Directive 005: Calculating Subsurface Pressure via Fluid-Level Recorders

1977

Effective June 17, 2013, the Energy Resources Conservation Board (ERCB) has been succeeded by the Alberta Energy Regulator (AER).

As part of this succession, the title pages of all existing ERCB directives now carry the new AER logo. However, no other changes have been made to the directives, and they continue to have references to the ERCB. As new editions of the directives are issued, these references will be changed.

Some phone numbers in the directives may no longer be valid. Contact AER Inquiries at 1-855-297-8311 or inquiries@aer.ca.

Calculating Subsurface Pressure via Fluid-Level Recorders

1978

Effective January 1, 2008, the Alberta Energy and Utilities Board (EUB) has been realigned into two separate regulatory bodies, the Energy Resources Conservation Board (ERCB), which regulates the energy industry, and the Alberta Utilities Commission (AUC), which regulates the utilities industry.

As part of this realignment, the title pages of all existing EUB directives now carry the new ERCB logo. However, no other changes have been made to the directives, and they continue to have references to “EUB.” As new editions of the directives are issued, these references will be changed.

ENERGY RESOURCES CONSERVATION BOARD
Directive 005: Calculating Subsurface Pressure via Fluid-Level Recorders

1978

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ERCB

Calculating Subsurface Pressure

Via

Fluid-Level Recorders

ENERGY RESOURCES CONSERVATION BOARD
GUIDE SERIES

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- G-12 Planning, Conducting, and Reporting Subsurface Pressure Tests
- G-15 Effect of Tensile Loading on Casing Collapse

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1 INTRODUCTION

1.1 PRESSURE MEASUREMENT ALTERNATIVE

The most accurate means of determining the static subsurface pressure of oil and gas wells is the subsurface instrument. However, the acoustical well sounder (AWS) provides an alternative method for use in pumping wells wherein the pulling of pump and rods is uneconomical.

The AWS method comprises the firing of a blank cartridge into the annulus; the recording, on a moving chart, of the soundwave reflections from the tubing collars and fluid level; and the subsequent interpretation of static subsurface pressure.

The use of AWS equipment has become widespread in Alberta in recent years, accounting for one-half of the surveys performed in the province from 1975 through 1977 - a total of 4000 in 1977 alone.

1.2 ABOUT THIS GUIDE

This guide sets forth the Energy Resources Conservation Board's recommendations on methods to use when calculating subsurface pressure via fluid-level recorders. It discusses the errors frequently made in determining pressure, and presents helpful graphs developed by the Board.

1.3 THE PROBLEM

Experience has shown that the accuracy of subsurface pressures obtained from fluid-level calculations has, at times, proved questionable. Although the producing characteristics of many wells preclude great accuracy, the lack of accuracy can be attributed in many cases to improper data-gathering procedures, interpretation, and pressure calculation techniques.

In 1967 and 1968, examination of AWS charts for wells surveyed in the Pembina, Leduc-Woodbend and Zama fields, submitted to the Board by various companies, showed some 44 per cent to be of poor quality and only 21 per cent of good quality (Table 1). Although procedures have since improved somewhat, further improvement can still be made.

TABLE 1 COMPARISON OF AWS CHART QUALITY

Field	Poor		Fair		Good		Total	
	No.	% of Total	No.	% of Total	No.	% of Total	No.	% of Total
Pembina	31	53.4	15	25.9	12	20.7	58	100
Leduc-Woodbend	16	51.6	12	38.7	3	9.7	31	100
Zama	23	32.4	29	40.8	19	26.8	71	100
Total	70	43.8	56	35.0	34	21.2	160	100

1.4 MEASURING SURFACE-CASING PRESSURE

The calculation of subsurface pressure necessitates the measurement of surface casing pressure. To ensure the accuracy of the latter, we recommend the use of a portable deadweight tester whenever possible.

If a dial gauge must be used, it should be calibrated immediately preceding or following the pressure survey. Several spot checks in the field during 1967 revealed that uncalibrated dial gauges were in error by as much as 400 kPa.

2 EQUIPMENT CONTROLS AND ADJUSTMENTS

The AWS operator should possess a general familiarity with the instrument. Detailed operation instructions come with the recorder or can be obtained from the equipment distributor.

2.1 PROPERTIES OF SOUNDWAVES

The quality of the data obtained in AWS surveys depends on the proper choice of frequency, sensitivity, and cartridge size. The choices available reflect certain principles of physics related to sound:

1. The transmission of sound varies with the pressure, density, temperature, and type of the medium through which the soundwaves pass.

2. The lower the frequency, the farther the soundwave will travel.

3. The higher the pressure, the farther the soundwave will travel.

These principles should be borne in mind when selecting AWS control settings.

2.2 FREQUENCY

A filter switch controls the band of the frequencies to which the instrument is receptive. Some instruments have a range of narrow-band frequency selections, while others group the frequencies into broader ranges such as upper collar and lower collar. Collar-reflection shots are usually recorded at frequencies from 15 to 85 cycles per second (cps). The lower of three frequencies are used in low-pressure or deep wells, the higher normally in high-pressure or shallow wells.

A low-frequency switch shifts reception to frequencies below 10 cps and disengages the automatic gain control (see 2.3). The switch is used in special cases only, such as:

1 for wells having a small annulus (that is, small-diameter casing or large-diameter tubing)

2 for wells thought to be obstructed, in which case reflections due only to the obstruction and the fluid level (but not the tubing joints) may be required

In either of the above cases, failure to depress the low-frequency switch may result in excessive sound reverberation and resultant severe distortion of the original signal.

2.3 SENSITIVITY

Minimum setting. The best results are obtained when the sensitivity control is set at the lowest point that will give a good chart. Low sensitivity settings are usually needed for wells with high gas-column pressure, and vice versa.

Maximum setting. Too high a setting of the control can cause signal distortion by overloading the amplifier, thus hindering distinction of the fluid level from the collar reflections. The distortion may result in excessive stylus travel, rendering parts of the recording unreadable.

The maximum setting is also limited by wellhead noise. Before a recording is made, the recorder should be turned on and the sensitivity gradually increased until deflection of the stylus due to wellhead noise is sufficient to affect the recording. The control's position should then be noted, for it should not be exceeded during recording.

Cleanliness. Controls should be cleaned periodically with a good-quality volume-control cleaner because a dirty sensitivity control results in an erratic recording.

Suppression Control

Some modern recorders are equipped with a suppression control, the purpose of which is to reduce initial sensitivity so that echoes from the first few tubing collars will not be obliterated.

Automatic Gain Control

The automatic gain control of most modern recorders requires no manipulation by the user. Its purpose is to decrease the amplitude of strong signals such that no overloading of the amplifier will result.

2.4 CARTRIDGE SIZE

Sizes of cartridge include 10- and 12-gauge as well as 38- and 45-calibre. The 12-gauge and 45-calibre are commonly used in AWS surveys - the smaller (45-calibre) in shallow or high-pressure wells and the larger generally in deep or low-pressure wells.

3 RUNNING THE SURVEY

3.1 USUAL PROCEDURE

For best results, the following procedure should normally be used:

1 Pre-warm the instrument.

2 Determine the sensitivity setting that may not be exceeded due to wellhead noise.

3 Discharge, and make a recording using the low-frequency switch, to determine the length of gas column and whether any obstructions are present in the annulus. (This step can be omitted with dual-channel recorders because they take a fluid-level recording simultaneously with a collar-reflection recording.)

4 Make a collar-reflection recording and allow the chart to run the length of two fluid-level deflections. (A good estimate of the frequency, sensitivity, and cartridge size needed for an undistorted recording can be made, given a knowledge of the gas pressure, approximate depth to fluid, and possible presence of obstructions.)

5 Check the collar-reflection chart for quality, and verify it with the fluid-level chart.

6 Repeat any of the previous steps, making the adjustments necessary to obtain a good chart. (Extra attempts to obtain a readable

chart while in the field are worthwhile. Most of the survey costs will have been incurred, whereas once you have left the field, another chart cannot be made without the major expense of returning to the field and of any additional lost production.)

7 Record any details that will aid the proper interpretation of the chart and the calculation of pressures, to establish confidence in the resulting calculated pressures. For example, specify the total number of tubing joints and the tubing depth. (This information helps interpret any "double kicks" on the recording, the double kicks being characteristic of systems in which the fluid level is below the bottom of the tubing.)

3.2 SPECIAL PROCEDURE

If salt, paraffin, or other material obstructs the annulus, use a low sensitivity setting, the low-frequency switch, and a large (12-gauge) cartridge.

Under adverse well conditions, particularly where a great depth to fluid exists, use the following procedure:

1 Set the sensitivity control to the minimum needed for an initial recording.

2 Adjust the instrument to a lower collar-reflection setting or, in the units with variable filter settings, to a frequency range of about 15 to 25 cps.

3 Use a large (12-gauge) cartridge except in high-pressure wells; and, while watching the chart, manually adjust the sensitivity control so that a proper degree of stylus deflection is maintained throughout the recording.

