifiers required along a particular pipeline. Rectifiers are a common sight, but probably few people can identify what they are (fig. 9–13).



Fig. 9–13. Pipeline rectifier. Note the power meter and breaker box on the pole next to the rectifier and the line markers in the background. (Courtesy Miesner, LLC)

There is one last important note regarding external corrosion and cathodic protection. Anything near a pipeline that is prone to corroding or generating electric currents must be considered by the corrosion technician or engineer. The electrical potential of power lines, other pipelines, railroad tracks, steel bridges, and the like are taken into account in the corrosion mitigation plan.

Internal corrosion normally occurs in low spots where contaminants like water tend to collect. Regular pig runs to keep the line clean and free of contaminants is one of the first defenses against internal corrosion. (Pigging is covered in more detail later in this chapter.) Inhibitors are also injected into the pipeline to prevent corrosion. Inhibitors can work by coating the internal wall of the pipe to prevent current flow or by interacting with the pipe materials to lower their electrochemical potential. They can also react with oxygen and other corrosive agents before they corrode the metal or neutralize acids that cause corrosion. Inhibitor concentrations can be tricky. In the wrong concentrations or combinations, they can actually accelerate rather than retard corrosion.

Stress corrosion cracking (SCC) is a phenomenon that may initiate on the outside surface of a pipe under stress. This can occur if the protective coating is absent or disbonded and the surface becomes exposed to certain types of soil/groundwater environments. It starts as a colony of small cracks that grow as the pipeline undergoes pressure cycles. If this growth continues unabated, it can cause the pipe to leak or rupture. Dealing with this phenomenon can be difficult and expensive, so the preferred solution is to prevent it from occurring. The best way to prevent SCC is a sound protective coating that remains tightly bonded to the pipe.

Mechanical failures

Mechanical failures are attributable primarily to either manufacturing flaws, construction-related flaws, or mishandling of the pipe during transportation. They are best minimized with robust standards and specifications, followed up by conscientious inspection and quality control. Pipe manufacturing and quality control are covered extensively in chapter 11. Construction welding is covered in chapter 13.

Natural hazards

It is important that pipeline companies recognize the potential for floods, seismic activity, landslides, and other types of soil movement, and design pipelines accordingly. This will go a long way toward preventing failures from natural hazards. Ongoing inspection is also critical to understand when corrective action is necessary. Design is covered in chapter 12, so the focus of this section is ongoing inspection.

Aerial patrols, mentioned earlier, can give early warning of impending earth movement. Trees leaning over, fresh earth scars on hillsides, newly exposed pipe, and water seeping from hillsides indicate potential problems.

Inclinometers are sometimes installed along the slope for an early warning of slope movement. Sometime exposed pipes in rivers and streams are visible during dry periods when the water is low. Strain gauges, electrical resistance or fiber optic, can also be installed on or near the pipeline to monitor pipeline stress due to earth movement. Strain gauges measure very small changes in pipe length. Increased strain indicates stress is building up in the line, which could cause a rupture.

Other causes of failure

Proper training and supervision are the best ways to prevent operational failures and the releases caused by them. The pipeline industry has traditionally employed on-the-job training, often pairing a new person with a senior person to observe and learn from them. This can be an effective means of training but should be supplemented with classroom, computer-based, and simulator work.

Finding Potential Problems before They Become Failures

Pipeline workers of the late 1800s had rudimentary tools to understand pipeline conditions, and they mostly used their eyes. (They might have observed whether the line was pulling apart or leaking.) Today, pipeline workers strive to anticipate and avoid repair problems using the ideas already mentioned, plus a variety of *destructive* and *nondestructive tests* to understand asset condition.

Destructive tests drive the material to failure by bending, pressurizing, impacting, and other forms of stress and strain, usually in a laboratory. Nondestructive tests do not damage the pipeline and are usually a better choice for operating pipelines.

Internal inspection devices

Smart pigs are pushed through pipelines just like regular pigs. The difference is that smart pigs are smart. The more appropriate name for a smart pig is *internal line inspection (ILI)* tool (fig. 9–14).

Traveling through the pipe, ILI tools look for potential problems such as metal loss, wall deformations, and cracks. They also indicate the location of extra metal, like taps or fittings welded onto the line—the purpose of which may be long since forgotten.

ILI tools employ various technologies, including deflection, magnetic flux, and ultrasonic. Each has specific applications. Some vendors combine technologies to measure several things.



Fig. 9–14. Combination MFL and caliper tool. This tool is capable of detecting both metal loss and mechanical damage. (Courtesy Baker Hughes)

Not all pipelines are suited to using pigs. From figure 9–14, it is obvious that ILI tools are rather long. Restrictions to pipeline diameter and sharp bends make traversing some lines impossible. The majority of oil lines were constructed in ways that allow ILI passage. Gas lines are more likely to contain loops for capacity expansion, sharp bends, and reduced port valves, all of which can be a problem for ILI tools.

Deflection tools. Devices using deflection technology are normally called *geometry tools*. Their purpose is to obtain information regarding the geometry or shape of the pipe wall. They are particularly useful for finding equipment- or construction-related damage. Geometry tools have sets of mechanical fingers that ride against the inside of the pipe. Pipe deformations move the finger, revealing the locations. More advanced geometry tools use electromagnetic methods to detect deformations. Most geometry tools also contain gyroscopes to provide the location of the deformation around the circumference of the pipe.

Magnetic flux tools. *Magnetic flux leakage* (MFL) tools induce a magnetic field into the pipe. Defects in the wall thickness, such as metal loss, cause disruptions in the magnetic flux field that the tools detect. Flux variations are analyzed to reveal the amount and location of wall loss due to internal and external corrosion and equipment damage. Improving technology has given rise to MFL tools with increased sensitivity—high-resolution as opposed to low-resolution tools.

Unfortunately, current versions of MFL tools are not very good at finding narrow defects. These are defects that are oriented parallel to the longitudinal axis of the pipe, such as seam cracks, stress corrosion cracking, and axial gouges. Transverse MFL tools may help in detecting these types of defects as the technology continues to improve.

Ultrasonic tools. Ultrasonic testing (UT) tools use the same technology as the ultrasound used in medical diagnosis—the ones that generate the familiar in vitro baby pictures. Ultrasonic pulses are sent into the pipe. When they encounter a boundary (the outside of the pipe wall), a portion of them bounce back. The times required for the pulse to bounce back are used to calculate wall thickness.

UT technology does have some limitations. Acquiring a signal requires a coupling fluid capable of transmitting the ultrasonic pulse from a noncontacting device into the pipe wall. (This is similar to the jelly used for medical ultrasounds.) Oil lines have sufficient lubrication to act as the couplings, but UT tools do not work as well in natural gas lines, since they are much drier. Another problem for UT is lines with internal buildup, such as crude oil lines

with paraffin adhering to the inside. Buildup causes the ultrasonic pulse to travel through more than just the metal, giving false thickness indications. UT also works better with heavy wall pipe than with thinner pipe.

Technology and tool research. There are millions of miles of pipelines in the world. It is not surprising that interest in pipeline safety drives research and development aimed at improving the sensitivity and reliability of these nondestructive ILI tools. (Sensitivity refers to how well the tool detects very small anomalies or features. Reliability has to do primarily with how well the results match what actually exists on the pipeline.) To have confidence in a pipeline based on ILI tools, the operator needs to know how accurate the results are. Specifically, the operator needs to know how accurately the tool indications represent the actual characteristics (depth, size, and location) of the anomaly in the wall of the pipe. Tool data also require extensive interpretation before they can be seen as reliably representing the condition of the pipeline. Development of better interpretation techniques is ongoing.

Another important ILI development area is miniaturization of the technology to fit into smaller diameter lines. Some of the oldest lines are in the 6-in. to 12-in. diameter ranges, making the need for smaller diameter tools apparent.

Hydrostatic testing

One of the earliest pipeline analytical techniques, *hydrostatic testing*, determines if a pipeline can hold its intended operating pressure. Hydrostatic testing can be a form of destructive testing. It involves filling a line with water, pressuring it to a predetermined level, and holding it at that pressure for some period. Water, rather than oil or gas, is used because the consequences of a rupture with water in the line are much less than with oil or gas. If a piece of pipe, a valve, or some other component fails before reaching the specified test pressure, it is replaced, and the test is restarted. New pipelines are always hydrostatically tested before they are placed into service. Existing pipelines also are sometimes hydrostatically tested. This might be done to eliminate defects that may have been created or enlarged during a period of servicing or modification that could cause the pipeline to fail if left unrepaired or undiscovered.

Long-distance pipelines are normally tested in sections of 15 to 20 mi in length, depending on the configuration and elevations of the specific line. Testing in relatively short sections increases sensitivity to detecting small leaks and reduces the amount of water required (and the associated treating and disposal costs). Spheres are inserted between the oil or natural gas and water as separators (fig. 9–15).

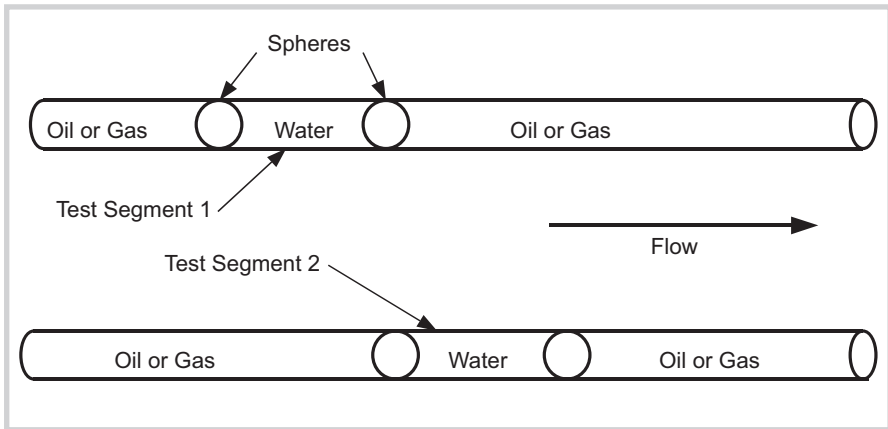


Fig. 9–15. Pigs segregating water from oil or natural gas. The oil or gas pushes the water into position for hydrostatic testing.

When one segment is finished, more oil or natural gas is put in at the origin, pushing the water along to the next segment and pushing oil or natural gas out at the destination.

Hydrostatic testing is relatively straightforward, but there are two special considerations. Chapter 8 discussed the impact of temperature on pressure. As temperature drops, so does pressure (in a closed pipe). Since pressure drop is the mechanism by which leaks are detected, it is essential to understand and minimize the pressure drop caused by decreasing temperature. During a hydrostatic test, the change in temperature must be monitored and factored into pressure drop calculations. Holding the test for 8 to 24 hours allows the temperature of the water in the pipe to equalize with the temperature of the surrounding soil, giving more dependable results.

The other special consideration is elevation change. Differences in elevation mean pressure differences. Engineers calculate the pressure due to elevation in each hydrostatic test section to ensure that test pressure at each point is high enough for a good test but not so high it stresses the pipe beyond its limits. Significant elevation changes may require short test segments to allow a high enough pressure at the highest elevation while not over pressuring the pipe at the lower elevation (fig. 9–16).

Even though hydrostatic testing is expensive and disrupts supply, it continues to be a widely used integrity assurance tool.

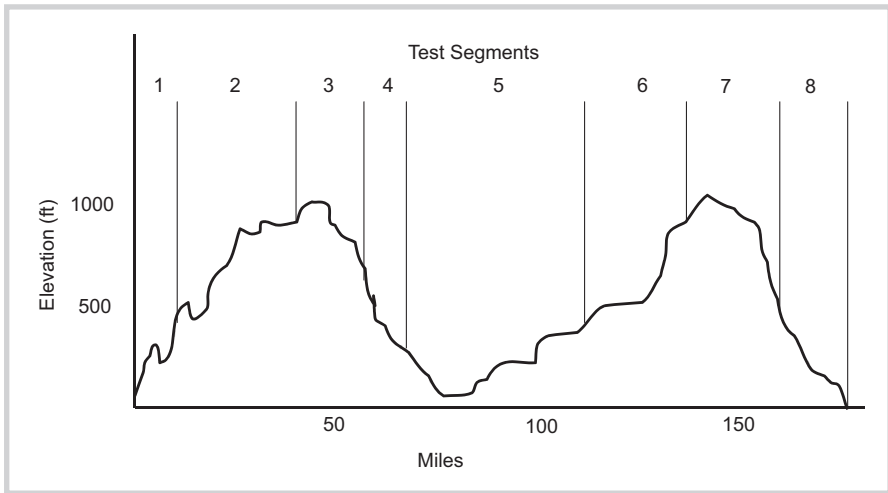


Fig. 9–16. Test segments for a pipeline. This pipeline is 175 mi long, with an elevation change along the route of 1,000 ft.

Electrical surveys

Corrosion is associated with the exchange of electrons. Knowing the electrical potential along the pipeline helps corrosion engineers and technicians to understand the condition and performance of the cathodic protection system. (This system consists of the coating, the rectifier, and the groundbed.) Cathodic test stations are used to make electrical contact with the buried pipeline from the surface to measure the difference in electrical potential between the pipe and the surrounding soil. They also have a secondary function, which is to measure current flow (fig. 9–17).

Test stations may have one or more wires connecting to the pipeline; the other end is connected to test station terminals installed about every mile along the pipeline. Normally they are located at convenient locations such as roads and fence lines (fig. 9–18).

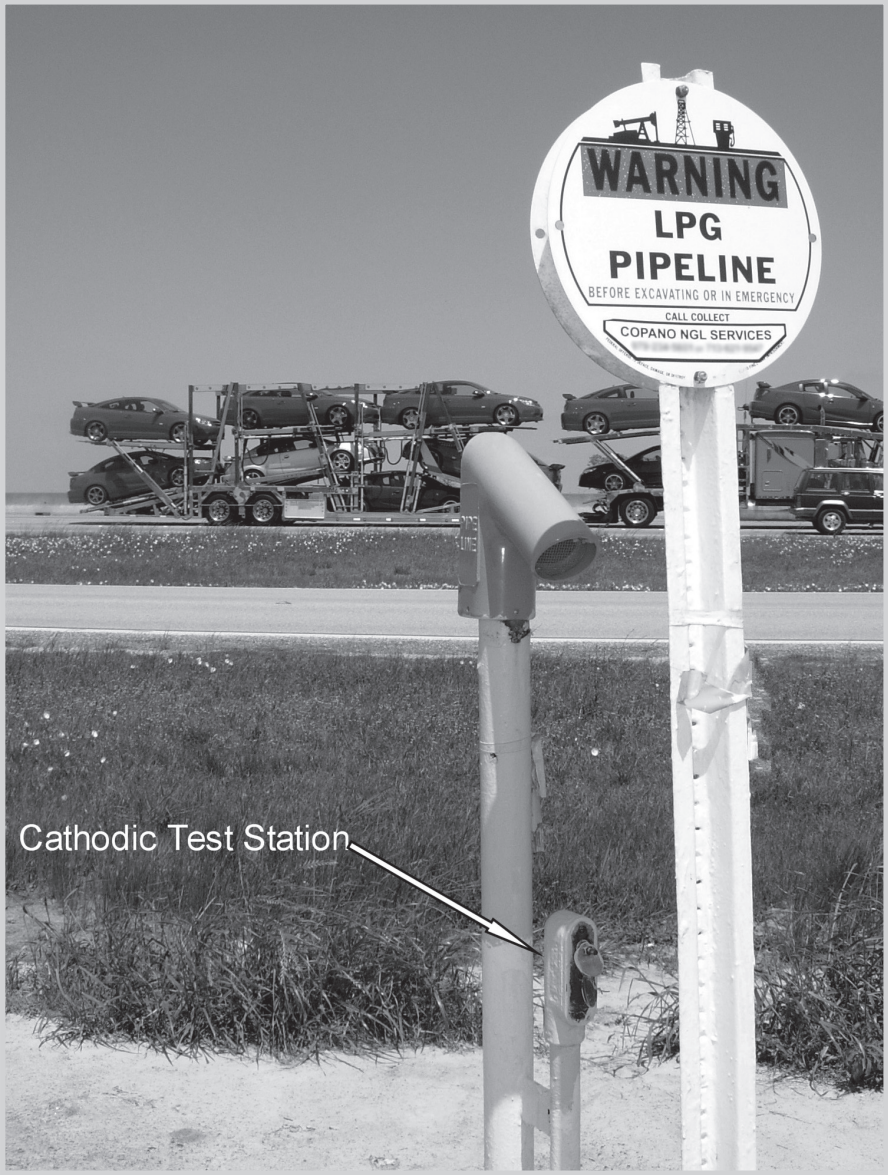


Fig. 9-17. Cathodic test lead station (Courtesy Miesner, LLC)

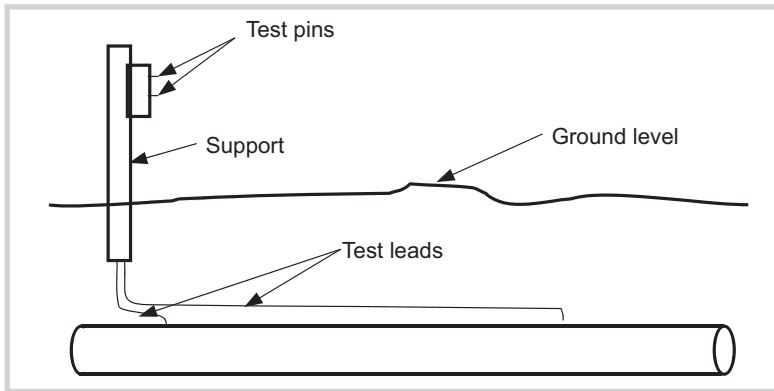


Fig. 9–18. Cathodic test lead schematic. Two wires are connected to test pins on the test station and then fastened to the pipeline a known distance apart.

Pipe-to-soil potential. To measure *pipe-to-soil potential*, technicians connect one terminal of a voltmeter to the test lead that is connected to the pipeline. The other terminal of the voltmeter is connected to a copper–copper sulfate reference electrode (half cell) that is placed in contact with the ground above the pipe. These readings (in millivolts) are compared to various benchmarks and historic readings to determine the level of cathodic polarization, or the difference in electrical potential. Then these readings along the line are plotted, allowing the technician to spot trends (fig. 9–19).

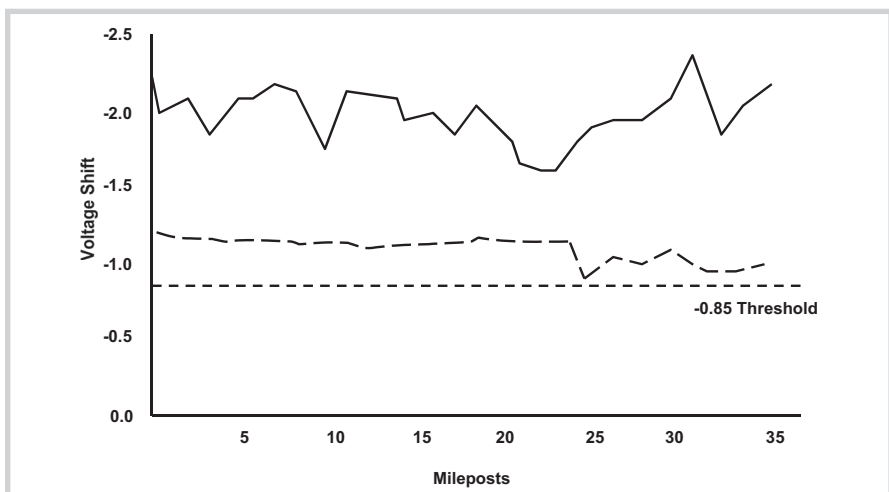


Fig. 9–19. Pipe-to-soil profile. The solid (most negative) line is the electrical potential of the pipeline with all the rectifiers turned on. The line with long dashes shows the “polarized” potential of the steel with the rectifiers turned off. The straight, short dashed line is a reference line. Generally speaking, if the two potential lines are above (more negative than) the reference line, cathodic protection of the pipeline is adequate.

Current drop. In addition to measuring pipe-to-soil potential, technicians use some test stations to measure voltage drop along the pipeline, allowing them to calculate current flow. They connect a voltmeter to test stations pins, which are fastened to wires connected to the pipeline a known distance apart. The voltmeter displays the voltage drop between those two points on the pipeline. From distance, wall thickness, and pipe diameter, resistance to current flow is known. The following electrical engineering formula comes into play:

$$\text{Voltage} = \text{Resistance} \times \text{Current}$$

Since resistance and voltage drop are known, current can be calculated. High current flow at one test lead and low current flow at the next test lead indicates a problem between the two points.

Close interval potential survey. Another current survey method, the *close interval potential survey* (CIPS), measures electrical potential with the rectifiers on and off. These measurements are taken at intervals of about 3 to 10 ft along the pipeline. Performing a CIPS requires a surveyor to physically travel along the entire section of pipeline being surveyed (fig. 9–20).

Surveyors may use a global positioning system (GPS) unit to determine the coordinates of their location. These readings are fed to the CIPS unit, making it possible to connect the CIPS readings with physical locations along the pipeline. CIPS measures the cathodic protection on the line as well as the condition of the coating



Fig. 9–20. CIPS surveyor walking the pipeline
(Courtesy Cathodic Technology Limited)

Voltage gradients. There are two types of voltage gradient tests: direct current voltage gradient (DCVG) and alternating current voltage gradient (ACVG). Both are used to find coating damage. For DCVG, a current pulse is created along the line, either by interrupting the rectifier or by applying a direct current (DC) pulse from an outside source. For ACFG, a current pulse is also created, but this time with low-frequency alternating current (AC). The voltage gradients in the soil are measured around the pipeline to locate coating defects. In both cases, voltage drop is measured along the line and plotted on a graph creating a gradient (with a sloping line much like hydraulic gradients).

Combined CIS and DCVG surveys. Modern electronic equipment allows measurement of CIS and DCVG values at close intervals (3 to 5 ft) simultaneously along a buried or submerged pipeline. The data from a combined CIS and DCVG survey allow the corrosion engineer to more accurately assess the level of cathodic protection on the pipeline. The engineer can also assess the effect of coating damage on the level of cathodic protection.

Pearson survey. This method, devised by J. M. Pearson, applies an AC signal to a short section of pipeline. Surveyors walk along the pipeline wearing metal cleats to provide good contact with the soil. Wires run from the metal cleats to a Pearson receiver, worn by the surveyor. A surveyor who walks over a section of the pipeline with coating damage will hear a distinctive tone in his headphones, indicating the location of the damage.

The survey methods in this section all have common goals—understanding the condition of the buried pipeline to prevent corrosion, ultimately to eliminate releases.

Direct assessment

Direct assessment (DA) is an old concept involving excavating and physically examining the pipe to determine its condition. Advances in statistical techniques make DA an alternative to ILI, especially for those pipes constructed in ways that do not allow ILI tool travel. It involves using all available data about the line to determine the most likely problem locations. These locations are excavated, and the pipe and coating are examined to determine their condition. Pipe wall thickness is measured to determine any wall loss.

The process and the science of DA continue to evolve, but generally people agree there are at least four steps in the process:

- Preassessment
 - Collecting historic data to determine what data gaps exist
 - Recommending further testing to fill the data gaps
- Indirect examination
 - Conducting additional tests to identify coating faults, anomalies, soil condition, and some types of corrosion activity
 - Analyzing soil environments and comparing them to specific models to evaluate the potential for stress corrosion cracking
 - Performing flow modeling for internal corrosion
 - Selecting sites for the next step (direct examination)
- Direct examination
 - Excavating the pipe at selected locations
 - Conducting visual and nondestructive testing to determine coating and pipe integrity
- Postassessment
 - Analyzing the data from the previous steps to establish pipe and coating integrity
 - Making repairs as needed
 - Determining the reinspection interval required to ensure integrity

The final step is critical. As lines age, they need to undergo continued inspection, testing, and maintenance to assure safe operations.

Risk and Pipeline Safety

The ultimate goal of inspecting the pipeline is to understand its condition, prevent releases, and assure safety. But what is a “safe” pipeline? Is it one without a past release? Is it one that will never have a release? How can future release potential be understood? Most people agree that it is impossible for anything to be completely safe. That leads to the topic of risk.

The typical definition of risk, and the one used in this book, is given in terms of consequences and probabilities:

$$\text{Risk} = \text{Probability} \times \text{Consequences}$$

The risk equation looks simple, and it is for one probability and one consequence. However, pipeline risk involves multiple probabilities, multiple consequences, and multiple sections of pipe. Risk is the sum of all those probabilities, and all those consequences, for each section of the pipeline. Entire books, like W. Kent Muhlbauer's *Pipeline Risk Management Manual*, deal with pipeline risk.⁸ Only the basic concepts will be presented here.

Consequences

A leak from a natural gas pipeline in the farming region of Belgium may cause a crater and scare some people. When a similar leak occurs in the densely populated town of Ghislenghien, 20 mi southeast of Brussels, the consequences may be lives lost, property damage, business disruptions, and supply curtailments. Diesel leaking from a pipeline in one of the wheat fields crossing the plains of Montana is terrible, but gasoline leaking into the water source for a city is worse. Consequences depend on many factors—size, location relative to water, population density, time of day, time of year, and weather, just to mention a few.

Probabilities

Probabilities are the likelihood of something happening and are based on statistics and past occurrences. The probability of a coin landing “heads up” is 50% over repeated attempts. The 50% probability can be predicted with a small margin of error. Predicting the probability of a pipeline release is difficult. It is also difficult to predict the probability of its being a large or small release, the probability of its getting into water, or the probability of its injuring someone. There will be wide margins of error.

Framework for considering risk

In figure 9–21, the left column lists the causes of a release listed earlier. The second column has the probability of a release from the individual cause. The third column lists consequences. Finally, the fourth column has the general types of consequences.

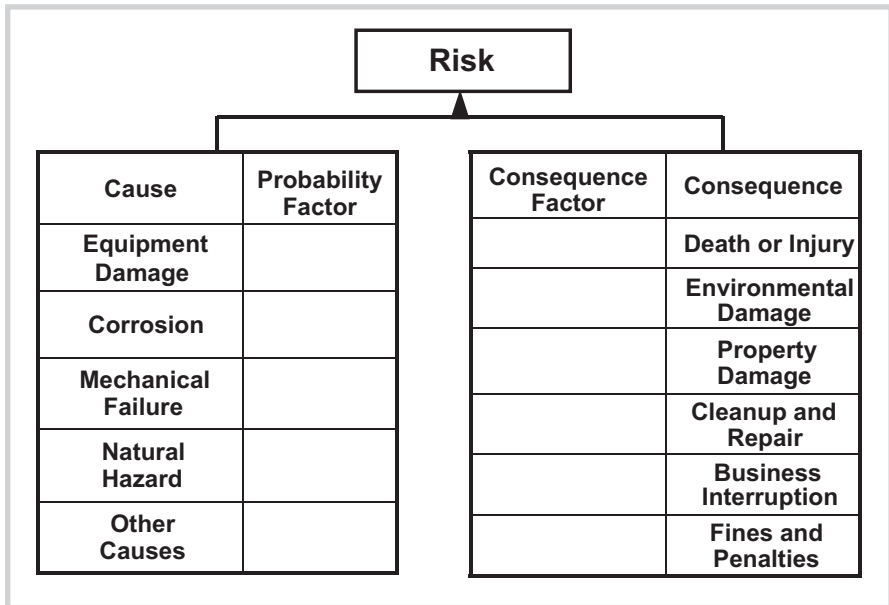


Fig. 9–21. Framework for considering risk. Note some cells are blank; filling these out is the work of integrity engineers.

These factors can be broken down even further (table 9–1). Causes, probabilities, and consequences are combined to determine the total risk for one section of the pipeline. Each section of the pipeline has its own combination of causes, probabilities, and consequences, and all sections are summed to determine total pipeline risk.

Each cell in table 9–1 requires a number. Ideally, the numerical values of probabilities and consequences would be very objective and quantifiable. Again, the challenge of accurately determining probabilities and consequences leaves a wide margin of error. While approaches vary, in general, pipeline operators use historic, quantifiable values where they can. When these numbers are not available, or are not dependable, they rely on the opinion of experts, with many years of practical experience.

The difficulty in arriving at a number for each probability and consequence gave rise to the *index method* for risk ranking. Instead of the actual probability or consequences, a relative ranking, usually between 1 and 10, is inserted into each cell, again based on all available information and the judgment of experts. Risk is calculated based on these relative rankings.

Table 9–1 Risk matrix

Probability of release from	Probability of	Cost or consequences of	Risk
Equipment damage	Injury or death	Injury or damage	
Equipment damage	Environmental damage	Environmental damage	
Equipment damage	Property damage	Property damage	
Equipment damage	Cleanup and repair	Cleanup and repair	
Equipment damage	Business interruptions	Business interruptions	
Equipment damage	Fines and penalties	Fines and penalties	
		Subtotal risk for equipment damage	
Corrosion	Injury or death	Injury or damage	
Corrosion	Environmental damage	Environmental damage	
Corrosion	Property damage	Property damage	
Corrosion	Cleanup and repair	Cleanup and repair	
Corrosion	Business interruptions	Business interruptions	
Corrosion	Fines and penalties	Fines and penalties	
		Subtotal risk for corrosion	
Mechanical failure	Injury or death	Injury or damage	
Mechanical failure	Environmental damage	Environmental damage	
Mechanical failure	Property damage	Property damage	
Mechanical failure	Cleanup and repair	Cleanup and repair	
Mechanical failure	Business interruptions	Business interruptions	
Mechanical failure	Fines and penalties	Fines and penalties	
		Subtotal risk for mechanical failure	
Natural hazards	Injury or death	Injury or damage	
Natural hazards	Environmental damage	Environmental damage	
Natural hazards	Property damage	Property damage	
Natural hazards	Cleanup and repair	Cleanup and repair	
Natural hazards	Business interruptions	Business interruptions	
Natural hazards	Fines and penalties	Fines and penalties	
		Subtotal risk for natural hazards	
Other causes	Injury or death	Injury or damage	
Other causes	Environmental damage	Environmental damage	
Other causes	Property damage	Property damage	
Other causes	Cleanup and repair	Cleanup and repair	
Other causes	Business interruptions	Business interruptions	
Other causes	Fines and penalties	Fines and penalties	
		Subtotal risk for other causes	
		Total risk	

As an example, the probability of equipment damage might be 10 in an area with lots of construction, and low, perhaps 1, in a national forest or park. The consequences of environmental damage in a park might be 10, and the consequences of environmental damage in an area of heavy construction 1. The risks from equipment damage in both cases are 10 (in one case, 1×10 ; in the other, 10×1). Quantifying risk in this manner allows pipeline operators to rank risk and spend money to mitigate the most severe risk areas.

Pipeline operators and vendors have various approaches to risk calculations. The factors can be subdivided or lumped together depending on the needs. Corrosion, for example, could be divided into external and internal, each with its own probability. The various risks for each pipeline segment for each cause are summed and then can be presented graphically (fig. 9–22).

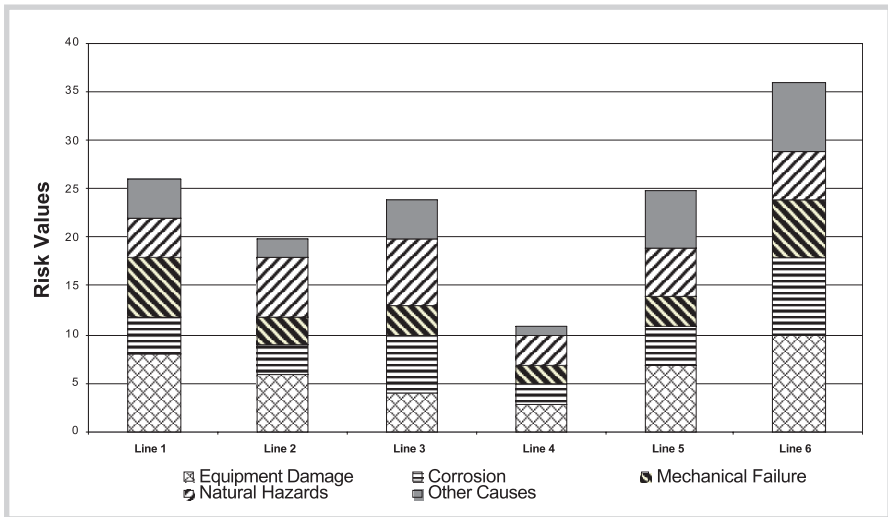


Fig. 9–22. Results by cause and segment

Each vertical bar represents the total risk of an individual pipeline, comprised of risks associated with various damage causes. Based on this graph, line 4 has the lowest risk and line 6 the most. The greatest risk for line 4 is natural hazards, and equipment damage is the highest for line 6. Tools like these help pipeline operators decide where and how to allocate their maintenance dollars.

Data

Most pipeline operators collect and store a great deal of information about their lines, including data such as:

- Original construction
 - Materials of construction
 - Construction techniques
 - Quality tests performed during construction
 - Components installed
- Operating history
 - Types and frequency of failures
 - Pressure history
 - Cathodic protection program
 - Coating and condition surveys
- Geography traversed
 - Population concentrations
 - River and stream crossings
 - Environmentally sensitive areas
 - Culturally sensitive areas
 - Elevations and soil conditions
- Inspection data
 - ILI
 - Coating surveys
 - Current surveys
 - Hydrostatic test records

This information can be used to feed risk algorithms such as those in figure 9–23.

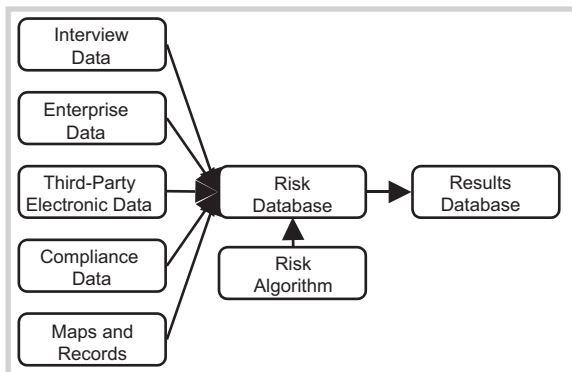


Fig. 9–23. Flow of database inputs and results for risk analysis. (Courtesy American Innovations [formerly Bass-Trigon])

Integrity Management Plan

Risk rankings, causes of pipeline damage, prevention activities, and other factors are combined into an overall plan to manage risk. Increasingly in the United States, this plan is becoming known as the Integrity Management Plan (IMP). In the United States, both industry institutions and federal regulations define IMPs. API Standard 1160 deals with integrity management for oil lines, and ANSI B31.8S covers integrity management for natural gas lines. Multiple vendors offer risk management software and plans.

The U.S. Department of Transportation's PHMSA defines an IMP as:

- *A documented set of policies, processes, and procedures that includes, at a minimum, the following elements:*
 - *a process for determining which pipeline segments could affect a high-consequence area (HCA),*
 - *a Baseline Assessment Plan,*
 - *a process for continual integrity assessment and evaluation,*
 - *an analytical process that integrates all available information about pipeline integrity and the consequences of a failure,*
 - *repair criteria to address issues identified by the integrity assessment method and data analysis (the rule provides minimum repair criteria for certain, higher risk features identified through internal inspection),*
 - *a process to identify and evaluate preventive and mitigative measures to protect HCAs,*
 - *methods to measure the integrity management program's effectiveness, and*
 - *a process for review of integrity assessment results and data analysis by a qualified individual.⁹*

Pipeline operators consider all the factors discussed in this chapter to produce a written plan and set of procedures to assure themselves, the regulators, and the public that their operations are tolerably safe. As the IMP concept becomes more pervasive in both liquid and gas pipelines, pipelines should continually get safer. Further, since it makes sense to consider the entire pipeline as a whole, IMPs may expand to include the whole notion of a risk management plan.

Repairs

People normally think of repairs when they hear “maintenance,” but obviously repairs are only one aspect. Steel pipes are tough, strong, and hard to damage. However, once damaged, there are several options for repair. These include replacing the damaged section of pipe, reinforcing it from the outside, grinding it to reduce stress concentrations, or replacing metal loss by depositing weld metal. Repairing damaged coating usually involves removing the previous coating, cleaning, and applying new coating.

Replacing the pipe

One of the most obvious solutions, replacing the pipe, sounds simple but is expensive, exposes workers to hazards, and often disrupts supply. Sometimes scheduling allows shutting down the line to replace a section. In other cases, a temporary bypass can be installed to allow the defect to be remedied.

After planning the job, and ensuring that all materials and equipment have been made ready, the line is shut down, and the natural gas or oil is evacuated. The pipe is then cold cut with a mechanical cutter and lifted away from the pipeline. A new section is dropped in and welded, and the pipe is recoated and reburied, much the same as with original construction. Evacuating (draining up for oil, and blowing down for natural gas) prior to cutting the line apart can be the most time-consuming step, depending on the location of isolation valves.

Sometimes special procedures such as hot tapping and plugging are used to minimize drain up or blow down time. Hot tapping and plugging involves first welding a tee fitting onto the line without evacuating the oil or gas from the line (fig. 9–24).



Fig. 9–24. Welding a hot tap fitting onto the line (Photo by Frank Gonzales)

Next a valve and then a tapping machine are bolted to the flange on the hot tap fitting (fig. 9–25). The valve is opened and the hot tap machine extended through the valve to cut a hole into the pipe. The hot tap machine cuts the hole and withdraws the piece of pipe through the valve, and the valve is closed. Next, the hot tap machine, still holding the piece of pipe, is removed, and a plugging machine is attached in its place. The valve is reopened, and the plugging machine inserts an expandable plug that blocks any flow along the pipeline. The same procedure is performed on the other end of the section to be removed. In that way, only the oil or natural gas between the two plugs needs to be evacuated. After the replacement pipe is welded in, the plugs are removed, unstopping the line, and the line is restarted. A well-planned procedure like this may take only 24 hours or less of line shutdown.

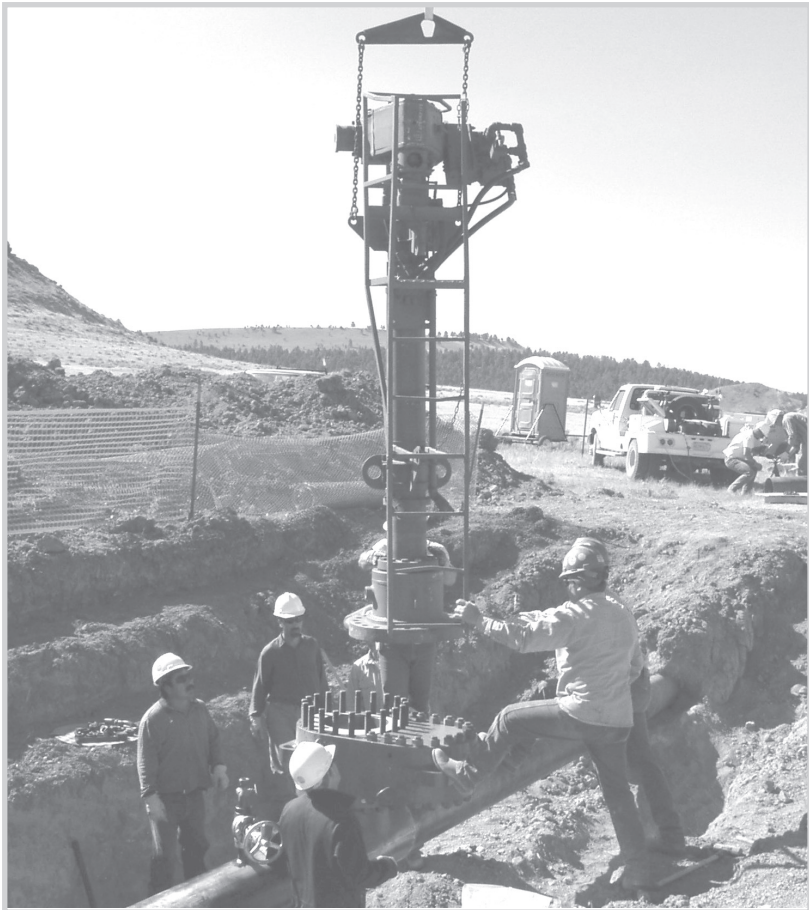


Fig. 9–25. Lowering the tapping machine. Note the valve is already bolted to the hot tap fitting. (Photo by Frank Gonzales)

When scheduling and supply do not allow a shutdown, a bypass must be established around the replacement section, allowing the natural gas or oil to continue flowing. The hot tap machine again is called into action. For a bypass, two pairs of hot tap fittings and valves are welded to each side of the cut-out section. One plugs flow, the other connects to a bypass pipe. Once the cut-out section is welded back in, the bypass is removed. The hot tap fittings are capped and left on the line.

