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RULISON PROJECT

Austral Oil Company

25-95 A Hayward

Rulison Field

Garfield County, Colorado

Emplacement & Cementing of

10 3/4" Casing to 8701 Feet

COPY

Representatives Present During Operations

Company	Representative
Austral Oil Company	Miles Reynolds Wilbert Veronie Alvin Toniette
AEC	Don Dahle C. Bromley
LASL	R. Bradshaw Francis West
Continental Oil Company	K. McDaniels
C.E.R.	G. Luetkehans
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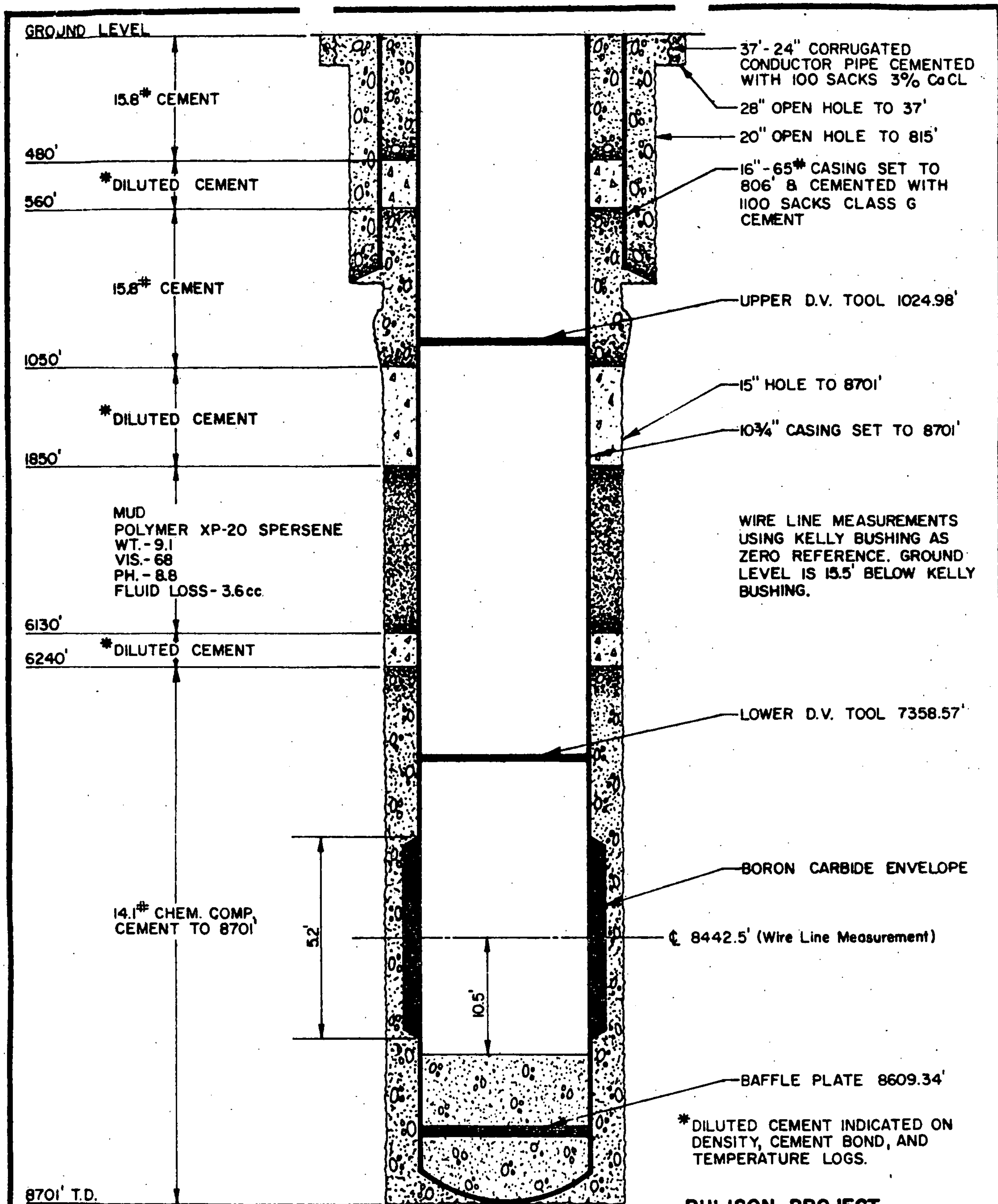
Lamb, Inc.	Carl Schwab Larry Meaux & Crew
Dresser Atlas	R. Smith N. Pomerenke B. McDonald K. Deakins W. Bains & Crew



RULISON PROJECT

PREPARED BY **FENIX & SCISSON, INC.** ENGINEERS & CONTRACTORS LAS VEGAS, NEVADA	FOR **U.S. ATOMIC ENERGY COMMISSION** NEVADA OPERATIONS OFFICE — LAS VEGAS, NEVADA

CASING SCHEMATIC DIAGRAM	DRAWING NO. DIAGRAM NO. 1

DRAWN	CHECKED	DATE	SCALE	
B. FISHER		2/19/69	NONE	SHEET ____ OF ____

SUMMARY

This interim report, on the Rulison Project, covers the casing emplacement and cementing operations on the Austral Oil Co.'s Number 25-95 A Hayward Well in Garfield County, Colorado. A string of 10-3/4" casing was placed to a total depth of 8701' and cemented in three stages. Cement quality was verified by the use of an acoustic bond log and a density log.

The package envelope, 5.2' long and containing boron carbide in its annulus, was included in the 10-3/4" casing string so as to be in the Mesa Verde Section at 8442-1/2'*. Inside the 10-3/4" casing, the cement was drilled out to a depth of 10-1/2' below centerline of the boron carbide envelope. This total depth was confirmed by wire line measurements, and a casing collar locator, to be 8453'*.

A 900 CFM air compressor was used in conjunction with gas lift valves, appropriately placed in a string of 2-3/8" tubing, for the removal of all fluid from the 10-3/4" casing. Dryness of the casing was tested by dumping a 100# sack of micro-cel in the annulus between 2-3/8" tubing and 10-3/4" casing and observing the dust ejected from the "Blooie" line.

Strength of the cement plug in the 10-3/4" casing, at 8453'*, was tested by an applied load of 84,000#. Diameter uniformity and casing straightness were checked by running a 9" diameter, 15' long mandrel to the total depth of 8453'*. Dryness was double checked by a bailer, filled with sample sacks of micro-cel, run on sand line to 8453'*. Smoothness of the cement top in the casing was inspected by a 9" diameter lead impression block with 20,000# applied pressure.

All tests were favorable and acceptable to participating parties.

* Wire line measurements used zero at kelly bushing. Ground level is 15.5' below K.B.

A total depth of 8701' (drill pipe measurements) was attained on January 18, 1969. The drilling mud was circulated three hours in preparation for a suite of open hole logs. A gamma ray neutron, caliper, multi-shot directional survey, and compensated density logs were completed on January 21. Immediately following the logging operation, a trip was made to total depth.

Eight feet of soft fill was detected on bottom. The mud was circulated for four hours. A precaution of pulling ten stands of drill pipe, establishing circulation then returning to total depth and again establishing circulation, was followed. Mud and hole conditions were found ready to accept 10-3/4" casing. The drill pipe was pulled from the hole and preparations were made for using the joint analyzed casing make up.

The casing equipment, Lamb, Inc., was rigged up for J.A.M. operation. Eight turns and 7500 foot pounds of torque were set on the computer that was tied into the power tongs. A recording was made of each joint as the connection was made. Baker LOK was used only for the shoe joint and float joint make up, whereas the special compound provided by Lamb, Inc. was used on all additional collar and joint connections.

Casing emplacement was initiated at 2200 hours, January 21. The casing string make up is shown in Chart #1 with the exception that the two top joints are S-95 - 55.5# pipe.

CHART I

Interval	Weight	Type Casing	Amount
0 - 2500 Ft.	51#	N-80	2500 Ft.
2500 - 3500 Ft.	51#	J-55	1000 Ft.
3500 - 4700 Ft.	51#	N-80	1200 Ft.
4700 - 5700 Ft.	51#	P-110	1000 Ft.
5700 - 6500 Ft.	51#	S-95	800 Ft.
6500 - 8700 Ft.	55.5#	S-95	2200 Ft.

Ruff coated casing was placed in the interval 8049.42' to 7618.87'*. The casing shoe was set at 8701* with 10,000 lbs. of weight. A float collar was placed at 8652.40'*. After some modification, a baffle plate was set at 8609.34'*. The lower DV tool was set at 7358.37'* and a second DV tool was set at 1024.98'*. The center line of the boron carbide container was placed at 8450.08'*. A distance of 1091.71'* was noted between the lower DV tool and boron carbide container. Distance to be drilled from lower DV tool to 10-1/2' below center line of boron carbide envelope was 1102.21'*. Centralizers, when placed, were positioned 10' to 15' below the collars except at DV tool, then the spacing interval was the middle of the joint (see Chart #2 for all centralizer depths*).

Casing shoe was placed to a total depth of 8701'* on January 22 at 2100 hours, with drill pipe measurements and casing measurements in agreement. Casing measurements were made on the rack. Mud was circulated through the casing shoe for five hours prior to cementing the first stage, during which time the cement computations were double checked and the operating plan was outlined.

The first stage of cement would be the shoe stage. Cement was to be pumped through the casing shoe in sufficient quantity so as to reach 6000' in the annulus between the 10-3/4" casing and open hole. A safety precaution was provided by placing a DV tool at 7358'*. Remedial action could be taken through this lower DV tool should problems develop on the first stage. Two additional precautions were observed. The mud tanks were measured and marked, and two cementing trucks would be pumping while the third truck would monitor the mud during mixing & displacement operations.

A second DV tool was set at 1025'* for cementing the 10-3/4" casing from 1025' to the surface.

Cement volumes as determined by Austral and Dowell for annulus fill up plus a 100' height in the casing was computed as 1837 sacks of expanding cement - chem. comp. - 14.1#/Gal. - yield 1.5 Cu.Ft/sack - with additives of 12.5 lbs. of Kolite per sack of cement and 3/10 of 1% D74R. Allotment of cement to volumes was as follows; annulus outside casing from 8701' to 6000', 1707 sacks or 2560.5 Cu.Ft.; volume inside casing from baffle plate to casing shoe, 30 sacks or 45 Cu.Ft.; volume inside casing from top of cement to baffle plate, 100 sacks or 150 Cu.Ft.

* Measurements were made on casing while racked, with the K.B. as zero reference.