4 INTERPRETING THE CHART

4.1 ANOMALOUS CHARTS

Single- and Dual-channel Recorders

In order to establish a fluid level in a well with confidence, make both a fluid-level and a (higher frequency) collar-reflection recording, and compare them. Dual-channel recorders are available for this purpose (Figure 1) but separate collar and fluid-level charts obtained on individual runs with a single-channel recorder serve equally well. Occasionally the fluid level on a seemingly good single-channel chart is misinterpreted due to the lack of a fluid-level verification chart.

Well Blockage

A partial blockage downhole is sometimes mistaken for a fluid level on an unverified single-channel chart. Figure 2 is such an example.

Here, an AWS collar chart obtained from a Pembina Belly River well was interpreted and recorded as having 10.3 tubing joints to the fluid. The subsurface pressure determined with a gauge on the same well indicated 62 joints to the fluid, showing the value of 10.3 to be incorrect. Unfortunately, the AWS operator failed to confirm the fluid level with a fluid-level verification chart; and the chart interpreter, not recognizing the unusual characteristics, accepted the joint count as a basis for pressure calculation.

Detailed examination of the chart revealed a major obstruction some 10 joints below the surface, and the accentuated kicks were merely repeated echoes from the obstruction. Had a recording at the lower frequency been made to verify the collar chart, it would probably have revealed the obstruction and the more accentuated kick of the fluid level.

High Fluid Level

High fluid levels are difficult to recognize, and when they are suspected, several charts should be obtained at different frequency settings. One of the high-frequency charts will often clearly show the fluid level to be near the surface.

Wax Plug

Anomalies such as those caused by a wax plug are difficult to distinguish, even with a fluid-level verification chart.

In such cases produce the well and take a fluid-level measurement. Then shut in the well and take a series of measurements during the pressure build-up. This procedure will indicate a changing fluid level, thereby enabling the operator to distinguish between the wax plug and fluid level.

When a static fluid level is to be taken, obtain a fluid-level measurement prior to shutting in the well for the static survey; or, following the survey, take a fluid-level measurement after some of the casing pressure has been released. If a wax plug or other obstruction is causing an apparent fluid-level reflection, it can be detected by comparison of the resulting charts.

4.2 NUMBER OF TUBING JOINTS TO THE GAS-LIQUID INTERFACE

Table 2 (p. 15) compares Board and operator interpretations of the number cf tubing joints to the gas-liquid interface. Discrepancies of more than two joints occurred in about 40 per cent of the cases. Since each joint introduces an error of about 70 kPa, charts with an error greater than two joints should be rejected.