Reinforcing the pipe

One way to reinforce the pipe involves welding a special *split sleeve* to the pipe, sometimes called a *full encirclement split sleeve* or a reinforcing sleeve. The sleeve comes in matching halves designed for the outside diameter of the pipe. The two halves are placed snugly on the pipe and are then welded together longitudinally (fig. 9–26). Before the sleeve is installed, any dents, gouges, or pits are filled with an epoxy material to eliminate voids.

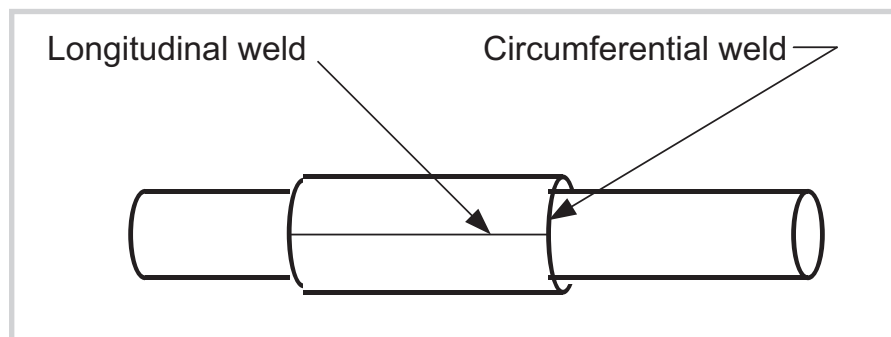


Fig. 9–26. Split sleeve installation

If the defect is leaking, the ends of a sleeve may be welded circumferentially to contain pressure. This weld is sometimes done even when no leak exists if the purpose of the sleeve is to reinforce the damaged or defective area of the pipe.

Another technique involves applying a nonmetallic reinforcing wrap around the damaged section of pipeline (fig. 9–27). Several different wrap systems exist, but each works on the same principle. The basic idea is to prevent failure of a damaged or defective pipe by keeping the defective area from bulging radially until it ruptures the pipe. These systems rely on glass or carbon fiber-reinforced polymer rather than steel to reinforce the pipe. Examples of brand names include Clockspring, Aquawrap, Strongback, Petrosleeve, Black Diamond, and Armor Plate.



Fig. 9–27. Composite wrap reinforcing the pipe (Courtesy CorroDefense, LLC)

With some of these systems, the “composite” is preformed in the factory and hauled to the field where it is coiled around the pipe and glued in place. Other systems involve wrapping the defective pipe with a fabric composed only of the reinforcing fibers. The fiber is impregnated with polymer resin in the field, and it cures to form the composite in place. Composite wrap systems are a proven way to repair many forms of pipeline damage.

Grinding to reduce stress concentrations

Small gouges or small cracks that by themselves might not be large enough to cause immediate failure of the pipe can still cause problems if left unrepaired for long periods. Any abrupt change in wall thickness creates a *stress concentration point* that can lead to crack propagation under repeated stress cycles. This is similar in effect to the bouncing rail car example earlier in this chapter. Pipelines experience stress cycles as they pack and unpack. As the pipeline cycles, stress concentration points are repeatedly stressed and unstressed, and a crack may develop, leading to a failure. Grinding is one way to repair gouges (fig. 9–28).

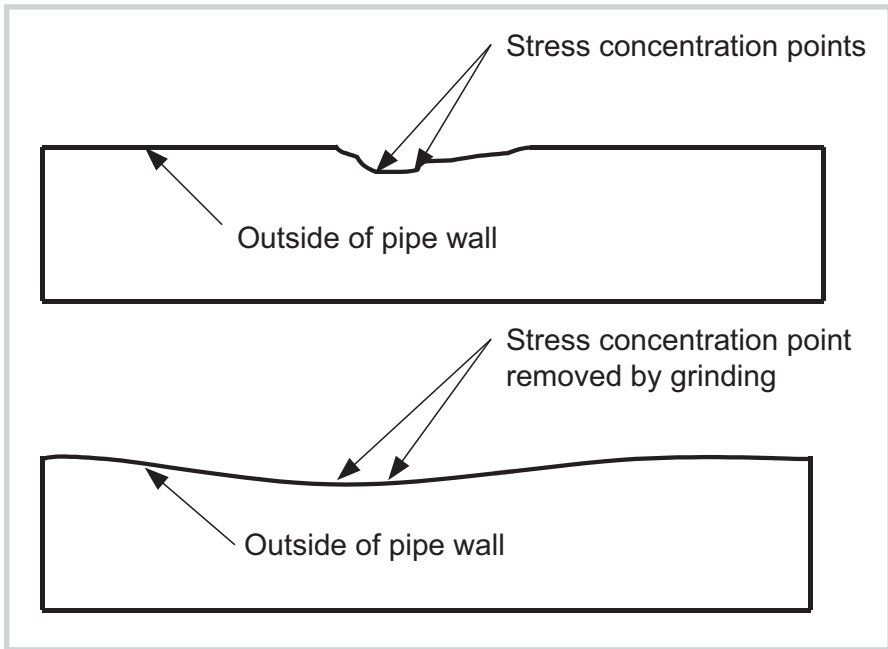


Fig. 9–28. Repairing a gouge by grinding

After grinding, stress is no longer concentrated at one point but is spread uniformly over the area. Obviously, grinding repairs are only appropriate for shallow gouges.

Deposited weld metal

Under certain conditions, areas of metal loss caused by external corrosion may be restored to full strength by depositing weld metal in the thin areas. Because of the risk of burning through the remaining wall thickness, this technique requires special procedures and specially trained welders. While this technique can result in high-quality repairs, procedures and training methods developed by experts in the technology must be used to ensure safety.

Coating repairs

As before, external pipeline coatings function as electrical insulators to stop corrosion by preventing the flow of electrons from the surface of the pipe. Damaged coating allows (and concentrates) current flow and must be repaired to limit corrosion. Repairs are accomplished by removing some of the surrounding coating, especially any that is loose or disbonded, and

replacing it with new coating. Any time the coating is removed or disrupted while making a repair to a pipeline, it ought to be repaired to protect the pipe. Recoating over existing coating is difficult and can lead to further problems if air pockets remain under the coating. Water sometimes collects in these pockets, leading to even more corrosion problems.

Other Maintenance Activities

Other important maintenance activities include line lowering, ROW maintenance, cathodic measurements, maintenance pigging, and various inspections.

Line lowering

Maintaining proper *depth of cover*, the distance from the top of the pipe to the surface, is one of the best pipeline protection mechanisms. In general, the deeper the pipeline, the less likely it is to be damaged by equipment. Erosion, farming, and construction activities sometimes remove cover from the line. When this happens, the line is lowered by carefully digging along the line, removing soil from under the line, and reburying the line. Before lowering lines, pipeline operators plan the work and calculate pipeline stresses to ensure the pipe is not pushed beyond allowable limits. During lowering, the pipe must be handled carefully and lowered gently. Safe *lowering in* techniques are followed as detailed in chapter 13. Once successfully lowered, the pipe is reburied, and the ROW is restored as nearly as possible to its original condition.

ROW maintenance

Maintaining the ROW consists of keeping it clear of obstructions—trees, shrubs, and such—to facilitate patrols and clearly indicate the location of the line. When pipeline companies fall behind on ROW clearing, and then try to catch back up, they may encounter resistance from landowners. This is particularly true if they wait so long that beautiful shade trees have grown on the ROW. Keeping up with ROW-clearing activities is the best way to prevent these situations.

Proper upkeep of pipeline markers and signs is important to ensure the public knows about nearby pipelines. Pipeline operators regularly patrol the line looking for damaged or missing signs and markers.

Cathodic maintenance

Pipeline operators regularly inspect rectifiers, groundbeds, and test leads. Fortunately, cathodic test stations may function even when they need repair (fig. 9–29).



Fig. 9–29. Damaged cathodic test station (Courtesy Miesner, LLC)

Maintenance pigging

Regular running of cleaning pigs helps keep a pipeline clean and free of water, paraffin, and sediment. This reduces the likelihood of internal corrosion and undue resistance to the flow of product in the pipeline. Pigging spheres are useful for pushing out water and separating batches (fig. 9–30). Brush pigs sweep debris to the end of the line, and scraper pigs remove materials like paraffin that can build up in a crude oil pipeline.



Fig. 9–30. Spheres waiting to be launched in a natural gas pipeline (Courtesy Miesner, LLC)

Pipeline operators launch pigs from a *pig launcher* and catch them in a *pig receiver*. Pig launchers and receivers are also generically called *pig traps* or *scraper traps* (fig. 9–31). Launcher barrels are generally shorter than receivers. A bypass line is near the back of the barrel, directing the flow behind the pig, forcing it forward and out of the launcher. Receivers have longer barrels, and the bypass line is near the front. With this arrangement the pig is forced into the trap and past the bypass line. The longer barrel gives it time to decelerate before it reaches the end of the trap.



Fig. 9–31. Pig receiver. Note the “barrel” of the receiver has a larger diameter than the pipeline. Flow pushes the pig past the outlet on the bottom of the barrel, and it coasts to a stop. A valve (not shown) is closed to stop flow through the receiver, and the pig is removed by opening the closure on the end (left). (Courtesy Miesner, LLC)

References

1. U.S. National Transportation Safety Board. *Pipeline Rupture and Subsequent Fire in Bellingham, Washington*. June 10, 1999, PAR-02/02, PB2002-916502, p. 72.
2. U.S. National Transportation Safety Board. *Rupture of Enbridge Pipeline and Release of Crude Oil near Cohasset, Minnesota, July 2, 2002*. Pipeline Accident Report, June 23, 2004, NTSB/PAR-04/01, PB2004-916501 Notation 7514A, p. 33.
3. Kiefner, J. F., and C. J. Trench. *Oil Pipeline Characteristics and Risk Factors: Illustrations from the Decade of Construction*. Report prepared for the American Petroleum Institute, December 2001.
4. Muhlbauer, W. K. *Pipeline Risk Management Manual*. 3rd ed. Burlington, MA: Gulf Publishing, 2004, pp. 110–113.
5. U.S. National Transportation Safety Board. *Evaluation of Pipeline Failures during Flooding and of Spill Response Actions, San Jacinto River near Houston, Texas, October 1994*. September 6, 1996, NTSB/SIR-96/04, PB96-917004, p. v.
6. “Caspian Pipeline: A History of Square Pegs into Round Holes,” *Alexander’s Gas & Oil Connections*, vol. 7, no. 12. June 13, 2002. Retrieved February 19, 2005, from: <http://gasandoil.com/goc/news/ntc22449.htm>
7. Common Ground Alliance. *Best Practices—Version 2.0*. December 2004.
8. Muhlbauer. *Pipeline Risk Management Manual*. 2004.
9. U.S. Department of Transportation. “Integrity Management Rules—Glossary of Terms.” Retrieved March 9, 2005, from: <http://primis.rspa.dot.gov/iim/glossary.htm>

10

Investment Decisions

*Long-range planning does not deal with future decisions,
but with the future of present decisions.*

—Peter Drucker (1909–2005)

There are 5 million miles, more or less, of pipeline in operation around the world, if all the oil, gas, gas distribution, and lines in other service are taken into account. Connected end to end, they would circle the Earth at the equator 200 times.

Companies build and expand pipelines every day. Ownership on various lines changes continually. This raises questions concerning pipelines:

- Why are they built?
- Who decides to build them?
- Why are they bought and sold?
- How are the decisions made?

Why Are They Built?

When large quantities of fluids require long-distance transportation across land, pipelines are normally the first option based on economics, safety, environmental considerations, and reliability. The history chapter reported how early crude oil lines replaced labor-intensive and clearly less-efficient forms of

transportation. These included barrels on carts pulled by mules and, incredibly enough, goat skins filled with crude oil carried by peasants. Pipelines quickly proved their merit in transporting crude oil to railheads. Rather quickly, long-distance pipelines replaced the railroads as the primary crude oil transportation mode. Refined products lines quickly followed. At one point during World War II, Nazi U-boats began sinking oil tankers hauling crude oil from the U.S. Gulf Coast to East Coast refineries. The 24-in. Big Inch and the 20-in. Little Inch lines were built as safe alternatives.

Natural gas pipelines have been around about as long as oil lines but did not catch on quite as quickly. In the late 1800s, most gas found in connection with oil production was burned at the site in a flare. Gas-only discoveries were just shut in. Some natural gas was transported short distances to markets by pipeline. However, by the middle of the 20th century, improved welding, compression, and pipe manufacturing techniques had been developed. These allowed the pressures needed to make long-haul pipeline transportation efficient and economical. By the end of World War II, natural gas pipeline construction gave producers access to distant markets.

History has demonstrated that pipelines are built (almost always) when they are the most economical means of transportation. It is true that pipeline failures are sometimes spectacular. Yet over the years, pipelines have proven to be the safest, most environmentally friendly way to move large amounts of gas and oil across land.

Who Decides to Build?

The answer seems obvious—the owners, or those providing the capital, decide to build a pipeline. But even though the prospective owners make the initial decision to build, based on their appraisal of the economics, other groups involve themselves in the final decision. Even in the early days, others played a critical role in the decision process. Owners of plants manufacturing town gas from coal vigorously opposed construction of early natural gas lines. Teamsters hitched their teams to crude oil lines, wrenching them apart in protest to protect their jobs. Railroads used their ownership of land and ROWs to block pipeline construction.

The cast of characters changes, but the list remains long. Today the stakeholders include:

- Owners
- Customers and shippers
- Consumers
- Competitors
- Local and national legislators
- Regulators
- Elected officials
- Local emergency response organizations
- Landowners and tenants near the route
- Communities
- Activist groups
- Private parties with specific agendas
- Suppliers
- Contractors
- Labor unions

Pipeline Stakeholders

Sometimes one stakeholder has power over others, and seemingly illogical results occur. For example, a portion of a pipeline had to be shut down when the lease expired, and the landowners exercised their unilateral right not to renew. After extensive negotiations with neighboring landowners, regulators, and special interest groups, the pipeline owner concluded it could not expect to receive approval for an economic route. It abandoned the project, using rail transportation to replace the section of pipe. In this case, rail transportation was more expensive and probably had greater environmental and safety risks.

The motives and interests of each of these stakeholders are worth almost a whole section themselves and, in fact, make up the bulk of chapter 14. Sometimes the members of the stakeholder groups overlap. Owners may also be customers or competitors, private parties with specific concerns or agendas, members of the community, or local emergency response organizations. Pipeline builders would like to deal only with the traditional criteria—construction costs, operating expenses, volumes, and rates. But an internalized world no longer exists. They have to address the concerns and interests of all the stakeholders, often a messy process.

How Is the Decision Made?

The decision to build or expand is made in an iterative process involving demand, supply, cost, and revenue forecasts, tempered with public opinion and public policy considerations. Demand and supply imbalances are linked, indicating potential routes. Preliminary economics are calculated from costs and revenues to determine pipeline economics. If they are favorable, they are refined, and the ability to secure permits and ROWs is investigated. That information clarifies the routing and affects the construction costs and economics. Further engineering and permit feasibility work is done. At some point, the prospective owners are comfortable enough to make the decision.

Figure 10–1 is a flow chart showing some of the factors considered to arrive at a preliminary decision concerning whether or not to build a line.

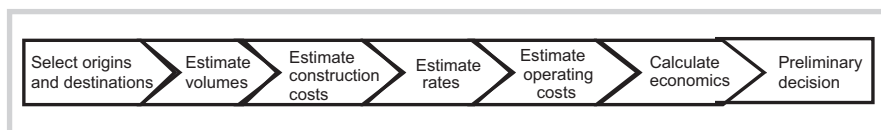


Fig. 10–1. The preliminary decision-making process

Demand and supply

It is simplistic and even seems ridiculous to state, but one of the first steps in planning a line is to decide the starting, ending, and intermediate delivery points. This basic step can be instigated by a need for pipeline transportation that is demand driven, supply driven, or market driven.

A *demand-driven scenario* can see the consumer market for fuels growing. Perhaps a power plant is being built or new refinery capacity or chemical plant capacity is coming on stream. Alternatively, an existing market can currently receive its supply by truck, rail, barge, or tanker—more costly forms of transportation. The changes present an opportunity for new pipeline capacity to move oil, natural gas, or other commodities to satisfy demands.

In a *supply-driven scenario*, perhaps new oil and natural gas fields have been discovered. Alternatively, perhaps refinery or natural gas processing plants have been built or expanded, or new tanker terminals are put in place. These new sources of pipeline-transportable commodities will need to access markets.

In a *market-driven scenario*, there is new availability of a commodity, typically a natural gas discovery. This calls for the simultaneous development of a new (perhaps distant) market, and a pipeline to connect the two. This happened in the United States in the first half of the 20th century as huge deposits of natural gas were found in the Southwest. Happily, that was accompanied by the development of pipe technology that enabled development of markets in the Midwest and Northeast. It continues to happen in developing areas of the world as gas resources and gas distribution systems are created simultaneously (fig. 10–2).

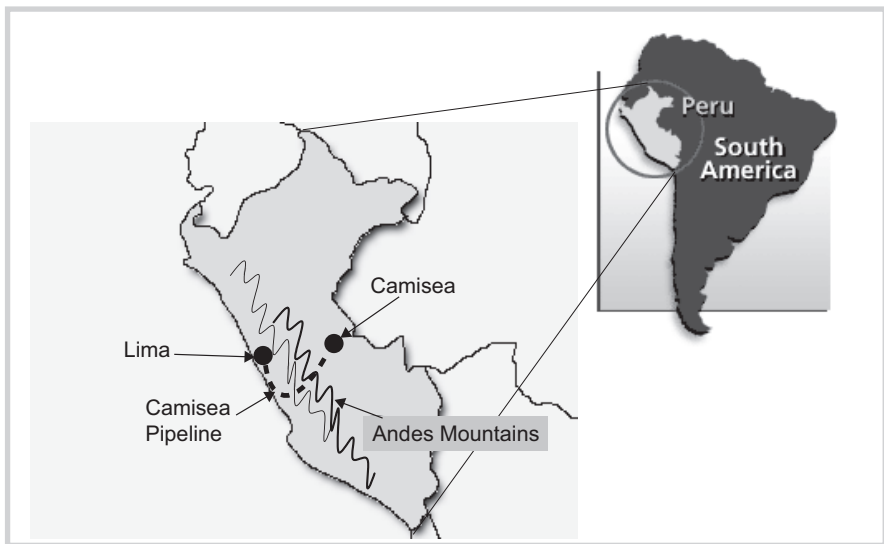


Fig. 10–2. The Camisea Pipeline. The whole Camisea project involved the development of a large natural gas discovery in the Andes Mountains. It further involved a pipeline across the mountains to the Pacific Coast, terminating at Lima, Peru, as well as the development of a natural gas distribution grid in Lima, a natural gas processing plant, and an LPG export terminal.

Sometimes, as in the case of a new offshore natural gas discovery, or even the Camisea case, the origin decision is obvious—it starts at the gas well. The destination point may not be as obvious. Should the gas be brought to the nearest location where it can be converted to LNG for transportation by ship? Or is building a line to bring the gas to a major population center or hub a better decision? Planners usually consider many scenarios to arrive at the best choice.

Satisfying supply and demand does not always mean laying a new pipeline. Existing lines can be expanded or converted. The Big Inch and Little Inch lines were mentioned earlier. They were originally built as crude oil lines but were

purchased by Texas Eastern Transmission Company at the end of World War II and placed into natural gas service. Seaway Pipeline, extending from the U.S. Gulf Coast to Cushing, Oklahoma, began as a crude oil line. It was converted to gas in the early 1980s, and then back to crude oil in the mid-1990s.

Economics

Decisions to build or expand are primarily based on allocation of scarce resources, one of which is money. To justify spending funds on a pipeline, the purse-string holder has to be convinced it will generate an attractive return. That calls for the people putting together the proposal to forecast the size of the investments, the revenues, and the operating costs to calculate earnings and return rates.

Investments. The amount of capital outlay, the cost of ROW acquisition and construction, is one of the first items questioned. Pipeline planners develop a *design document* as the first step toward estimating construction and procurement costs. The design document specifies origins, destinations, flow rates, acceptable gas, crude, or petroleum quality, and other items important to the success of the line. In most cases, the design document includes a range of values for each parameter.

Planners develop preliminary designs including line size, horsepower, storage facilities, delivery stations, and SCADA, controls, and leak detection systems based on the design document. Preliminary cost estimates with an accuracy of $\pm 50\%$ are then developed for the initial designs. The designs are updated and refined as details are confirmed, customer needs are identified, and issues associated with the project are resolved. Environmental or community issues, such as roads, parks, river and stream crossings, and wetlands are identified. The costs to avoid or safely cross these features are added to the costs estimated. These costs are likely to change, even before construction begins, after the detailed engineering and design work described in chapter 12 is done. But that comes after the decision to build.

Revenues. Pipeline revenues are the “cash register” for the line and a critical component of profitability and return. Revenues are calculated as the rate per barrel, tonne, thousand cubic feet, or cubic meters, multiplied by the total number of barrels, tonnes, thousand cubic feet, or cubic meters moved. Confident revenue estimates require volume and rate based on good demand and supply forecasts. Figure 10–3 shows a representative example of a 10-year volume forecast. Note the high, low, and base case projections. Typically a pipeline proposal has a base case with a 50% probability of achieving it. It will also have a low case with a 90% probability, and a high case with a 10% probability.

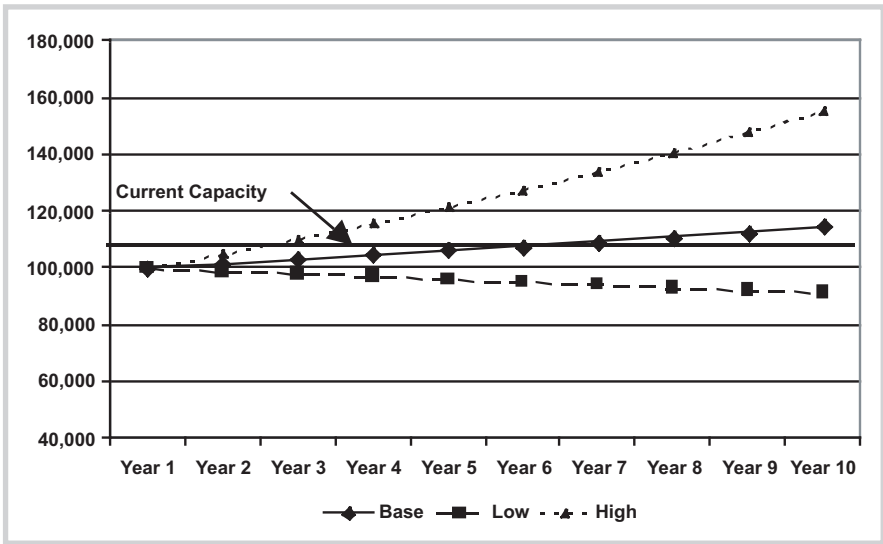


Fig. 10-3. Area demand and existing capacity

In this case, current pipeline capacity into the area exceeds average yearly demand. In the low case, no additional capacity is needed. In the high case, additional capacity is required by the third year. Figure 10-4 shows a closer look—the average monthly demand instead of average yearly demand.

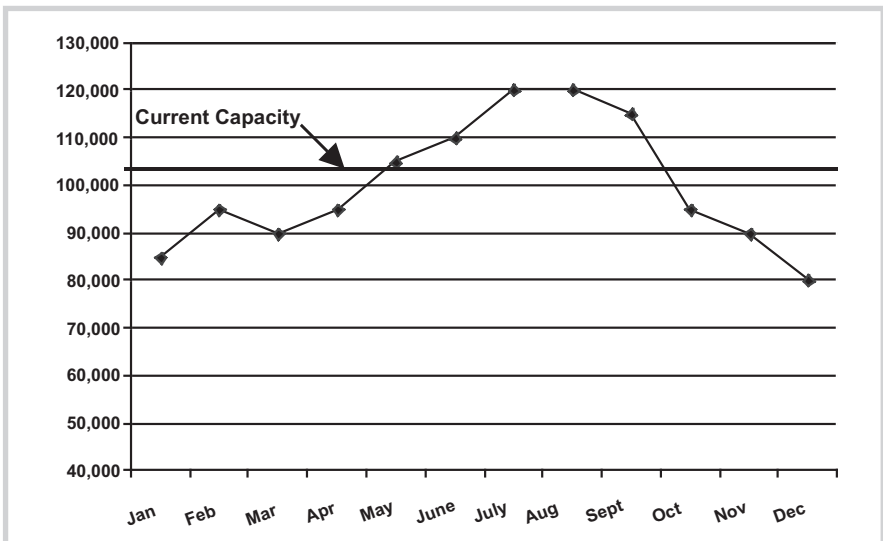


Fig. 10-4. Monthly demand forecasts and existing pipeline capacity

In this view, demand exceeds available capacity on a seasonal basis. Planners consider the volumes a new line can capture. Can it capture a share of the base demand plus the seasonal imbalance plus growth? Can it just capture seasonal imbalance? Is seasonal imbalance already handled with storage? The answers to these questions impact the volumes and economics for the new line. Consequently planners consider all known factors to arrive at the amount of demand the line can expect to capture.

In some cases pipeline companies require minimum volume commitments from shippers to reduce risk before they agree to build or expand the line. If the volumes do not materialize, the pipeline company still gets paid.

Supply-driven cases often have “lumpy” forward profiles as a small number of large investments in capacity come on stream (i.e., in contrast to typical, smooth demand forecasts, where a large number of small investments cause the growth). Figure 10–5 has the base case for a characteristic 10-year supply outlook. The forecast shows current volumes declining, but two new increments of production are expected to begin in subsequent years. High-case and low-case forecasts would make the chart quite complicated, but they also merit consideration.

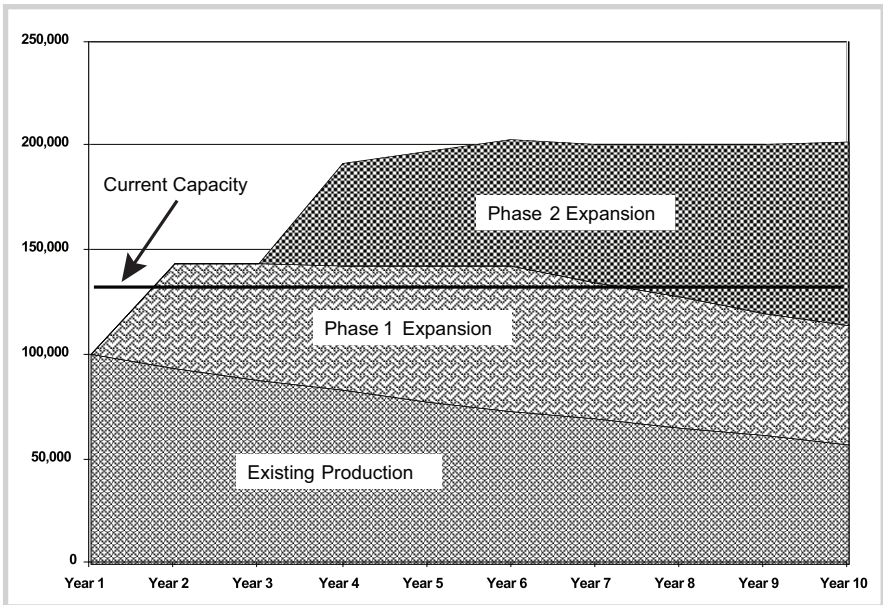


Fig. 10–5. Production forecasts and existing pipeline capacity

Volume is one half of the revenue components. The other half is the rate—the amount shippers pay per unit. Sometimes the pipeline supports a larger project, like an offshore production field. The pipeline investment may be a small part of the cost of the offshore production field. Consequently, the pipeline rate can be quite high and still be inconsequential to the project development. More often, economic returns for pipeline projects are rather low (12% to 15%), and small changes in rates have large impacts on project economics. In that case, pipeline planners negotiate with customers and regulators to make sure they understand the future rate structure before committing to the project.

Common ways to establish rates include:

- Cost of alternative transportation
- Rates on competing pipelines
- Location differentials
- Shipper or customer negotiations
- Cost of service
- Regulatory schemes

These methods apply primarily to independent or quasi-independent pipelines. (A quasi-independent line is owned by a government or a government agency but charges customers for services.) Projects that have a pipeline imbedded may or may not calculate a separate rate as mentioned previously.

The *cost of alternative transportation* method involves understanding the rates charged by the competing forms of transportation—ship, barge, rail, truck. The pipeline charge will be set equal to or slightly below those rates. Calculating rates using this method can be very favorable for the pipeline owner, especially for long-distance transportation.

Rates can also be based on pipeline competition. It is not uncommon for pipelines to “discount” rates along some segments to ensure they capture a share of the transportation market in that area. Colonial Pipeline and Plantation Pipeline have many points of competition in the southeastern United States.

A few pipelines use *location differentials* as a basis for their rates. Location differentials are the differences between the price of the commodity at the origin (normally an area of oversupply) and the price of the same material at the destination (an area of undersupply). The supply imbalance could be caused by supply shortages or bottlenecks in other transportation alternatives,

including another pipeline. Location differentials are dependent on the changing supply/demand balances and can swing wildly. Pipeline planners who estimate rates based on differentials are sometimes disappointed as they watch differentials quickly collapse when new supply enters the market.

Rates that are negotiated between the pipeline owner and the shippers can come under this subtopic. In the negotiation, the pipeline and the shipper are both mindful of the alternative mode of transportation. The parties meet, discuss their respective needs and try to arrive at a mutually agreeable rate structure. The result may or may not require concurrence from a governmental regulatory body. In some cases, the negotiated rate is posted, allowing all shippers to transport at that rate. At other times, the rate remains a private contract between the pipeline and shipper.

The *cost of service* (a regulatory term) method assumes the pipeline owners are entitled to a reasonable rate of return on their investment. (*Reasonable*, of course, is based on the eye of the beholder.) Calculations are based on recovering capital costs, operating costs, and an allowed rate of return for equity and debt. Once the numbers are determined, they are added to yield the total revenue the pipeline owners are *allowed* to earn from the pipeline. (There is no guarantee they will achieve it.) This total number is divided by the expected volumes to arrive at the rate per barrel, million cubic feet, tonne, or cubic meter.

Cost of service is only one example of regulatory schemes to determine allowable rates. Even though pipeline rates are usually only a very small part of the ultimate consumer's cost, complex and arcane regulations that vary among countries still apply in many cases.

Operating costs. The major operating costs include:

- Salaries, wages, and benefits
- Fuel and power
- Operating supplies
- Inspection and maintenance
- Insurance
- Local, state, and federal taxes and fees

As with volume, to increase confidence in the forecasts, planners work with other groups inside the company, such as people from operations, engineering, maintenance, or controls. They will develop scenarios of how

the pipeline might operate. They prepare cost estimates for each category using agreed-upon operating scenarios and run different sets of economics based on combinations of scenarios.

Power costs may be based on the local power provider's standard usage and rates. Since power costs are a significant percentage of overall operating costs, they may negotiate contracts with lower rates for off-peak usage or lower overall rates. They also might optimize the design to accommodate varying power plant area rates. Other costs, like operating supplies and maintenance, are forecasted based on experience with other lines. Property, ad valorem, and income taxes differ for each local, state, and federal jurisdiction. Figure 10–6 is a simple example of an income buildup spreadsheet.

Category	Year 1	Year 2	Year 3	Year 4	Year 5
Volumes (bpd)	50,000	51,500	53,045	54,636	56,275
Rate	\$0.50	\$0.51	\$0.52	\$0.53	\$0.54
Total Revenue	\$9,125,000	\$9,586,725	\$10,071,813	\$10,581,447	\$11,116,868
Salaries and Wages	\$2,500,000	\$2,575,000	\$2,652,250	\$2,731,818	\$2,813,772
Benefits	\$875,000	\$901,250	\$928,288	\$956,136	\$984,820
Fuel and Power	\$3,050,000	\$3,233,000	\$3,426,980	\$3,632,599	\$3,850,555
Operating Supplies	\$425,000	\$437,750	\$450,883	\$464,409	\$478,341
Maintenance	\$250,000	\$257,500	\$265,225	\$273,182	\$281,377
Insurance	\$75,000	\$77,250	\$79,568	\$81,955	\$84,413
Property Taxes	\$150,000	\$154,500	\$159,135	\$163,909	\$168,826
Other	\$725,000	\$746,750	\$769,153	\$792,227	\$815,994
Depreciation and Amortization	\$450,000	\$450,000	\$450,000	\$450,000	\$450,000
Total Expenses	\$8,500,000	\$8,833,000	\$9,181,480	\$9,546,234	\$9,928,099
Pretax Income	\$625,000	\$753,725	\$890,333	\$1,035,213	\$1,188,769

Fig. 10–6. Simple income buildup example

The main point of this section is not the mechanics of economic calculations, but the importance of the assumptions used for those calculations. Most of the pipeline planner's effort is directed toward understanding market forces and other factors. These could include competition, the regulatory and public issues, and ways to limit these factors to increase the likelihood the assumptions used in the calculations come to fruition.

Ownership Changes

Buying and selling usually has its genesis in strategies or repositioning portfolios of investments for managing risks and returns. Sellers are motivated by:

- Managing the portfolio of investments
 - Returns from upstream (exploration and production [E&P]) and downstream (refining and marketing) projects are often thought to be higher than returns from pipeline investments. Some integrated oil and gas companies sell their pipelines to raise cash for other, higher return investments.
 - Gas companies in financial difficulties may sell pipelines as a way to raise cash to reduce debt and make other investments.
- Implementing strategic changes
 - Historically, integrated oil and gas companies' ownership of pipelines was part of their strategies to ensure markets for their E&P and refining efforts, and to support marketing. As markets have matured and infrastructure has become redundant, in many cases oil and gas companies have decided that the strategic imperative to protect logistical interests no longer exists.
 - Some sales occur when privatizing pipelines formerly owned by the state. In those countries liberalizing their attitudes toward capitalism, governments are shedding assets in favor of the private sector.
- Managing risk—selling an asset with unacceptable risk
 - High potential cash costs of failure can cause a sale of a pipeline. Big companies have a reputation for deep pockets and can be the targets of expensive liability lawsuits and judgments.
 - In the United States, the passage of the Clean Water Act in 1972 established criminal penalties for water pollution (including pollution from pipeline leaks). The potential for criminal penalties has rarely been cited as a reason to sell, but “the risk associated with pipeline ownership” has been cited.

Buyers are motivated by:

- Managing the portfolio of investments
 - Investing in assets with consistent cash flow
 - Buying assets having cash generation above the cost of capital to increase distributions to owners

Master limited partnerships (MLPs), as discussed later, are champions of this approach.

- Implementing strategies
 - Owning high cash flow versus high earnings assets. Companies with growth-through-acquisition strategies need cash, not earnings (and they are different) to support their strategies.
 - Controlling one part of the value chain to complement other parts. Companies heavily involved in natural gas trading activities sometimes want pipelines to give them logistical capabilities to support buying and selling.

Both buyers and sellers are motivated by tax code and regulatory changes that may make assets more valuable to one form of entity than another. MLPs have tax treatments favorable to investors that permit them to value pipeline assets in a different fashion than corporations.

Master Limited Partnerships

An MLP is a legal entity, sold publicly as units of ownership. The MLP is a U.S. entity, but similar forms of ownership exist in other countries. A general partner (GP) owns a small part of the company and operates the assets either directly or through contracts with others. GPs are paid a fee for providing operating and management services. The GP is usually owned by another entity—often a corporation—that also owns some of the MLP units. The rest of the MLP units are publicly owned and often are traded on the major stock exchanges. Cash distributions are paid periodically to the unit owners. GPs normally seek to grow the company and may have incentive packages to induce them to do so. Consequently they are driven to acquire assets to increase earnings and distributions.

Determining the Purchase and Sales Price

There are five common valuation methods for pipelines. These are: economic value, comparable sales, highest and best use, reconstruction cost new (or depreciated reconstruction cost new), and book value.

Economic value

There are various ways of calculating economic value. Together they are the criteria most often used to establish the seller's bottom acceptable price and the purchaser's maximum purchase price.

Existing pipelines have a history of returns. Potential purchasers may base the price they are willing to pay on forecasts of volumes, rates, and expenses based on history. The forecasts are used to develop a future stream of cash flows. These are then discounted to arrive at a value, called *net present value* (NPV). The discount factors represent the time value of money. Receiving \$1 today is worth more than getting \$1 five years from now, simply because of interest rates. Discounting future streams of cash flows by a factor equivalent to interest rates allows comparison of present and future values.

The promise of \$1 in the future also has more risk than getting \$1 today. That gets reflected in the returns from various kinds of investments. A secure government bond may yield 4.0%, while a bond issued by a pipeline company might deliver 6.25%. Pipeline companies as a group have a less favorable track record than the U.S. government. A new pipeline into a new area has more risk than a line currently in operation. One has a track record and the other does not. Investors will demand a higher return from pipelines than from government bonds to reflect the higher risk, especially for new pipelines. Thus some companies will discount future cash flows with a factor that includes both interest rates and a risk factor. This is used to determine if the sum total of those discounted flows is more than their cash outlay as an investment.

Another economic valuation uses a multiple of the current cash flow. In this case, the average annual cash flow is multiplied by a factor in the range of six to nine to arrive at a value. It may seem easy, but getting agreement between buyer and seller on the six or the nine is a matter of intense negotiation. The choice implicitly includes both the rate of return each party expects plus the risk associated with future cash flows. The higher the risk (in the eye of the buyer), the lower the multiple. Just as in justifying an expansion or a new line, the assumptions, not the mechanics of the calculations, are of critical importance.

In almost all cases, the buyer and seller make different assumptions. The seller may have a strategic imperative to dispose of the asset. The buyer may dream of expansion possibilities or volumes that the seller does not.

The calculations may seem simple, but the buyer and seller both go through time-consuming processes to decide what cash flow to use, and which discount factors or multiples to apply.

Potential purchasers, particularly those operated as investment vehicles such as MLPs, also run cases with the new line consolidated into the balance of their existing portfolio. This is done to ensure ownership is accretive to earnings. Accretion is critical to increase distributions.

Comparable sales

Establishing value based on sales of similar items works well where similar assets, like houses, are sold every year, thus establishing a market value. It does not work well for pipelines. Too many adjustments are needed to arrive at an appropriate value—age, throughput, and the supply/demand outlook for the commodities being transported. Buyers and sellers may use similar sales as indicators to help them understand the range of values. However, this valuation method normally only complements the economic value method in pipeline sales.