Cement Stage #1

The first stage of cement was initiated on January 23 at 0400 hours, with the plug down at 0615. All first stage annulus cement was placed through the casing shoe with 10 bbls. lost during cementing. Since the lower DV tool was not needed, a bomb actuator was used to open and immediately close the cement ports for a safe drill out operation. Six hours was spent waiting on cement.

Cement Stage #2

A bomb actuator was used to open the upper DV tool and begin Stage #2, with circulation established for three hours. Cementing the interval 1025' to the surface with 700 sacks of 15.8#/Gal. - 1% calcium chloride - yield 1.14 Cu.Ft. per sack, Class "G" cement was started on January 23 at 1310 hours with the plug down at 1400 hours. The plug closed the DV tool for safe drill out operation. A pressure of 2000# was held for five minutes and released. Mud returns were lost when 47 barrels or 264 Cu.Ft. remained in displacement. Cement rise was calculated to be approximately 234' from surface when the formation broke. Eleven hours was spent waiting on cement. Stage two cement top was located at 677' by a temperature survey.

Cement Stage #3

Stage two cement top was tagged with 1" tubing at 682' in annulus between 10-3/4" casing and 16" casing. The mud was displaced with water, using the 1" tubing. Cement Stage #3, 0 - 682', was accomplished through one inch tubing. A total of 425 sacks of 15.8#/Gal., yield 1.14 Cu.Ft./sack, 2% calcium chloride, Class "G" cement was used. A minimum of 25 sacks were circulated. The third stage was started on January 24 at 1250 hours and completed at 1330 hours. Seven and one half hours was spent waiting on cement, during which time the casing hanger was installed - dropped slips - cut casing - removed blowout preventer and installed tubing head.

The upper DV tool at 1025' was drilled out and circulation established from total depth of 1060'. A temperature survey was run from the surface to 7353'*.

Temperature of mud in interval (0 - 1060') was not allowed time to reach cement temperature after circulation. The second cement stage, which covered the interval 1025' to 682', was recognizable by temperature rise immediately below circulated zone and temperature decrease from 1800' to 1850'. A normal gradient was experienced from 1850' to 6130' where a slight increase in gradient is evident with the cement top of Stage #1 indicated at 6240'. It was notable that the cement top on this first stage could be detected after an elapsed time of 52 hours.

The lower DV tool at 7358' was drilled out and the cement top inside casing was found at 8238' (drill pipe measurement). This was 114' higher than calculations indicated. Cement was drilled out to a point estimated at 5' below center line of boron carbide envelope (drill pipe measurements). Circulation was continued for two hours prior to pulling the drill pipe from the hole (pipe strapped in and out of hole).

* Measurements were made on casing while racked, with the K.B. as zero reference.

A density log, an acoustic cement bond log, and a casing collar log were completed on January 26 as a check on total depth and cement integrity. The boron carbide container, casing collars, and total depth were identified from the casing collar log and verified by the density and acoustic cement bond log. It was decided that the total depth of 10-1/2' below the center line of the boron carbide envelope could be attained by drilling two feet deeper. Additional footage was drilled on January 27 and the drilling mud was displaced with water before pulling out of the hole laying down drill pipe.

Two hundred seventy joints of 2-3/8" tubing was placed in the hole with gas lift valves installed at 8422.55', 8010.47', 7192.95', 6412.14', 5595.85', 4714.61', 3715.03', 2716.94' and 1469.52' (tubing measurements).

A Dresser Magcobar 900 CFM air compressor was placed in operation on January 28. Air (860 psi) was injected into annulus between the tubing and 10-3/4" casing. Continuous air injection was used January 28, 29 and 30. The "Blooie" line exhaust indicated the casing was dry at 1800 hours on January 30. Drying operations were continued until 2100 hours. A check on moisture content was made by dumping a sack of micro-cel in the annulus between the tubing and casing with dust soon seen in the "Blooie" line exhaust. A second check was made for possible water by running a casing collar locator, with a short-out switch on bottom, inside the 2-3/8" tubing to total depth. No water was detected. Tubing was pulled from hole and laid down.

A third check for possible moisture was made by filling a metal basket (5' length of slotted 7" casing) with sample bags of micro-cel and lowering the basket to total depth on the sand line. No water was detected.

A mandrel 9" in diameter and 15' long was run on the sand line to total depth as a check on the drift of the casing. No tight spots were indicated.

An open end drill collar (9" diameter) with additional drill collars and drill pipe were used to apply 84,000# load on cement in casing. Support properties of the cement were satisfactory. Some asphalt sediment, probably Kolite from the cement, was removed from the hole by the open end drill collar.

A 9" diameter lead impression block was run to total depth for a check on smoothness of cement. Results obtained were quite satisfactory with an applied load of 20,000#.

A barrel was placed over the casing preparatory to installing a blanking flange.

The logging, casing running and cementing operations, conducted after total depth had been reached, were witnessed on a continuous basis by F&S drilling and logging engineers. We are of the opinion that this was a well planned operation executed in a workmanlike manner by competent technical personnel.

CHART 2

CENTRALIZER DEPTHS

Approximate Attachment Points
(not measured)

1. Baker LOK pins used to attach the hinged centralizers to the casing.

2. Depths approximated from casing measurements.

Number	Depth	Number	Depth
1	8675	22	7196
2	8630	23	7068
3	8533	24	6938
4	8462	25	6809
5	8435	26	6680
6	8318	27	6551
7	8189	28	6422
8	8060	29	6293
9	8006	30	6164
10	7963	31	6034
11	7920	32	5806
12	7877	33	1049
13	7834	34	1005
14	7791	35	871
15	7748	36	760
16	7705	37	633
17	7662	38	507
18	7619	39	383
19	7500	40	256
20	7380	41	130
21	7336		

CHART 3

CEMENT COMPUTATIONS

STAGE #1 - 8701 to 6000'

Depth	Total Volume In Cubic Feet
8701 - 8600	157.63
8600 - 8500	157.63
8500 - 8400	157.63
8400 - 8300	162.30
8300 - 8200	167.03
8200 - 8100	157.63
8100 - 8000	157.63
8000 - 7900	157.63
7900 - 7800	157.63
7800 - 7700	157.63
7700 - 7600	148.49
7600 - 7500	157.63
7500 - 7400	157.63
7400 - 7300	157.63
7300 - 7200	148.49
7200 - 7100	143.34
7100 - 7000	144.02
7000 - 6900	148.49
6900 - 6800	148.49
6800 - 6700	148.49
6700 - 6600	144.02
6600 - 6500	139.63
6500 - 6400	135.30
6400 - 6300	148.36
6300 - 6200	147.15
6200 - 6100	146.24
6100 - 6000	145.46

Total Open Hole Volume	4099.23 Cubic Feet
Less 10-3/4" Volume	- 1765.47 Cubic Feet
Annulus To Be Cement Filled	2333.76 Cubic Feet
Plus 10%	+ 234.00
Computed Cement Volume	2567.76 Cubic Feet
Cement Used	2560.5 Cubic Feet

CHART 4

CEMENT COMPUTATIONS

STAGE #2 - Surface to 1025'

1.	Volume 0' - 800' 15 1/4" Diameter (I.D. of 16" casing)		+ 1014.72 Cubic Feet
2.	Volume 800' - 1025' 16" Diameter Open Hole		+ 314.17 Cubic Feet
		Total Volume	1328.89 Cubic Feet
3.	Volume 0' - 1025' 10-3/4" Casing Displacement		- 646.06 Cubic Feet
4.	Computed Volume of Cement Required for Annulus 0' - 1025'		682.83 Cubic Feet
		Add 10%	68.3 Cubic Feet
5.	Total Volume of Cement Required		751.13 Cubic Feet
6.	Cement Used - 700 Sacks - 15.8#/Gal. Slurry Yield of 1.14 Cubic Feet Per Sack		798.00 Cubic Feet

7. Mud returns lost when 47 Bbls. displacement remained for plug to be down.

47 bbls. = 264 Cubic Feet

8. Computations for height of cement in annulus at the time of lost mud returns.

Total Volume Cement Used	798	Cubic Feet
Volume of Cement Not Displaced	- 264	Cubic Feet
Volume of Cement in Annulus	534	Cubic Feet
Annulus Volume 800' - 1025'	172	Cubic Feet
Annulus Volume 234' - 800'	362	Cubic Feet
	534	Cubic Feet

9. Computed Cement Rise in Annulus at the Time of Formation Breakdown. — 234' From Surface

10. Cement top found with temperature survey at 677' in annulus. This was confirmed with 1" tubing measurements.

11. Computations for cement volume in annulus outside 10-3/4" casing below the DV tool at 1025'.

Volume of Cement From 677' - 800'	79 Cubic Feet
Volume of Cement From 800' - 1025'	172 Cubic Feet
	- 251 Cubic Feet
Total Volume of Cement Used Stage #2	+ 798 Cubic Feet

12. Volume of cement below DV tool and outside 10-3/4" casing. 547 Cubic Feet

13. Temperature Log indicates possible cement to 1850'.

14. Volume of annulus outside 10-3/4" casing from 1025' - 1850'. 369 Cubic Feet

15. It is concluded that apparently some cement went into the formation.

CHART 5

CEMENT COMPUTATIONS

STAGE #3 - Surface to 682'

1.	0 - 682 - (682 x .6381) - Annulus between 10-3/4" casing and 16" casing	435.18 Cubic Feet
	Plus 10%	43.50
		478.68 Cubic Feet
2.	Used 425 sacks - 1.14 yield = and circulated cement	485 Cubic Feet

CHART 6

MUD TANK VOLUMES

#1 Tank	7.10' x 36.40	=	3.8 bbls/inch
#2 Tank	9.50' x 29.95	=	4.2 bbls/inch
#3 Tank	7.95' x 27.85	=	3.2 bbls/inch
#4 Tank	9.4' x 30.00	=	4.2 bbls/inch

LOST CIRCULATION ZONES DURING OPEN HOLE DRILLING

Depth	Fluid Lost
1342'	20 bbls.
6162'	25 bbls.
6430'	30 bbls.
6630'	20 bbls.
7028'	75 bbls.
7473'	25 bbls.
7565'	25 bbls.