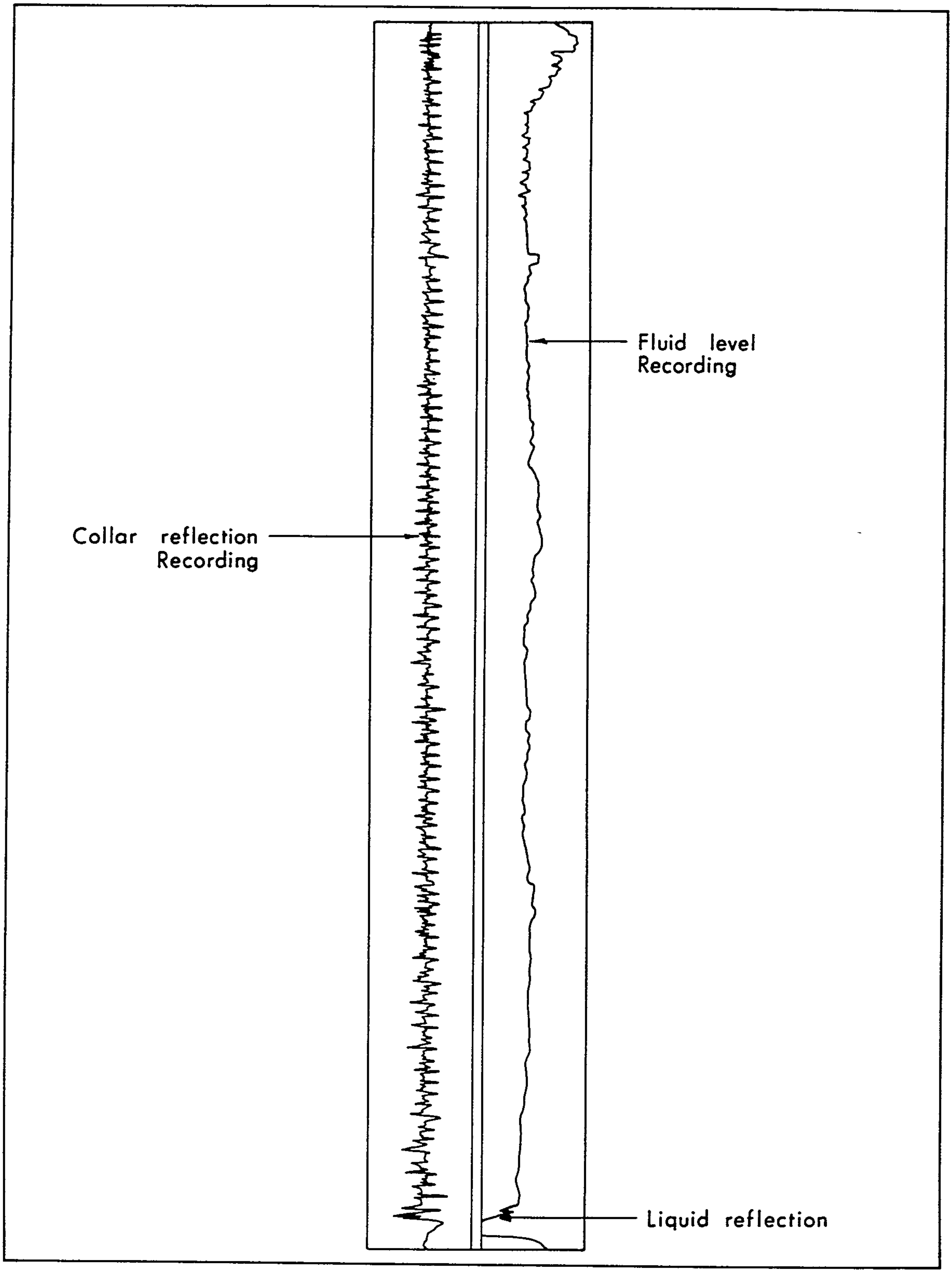

FIGURE 1 DUAL CHANNEL RECORDING OF BOTH COLLAR REFLECTION AND FLUID LEVEL

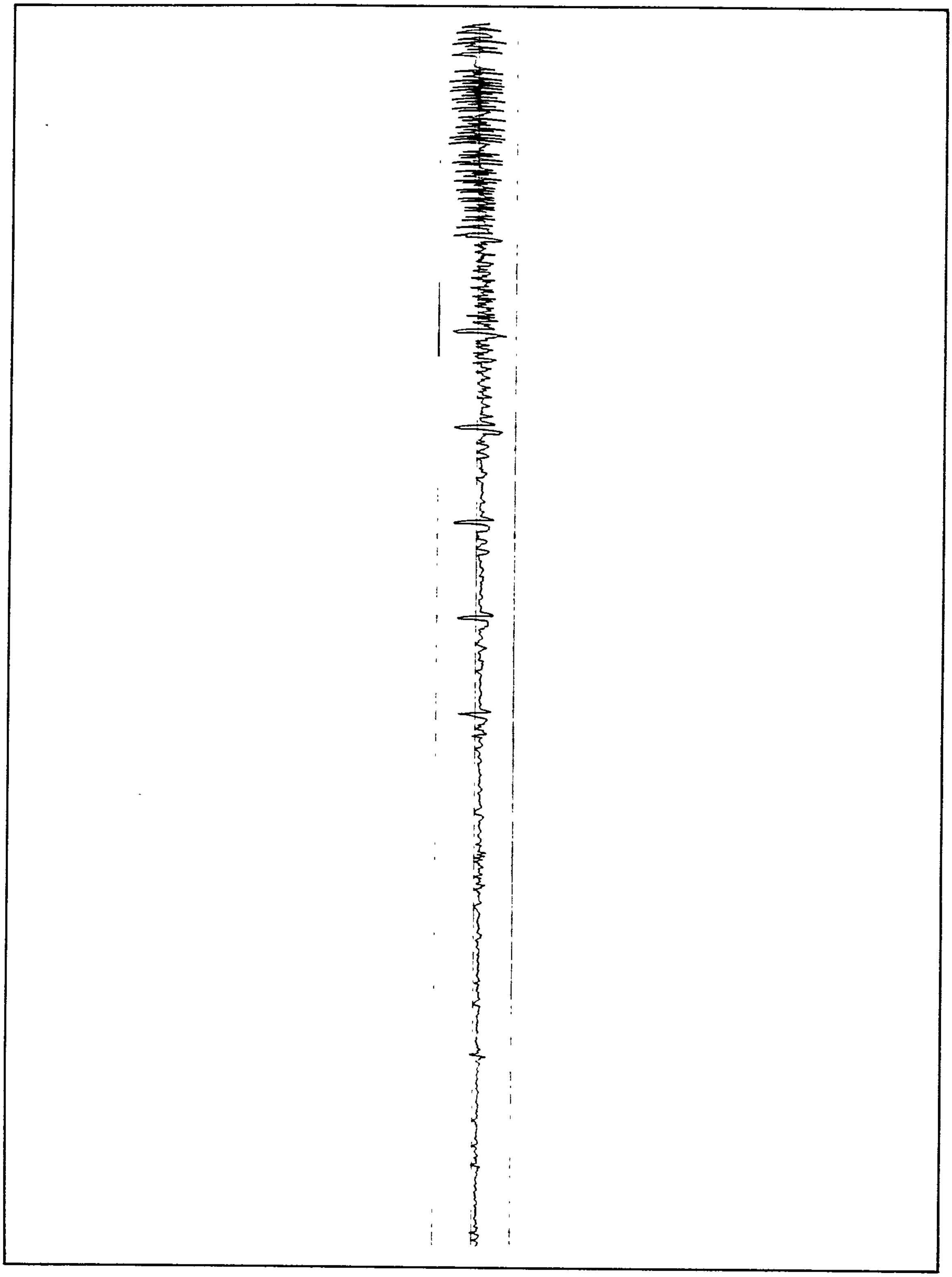

FIGURE 2 EFFECT OF AN ANNULAR OBSTRUCTION ON FLUID LEVEL DETERMINATION

TABLE 2 NUMBER OF TUBING JOINTS TO FLUID
Board and Operator Interpretations Compared

	Pembina	Zama	Total		
Interpretation Discrepancy - No. of Joints	No. of Charts	No. of Charts	No. of Charts	% of Total	Cumulative % of Total
0 - 1.0	10	21	31	45.6	45.6
1.1 - 2.0	3	8	11	16.2	61.8
2.1 - 3.0	2	3	5	7.4	69.1
3.1 - 4.0	2	2	4	5.9	75.0
4.1 - 5.0	1	1	2	2.9	77.9
5.1 - 6.0	2	2	4	5.9	83.8
6.1 - 7.0	1	2	3	4.4	88.3
7.1 - 8.0	1	2	3	4.4	92.7
8.1 - 9.0	1	-	1	1.5	94.1
9.1 - 10.0	1	-	1	1.5	95.6
10.1 - 20.0	-	2	2	2.9	98.6
20.1 - 30.0	-	-	-	-	-
30.1 - 40.0	-	-	-	-	-
40.1 - 50.0	-	1	1	1.5	100.0

Significant error can result if the number of joints is estimated on the basis of a uniform chart distance of 10 joints applied as a constant throughout the entire chart. Factors such as variation in the speed of sound in a medium of increasing density; and in chart speed due to faulty drive mechanisms, weak power supplies, or manual pulling on the chart, can change the spacing per joint. Therefore, the actual count of each tubing-collar reflection on the chart should be made.

5 DETERMINING THE PRESSURE DUE TO THE GAS COLUMN

5.1 RECOMMENDATIONS

The density of the gas in the well, relative to dry air at standard temperature and pressure, must be known to calculate subsurface pressure. In this connection, the following are recommended:

1. Measure the relative density of the gas in the annulus whenever possible.

2. Avoid using an average of gas relative density measurements for the pool, or one obtained from the analysis of a bottom-hole, flow-line, or separator sample, except when the pressure exerted by the gas column is relatively small.

3. The Cullender and Smith method is one of the better methods for calculating gas-column pressure, because it takes into account variations in pressure, temperature, and the gas compressibility factor with depth.

The importance of ascertaining the correct relative density should not be underestimated for, as Table 3 (p. 18) shows, the gauge pressure due to the gas column increases non-linearly with increasing relative density. Moreover, the rate of increase increases with the length of the gas column.

5.2 MEASURING

Direct Measurement

The best way to obtain the relative density of the gas in the annulus is by measuring it directly with a portable balance. It is important to flow gas through the balance (or meter) at a controlled rate for several minutes to allow warm-up and stabilization of the instrument.

TABLE 3 PRESSURE DUE TO THE GAS COLUMN

Length of Gas Column m	Gauge Pressure at Surface kPa	Gas Relative Density	Gauge Pressure Due to Gas Column kPa
610	5 345	0.6	290
		0.7	358
		0.8	448
760	6 445	0.6	441
		0.7	552
		0.8	703
915	7 410	0.6	620
		0.7	779
		0.8	1007
1 220	8 965	0.6	1007
		0.7	1289
		0.8	1710
1 525	10 340	0.6	1448
		0.7	1882
		0.8	2544

The relative-density measurement should not be taken immediately before running the fluid-level shot, since gas flowing from the annulus may cause the fluid level to rise.

Measurement Averages

The use of an average of the gas relative densities or gradients from several wells will often lead to erroneous pressure calculations. Table 4 shows the annular gas relative-density data obtained from three major oil pools in Alberta, and illustrates a significant variation from well to well. Comparison of the gas relative densities of individual wells with the average for each of the pools indicated that differences of $\pm$ 0.1 are possible.

TABLE 4 ANNULAR GAS RELATIVE-DENSITY DATA For Three Major Alberta Oil Pools

Pool	No. of Wells Sampled	Gauge Pressure of Casing (kPa)		Gas Relative Density		
		Min	Max	Min	Max	Range
Kaybob South Triassic	35	3 490	10 600	0.610	0.730	0.120
Leduc-Woodbend D-2A	14	490	6 230	0.625	0.830	0.205
Pembina Cardium	23	2 040	13 710	0.625	0.715	0.090

Sample Measurement

The relative density obtained from an analysis of a bottom-hole, flow-line, or separator-gas sample will lead to errors in subsurface pressure calculations, since those samples are usually unrepresentative of the gas in the annulus.

The conditions under which a sample for a pressure-volume-temperature (PVT) analysis will have been taken will not approximate closely enough those in the annulus at the time of the pressure survey. However, the PVT analysis can be used to determine the amount of impurity in the gas so that appropriate corrections can be made to the gas compressibility factor.

5.3 ADJUSTMENT TO DATUM DEPTH

Cullender and Smith Method

The Board recommends the Cullender and Smith method, described elsewhere,[1] for adjusting gas-column pressure to datum depth, because unlike other simplifying methods, it takes into account the variation in temperature, and in the gas compressibility factor with depth.

The method includes a multi-step calculation in which the gas column is divided into several lengths for which individual calculations are made.

Alternative methods, which are based on more simplified assumptions, should be used only for shallow, low-pressure gas wells, or oil wells with gas columns having relatively small temperature gradients. Figure 3 compares the pressure of a 1 525 m gas column, calculated by the Cullender and Smith method with values obtained using tables from the United States Bureau of Mines Monograph 7.[2] The latter does not account for a varying gas compressibility, and it should be noted that the Cullender and Smith values increase non-linearly with increasing surface wellhead pressure.