Highest and best use

This valuation technique is not normally used for pipelines. It is based on the notion that the current use of an asset may not be the best economic use. A group of houses may be bought for more than comparable houses and demolished to make way for a shopping center. In this case, the houses were bought to secure the land. The highest and best use for an 8-in. crude oil line with declining volumes may be to replace it with a 20-in. gas line. The 8-in. line might be purchased for more than its economic value as a way to secure the ROW for the 20-in. line. Highest and best use can be used in combination with economic value for pipelines.

Reconstruction cost new

Reconstruction cost new (also called replacement cost) is the cost of rebuilding the same pipeline. It is valuable primarily as a check by purchasers to assure themselves they do not pay more than it would cost them to build

the same or a similar pipeline. Reconstruction cost new can also be used as a starting point from which to devalue an asset to account for its current condition. Depreciated reconstruction cost new can be a valuable tool during the negotiation process to help the buyer drive the price lower than economic value. If sellers expect to receive reconstruction cost new for a line, they may be disappointed if it exceeds the economic value. No savvy purchasers will pay in excess of economic value just because reconstruction cost new is higher.

Book value

Book value is used by sellers to allow them to understand if they need to record a financial gain or loss for the sale. It is not particularly useful for purchasers, since book value has little relevance to what the asset is currently worth. Sometimes it is used to reallocate ownership between joint venture partners if the venture was set up to provide for this approach.

After all the valuation work is completed, the price comes down to negotiation. Buyers always want to pay less, and sellers always want to receive more. In the seller's ideal world, if more than one buyer is interested in purchasing the pipeline, the seller can leverage them to achieve the highest potential price. The reverse is seldom true. In the unique market for pipeline assets, more than one pipeline in an area is rarely on the block simultaneously.

11

Major Components and How They Work

Is that all there is?

—Song by Jerry Lieber and Mike Stoller,
sung by Peggy Lee (1920–2002)

When most people think of pipelines, they think of pipe. But there are many other essential components needed to build and operate pipelines. These include pumps, compressors, meters, valves, fittings, prime movers, valves, meters, provers, and many other pieces of equipment, all of which are covered here. Nevertheless, the bulk of a pipeline is pipe.

Pipe

Early pipelines were made from a variety of materials, including hollowed-out logs, lead, copper, and cast iron. Today steel is the material of choice for most high-pressure pipelines. Low-pressure applications often use various types of plastics and fiberglass in addition to steel. Some subsea applications use a more flexible pipe made of polymer and steel composites. These novelties are discussed in chapter 7.

Pipe used to construct cross-country pipelines, called *line pipe*, is produced in standard sizes and strength ratings. Incongruously, the outside diameters of 4-, 6-, 8-, 10-, and 12-in. line pipe are 4.5, 6.625, 8.625, 10.750, and 12.750 in., respectively. Starting at 14-in. pipe, the outside diameters are whole numbers, 14, 16, 18, and so on, in 2-in. increments. In any event, standards agreed to by line pipe manufactures and pipeline companies list the possible diameters and corresponding wall thicknesses.

Manufacturing methods

Most line pipe is made by one of two methods: piercing or bending. In the 150-year-old piercing process invented by the Mannesmann brothers, a super-hot steel cylinder is pushed over a mandrel (a solid rod) that hollows out the cylinder, forming *seamless pipe*. The cylinder is further rolled to ensure roundness, the ends are trimmed to ensure square fit, and the insides are smoothed. Depending on the length of the cylinder, sometimes several pieces of pipe are welded together to produce the proper length.

In the other method, flat steel plate, commonly called *skelp*, is bent into a cylinder and welded to form *welded pipe*. The bend can be along the longitudinal axis, with one weld down the length. It can also be twisted in a spiral shaped like the core of a toilet paper roll (fig. 11–1).

Whether the skelp is bent into a cylinder or twisted into a spiral, the edges are welded together to produce line pipe. There is more than one welding method that can be used:

- The edges can be forced together and heated to molten temperatures with common electric resistance welding (ERW) or laser welding.
- The edges can be joined using filler material. Submerged arc welding and gas arc welding are the two common means.

In both the submerged arc and gas arc welding processes, filler material in wire form is rolled up on large spools. One end is placed above the edges of the skelp to serve as an electrode. An electrical source is connected to the filler material and the pipe. Current jumps across the gap from the filler material to the skelp, forming an arc. The arc heats the edges of the skelp and at the same time melts the filler material. The filler material slowly unwinds and melts as the skelp is pushed past the spool, resulting in a smooth and uniform weld seam.



Fig. 11-1. Spiral welded pipe. The weld seam is visible next to the girth weld. (Courtesy U.S. Pipeline, Inc.; photo by Adam Aronson)

After it is welded, the pipe is cut to specified lengths. Each manufacturing method also includes postwelding treatment to relieve stress, and to size and straighten the pipe. During the manufacturing process, the pipe undergoes numerous checks to ensure quality.

Properties of pipe

Selecting line pipe for a particular application is all about properties. The API publishes one of the oldest and most frequently used standards in the pipeline industry.¹ It specifies chemical and physical properties for the parent metal and the pipe, and the testing to verify those properties.

Chemical properties. Other than iron, carbon is one of the key components of steel pipe, affecting its strength, ductility, and other properties. Other chemicals, including manganese, phosphorus, sulfur, columbium, chromium, copper, molybdenum, vanadium, silicon, and titanium are also added as needed to achieve special properties.

Physical properties. Those who design and construct pipeline are only interested in the chemical properties of the metal, as they affect the performance of the pipe. Strength, ductility, fracture toughness, and weldability are important considerations and are tested according to industry standards.

Specified minimum yield strength (SMYS), the lowest point at which the pipe begins to yield, is the pipe property that gets the most airtime. As pressure builds in a pipeline, the pipe gets a little bigger around. This stretching results in *strain*, a measure of change in length (in this case, diameter). As a pipe stretches, an internal force, called *stress*, builds up. Pipe, just like a rubber band, is elastic within certain *stress ranges*. As long as stress remains below the SMYS, pipe, like a rubber band, returns to its original size when the pressure is relieved. But stretching it too far imparts too much stress, and the pipe permanently gets bigger around (thus the pipe wall gets thinner). That could be okay, except that at some point the pipe wall might have gotten too thin, reducing the strength of the pipe. If stretched too far, it will burst.

Pipe is produced in various levels of SMYS: X-42 has an SMYS of 42,000 psi; X-46 has an SMYS of 46,000 psi; and so forth, all the way up to X-80 or even higher. Pipeline designers use this information to ensure that a pipe's yield point is well above the line's operating pressure.

Nonferrous pipe

Other, nonferrous (not iron-based) types of pipe, such as plastic and fiberglass, have several advantages compared to steel. They do not corrode and are lighter. Sometimes they are also less expensive and easier to install. However, the strength of most plastic and fiberglass pipes limits them to applications where pressures do not exceed more than about 100 psi. (Some specialty fiberglass composite and steel-reinforced pipes can handle much higher pressures.)

Coatings

Unprotected steel rusts, and so do pipelines. Properly protected pipe can last virtually forever. Pipeline coatings protect pipelines from common rusting from exposure to air and moisture. More profoundly, they insulate the line electrically, protecting it from current flow and corrosion. Consequently, pipeline operators have regularly applied external coatings to pipelines since

the 1940s.² Early coatings were installed *over the ditch* during construction, but most pipe is now coated to within 1 ft or so of each end in distant coating plants. After the pipe is welded, a final coating is applied in the field to the area around the welds.

The most common types of pipeline coatings for corrosion control include fusion bond epoxy (FBE), coal tar, extruded plastics, and various cold wrap tapes and shrink sleeves. FBE has largely replaced the other coatings for new construction because of its superior adhesion properties (fig. 11–2). Pipelines are also sometimes concrete coated for protection from mechanical damage.



Fig. 11–2. Pipe with FBE coating welded to a pipe with coal tar enamel coating. The replacement pipe on the left is coated with FBE and welded to the older pipe on the right coated with coal tar. (Courtesy Miesner, LLC)

Fusion bond epoxy

FBE is a powder that is sprayed onto the pipe surface after it has been cleaned and heated to more than 450°F. The epoxy powder melts onto the steel surface and fuses to the pipe, creating a hard barrier. Most FBE applications take place at a coating facility, but they can also be applied at the job location to cover the ends of the pipe after welding.

Coal tar

Coal tar enamel (CTE) was one of the first coatings used on pipelines. More miles of pipeline worldwide are coated with CTE of one form or another than with any other coating. CTE is a thick residue that comes as a by-product from coal coking ovens. Inert fiber fillers are added to improve performance properties, and fiberglass mats are embedded as a wrap to give added strength and stability. As epoxy resins have become available, CTE wraps have evolved into coal tar/epoxy composites.

Plastics

Plastic coatings such as polyurethane are sometimes used to externally coat pipe. To apply it, the pipe is first cleaned to ensure a good bond. Then it is passed through a coating machine, and hot plastic is extruded around the pipe. The plastic cools, forming a tight bond to the pipe.

Tapes

Plant-applied coatings do not extend quite to the end of a piece of pipe, allowing the pipe to be welded to its neighbor. After pipes are welded together in the field, tape is commonly applied to complete the coating job. The composition of tapes varies, but they are chosen to be compatible with the coating on the rest of the pipe. The tape is supplied in rolls of varying widths, depending on the diameter of the particular piece of pipe—wider tapes for larger diameter pipes. They are spiral wrapped on the pipe, overlapping the plant-applied coating. Each subsequent wrap of the spiral overlaps the previous wrap to form a tight seal.

Tapes are also used extensively to repair damaged coating. The damaged or loose coating is removed, and the pipe is cleaned off. Tape is spiral wrapped to cover the damaged area, taking care to overlap undamaged coating to ensure a good seal (fig. 11–3).

Some tapes require a *primer*, liquid applied to the bare pipe, to improve bonding between the pipe and the wrap. Thorough cleaning and careful application is always necessary to ensure no voids or holes remain that could concentrate current flow and create corrosion hot spots.



Fig. 11-3. Applying spiral wrapping tape to a pipe (Courtesy Corrosion Control Products Company)

Shrink sleeves

Shrink sleeves, a special class of wrap, are much like tape, in that they are frequently used to cover weld areas during new construction or to replace damaged coating. However, there is one interesting difference—heat is used to apply shrink sleeves.

Shrink sleeves are polymers that come in either precut sections to fit around a particular diameter pipe or in large rolls from which pieces are custom cut to fit the pipe. The pipe is cleaned off, and the shrink sleeve is applied. Then, as it is heated, the sleeve shrinks to conform tightly to the joint profile. At the same time, molten adhesive is forced into all surface irregularities, completing the seal (fig. 11-4).



Fig. 11–4. Shrink sleeve being installed on a girth weld (Courtesy Canusa–CPS)

Concrete coating

Abrasion damage can occur when the pipe is pulled through a hole bored under a road, railroad, or river or stream crossing. This situation calls for extra protection to keep coatings from being damaged. Concrete coating can be applied to the pipe over the insulating coatings. At a concrete-coating mill, the coated pipe is pulled through, and an inch or two of protective concrete is applied. The concrete is formulated to allow some flexibility in order to avoid cracking during handling and installation. Concrete coating is applied over weld joints at the work site.

Fittings and Flanges

Pipelines constantly change direction and sometimes diameter. Because of the awkward shapes these changes involve, it is often better to weld on a factory-produced fitting or flange, and bolt on the rest of the unusual line change.

Fittings

Fittings come with a variety of names, some more descriptive than others: 90s, 45s, 180s, tees, weldolets, threadolets, reducers, caps, and return bends, to mention a few (fig. 11–5)

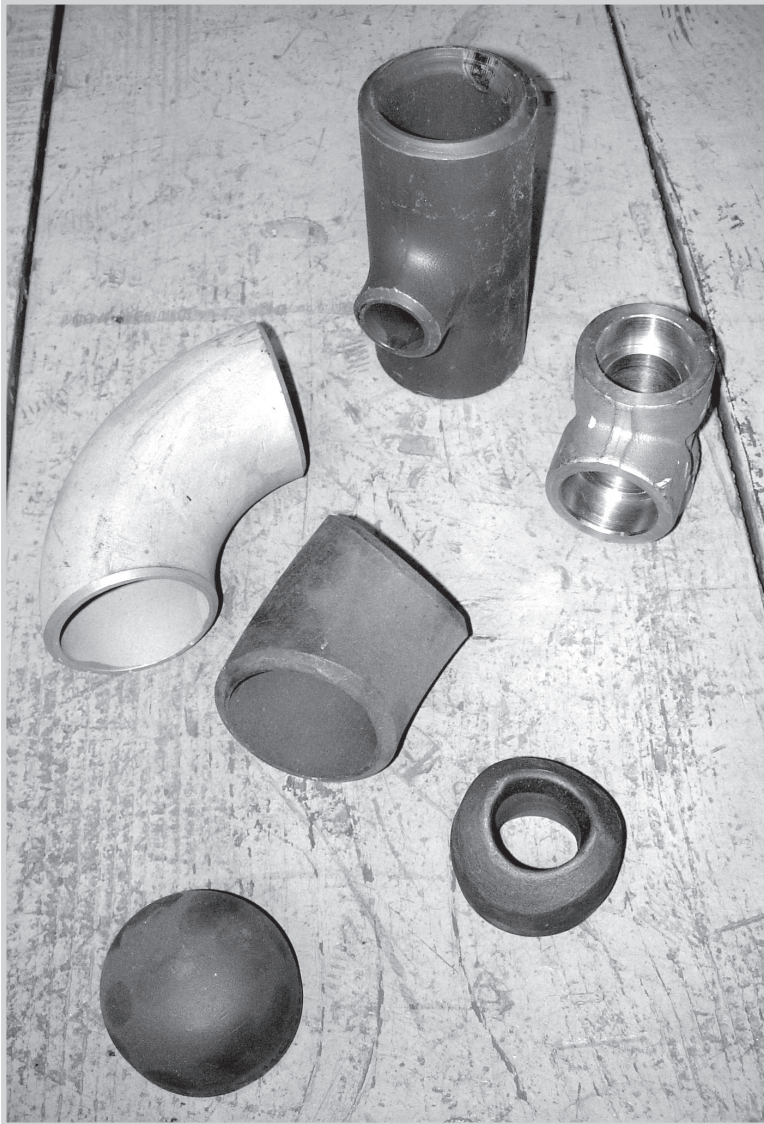


Fig. 11-5. Assortment of weld fittings (Courtesy Miesner LLC)

Their use is often intuitive. Rather than bend a pipe when it needs to turn a corner, just weld in a factory-provided 45, 90, or 180 (if it really needs to head back in the opposite direction) fitting. Tees provide a line perpendicular to the main line. For small line connections, a weldolet may be welded to the line pipe and a small line welded to that. Thredolets allow threaded connections. Sometimes fittings have more unusual uses, such as closures on the end of scraper launchers, receivers, and other pressure-containing vessels.

Flanges

Like fittings, flanges come in various configurations: weld neck, slip on, raised face, flat faced, ring joint, and blind, just to mention a few. Each has a specific application. One of the more common flanges is the raised-face weld neck (fig. 11–6).



Fig. 11–6. Flanges welded to the pipe and bolted to a valve. Not visible between the flanges is a gasket of flexible material inserted to form a tight seal. (Courtesy Miesner, LLC)

Valves

Valves perform the critical function of controlling flow. Just like the faucets in home plumbing systems, they can open, allowing flow to begin or speed up, or shut, slowing flow or stopping it all together. They come in many varieties, each with its own purpose. Sometimes valves are referred to by their type and sometimes by their function. A block valve prevents flow on the line but can be one of several different types of valves—for example, a gate valve or a ball valve.

Gate valves

The principle of a *gate valve*, which is to slide a flat piece of metal across an opening to close it, has been around a long time. The most common gate valve is the slab gate, essentially a plate of metal inserted into a frame in the pipe (fig. 11-7).

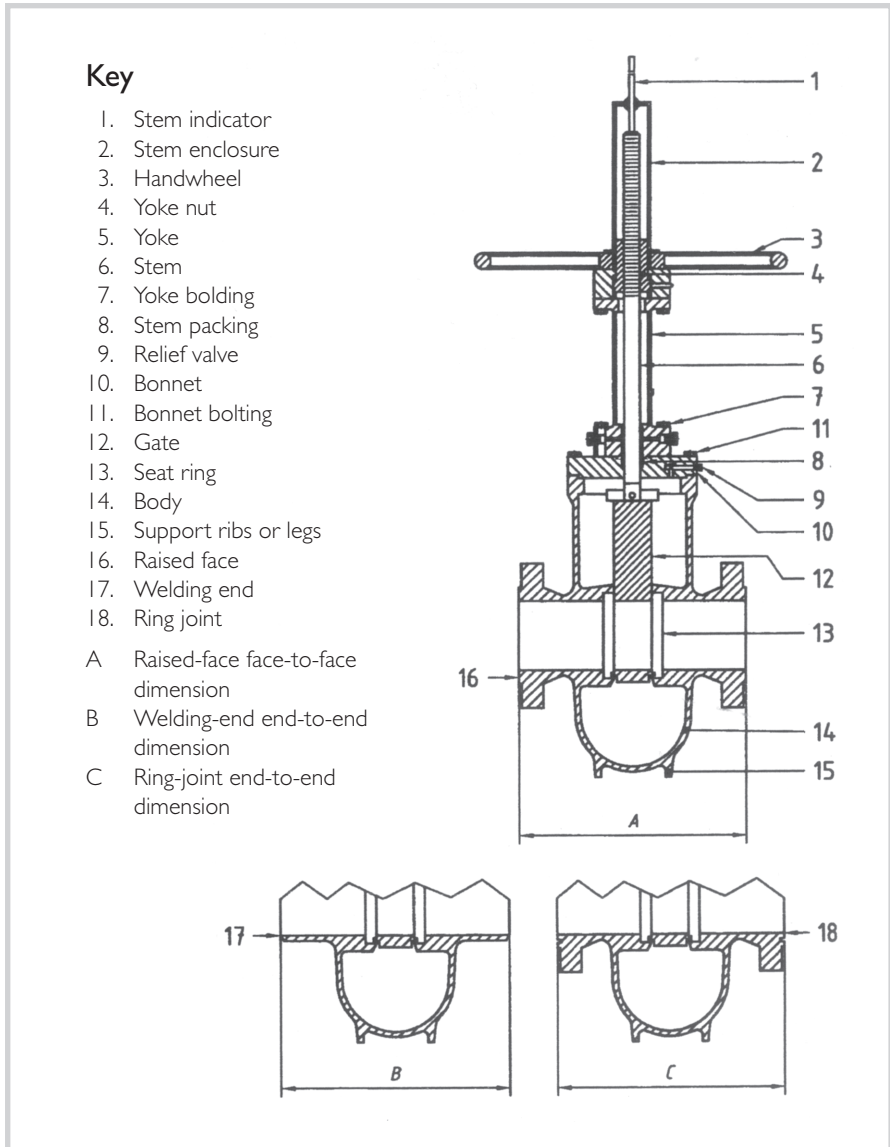


Fig. 11-7. Slab gate valve. The higher pressure side pushes the slab against the seat, forming a tight seal. (Courtesy API)

Tight seals are always an issue with valves, but high pressures are not a challenge for a slab gate valve. High differential pressure across the valve forces the slab against the *seats*, forming a tight seal. Sometimes valve seats are spring-loaded to help make a tight seal at low pressures.

The gate valve slab is fastened to a long screw, called a stem, which in turn goes through a threaded handwheel. As the handwheel turns, the screw goes up or down, opening or closing the valve. Packing is tightly applied along the stem to keep it from leaking. The main use of gate valves is to block flow completely.

Ball valves

The inside component of a *ball valve* looks, not surprisingly, like a ball with a hole pierced through the middle (fig. 11–8). Ball valves rotate to open or close. When the ball is turned so the hole through the ball points along the pipe, fluids flow. When it points perpendicular to the flow, flow stops. As with gate valves, differential pressure helps push the ball against the seats, creating a tight seal. Ball valves are used mostly to block flow, but some are also specially designed to control flow rates. One problem with ball valves is that they are often *reduced port* (the size of the opening through the valve is smaller than the diameter of the pipe). That makes passage of pigs difficult or impossible.

Plug valves

The main internal component of a *plug valve* is a tapered plug. Like a ball valve, the plug has a hole through it. Turning the plug so the hole is in line with the pipeline allows flow; turning it perpendicular to the pipeline stops flow.

Some plug valves use the tapered feature of the plug to add an additional sealing element. An actuator (handle) is designed to rotate the valve to a closed position and then push down on the plug, forcing it tightly against the seat—something like forcing a doorstop under a door. To open the valve, the plug is first raised to pull it away from the seats and then rotated 90°.

Some plug valves are designed as *double block and bleed*. Forcing the tapered plug down against the seats forms two tight seals, hence the name double block. For the bleed feature, since both sides of the plug have tight seals, the inside cavity (when the hole is perpendicular to the flow) can be drained or bled out (fig. 11–9).

Key

1. Stem
 2. Body cover
 3. Stem seal
 4. Body
 5. Seat ring
 6. Ball
 7. Closure
 8. Raised face
 9. Welding end
 10. Ring joint
- A Raised-face face-to-face dimension
B Welding-end end-to-end dimension
C Ring-joint end-to-end dimension

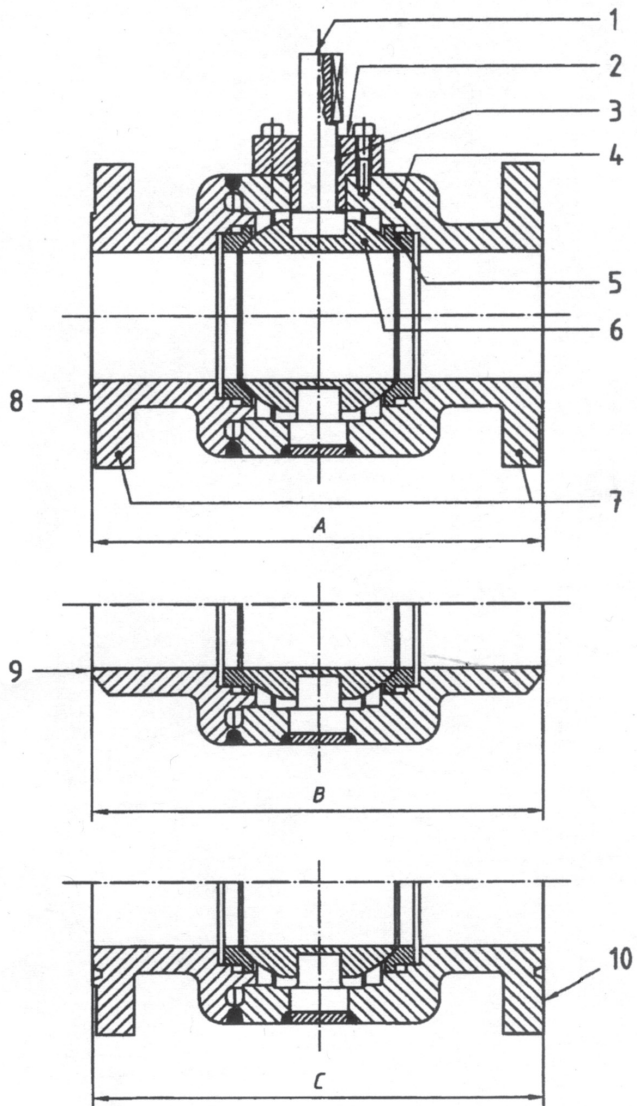


Fig. 11-8. Ball valve (Courtesy API)



Fig. 11-9. Double block and bleed plug valve (Courtesy Cooper Cameron Valve)

Why is that useful? Emptying the cavity and verifying that flow stops once the cavity is empty indicates no fluid is leaking across the valve. Double block and bleed valves are especially useful in metering applications, where tight seals are critical. They are also especially useful in multiproduct systems to segregate the different products, minimizing contamination.

Check valves

Check valves allow flow in only one direction. In shutdown lines, the weight of the *clapper disc* keeps the valve closed (fig. 11–10). When the line starts up, fluid pushes against the clapper disc, forcing it open and then holding it in that position. When flow stops or tries to reverse, the clapper disc slams shut. As long as there is equal or more pressure on the downstream side of the check valve, it remains shut.

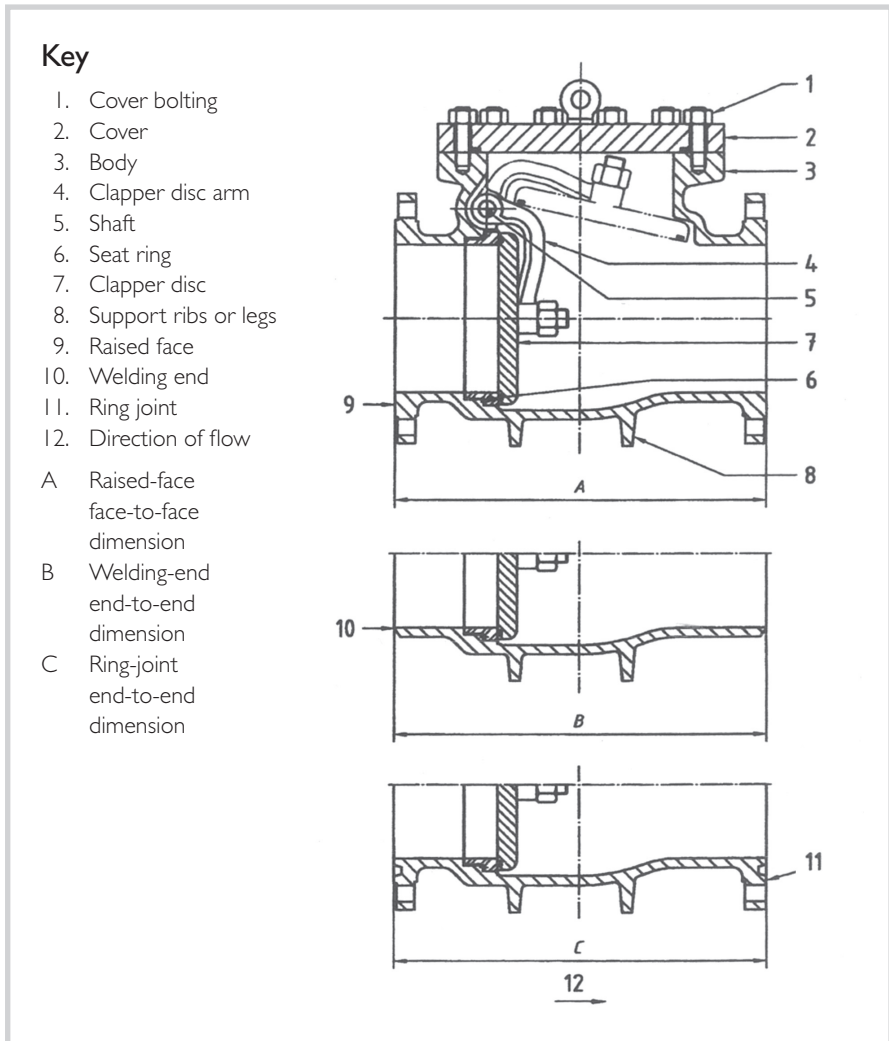


Fig. 11–10. Check valve (Courtesy API)

One important use of check valves for oil pipelines is on the downstream side of river and stream crossings. This brings up some almost self-evident facts about rivers and streams and some not-so-self-evident conclusions. Due to the force of gravity, the pressure in a pipeline at the bottom of a stream is higher than the pressure in the pipeline at the banks. Further, streams and rivers are always at the bottom of a valley or a cut, which adds to the pressure profile of a pipeline at these points. That is one reason why a seemingly disproportionate share of pipeline leaks happens around flowing water. When a leak happens in a river or stream, a properly placed check valve can reduce the release size (fig. 11–11).

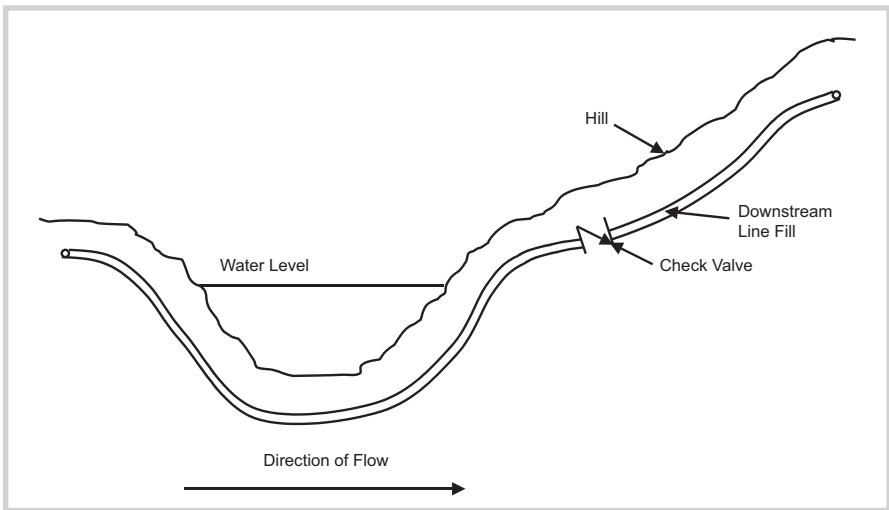


Fig. 11–11. Leak at the bottom of a river crossing. If a leak occurs in the river, the upstream line fill would flow backward, slamming the check valve closed and preventing the line fill from draining down the hill out the hole.

Globe valves

Globe valves also effect closure with a plug, but in this case, the plug is solid, and closure is accomplished by lowering the plug onto a circular horizontal seat. The end of the plug and the seat normally have matching tapers to ensure a forced fit and good seal. Globe valves are frequently installed on the outside of homes as the connection point for garden hoses. They can start and stop flow, but their design also lends itself to smooth, uniform flow control. Unfortunately, their design causes more friction loss than the other valves

already mentioned, and pigs cannot pass through them. However, globe valves in different permutations and designs are used extensively as pipeline control valves (fig. 11–12).

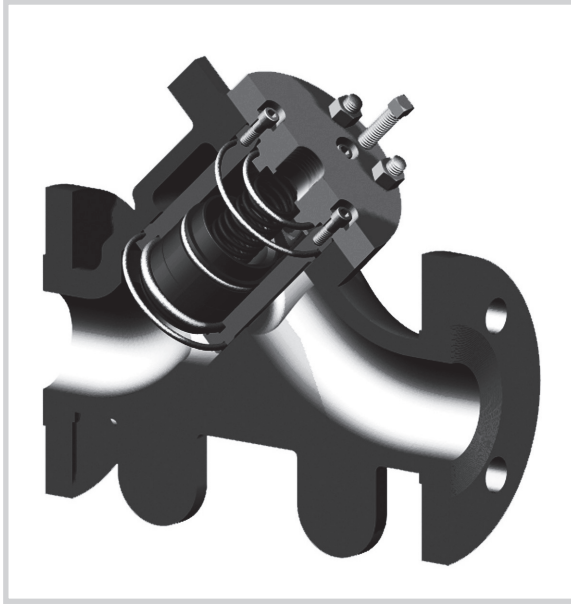


Fig. 11–12. Pipeline control valve. The majority of control valves (a function) are globe valves (a type). Flow is from left to right. An actuator bolted to the top of the control valve moves the plug up and down, creating friction loss. More loss equals lower flow. (Courtesy Emerson Process Management, Daniel Measurement and Control, Inc.)

Pressure relief valves

The several types of *pressure relief valves* all have the same purpose—to protect a pipeline or a vessel from excessive pressure. Most of the designs use the same principle. Typically, the balance between line pressure and a spring inside the valve holds the valve closed. If the pressure in the line reaches a preset limit, it overwhelms the spring and pushes the valve open. The activation range is determined by the strength of the spring, with small adjustments made by tightening or loosening a bolt or set screw. Some pressure relief valves are intended to operate on a routine basis; others are meant only to operate as a last-resort defense.

Actuators

The devices that mount on valves to open and close them are *actuators*. They are often also called operators (as if that term was not used to refer to enough different things already). Actuators can be manual, electric, pneumatic, and hydraulic. Manual operators have been around since valves were invented. They consist of levers, wheels, and gears, and are turned by an operator standing next to the valve. The other forms of actuators can be operated either locally by a person standing next to the valve pushing a button or remotely in the same manner. *Electric actuators* use electric motors; *pneumatic actuators* use cylinders driven by compressed air; and *hydraulic actuators* have cylinders driven by hydraulic oil (fig. 11–13).

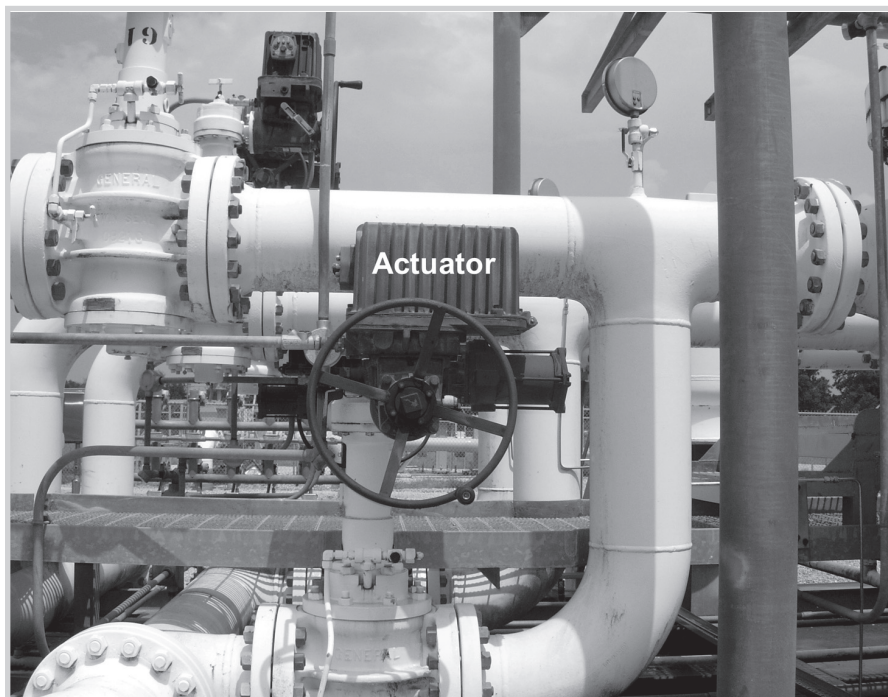


Fig. 11–13. Electrical actuator. Sometimes called a motor operator, the electrical actuator in the middle of the picture is mounted on a double block and bleed valve. The electrical motor and associated gears open and close the valve. Note the electrical conduit into the motor operator box, and the handwheel that can be used if the motor does not work. (Courtesy Miesner, LLC)

Pumps and Compressors

Pumps are used in oil service. Compressors handle natural gas. In many ways, they are quite similar, but the characteristics of natural gas and oil cause differences in design, operations, and control.

Both positive displacement (PD) and centrifugal designs are used for both natural gas and oil pipelines. PD pumps and PD compressors add pressure (potential energy) by simply forcing more fluid in the pipeline. In general, the more they force into the line over the same period, the more the pressure builds (temperature builds also).

Centrifugal pumps and centrifugal compressors are a bit more complex about how they do their job. They spin oil or natural gas molecules around, speeding them up and imparting kinetic energy, the energy of motion. Then they force the molecules into an area of the pump or compressor especially designed to slow them down, converting the kinetic energy to potential energy (pressure). The process of converting kinetic energy to potential energy also releases some thermal energy (heat), more for natural gas than for oil because of the compressibility differences.

Positive displacement pumps and compressors

PD pumps and compressors are further subdivided into *reciprocating pumps* and *rotary pumps*. Reciprocating pumps and compressors are more commonly used for oil and natural gas pipelines.

Reciprocating pumps and compressors. Reciprocating pumps and compressors have pistons, rings, valves, and cylinders. Suction valves open, allowing oil or natural gas to enter the cylinder as the piston moves back. They close, and discharge valves open as the piston moves forward, forcing the oil or natural gas out, adding pressure to the line. Sealing elements, located on the pistons, keep oil or natural gas from leaking between the piston and cylinder wall.

Single-acting reciprocating pumps and compressors have a set of valves at only one end of the cylinder, so the piston pumps out only that end. Double-acting reciprocating pumps and compressors have valves on both ends of the cylinder and pump or compress from both ends (fig. 11–14).

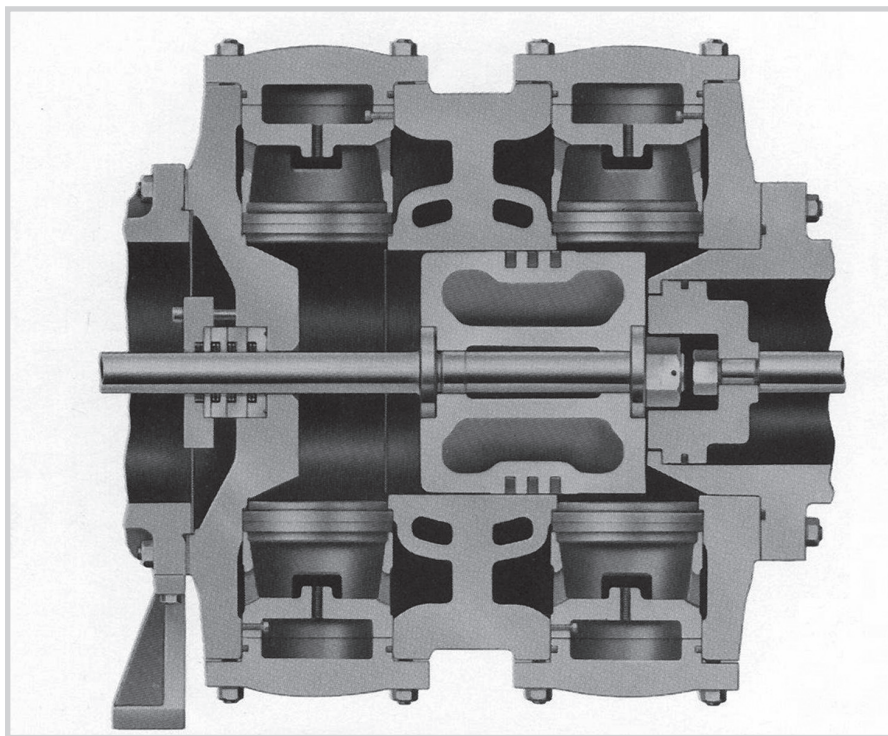


Fig. 11–14. Cross section of a reciprocating compressor cylinder. Note the valves on both ends of the cylinder. (Courtesy Cooper Compression)

Another type of reciprocating pump or compressor uses a *plunger* instead of a piston. The plunger moves back and forth inside a cylinder, just as pistons do, but it acts in only one direction. Unlike the piston compressor or pump, the sealing elements are mounted on the cylinder wall rather than on the plunger.

Since pistons and plungers force fluids into the pipeline only part of the time, they produce pressure pulses and flow pulses. Pipeline designers install multicylinder units and pulsation dampeners (shock absorbers) to dampen the pulsations and reduce the vibrations and surges they produce.

Rotary pumps and compressors. The most common types of rotary pumps and compressors used for pipeline applications are *gear* and *screw*. Screw pumps and compressors have parallel screws with a small clearance between them (fig. 11–15). As the screws turn, they force oil or gas to move along the axis of the screws.