CHART #7

JOINT BREAKDOWN

10 3/4" EMPLACEMENT CASING

	Howco Type F Guide Shoe	3.83'
1 Jt.	10 3/4" OD 55.5# S-95 ST & C R-3 Casing	43.15
	Howco Type F Float Collar	1.62
1 Jt.	10 3/4" OD 55.5# S-95 ST & C R-3 Casing	43.06
13 Jts.	10 3/4" OD 55.5# S-95 ST & C R-3 Casing	559.92
10 Jts.	10 3/4" OD 55.5# S-95 ST & C R-3 (Ruff-Cote) Csg.	430.55
6 Jts.	10 3/4" OD 55.5# S-95 ST & C R-3 Casing	258.42
	Howco DV Stage Collar	2.08
21 Jts.	10 3/4" OD 55.5# ST & C R-3 Casing	903.71
21 Jts.	10 3/4" OD 51# S-95 ST & C R-3 Casing	904.70
29 Jts.	10 3/4" OD 51# P-110 ST & C R-3 Casing	1,106.17
30 Jts.	10 3/4" OD 51# N-80 ST & C R-3 Casing	1,224.86
29 Jts.	10 3/4" OD 51# K-55 ST & C R-3 Casing	1,128.46
26 Jts.	10 3/4" OD 51# N-80 ST & C R-3 Casing	1,063.41
	Howco Stage Collar	2.08
23 Jts.	10 3/4" OD 51# N-80 ST & C R-3 Casing	946.80
2 Jts.	10 3/4" OD 55.5# S-95 ST & C R-3 Casing	86.09
212 Jts.	Total	8,708.91'
	Less Casing Above KDB	(7.91)
	Casing set with respect to KDB	8,701.00'

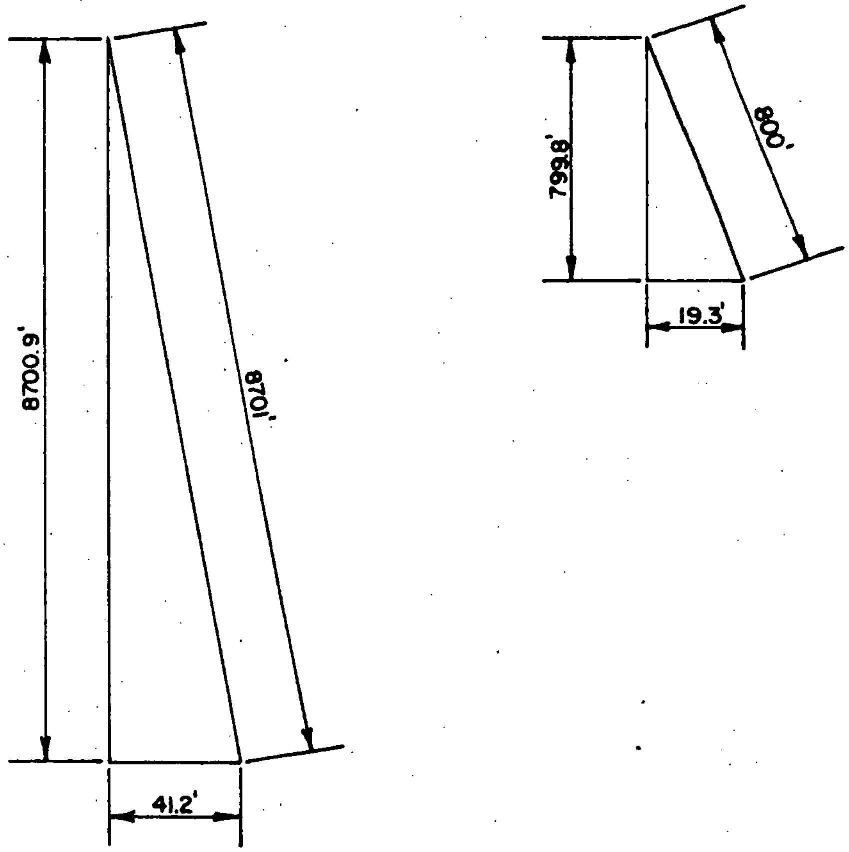
MULTISHOT DIRECTIONAL SURVEY

1. Readings taken every 100' from 8700' to surface.

2. True vertical depth - approximately 8700.9'.

3. Calculated distance of the 8701' point is 41.2' N. 70° E. from surface entrance point.

4. Calculated distance of the 800' point. (Bottom of surface casing) is 19.3' N. 80.2° E. of surface entry point.



RULISON PROJECT

PREPARED BY FENIX & SCISSON, INC. ENGINEERS & CONTRACTORS LAS VEGAS, NEVADA	FOR U.S. ATOMIC ENERGY COMMISSION NEVADA OPERATIONS OFFICE LAS VEGAS, NEVADA
MULTISHOT DIRECTIONAL SURVEY	DRAWING NO. DIAGRAM NO. 2

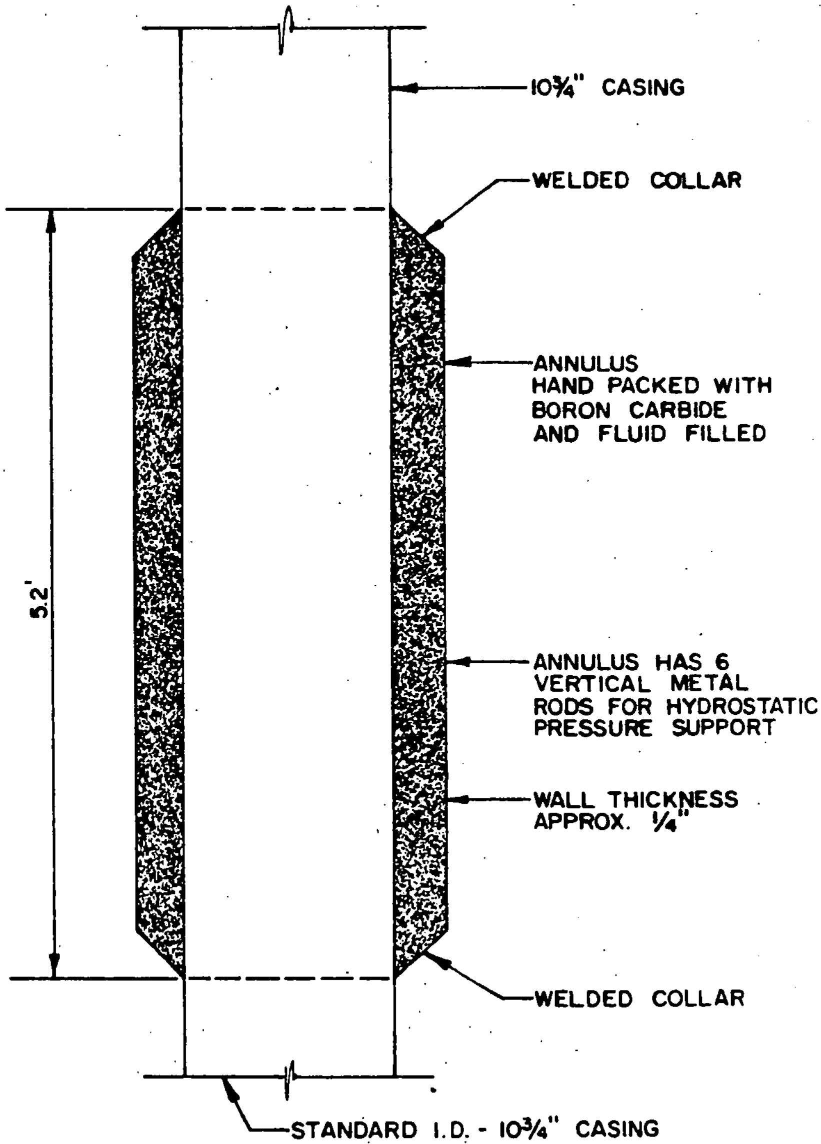
DRAWN	CHECKED	DATE	SCALE	SHEET

THIS ENVELOPE WILL HOUSE EMPLACEMENT PACKAGE

SMOOTH CEMENT BOTTOM TO BE 10½' BELOW
CENTER LINE OF THIS ENVELOPE.

CENTER LINE OF CONTAINER
8442.5'
10.5'
*8453'

COLLAR CHECK ABOVE
CONTAINER
8428.5'
11.0'
*8439.5'



*WIRE LINE MEASUREMENTS USING
KELLY BUSHING AS ZERO REFERENCE.
GROUND LEVEL IS 15.5' BELOW
KELLY BUSHING.

RULISON PROJECT

PREPARED BY	FOR
FENIX & SCISSON, INC. ENGINEERS & CONTRACTORS LAS VEGAS, NEVADA	U.S. ATOMIC ENERGY COMMISSION NEVADA OPERATIONS OFFICE LAS VEGAS, NEVADA

BORON CARBIDE ENVELOPE	DRAWING NO. DIAGRAM NO. 3

DRAWN	CHECKED	DATE	SCALE	SHEET OF

E. Campbell

LRL 11/17/69

II. RULISON

A. Maximum Credible Accident

1. Maximum Credible Flow

Reference: Handbook of Nautral Gas Engineering by Donald L. Katz et al., Published by McGraw-Hill Book Co. Inc., 1959, Library of Congress Catalog Card Number 58-6686.

The following calculations will assume a chimney of natural gas and a constant down-hole pressure. A similar calculation will be done assuming a chimney of Gasbuggy gas.

a. Cookbook Method - ~~1~~ #1

Boundary Conditions: (nomenclature used included)

Surface Chimney Pressure = 2430 psig

Chimney Pressure = P_1 = 2840 psia

Atmospheric Pressure = $P_o=P_2=10.67$ psia

Chimney Gas Temperature = T = $400^oF = 860^oR$

Surface Temperature = $T_o = 40^oF = 500^oR$

Gas Gravity (preshot from RE-X) = G = 0.634 (air=1)

Gas Viscosity = μ = 0.019 centipoise
(from Fig. #4-106, p. 175 and Fig. #4-107, p. 176)

Surface Elevation = 8600 ft

Depth of Burial of Explosive = DOB = 8443 ft

Depth of Top of Chimney = 8067 ft.

Proposed Casing Schedule:

From	To	Length = L	Inside Diameter = (D)
Surface	5860'	5860'	6.969"
5860'	~7600'	1740'	4.950"
~7600'	8067	467	4.75" (Open Hole)

Proposed Production Tubing Schedule:

Surface	8067'	8067'	2.992"

Pipeline Flow Equation - from p. 305 (assumes horizontal pipe)

$$Q = (3.973)(10^3)\ \frac{Z_oT_oP_c}{P_o}\left[\frac{D^5}{GTLf}\left(\int_0^{P_{r,1}} \frac{P_r}{Z}\,dP_r - \int_0^{P_{r,2}} \frac{P_r}{Z}\,dPr\right)\right]^{1/2}$$

Nomenclature for new terms:

Q = volumetric flow rate in 10^3 - standard ft^3/day

Z_o = gas compressibility factor at $T_o + P_o \approx 1$

P_c = pseudocritical pressure = 670 psia from Figure #4-22, p. 112

D = pipe inside diameter in, ft

L = pipe length in ft

f = friction factor = from Figure #7-3, p. 303

P_r = pseudoreduced pressure = $\frac{P}{P_c}$

Values of the integrals functions $\int_0^{P_r} \frac{P_r}{Z}\, dPr$ are from Table A-6, p. 732.

$$\alpha = \frac{(3.973)(10^3)(Z_o)(T_o)(P_c)}{P_o}$$

$$\alpha = \frac{(3.973)(10^3)(1)(5)(10^2)(6.7)(10^2)}{(1.067)(10^1)}$$

$$\alpha = 1.247 \times 10^8$$

$$\beta = \frac{D^5}{GTLf}$$

As there are three diameters, an arbitrary weighting of the D^5 term by % of total length for each diameter will be made.