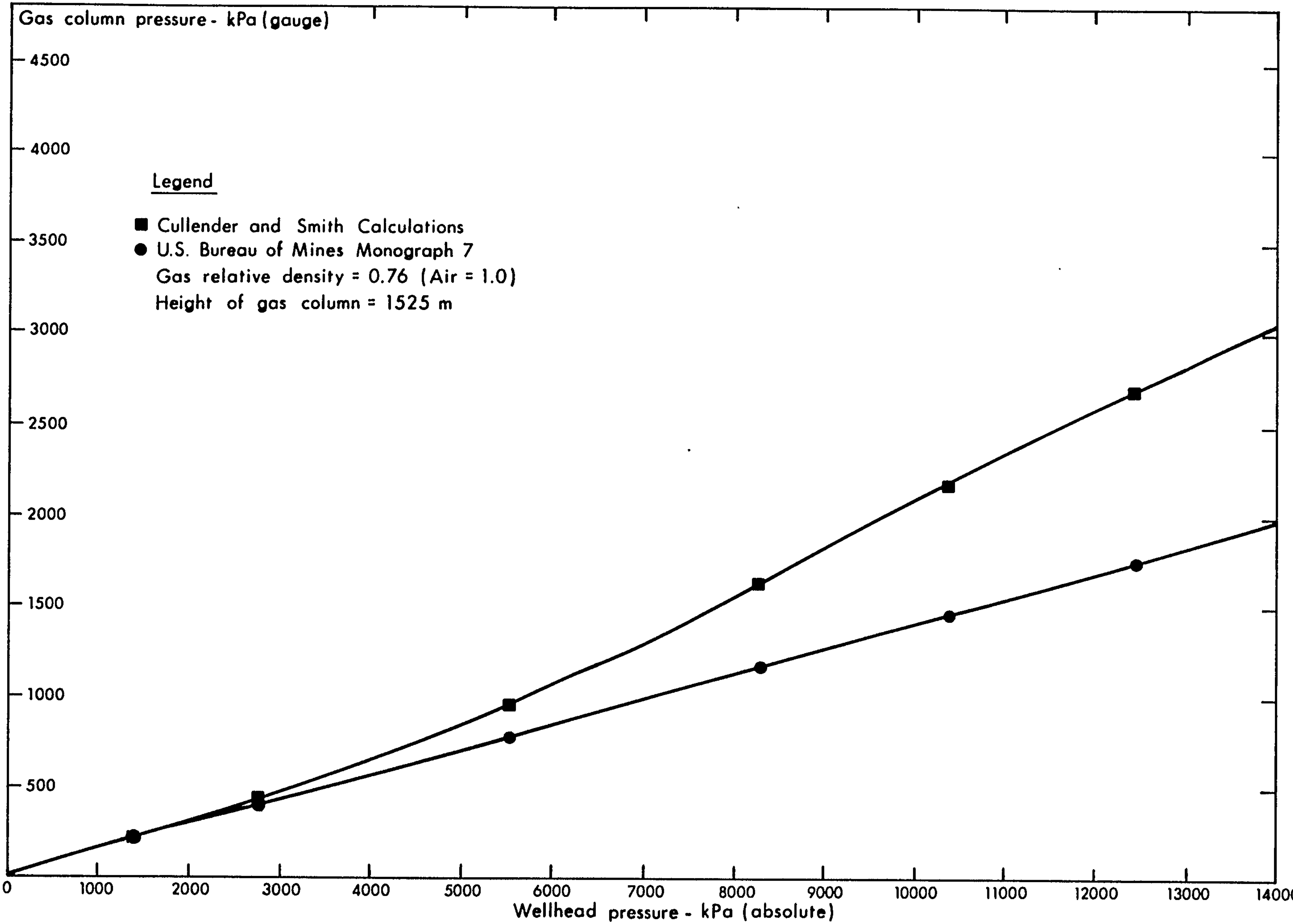

FIGURE 3 EXAMPLE SHOWING EFFECT OF COMPRESSIBILITY FACTOR ON GAS COLUMN PRESSURE

Graphic Calculation Aids

Figure 4 presents a simple means of determining the gas-column pressure if the wellhead surface casing pressure, the gas relative density, and the height of the gas column are known. A mean surface temperature of 1.7°C and mean temperature gradient of 3.6°C per 100 m (0.036°C/m) were used to prepare the chart.[3]

Figure 5 is used to make a pressure correction to the results obtained from Figure 4 for cases where the temperature gradient is known to deviate from 0.036°C/m.

Figures 4 and 5 were prepared using the Cullender and Smith method to aid determination of the pressure due to the static-gas column. The gas relative density, casing pressure, and height of gas column used in these figures span the range of properties normally found in Alberta's crude oil pools.

Large (11 x 17) copies of these figures appear at the back of the guide. Full-size (24 x 37 and 30 x 31) copies are available upon request from the Board's Oil Department.

The mean surface temperature required to calculate the temperature gradient in the wellbore can be obtained from the map in Figure 6. The use of a constant mean for any area is satisfactory, since the subsurface temperature at a depth of 15 m can be expected to be at or near the annual surface mean of the area.[4]

Subsurface Temperature

A subsurface temperature for use in calculating the temperature gradient can usually be obtained by referring to a reservoir fluid study survey. In cases where numerous temperature readings are available it is important to adjust all temperatures to that at a common datum depth.

The example in Section 7-1 illustrates the use of Figures 4, 5, and 6 to determine the pressure due to the gas column.

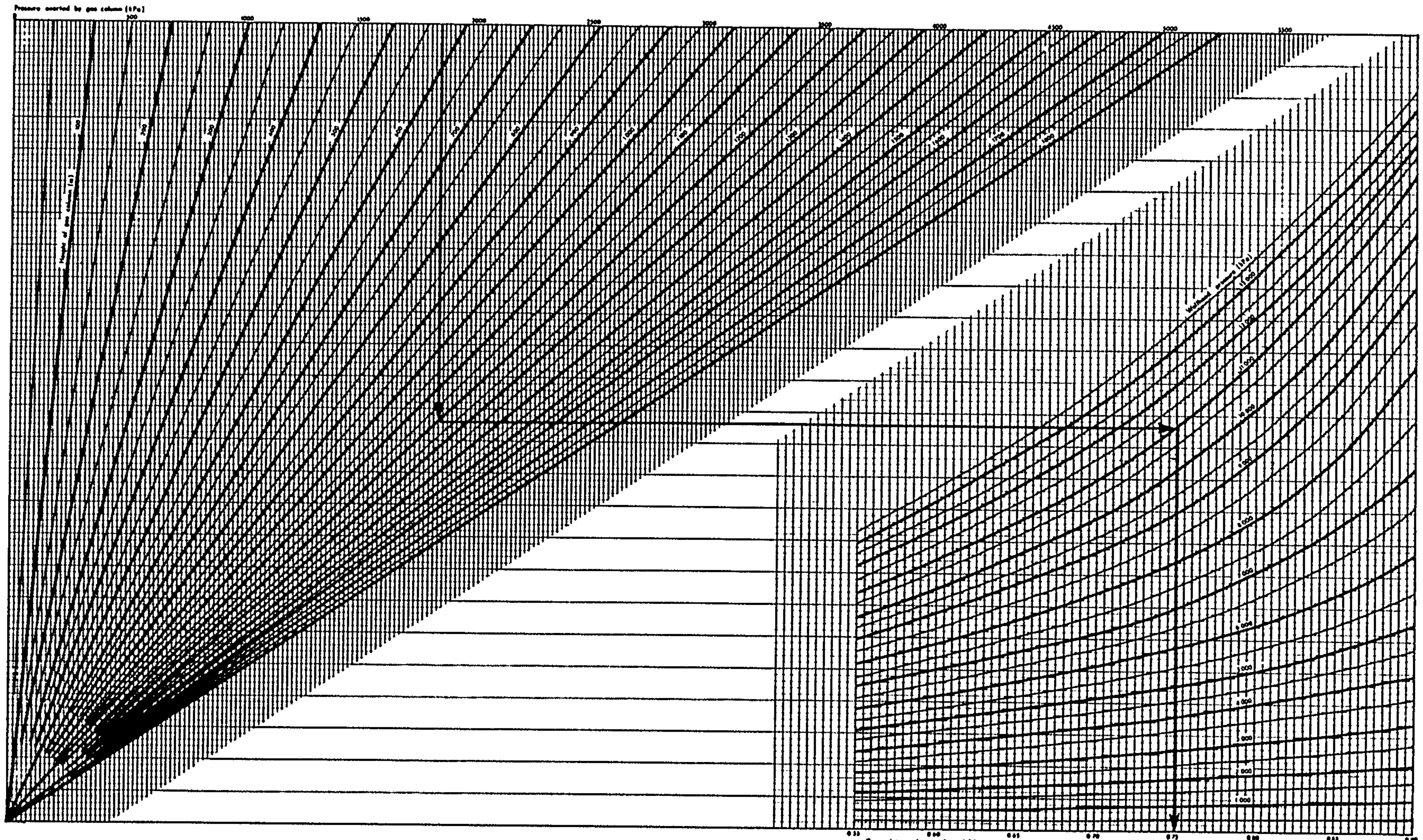

FIGURE 4 CHART FOR ESTIMATING PRESSURE EXERTED BY GAS COLUMN BASED ON AVERAGE TEMPERATURE GRADIENT OF 0.036 °C/m AND SURFACE TEMPERATURE OF 1.7 °C. Cullender and Smith method.