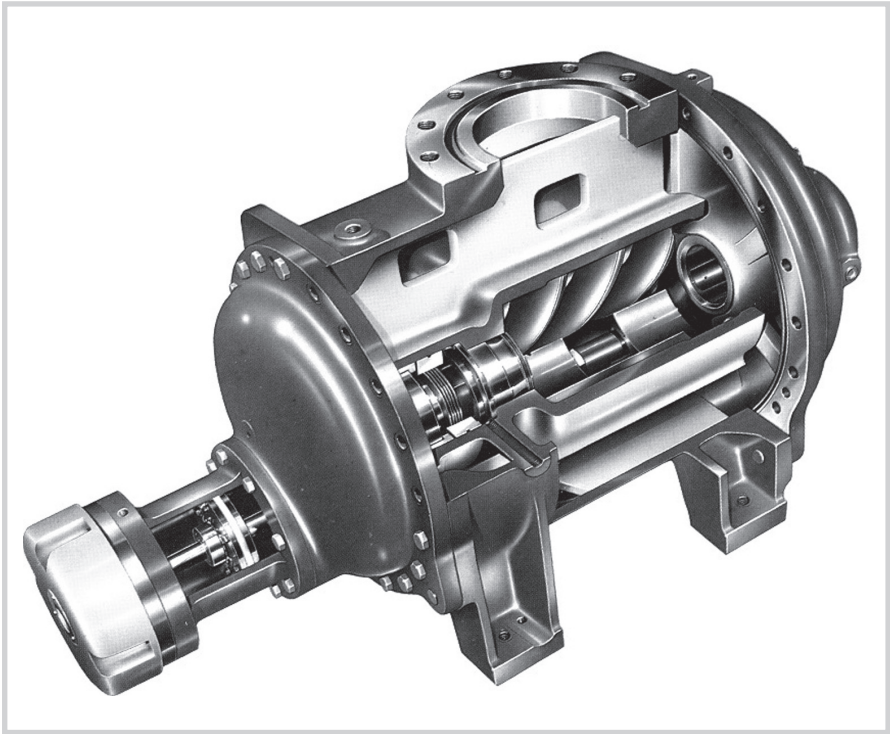


Fig. 11–15. Cutaway of a screw compressor. Interlocking screws turn in opposite directions, pushing oil or natural gas through. (Courtesy Cooper Compression)

Gear pumps and compressors work using the same principle but use interlocking gears instead of screws. Gear and screw compressors are used in high-pressure applications for both oil and natural gas. High-viscosity oil lines sometimes use screw or gear pumps because the high-viscosity oil does not flow smoothly into the cylinders of reciprocating pumps. It does not move through centrifugal pumps easily.

PD control. So far, PD pumps and PD compressors have been described together, but the pesky notion of compressibility causes some subtle differences that are vital in operations.

PD pumps are constant output machines. Each stroke or revolution of a pump pushes the same amount of oil. It forces the fluid into the line, generating as much pressure as needed to move the designated amount. When the discharge from a PD pump is blocked, the pump continues to pump for a short time, increasing pressure until something breaks or a relief device operates.

PD pumps are controlled to match pump rates and discharge pressures to those needed to achieve the operating plan and to ensure safe operations. On oil lines, PD pumps are also controlled to increase or decrease the pump's *suction pressure*, the amount of pressure available to force oil into the pump. If the suction pressure drops below the oil vapor pressure, some oil vaporizes, and bubbles of vapor enter the pump. When the pump adds pressure, these bubbles implode back into liquids. The energy release from this phenomenon, called cavitation, can damage the pump.

One of the most straightforward PD pump control methods is *speed control*, making it go back and forth (or around) faster or slower. With speed control, the pump still moves the same amount per stroke or revolution pumping less or more volume over time.

Recycle control is another common method of controlling PD pump rates. It involves adding a control valve and a recycle line to the pump discharge piping. The line runs back to the suction line. The control valve releases just the right amount of oil back to the suction line to control the discharge pressure (fig. 11-16). Recycle control actually indirectly controls flow by controlling pressure.

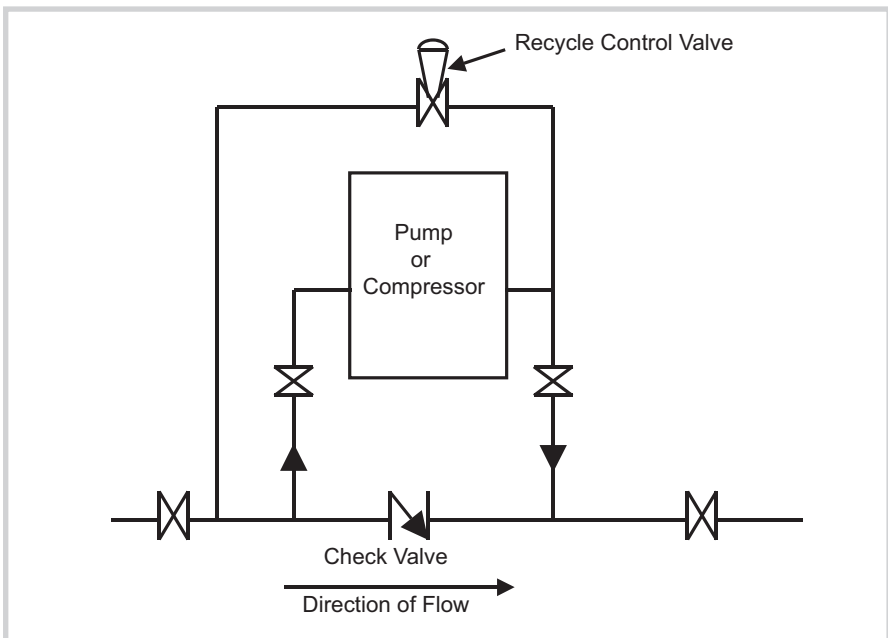


Fig. 11-16. Recycle control pipeline. The control valve pinches down on the recycle stream, creating more or less friction loss, thereby controlling the amount of oil recycled.

When it is activated, the control valve on the recycle line pinches down on the oil flowing past it, generating friction and consuming energy. Thus recycle control is a less efficient way of controlling pump rate than speed control.

Like PD pumps, PD compressors add as much pressure as needed to overcome line pressure and force fluid, in this case natural gas, into the line. Unlike PD pumps, this is not always the same quantity, since natural gas is compressible. Speed control and recycle control are used for PD compressors just as for PD pumps, but PD compressors add another clever control scheme—*pockets*. Pockets are located along the compressor cylinder and can open and close, effectively making the cylinder volume larger or smaller (fig. 11–17).

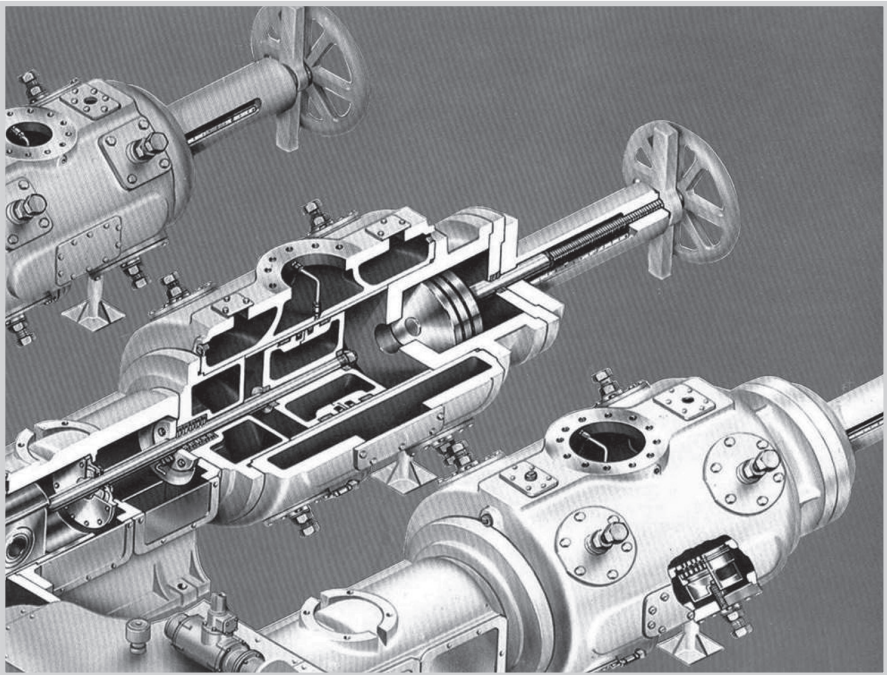


Fig. 11–17. PD compressor cylinder. Note the variable clearance pocket on the end of each cylinder. (Courtesy Cooper Compression)

How do pockets control pressure and rate? As an example, one could imagine a small balloon. If it is poked just a bit, the volume inside the balloon shrinks by a certain amount, increasing the pressure inside the balloon. Similarly, a larger balloon can be poked in the same manner, so the volume inside shrinks by the same amount (but a smaller percentage). The pressure

increases more inside the small balloon than inside the larger balloon, with the same size poke. Pockets work the same way. Compressing the amount of natural gas in the cylinder by a smaller percentage decreases pressure less than decreasing it by a larger percentage (fig. 11–18).

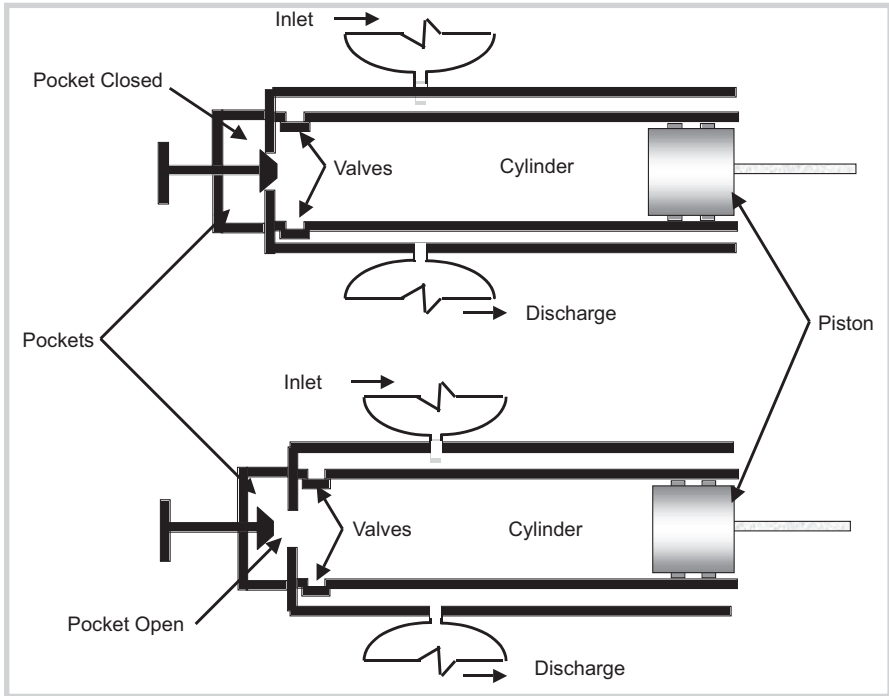


Fig. 11–18. Pocket drawing. The top cylinder has the pocket closed. The bottom has it open, effectively increasing the cylinder’s volume and decreasing the discharge pressure. (Courtesy Cooper Compression)

PD compressors, unlike PD pumps, do not present worries about cavitation. The gas never turns to liquid, so cavitation does not occur. They do, however, give concerns about liquids. Liquids in compressors can wreak havoc with the close clearances and tolerances in PD compressors. Scrubbers are included at the suctions of compressors to remove any free liquids.

Centrifugal compressors and pumps

Centrifugal pumps and compressors use the principle of centrifugal force to add pressure to oil or natural gas. *Impellers* are the crucial elements of centrifugal pumps and compressors (fig. 11–19).

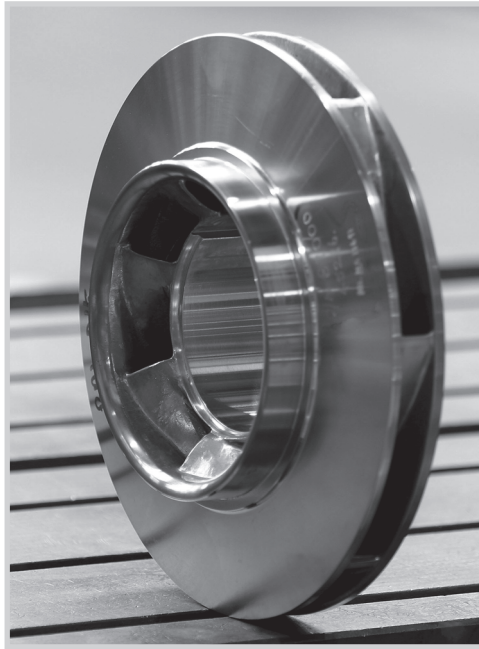


Fig. 11-19. Impeller from a centrifugal pump. Fluid flows into the eye of the impeller, located in the center, and is accelerated toward the outside as the impeller rotates. (Courtesy Sulzer Pump)

Pumps and compressors that have a single impeller are called single stage; those with two impellers are called two stage, and so on. Impellers are mounted on shafts oriented either horizontally or vertically. It should come as no surprise that those mounted horizontally are called horizontal pumps or compressors and those mounted vertically are called vertical pumps or compressors. Most large, mainline centrifugal pumps and compressors are horizontal.

Vertical pumps are normally used as booster pumps. They are used to boost the suction pressure when there is not enough to meet the suction pressure requirements of the larger mainline horizontal pumps. For multistage vertical pumps, the first stage is positioned at the bottom of the string of impellers, at an elevation lower than the first impeller of a horizontal pump. In that way, gravity has less ability to steal pressure from the system. Consequently, more pressure is available to force the oil into the pump. Sometimes specially designed vertical pumps are even buried in *cans* so gravity can provide more suction pressure. The next chapter has more discussion on suction pressures.

Rather than dealing with equations for the amount of pressure added by centrifugal pumps and compressors, one could look again at figure 11–19. The amount of pressure added depends on two main factors: the speed at which the fluid leaves the impeller and the weight of the fluid. (Engineers say it depends on one factor, the momentum, a combination of speed and mass.)

The speed at which the fluid leaves the impeller depends on the radius of the rotating element and the speed of rotation. With an impeller spinning around, the outer tip travels faster than any point closer to the center. Therefore, fluid accelerates as it moves from the center to the outside. Velocity, and therefore the increase in pressure (pressure-add), will depend partially on speed of rotation. However, since the outside tip of a larger diameter impeller travels faster than the outside tip of a smaller diameter impeller, velocity, and therefore pressure-add, also will depend on impeller diameter.

Finally, considering heavier fluids versus lighter fluids in the system, both traveling at the same velocity, heavier fluids have more momentum than lighter fluids. Because natural gas is all about the same weight, this is not particularly important for natural gas centrifugal compressors, but for oil centrifugal pumps it is. The same pump pumping a heavier product (e.g. diesel fuel) generates more pressure, or feet of head, than when pumping gasoline.

In summary, a given impeller, turning a given number of revolutions per second, “throws” each fluid out at the same velocity. Heavier fluids have more momentum (kinetic energy) when they leave the impeller, and heavier fluids demand more energy (horsepower) from the motor or engine driving the pumps or compressor.

After impellers add velocity (kinetic energy) to fluids, it must be converted to pressure (potential energy). This is where *volute*s come in. *Volute*s are specially designed forms that are built into pump or compressor cases—the housing that goes around the rotating shaft containing impellers (fig. 11–20). Their geometry slows down the fluid, converting kinetic energy to potential energy in the form of pressure, which pushes fluids through the pipeline.



Fig. 11-20. Pump case. Volutes are built into the pump case. (Courtesy Sulzer Pump)

Performance characteristics. Centrifugal compressor and pump characteristics are different from PD pumps and compressors that displace a specific volume on each stroke regardless of the pressure requirements. With centrifugal pumps and compressors, pressure and flow rate are interrelated. When less pressure is required, they move more volume, giving rise to the typical performance curve for liquids shown in figure 11–21 as a chart of feet of head versus flow rates.

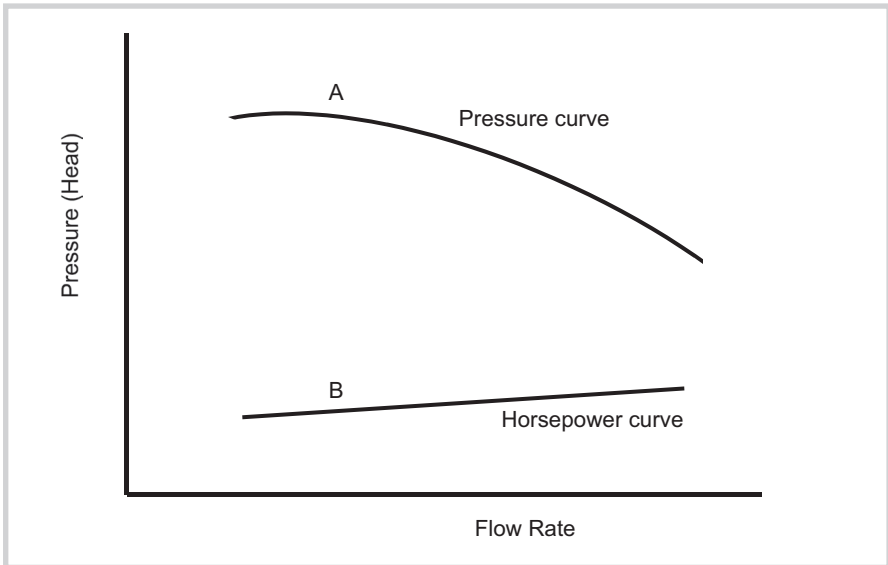


Fig. 11–21. Performance curve for centrifugal pump or compressor. Curve A is the pressure curve, expressed in feet of head. Curve B is the brake horsepower curve.

The general shape of the performance curve applies to both centrifugal compressors and centrifugal pumps, but compressibility adds an additional element to compressor performance.

For a given centrifugal pump moving oil, figure 11–21 indicates the flow rate the pump delivers at each discharge pressure, measured in feet of head. It also indicates the amount of energy (horsepower required). When gasoline, diesel fuel, and crude oil are discharged at the same feet of head, they are each discharged at different pressures. If figure 11–21 were redrawn in psi, there would be different curves for gasoline, diesel fuel, and each type of crude oil, depending on the specific gravity involved. Each type of oil would also have its own *brake horsepower curve*, the amount of horsepower required from the prime mover for the specific load. (Simplistically, load is equal to pressure times rate.)

However, unlike oil, where one barrel equals essentially any other barrel at most pipeline pressures, one cubic foot of gas at 50 psi does not equal another cubic foot of gas at 500 psi. Thus the curves are more difficult to draw and interpret. Charts and graphs could all be displayed here, but showing and interpreting them is more than this nontechnical treatment can address.

Control of centrifugals. As with PD pumps and compressors, centrifugal pumps and compressors are controlled to match operating plans and ensure safe and efficient operations. If suction pressures fall too low, cavitation causes problems for centrifugal pumps, just as for PD pumps.

Throttling and *speed control* are the two most common means of controlling centrifugal pumps and compressors. Throttling involves installing a control valve on the discharge of the pump or compressor. Unlike PD pumps and compressors, this control valve does not recycle. Instead, the valve creates additional friction loss in the system by pinching down on flow. This additional friction requires higher discharge pressures and moves the pump or compressor to the left on the curve shown in figure 11–21, reducing flow rate. More on this is given in the next chapter.

Speed control involves changing the rotational speed of the pump or compressor. There are three principles—the affinity laws—that are involved when rotation speed is changed:

- Flow rate or capacity is directly related to pump rotational speed.
- Discharge head changes as the square of the pump rotational speed.
- Brake horsepower changes as the cube of the pump rotational speed.

Increasing rotational speed by 10% increases flow by 10%, discharge head by 21%, and brake horsepower by 33%. Pump and compressor curves can be based on the affinity laws to show operating characteristics at various speeds.

There are two more permanent ways to change the performance of centrifugal pumps and compressors. These are to *trim the impellers*, which involves uniformly machining from the impeller to decrease its diameter, or to *destage* the pump or compressor by removing one or more impellers.

Prime Movers

Compressors and pumps are driven by prime movers. These are normally engines, electric motors, or turbines connected to the pump or compressor either directly or through a transmission called a *variable speed drive* (VSD).

Engines

Natural gas pipelines contain a ready source of consistent quality fuel for natural gas engines, so they are quite common on these gas pipelines. Several types of products go past refined products pump stations, making the stream an inconsistent fuel for an engine. Likewise, the wide range of hydrocarbons contained in crude oil makes it a poor fuel. Consequently, oil lines tend to use electric motors. In cases where oil lines use engines, it is normally because electricity is not easily available and the fuel, usually diesel, is hauled to the site.

The engines involved work virtually the same as car engines, with all the attendant moving parts and maintenance requirements. However, they are much larger—10,000 and even 20,000 horsepower engines are quite common driving natural gas compressors. They can be part of an integrated unit with the compressor or placed separately and connected to the compressor with a shaft (fig. 11–22). The reciprocating nature of engines makes them ideal drivers to handle reciprocating pumps and compressors.



Fig. 11–22. Natural gas engine driving a reciprocating compressor. The engine is coupled to the compressor. (Courtesy Cooper Compression)

Electric motors

Electric motors driving pipeline pumps and compressors work on the same principle as common household electric motors. They have a limited number of moving parts, operate at constant speed, are reliable, and require limited maintenance. Their relatively high constant speed rotating characteristics make them ideally suited for driving centrifugal pumps and compressors. They also operate with less noise emissions than engines and produce no (local) hydrocarbon emissions, making them logical choices for pump and compressor stations located in populated areas (fig. 11–23).



Fig. 11–23. Electric motor driving a centrifugal pump (Courtesy Miesner, LLC)

Turbines

Turbines are essentially the same as jet engines. Like engines, they run on hydrocarbon fuels; like electric motors, they rotate at high speeds; and they have fewer moving parts than engines. Because they require uniform quality hydrocarbon fuels, they have limited applications on oil lines but are growing in popularity as centrifugal compressor drivers on natural gas pipelines. Turbines can be mounted on a skid along with a centrifugal compressor and ancillary lubricating, cooling, and control equipment and can be brought to site quickly to provide short lead-time installations.

Variable Speed Devices

Speed control is one of the ways to control pumps and compressors. Increasing or decreasing the amount of fuel supplied to the engine or turbine is the most common way to control their speeds. (It also consequently controls the speed of the pumps or compressors they drive.) VSDs are the normal way to control electrical motors. They are broadly separated into mechanical and electrical VSDs.

Mechanical VSDs

The three types of mechanical VSDs differ by how they couple the input and output. *Fluid couplings* consist of two opposing impellers, one mounted on the shaft connected to the prime driver and the other mounted on the shaft connected to the pump or compressor. They are enclosed in a housing into which more or less hydraulic fluid is pumped by a small pump located on the VSD. The prime mover turns one impeller at a constant speed. To increase the speed of the pump or compressor, more fluid is added inside the enclosure. That reduces the slippage between the two impellers and drives the second impeller faster.

Eddy current couplings and *magnetic couplings* work in a similar way except they use electric eddy currents or magnetism to engage or disengage the driven side. Fluid couplings are the most common in oil and natural gas pipelines.

Electrical variable frequency drives

The most common type of electrical VSD is the *variable frequency drive* (VFD). The speed of synchronized AC motors used in pipeline service is determined by their internal configuration and the frequency of the electrical current supplied. Some parts of the world, such as North America, have electrical current at 60 hertz (Hz), or cycles per second. Europe has electrical current at 50 Hz. (The choice of 60 Hz versus 50 Hz has no technical basis. It is a holdover from competing generator manufacturers in the early to mid-20th century.) VFDs vary the frequency of the current supplied to motors, thereby controlling the motor's rotational speed. If a VFD supplies 25 Hz electricity to a motor designed to run at 3,600 rpm in Europe, it turns at 1,800 rpm. One-half the cycles equals one-half the speed.

Meters

Pipeline customers demand to know they received the same amount of oil or natural gas they put in. The public demands pipeline companies operate in a way that prevents any safety and environmental concerns. Pipeline companies meet these two demands through accurate measurement, ensuring that any oil or natural gas leaking from the pipeline is detected quickly. They also ensure that delivered volumes equal received volumes over time. Pipeline companies generally use *direct volume meters* or *inference meters*. Direct volume meters, not surprisingly, measure the volume directly by continuously separating the flow stream into discrete volumetric segments. Inference meters determine the volume by measuring various properties of the flow stream and using those properties to calculate rate.

Regardless of the type of meter, the raw measurement made by the meter must be corrected to standard pressure and temperature conditions. This correction can be accomplished manually, automatically by devices located on the meter, or electronically by computers. Meters also normally have an individual *meter factor*, a number peculiar to that specific meter. It is used to correct for differences between what the meter says has gone through it and how much actually has gone through. Meter factors are important and are established with provers. They vary with time as meters wear.

Positive displacement meters

PD meters are direct measurement meters. They work much like a revolving door or a turnstile. The flow is separated into discrete segments, and the segments or chambers are counted as they go by (fig. 11–24). Adding the segments together determines total volume. (Actually, PD meters and turnstiles work better than revolving doors. Sometimes the chambers in the latter go by empty or have two people in them, but not so for PD meters and turnstiles.)

PD meters handle oil well, but do not work well with natural gas (or any other kind of gas). Gases tend to decompress as they go through PD meters, causing the meter to spin excessively. PD meters on oil lines require enough pressure to keep the oil above its vapor pressure as it passes through the meter. Otherwise, the revolving door syndrome applies, spinning the meter like an empty door. Sometimes the friction loss or elevation past the meter is sufficient to maintain this pressure. Sometimes a back-pressure valve is added to ensure the oil does not vaporize. PD meters have been the standard for oil pipeline custody transfer for many years and are still used extensively.

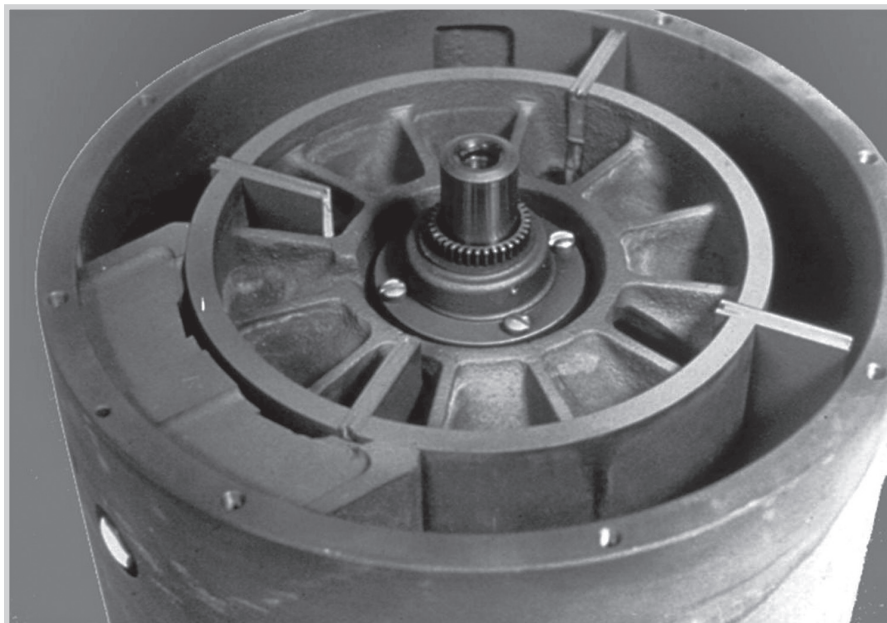


Fig. 11–24. Rotating vane PD meter. Each of the four vanes slides in and out, exactly capturing a known volume. (Courtesy FMC Technologies)

Turbine meters

Turbine meters are inference meters that began to receive recognition in the 1960s and have become well accepted as their technology has developed. They determine flow rate by measuring the speed of a bladed rotor suspended in the flow stream (fig. 11–25).

The rotational speed of the rotor is proportional to the flow rate. For oil, the volume flow rate is equal to the cross-sectional area times the rotor's velocity, adjusted by the meter factor and corrected for temperature and pressure. The natural gas calculation is the same except that compressibility is also taken into account.

Turbine meters do best when the flow rate is smooth and the properties of the fluid are consistent, that is, when density and viscosity do not vary. Turbine meters also like smooth, straight flow. That calls for a certain length of straight pipe before the oil or natural gas enters the meter and after it leaves. Straightening vanes, essentially small pipes inside the larger diameter pipeline, can be installed if there is not enough room to install the straight pipe runs.

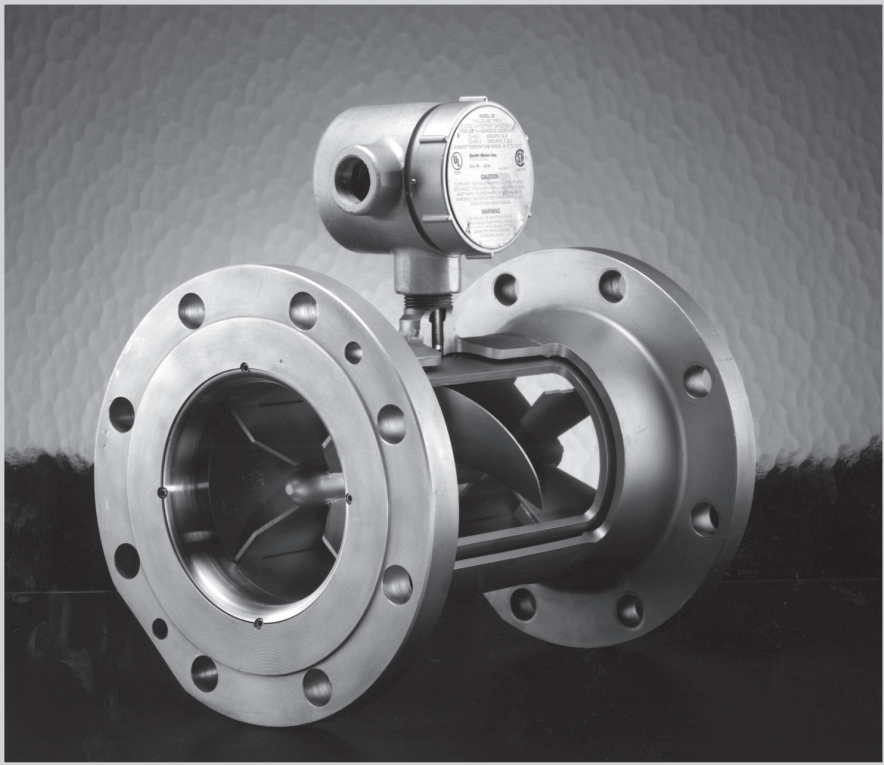


Fig. 11–25. Turbine meter. The turbine looks something like a propeller. It is driven by the flowing stream, and its speed is proportional to the flow rate. (Courtesy FMC Technologies)

Orifice meters

Orifice meters are used to measure gas flow. Their design is based on Bernoulli's Principle (chapter 3) concerning mass flow, velocity, and pressure. The meter has an orifice plate of known size and configuration. It also contains sensors to measure line temperature, line pressure, and differential pressure from the front of the orifice plate to the back (fig. 11–26).

The hole in the orifice plate is smaller than the inside diameter of the line, so the gas velocity increases as it passes through the orifice plate. Since the gas is going faster, the pressure has to decrease. Gas quantities can be calculated using differential pressure across the orifice plate, line pressure, temperature, pipe diameter, and orifice plate configuration.

The large pressure drop associated with the relatively higher viscosity of oil makes orifice meters impractical for oil service.



Fig. 11–26. Orifice plate holders. The orifice plate carrier in the middle allows the orifice plates to be changed without shutting down the line. The crank lifts the plate carrier above a shut-off valve. The valve is shut, and the orifice plate is changed. Then the valve is opened, and the orifice plate is reinserted. The other two holders require shutting down the line to change the orifice plate. (Courtesy FMC Technologies)

Ultrasonic meters

Ultrasonic meters calculate flow rate from stream velocity, the cross-sectional area of the meter, and fluid density. They work by sending high-frequency sound pulses or waves from a transmitter on one side of the pipe to a receiver on the other side. The velocity of the flowing stream affects how long it takes for the pulse to travel across the pipe. Ultrasonic meters have several transmitters and receivers located around the meter. Each transmitter sends pulses frequently, and computers average the results to get accurate results.

Ultrasonic meters have several advantages over other meters. They are nonintrusive, meaning there are no obstructions to flow. They have no moving parts and cause no additional pressure loss. The precise timing of pulse measurements required to get an accurate reading is a challenge. The inability to measure fluids with varying properties such as density is also a disadvantage.

Coriolis meters

Gaspard-Gustave de Coriolis (1792–1843) discovered the Coriolis force, the principle on which these meters operate. This same force influences weather patterns, sea currents, and the direction the water turns as it flows down the drain. The force has to do with angular momentum, making it a bit difficult to explain. For this text, it will suffice to say the mass, not the flow rate or velocity, of the fluid moving through Coriolis meters acts on a vibrating tube, deflecting the tube. The amount of deflection is proportional to the amount of mass acting on the tube. Coriolis meters work for both gas and liquids. In pipeline applications where flow rate, rather than mass, is needed, a densitometer is used to convert to volume. However, that undoes the advantage of a Coriolis meter. Consequently, these meters are used mostly for fluids having uniform density.

Provers

Meters are not 100% accurate when they arrive from the factory. Nor are they ever, by themselves, 100% accurate. But a good meter is wrong in a consistent fashion that can be adjusted. *Provers* are the devices used to establish the factors needed to correct for meter inaccuracies.

The concept of provers is simple: construct a device of known volume, put a fluid through a meter into the known volume, and compare the meter reading to the known volume. As an example, if gasoline were pumped into a 1,000-gal prover, and the meter said it pumped in 1,001 gal, the meter factor is $1,000/1,001 = 0.9990$. There are two popular types of provers: *pipe provers* and *master meters*.

Pipe provers

Pipe provers, also called mechanical displacement provers, are used to prove PD, turbine, and Coriolis meters in oil service. They are not used to prove natural gas meters (fig. 11–27).

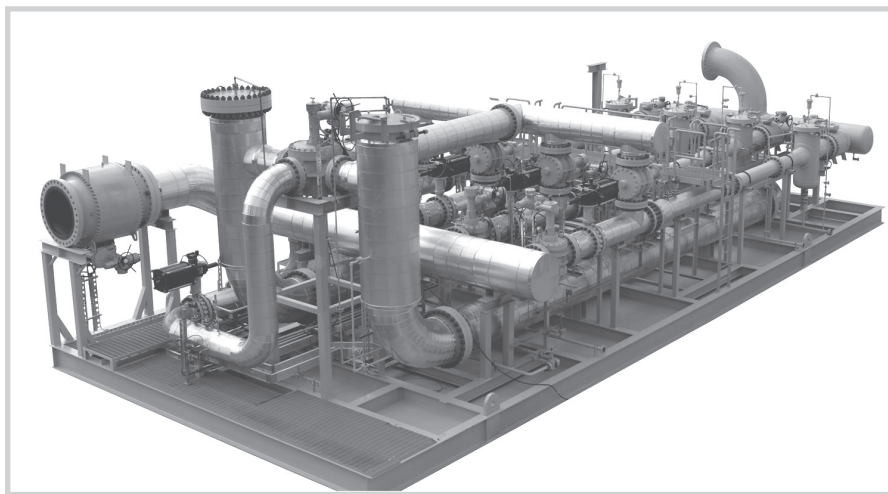


Fig. 11–27. Pipe prover (Courtesy Emerson Process Management, Daniel Measurement and Control, Inc.)

Pipe provers consist of a sphere or piston that travels inside a pipe. To prove a meter, flow is diverted through a pipeline meter, to the prover, and then back into the pipeline. This flow pushes the sphere or piston in front of it, activating a switch. When the sphere or piston reaches the other end of its travel, it activates another switch. The distance between the two switches has already been exactly calibrated. The volume measured by the meter during the sphere's or piston's travel time between the switches is compared to the known volume between the switches. This is used to establish a meter factor. Of course, everything must be corrected for the impact of pressure and temperature, and multiple runs are performed and averaged to establish accuracy.

Master meters

Master meters are meters excruciatingly calibrated against standards under controlled settings to ensure accuracy. They are used to prove PD, turbine, and Coriolis meters and can also be used to prove the provers and other master meters, called *transfer proving*. Proving using master meters involves diverting flow from the pipeline meter through the master meter and back into the pipeline for a specified period. The amount measured by the master meter during this time is compared to the amount measured by the meter being proved, establishing the factors. As with provers, corrections and repeated runs are done to ensure accuracy.

Other Components

So far this discussion has addressed pipe, coating, fittings and flanges, valves, actuators, pumps and compressors, engines and motors, and meters and provers. These are the main, or what could be called the “mission critical,” elements of a pipeline system. But by no means are they the only components. There are also hundreds of instruments, sensors, transmitters, flow computers, strainers, scrubbers, knockouts, and other assorted components. Although not discussed in detail here, these components enhance the efficiency, integrity, and safety of pipeline operations.

References

1. API. *Specification for Pipeline*. API 5L, 43rd ed. Washington, DC: API Publishing Services, March 2004.
2. Kiefner, J. F., and C. J. Trench. *Oil Pipeline Characteristics and Risk Factors: Illustrations from the Decade of Construction*. Report prepared for the American Petroleum Institute, December 2001, p. 19.

12

Engineering and Design

*If a man takes no thought about what is distant,
he will find sorrow at hand.*

—Confucius (551–479 B.C.)

The pipeline planners have developed a plan with preliminary routes and volumes. After uncountable iterations, they have received approval from executive management. The new pipeline project has been announced with great fanfare, and the preliminary design document is handed off to the design group for detailed engineering. Probably the design group was involved in preliminary design and is not totally shocked by what they read.

The preliminary design document includes the line's intended use (natural gas, crude oil, refined products, or chemicals), its approximate route, and its intended volumes. It has the primary receipt and delivery points, and probably has suggested operating pressures, line diameters, and wall thicknesses. Pumping or compression needs, and ideas about booster station spacing, storage needs, metering, instrumentation, and control may also be included. Every company, and sometimes every project, varies, with larger projects usually more fully developed than smaller ones. Now the design engineers have to turn the preliminary plan into a practical pipeline scheme, with all the information the constructors will need to build it.

Safety Considerations

Any chapter on pipeline design has to start by discussing safety—the overriding design theme. Beginning with the early Pennsylvania and Baku pipeline booms and extending right up to the present, pipeline companies have always been concerned with safety. When they learned how to design safer pipelines, they shared this knowledge with others, largely through industry associations. Numerous standards and best practices resulted. Pipeline designers depend on these codes and standards, as well as the education and practical knowledge of other pipeline companies. This knowledge helps them minimize the chance of failures once the pipeline is built. In addition to the standards, each country and sometimes local governments have pipeline safety regulations to insure safe pipeline design, construction, and operation. Safety considerations are woven throughout this chapter and throughout most of the book.

Route Selection

If there were only one origin and one destination, with nothing in between, and cooperative landowners, route selection would be easy. One could draw a straight line between the two points and be done. In reality, pipeline designers normally work with multiple receipt and delivery points, all located along something that hardly looks like a straight line. Sometimes it makes sense to divert the line through a major consumption center. At other times *spur lines*, smaller diameter lines extending to a location remote from the main line, make sense.

Pipeline designers balance many factors as they search for the safest, economic, and environmentally and politically friendly route that can be permitted and constructed. Many of the items are external to the engineering aspects of the new line:

- Existing utility corridors
- Population centers and populated areas
- Future development plans and land use planning
- Major crossings
 - Road
 - Railroad
 - River
 - Stream

- Environmentally sensitive areas (wetlands, threatened and endangered species, environmental cleanup areas)
- Sensitive areas (archeological, paleontological, and cultural)
- Abrupt elevation changes or steep slopes
- Earthquake and fault zones (landslide- or flood-prone areas)
- Government lands
- Politically sensitive areas

Taking into account all these factors, pipeline designers choose several potential routes for development and then send people to the field to research possibilities. Inevitably, final route selection requires time-consuming iterations. Changes are made to the route to accommodate discoveries made, even as construction progresses.