ID inches	6.969	4.950	4.750
ID feet	0.5807	0.4125	0.3958
$(\text{ID-feet})^5$	0.06602	0.01194	0.00972
% of total length	72.7	21.5	5.8
$(\%)(D^5)$	0.04800	0.00257	0.00056

Weighted $(\text{Pipe Diameter})^5 = D^5 = 0.05113$

f = friction factor - an imperically determined quantity dependent on the Reynolds Number (R_e) for the system and the relative pipe/hole roughness.

Reynolds Number:

$$Re = \frac{(2.0)(10^1)(Q)(6)}{\mu d} \quad \text{from page 320.}$$

Q = gas flow in 10^3 standard ft^3/day

= 280,000 (guess)

d = pipe diameter in inches

using the result of the weighted pipe $(\text{diameter})^5$

$$d = (0.05113)^{1/5} = 0.5515 \text{ feet} = 6.618 \text{ inches}$$

$$Re = \frac{(2.0)(10^1)(2.8)(10^5)(6.34)(10^{-1})}{(1.9)(10^{-2})(6.618)} =$$

$$Re = 2.82 \times 10^7$$

Relative Roughness

As there are three roughnesses, an arbitrary weighting of the relative roughness by % of total length for each roughness will be made. The final result is not too sensitive to the friction factor f as it appears in the final result as $f^{1/2}$ and f does not change by a factor of 2 for an order of magnitude change in relative roughness at $Re > 10^7$.

Relative roughness of pipe = e/D

e = roughness in feet - from Figure #7-5, p. 304.

D = diameter in feet

D"	6.969"	4.950"	4.750"	
D'	.5807'	.4125'	.3958'	
e	.00015	.00015	.01	(assume open hole similar to concrete pipe)
e/D	.000258	.000363	.0253	
% total length	72.7	21.5	5.79	
(%)(e/D)	.000188	.000078	.001465	

weighted e/D = 0.001731

f at (e/D = 0.001731, Re = 2.8×10^7) = 0.0226

from figure #7-3, p. 303.

$$\beta = \frac{(5.113)(10^{-2})}{(6.34)(10^{-1})(8.60)(10^2)(8.067)(10^{-3})(2.26)(10^{-2})}$$

$$= 5.144 \times 10^{-7}$$

Pseudoreduced pressure and temperature

$$Pr,1 = \frac{P_1}{P_c} = \frac{2840}{670} = 4.24$$

$$Pr,2 = \frac{P_2}{P_c} = \frac{10.67}{670} = 0.0159$$

T_c = pseudocritical temperature = 369°R from Fig. #4-22, p.112

$$T_r = \frac{T}{T_c} = \frac{860}{369} = 2.33$$

$\int_0^{P_{r,1}} \frac{P_r}{Z} dPr = 9.19 \int_0^{P_{r,2}} \frac{P_r}{Z} dPr = 0$, values of integrals functions are from Table #A-6, p. 732.

$$Q = \alpha \left[\beta\left(\int_0^{P_{r,1}} - \int_0^{P_{r,2}}\right)\right]^{1/2}$$

$$= (1.247)(10^8)\left[(5.144)(10^{-7})(9.19-0)\right]^{1/2}$$

$$= (1.247)(10^8)(2.174)(10^{-3})$$

$$Q = 2.71 \times 10^5 \; 10^3 \text{ standard ft}^3/\text{day}$$

$$= 2.71 \times 10^8 \text{ standard ft}^3/\text{day}$$

$$\boxed{Q = 270 \text{ MMSCF/day}}$$

b. ~~B~~. Cookbook Method #2:

Pipeline flow equation, from p. 306 (accounts for change in elevation between input and outlet of pipeline)

$$Q' = (3.22)\left(\frac{T_o}{P_o}\right)\left[\frac{(P_1{}^2 - e^s P_2{}^2)d^5}{GT_a f Z_a Le}\right]^{1/2}$$

Nomenclature for new terms:

Q = volumetric flow rate in, standard ft^3/hour at T_o, P_o

$$S = \frac{(3.75)(10^{-2})GX}{T_a Z_a}$$

d = pipe inside diameter in, inches = 6.618 inches

T_a = average line temperature in ^oR = 860^oR

Z_a = average compressibility factor = 0.987
from Table #A-2, p. 710, or Figure #4-16, p. 106.

X = change in elevation in feet

L_e = effective length of pipeline in, miles

$$L_e = \frac{e^{s-1}}{S} \; L$$

$$\gamma' = (3.22)\left(\frac{T_o}{P_o}\right) = \frac{(3.22)(5)(10^2)}{(1.067)(10^1)}$$

$$= 1.509 \times 10^2$$

$$S = \frac{(3.75)(10^{-2})(6.34)(10^{-1})(8.067)(10^3)}{(8.60)(10^2)(0.987)(10^{-1})}$$

$$S = 2.26 \times 10^{-1}$$

$$e^s = 1.254$$

$$d^5 = (6.618)^5 = 1.270 \times 10^4$$

$$L_e = \frac{(1.254-1)(8.067)(10^3)}{(2.26)(10^{-1})(5.28)(10^3)}$$

$$L_e = 1.716$$

$$D_1^{\,2} = \left[(2.840)(10^3)\right]^2 = 8.066 \times 10^6$$

$$P_2^{\,2} = \left[(1.067)(10^1)\right]^2 = 1.138 \times 10^2$$

$$Q' = (1.509)(10^2)\left\{\frac{\left[(8.066)(10^6)-(1.254)(1.138)(10^2)\right]\;(1.27)(10^4)}{(6.34)(10^{-1})(8.60)(10^2)(2.26)(10^{-2})(9.87)(10^{-1})(1.716)}\right\}^{1/2}$$

$$Q' = (1.509(10^2)\left[(49.09)(10^8)\right]^{1/2}$$

$$= (1.509)(10^2)(7.006)(10^4)$$

Q' = 1.057×10^7 standard ft^3/hour

Q' = $(1.057)(10^2)(2.4)(10^1)$

Q = 2.54×10^8 standard ft^3/day

$\boxed{Q = 250 \text{ M MSCF/day}}$

C. Cookbook - bottom hole pressure equation from p. 300.

$$P_2 = (P_1)\left(e^{\frac{(1.877)(10^{-2})(G)(X)}{T_a Z_a}} \right)$$

nomenclature for new terms

P_1 = surface chimney pressure = 2430 psig

= 2440 psia

It is assumed the gas in the back fill is in temperature equilibrium with the surrounding formation. Therefore, the average temperature of that gas is assumed to be the average of the surface temperature and the preshot downhole temperature.

T_d = preshot temperature at 8443 ft = 216°F

= 676°R

$$T_a = \frac{500+676}{2} = 588°R$$

P_c = 670 psia T_c = 369°R

assuming P_2 = 2980 psia

$$P_a = \text{average pressure} = \frac{2440+2980}{2}$$

= 2710 psia

$$P_r = \frac{P_a}{P_c} = \frac{2710}{670}, \quad T_r = \frac{T_a}{T_c} = \frac{588}{369}$$

P_r = 4.045 T_r = 1.592

Z_a = .816 from Table #A-2, p. 710, or Figure #4-16, p. 106.

$$P_2 = (2.44)(10^3)\left(e^{\frac{(1.877)(10^{-2})(6.34)(10^{-1})(8.067)(10^3)}{(5.88)(10^2)(8.16)(10^{-1})}}\right)$$

$$= (2.44)(10^3)\left(e^{2.005\times10^{-1}}\right)$$

$$= (2.44)(10^3)(1.2225)$$

BHP

$$\boxed{P_2 = 2983 \text{ psia}}$$

The downhole chimney pressure given P_2 = 2840 psia.

$$\text{The pressure ratio} = \frac{P_2^{\text{calc}}}{P_2^{\text{given}}} = \frac{2983}{2840}$$

$$= 1.05$$

X Since the flow is proportional to pressure there would be no substantial change in the previously calculated maximum flow.