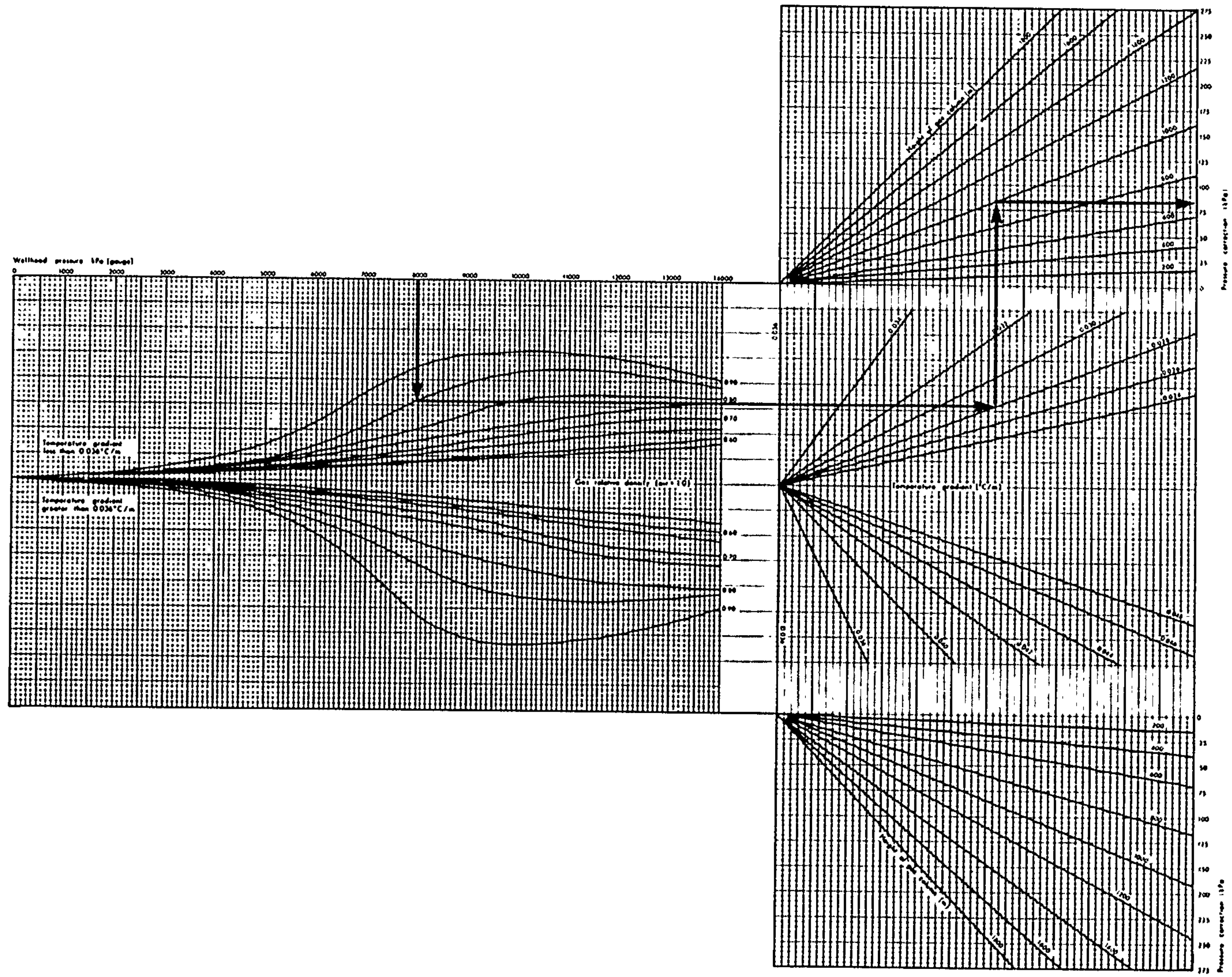

FIGURE 5 CHART FOR CORRECTING ESTIMATED PRESSURE EXERTED BY GAS COLUMN WHEN TEMPERATURE GRADIENT DEVIATES FROM 0.036°C/m

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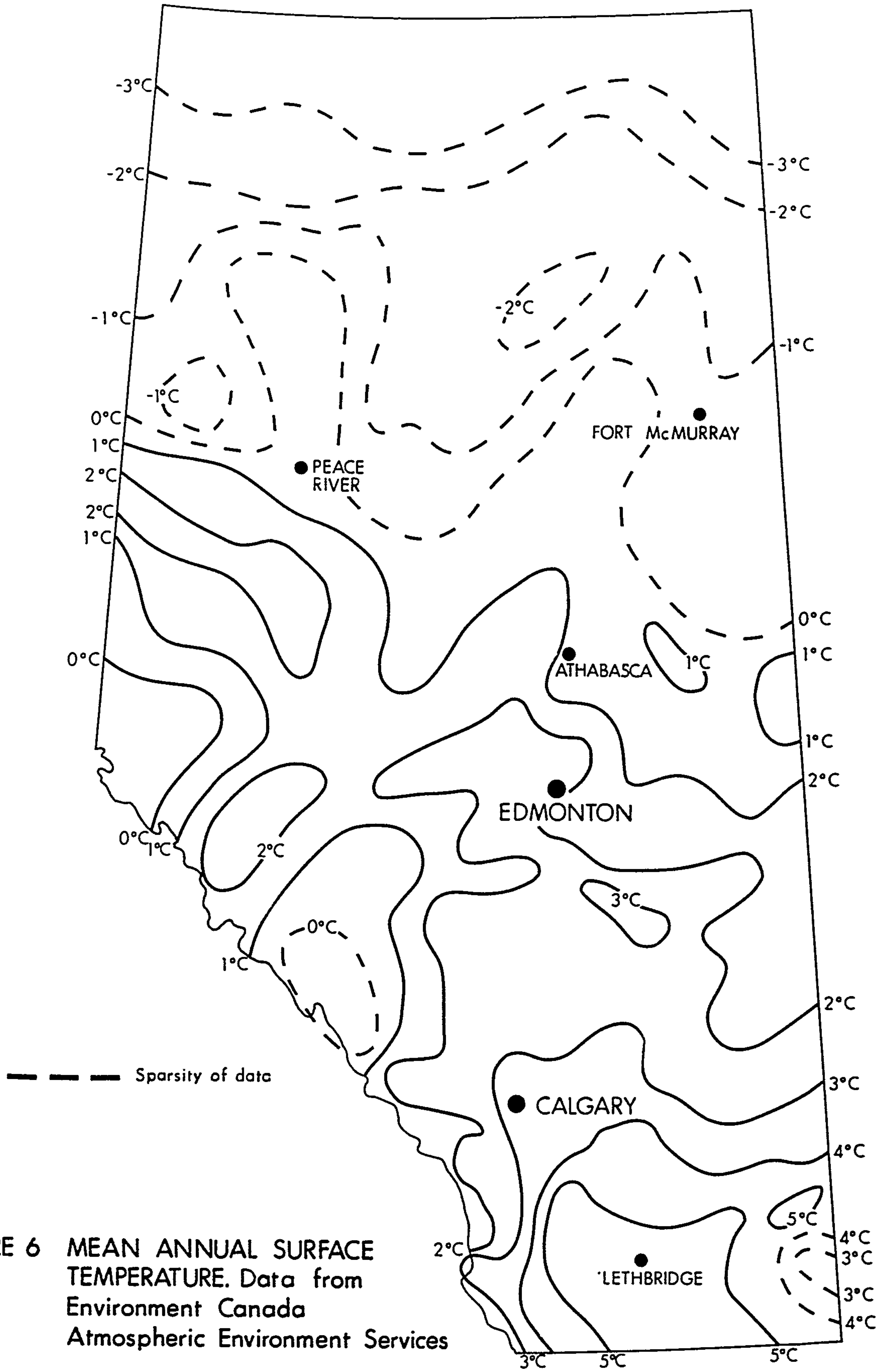

FIGURE 6 MEAN ANNUAL SURFACE TEMPERATURE. Data from Environment Canada Atmospheric Environment Services

6 DETERMINING THE PRESSURE GRADIENT OF THE LIQUID IN THE ANNULUS

6.1 GRADIENT FOR WELLS PRODUCING HEAVY-DENSITY OIL

The pressure gradient of the liquid (usually oil) in the annulus is required to calculate a static subsurface pressure from AWS measurements. For pools producing heavy-density oil (900 kg/m^3 or denser), the variation of oil gradient within a pool is usually small because of small temperature variation, shallowness, and low gas solubility. Consequently, an average of the measured oil gradients for the pool can be used with fair success.

6.2 GRADIENT FOR WELLS PRODUCING LIGHT- OR MEDIUM-DENSITY OIL

For wells producing light- or medium-density oil, greater ranges of temperature, depth, and gas solubility occur. For example, Figure 7 shows the variations in the oil-column gradient from well to well in the Kaybob South Triassic A and Edson Cardium B pools. The figure illustrates that use of an average oil gradient in these pools will cause significant error in the calculated static subsurface pressure.

To determine the factors which significantly affect the pressure gradient of the oil in the annulus, fluid-column data were gathered from 23 pools where:

1 The fluid columns of all wells in the pool were water free.

2 Numerous static subsurface gauge pressure surveys with gradient steps throughout the fluid column were available.

3 Ample PVT analyses were available.

The chosen pools covered a wide range of oil density, temperature, pressure, depth, and gas solubility. A correlation relating the pressure gradient to gas-oil interface pressure, oil density, and the average pressure and temperature of the liquid was developed. Measured pressure gradients in the oil column at various depth intervals were plotted versus the corresponding pressures at the gas-oil interface in the wellbore. Best-fit lines were then drawn through the points representing the gradients at various depth intervals. Figures 8 and 9 are typical of the relationships obtained. Average pressure and temperature were determined for each depth interval.

The effect of varying separator pressure and temperature was eliminated by using residual-oil density.

Figure 10 is the resultant correlation. This figure provides a convenient way to estimate the pressure gradient of the liquid in the annulus. An example of the use of the chart is given in Section 7 of this guide. A large (11 x 17) copy of the figure appears at the back of the guide, and a full-size (26 x 37) copy is available upon request from the Board's Oil Department.

The use of Figure 10 can be hampered by the difficulty experienced in defining an appropriate oil density. In such instances oil density can be obtained by applying Figure 10 in reserve (that is, determining the residual-oil density using the oil gradient from a previous static-gradient test for the well, or from nearby wells). When a PVT analysis or pressure data are not available, the residual-oil density can be estimated from Figure 11, which relates stock-tank-oil to residual-oil densities. It was prepared using differential and flash data from 135 reservoir fluid studies for pools throughout Alberta. The actual stock-tank densities for individual wells as submitted by operators were used whenever available. Figure 11 should only be used if representative reservoir fluid analyses or pressure data are not available.