Line Size, Wall Thickness, and Looping

Line size, wall thickness, and looping are all about meeting market needs at the lowest cost. These items are so interrelated that they take a good share of the iterative process.

Engineering aspects of friction loss

Pushing fluids through a pipe requires pressure to get the molecules moving and pressures to overcome the friction between the fluid and the pipe walls. This subject has fascinated a cadre of engineers and physicists for a long time. Formulas have been developed to describe how fluids behave and what the pressure requirements are.

Friction loss equations. Frenchmen Gaspard de Prony and Henry Darcy, and the German Julius Weisbach, studied this subject in the late 18th and early 19th centuries. They are generally credited with developing the equations on which modern pipeline designers base their pressure loss equations. Prony developed (and Darcy and Weisbach refined) the equations that finally became:

$$h = f \times \frac{L}{D} \times \frac{V^2}{g}$$

where

h is pressure loss due to friction,
f is a friction factor,
L is pipe length,
D is pipe internal diameter, and
g is acceleration due to gravity.

In the previous equation, f is a dimensionless number, but all the others in the equation have dimensions—feet, inches, feet per second, and so on. However, when everything on the right side is laid out, canceled, and consolidated, the result is feet. This means that the pressure loss due to friction (h) is measured in feet of head.

The previous equation, called the *Darcy-Weisbach* equation, forms the basis for numerous other equations developed by engineers to determine pressure loss in specific applications. They all have the same underlying factors but use different dimensions and unique friction factors for their particular application.

In this equation, viscosity, density, and internal pipe roughness do not appear. However, friction loss depends on these factors. One might wonder how the equation accounts for all three. The answer is that f , the friction factor, takes care of it all. (Engineers, and even professors, just as easily refer to f as the *fudge factor*, since the calculation of friction includes so many parameters.)

Friction factor. Early pressure loss experiments used water at room temperature. The density and viscosity did not vary much, so the change in f was mainly a function of pipeline roughness. Prony, Darcy, and Weisbach each conducted experiments in which they knew, or could measure, all the other factors in the equation, including pressure loss. They conducted repeated experiments at different flow rates, pipe diameters, and lengths, then calculated f and plotted the results. Equations like the previous one, which are based on experiments, are called *empirical equations*, and pipeline designers use many of them that have endured over time.

Reynolds number. In 1883, Osborn Reynolds proposed a number he self-promotingly called the *Reynolds number*. It characterized whether a fluid was in laminar, fully turbulent, or transitional flow, based on density, viscosity, and velocity. The Reynolds number can be calculated several ways, but one popular version is:

$$\text{Re} = \frac{v_s \times L}{\nu}$$

where

Re is the Reynolds number,
 L is length,
 v_s is fluid velocity, and
 ν is kinematic fluid viscosity.

At first, it may appear that this equation for the Reynolds number does not consider density, but kinematic fluid viscosity is equal to dynamic fluid viscosity divided by density.

From empirical observation, Reynolds numbers below 2,000 indicate laminar pipeline flow. Internal roughness is mild, and the molecules move down the pipe in an orderly fashion, hardly bouncing off the walls. The friction factor, f , is calculated as:

$$f = \frac{K}{Re}$$

where

f is the friction factor,
 K is a conversion factor, depending on the dimensions, and
 Re is the Reynolds number.

Reynolds numbers higher than 4,000 indicate that the flow is turbulent, so between 2,000 and 4,000 the flow is transitional—partly laminar and partly turbulent. This makes the friction loss between these two numbers hard to calculate. To compensate, designers calculate friction loss assuming both laminar and turbulent flow and take a number somewhere in between.

Moody diagram. Pipeline construction experienced a boom in the early to middle part of the 20th century, and so did research into fluid mechanics. Inevitably, the relationship between f and the Reynolds number was reduced to a chart. Professor Lewis F. Moody at Princeton developed it as the Moody diagram around 1944 (fig. 12–1). His work was based, again, on water and showed f for pipes of varying internal roughness.

By the time Moody developed his diagram, almost all oil and natural gas main lines had been constructed of steel of fairly uniform properties, including internal roughness. Pipeline engineers proceeded to construct diagrams, based on Moody's, where they related the Reynolds number to the friction factor for their own fluids and pipelines.

Nowadays, with the widespread use of computers, and well-developed programs, engineers seldom perform loss calculations manually. They input the required variables and let the computers calculate pressure losses.

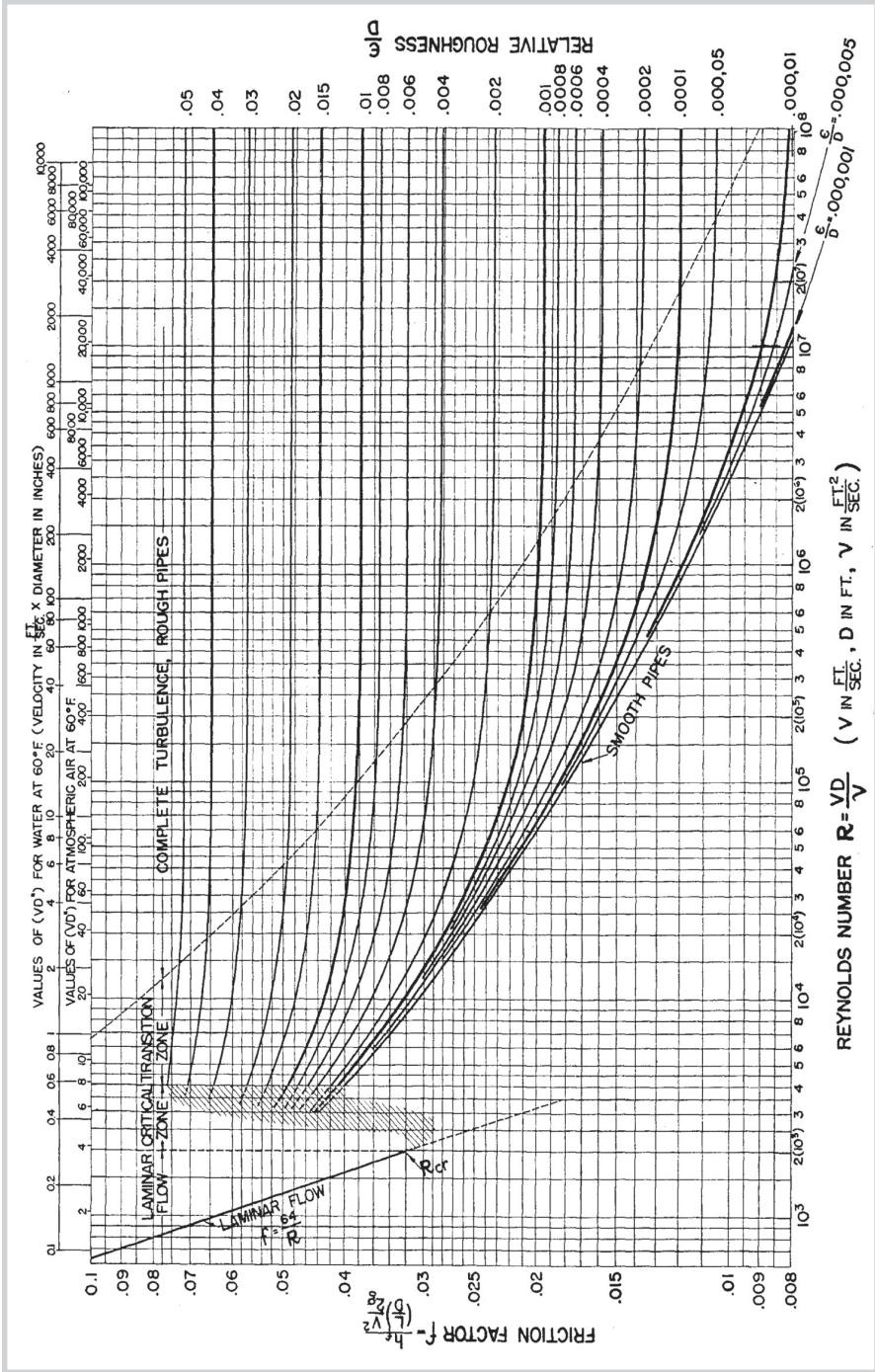


Fig. 12-1. Moody diagram (Courtesy ASME)

Systems Curves

Pipeline engineers use pressure loss, combined with elevation changes, to produce *systems curves*, graphical representations of pressure required at various flow rates for a given pipeline (fig. 12–2). To use a systems curve, one starts with a flow rate on the horizontal axis and draws a vertical line. When the vertical line intersects the systems curve, one draws a horizontal line to the left until it intersects the vertical axis. This is the pressure required to achieve the desired flow rate over the entire length of the pipeline. Systems curves are valuable tools when selecting pumps or compressors (as shown later in this chapter).

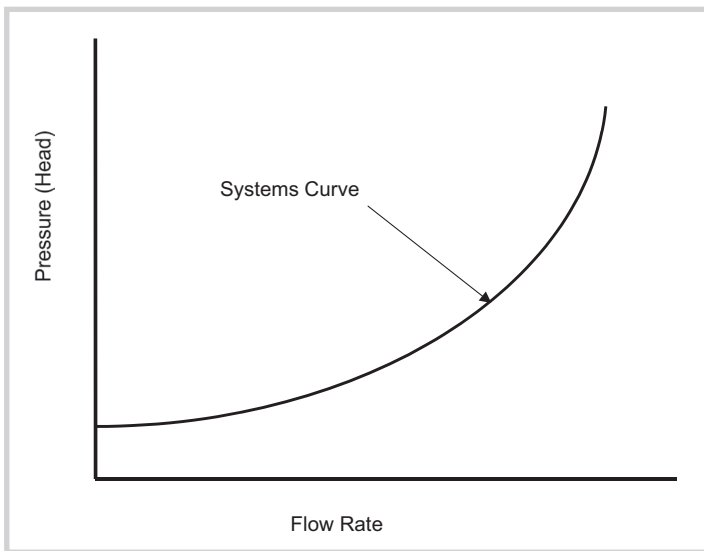


Fig. 12–2. Systems curve

In some ways, total pressure loss calculations are more difficult for natural gas than for oil. For a given fluid, velocity and density are the same along the length of a given oil pipeline. Oil pipeline designers determine friction loss per mile, multiply it by total miles, and get total friction loss. However, in natural gas pipelines, velocity and density vary. Velocity increases and density decreases as natural gas travels along, losing pressure to friction and expanding. Natural gas pipeline designers used to calculate the pressure loss in the first mile and in the last mile and average them, and then multiply by the total miles to get the total pressure loss. Now they use computer models.

In other ways, oil pipeline systems curves are more difficult. The diesel systems curve differs from the gasoline systems curve. Diesel and gasoline have different densities and viscosities, so they have different pressure losses per mile. Oil pipeline designers used to deal with this by assuming a weighted average of the product or crude oil batches in the line, producing composite systems curves.

Now systems curves are done on computers, and the primary value of the graphical curves is as an illustrative tool. Both oil and natural gas pipeline designers calculate pressure required for various different diameters, balancing cost and performance as they determine optimum diameter and wall thickness of the line.

Fittings, Flanges, and Valves

Systems curves are fine for straight pipe, but what about fittings, flanges, and valves? The manufacturers of these items typically provide *equivalent lengths* or K factors for the various types and sizes. When pipeline designers use equivalent lengths to determine pressure loss through valves and fittings, they add together all the equivalent lengths for each and multiply by the pressure loss per mile. K factors are individual pressure losses across a fitting or valve. To use them, a designer adds together these pressure losses and the pressure loss of the straight pipe. In some cases, both factors have to be added separately.

Wall Thickness and Grade of Pipe

With total pressure required in order to move various amounts of oil or natural gas in hand, pipeline designers have to determine the optimum pipe size and grade. They calculate the *hoop stress*, the force produced in the pipe wall by the fluid pressure inside the pipe pushing against the pipe wall. To do so, they use *Barlow's formula*:

$$S = \frac{2t}{D} \times P$$

where

- S is hoop stress,
- t is wall thickness,
- D is pipe outside diameter, and
- P is internal pressure.

Barlow's formula figures in an important computational, albeit convoluted, procedure. Pressure inside the pipe pushes perpendicularly against the wall all around its circumference, trying to push it apart. Steel molecules making up the pipe desperately cling to each other circumferentially, trying to hold it together. Figure 12–3 shows one slice of that pipe.

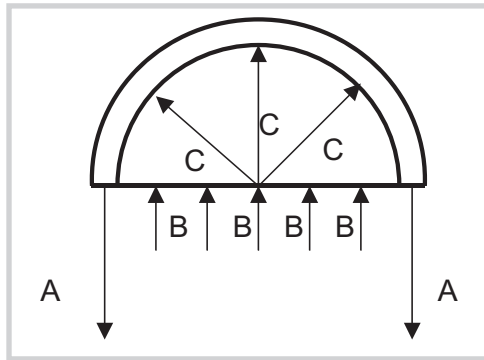


Fig. 12–3. Free-body diagram of pipe under pressure. A represents the counterforce to B, holding the pipe together. B represents the component of C trying to push the wall apart. C represents the force on the pipe wall.

The arrows labeled C represent the forces pushing out uniformly on the pipe. At a given pressure inside the pipe, each molecule of oil or natural gas pushes against every other molecule and against the pipe wall, all around the pipe. The bigger the diameter of the pipe, the more area over which the pressure is applied, and the bigger the force on the pipe. The offsetting force holding the pipe together is a function of the strength of the steel and the thickness of the pipe.

Pipeline designers choose pipe diameter, wall thickness, and steel to safely contain the expected pressures on the line. The MAOP of the pipe is calculated with a rearrangement of Barlow's formula:

$$\text{MAOP} = \frac{2t}{D} \times \text{SMYS} \times \text{SF}$$

where

MAOP is maximum hoop stress,

t is wall thickness,

D is pipe outside diameter,

SMYS is specified minimum yield of the steel, and

SF is a safety factor as established by standards or regulations.

As an example, the MAOP of a 30-inch piece of X-52 pipe, 0.25 in. thick, assuming a safety factor of 0.72, is:

$$(2 \times 0.25 \text{ in.}/30 \text{ in.}) \times 52,000 \text{ psi} \times 0.72 = 624 \text{ psi}$$

If the wall thickness is increased to 0.375 in., the MAOP goes up to 936 psi. If the diameter is decreased to 28 in., the MAOP increases further to 1,002 psi. Of course, the maximum amount flowing through the 28-in. line at its MAOP is less than the amount flowing through a 30-in. line at its MAOP. Engineers work iteratively to get the wall thickness, diameter, and grade of steel that gives the best (least costly) combination to handle the planned volumes.

Looping

Constructing two parallel lines, known as *looping*, is sometimes done during original construction to accommodate higher flow rates. More often lines are looped following original construction to increase capacity (fig. 12–4).

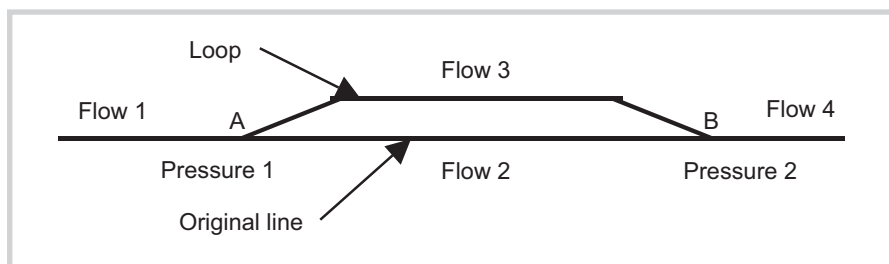


Fig. 12–4. Looping diagram

Figure 12–4 demonstrates why loops work well for natural gas pipelines but are not often used for oil pipelines. In this case, the loop starts at point A. The pressures at point A are equal in both the original line and the loop, and where the loop and original line come back together at point B. Since the loop is slightly longer than the original line, it has slightly more friction loss and consequently slightly less flow. The molecules entering the loop at point A do not exactly catch up with those traveling the original line when they come back together at point B. In a natural gas line, that is no concern. One molecule is the same as the next, more or less. However, in an oil pipeline, if the interface in the loop does not match at point B, contamination occurs. That may not be critically bad in a crude oil line, since the crude oil is processed before it goes to the ultimate customer. But contaminating a batch of refined products lines can be expensive if it requires reprocessing.

Pressure and flow calculations for loops work just like those for other lines. The pressure and flow rates are calculated separately in each of the lines, with the pressure in each line starting out the same at point A. They have to also be the same in both lines at point B.

Pump, Compressor, and Prime Mover Selection

On natural gas pipelines, PD compressors are more prevalent than centrifugal compressors. The reverse is true for oil lines. Centrifugal compressors, by their nature, offer increased reliability and take up less space than PD compressors, and are gradually taking over the natural gas compressor market. Still, many reciprocating compressors remain faithfully operating, as they have for years.

Pump selection

PD pumps push the same amount of oil regardless of pressure requirements. Centrifugal pumps move varying amounts, depending on the pressures. Superimposing a pump curve on a systems curve establishes an *operating point*, the pressure and flow rate at which a system runs (fig. 12-5).

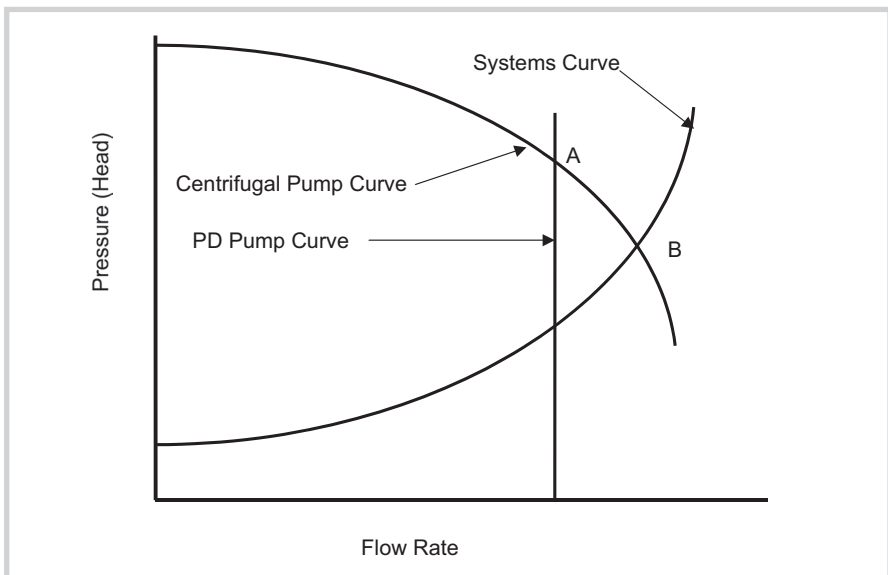


Fig. 12-5. Pump curve drawn on the systems curve. The operating point for the PD pump is A, and for the centrifugal pump, B.

Why does the pipeline operate at the operating point? It is because it is the point at which the force exerted by the pumps or compressors, the pressure added or subtracted by elevation changes, and the total friction loss are all equal and offsetting. In other words, it is the point of system dynamic equilibrium.

Until recently pipeline engineers laboriously placed pump curves over systems curves to select the best match. Today, the tedious parts of this set of calculations are done by hydraulic simulation computer programs. Still, the curves help visualize how pumps and systems interact.

Most pump stations are outfitted with two or three pumps, giving operators flexibility to vary pressures and rates. Centrifugal pumps are usually installed in series. The discharge of one feeds the suction of the next (fig. 12–6). Both pumps discharge at the same flow rate. The first pump receives the oil and raises the pressure before handing off the oil to the second one to add more pressure. The flow rates are the same, but the pressure increases are additive. Just like pumps, pump stations have representative curves. They are developed from adding together the individual pump curves (fig. 12–7).

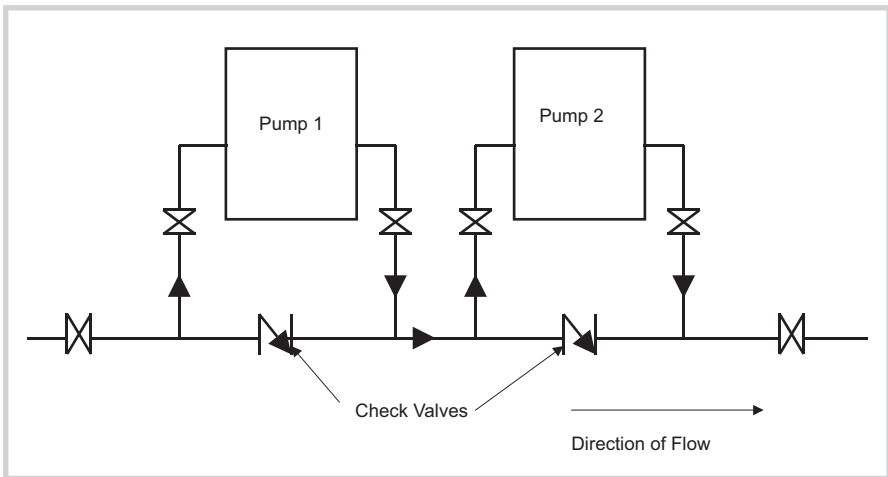


Fig. 12–6. Two centrifugal pumps installed in series. The check valves close when the pumps are operating, preventing the pumps from merely circulating product.

Where PD pumps are used, they are normally installed in parallel. PD pumps have a common suction line and discharge into a main line. Unlike pumps in series, each molecule is boosted only once (fig. 12–8). In contrast to centrifugal pumps, PD pumps installed in parallel can pump at different rates, but they discharge at the same pressure into a common discharge line.

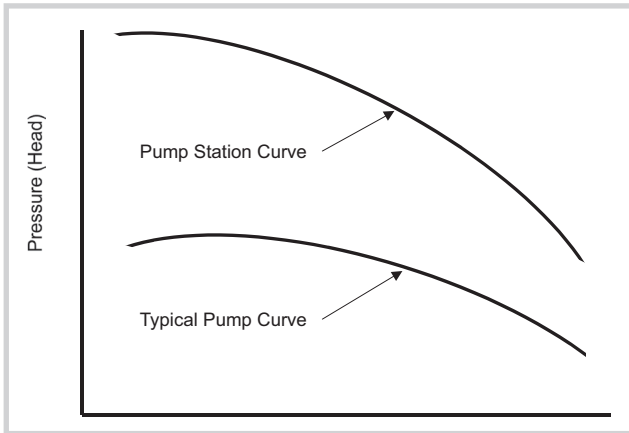


Fig. 12-7. Pump station curve. The curves for two pumps, each having a typical curve, are added together.

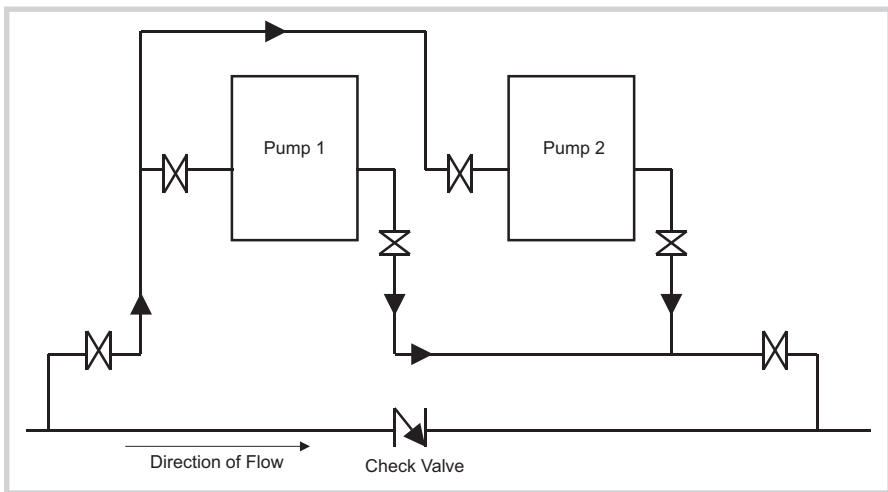


Fig. 12-8. Two PD pumps installed in parallel. The pumps have a common suction and discharge line.

The amount of pressure needed at the pump's inlet to keep the oil above its vapor pressure is the *net positive suction head* (NPSH) required. When NPSH available is less than NPSH required, vapor bubbles form as oil enters the pump impeller's eye. As the bubbles travel through the impeller and enter the volute, pressure builds and they collapse, releasing energy and causing cavitation. That can damage the pump. Different pump designs have their own required NPSH. Proper sizing and construction of the suction piping to the pump are important to prevent the excess pressure loss that can result in insufficient available NPSH.

Frequently, origination stations provide one or more small, single-stage booster pumps prior to the mainline pumps. These booster pumps have low NPSH requirements and boost the pressure into the mainline pumps to prevent cavitation.

Compressor selection

Each stroke of a PD compressor displaces the same volume. This is similar to PD pumps, with one important difference. One piston stroke displaces more natural gas molecules if the gas in the cylinder is at 1,000 psi than if it is at 100 psi. The volume may be the same, but the number of gas molecules (the weight of the gas) pushed out by PD compressors depends on the density of the natural gas in the cylinder. Unlike the line that is vertical on the PD pump curve in figure 12–5, PD compressor curves vary depending on the system pressure.

Natural gas pipelines have systems curves just like oil pipelines. Like them, the operating point is where the compressor curve (actually the compressor station aggregate compressor curve) intersects the system curve.

Compressor stations employ multiple compressors, sometimes even mixing centrifugal compressors with PD compressors. Sometimes compressors are installed in series, and sometimes they are installed in parallel. This depends on *compression ratios* (discharge pressure divided by suction pressure) and system needs. Compressors are generally operated in series to achieve additional pressure (fig. 12–9). Compressors operated in parallel into the same discharge piping (and necessarily at the same discharge pressures) have additive flow rates (fig. 12–10).

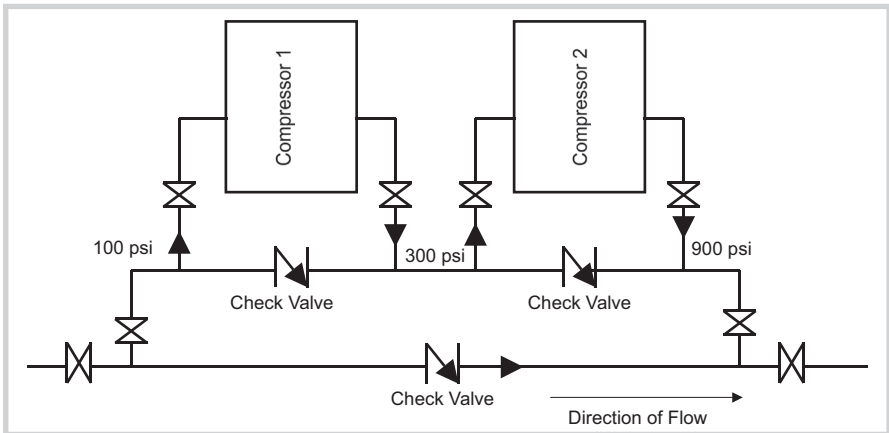


Fig. 12–9. Two compressors installed in series. Each compressor has a compression ratio of 3, raising pressure from the station inlet to the station outlet from 100 psi to 900 psi.

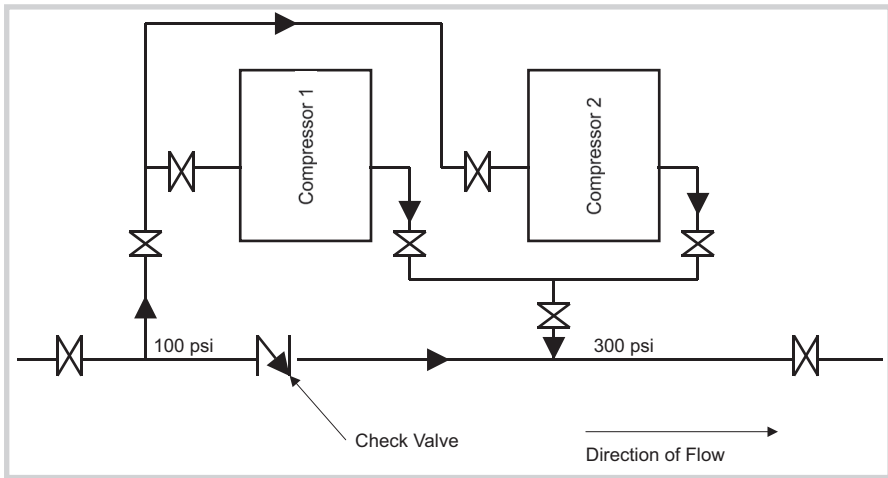


Fig. 12–10. Two compressors installed in parallel. Each compressor has a compression ratio of 3, each taking gas in at 100 psi and compressing it to 300 psi.

Prime mover selection

No one seems to know where the name *prime mover* originated. The most popular and obvious answer seems to be they are the first, or primary, source of mechanical power that drives the pumps or compressors to create pressure. Whatever the reason, the prime movers (electric motors, gas engines, or turbines) that are used to power natural gas and oil pipelines are familiar to most. As designers develop the optimum prime mover, they consider several factors:

- Compressor or pump type
- Power (primarily electrical or natural gas)
 - Source
 - Availability
 - Cost
 - Reliability
- Emissions permits and limitations
- Noise limitations

The reciprocating nature of engines coupled with ready availability of natural gas as fuel made engines (either integral or separable) ideal candidates to drive PD compressors for natural gas pipelines. This combination has been the de facto standard for natural gas pipelines for years, but centrifugal compressors are gaining popularity. Centrifugal compressors operate at higher speeds (3,000 to 12,000 rpm) than PD compressors (200 to 1,200 rpm) and call for

high-speed turbines or electrical motors. The latter have fewer moving parts than engines and generally require less maintenance. As emissions and noise concerns grow, electrical motors are replacing both engines and turbines.

Early oil pipelines had steam-driven engines, but later switched to liquid fuel engines, and gradually to electric motors where electricity was readily available. Where electricity has not been accessible, engines or turbines are still used.

Flow and Pressure Control

Pipeline designers normally place several pumps or compressors in each station, giving controllers flexibility to run all, none, or any combination to achieve the required level of pressure and flow control. Beyond unit selection, there are several other ways to achieve flow and pressure control. Speed control, achieved with VSDs, is used for both PD and centrifugal pumps and compressors, and it works essentially the same for natural gas and liquids. VSDs change the speed between the prime mover and the pump or compressor, changing their curves to match the desired flow on the systems curve (fig. 12–11).

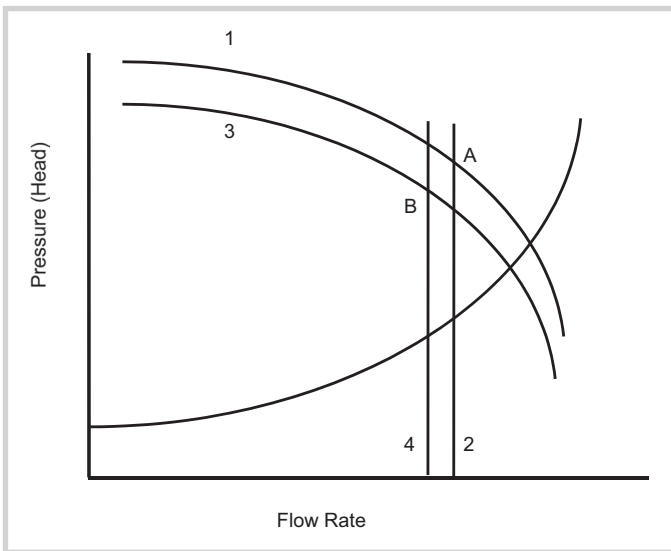


Fig. 12–11. Speed control used to move the operating point from A to B. Curves 1 and 2 are for a centrifugal and PD pump, respectively, prior to reducing their speed. Curves 3 and 4 are for the same pumps after reducing their speed.

Bypass control is also sometimes used to control PD pumps and compressors, simply recirculating some of the fluid from the discharge pipe back to the suction pipe. As mentioned previously, a pressure control valve installed in the recirculation line allows more or less flow. Recirculating more fluid gives lower pressure and flow into the pipeline, and vice versa. Recirculation is also used to control natural gas centrifugal compressors but not oil centrifugal pumps, as discussed later. Beyond speed control and recirculation, natural gas and oil controls are quite different.

Natural gas

Unit selection, speed control, bypass control, and pockets are the four ways used to control natural gas PD compressors. Pockets, discussed briefly in chapter 11, change the compressor curve by increasing or decreasing the volume of the cylinder, but leave the volume displaced with each stroke constant. Opening pockets provides less compression with each stroke, while closing them provides more.

Centrifugal compressors, in addition to using speed control, can use bypass control as well as *throttle valves* and *inlet guide vanes* (IGVs). Throttle valves are control valves installed in the compressor suction piping. They close or open, creating more or less fluid friction, allowing more or less natural gas into the compressor. IGVs are movable vanes installed inside the compressor suction piping. Moving the vanes makes the natural gas strike the impeller at different angles, changing the head characteristics of the compressor and consequently its curve. IGVs tend to be more efficient than throttle valves, since throttle valves turn pressure energy into heat by generating friction. IGVs simply change flow patterns, causing the compressor to produce more or less head.

Oil

PD pumps on oil pipelines have speed control and bypass control, just as those on natural gas pipelines. Centrifugal pumps use speed control but not bypass control. Unlike natural gas pipelines, they use control valves to change the discharge pressure, but they do not recirculate. Rather than changing the pump curve, the discharge control valves change the systems curve by creating friction loss. Discharge control valves move the systems curve to match the desired operating point on the pump curve (fig. 12–12).

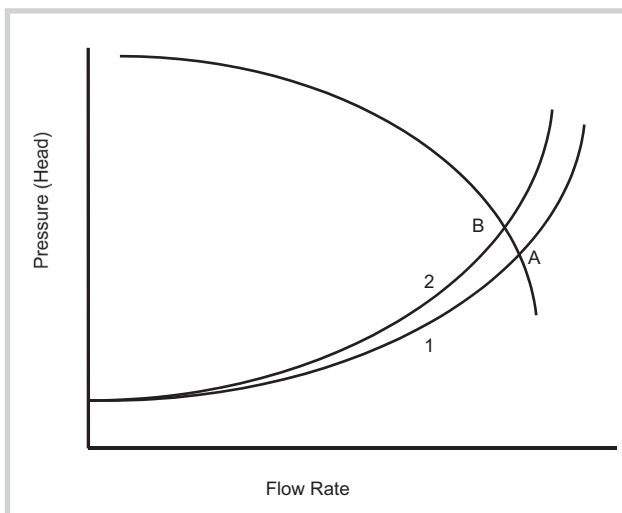


Fig. 12–12. Discharge control valve used to move the operating point from A to B. Curve 1 is the system curve with the control valve open. Curve 2 is the system curve with the control valve partially closed, moving the operating point from A to B. The distance between the curves is the amount of friction loss caused by the control valve.

There is a good reason that oil pipelines do not use recirculation to control centrifugal pumps. Each successive impeller and each successive centrifugal pump adds pressure. Relieving some of the discharge pressure back to the suction side of the pump causes the suction pressure to rise and the discharge pressure to rise. That means more recirculation, with the suction pressure rising, and so on, until the pump shuts down due to too much pressure. Compressible natural gas does not present the same spiraling problem.

Number of Stations

As a first pass to determine the number of stations, pipeline designers divide the total pressure required by MAOP. For example, one could consider a 250-mi-long, 24-in. line, with an MAOP of 1,500 psi, that requires 5,000 psi to move the desired amount. It would need about four pump stations ($5,000/1,500 = 3.33$). With this preliminary indication, pipeline designers decide if three or four is the best number. Perhaps it would make sense to increase wall thickness or pipe grade to increase the MAOP above 1,667 psi, thereby requiring only three stations ($5,000/3 = 1,667$). The capital and operating costs saved by eliminating one station may be more than the extra cost for stronger pipe. The converse could also be true, and the designers may elect to reduce wall thickness or pipe grade and build four stations.

The economic trade-off between diameter, wall thickness, pipe grade, and pump and compressor sizes typically drives station spacing to around one station every 40 to 60 mi. Economic operating pressures can cover a wide range, depending on the system. Normally though, they are between 500 psi and 2,500 psi, with most near the middle of the range.

Station Location

Pipeline designers normally try to locate intermediate (booster) pump or compressor stations near *hydraulic center points*, the points where each station on the line discharges at the same pressure. That allows pipeline designers to use identical pumps or compressors for each station, simplifying design and reducing costs. The number of stations determines the number of hydraulic center points.

All that sounds simple enough for a line with constant diameter and no elevation change, moving only one fluid. It gets more complicated when everything changes along the way, particularly for oil lines. Finding the hydraulic center for oil lines is more difficult and more important than for natural gas. Many oil pipelines operate as batch systems, moving varying grades of refined products or crude oil sequentially down the line. Hydraulic gradients and systems curves change depending on the particular assortment of refined products or crude oils in the line. For the hydraulic center, pipeline designers do the best they can, considering the array of fluids likely to move on the line.

The example introduced in chapter 4 (figure 4–14), included in figure 12–13, demonstrates how oil pipeline designers use hydraulic gradient to determine station locations. Suppose the pipe company decided to add a pump station to increase the capacity of this line. Where should they build it? The answer, based on diesel fuel, is somewhere between point A and point B.

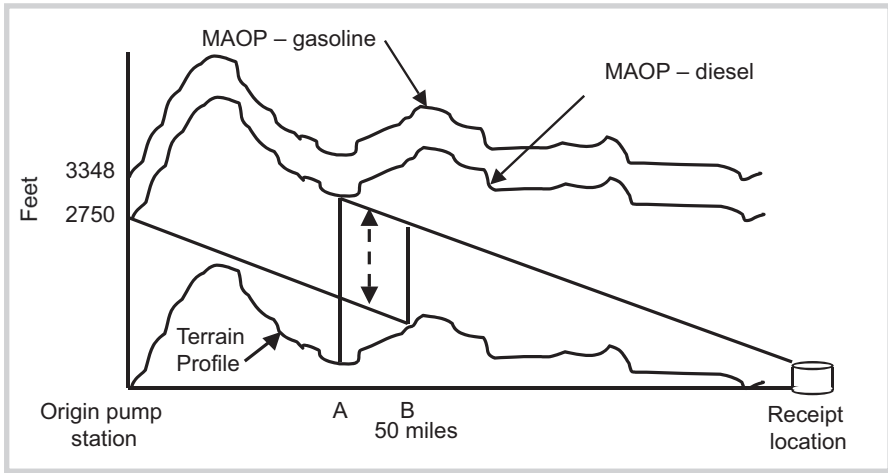


Fig. 12–13. Diesel hydraulic gradient after adding a pump station. The new station only needs to add the amount of head shown by the dashed line.

The hydraulic center point is theoretically unique for one flow rate and one fluid type. Change either, and the hydraulic center point changes as well. Locating hydraulic center points is tricky, and there is no perfect solution for batched oil pipelines. In figure 12–13, the pressure required at the origination station to pump diesel oil over the hill at the desired rate is more pressure than is needed anywhere else along the line. Consequently some might say there is not a hydraulic center point. This is different from the case of gasoline in figure 12–14. With gasoline at the given flow rate, there is a clear hydraulic center point where building an intermediate station results in discharge pressures identical to that at the origination station.

The pump station can be built anywhere between A and B and meet diesel pumping needs. Locating it at B best meets gasoline needs.

Establishing the locations of natural gas compressor stations has many of the same challenges as locating oil pump stations, but with several interesting differences. Line profiles are not as important for natural gas. “Pulling the line apart” causes contamination and interferes with leak detection in an oil line. Natural gas lines operate in a gaseous state, with flow rates varying along the line all the time.