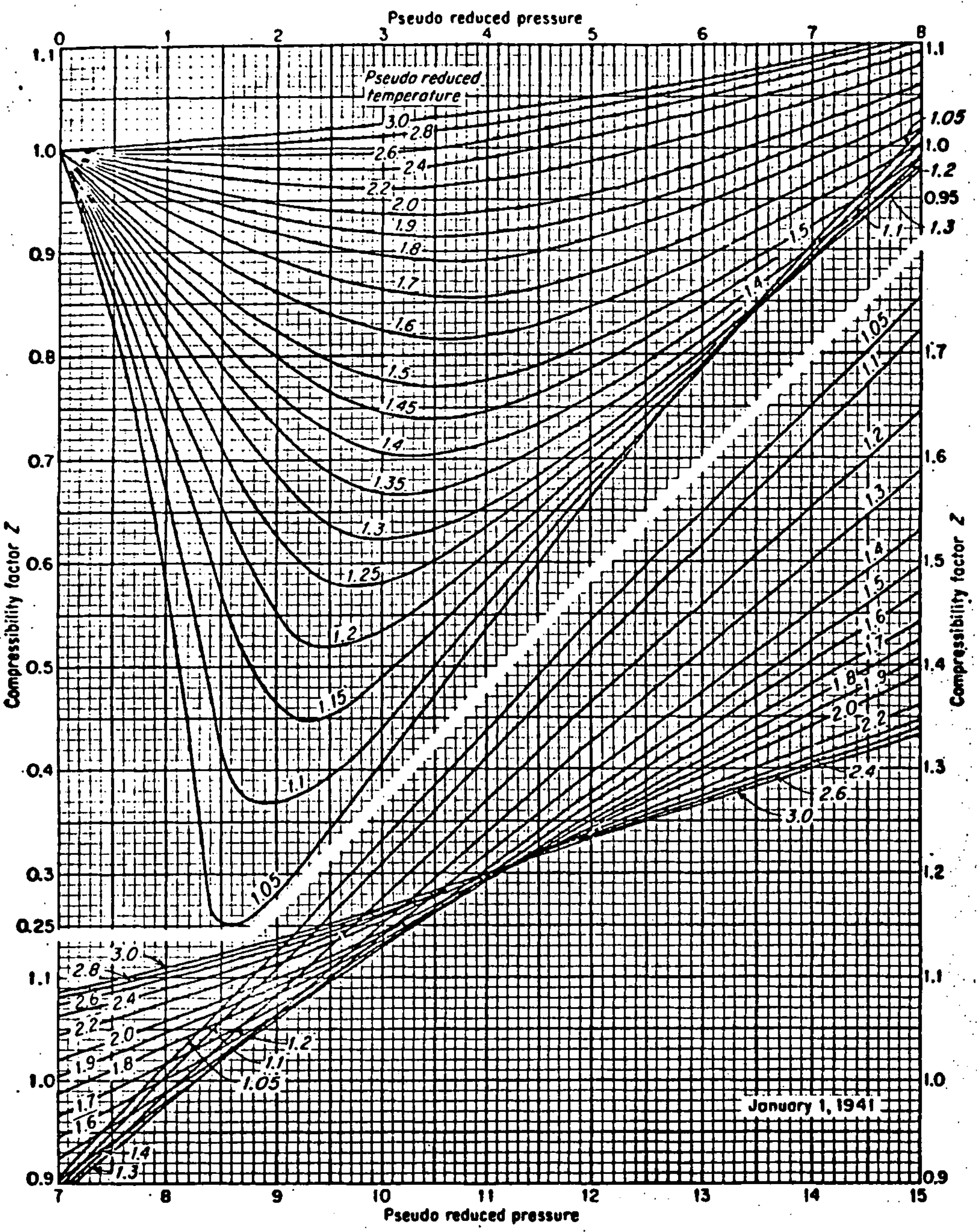


Fig. 4-16. Compressibility factor for natural gases. (*Standing and Katz, 4-87. Courtesy AIME.*)

degree of conformity to the theorem of corresponding states must be considered.

The *P-V-T* relations for methane-nitrogen mixtures were determined by Keyes and Burks (4-55) and for a natural gas containing 8.5 and 18.8 mole % nitrogen by Eilerts, Carlson, and Mullens (4-30). Table 4-10 gives the analyses of the natural gases, and Table 4-11 gives a comparison of the compressibility factors computed from Fig. 4-16 and the reduced temperature and pressure, with the experimental values for these compressibility factors. The calculated compressibility factors are lower than the measured values by about 2 per cent at the higher temperatures and intermediate pressures. The factors for the gases with nitrogen are lower on the average over the full range of temperature.

Reamer, Olds, Sage, and Lacey (4-72) have measured the compressibility of four mixtures of methane and carbon dioxide from 100 to 460°F and up to 10,000 psia, with data at 100 and 280°F reproduced in Table 4-12. For gases with 1 or 2 mole % carbon dioxide, the pseudocritical chart is reliable but, for higher percentages, a correction may be necessary as indicated by comparing computed compressibilities with the measured compressibilities in Table 4-12.

Likewise, for methane-hydrogen sulfide mixtures,

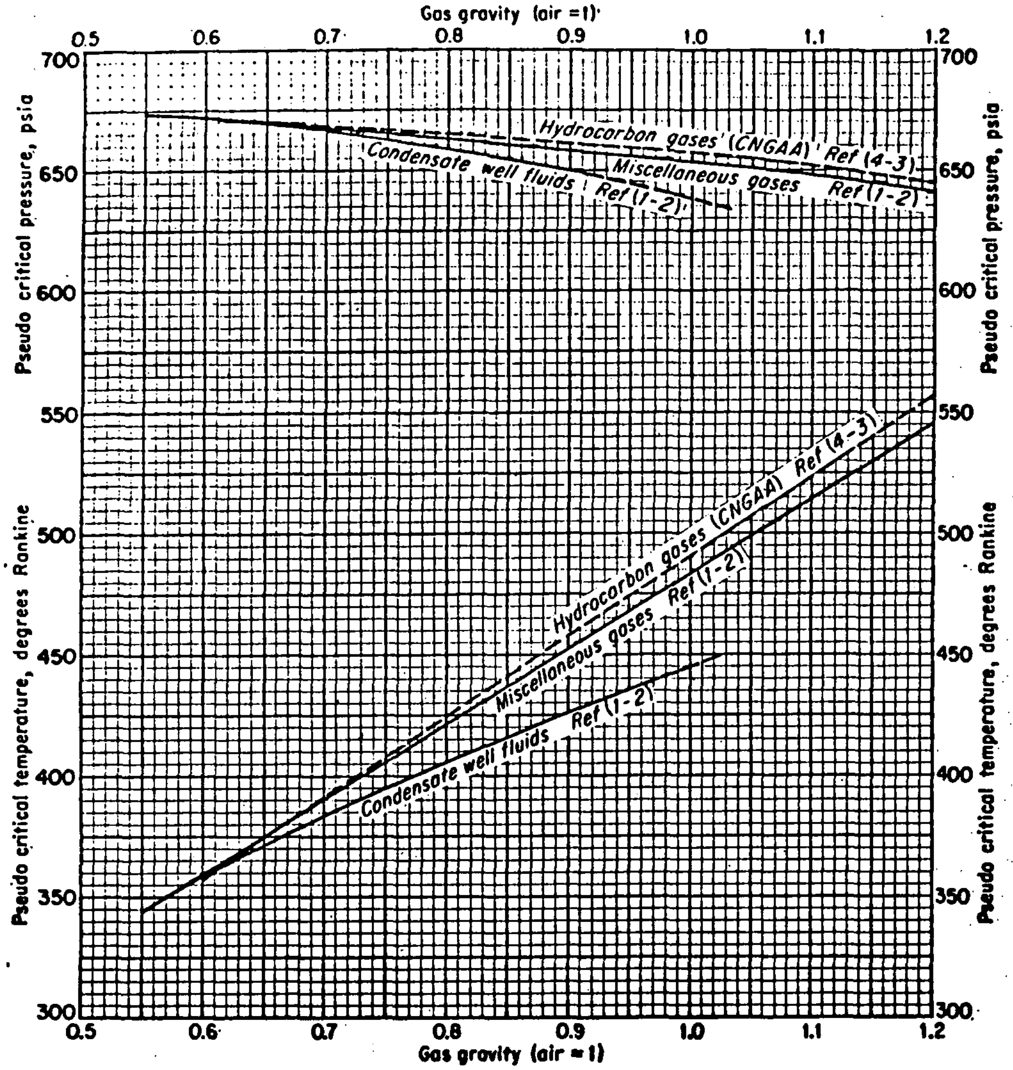


Fig. 4-22. Pseudocritical properties of natural gases. (Brown, Katz, Oberfell, and Alden, 1-2.)

the 0.7 and 0.8 gravity gases corresponding to the condensate well fluids.

Effect of Liquid Phase

It was found that certain natural gases entered the two-phase region during *P-V-T* studies and that the compressibility factor for the entire mixture was similar to that for a single phase. To study the use of the compressibility factor for density calculations in the high-pressure two-phase region, data on a natural gas–natural gasoline mixture were used. The phase diagram for the mixture is given by Fig. 4-24 and includes the regions likely to be encountered in high-pressure gases. The effect of a small amount of liquefaction on the over-all density is of especial interest in meter calculations.

Table 4-14 gives the comparison between experimental and calculated densities for the natural gas–natural gasoline mixture. The calculations were made assuming that the system density could be computed from Eq. (4-2), including the compressibility factor. The observed volume percentages of liquid were taken from the phase diagram (Fig. 4-24). Table 4-14 demonstrates that the compressibility-factor method can be used to compute the density of a mixture in the single-phase region above the bubble-point curve, a short way into the two-phase region below the bubble-point curve, and completely through the two-phase region at high temperatures where a small volume percentage of liquid is present. The region in which these calculations may be made is limited to T_R of 1.05 or higher.

A study of the methane-butane system also indicated that the over-all density of a system existing as a small proportion of liquid and the remainder gas can be computed at high pressure by assuming that the system is a single phase. The explanation of this remarkable behavior lies in the relatively small change in partial molal volume between the vapor and liquid phases at these conditions. Hence, it matters little