Using the oil-column pressure gradient chart (Figure 10) to determine the residual-oil densities of wells in several pools, a slight areal variation was noted in the densities in some pools - for example, the

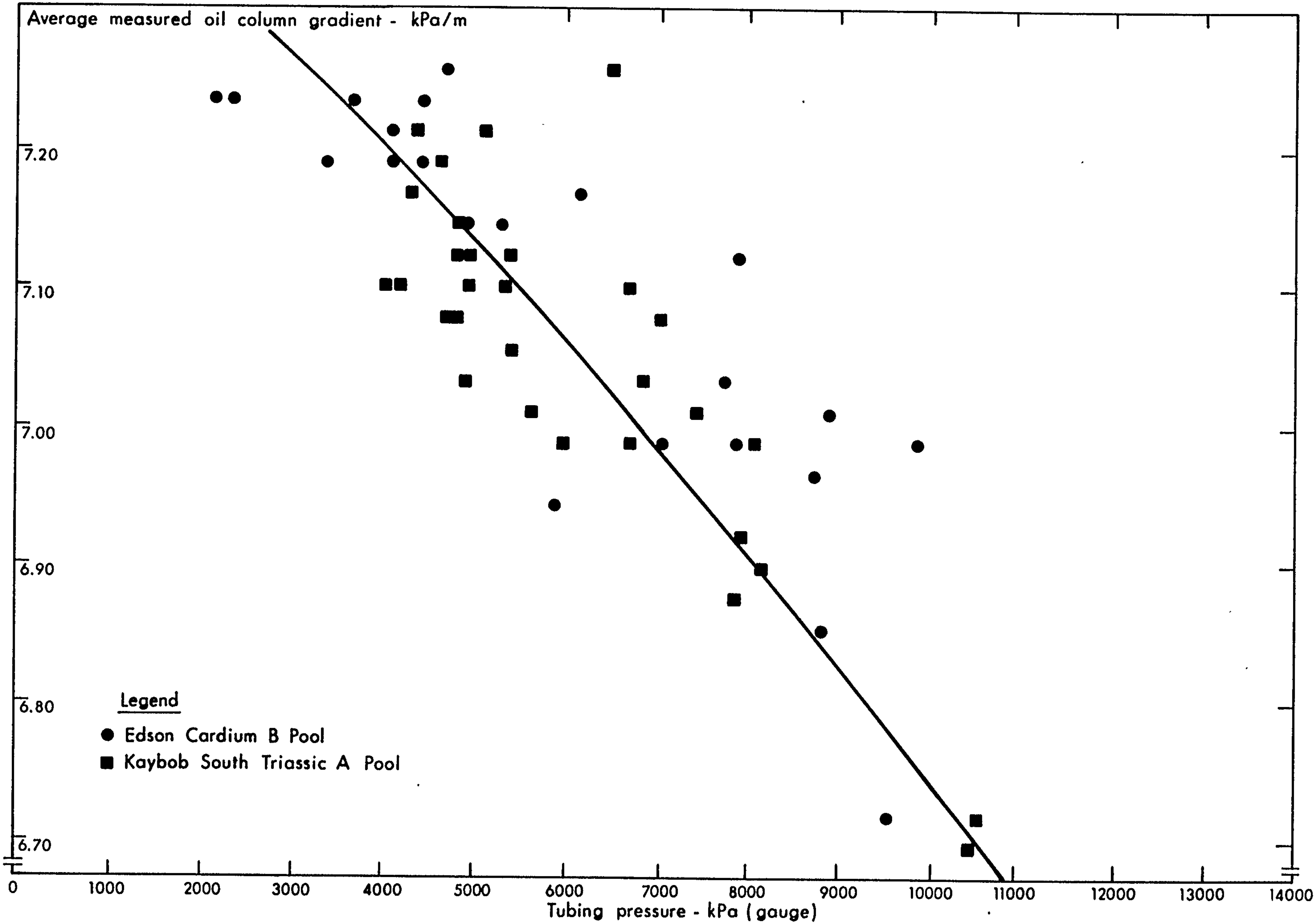

FIGURE 7 EXAMPLE SHOWING EFFECT OF GAS COLUMN PRESSURE ON THE OIL COLUMN GRADIENT

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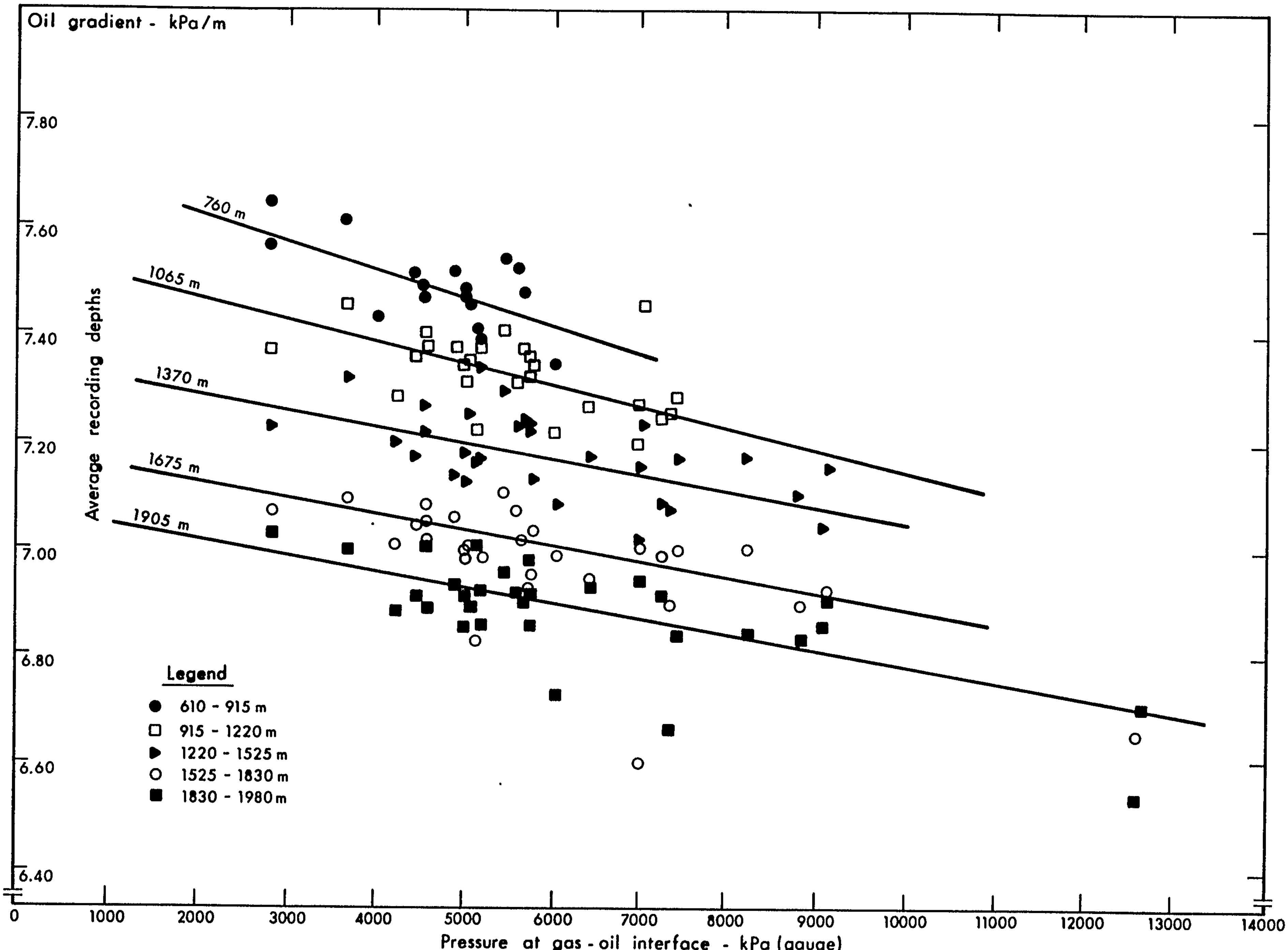

FIGURE 8 EXAMPLE SHOWING RELATIONSHIP OF OIL GRADIENT TO DEPTH AND GAS-OIL INTERFACE PRESSURE IN KAYBOB SOUTH TRIASSIC A POOL