Since natural gas pipelines normally have more receipt and delivery points than oil lines, natural gas pipeline designers pay attention to pipeline pressures near these points. A receiving pipeline may place compressors or compressor

stations downstream of receipt locations to enable the delivering pipeline to get the gas into their line. A delivering pipeline may place them upstream of delivery locations to allow enough pressure to deliver.

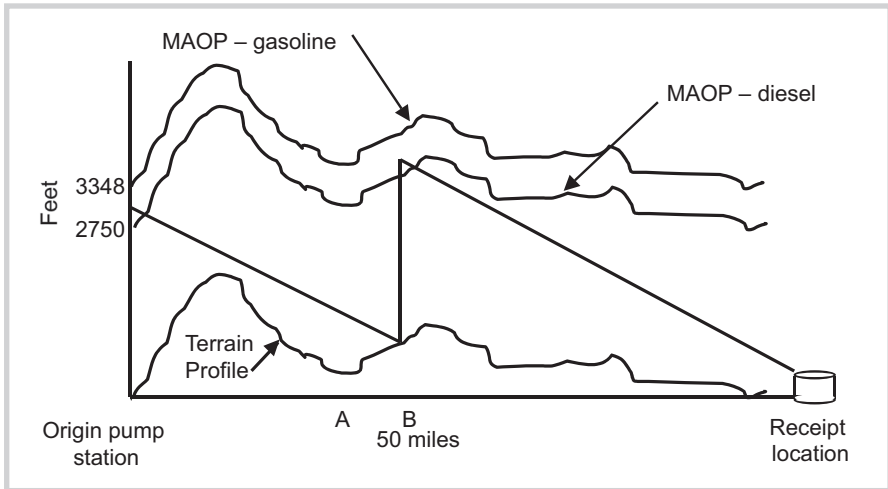


Fig. 12-14. Gasoline hydraulic gradient after adding a pump station. When pumping only gasoline, the line's hydraulic center point is at point B.

Storage

Oil is normally stored in aboveground fabricated steel storage tanks. Natural gas storage options include caverns (either washed salt dome or mined), depleted oil or gas reservoirs, aquifers, and aboveground steel storage.

Location of oil storage

Receipt and delivery points dictate the location of oil *tank farms*, groups of tanks located together. For example, one could consider refined products pipelines sequentially pumping batches of gasoline, diesel fuel, and jet fuel up the line. Along the way they may deliver into intermediate storage, used as staging areas for delivery to other pipelines. Alternatively, they might deliver into *refined products terminals*, sometimes called *bulk plants*, where gasoline and diesel fuel are stored for truck hauls to customers or gasoline stations.

Number and size of oil tanks

Each intermediate storage location or petroleum products terminal must have enough tanks of sufficient size to segregate the various product and grades. Each of these tanks (or combinations of tanks) must be sufficiently large to store the market demand of their product as other grades pass by on the pipeline. The basic elements of the tank sizing formula are:

$$\text{Tank size} = (\text{Average daily demand} \times \text{Cycle time}) + \text{Safety stock} + \text{Tank bottoms} + \text{Safe fill allowance}$$

where

- Tank size is the optimum size of tank,
- Average daily demand is the annual demand divided by 365,
- Cycle time is the time in days between batches of the particular product,
- Safety stock is the extra product kept on hand to avoid running out between deliveries or running over during delivery,
- Tank bottoms is the product inaccessible in the bottom of the tank, and
- Safe fill allowance is the safety factor allowed to keep from overfilling the tank.

Figure 12–15 shows the structure.

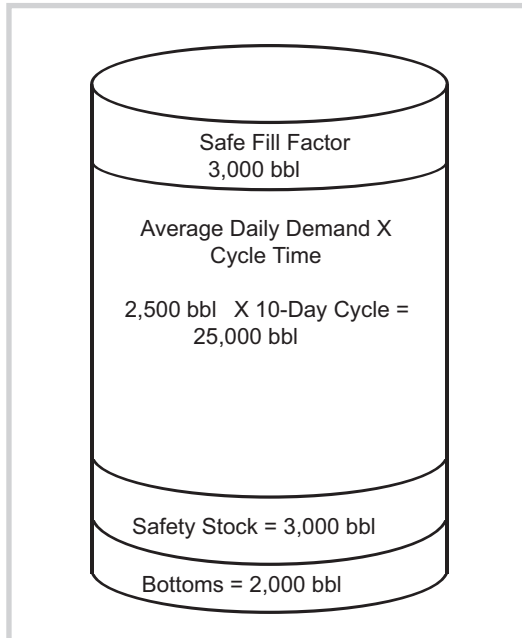


Fig. 12–15. Typical components of tank sizing. The indicated size of this tank is 30,000 bbl.

This formula seems straightforward enough, but gasoline demand is typically higher in the summer, and demand for heating fuel is higher in the winter. Thus average daily demand may also need to be multiplied by a seasonality factor. Another complicating factor concerns truck loadings. Typically more trucks load during the week than on weekends. When cycle times are 10 days, another factor, to account for the fact that two weekends occur between some deliveries into the tank and only one weekend between others, may be added.

Crude oil tank sizing, both on the receipt and delivery ends, uses the same concepts, adapting them to individual situations.

Sometimes for purely commercial reasons, pipeline companies and others build storage, and lease space to companies that attempt to buy at lower prices and sell at higher prices, keeping the commodity in storage as pricing changes.

Location of natural gas storage

Natural gas can be stored under pressure in depleted natural gas or oil reservoirs, in aquifers (water-bearing rock formations), in salt domes, or in mined caverns. If aboveground steel storage tanks are used, storage vessels are pressurized or partly pressurized and partly refrigerated to contain the gas.

Of course, depleted oil and gas reservoirs cannot be moved, and geology dictates the location of aquifers and salt deposits. Natural gas designers are therefore more constrained when it comes to storage locations. They use what is available, or build new aboveground or underground storage where geology and public opinion allow. They also build pipelines as needed to connect the storage to natural gas transmission pipelines.

One other important source of storage is the line pack on the pipeline itself. The compressibility of natural gas allows putting more into the line than is withdrawn, as long as MAOP is not exceeded. Line pack serves as important short-term storage.

Natural gas storage management

Natural gas demand varies seasonally with demand, particularly home-heating demand that is higher in the winter heating season. It fluctuates daily, and even during the day, as more natural gas is used during daylight hours when people are active and less at night as much of the population sleeps. At the same time, natural gas production capacity swings during the year

(sometimes due to well maintenance) and during the day, but not with the same pattern as demand. Producers, pipeline companies, and suppliers use storage, to the extent it is available, to balance all these factors. In many natural gas pipeline systems in the world, production has to be throttled back in the summer to avoid overflowing storage capacities.

Operating storage

Pipeline companies use operating storage to balance short-term demand swings. Even in winter, they pull natural gas from storage during the day and replace it at night. In the summer, the same is true, because higher temperatures mean more air conditioners run, consuming electricity produced by natural gas-fired generation stations. During any day of the year, natural gas may be placed into storage at night. It may then be withdrawn early the next morning as people wake up and head to the shower, firing up their hot water heaters. They probably also turn up the heat in the winter, and as the sun comes up in the summer, the air conditioner kicks on.

Gas stored on the U.S. Gulf Coast takes about four days to a week to reach the U.S. Northeast. Pipeline companies would like to have storage close to the point of consumption, allowing them to respond quickly to demand changes. However, most depleted gas and oil storage fields are not located near major consumption centers. This leaves pipeline companies searching for aquifers or geologies suitable for caverns. Alternatively, it forces them to consider expensive aboveground storage or large-diameter lines to meet customer needs.

Seasonal storage

Determining the amount of seasonal storage seems straightforward. One could take the production and demand profiles and calculate how much storage is needed to balance the two. But who is responsible for seasonal storage? Sometimes pipeline companies own seasonal storage, even though they do not need it for operating reasons. Other times local distribution companies, natural gas producers, natural gas storage companies, or even trading companies own the seasonal storage. Of course, any type of storage can be used for operating as well as seasonal storage.

Station Design and Layout

In general, pipeline stations function as compressor or pump stations (origination as well as intermediate), delivery stations, storage stations (tank farms or storage fields), or interconnecting stations. They can also function as a combination of these. There are probably as many station designs as there are station designers. Accordingly, this section covers the general aspects of station design and layout, but not all the specifics.

Compressor and pump stations

These stations add pressure to the pipeline, either at the origin or along the way. One or more pipelines enter the station, and one or more exit the station. An origination station is the first pipeline station on the line. Several pipes may enter the station from natural gas or crude oil production fields, import facilities, gas plants, refineries, tank farms, storage fields, or other pipelines. Just prior to entering the station, each of these lines usually has a *station block valve*, normally a gate or ball valve used to isolate the station from the line if needed.

The line may or may not connect to a scraper receiver, used to trap pigs and keep them from entering the station. In addition, natural gas compressor stations may have scrubbers to remove liquids that have dropped out of the stream. Removing these liquids near the station entry point protects station equipment, such as compressors. Sometimes the lines have incoming meters at the station, allowing the natural gas or oil to be measured before it gets to the station.

Incoming lines may feed one or more *manifolds*. These are collections of valves, pipes, and fittings designed to commingle and feed the various streams into the compressors or pumps in an orderly fashion (fig. 12–16).

Typical station layouts include meters located where natural gas or oil moves from the incoming manifold to the compressors or pumps. *Strainers*, mesh baskets like large kitchen strainers only much larger and robust, are often installed as a precaution. These remove any rust, scale, and debris from the stream before it enters the meters, pumps, or compressors. The stream exits pumps or compressors and is discharged into the main line. Oil pipelines may have control valves between the pumps and main line, and most origination stations have launchers for inserting scrapers into the pipeline. Outgoing station block valves provide isolation on the discharge side of the station.

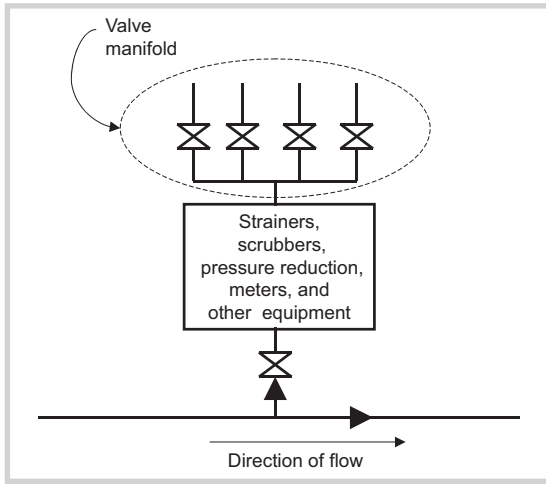


Fig. 12–16. Refined products pipeline manifold. Manifolds direct flow to specific tanks, pumps, compressors, or other equipment.

Booster stations are laid out much like origination stations, but they usually have only one or perhaps two lines entering and leaving. A booster station is normally installed on a station loop to allow it to be isolated from the main line with block valves (fig. 12–17). Like natural gas origination stations, booster stations may have scrubbers to remove liquids that have condensed out of the stream. Typically, booster stations do not have meters, since oil or natural gas does not enter or leave the stream at the station.

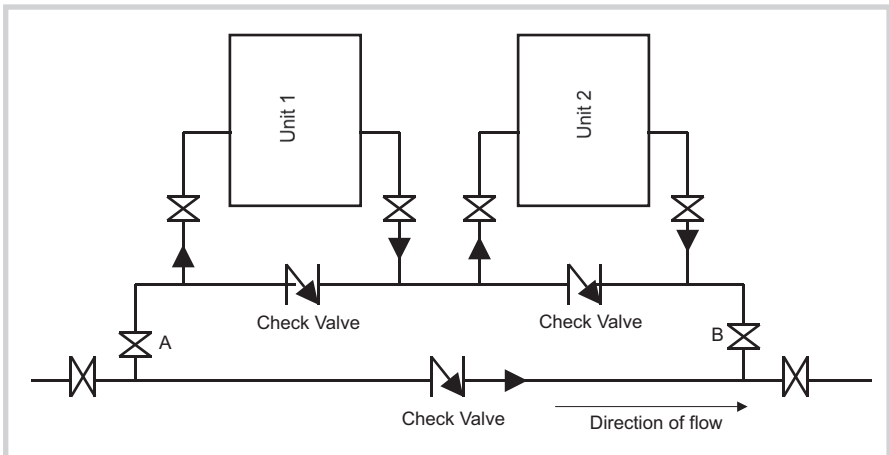


Fig. 12–17. Station loop. Closing valves A and B isolates the station from the main line to enable maintenance work.

Delivery stations

Delivery stations reduce pipeline pressures down to a level acceptable to a receiving party and measure the oil or natural gas. A typical delivery station consists of a station block valve, possibly a scrubber and a strainer, a pressure control valve, meters, and a delivery manifold.

Storage fields and tank farms

Storage fields and tank farms receive oil or natural gas, store it, and redeliver it, sometimes back to the same pipeline, sometimes to another. The equipment and its layout are essentially the same as that of receipt and origination stations, but with some additional considerations.

Storage fields. Unfortunately, not all the natural gas stored in abandoned oil or gas formations can be easily withdrawn. In actual practice, as much as 50% stays in the formation as *cushion gas* to maintain the integrity of the formation. Withdrawing too much of the natural gas in the reservoir may cause the pores of the structure, where the gas resides, to collapse, blocking the flow and reducing the useable storage space.

Salt dome caverns also require careful design and management. They have been washed out of salt formations by pumping fresh water down a shaft, dissolving the salt. Salt dome storage may be operated as either wet or dry systems. Wet systems pump brine (water saturated with salt) in or out of the dome to maintain pressure and dome integrity. If the salt concentration of the brine drops too low, additional salt dissolves from the dome walls, potentially weakening the structure. In addition, enough pressure needs to be maintained in the salt dome to keep it from collapsing. Pressure is maintained by pumping in brine and compressing the gas. Designers lay out pumps, instrumentation, and controls to keep pressures, flow rates, and brine concentrations at the correct levels to meet demand while maintaining storage field integrity. Dry systems depend on the vapor pressure of the natural gas to move it out of the cavern. As with wet systems, dry systems must maintain adequate pressure to sustain cavern integrity.

Tank farms. If natural gas inadvertently escapes, it goes into the atmosphere. If oil leaks, it can pollute surface and groundwater. Tank farm designers include earthen dikes around the tanks to contain oil if it leaks from the tank (fig. 12–18). Dikes are sized to include enough volume to hold the entire tank contents in case of complete tank failure.



Fig. 12–18. Tank dikes. These dikes contain spills, keeping them from spreading and enabling quick cleanup. (Courtesy Explorer Pipeline Company)

The pressure head inside storage tanks pushes oil out of the tank and to the pumps. The friction loss in the line and the pressure head loss or gain due to elevation differences between the tank and station pump can reduce the pressure head. As a consequence, there may not be enough NPSH available to the mainline pumps. Designers compensate by including *tank boosters*, relatively small (usually single-stage) pumps, at a tank. Alternatively, they may include one or more *yard boosters*, with connections to several tanks.

Ancillary station equipment

Most people think of piping, compressors, and pumps when they think of stations. However, there is a great deal of other ancillary and support equipment:

- Incoming electrical power and transformers
- Instruments and control equipment (discussed in chapter 8)
- Air compressors for purging and starting main compressors, and in some cases, for instruments and valve actuators
- Hydraulic pumps and motors to supply hydraulic power valve actuators

Additional Design Considerations

Designers deal with two final design considerations: crossings and block valve placement.

Crossings

Pipelines are long assets. They intersect many physical barriers—roads, railroad tracks, rivers, streams, and other pipelines, as well as residential communities and businesses. During route selection, pipeline designers attempt to minimize the number of crossings required in the final route. Invariably it is not practical or possible to go around some barriers, so plans are made to pass over or under those that cannot be avoided.

The most popular approach is a buried crossing, and pipeline designers decide whether to bury the pipe by trenching across the feature or boring under it. Trenching is usually cheaper and faster but is not always popular with the landowner.

Obstructing traffic or interfering with rivers or streams causes problems. During early attempts to bore under obstructions, the front of the drill bit sometimes was deflected from the intended route when it encountered hard dirt or a rock. This caused it to exit in unintended locations. Advances in boring with horizontal directional drilling (HDD), based on technology learned in the oil patch, has significantly improved boring reliability. This has facilitated longer and more accurate drilling.

Early in pipelining history, it seemed a good idea to place buried road and railroad crossings inside carrier pipes called casing (fig. 12–19). This practice intuitively makes sense. If the pipeline leaked under the road, it could be pulled out and replaced. Vent pipes were usually added to the casing so that vapors could escape through them to indicate a leak.

However, ideas that seem to make sense do not always work out. The two pipes, one inside the other, had to be electrically insulated from each other to prevent galvanic corrosion. Insulating spacers were developed to fill this need. Unfortunately, getting the spacers installed correctly was difficult, and corrosion problems still occurred. In addition, the vent pipes allowed airflow to the underground pipe, and humidity in the air condensed against the ground temperature pipe, speeding up corrosion.

Now, rather than cased crossings, pipeline designers normally specify installing thicker wall pipe in crossings. Concrete protective coating is typically installed to protect the cathodic coating as the pipe is pulled through bored crossings.

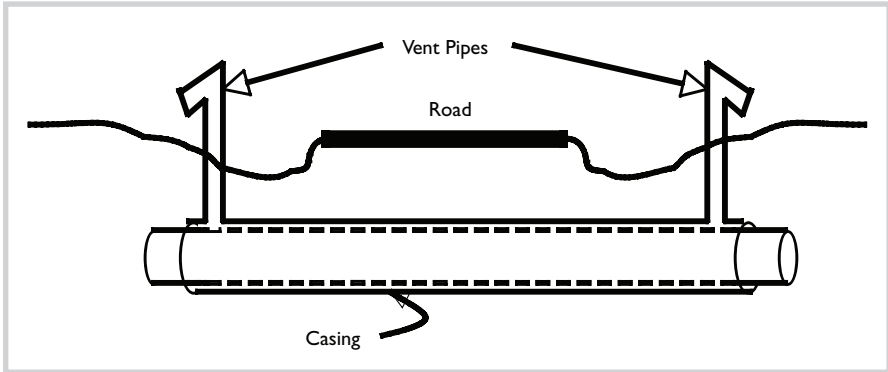


Fig. 12-19. Cased crossing. Vent pipes connected to the casing come above the surface.

Block valves

Block valves are installed along the pipeline to segment the line. They are useful during maintenance when a section of the line needs to be isolated from the rest of the line. They can also shut off sections of the line in the event of a leak. Designers look at the route profile, water, crossings, population, and other factors as they decide the number of block valves and their placement.

Conclusion

Experienced pipeliners reading this chapter will say, “It is a lot more involved than that!” They are right. This chapter simply introduces the topic of pipeline design. There are volumes of standards and recommended practices containing excruciating details. These cover all aspects of pipeline design, and detailed texts exist for those who would like to learn more.

13

Construction

If you build it, he will come.

—**Field of Dreams (1989)**

The design nears completion. The final cost estimates are supported by firm bids. The pipeline company management has one last chance to cancel the project. They look anxiously at updated cost estimates based on the detailed design. They take a last look at pricing, supply, demand, and how many customers have signed contracts to move volumes. Based on the most up-to-date numbers, project economics are considered one last time. The company thinks seriously about the permitting process. They consider whether or not the line can be permitted, and what concessions will need to be made in order to secure the permits.

Satisfied with the undated economics and permitting prospects, they turn to thoughts about construction and the construction organization. They consider who should be the project manager—the experienced engineer who oversaw the last large project, or the promising, younger, less-experienced person with executive management potential? How should quality control and inspection be handled? What kind of support organization is required? What kind of public relations effort is appropriate, and what safety programs are needed to insure no one is hurt during the job? With all these decisions made, and after just one more final look at the economics, they approve the project and it moves into construction.

Permitting

Most experienced pipeline constructors know the time required to secure permits usually exceeds the time required to build the line. Permitting can take a year or more for small projects and three to five years or more for large, complex projects. If projects have high public interest, requiring massive studies and public hearings, the seeming interminable permitting process can last for years. It should come as no surprise the permitting process starts well before other construction activities.

Normally the permitting process starts, informally, long before the final decision to build. Early in the process, pipeline officials meet with regulators, legislators, local emergency response officials, and other interested parties, educating them about the project. During these meetings, they attempt to clarify which permits are required, the most likely issues of interest, and the submissions and studies needed to meet permit application requirements. What pipeline officials learn during these meetings has a direct bearing on the decision to build.

Permitting varies between and even within countries. Permits fall into three categories—land use, environmental impact, and safety. The challenges of these three areas of permitting are covered in detail in chapter 14.

Contracting and Procurement

Physically creating pipelines takes two main functions. The first is procurement, which includes securing the materials, pipe, valves, fittings, meters, pumps, compressors and the like. The second is construction, or putting all of the parts together. Pipeline companies normally use a bidding process to secure the best pricing for both construction and materials.

Pipeline designers have developed maps showing the route and special considerations such as road, railroad, and river or stream crossings. That lets them create construction specifications detailing how the line is to be built. Contractors carefully examine the maps and specifications, estimating the cost to build the line. They submit construction bids, and the pipeline company selects the contractor or contractors to build the line.

Material procurement is done much the same way. Specifications go out to manufacturers and vendors, bids come back, and suppliers are selected. Often construction contractors also procure materials, as approved by the pipeline company.

ROW and Land Acquisition

Pipelines are buried along most of their route, allowing the landowner to use the surface. Consequently pipeline companies normally purchase easements or ROWs, the right to use the subsurface, rather than purchasing the land itself. ROW agreements spell out what the pipeline company and the owner are entitled to. The owner receives a negotiated payment, and the pipeline company gets access to and use of the land.

Early in the design process, ROW agents take preliminary routes and consult local government records to determine who owns land along the potential routes. ROW agents use these lists to contact landowners, asking about purchasing ROWs across the landowner's property. In some cases, pipelines already cross the landowner's property, and they are quite familiar with pipelines and their safety record. In other cases, the landowners are surprised, or even shocked to learn a pipeline may cross their land.

ROW acquisition is often a long and arduous process, and slight (or even major) deviations may be made to the route based on landowner sentiment. Sometimes the route is even shifted across the property lines from one landowner to another depending on the negotiation process. Given a choice, most people would rather not have pipelines across their property. However, pipelines are necessary to support the energy-intensive life styles of developed countries. Thus most countries have laws setting forth how ROWs are purchased from reluctant landowners. Exactly how this works depends on the land use laws and regulations and varies between jurisdictions.

Normally, building the line requires more space than maintaining it after it is constructed. So the temporary use of a larger ROW, perhaps 50 ft to 100 ft on either side of the *pipeline centerline* (the intended center of the pipe after it is installed), is normally acquired during construction. The ROW may revert to widths more like 25 ft to 30 ft on either side of the centerline when construction is completed to provide for normal maintenance. The ROW payments compensate for the right to use the subsurface for the long term, and the surface during construction and subsequent maintenance activities.

Station sites do use the surface, so they are normally purchased or leased on a long-term basis.

After using the surface, pipeline companies usually restore it as nearly as possible to its original condition, rebuilding roads or parking lots, for example. However, in some cases restoration is not possible, such as when crops are damaged. In these cases, pipeline companies may pay *damages*, or compensation for the loss of use or loss of income.

Inspection

Pipelines are huge investments, and pipeline companies want to ensure they are well constructed. They hire specially trained inspectors or assign some of their own employees to provide construction quality control. Each project normally has a chief inspector coordinating the work of other inspectors overseeing geographic areas or specific tasks. A welding expert may work with the welding crews to insure quality. Another inspector may oversee lowering in and backfilling over the pipeline.

Construction contractors are justifiably proud of their work and want to construct a high-quality project. However, pressures can become intense, especially if a job is behind schedule or over budget. In addition to using their technical expertise, inspectors sometimes also fill the roles of police officers or diplomats as they work with the construction contractor and crew to ensure a high-quality job. Inspectors may even work in the procurement process, inspecting pipe, valves, and other components as they are manufactured and tested.

Staking the Line

When the designers selected the route, they used topographic maps and followed up with helicopter or fixed-wing flyovers. They may also have driven or walked all or part of the proposed route, getting a good understanding of its geology, topography, and physical characteristics.

ROW agents used these maps to purchase ROWs, and others used the maps to secure permits. However, before construction starts, the line on the paper must finally be translated to points on the ground. Surveyors take the information from the maps and *stake the line*, driving in stakes along the pipeline centerline, showing the center of the proposed pipeline.

In addition to staking the centerline, surveyors normally mark the edge of the ROW and identify areas requiring extra space for construction, such as a river crossing. Surveyors often recommend slight deviations to avoid obstacles, make construction easier, or meet landowner needs. If the project managers agree and ROW agreements allow, the route is adjusted accordingly.

Pipeline Construction Spreads

Pipelines are constructed by groups of crews and equipment, normally called *spreads*. Each spread moves along a route, performing its assigned tasks, somewhat like an assembly line, except that the crews move rather than the work. Short lines normally include only one spread, but longer ones may use several spreads to speed the work.

Preparing the ROW

After all the preliminary work, construction finally starts in earnest as workers begin preparing the ROW for the main construction crews and equipment. They use bulldozers to clear and grade the ROW, removing trees and brush and building temporary access roads. Often topsoil is stripped from the route and stockpiled so it can be placed back on top of the line after the backfill operation (fig. 13–1).



Fig. 13–1. Stockpiling topsoil. Topsoil is stripped from the right-of-way, stored in piles, and put back when the pipeline is complete. (Courtesy U.S. Pipeline, Inc.; photo by Adam Aronson)

Crews also build temporary bridges to cross rivers and streams, and use mats to cross wetlands. Sometimes bulldozers with ripper blades are needed to remove tree roots and rocks. Rocks that cannot be removed with rippers are usually blasted apart and then hauled out of the way.

When the route goes through cities and towns, preparing the route may have more to do with talking to business owners and making arrangements for traffic control rather than clearing obstructions. Whatever the case, the job of the crews preparing the ROWs is to ensure smooth and efficient progress of the main construction spread.

Stringing

With the route prepared, the first part of the main construction spread moves in, *stringing the pipe*, or lifting it from trucks and placing it end-to-end along the route (fig. 13–2).



Fig. 13–2. Positioning pipe joints along the route. The pipe is hauled to the site by trucks, lifted off, and carefully placed into position prior to welding. (Courtesy U.S. Pipeline, Inc.; photo by Adam Aronson)

During stringing, and in fact during the entire construction process, care is exercised to protect the pipe, especially ensuring that the cathodic coating is not damaged. In forests and agricultural lands, stringing crews consider where to leave openings to facilitate movement of animals during the construction process. In congested areas, the pipe is often stockpiled at storage sites near the route, with each joint brought in one at a time as the crew is ready for it.

Welding

Pipeline welding is accomplished using sacrificial electrodes that are melted by an electrical arc, forming the filler material that holds the two ends of each pipe joint together. There are many different electrode metallurgies. The pipeline company and construction contractor agree on the best electrodes to meet the welding requirements for the specific pipe and welding conditions. The pipeline company and contractor also agree on the *welding procedure*, a written description of how welding should be performed. Welders can be tested to ensure they produce high-quality welds following these procedures, and those passing the test are certified to weld on the pipeline.

Windy weather can affect weld quality by blowing dust into the welds, so contractors sometimes use portable tents, complete with air conditioning (fig. 13–3).



Fig. 13–3. Welding tents. Tents are sometimes used to cover the pipe and improve welding or working conditions. (Courtesy U.S. Pipeline, Inc.; photo by Adam Aronson)

During the manufacturing process, each end of line pipe is produced with a slight bevel to allow the *root bead*, the first weld pass, to easily penetrate all the way to the inside of the pipe. Prior to welding one joint of pipe to the next, the two beveled ends are carefully lined up with the proper clearance (fig. 13–4).

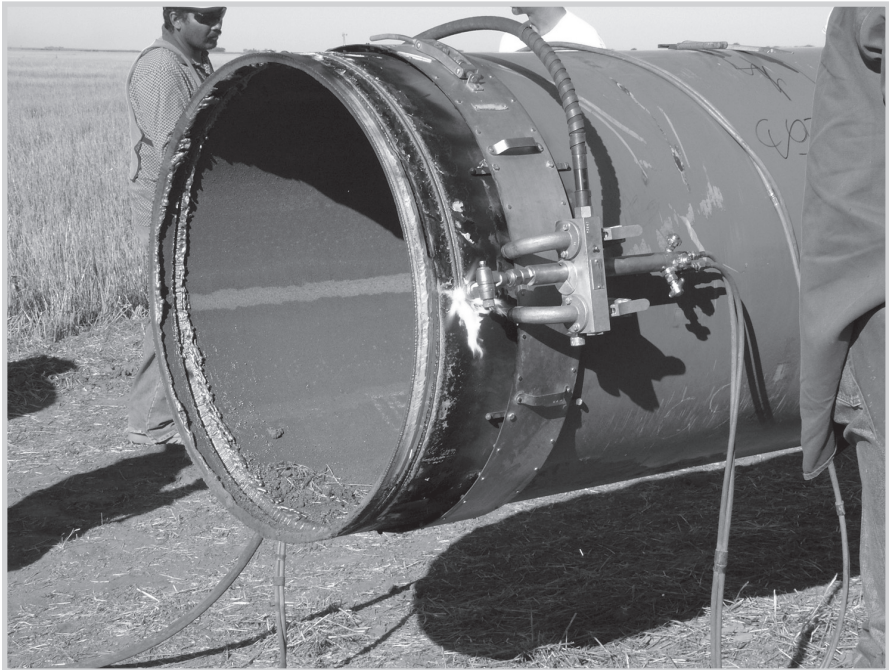


Fig. 13–4. Beveling a piece of pipe. Pipe ends are beveled when they are manufactured to improve welding. When pipes are cut to length in the field, the bevels are cut with a torch. (Courtesy U.S. Pipeline, Inc.; photo by Adam Aronson)

Construction workers use internal or external *alignment clamps* to bring the two pipes into just the right position for welding. Internal alignment clamps are left in position during welding and then moved to the next joint as the welding progresses along the line. When external clamps are used, the pipes are commonly *tack welded* (short welds around the circumference of the pipe) to hold them in place. Next the clamps are removed, and the welding process is finished.

The joints of pipe are welded together, either by welders holding electrodes and welding around the pipe, or by automatic welding machines (figs. 13–5 and 13–6).



Fig. 13-5. Manual welding (Courtesy U.S. Pipeline, Inc.; photo by Adam Aronson)



Fig. 13-6. Automatic welding (Courtesy U.S. Pipeline, Inc.; photo by Adam Aronson)

Successive weld passes are called the root bead, hot pass, filler beads, and cap, with the number of filler beads depending on the wall thickness (fig. 13–7). Each subsequent pass must fuse smoothly with the pipe and the previous weld bead. After the weld is completed, it is tested, and then the area around the weld is coated for cathodic protection.

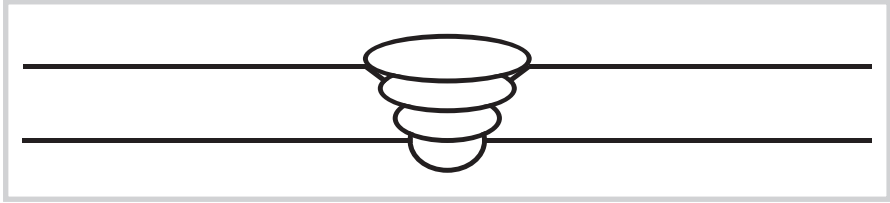


Fig. 13–7. Weld beads comprising the weld. The first bead is normally called the root bead; subsequent passes are the hot pass, the filler pass (or passes, depending on wall thickness), and finally the cap bead.

Weld Inspection

Weld quality is critically important, so inspectors observe the welding process and examine welds after completion. The most popular techniques to inspect welds after completion are *radiography* and *automated ultrasonic*.

Radiographic weld inspection has been used since the late 1950s. It involves fastening film around the outside of the weld and exposing it to X-rays or gamma rays, much like medical X-rays, from inside the pipe. In cases where the access to the inside of the pipe is not possible, the X-ray is taken in several sections with the source on the outside. Technicians develop the film in truck-mounted dark rooms and read the results, comparing what they see in the X-ray against established criteria to determine weld quality.

Like the familiar medical device, ultrasonics use sound wave reflections to establish a picture of weld internals. Technicians clamp a track holding the testing device to the pipe, and it travels around the weld, sending out sound waves. It receives back echoes as the sound waves bounce back from boundaries within the weld (fig. 13–8). The reflections (echoes) produce pictures used to manually judge weld quality. Automated ultrasonic testing uses specialized techniques and imaging to evaluate pipeline welds, reducing lag time between welding and inspection versus radiography. With both processes, when weld defects are found, they are ground or cut out, repaired, and retested.



Fig. 13–8. Automated ultrasonic testing device clamped to the pipe. The same ultrasonic technology used in smart pigs is used to ensure weld quality during construction. (Courtesy Olympus NDT)

The ends of each joint are left uncoated at the pipeline-coating mill to facilitate welding. After welding, they are coated with compatible materials to ensure corrosion protection.

Trenching

Pipeline companies and construction contractors think carefully about when to dig the trench for the pipe. Sometimes trenching proceeds ahead of stringing, but many times the trench is not opened until the joints of pipe are welded together and ready for lowering in and backfilling. Open trenches are prone to having things fall into them or washing out in the event of rainstorms, so the amount of time the trench is open is minimized.

In open terrain with relatively easy-to-dig soils and limited obstructions, specially built trenching machines are used (fig. 13–9). They are well suited to digging long lengths of straight trench in open terrain. They can dig trenches with slight bends, but their design makes it difficult to handle mild to sharp bends.



Fig. 13–9. Trenching machine. Soil from the trench is placed on one side of the ditch. The other side is used for construction activities. (Courtesy U.S. Pipeline, Inc.; photo by Adam Aronson)

Backhoes are normally used to dig short trenches, trenches close to obstructions, and trenches that turn corners. Sometimes backhoes complete the entire job. Trenching close to obstructions and near buried underground utilities is usually accomplished by a combination of hand digging and mechanical excavation to avoid damaging those structures.

Lowering In

With the joints of pipe welded together into a continuous pipeline, and the trench dug, it is almost time to *lower in* the pipe. One or two more steps are performed to ensure quality and long life. Trenches with features that could damage the coating, like those in rocky soil, are commonly *padded* by placing a layer of sand or other protective material into the trench before the pipeline. The pipe coating is also inspected one last time with a holiday detector to locate coating damage that may have inadvertently happened during construction (fig. 13–10). Any coating damage is repaired, and the pipeline is finally ready for lowering in.

A series of side-boom tractors holds the pipeline in cradles, driving forward and lowering it into the ditch with a gently rolling action (fig. 13–11). There is no exact guideline for the length of pipe that is welded together before it is lowered into the ditch. Mainly it depends on what is convenient. In open, straight terrain, the length can be miles. In congested city construction, individual joints may have to be painstakingly lowered in and welded together. Extreme cases may even require cutting up joints to make them fit.



Fig. 13–10. Final inspection with a holiday detector. The detector produces an audible signal when it encounters a coating holiday. (Courtesy Canusa-CPS)



Fig. 13–11. Lowering in the pipeline (Courtesy U.S. Pipeline, Inc.; photo by Adam Aronson)

Backfilling

After the pipeline is lowered in, additional padding may be placed around it to protect the coating from rocks and other debris. Rock shield, material that looks like a long, wide doormat, can also be placed over the pipeline to protect the coating. Finally, the soil removed from the trench is filled back into the trench by backhoes or bulldozers in a process called *backfilling* (fig. 13–12).



Fig. 13–12. Backfilling the trench. The bulldozer and front backhoe fill the trench, and the one in back compacts the backfill. Another pipeline sits in the middle of it all. (Courtesy Miesner, LLC)

Bends, Crossings, and Tie-Ins

When there are limited or no obstructions, creating straight sections is relatively straightforward. However, there can be crossroads, rivers, streams, and other buried or aboveground structures that have to be skirted with sharp bends. Each of these is accommodated with specially handled pipe and then is *tied in* to the long, straight sections.

Bends

Pipe has enough flexibility that it can accommodate gentle turns and changes in elevation. In such cases, it conforms to the curvature of the trench as it is lowered in. For more severe turns and elevation changes, the pipe has to be bent, either in a pipe-bending plant or at the construction site. On-site bending calls for a hydraulic bending machine. Construction crews carefully calculate the bends required and position the bending machine accordingly. Side-boom tractors place the pipe in the bending machine. If the pipe is already coated, protective materials are placed around it to prevent coating damage. Once the pipe is in place, hydraulic force slowly bends the pipe.

Several successive bends are sometimes required in order to achieve the final curvature, taking care to prevent wrinkling or buckling the pipe. If the bend is not too severe, it may be welded onto the string of pipe before it is lowered into the trench. At other times, it is lowered into the ditch and welded to the previous joint. Sometimes several joints around the bend are welded together outside the ditch and then lowered in (fig. 13–13). Exactly how the bends are placed depends on the individual configuration and circumstances.



Fig. 13–13. Bent pipe stored for future use. A section of natural gas pipeline is bent to fit under a crude oil line. (Courtesy Miesner, LLC)

Crossings

Pipelines sometimes have to cross obstructions along their route, such as streets, roads, rivers, streams, underground utilities, and aboveground structures. When these obstructions are encountered, crews cut through them, bore under them, or expose them and carefully thread through them. In some limited instances, mainly with rivers and streams, aerial crossings are used (fig. 13–14).



Fig. 13–14. Aerial crossing. A 30-in. natural gas pipeline crosses a small river. (Courtesy Miesner, LLC)

There are several ways to bore under obstructions. The simplest is to dig holes on each side of the obstruction. Then a boring machine (essentially an engine with an auger) is lowered into the hole. It drills horizontally, with the objective of intersecting the other hole at the proper elevation. Rather than drilling the entire diameter of the hole at one time, a pilot hole is drilled under the obstruction. Once the small passage is established, successively larger reaming bits are pulled through the passage until it gets large enough to pull through the pipe. Unfortunately, since the bit is not guided, a rock or other obstruction may divert the bit and cause it to emerge in an unexpected location, necessitating a redrill.

A similar but more expensive and more reliable method mentioned in chapter 12 is HDD. It uses a bit that can be guided as it bores through the soil. It also circulates drilling cuttings out of the hole with drilling mud as they develop. Directional drilling allows guiding the bit up, down, and around, in precise movements so the bit emerges where it is expected. After the pilot hole is completed and enlarged with successive reaming passes, the pipe is pulled through the hole (fig. 13–15).



Fig. 13–15. Pulling the pipe through a directional drill (Courtesy Mears Group, Inc.)

Tie-ins

Once they are installed, crossings (and sometimes bends, as discussed earlier) are *tied in* or connected to the long stretches of pipeline previously welded together by the production welders. As they install bends or crossings, construction crews are careful to leave the pipe long enough that it overlaps the longer sections of pipe. A large hole, commonly called a *bell hole* because of its bell shape, is excavated where the two pipes meet. They are carefully lined up and one or both are cut off, so the two ends meet precisely and squarely. The ends are beveled, lined up, and then welded together, completing the tie-in (fig. 13–16).



Fig. 13–16. Welder tying in a bend (Courtesy U.S. Pipeline, Inc.; photo by Adam Aronson)

Quality Control

During welding and just prior to lowering in, welds and coating are inspected. After the pipe is completely welded together, it undergoes even further quality checks.