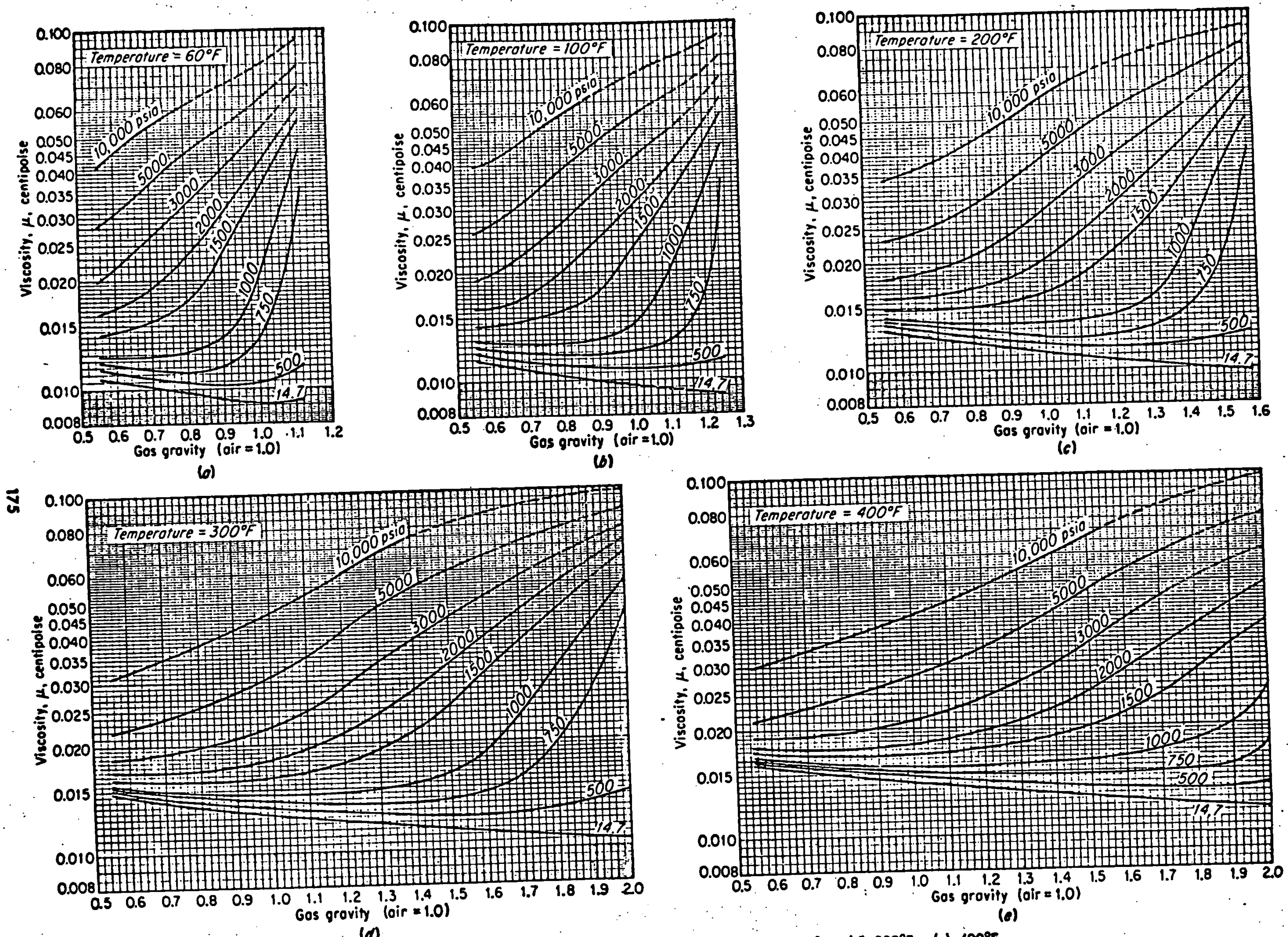


Fig. 4-106. Viscosity of natural gases. (a) 60°F. (b) 100°F. (c) 200°F. (d) 300°F. (e) 400°F.

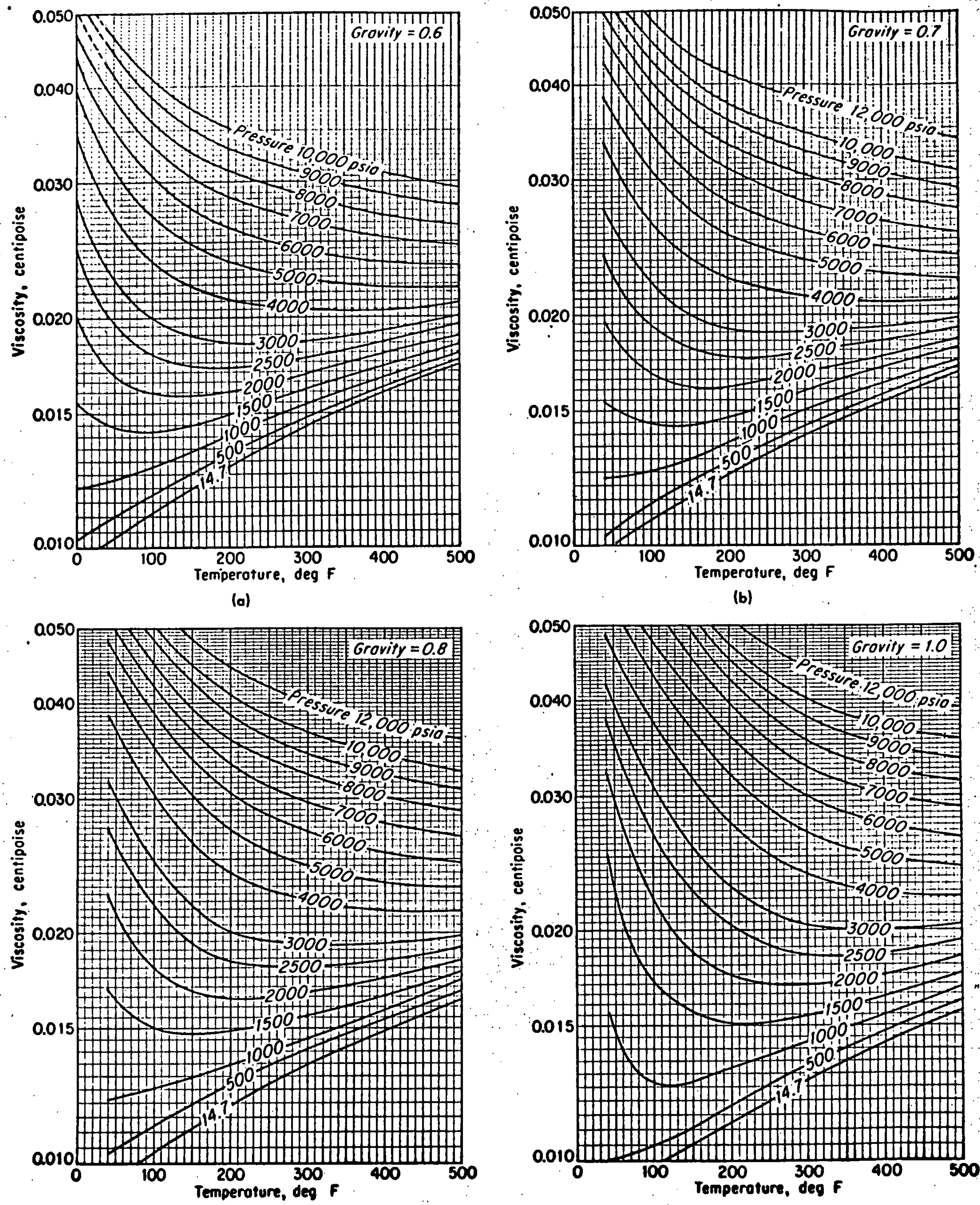


Fig. 4-107. Viscosity of natural gases. (a) 0.6 gravity. (b) 0.7 gravity. (c) 0.8 gravity. (d) 1.0 gravity. (2-42.)

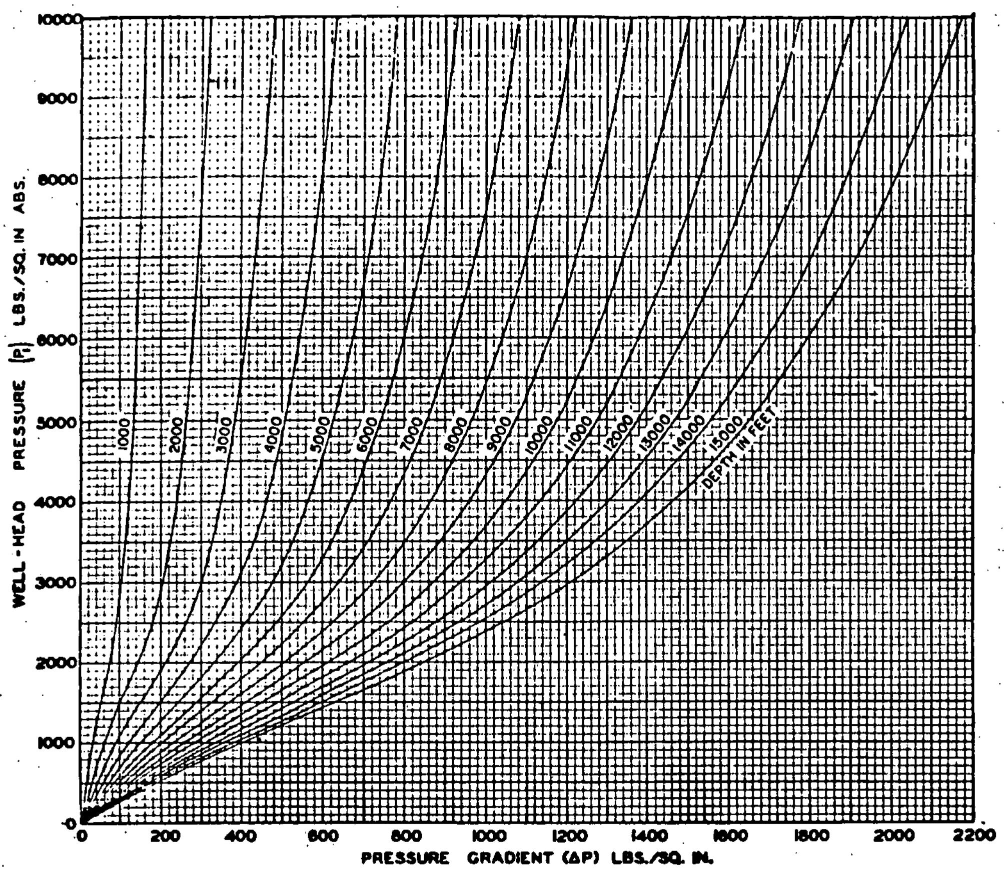


Fig. 7-2. Pressure gradients in gas wells. (*Katz and Rzasa, 7-34. Courtesy AIME.*)

is dimensionless,* but may be converted to field units.

$$\mathrm{Re} = \frac{Dv\rho}{\mu} = \frac{DW}{\mu A} = \frac{4dQ \times 12 \times 29G \times 1{,}000}{\mu 24\pi d^2 \times 379 \times 2.42}$$

$$= 20.0 \frac{QG}{\mu d} \qquad (7\text{-}22)$$

where Q = gas flow at 60°F and 14.7 psia, Mcf/day
G = gas gravity
W = mass flow, lb mass/hr
d = diameter of pipe, in.
μ = viscosity, centipoises
A = flow area, sq ft

Fluid flow ranges in nature between two extremes, laminar or streamline flow and turbulent flow (Fig. 7-3). For Reynolds numbers up to 2,100, flow is in the laminar region and f can be expressed by $f = 64/\mathrm{Re}$, which is the equation for the straight line in Fig. 7-3. It is to be noted that, in the laminar region of flow, the f factor is independent of pipe roughness. The stagnant film on the pipe surface minimizes the roughness of the pipe, and resistance to flow is due primarily to the internal resistance to shear, that is, the viscosity of the fluid.

* In dimensionless form

$$\mathrm{Re} = \frac{D\ (\mathrm{ft})\ v\ (\mathrm{ft/sec})\ \rho\ (\mathrm{lb/cu\ ft})}{\mu\ [\mathrm{lb/(ft)(sec)}]}$$

μ in pounds per foot per second = centipoises × 0.000672.

For Reynolds numbers between 2,100 and 4,000, flow is in an unstable region, as indicated by the shaded area of Fig. 7-3. At Reynolds numbers greater than 4,000, flow is partially turbulent, falling in the region of transition; it definitely becomes a function of relative roughness, with viscosity effects becoming less significant. In this region of transition (Fig. 7-3) the f factor is expressed by the empirical equation proposed by Colebrook (7-11).

$$\frac{1}{\sqrt{f}} = 2 \log \frac{D}{e} + 1.14 - 2 \log \left(1 + 9.34 \frac{D/e}{\mathrm{Re}\sqrt{f}}\right) \qquad (7\text{-}23)$$

Smith and coworkers (7-36, 7-37, 7-38) have shown from carefully executed experimental studies that in actuality the f factors in the region of transition lie between those empirically predicted by the Colebrook relationship (7-11) and those predicted by Nikuradse (7-28) using pipes artificially roughened with coatings of uniform sand grains. According to these studies, use of the Colebrook expression in the transition region will lead to conservative design results.