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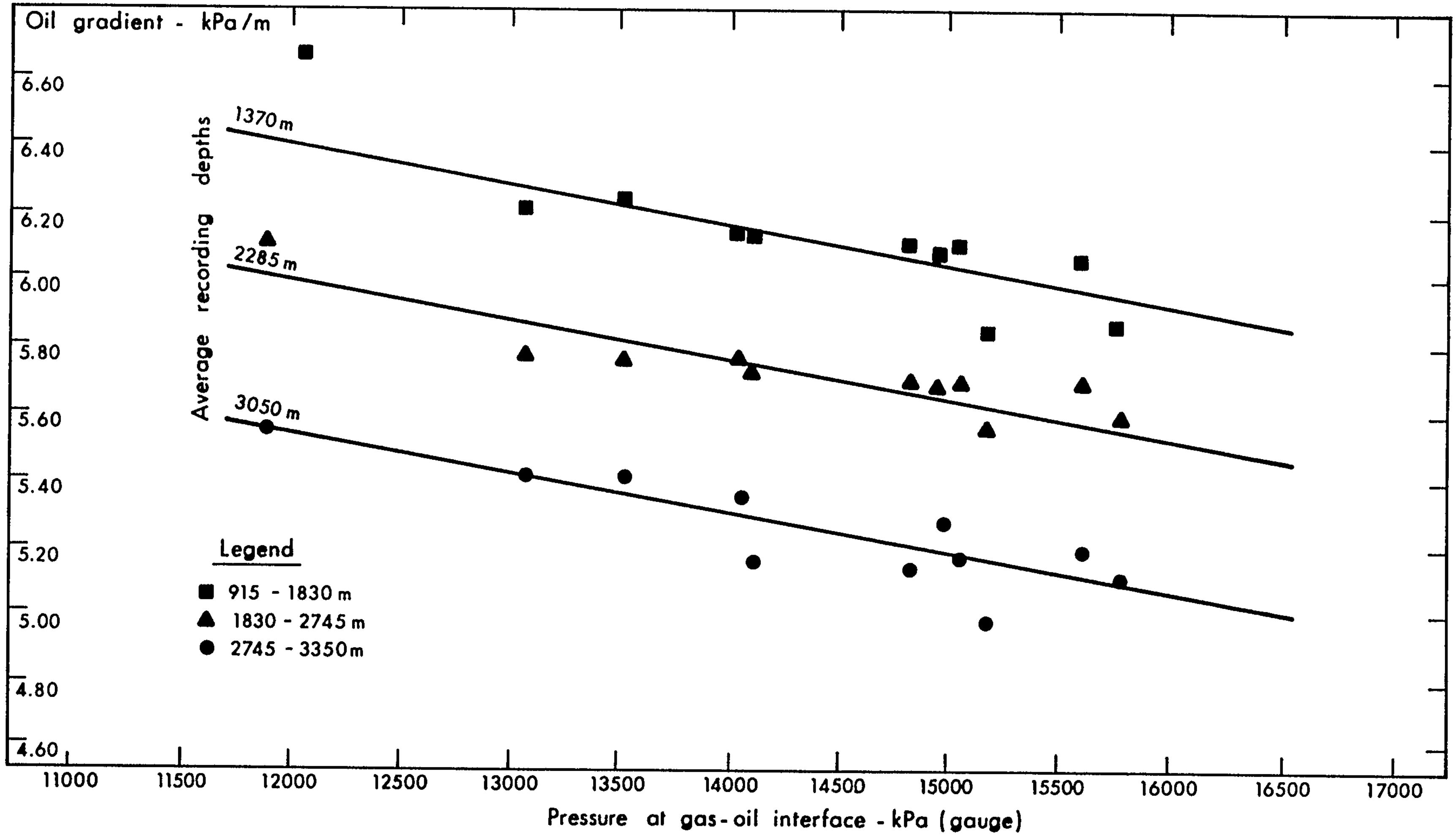

FIGURE 9 EXAMPLE SHOWING RELATIONSHIP OF OIL GRADIENT TO DEPTH AND GAS-OIL INTERFACE PRESSURE IN ANTE CREEK BEAVERHILL LAKE POOL

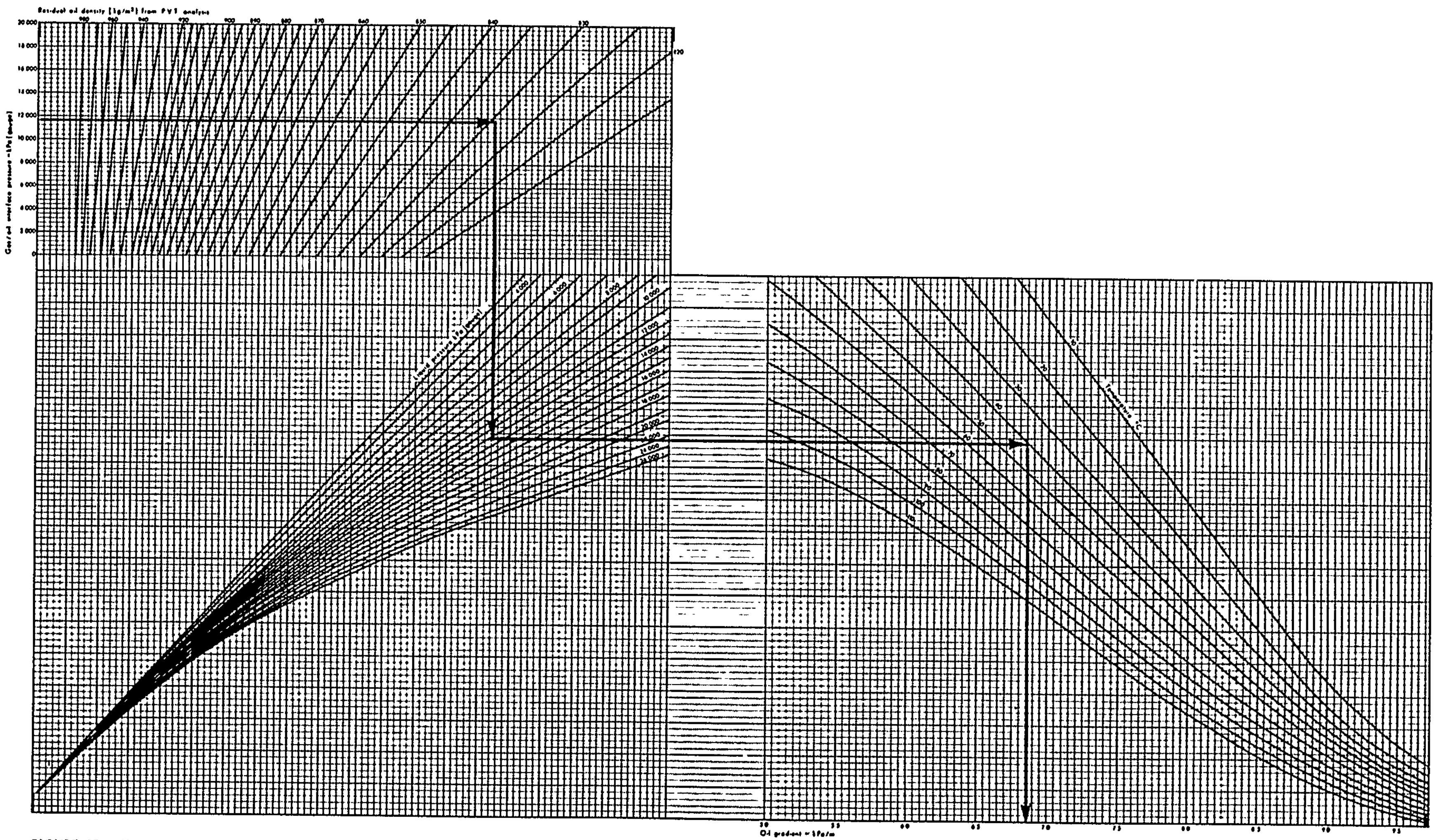

FIGURE 10 CHART FOR ESTIMATING OIL COLUMN PRESSURE GRADIENT. This chart is not applicable to pools with residual oil densities less than 815 kg/m^3