Cleaning and Sizing

A cleaning pig is normally the first pig pushed through the pipeline, using compressed air to remove any remaining debris. Then a *sizing pig* or a *caliper pig* is pushed through the line, again with compressed air. Sizing pigs have *sizing plates* with a diameter slightly less than the pipe internal diameter. If the sizing plate has deformations when the pig emerges, the construction contractor must locate and repair the obstructions that caused the deformation.

Hydrostatic Testing

The final quality check is usually a hydrostatic test, previously discussed in chapter 9. The line is filled with water, and the pressure is increased to well above intended operating pressure. The amount depends on the regulations and practices of the jurisdiction. Once it reaches test pressure, pressurization stops, and the water in the line is allowed to thermally stabilize. Sensitive instruments record any changes in pressure. Pressure drops can indicate a leak, so engineers carefully evaluate the pressure recordings. Any leak indications start the process of finding and repairing the leak, which can be excruciating, especially if the leak is small. If it cannot be located as a wet spot on the ground, the pipeline is divided into smaller and smaller test sections, eliminating nonleaking sections until the leak is finally located. Testing continues until all sections hold the required pressure for the designated time, and then the water is pushed out and disposed of in an environmentally responsible manner.

Commissioning

Next, natural gas pipelines are dried down to the required dew point (a measure of the relative humidity in the “empty” pipeline). (Oil pipelines do not normally require drying. Sometimes, however, a methanol wash is placed between the hydrostatic test water and the oil filling the line to soak up any remaining water.)

Drying can be accomplished in several ways, including methanol washing, purging with nitrogen or superdry air, vacuum, or even with natural gas. Each has advantages and disadvantages, and the contractor or company selects the method or combination of methods best fitting the particular situation. Whichever method is used, it is important that all standing water and even water vapor is removed from natural gas lines. Moisture left in a gas line can collect in low spots, causing internal corrosion. It can also be passed on to customers and connecting pipelines, causing them problems.

Station Construction

In addition to building the pipeline, stations with pumps, compressors, receipt and delivery facilities, and metering are constructed along the way. The order in which station construction proceeds is similar to other types of construction. Vegetation is removed from the site and it is graded, either flat

or to the desired contours. Stakes are placed indicating the locations of major equipment and facilities. Foundations and supports are constructed, and major pieces of equipment (e.g., pumps, compressors, engines, motors, and electrical transformers) are put into place. Equipment such as scraper traps and meter assemblies are often constructed off-site at a fabrication shop, hauled to the site, and set into place. The equipment is then tied together, assembling pipe, fittings, valves, and other components to tie in the flow paths.

The installation of the electrical and control equipment proceeds in much the same way. The major components, electrical switchgear, control panels, and flow computers, are often installed into modular control buildings constructed off-site. Then they are hauled to the site and placed onto foundations waiting to receive them. Other equipment, such as transmitters, actuators, and switches and sensors, is installed. Finally, cable and wires are pulled through conduits and placed in cable trays, hooking all the equipment together.

During the installation process and once more when everything is completed, electricians conduct testing. They ensure everything is connected together and works correctly before starting the station.

Cleanup and Restoration

Following construction, the sites and the route are cleaned up. Crews remove any remaining trash and haul off temporary bridges and other facilities installed during construction. They rebuild river and stream banks, replace topsoil, plant specialized grass, and build terraces and water bars across hillsides to keep them from washing out. They also make final repairs to roads, fences, or other crossings. They restore the route (as close as is practical, consistent with safe operations) to its original condition.

Handoff for Operations

Finally the construction contractor is ready to transfer responsibility for the line to the operating company. The transfer is not abrupt. Those people who will operate the line are usually involved during the construction process, sometimes as inspectors. The balance of the operating people will usually be brought to their locations for training and orientation several months before the completion of construction. They study equipment and operating manuals, receive training as required, and assist with commissioning to prepare for ongoing operations.

Documentation

One last task is documentation. This includes correcting the plans and drawings, turning them into *as built* drawings, reflecting not what was planned, but what was actually constructed. Often these two are quite different. It also includes ensuring all the correct information about the myriad of pumps, motors, compressors, valves, transmitters, flow computers, and other equipment is properly filed for later reference. Operators and maintenance people think kindly of construction engineers and contractors who leave them complete and accurate documentation. Unimaginably disparaging remarks are directed toward those who do not.

Eventually these tasks are completed. The construction workers take a final look, produce handsome plaques and other endearing mementoes commemorating the project, and move on to the next job.

Satisfying Stakeholders

It is our responsibilities, not ourselves, that we should take seriously.
—Peter Ustinov (1921–2004)

Every pipeline company's second-worst nightmare unfolds at the Administrative Law Judge's hearing room. Outside the building, a ragtag group holds placards and chants sound bites for the local news station cameras. Inside, at the applicant's table, sit attorneys and management for a pipeline proposed to pass near a heavily populated community.

In the plaintiffs' section sit dozens of people, some with boxes of documents, some with scowls, and some with children in tow. Thirty residents are registered to speak. These include a mayor, a marina manager, a parks administrator, a representative of AARP, a fire chief, the presidents of five homeowners associations, and representatives of 27 other organizations.

A member of CAPON, the Coalition to Assure the Protection of Our Neighborhood, is passing out loose-leaf binders. The following sections are tabbed: environmental impact of pipelines; economic disruption of pipeline construction; explosions and other safety concerns; protecting your right-of-way; and bargaining with pipelines.

Introduction

While it sounds grandiose, nearly everyone in the world has a stake in the oil and natural gas pipeline industries. They are stakeholders because their standard of living depends on the oil and gas moving quietly through pipelines, 24 hours a day, seven days a week.

Pipelines are largely buried and unseen. Communities grow up along their routes, and the people living in those communities sometimes do not even know the pipeline exists until there is a supply disruption or other problem.

Against this need for energy, and the lack of familiarity with its transport, the spectacular nature of some pipeline failures can be juxtaposed. Pictures of fireballs associated with natural gas pipeline leaks, animals killed, and waterways soiled by an oil pipeline leak make eye-catching news. Sometimes these images create the impression pipelines are not safe. Pipeline accidents do happen, as do tanker truck, rail car, barge, and ship accidents. However, pipelines move more ton-miles of oil with less incidents than any other forms of transportation.¹ (One ton moved 1 mi equals 1 ton-mile; 1 bbl moved 1 mi equals 1 barrel-mile.) There are no comparative statistics for natural gas transportation by pipelines versus other modes of transportation. This is because moving natural gas by transportation means other than pipeline (except for LNG ships) is uneconomic.

In any event, the key challenge oil and natural gas pipeline companies face is balancing the energy supply and safety needs of all stakeholders. They also must consider the desires of the numerous other stakeholders, each with a unique agenda.

Stakeholders

It is easy for pipeline companies to identify some stakeholders. They already know almost everyone in the world depends on them to deliver energy. At the same time, the composition of the most relevant stakeholders continuously changes as their different needs are encountered. Figure 14–1 shows the stakeholders surrounding pipeline companies.

With all these stakeholders maneuvering for position, it is sometimes difficult for pipeline companies to remain focused on the two main needs: safety and a secure, dependable supply.

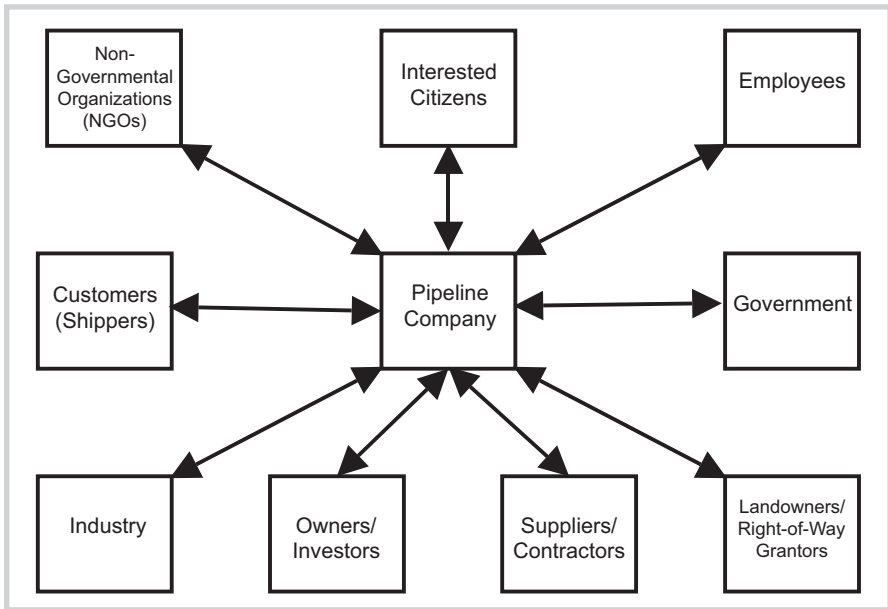


Fig. 14-1. Major pipeline stakeholders

The following discussion of the stakeholder groups may give the impression that each person fits neatly into one group or another. However, any stakeholder can belong to several groups. A person can be an owner, customer, interested citizen, and part of a *nongovernmental organization* (NGO). Another can be a landowner, customer, employee, and part of a governmental group, such as a local volunteer fire department.

Owners

Pipelines are ultimately owned by people. Ownership may be direct, by a partnership or corporation, or indirect, as an individual. The direct owners are generally involved in making decisions and operating the line. Many individual owners do not even realize they have an interest in a pipeline. Their ownership may come through stock, ownership, pension plans, and mutual funds, or through citizenship in a country with state-owned pipelines. With the usual exception of state-owned pipelines, the primary interest of direct owners is to earn a return on their investment. They want to make money. Indirect owners may or may not subscribe to this objective.

Customers

Customers expect reliable, low-cost, high-quality services. Pipeline customers are a complex group, spanning the oil and natural gas value chain. They could be producers who depend on pipelines to move oil and gas to market. They could also be the ultimate consumers who depend on pipelines to supply gasoline or diesel fuel to power their transportation needs, or natural gas and fuel oil to keep them warm and to power their businesses.

Landowners and neighbors

Landowners and neighbors, those who own the land that pipelines traverse and those who live near a pipeline route, expect to feel safe and be fairly treated. However, notions of safe feelings and fair treatment vary by person and are difficult to define. To some, fair treatment means staying away from their property entirely; to others it means receiving maximum payment for use of their land. Only sometimes, as in rural areas, is it easy to keep pipelines away from houses (fig. 14–2).



Fig. 14–2. Rural ROW. The pipeline runs through a rural area, making it easy to avoid houses. (Courtesy Miesner, LLC)

Residential and commercial developments grow up around pipelines, creating imperatives for pipeline companies and developers to work together (fig. 14–3).



Fig. 14–3. Suburban ROW. Two pipelines snake between a shopping center and a housing development. In this case, the subdivision and pipeline companies cooperated to build a green belt with a walking path. (Courtesy Miesner, LLC)

In the case of figure 14–3, a pipeline was installed well before the developer bought the land. When the homeowners bought the property from the developer, they also bought the fact that the pipeline runs near their home. They may have not even realized a pipeline ran through the green belt close to their back yards. They have inherited the risks but probably received none of the compensation given the original landowner.

Landowners and neighbors, particularly those opposed to pipelines (or at least pipelines close to them) sometimes feel they bear a disproportionate share of the burden of ensuring a secure energy supply. They do enjoy the benefits of affordable and reliable energy delivery from the pipeline, but the pipeline passing through their backyards also benefits people living miles away.

Governments

National and state legislators and regulators, local authorities, and emergency response personnel have very similar needs. They want to ensure that their constituents, comprising the collection of stakeholders, are safe and happy. They also want to provide their citizens a reliable supply of energy at low cost. (Furthermore, they also want to keep their positions.)

Regulators do their best to understand pipelines and how to improve their safety. Often they are caught in a dilemma. They realize pipelines are generally safe but understand the public expects *zero failures*, a goal that is virtually impossible to achieve. They take a carrot-and-stick approach, penalizing pipeline companies for failures, and funding research and development to improve materials, equipment, and operating practices.

The needs of emergency response authorities, primarily fire and police, include knowing how to respond to an emergency. They need more training than do the other governmental stakeholders.

Nongovernmental organizations

The World Bank defines NGOs as “private organizations that pursue activities to relieve suffering, promote the interests of the poor, protect the environment, provide basic social services, or undertake community development.”² Such groups could include the Red Cross, the Sierra Club, and the Ogoni Community Association of Nigeria. Some people think more broadly of NGOs as *special interest groups*, advocacy groups, or any collection of people interested in a particular issue or cause. People or companies can form ongoing NGOs or ones that simply fade away after dealing with their issue. NGOs that impact pipelines are mostly advocacy groups. They typically are groups with a special interest in protecting the environment, animals, fish, a specific way of life, or the value of their constituents’ property.

Competing interests may fund advocacy groups. For example, the maritime industry may try to stop pipeline construction into coastal areas that would eliminate barge transportation. Pipeline companies may form an advocacy group to promote the project. The purposes of these advocacy groups and special interest groups are the same—to advance their issues, sometimes to the exclusion of all others.

Interested citizens

Media coverage of pipeline failures, new pipeline projects, limited supply, or high prices makes people stop for a second look. Some become interested, wanting to learn more. When they get information, they may move from this category to another stakeholder group. The Internet provides individuals who become interested in pipeline issues a forum to start new groups that can quickly move to NGO status. But if they just stay interested citizens, their need is for information. This stakeholder group is an unorganized assortment of people. Understanding their needs, beyond their interest in information, is difficult.

Industry

In general, the public does not differentiate between pipeline companies. Failures by one affect the public's perception of all. That gives pipeline companies an incentive to work together to develop standards, share best practices, and sponsor research and development aimed at promoting safe operation. Most pipeline companies understand the expectation that there will be no safety breaches or environmental incidents. They also wrestle with the law of diminishing returns—each improvement may cost more than the previous. Since most stakeholders lump all pipelines into a common perception, the industry forms organizations that promote performance excellence from all members of the industry, even globally.

Suppliers and contractors

Closely connected to the industry are suppliers and contractors, those who manufacture and sell equipment and build and maintain pipelines. Their need is to make money, and they compete, sometimes aggressively, against each other to do so. Individual companies routinely work to develop new equipment, products, and approaches. Their goal is to convince the pipeline companies that what they are selling is better than what their competitor has.

While each company wants to excel, related suppliers sometimes form industry associations to promote their common approach. ILI vendors, for example, formed the Inline Inspection Association to develop and propose best practices for ILI. Members want to protect their ideas from infringement by others but also want to promote their part of the industry. They compete for research and development funding to improve products and services.

Competitors

The days are long gone when competing teamsters (those driving teams of horses and mules, not the union) opposed pipelines by tearing them apart. Opposition today is more subtle—announcing a competing expansion, aggressively intervening in the permitting process, or funding citizen groups to oppose the line.

Employees

Employees, the smallest stakeholder group, are fathers, mothers, sons, and daughters. Their needs are the same as any other group of employees—safety, security, good pay, job satisfaction, a social contact, and recognition.

Media

A special case is represented by the media. While not directly stakeholders, the media influence stakeholders' perceptions about the industry and individual companies. Members of the media may aggressively report pipeline failures and controversies surrounding new pipeline projects. However, sensational stories are often considered more newsworthy than the good news stories, a fact that creates a tension with the industry. When something occurs, the media need timely, factual information. Most also have a need to further their own companies and careers.

An Act of Congress

The crude oil pipeline across Alaska might be a symbol of the quintessential stakeholder accord. On February 18, 1968, an Arco/Humble/British Petroleum consortium announced a discovery that would turn out to be the largest oil deposit in the United States. A year later, they made known their plans for the Trans-Alaska Pipeline System (TAPS), a line from the oilfield at Prudhoe Bay on Alaska's north coast to Valdez, 800 mi south.

Along the way to achieving approval to construct the line, the three oil giants had to mollify, bargain with, compromise with, and otherwise contend with an impressive array of stakeholders. These included:

- **Alaska natives.** Aleuts, Indians, and Eskimos had long-standing land claims against various governments. The Alaska Natives Claims Settlement Act of 1971, a direct result of the escalating TAPS debate, gave 70,000 people among these groups 44,000 acres and a share of the Prudhoe royalties.
- **States rights.** The citizens of Alaska and their state government saw huge riches available to them from the Prudhoe royalties. They have since enjoyed billions of dollars in direct payments, collectively and individually.
- **Environmentalists.** The National Environmental Policy Act had just passed in 1969, requiring extensive—and legally challengeable—environmental impact statements before any federal permits could be issued. Scores of emergent organizations litigated and lobbied their fears about the destruction of the Alaska tundra flora and fauna, among other things. They forced extraordinary safeguards to be included in the pipeline construction.
- **Security concerns.** U.S. oil imports were rising at rates that alarmed many. Indeed, several OPEC countries had already nationalized or confiscated oil company assets that were producing millions of barrels per day.

Litigation in the state and federal courts lasted through 1971. Resolution of numerous conflicts required bitter national debate and finally an act of Congress. This was passed by Spiro Agnew's tie-breaking vote in the Senate and became law on August 2, 1973.

Eleven weeks later, OPEC announced an oil embargo against the United States, precipitating the first modern oil crisis and tripling oil prices.

TAPS, by then renamed Alyeska pipeline, started pumping oil in June 1977, nine years after the decision to build.

Balancing Needs and Wants

The two needs affecting the largest number of stakeholders fit broadly into the categories of safety (both human and the environment) and dependable supply. Pipeline companies must meet these two needs before they can make progress toward balancing the many other stakeholder wants.

Safety

“Performance Excellence Is No Accident” is a statement posted on office walls. Is it possible to avoid all accidents? The answer, for pipeline accidents, just as for automobile and airplane accidents, as everyone knows, is *no*. Accidents damage pipelines’ reputations, injure people and the environment, cost money, and are used as reasons to keep new facilities from being built. This occurs even when the new facilities are sorely needed to supply transportation and heating fuels. How do pipeline companies operate to prevent accidents and recover from them when they happen?

Returning to the car analogy, the design and construction of the car, the development and maintenance of the roadways, the training of the driver are all designed to encourage safety and mitigate accidents. Nevertheless, accidents happen, so there are insurance companies, tow trucks, ambulances, and hospitals in which to recover.

In the same way, pipeline companies use all the approaches previously covered in this book, including maintenance programs, training, control systems, improved components, and safer designs. They also work on improved industry standards, best practices sharing, hazards analysis, research and development, managing processes, and public education.

Industry standards. The pipeline industry has a long history of cooperation. Pipeline companies share knowledge and develop recommended practices and standards, thereby helping to ensure sound design and operations and improve safety. The API, established on March 20, 1919, is one such organization. Most other countries also have similar standards organizations, and the International Standards Organization (ISO) has harmonized many of the standards into international standards. Not all countries have adopted the ISO standards. Some say that national pride and reluctance to change stand in the way. Others allege local contractors and suppliers do not want to be exposed to the new competition tighter standards might bring.

Developing standards is usually an extended process, because the standards organization tries to meet the needs of all.

Best practices sharing. A step away from industry standards is sharing best practices. Companies meet, sometimes on a formal basis, and sometimes on an ad hoc basis, to discuss how they build and operate pipelines. Improvement through best practices sharing is often quicker than developing standards. When a company learns of a better process, it can be implemented quickly.

Hazards analysis. There are numerous hazard analysis techniques, including Hazards and Operability Study (HAZOP), Failure Modes and Effects Analysis (FMEA), and Major Hazards Analysis (MHA). Hazards analyses are performed to identify and think through abnormal operations, and unplanned events or situations that precipitate an accident. They usually involve a trained expert leading a team of experienced technical and operating people. They think through multiple scenarios and identify what could happen and how to prevent it or mitigate the consequences. The hazards analysis learnings are incorporated into new designs or are used to modify existing facilities or operating practices.

Research and development. New or improved materials, construction and maintenance practices, instruments, and operating procedures can improve safety, increase reliability, or reduce costs. These efforts can be funded by individual pipeline companies, consortiums of companies, governmental agencies, vendors, or a combination of all four. Research and development is an investment in the future paid for with today's dollars.

There is a wide diversity of groups participating in the pipeline research efforts, from industry to government to commercial vendors and suppliers. Thus selecting the research and development areas and supplying investment dollars can be contentious. It is unlikely all these interests can be arrayed within one decision-making structure. However, it is possible they can work together in a "virtual" research environment. This would foster collaboration through information sharing, joint project funding and development, and cooperative technology transfer.

Managing processes. Process Safety Management (PSM) was promulgated by the U.S. Occupational Safety and Health Administration (OSHA), on February 24, 1992. It provides one framework for developing

a managing process. These processes normally break down a company's activities into its major components or elements. There are many areas that PSM addresses:

- Employee participation
- Process safety information
- Process hazard analysis
- Operating procedures
- Training
- Contractor safety
- Prestartup safety review
- Mechanical integrity
- Hot work permit
- Management of change
- Incident investigation
- Emergency planning and response
- Compliance audits

Dividing processes into their subparts is the primary focus of the effort. It can sometimes become unwieldy, weighted down by a mountain of paper. However, used correctly, it can provide valuable training and documentation tools. One of the most critical elements is *management of change*, which establishes how equipment and operations changes are approved and implemented.

Public education. Excavators, public officials, emergency response personnel, and those living along the pipeline can be effective in improving safety. To do so they must know how to prevent third-party damage and respond to accidents when they occur. Excavators should know how to locate pipelines and other underground utilities before they dig, as well as know how to dig carefully. Public officials, particularly planning and zoning officials, need to know about pipelines, their locations, and what precautions to take around pipelines. This will aid them in facilitating safe development along the pipeline route. Emergency response personnel should be trained to respond to pipeline accidents, including conducting periodic drills and simulations. Finally, landowners, if properly trained, can serve as the pipeline company's eyes and ears, reporting any excavation or other activity along the pipeline.

Supply

There is no end in sight in the growth of oil and natural gas demand anywhere in the world. New pipelines and expansions of existing pipelines will inevitably be required to satisfy the expanding markets. If pipeline companies satisfy the stakeholders' safety and environmental requirements, they will retain the privilege of working to meet their supply needs.

Supplying short-term needs requires having enough current capacity and avoiding interruptions caused by poor maintenance or operations. Meeting long-term needs requires expanding current pipelines or building new pipelines as required. However, building new pipelines requires permitting, where the myriad of stakeholder needs comes into play.

Refined product quality specifications. In the quest for reduced emissions and cleaner air, governments are promulgating new fuel regulations, sometimes sharply driving up the number of fuels pipelines have to handle. In general, refined products pipelines were designed to handle three grades of gasoline and two grades of distillate. Today, they handle multiples of that. Increasing the number of grades calls for more individual tanks and different operating procedures to segregate each grade and protect its quality. So oil pipeline companies face the prospect of constructing more tanks, limiting the grades they handle, or changing operations practices. All of these require investment to maintain current capacity.

Natural gas quality issues. The value of natural gas is driven by the energy content it contains, driving producers to include as much energy in the gas as possible. (The topic of extracting molecules other than methane from the natural gas stream was discussed in earlier chapters.) But the quest for higher efficiency hot water heaters, stoves, furnaces, and other home appliances, as well as industrial equipment, drives them to a narrower quality band. When the energy contained in the natural gas stream exceeds the energy band of the appliance or equipment, disastrous results can follow. Consequently, natural gas pipeline companies face a growing job of policing the quality of the suppliers' inputs.

Other wants

Covering all the other wants of the myriad of stakeholders would be nearly impossible. Some of the most basic include funding, visual beauty, property rights, cultural and spiritual traditions, endangered species, and the right to be heard. While it may not be true, it has certainly been said that everyone has a price. Opposition to new construction by certain groups sometimes disappears when pipeline companies agree to fund favorite projects of various organizations.

The rights of the many to have secure energy supplies sometimes clash with the rights of the few to use their property as they see fit, preserve the culture they desire, or even preserve endangered species. For example, pipelines normally keep their ROWs cleared and post signs to protect the pipeline and the public. However, cleared ROWs can be unsightly, particularly through natural areas. In each case, compromise is crucial.

Finally, the right of each individual to be heard versus the right of the many for energy can also become an issue.

Conclusion

If the court room proceeding is the second-worst nightmare, what is the worst? The worst nightmare is a large leak with associated loss of life and environmental and property damage. It is hard to imagine an energy future that does not include oil and natural gas pipelines. They are integral to the global economy, doing their job of hauling much of the world's energy needs. But the attendant risk of that nightmare, although remote, still remains. So how do pipeline companies mitigate its likelihood?

The answer is that they cannot do so by themselves. All of the varied stakeholders have a role in continued supply and pipeline safety, demanding that all work together collaboratively to achieve a safe and reliable supply of energy. Nonetheless, at the end of the day, the burden ultimately falls on the pipeline companies. Using robust design, public education, dependable SCADA, careful operating practices and processes, and strong leadership, they can move toward seeing that it all happens without interruption and without error.

References

1. Association of Oil Pipe Lines. "Safety Record—Accident Rates of Petroleum Transportation Methods," Retrieved July 28, 2005, from: <http://www.aopl.org/safety/record.html>
2. Duke University, Perkins Library, Public Documents and Maps Department. "Categorizing NGO's—Definition," *Non-Governmental Organizations Research Guide*, p. 1. Retrieved July 28, 2005, from: <http://docs.lib.duke.edu/igo/guides/ngo/define.htm>

Appendix

Abbreviations and Acronyms

AC	alternating current
ACT	automatic custody transfer
ACVG	alternating current voltage gradient
AGA	American Gas Association
AOPL	Association of Oil Pipe Lines
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing of Materials International (formerly American Society for Testing and Materials)
bbbl	barrel(s)
bpd	barrels per day
bph	barrels per hour
BS&W	basic sediment and water
BTU	British thermal unit
cf	cubic feet
CIPS	close interval potential survey
CONCAWE	Conservation of Clean Air and Water in Europe
CPM	computational pipeline monitoring
CTE	coal tar enamel
DA	direct assessment
DC	direct current
DCVG	direct current voltage gradient
DT	dekatherm, million British thermal units
ERW	electric resistance welding
FBE	fusion bond epoxy

FMEA	Failure Modes and Effects Analysis
FPS	floating production system
FPSO	floating production, storage, and off-loading
ft	feet
gal	gallon
GP	general partner
GPS	global positioning system
HAZOP	Hazards and Operability Study
HDD	horizontal directional drilling
HMI	human-machine interface
Hz	hertz
IGV	inlet guide vanes
ILI	internal line inspection
IMP	integrity management plan
in.	inches
INGAA	Interstate Natural Gas Association of American
ISO	International Standards Organization
LACT	lease automatic custody transfer
LDC	local distribution company
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MAOP	maximum allowable operating pressure
Mcf	thousand cubic feet
Mcfd	thousand cubic feet per day
MDT	thousand dekatherms
MFL	magnetic flux leakage
MHA	Major Hazards Analysis
mi	mile
MLP	master limited partnership
NBP	National Balancing Point (pipeline hub in the United Kingdom)
NGL	natural gas liquids
NGO	nongovernmental organization
NPSH	net positive suction head
NPV	net present value
NTSB	National Transportation Safety Board

OSHA	Occupational Safety and Health Administration
OTA	Oil Transportation Association
P&ID	process and instrumentation diagram
PD	positive displacement
PHMSA	Pipeline and Hazardous Materials Safety Administration
ppm	parts per million
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PSM	process safety management
RGLC	Rochester Gas Light Company
ROV	remotely operated vehicle
ROW	right-of-way
rpm	revolutions per minute
RVP	Reid Vapor Pressure or pounds Reid Vapor Pressure
SCADA	supervisory control and data acquisition
SCC	stress corrosion cracking
scf	standard cubic foot
SI	International System of Units
SMYS	specified minimum yield strength
SPR	Strategic Petroleum Reserve
t	tons
TAPS	Trans-Alaska Pipeline System
USC	U.S. Customary System
UT	ultrasonic testing
VFD	variable frequency drive
VSD	variable speed drive

Index

A

Abbreviations, 335–337

Abnormal operations (central control room), 84–85, 106–107:
valve closure/shutdown, 84;
pressure or flow rate increase/decrease, 84–85;
loss of communications, 85;
safety device operation, 85

Absolute pressure, 44

Absolute viscosity, 40

Acceleration, 36

Accessibility (market), 27–28

Accuracy (leak detection), 161

Acoustic/negative pressure wave, 166

Acronyms, 335–337

Actuators, 246

Alarms/alarm filtering (SCADA), 153–155:
station discharge pressure, 154;
station sequence, 154;
station sump level, 154;
station manifold, 154;
unit pressure, 154;
pump suction pressure, 155;
unit bearing temperature, 155;
motor winding temperature, 155;
unit temperature, 155;
unit vibration, 155

Alaska North Slope pipeline, 27

Alignment clamps, 306

Alternating current voltage gradient (ACVG), 196

Alyeska pipeline, 27–28, 328:
history, 328

American Gas Association (AGA), 170

American Petroleum Institute (API), 170

American Society of Mechanical Engineers (ASME), 170

Ancillary station equipment, 296

Anhydrous ammonia, 1

Anodes, 184

API gravity, 38–39

Application interface (SCADA), 150

As built drawings, 319

Aseismic faulting, 178

Associated gas, 14–15, 89

Association of Oil Pipe Lines (AOPL), 170

Attached risers, 131–132

Automation/automatic control, 63–64, 143, 308–309:
manual control, 143;
ultrasonic inspection, 308–309

Azerbaijan, 19–20

B

Backfilling, 312

Baku pipeline, 29–20, 27

Balancing needs and wants (stakeholders), 329–333:
safety, 329–331;
supply, 332;
other wants, 332–333

Ball valves, 240–241

Barlow's formula, 276–277

Basic sediment and water (BS&W), 61

Batch following, 70–71

Batching, 3, 26, 31–32, 65–66, 68–72:
 batch following, 70–71

Bearing temperature, 155

Bell hole, 315

Bends (pipe), 312–313

Bernoulli's principle (equation), 48–49, 95,
 263

Best practices sharing, 330

Block valves, 298

Book value, 228

Booster stations, 72, 294

Bottom conditions, 131

Boyle's law, 45

Brake horsepower curve, 256

BTU content, 6, 37, 91–92, 96

Building pipeline (investment), 213–228:
 why build, 213–214;
 who decides, 214–215;
 decision making, 216–223

Bulk modulus, 45, 164–165

Bulk plants, 289

Buoyancy, 124

Buried pipelines, 176–180

Business models, 21–22

Bypass control, 285

C

C2 products, 111

C3 products, 111

C4 products, 110

Caliper pig, 316

Camisea pipeline, 217

Carbon dioxide, 1, 26

Cash flow analysis, 226–227

Caspian Sea, 19–20

Catenary riser, 132–134

Cathodic protection, 184–185, 192–194, 210:
 maintenance, 192–194;
 cathodic test lead station, 192–194

Cathodic test lead station, 192–194

Cavitation, 252

Central control, 142–143:
 local control, 142–143

Central control room (crude oil), 59–85:
 field operations, 59–63;
 control room operations, 63–85;
 operator training, 85

Central control room (natural gas), 94–107:
 field operations, 94–100;
 control room operations, 100–107;
 operator training, 107

Central control room operations (crude oil),
 63–85:
 planning and scheduling, 65–66;
 scheduler's role, 66–68;
 controller's role, 68–72;
 hydraulic concepts (mainline), 72–79;
 routine, 80–83;
 abnormal, 84–85;
 operator training, 85

Central control room operations (natural gas),
 100–107:
 planning and scheduling, 101–103;
 monitoring and controlling, 103–104;
 hydraulic concepts, 104–105;
 routine, 105;
 quality control, 106;
 abnormal, 106–107;
 operator training, 107

Centrifugal compressors, 252–257:
 performance, 256–257;
 control, 257

Centrifugal pumps, 252–257:
 performance, 256–257;
 control, 257

Charles' gas law, 45–46

Check valves, 243–244

Chemical liquids, 1

Citizen stakeholders, 326

City gates (natural gas delivery), 99–100

Clapper disc, 243

Clean Water Act of 1972, 224

Cleaning and sizing (pipeline), 316

Cleanup and restoration (site/route), 318

Close interval potential survey (CIPS),
 195–196:
 DCVG combined, 196

Coal gas, 9–10

Coal tar enamel (CTE), 234

- Coating repairs, 208–209
- Coatings, 208–209, 232–236:
 - repairs, 208–209;
 - fusion bonded epoxy, 233;
 - coal tar, 234;
 - plastics, 234;
 - tapes, 234–235;
 - shrink sleeves, 235–236;
 - concrete, 236
- Command processing time (SCADA), 156
- Commissioning/decommissioning, 114–115, 317:
 - freezing temperatures, 114–115
- Commodity diversity, 26
- Common Ground Alliance (CGA), 180
- Communications (SCADA), 143–146, 155:
 - design, 144–145;
 - redundancy, 146;
 - latency, 155
- Communications loss, 85
- Communications system, 85, 105, 143–146, 155:
 - SCADA, 143–146, 155;
 - design, 144–145
- Comparable sales, 227
- Compensated mass balance, 165
- Competitors as stakeholders, 327
- Compliant tower, 133
- Components, 229–267:
 - pipe, 229–232;
 - coatings, 232–236;
 - fittings and flanges, 236–238;
 - valves, 238–245;
 - actuators, 246;
 - pumps and compressors, 247–257;
 - prime movers, 257–259;
 - variable speed devices, 260;
 - meters, 261–265;
 - provers, 265–266;
 - other, 267;
 - references, 267
- Compressibility, 35, 44–46, 112:
 - petrochemical, 112;
 - LPG, 112
- Compression ratio, 282–283
- Compressor stations, 5, 97–99, 247–257, 282–283, 293–294:
 - operations, 97–99;
 - design and layout, 293–294
- Compressors, 247–257, 282–283:
 - positive displacement, 247–252;
 - centrifugal, 252–257;
 - selection, 282–283
- Computer decision making, 141–142:
 - vs. human, 141–142
- Concrete coating, 236
- Configuration tool (SCADA), 150
- Consequences (risk analysis), 198
- Conservation of Clean Air and Water in Europe (CONCAWE), 170
- Consolidators, 21
- Construction (pipeline), 24, 124–131, 299–319:
 - subsea pipeline, 24, 124–131;
 - permitting, 300;
 - contracting and procurement, 300–301;
 - right of way and land acquisition, 301–302;
 - inspection requirements, 302;
 - staking the line, 302–303;
 - construction spreads, 303;
 - right of way preparation, 303–304;
 - stringing, 304–305;
 - welding, 305–308;
 - weld inspection, 308–309;
 - trenching, 309–310;
 - lowering in, 310–311;
 - backfilling, 312;
 - bends, crossings, and tie-ins, 312–316;
 - quality control, 316;
 - cleaning and sizing, 316;
 - hydrostatic testing, 317;
 - commissioning, 317;
 - station construction, 317–318;
 - cleanup and restoration, 318;
 - handoff for operations, 318;
 - documentation, 319
- Construction (subsea pipeline), 24, 124–131:
 - pipelaying vessels, 24, 125–131;
 - buoyancy, 124;
 - laying pipe, 125;
 - S-lay, 125–126;
 - J-lay, 126–127;
 - reel barge, 128–129;
 - tow-in, 130–131
- Construction data, 202
- Construction flaws, 175–176
- Contracting and procurement, 300–301
- Contractors as stakeholders, 327
- Control philosophy, 139

- Control room (crude oil), 59–85:
 - field operations, 59–63;
 - control room operations, 63–85;
 - operator training, 85
 - Control room (natural gas), 94–107:
 - field operations, 94–100;
 - control room operations, 100–107;
 - operator training, 107
 - Control room operations (crude oil), 63–85:
 - planning and scheduling, 65–66;
 - scheduler's role, 66–68;
 - controller's role, 68–72;
 - hydraulic concepts (mainline), 72–79;
 - routine, 80–83;
 - abnormal, 84–85;
 - operator training, 85
 - Control room operations (natural gas), 100–107:
 - planning and scheduling, 101–103;
 - monitoring and controlling, 103–104;
 - hydraulic concepts, 104–105;
 - routine, 105;
 - quality control, 106;
 - abnormal, 106–107;
 - operator training, 107
 - Control system design and operation (SCADA), 141–158:
 - human vs. computer decision making, 141–142;
 - local or central control, 142–143;
 - manual or automated control, 143;
 - communications, 143–146;
 - human–machine interface, 146–147;
 - real-time operating data, 147–149;
 - configuration tool, 150;
 - application interface, 150;
 - historic database, 150–151;
 - amount of data to gather, 151;
 - update frequency, 151–152;
 - update process, 152;
 - corrupted data, 152–153;
 - indicators, alarms, and alarm filtering, 153–155;
 - SCADA performance, 155–158;
 - data sharing, 156;
 - reports and logs, 156–157;
 - security, 157;
 - SCADA summary, 157;
 - local SCADA, 158
 - Controller's role (central control room), 68–72:
 - batch following, 70–71;
 - transmix minimizing, 71–72
 - Coriolis meters, 265
 - Corrosion, 91, 170, 173–174, 184–186:
 - prevention, 184–186
 - Corrupted data (SCADA), 152–153
 - Cost of alternative transportation, 221
 - Cost of service, 222
 - Crossings, 177–178, 297–298, 312, 314–315
 - Crude oil pipeline operations, 57–86:
 - crude oil, 57–58;
 - refined products, 58;
 - field operations, 59–63;
 - central control room operations, 63–85;
 - references, 86
 - Crude oil pipelines, 2–4, 12–15, 21–22, 57–86, 285–286:
 - gathering lines, 2–4;
 - mainlines, 2–4;
 - history, 12–15;
 - oil products, 21–22;
 - operations, 57–86;
 - flow and pressure control, 285–286
 - Crude oil, 2–4, 7, 12–15, 21–22, 38–39, 57–86, 285–286, 289–291:
 - pipelines, 2–4, 12–15, 21–22, 57–86, 285–286;
 - storage, 3, 289–291;
 - refinery/refining, 4, 7, 12–13, 15, 58;
 - pipeline operations, 57–86;
 - receipt and delivery, 59–62;
 - flow and pressure control, 285–286
 - Crude oil receipt and delivery (field operations), 59–62
 - Crude oil refinery/refining, 4, 7, 12–13, 15, 58
 - Crude oil storage, 3, 289–291:
 - location, 289;
 - number and size of tanks, 290–291
 - Current drop survey, 195
 - Customers as stakeholders, 324
- ## D
- Damage (equipment), 170–172, 180–187:
 - prevention, 170–172, 180–187;
 - planning and design, 180;
 - one-call centers, 180;
 - locating and marking, 181–182;
 - excavation, 182;
 - maps, 182;
 - regulations and compliance, 182;