For turbulent flow in smooth pipe—that is, pipe of zero roughness—the f factor (Fig. 7-3) over the entire range of Reynolds numbers can be expressed by the following relationship (7-28):

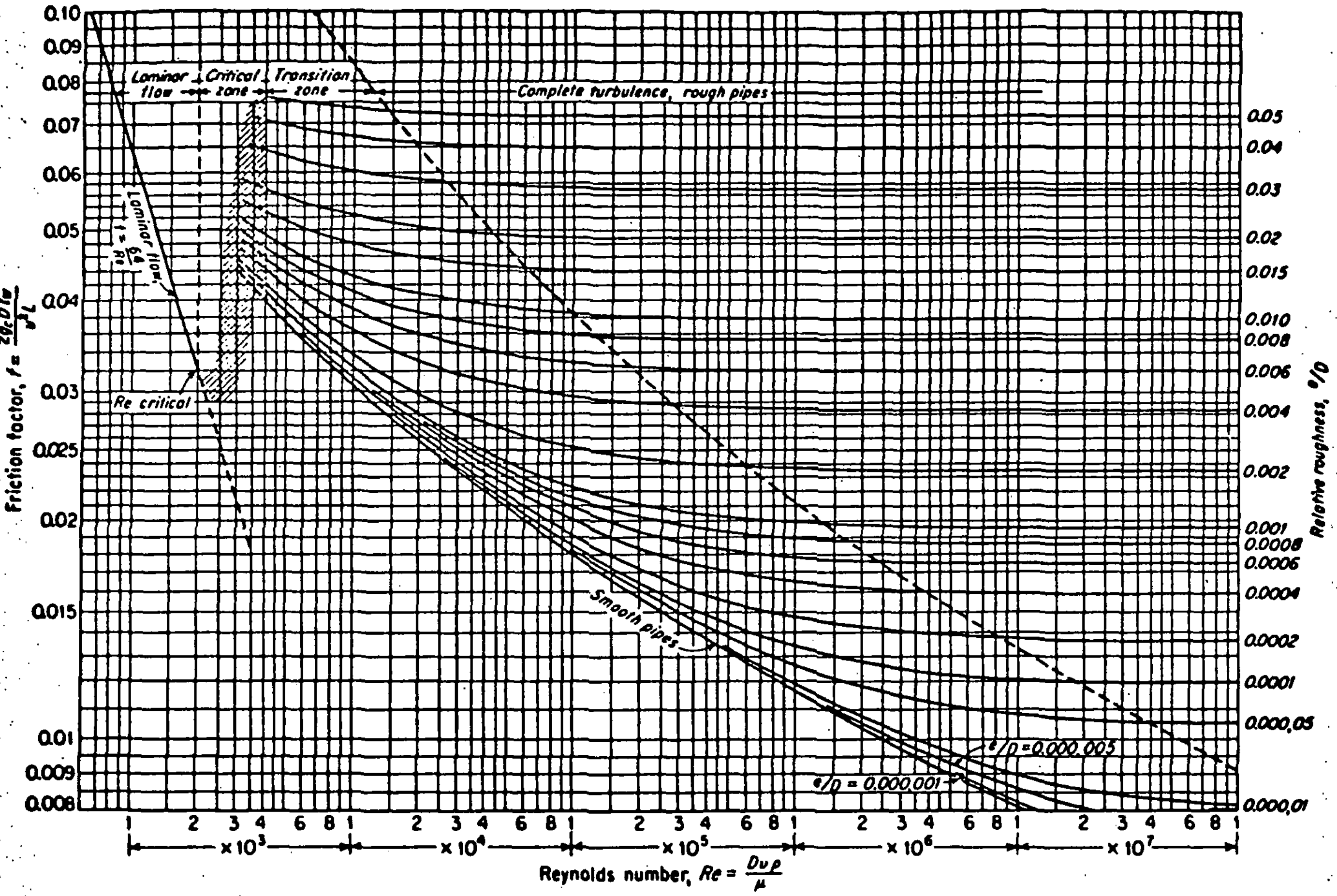


Fig. 7-3. Friction factor for flow of fluids in pipe. (Moody, 7-25. Courtesy ASME.)

$$\frac{1}{\sqrt{f}} = 2 \log (\text{Re}\sqrt{f}) - 0.80 \qquad (7\text{-}24)$$

When flow becomes completely turbulent—that is, beyond the transition region—it is no longer a function of the Reynolds number, but becomes a function of relative roughness e/D only. This is shown in Fig. 7-3, where the f-factor lines are horizontal at high Reynolds numbers. Figure 7-4 shows the variation of f as a function of e/D only for completely turbulent flow. Gas flow at high pressure drops occurs at these high Reynolds numbers. The f factor in this region of flow is completely independent of the physical properties of the flowing fluid. For fully turbulent flow the f factor is expressed by an equation obtained experimentally by Nikuradse (7-28).

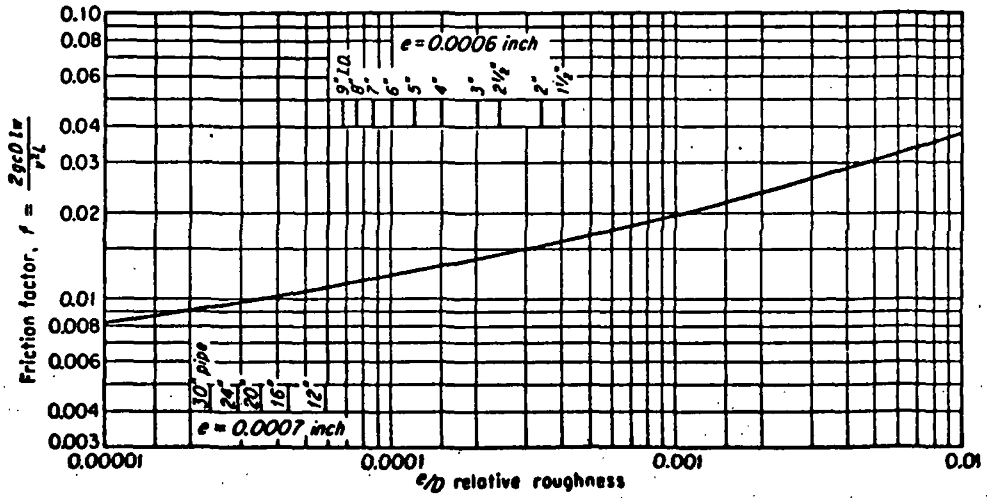


Fig. 7-4. Friction factor at completely turbulent flow as function of roughness.

$$\frac{1}{\sqrt{f}} = 2 \log \frac{D}{e} + 1.14 \qquad (7\text{-}25)$$

Figure 7-5 is a plot of relative roughness e/D as a function of diameter D and absolute roughness e for various types of pipe (7-25). Absolute roughness is best evaluated by an analysis of experimental flow data. Smith and coworkers (7-37, 7-38) have summarized, from their own experimental tests and from data available in the literature, absolute-roughness values for gas-transmission lines, flow strings in gas wells, and experimental pipelines (Table 7-1). These values are valid for clean steel pipe.

For turbulent flow in rough pipelines, the presence of liquid enough to wet the pipe wall will increase the flow capacity of the pipe. However, for laminar flow, the presence of a liquid film will decrease the flow capacity of the pipeline because the viscosity of the liquid in the surface layer is greater than the viscosity of the gas when the pipe is dry.

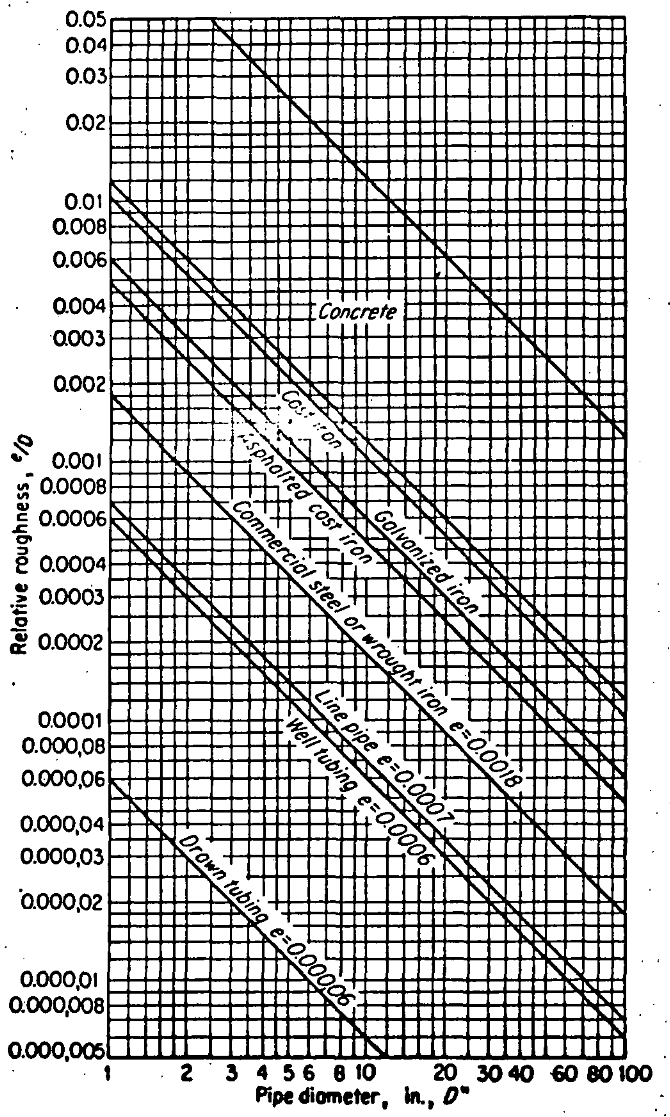


Fig. 7-5. Relative roughness of various pipes. (Moody, 7-25. Courtesy ASME.)