- public education, 182–183;
 - route monitoring, 183;
 - reporting and evaluation, 183
 - Damage prevention, 170–172, 180–187:
 - equipment damage, 170–172, 180–183;
 - corrosion, 184–186;
 - mechanical failures, 186;
 - natural hazards, 186–187;
 - other causes, 187
 - Data (risk analysis), 202
 - Data gathering (SCADA), 151
 - Data sharing, 156
 - Decision making (investment), 216–223:
 - demand and supply, 216–218;
 - economics, 218–223
 - Decision making, 141–142, 214–223:
 - SCADA, 141–142;
 - investment, 216–223
 - Decommissioning/commissioning, 114–115:
 - freezing temperatures, 114–115
 - Definitions, 109–110
 - Deflection tools, 189
 - Delivery stations, 295
 - Demand and supply, 216–218
 - Demand-driven scenario, 216
 - Densitometer, 70
 - Density (hydraulics), 35, 37–39, 46, 50, 70:
 - API gravity, 38–39
 - Deposited weld metal, 208
 - Depth of cover, 209
 - Design and control (SCADA), 141–158:
 - human vs. computer decision making, 141–142;
 - local or central control, 142–143;
 - manual or automated, 143;
 - communications, 143–146;
 - human-machine interface, 146–147;
 - real-time operating data, 147–149;
 - configuration tool, 150;
 - application interface, 150;
 - historic database, 150–151;
 - amount of data to gather, 151;
 - update frequency, 151–152;
 - update process, 152;
 - corrupted data, 152–153;
 - indicators, alarms, and alarm filtering, 153–155;
 - SCADA performance, 155–156;
 - data sharing, 156;
 - reports and logs, 156–157;
 - security, 157;
 - SCADA summary, 157;
 - local SCADA, 158
 - Design and engineering (pipeline), 269–298:
 - safety considerations, 270;
 - route selection, 270–271;
 - line size, wall thickness, and looping, 271–274;
 - systems curves, 275–276;
 - fittings, flanges, and valves, 276;
 - wall thickness and grade of pipe, 276–278;
 - looping, 278–279;
 - pump, compressor, and prime mover selection, 279–284;
 - flow and pressure control, 284–286;
 - number of stations, 286–287;
 - station location, 287–289;
 - storage, 289–292;
 - station design and layout, 293–296;
 - additional considerations, 297–298;
 - conclusion, 298
 - Design document, 218
 - Destination point, 148
 - Device status (operating data), 148
 - Direct assessment, 196–197
 - Direct current voltage gradient (DCVG), 196:
 - CIPS combined, 196
 - Direct volume meters, 261
 - Discharge pressure, 154
 - Documentation, 319
 - Dry gas, 90
 - Dry trees, 121
- ## E
- Earth station, 144–145
 - Economics (investment), 218–223:
 - investments, 218;
 - revenues, 218–222;
 - operating costs, 222–223
 - Economic value, 92–93, 226–227:
 - gas processing plants, 92–93
 - Eddy current couplings, 260
 - Elastic limit, 44
 - Electrical cable sensors, 167
 - Electrical potential, 185

Electrical surveys, 192–196:
 pipe-to-soil potential, 194;
 current drop, 195;
 close interval potential survey, 195;
 voltage gradients, 196;
 combined CIS and DCVG, 196;
 Pearson survey, 196

Electrical variable speed devices, 260

Electric motors (prime movers), 259

Elevation loss or gain, 51–53, 191–192

Employees as stakeholders, 327

Engines (prime movers), 258

Equations of state, 46

Equipment damage, 170–172, 180–187:
 prevention, 170–172, 180–187;
 planning and design, 180;
 one-call centers, 180;
 locating and marking, 181–182;
 excavation, 182;
 maps, 182;
 regulations and compliance, 182;
 public education, 182–183;
 route monitoring, 183;
 reporting and evaluation, 183

Ethylene, 1, 118–119

Evaporation and vapor pressure, 41–43

Events (real-time operating data), 149

Excavation (equipment damage), 182

External corrosion, 173, 185

External systems (leak detection), 162, 167–168:
 electrical cable sensors, 167;
 fiber optic sensors, 167;
 vapor and soil monitoring, 168;
 optical methods, 168

F

Failure modes and effects analysis (FMEA), 330

Fiber optic sensors, 167

Field operations to central control room (crude oil), 59–63:
 crude oil receipt and delivery, 59–62;
 refined products receipt and delivery, 62–63

Field operations to central control room (natural gas), 94–100:
 field operations, 94–99;
 delivery operations, 99–100

First law of thermodynamics, 33, 47

Fittings (pipeline), 236–238, 276

Fixed-interval reporting, 152

Flanges (pipeline), 236, 238, 276

Flexible pipe, 123

Flexible risers, 136

Floating production, shipping, and offloading vessels (FPSO), 133, 135

Floating production system (FPS), 133

Flow characteristics, 49–50

Flow computers, 95

Flow control, 100, 284–286:
 natural gas, 100, 285;
 crude oil, 285–286

Flowmeters, 261–266:
 positive displacement meters, 261–262;
 turbine meters, 262–263;
 orifice meters, 263–264;
 ultrasonic meters, 264;
 Coriolis meters, 265;
 meter provers, 265–266

Flow principles/equations, 47–54:
 first law of thermodynamics, 47;
 Bernoulli's equation, 48–49;
 flow characteristics, 49–50;
 friction loss, 50–51;
 elevation loss or gain, 51–53;
 flow rates and capacities, 54

Flow rate, 32–35, 54, 84–85:
 splitting flows, 34–35;
 capacities, 54;
 abnormal, 84–85

Fluid couplings, 260

Fluid flow physics, 29–31

Fluid mechanics, 34

Fluid properties, 35

Framework (risk analysis), 198–201

Freezing temperatures, 114–115

Friction factor, 30, 272

Friction loss, 30, 32–35, 50–51, 271–274:
 friction factor, 30, 272;
 splitting flows, 34–35;
 line size, 271–274;
 looping, 271–274;
 friction loss equations, 271–272;
 Reynolds number, 272–273;
 Moody diagram, 273–274

Friction loss equations, 271–272

Full encirclement split sleeve, 206

Fusion bonded epoxy (FBE), 233

G

Galvanic corrosion, 173

Gas behavior, 45–47

Gas distribution companies, 21

Gas field operations, 94–99:
 measurement, 94–97;
 stakeholder relations, 97;
 gathering station, 97;
 compressor station, 97–99

Gas flaring, 14

Gas hydrates, 89

Gaslights/gas lighting, 9–11, 14

Gas marketing, 14–15

Gas measurement, 94–97

Gas oil separation, 15

Gas pipeline operations, 87–107:
 natural gas pipelines, 88–93;
 gathering lines, 89–90;
 gas processing plants, 90–93;
 receipts from LNG facilities, 92;
 pipeline hubs, 93;
 field operations, 94–100;
 central control room operations, 100–107;
 operator training, 107;
 references, 107

Gas pipelines, 2, 5–6, 12, 14–15, 21, 87–107,
 285:
 history, 12, 14–15;
 operations, 87–107;
 flow and pressure control, 100, 285

Gas processing plants, 5, 90–93:
 slug flow and corrosion, 91;
 BTU content, 91;
 economic value, 92–93

Gas quality issues, 92–93, 332

Gas storage, 291–292:
 location, 291;
 management, 291–292;
 operations, 292;
 seasonal, 292

Gas transmission pipelines, 2, 6, 88–93,
 100, 285:
 gathering lines, 2, 89–90;
 gas processing plants, 90–92;
 receipts from LNG facilities, 92;
 flow and pressure control, 100, 285

Gate valves, 239–240

Gathering lines, 2–5, 89–90:
 crude oil, 2–4;
 natural gas, 2, 89–90

Gathering station operations, 97

Gauge pressure, 44

Gay-Lussac law, 45–46

Gear compressor, 248–249

Gear pump, 248–249

General partner (GP), 225

Geography traversed data, 202

Geometry tools, 189

Global positioning system (GPS), 195

Globe valves, 244–245

Government stakeholders, 325–326

Grade of pipe, 276–278

Gravimeter, 70

Gravity force, 32, 36, 53, 70

Grinding (stress concentrations), 207–208

Groundbeds, 185

Gulf of Mexico, 24

H

Handoff for operations, 318

Hazards analysis, 330

Hazards and operability study (HAZOP), 330

High-consequence area (HCA), 203

Highest and best use, 227

Historic data access time (SCADA), 156

Historic database (SCADA), 150–151

- History (pipelines/pipelining), 9–28:
 - gaslights, 9–11, 14;
 - natural gas pipelines, 12, 14–15;
 - crude oil pipelines, 12–15;
 - gas marketing, 14–15;
 - technology development, 16–18, 26;
 - teamster sabotage, 18;
 - railroad competition, 19;
 - Russia, 19–20;
 - business models, 21–22;
 - mileage expansion, 22–23;
 - offshore pipelines, 23–25;
 - commodity diversity, 26;
 - market accessibility, 27–28
 - Holiday detector, 310–311
 - Hoop stress, 276–278
 - Horizontal directional drilling (HDD), 297, 314–315
 - Human decision making, 141–142:
 - vs. computer, 141–142
 - Human-machine interface (HMI), 146–147
 - Hydrant system, 31
 - Hydraulic center points, 287–288
 - Hydraulic concepts (control room operations), 104–105
 - Hydraulic concepts (mainline operations), 72–79:
 - hydraulic gradient, 73–76;
 - line profile, 76;
 - maximum allowable operating pressure, 76–78;
 - combining concepts, 78–79
 - Hydraulic gradient, 73–76, 287–289
 - Hydraulic properties (hydrocarbon fluids), 35–47:
 - measures and dimensions, 35–36;
 - density, 37–39;
 - viscosity, 39–41;
 - pour point, 41;
 - vapor pressure and evaporation, 41–43;
 - pressure, 44;
 - compressibility, 44–45;
 - gas behavior, 45–47
 - Hydraulics, 35–47, 72–79, 104–105, 117–118, 287–289:
 - measures/dimensions, 35–36;
 - hydraulic properties, 35–47, 117–118;
 - hydraulic concepts, 72–79, 104–105;
 - hydraulic gradient, 73–76, 287–289;
 - petrochemical/LPG, 117–118;
 - hydraulic center points, 287–288
 - Hydraulics (petrochemical/LPG), 117–118
 - Hydrostatic testing, 190–192, 317
- I**
- Ideal gas, 45
 - Ideal gas law, 45
 - Impellers, 252–255
 - Impressed current, 184–185
 - Index method (risk ranking), 199, 201
 - Indicators (SCADA), 153–155:
 - station discharge pressure, 154;
 - station sequence, 154;
 - station sump level, 154;
 - station manifold, 154;
 - unit pressure, 154;
 - pump suction pressure, 155;
 - unit bearing temperature, 155;
 - motor winding temperature, 155;
 - unit temperature, 155;
 - unit vibration, 155
 - Industry stakeholders, 327
 - Industry standards, 329–330
 - Inference meters, 261
 - Information density, 147
 - Inlet guide vanes (IGV), 285
 - Inspection data, 202
 - Inspection requirements, 186–187, 302
 - Installing subsea pipelines, 124–131:
 - buoyancy, 124;
 - laying pipe, 125;
 - S-lay, 125–126;
 - J-lay, 126–127;
 - reel barge, 128–129;
 - tow-in, 130–131
 - Integrity management plan, 203
 - Interface material, 66
 - Internal corrosion, 173, 186
 - Internal line inspection (ILI), 187–190:
 - deflection tools, 189;
 - magnetic flux tools, 189;
 - ultrasonic tools, 189–190;
 - technology and tool research, 190
 - Internal systems (leak detection), 162–167:
 - parameter deviation, 163;
 - rate of change, 163;
 - line balance methods, 164–165;

- real-time transient modeling, 165–166;
 - acoustic/negative pressure wave, 166;
 - statistical analysis, 166;
 - shut-in pressure test, 166;
 - tuning, 167
 - International Standards Organization (ISO), 329
 - Interstate Natural Gas Association of America (INGAA), 170
 - Investment decisions, 213–228:
 - why build, 213–214;
 - who decides to build, 214–215;
 - decision making, 216–223;
 - economics, 218–223;
 - ownership changes, 224–225;
 - master limited partnerships, 225;
 - determining purchase and sales price, 226–228
 - Investment economics, 218–223:
 - investments, 218;
 - revenues, 218–222;
 - operating costs, 222–223
 - Investment portfolio, 224–225:
 - management, 224–225
- J**
- J-lay, 126–127
 - Jumpers, 121, 125
- K**
- Kinematic viscosity, 40
- L**
- Laminar flow, 49
 - Land acquisition, 301–302
 - Landowners and neighbors, 324–325
 - Latency (communications), 155
 - Law of conservation of mass and energy, 47
 - Leak detection, 112, 158–168, 170–180:
 - petrochemical/LPG, 112;
 - SCADA, 158–168;
 - systems, 160–162;
 - methods, 162
 - Leak detection (SCADA), 158–168:
 - leaks and releases, 159;
 - detection systems, 160–162;
 - detection methods, 162;
 - internal systems, 163–167;
 - external systems, 167–168
 - Leak detection systems, 160–162:
 - accuracy, 161;
 - reliability, 162;
 - robustness, 162
 - Leaks/releases, 106–107, 112, 158–168, 170–180:
 - leak detection, 112, 158–168, 170–180;
 - causes, 159, 170–180;
 - rate, 160;
 - location, 161;
 - equipment damage, 171–172;
 - corrosion, 173–174;
 - mechanical failures, 174–176;
 - natural hazards, 176–179;
 - other causes, 180
 - Lease automatic custody transfer (LACT), 61–62
 - Lease tanks, 59–60
 - Levant pipeline, 27
 - Line balance methods, 164–165
 - Line lowering, 209
 - Line pack, 54, 160–161
 - Line profile, 76
 - Line size, 271–274:
 - friction loss aspects, 271–274
 - Liquefied natural gas (LNG), 87, 92:
 - facilities, 92
 - Liquefied petroleum gas (LPG), 1, 109–119:
 - pipeline operations, 109–119;
 - definitions, 109–110;
 - product characteristics, 110–111;
 - compressibility, 112;
 - leak detection, 112;
 - measurement, 113;
 - quality control, 113–114;
 - commissioning and decommissioning, 114–115;
 - storage, 115–117;
 - hydraulics, 117–118;
 - supercritical fluids, 118–119
 - Local control, 142–143:
 - central control, 142–143
 - Local distribution company (LDC), 6, 21–22

Local distribution lines, 2, 6
Local SCADA, 158
Locating and marking (equipment damage), 181–182
Location differentials, 221–222
Looping, 271–274, 278–279:
 friction loss aspects, 271–274
Loss of communications, 85
Lowering in, 310–311
LPG pipeline operations, 109–119:
 definitions, 109–110;
 product characteristics, 110–111;
 compressibility, 112;
 leak detection, 112;
 measurement, 113;
 quality control, 113–114;
 commissioning and decommissioning, 114–115;
 storage, 115–117;
 hydraulics, 117–118;
 supercritical fluids, 118–119

M

Magnetic couplings, 260
Magnetic flux leakage (MFL), 189:
 tools, 189
Mainline operations hydraulics, 72–79:
 hydraulic gradient, 73–76;
 line profile, 76;
 maximum allowable operating pressure, 76–78;
 combining concepts, 78–79
Mainlines, 2–5, 72–79:
 operations hydraulics, 72–79
Maintenance, 169–212:
 causes of releases, 170–180;
 damage prevention, 180–187;
 finding potential problems, 187–197;
 risk and pipeline safety, 197–202;
 integrity management plan, 203;
 repairs, 204–209;
 other activities, 209–211;
 line lowering, 209;
 right of way, 209;
 cathodic maintenance, 210;
 pigging, 210–211;
 references, 212
Major Hazards Analysis (MHA), 330

Management of change, 224–225, 331
Manifolds, 122, 293
Manual control, 143:
 automated control, 143
Manufactured gas, 9–10, 14
Manufacturing flaws, 174, 186
Manufacturing methods (pipe), 230–231
Maps/mapping (equipment damage), 182
Market accessibility, 27–28
Market-driven scenario, 217
Mass (body), 36
Master Earth station, 144–145
Master limited partnerships (MLP), 22, 225
Master meters, 266
Maximum allowable operating pressure (MAOP), 76–78, 104, 277–278, 286, 291
Measurement/metering, 94–97, 113, 261–165:
 gas field operations, 94–97;
 petrochemicals/LPG, 113;
 meters, 261–265
Measures/dimensions (hydraulics), 35–36
Mechanical failures, 170, 174–176, 186:
 manufacturing flaws, 174;
 construction flaws, 175–176;
 prevention, 186
Mechanical variable speed devices, 260
Media as stakeholders, 328
Merchantable quality, 60
Meter factor, 261
Meter provers, 265–266:
 pipe provers, 265–266;
 master meters, 266
Meters, 261–266:
 positive displacement meters, 261–262;
 turbine meters, 262–263;
 orifice meters, 263–264;
 ultrasonic meters, 264;
 Coriolis meters, 265;
 meter provers, 265–266
Microbial influence corrosion, 173–174
Mileage expansion, 22–23
Miniaturization, 190
Modified volume balance, 164–165
Molecular structure (product), 110–111

Monitoring and controlling (control room operations), 103–104
 Moody diagram, 273–274
 Motor winding temperature, 155
 Municipal water systems, 31–32

N

National Environmental Policy Act, 328
 Natural gas, 1–2, 5–6, 12, 14–15, 21, 87–107, 285, 291–292, 332:
 flow and pressure control, 100, 285
 Natural Gas Act of 1938, 21
 Natural gas delivery operations, 99–100:
 city gates, 99–100;
 flow and pressure control, 100
 Natural gas distribution companies, 21
 Natural gas field operations, 94–99:
 measurement, 94–97;
 managing stakeholder relations, 97;
 gathering station operations, 97;
 compressor station operations, 97–99
 Natural gas gathering lines, 2, 89–90
 Natural gas liquids (NGL), 1, 5, 88
 Natural gas measurement, 94–97
 Natural gas pipeline operations, 87–107:
 natural gas pipelines, 88–93;
 gathering lines, 89–90;
 gas processing plants, 90–93;
 receipts from LNG facilities, 92;
 pipeline hubs, 93;
 field operations to central control room, 94–100;
 control room operations, 100–107;
 operator training, 107;
 references, 107
 Natural gas pipelines, 2, 5–6, 12, 14–15, 21, 87–107, 285:
 history, 12, 14–15;
 operations, 87–107;
 flow and pressure control, 100, 285
 Natural gas quality issues, 332
 Natural gas storage, 291–292:
 location, 291;
 management, 291–292;
 operations, 292;
 seasonal, 292
 Natural gas transmission pipelines, 2, 6, 88–93, 100, 285:
 gathering lines, 89–90;
 gas processing plants, 90–92;
 receipts from LNG facilities, 92;
 flow and pressure control, 100, 285
 Natural hazards, 170, 176–179, 186–187:
 prevention, 186–187
 Negative pressure wave, 166
 Net positive suction head (NPSH), 281–282
 Net present value, 226–227
 Newton's second law, 36
 Nomenclature (pipeline), 1–2
 Nonassociated gas, 89
 Nonferrous pipe, 232
 Nongovernmental organization (NGO), 323, 326
 Nonparametric values (operating data), 148
 North Sea, 24
 Number of stations, 286–287

O

Occupational Safety and Health Administration (OSHA), 330–331
 Offshore pipelines, 23–25, 121–138:
 pipeline design, 122–123;
 installing, 124–131;
 bottom conditions, 131;
 risers, 131–136;
 remotely operated vehicles, 136–138
 Oil, 2–4, 7, 12–15, 21–22, 38–39, 57–86, 285–286, 289–291:
 pipelines, 2–4, 12–15, 21–22, 57–86, 285–286;
 storage, 3, 289–291;
 refinery/refining, 4, 7, 12–13, 15, 58;
 pipeline operations, 57–86;
 receipt and delivery, 59–62;
 flow and pressure control, 285–286
 Oil pipeline operations, 57–86:
 crude oil, 57–58;
 refined products, 58;
 field operations to central control room, 59–63;
 central control room operations, 63–85;
 references, 86

Oil pipelines, 2–4, 12–15, 21–22, 57–86, 285–286:
 gathering lines, 2–4;
 mainlines, 2–4;
 history, 12–15;
 oil products, 21–22;
 operations, 57–86;
 flow and pressure control, 285–286

Oil products pipelines, 21–22

Oil refinery/refining, 4, 7, 12–13, 15, 58

Oil storage, 3, 289–291:
 location, 289;
 number and size of tanks, 290–291

Oil Transportation Association (OTA), 13

Oil-producing companies, 21

One-call centers, 180

Operating costs, 222–223

Operating history data, 202

Operator training (central control room), 85, 107

Optical methods, 168

Orifice meters, 94–96, 263–264

Origin point, 148

Owners as stakeholders, 323

Ownership changes (investment), 224–225

P

Parameter deviation, 163

Parameter values (operating data), 148

Pearson survey, 196

Performance (SCADA), 155–158:
 update time, 155;
 scan time, 155;
 communications latency, 155;
 screen update time, 155;
 command processing time, 156;
 historic data access time, 156;
 system utilization, 156;
 system availability, 156;
 summary, 157;
 local SCADA, 158

Permitting, 300

Petrochemical pipeline operations, 109–119:
 definitions, 109–110;
 product characteristics, 110–111;
 compressibility, 112;
 leak detection, 112;
 measurement, 113;
 quality control, 113–114;
 commissioning and decommissioning, 114–115;
 storage, 115–117;
 hydraulics, 117–118;
 supercritical fluids, 118–119

Pig launcher, 211

Pig receiver, 211

Pig traps, 211

Pigging, 16, 187, 210–211, 316:
 maintenance, 16, 210–211

Pipe, 229–232:
 manufacturing methods, 230–231;
 properties, 231–232;
 nonferrous pipe, 232

Pipe bends, 312–313

Pipe grade, 276–278

Pipe-in-pipe insulation, 123

Pipelaying vessels, 24, 125–131

Pipe length, 32–35, 50:
 splitting flows, 34–35

Pipeline categories, 1–7:
 nomenclature, 1–2;
 crude oil, 3–4;
 refined products, 4;
 natural gas, 5–6;
 pipeline customers, 6–7

Pipeline companies, 22

Pipeline construction, 24, 124–131, 299–319:
 subsea pipeline, 24, 124–131;
 permitting, 300;
 contracting and procurement, 300–301;
 right of way and land acquisition, 301–302;
 inspection requirements, 302;
 staking the line, 302–303;
 construction spreads, 303;
 right of way preparation, 303–304;
 stringing, 304–305;
 welding, 305–308;
 weld inspection, 308–309;
 trenching, 309–310;
 lowering in, 310–311;
 backfilling, 312;
 bends, crossings, and tie-ins, 312–316;
 quality control, 316;
 cleaning and sizing, 316;
 hydrostatic testing, 317;
 commissioning, 317;

- station construction, 317–318;
 - cleanup and restoration, 318;
 - handoff for operations, 318;
 - documentation, 319
- Pipeline construction (subsea), 24, 124–131:
 - pipelaying vessels, 24, 125–131;
 - buoyancy, 124;
 - laying pipe, 125;
 - S-lay, 125–126;
 - J-lay, 126–127;
 - reel barge, 128–129;
 - tow-in, 130–131
- Pipeline controls, 139–168:
 - SCADA system, 139–168;
 - control system design and operation, 141–158;
 - leak detection, 158–168;
 - conclusion, 168
- Pipeline customers, 6–7
- Pipeline design and engineering, 269–298:
 - safety considerations, 270;
 - route selection, 270–271;
 - line size, wall thickness, and looping, 271–274;
 - systems curves, 275–276;
 - fittings, flanges, and valves, 276;
 - wall thickness and grade of pipe, 276–278;
 - looping, 278–279;
 - pump, compressor, and prime mover selection, 279–284;
 - flow and pressure control, 284–286;
 - number of stations, 286–287;
 - station location, 287–289;
 - storage, 289–292;
 - station design and layout, 293–296;
 - additional considerations, 297–298;
 - conclusion, 298
- Pipeline and Hazardous Materials Safety Administration (PHMSA), 170, 203
- Pipeline hubs, 93
- Pipeline leaks/releases, 106–107, 112, 158–168, 170–180:
 - leak detection, 112, 158–168, 170–180;
 - causes, 159, 170–180;
 - rate, 160;
 - location, 161;
 - equipment damage, 171–172;
 - corrosion, 173–174;
 - mechanical failures, 174–176;
 - natural hazards, 176–179;
 - other causes, 180
- Pipeline maintenance, 169–212:
 - causes of releases, 170–180;
 - damage prevention, 180–187;
 - finding potential problems, 187–197;
 - risk and pipeline safety, 197–202;
 - integrity management plan, 203;
 - repairs, 204–209;
 - other activities, 209–211;
 - line lowering, 209;
 - right of way, 209;
 - cathodic maintenance, 210;
 - pigging, 210–211;
 - references, 212
- Pipeline mileage expansion, 22–23
- Pipeline operations, 29–55:
 - fluid flow physics, 29–31;
 - municipal water systems, 31–32;
 - friction loss, 32–35;
 - pipe length, 32–35;
 - flow rate, 32–35;
 - hydraulic properties of hydrocarbon fluids, 35–47;
 - hydraulics, 47;
 - basic flow principles and equations, 47–54;
 - conclusion, 55
- Pipeline pigs, 16, 187, 210–211, 316:
 - pigging, 16, 187, 210–211, 316
- Pipeline/pipelining history, 9–28:
 - gaslights, 9–11, 14;
 - natural gas pipelines, 12, 14–15;
 - crude oil pipelines, 12–15;
 - gas marketing, 14–15;
 - technology development, 16–18, 26;
 - teamster sabotage, 18;
 - railroad competition, 19;
 - Russia, 19–20;
 - business models, 21–22;
 - mileage expansion, 22–23;
 - offshore pipelines, 23–25;
 - commodity diversity, 26;
 - market accessibility, 27–28
- Pipeline pressure, 30, 122–123
- Pipeline repairs, 204–209:
 - replacing pipe, 204–206;
 - reinforcing pipe, 206–207;
 - grinding to reduce stress concentrations, 207–208;
 - deposited weld metal, 208;
 - coating, 208–209

- Pipeline safety (risk), 197–202:
 - consequences, 198;
 - probabilities, 198;
 - framework for considering risk, 198–201;
 - data, 202
- Pipeline stakeholders, 215
- Pipeline surveying, 186–187
- Pipeline terminal, 4
- Pipeline tie-ins, 312, 315–316
- Pipe manufacturing, 230–231
- Pipe properties, 231–232:
 - chemical, 231;
 - physical, 232
- Pipe provers, 265–266
- Pipe-to-soil potential survey, 194
- Planning and design (equipment damage), 180
- Planning and scheduling (control room operations), 65–66, 101–103:
 - batching, 65–66
- Plastic coatings, 234
- Plug valves, 240, 242
- Pocket control, 251–252
- Points (real-time operating data), 148–149
- Points database, 148
- Point tag/name, 148
- Polling/scanning, 152
- Portfolio management, 224–225
- Positive displacement compressors, 247–252, 282–283:
 - reciprocating pumps and compressors, 247–248;
 - rotary pumps and compressors, 248–249;
 - positive displacement control, 249–252;
 - performance, 249–252;
 - selection, 282–283
- Positive displacement meters, 261–262
- Positive displacement pumps, 247–252, 279–282:
 - reciprocating pumps and compressors, 247–248;
 - rotary pumps and compressors, 248–249;
 - positive displacement control, 249–252;
 - performance, 249–252;
 - selection, 279–282
- Potential problems (maintenance), 187–197:
 - internal inspection devices, 187–190;
 - hydrostatic testing, 190–192;
 - electrical surveys, 192–196;
 - direct assessment, 196–197
- Pounds Reid vapor pressure, 44
- Pour point, 41
- Pour point depressant, 41
- Power costs, 223
- Pressure control, 44, 100, 284–286:
 - natural gas, 100, 285;
 - crude oil, 285–286
- Pressure increase/decrease (abnormal), 84–85
- Pressure relief valves, 245
- Pressure wave, 32–33, 166:
 - negative pressure wave, 166
- Prime movers, 257–259, 283–284:
 - engines, 258;
 - electric motors, 259;
 - turbines, 259;
 - selection, 283–284
- Probabilities (risk analysis), 198–201
- Process and instrumentation diagram (P&ID), 148
- Process safety management (PSM), 330–331
- Procurement, 300–301
- Product characteristics, 110–111:
 - C4 products, 110;
 - C3 products, 111;
 - C2 products, 111
- Product quality specifications, 62–63, 332
- Production platforms, 122
- Products pipelines, 4, 21–22, 58, 62–63, 109–119:
 - receipt and delivery, 62–63;
 - petrochemical and LPG pipeline operations, 109–119
- Provers, 265–266:
 - pipe provers, 265–266;
 - master meters, 266
- Public education, 182–183, 331:
 - equipment damage, 182–183
- Pull tubes, 132
- Pulling apart the pipe, 43

Pump and compressor types, 247–257:
 positive displacement, 247–252;
 centrifugal, 252–257

Pumps, 247–257, 279–282:
 positive displacement, 247–252;
 centrifugal, 252–257;
 selection, 279–282

Pump stations (design/layout), 293–294

Pump suction pressure, 155

Purchase and sales price determination,
 226–228:
 economic value, 226–227;
 comparable sales, 227;
 highest and best use, 227;
 reconstruction cost new, 227–228;
 book value, 228

Q

Quality banks, 58

Quality control, 106, 113–114, 316:
 control room, 106;
 petrochemical/LPG, 113–114;
 pipeline, 316

R

Radiography, 308

Railroad competition, 19

Rate of change, 163

Raw gas, 89

Raw make, 26

Real-time operating data, 147–149:
 parameter values, 148;
 device status, 148;
 non-parametric data, 148;
 points, 148–149;
 events, 149

Real-time transient modeling, 165–166

Receipt and delivery (field operations), 59–63,
 92:
 crude oil, 59–62;
 products, 62–63;
 LNG, 92

Reciprocating compressors, 247–248

Reciprocating pumps, 247–248

Reconstruction cost new, 227–228

Rectifier, 185

Recycle control (pump), 250

Redundancy (communications), 146

Reel barge, 128–129

Refined product quality specifications, 332

Refined products pipelines, 4, 58, 62–63,
 109–119:
 receipt and delivery, 62–63;
 petrochemical and LPG pipeline operations,
 109–119

Refined products terminals, 289

Refinery/refining, 4, 7, 12–13, 15, 58

Regulations and compliance (equipment
 damage), 182

Reinforcing wrap, 206–207

Releases/leaks (causes), 159, 170–180:
 equipment damage, 171–172;
 corrosion, 173–174;
 mechanical failures, 174–176;
 natural hazards, 176–179;
 other causes, 180

Reliability (leak detection), 162

Remotely operated vehicles (ROV), 125,
 136–138

Repairs, 204–209:
 replacing pipe, 204–206;
 reinforcing pipe, 206–207;
 grinding to reduce stress concentrations,
 207–208;
 deposited weld metal, 208;
 coating, 208–209

Repeatability, 161

Replacement cost, 227–228

Replacing pipe, 204–206

Report by exception, 152

Reporting and evaluation (equipment
 damage), 183

Reports and logs, 156–157

Research and development (safety), 330

Restoration (site/route), 318

Revenue economics, 218–222

Reynolds number, 50, 272–273

Right of way (ROW), 13, 181–183, 209, 301–304, 324–325, 333:
 maintenance, 209;
 land acquisition, 301–302;
 preparation, 303–304

Risers, 122, 131–136:
 attached risers, 131–132;
 pull tubes, 132;
 steel catenary risers, 132–134;
 top-tensioned risers, 134–135;
 riser tower, 135;
 flexible risers, 136

Riser tower, 135

Risk algorithm, 202

Risk management, 224

Risk/risk analysis (pipeline safety), 197–202, 224:
 consequences, 198;
 probabilities, 198–201;
 framework for considering risk, 198–201;
 data, 202

Robustness (leak detection), 162

Root bead, 306, 308

Rotary compressors, 248–249

Rotary pumps, 12–13, 248–249

Roughness, 50

Route monitoring (equipment damage), 183

Route selection, 270–271

Routine operations (central control room), 80–83, 105

Russia, 19–20

S

Sacrificial protection, 184

Safety, 85, 87, 197–202, 270, 329–331:
 risk/risk analysis, 197–202;
 stakeholders, 329–331

Safety (stakeholder needs/wants), 329–331:
 industry standards, 329–330;
 best practices sharing, 330;
 hazards analysis, 330;
 research and development, 330;
 managing processes, 330–331;
 public education, 331

Safety considerations, 270

Safety device operation, 85

Sales and purchase price determination, 226–228:
 economic value, 226–227;
 comparable sales, 227;
 highest and best use, 227;
 reconstruction cost new, 227–228;
 book value, 228

Salt domes, 115–117

Satellite communications, 144–145

Saturation vapor pressure, 42

Scan time (SCADA), 155

Scheduler's role (central control room), 66–68:
 transit time, 67–68

Scraper traps, 211

Screen update time (SCADA), 155

Screw compressor, 248–249

Screw pump, 248–249

Seamless pipe, 16–17, 230

Seasonal storage (natural gas), 292

Security, 157

Seismic activity, 178

Shrink sleeves, 235–236

Shutdown unintended, 84

Shut-in pressure test, 166

Sizing (pipeline), 316

Sizing pig, 316

Sizing plates, 316

S-lay, 125–126

Slug flow, 91:
 corrosion, 91

Slugs (mass), 36

Smart pigs, 187

Spar structure, 133–135

Special interest groups, 326

Specific gravity, 37

Specified minimum yield strength (SMYS), 232

Speed control, 250, 257

Split sleeve, 206

Splitting flows, 34–35

Spur lines, 270

- Stakeholders, 28, 97, 215, 321–333:
 - management, 97;
 - satisfaction, 97, 321–333;
 - owners, 323;
 - customers, 324;
 - landowners and neighbors, 324–325;
 - governments, 325–326;
 - nongovernmental organizations, 326;
 - interested citizens, 326;
 - industry, 327;
 - suppliers and contractors, 327;
 - competitors, 327;
 - employees, 327;
 - media, 328
- Stakeholder satisfaction, 97, 321–333:
 - introduction, 322;
 - stakeholders, 322–328;
 - balancing needs and wants, 329–333;
 - conclusion, 333;
 - references, 333
- Staking the line, 302–303
- Station block valve, 293
- Station construction, 317–318
- Station design and layout, 293–296:
 - compressor and pump stations, 293–294;
 - delivery stations, 295;
 - storage fields and tank farms, 295–296;
 - ancillary station equipment, 296
- Station discharge pressure, 154
- Station location, 287–289
- Station manifold, 154
- Station sequence, 154
- Station sump level, 154
- Statistical analysis, 166
- Status system status, 151–152
- Steam-driven pump, 14
- Steel catenary risers, 132–134:
 - compliant tower, 133;
 - spar structure, 133;
 - tension leg platform, 133;
 - floating production system, 133;
 - floating production, shipping, and offloading vessels, 133
- Steel plate/skelp, 230
- Storage, 115–117, 289–292, 295–296:
 - petrochemicals/LPG, 115–117;
 - location (crude oil), 289;
 - number and size of tanks (crude oil), 290–291;
 - location (natural gas), 291;
 - gas storage management, 291–292;
 - gas storage operations, 292;
 - gas seasonal storage, 292;
 - storage fields, 295–296
- Storage fields, 295–296
- Strain (material), 44
- Strainers, 293
- Stranded gas, 92
- Strategic change, 224–225
- Strategic Petroleum Reserve (SPR), 117
- Stress concentrations, 207–208
- Stress corrosion cracking, 186
- Stringing, 304–305
- Strip/stripping, 71
- Subsea pipelines, 23–25, 121–138:
 - pipelaying vessels, 24, 125–131;
 - pipeline design, 122–123;
 - installing, 124–131;
 - bottom conditions, 131;
 - risers, 131–136;
 - remotely operated vehicles, 136–138
- Suction pressure, 155, 250
- Sump level, 154
- Supercritical fluids (petrochemical/LPG), 118–119
- Supervisory control and data acquisition (SCADA), 96, 103, 139–168:
 - basic system, 139–141;
 - design and control, 141–158;
 - performance, 155–158;
 - local SCADA, 158;
 - leak detection, 158–168;
 - conclusion, 168
- Suppliers as stakeholders, 327
- Supply (stakeholder needs/wants), 332:
 - refined product quality, 332;
 - natural gas quality, 332
- Supply and demand, 216–218, 332
- Supply-driven scenario, 216
- System availability (SCADA), 156
- System utilization (SCADA), 156
- Systems curves, 275–276

T

Tack welded, 306
Tank battery, 3
Tank farms, 289, 295–296
Tank location, number, and size (crude oil), 289–291
Tank strapping, 60
Tapes (coating), 234–235
Tapline pipeline, 27
Tax-favored structures, 22
Teamster vandalism, 18–19
Technology development, 16–18, 23, 26, 190:
 tool research, 190
Tension leg platform (TLP), 133–134
Terminology, 335–337
Throttle valves, 285
Throttling, 257, 285
Tie-ins, 312, 315–316
Tool research and technology, 190
Top-tensioned risers, 134–135
Tow-in, 130–131:
 surface tow, 130;
 mid-depth tow, 130;
 off-bottom tow, 130;
 bottom tow, 130
Town gas, 9–10
Training programs, 85, 107, 187
Transient modeling, 165–166
Transit time, 67–68
Transmed pipeline, 25–26
Transmix material, 66, 71–72:
 minimizing, 71–72
Transneft pipeline, 27
Trenching, 309–310
Trunk pipelines, 3, 15, 72
Tuning, 167
Turbine meters, 262–263
Turbines (prime movers), 259
Turbulent flow, 49–50

U

Ultrasonic inspection (weld), 308–309
Ultrasonic meters, 264
Ultrasonic testing (UT), 189–190
Ultrasonic tools, 189–190
Underwater pipelines, 23–25, 121–138:
 pipelaying vessels, 24, 125–131;
 pipeline design, 122–123;
 installing, 124–131;
 bottom conditions, 131;
 risers, 131–136;
 remotely operated vehicles, 136–138
Unit bearing temperature, 155
Unit pressure, 154
Unit temperature, 155
Unit vibration, 155
Unsupported span, 131
Update (SCADA), 151–152, 155:
 frequency, 151–152;
 process, 152;
 time, 155

V

Value chain, 2, 4, 88
Valve closure unintended, 84
Valves, 84, 238–245, 276:
 gate valves, 239–240;
 ball valves, 240–241;
 plug valves, 240, 242;
 check valves, 243–244;
 globe valves, 244–245;
 pressure relief valves, 245
Vapor pressure, 35, 41–43, 46:
 and evaporation, 41–43
Vaporization, 111
Vapor and soil monitoring, 168
Variable frequency drive (VFD), 260
Variable speed devices, 257, 260, 284:
 mechanical, 260;
 electrical, 260
Variable speed drive (VSD), 257
Velocity, 50–51

Viscosity, 35, 39–41, 46, 50:

- absolute viscosity, 40;
- kinematic viscosity, 40

Voltage gradients survey, 196

Volume valance, 164–165

Volutes, 254–255

W–Z

Wall thickness, 271–274, 276–278:

- friction loss aspects, 271–274

Water systems, 31–32

Weld inspection, 308–309

Weld passes, 308

Welded pipe, 230–231

Welding, 17, 204–206, 230–231, 305–309:

- weld inspection, 308–309

Wet trees, 121

Winding temperature, 155

About the Authors



Thomas O. Miesner is a past president of Conoco Pipe Line Company, with 26 years of experience spanning a broad range of engineering, operations, business development, strategy, and executive management positions. He chaired the Association of Oil Pipe Lines and spent many years on its executive committee and on the American Petroleum Institute Pipeline Committee. He was an active director and executive on numerous pipeline company boards and management committees. In 2004 he retired from ConocoPhillips and formed Miesner, LLC, to follow his passion for problem solving and “understanding why.” His firm provides expert consulting and educational services to the pipeline industry and its numerous stakeholders. He can be reached at nontechnical@miesnerllc.com.



Dr. William L. Leffler, a retired executive from Royal Dutch/Shell, spent 36 years with that company. During his career he worked in refining and marketing, exploration and production, petrochemicals, and corporate planning in the United States and London. He earned an MBA and PhD at New York University and a BS at MIT. His PennWell titles include the bestselling *Petroleum Refining in Nontechnical Language* (2000), *Petrochemicals in Nontechnical Language* (2001), *Deepwater Exploration and Production: a Nontechnical Guide* (2003), and *Oil and Gas production in Nontechnical Language* (2005). Dr. Leffler’s firm provides courses in nontechnical language on all these subjects.