Table 7-1. Values of Roughness for Gas Lines

Reference	Description	Diameter, in.	Absolute roughness e, in.
Smith (7-38).......	Gas-transmission lines (avg)	10–26	0.0007
Smith (7-37).......	Gas wells	1¼–7	0.00065
Cullender (7-13)....	Gas wells	1¼–8⅝	0.0006
Smith (7-38).......	Experimental pipelines	2–8	0.00055–0.0019

PIPELINE-FLOW CALCULATIONS

Engineering of long-distance transportation of natural gas by pipeline requires a knowledge of flow formulas for calculating capacity and pressure requirements. In the early development of the natural gas-transmission industry, pressures were low and the equations used for design purposes were simple and adequate. However, as pressures increased in order to meet increased capacity demands, equations were developed to meet the new requirements.

As stated previously, Eq. (7-2) is the starting point of all fluid-flow relationships involving the evaluation of friction losses. In the case of natural gas transmission, the initial assumptions usually made in the derivation of any specific flow equation are as follows:

1. The kinetic-energy change is negligible and can be taken as zero. With this assumption, Eq. (7-2) becomes

$$\int_1^2 V\,dP + \frac{g}{g_c}\,\Delta X + lw + w = 0 \qquad (7\text{-}26)$$

2. The flow is steady-state and isothermal.
3. The flow is horizontal.
4. There is no work done by the gas in flow.

Given these assumptions, Eq. (7-2) reduces to

$$\int_1^2 V\,dp + lw = 0 \qquad (7\text{-}27)$$

Substituting for lw from Eq. (7-21) then leaves

$$\int_1^2 V\,dP + \int_1^2 \frac{fv^2}{2g_cD}\,dL = 0 \qquad (7\text{-}28)$$

By making various additional assumptions, Eq. (7-28) can be made the starting point for the derivation of specific flow equations for the transmission of natural gas.

One of the earliest of such equations was that of Weymouth (7-42), now modified to include the compressibility factor (7-9).

$$Q = 3.22 \frac{T_0}{P_0}\left[\frac{(P_1^2 - P_2^2)d^5}{GTLfz_a}\right]^{0.5} \qquad (7\text{-}29)$$

where Q = gas flow measured at T_0 and P_0, std cu ft/hr
- L = length of line, miles
- d = internal diameter (ID), in.
- P = pressure, psia
- G = gas gravity (air = 1)
- T = average line temperature, °R
- z_a = average compressibility factor (in Weymouth's original equation $z = 1$)
- f = friction factor from Fig. 7-3 or 7-4

Weymouth assumed that f varied as a function of the diameter in inches as follows:

$$f = \frac{0.032}{d^{1/3}} \qquad (7\text{-}30)$$

Equation (7-29) then results in

$$Q = 18.062 \frac{T_0}{P_0}\left[\frac{(P_1^2 - P_2^2)d^{16/3}}{GTLz_a}\right]^{0.5} \qquad (7\text{-}31)$$

Another equation, the "Panhandle" formula, assumes that f varies as follows:

$$\frac{1}{f} = 52\left(\frac{GQ}{d}\right)^{0.1461} \qquad (7\text{-}32)$$

resulting in

$$Q = 435.87E\left(\frac{T_0}{P_0}\right)^{1.07881}\left(\frac{P_1^2 - P_2^2}{L}\right)^{0.5394}\left(\frac{1}{T}\right)^{0.5394}\left(\frac{1}{G}\right)^{0.4606} d^{2.6182} \qquad (7\text{-}33)$$

where Q = gas flow measured at T_0 and P_0, cu ft/day
- d = pipe ID, in.
- E = efficiency factor (0.92 average)
- L = length of pipe, miles
- T = mean flowing temperature, °R
- P = pressure, psia
- G = gravity of gas (air = 1)

The Ford, Bacon, and Davis flow formula for design of pipelines is given by Eq. (7-34).

$$Q = 840EMNd^{2.625}\left(\frac{P_1^2 - P_2^2}{L}\right)^{0.541} \qquad (7\text{-}34)$$

where Q = gas flow measured at P_0 and T_0, cu ft/day
- E = line flow efficiency (used as 94 per cent)
- M = measurement-base adjustment factor

$$M = \frac{14.735}{P_0}\frac{T_0}{520}$$

- P_0 = base pressure, psia
- T_0 = base temperature, °R
- N = gas-characteristic adjustment factor

$$N = B^{0.54}\left(\frac{0.6}{G}\right)^{0.46}\left(\frac{7.0}{\mu}\right)^{0.08}\left(\frac{520}{T}\right)^{0.54}$$

- B = $1/z$, or 1+ deviation from Boyle's law at average pressure
- G = specific gravity (air = 1.0)
- μ = viscosity, English absolute units $\times 10^6$ (centipoises $\times$ 672)
- T = flowing temperature, °R
- d = pipe ID, in.
- P_1 = line input pressure, psia
- P_2 = line output pressure, psia
- L = length of pipeline, miles

Equation (7-34) applies for 6- to 24-in. lines; the constant becomes 824 for 30-in. lines.

In addition to the Weymouth, Panhandle, and Ford, Bacon, and Davis equations, many others (7-23), such as the Cox and Pittsburgh, have been derived. Hanna and Schomaker (7-20) have presented a revised Panhandle formula, employing the AGA compressibility factors for natural gas.

The specific flow equation of Clinedinst (7-10) takes rigorously into consideration the deviation of natural gas from ideal behavior. This equation is a rigorous integration of Eq. (7-28). The only assumptions are those made in arriving at Eq. (7-28).

$$Q = 3{,}973.0\frac{z_0T_0P_c}{P_0}\left[\frac{D^5}{GTLf}\left(\int_0^{P_{r,1}}\frac{P_r}{z}\,dPr - \int_0^{P_{r,2}}\frac{P_r}{z}\,dP_r\right)\right]^{0.5} \qquad (7\text{-}35)$$

where Q = volumetric flow rate, Mcf/day
- P_c = pseudocritical pressure, psia
- D = pipe ID, ft
- L = length of pipe, ft
- T = flowing temperature, °R
- G = gas gravity
- z_0 = compressibility factor at T_0 and P_0, normally accepted as 1.0
- P_r = pseudoreduced pressure

Values of the integral functions

$$\int_0^{P_r}\frac{P_r}{z}\,dP_r$$

are obtained from Table A-6.

The use of the Clinedinst equation is perhaps best explained by means of a numerical example.

Illustrative Problem

A pipeline 100 miles long has an internal diameter of 13.375 in. The inlet pressure is 1,300 psia and the pressure at the end of

the line is 300 psia. The temperature of the flowing gas is 40°F, and its composition is as follows:

	Mole %
Methane	75
Ethane	21
Propane	4
	100

Calculate the volumetric flow rate measured at 14.65 psia and 60°F.

Solution

Calculation of pseudocritical and reduced conditions:

Component	Mole fraction	Molecular weight	Lb/mole	P_c, psia	Psia	T_c, °R	°R
Methane	0.75	16	12.0	673	505	343	257
Ethane	0.21	30	6.2	708	148	550	115
Propane	0.04	44	1.7	617	25	666	26
			19.9		678		398

$$G = 0.686$$

$$P_{r,1} = \frac{1{,}300}{678} = 1.91$$

$$P_{r,2} = \frac{300}{678} = 0.44$$

$$T_r = \frac{460 + 40}{398} = 1.25$$

The integral terms, as read from Table A-6, are

$$\int_0^{1.91} \frac{P_r}{z}\, dP_r = 2.43 \qquad \int_0^{0.44} \frac{P_r}{z}\, dP_r = 0.10$$

Using a roughness of 0.0006 in., $e/D = 0.000045$, the f factor as obtained from Fig. 7-4 is

$$f = 0.0104$$

for completely turbulent flow conditions. Then, from Eq. (7-35)

$$Q = \frac{3{,}973.0 \times 1.000 \times 520 \times 678}{14.65} \left[\frac{(1.1145)^5}{0.0104 \times 5.28 \times 10^5 \times 0.686 \times 500}(2.43 - 0.10)\right]^{0.5}$$

$= 140{,}000$ Mcf/day at 14.65 psia and 60°F

In actual practice, transmission lines often deviate considerably from the horizontal. Given all the previous assumptions with the exception of horizontal flow, Eq. (7-2) reduces to

$$\int_1^2 V\,dP + \frac{g}{g_c}\Delta X + \int_1^2 \frac{fv^2}{2g_c D}\,dL = 0 \quad (7\text{-}36)$$

This equation is the starting point for any flow calculations that take into consideration differences in elevation.

One such equation was that developed by Ferguson (7-16), to which has been added a term correcting for the compressibility of the gas.

$$Q = 3.22\,\frac{T_0}{P_0}\left[\frac{(P_1^2 - e^S P_2^2)d^5}{GT_a f z_a L_e}\right]^{0.5} \quad (7\text{-}37)$$

where $e = 2.7183$
d = pipe ID, in.
Q = gas flow, std cu ft/hr, measured at T_0 and P_0
P = pressure, psia
G = gas gravity
T_a = average line temperature, °R
z_a = average compressibility factor
$S = 0.0375GX/T_a z_a$
X = change in elevation, ft (X is positive if outlet is higher than inlet)
L_e = effective length of pipeline, miles

The effective length L_e of the pipeline is based upon the profile of the line between pressure-measuring stations. If the slope is uniform

$$L_e = \frac{e^S - 1}{S} L = JL \quad (7\text{-}38)$$

where $J = (e^S - 1)/S$.

If the slope is not uniform, the profile should be divided into sections of nearly uniform slope; the effective length is then calculated as follows:

$$L_e = L_1J_1 + L_2e^{S_1}J_2 + L_3e^{S_2}J_3 + \cdots + L_ne^{S_{n-1}}J_n \quad (7\text{-}39)$$

where $J_1, J_2, J_3, \ldots J_n$ are calculated for the increase or decrease in elevation in L_1, L_2, L_3, and so forth, and $e^{S_1}, e^{S_2}, e^{S_3}, \ldots e^{S_{n-1}}$ are calculated for the rise or drop from the inlet of the line to the end of sections $L_1, L_2, L_3, \ldots L_{n-1}$, respectively.

As the demand for gas changes and as old transmission systems are extended and paralleled in order to increase line capacity, a knowledge of the relationships involved in the solution of complex pipeline problems becomes necessary. Johnson and Berwald, in Bureau of Mines monograph 6 (7-23), were the first to develop these relationships, using as a basis the Weymouth equation in which the f factor was expressed as a power function of the internal diameter of the pipe. Recently Smith and coworkers (7-38) derived these relationships, but without expressing the f factor in terms of any of its variables.

The philosophy involved in deriving the special relationships used in the solution of complex transmission systems is to express the various lengths and diameters of the pipe in the system as equivalent lengths of a common diameter or equivalent diameters of a common length.

Where the flow of gas, pressure differential, temperature, gas gravity, and compressibility are the same for two different pipes, the relationship of diameters and pipe lengths is expressed as follows:

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