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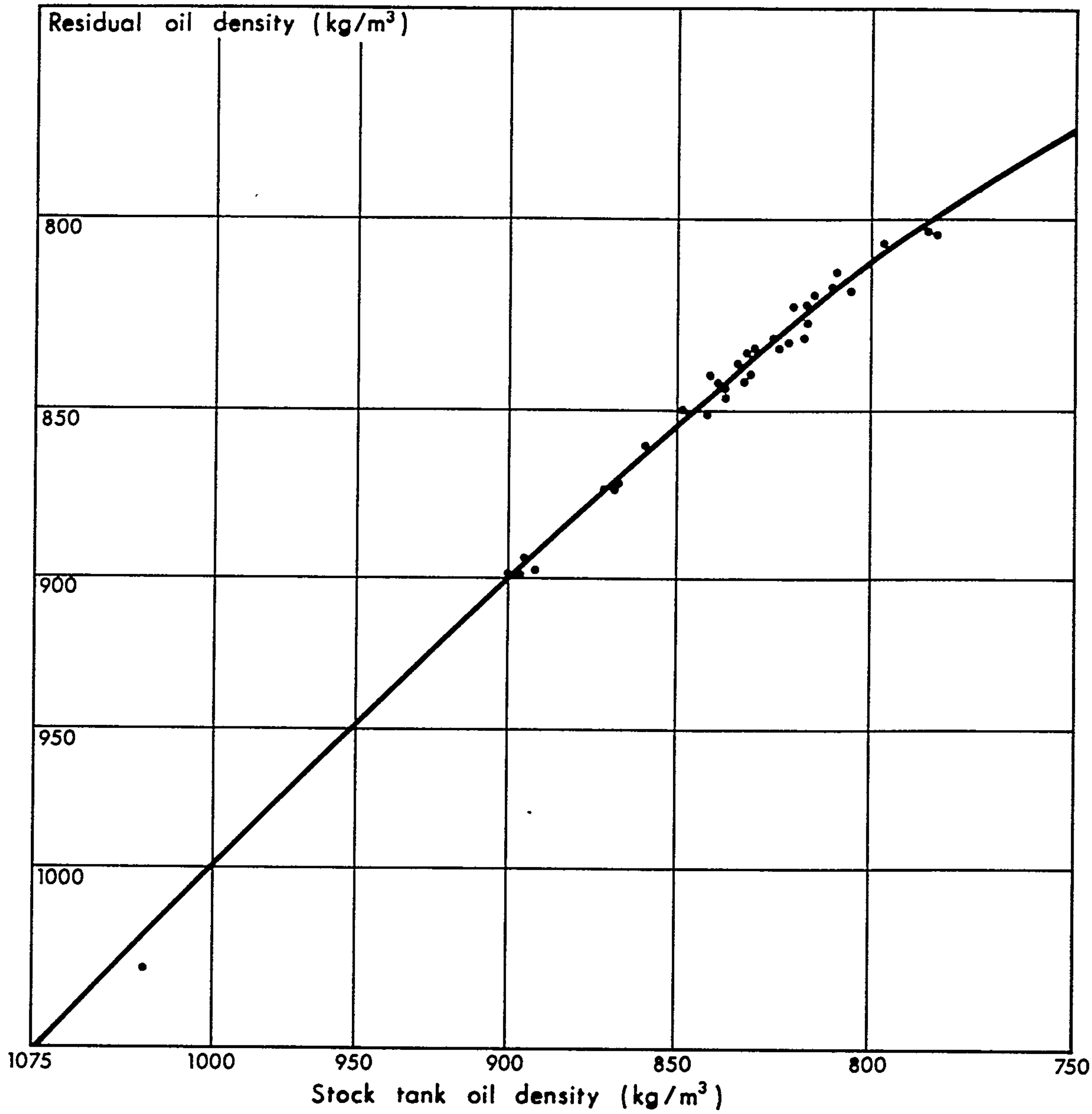

FIGURE 11 COMPARISON OF STOCK TANK AND RESIDUAL OIL DENSITY

Gilby Jurassic B Pool (see Figure 12). Whenever this type of variation is observed, the oil densities should be assigned on a single-well or, at most, a local-area basis.

In some cases areal variation is the result of the natural migration of the lighter hydrocarbons from lower-permeability portions of the reservoir. A typical example of this behaviour is the Nipisi Gilwood A Pool. The average residual-oil density for the pool was 827 kg/m^3 except in the portion north of Township 80, where it was 839 kg/m^3. Wells in the latter area were generally pumped, while the remaining wells in the pool were flowing, at the time the data was gathered.

For pools subject to waterflood, production wells near water injectors may have residual-oil densities below the pool average. A study using data from the 1966 and 1968 pressure surveys in the Swan Hills South Beaverhill Lake A and B pools confirmed this tendency. Most of the wells near the injectors were starting to produce water and were characterized by decreasing gas-oil ratios. Several other nearby wells also showed a drop in residual-oil density from the 1966 to the 1968 pressure survey. This example demonstrates the need for a periodic verification of residual-oil densities and gradients in pressure-maintained pools.

The selection of wells for AWS pressure surveys should have regard for the location of the well with respect to injectors or to the edge of the reservoir.

6.3 GRADIENT FOR WELLS IN HIGHLY UNDERSATURATED POOLS

Caution should be exercised when using Figure 10 for under-saturated oil pools (that is, pools having high reservoir pressure relative to the bubble-point). In these cases, the pressure at the gas-oil interface appears to have little or no effect on the oil gradient. Therefore, when calculating the average oil gradient in highly undersaturated conditions, the pressure at the gas-oil interface can be assumed to be zero. A well in this type of pool generally has a high liquid level and low surface pressure.

6.4 GRADIENT FOR WELLS IN LATTER STAGES OF DEPLETION

Figure 10 is not directly applicable to wells in the latter stages of depletion by solution-gas drive. In such cases, most of the solution gas in the oil has been produced and the wells have low surface-casing pressure and, usually, high fluid levels. A trend of continuously increasing oil density can be expected until a dead-oil condition is reached. The compressibility of dead oil is small, and the oil density can be considered a function of temperature only.

If a good correlation of increasing oil densities can be made from previous pressure surveys using Figure 10, these values can be used to extrapolate the oil gradient. If such a correlation cannot be developed, or dead-oil conditions have been reached, a direct conversion of stock-tank-oil density to oil gradient can be estimated using Figure 13.

6.5 GRADIENT FOR WELLS SUBJECT TO WATERFLOOD

Before Water Breakthrough

Where primary production methods have depleted reservoir pressure prior to waterflooding, producing wells often show a small but steady rise in oil density as the flood front advances. If enough free gas was produced prior to the start of waterflooding, the oil produced after fill-up contains little gas and the wells have a low surface pressure. In such cases a dead or a gas-free oil column can be assumed, and Figure 13 used to calculate the pressure gradient in the oil column.

After Water Breakthrough

The producing water-cut is seldom representative of water within the fluid column in the annulus, and should not be used when making calculations.

In wells producing light- or medium-density oil, the water settles and quickly separates from the oil such that the producing water-cut is representative of only the lower portion of the fluid column. However,

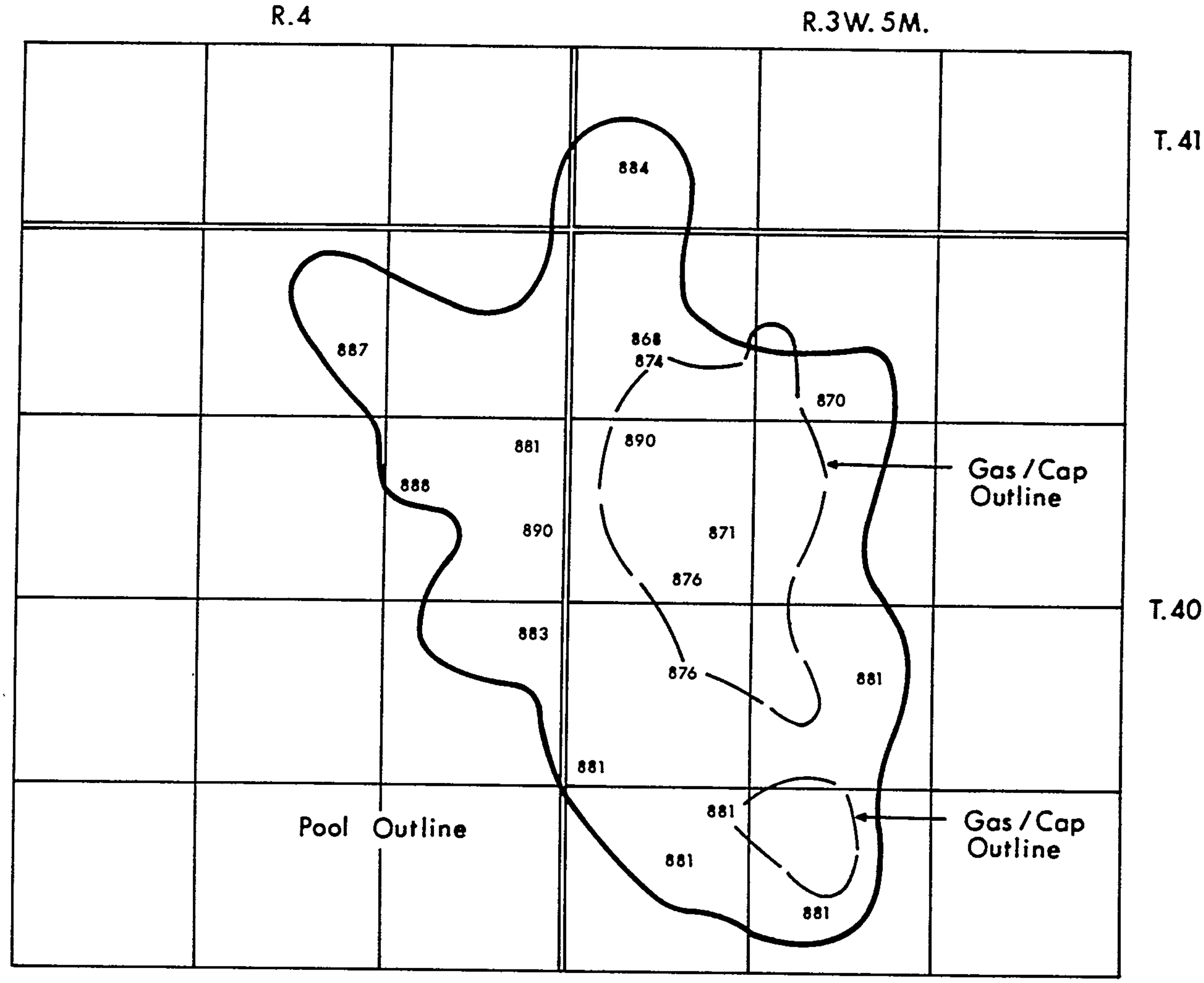

FIGURE 12 RESIDUAL OIL DENSITIES - kg/m^3. Gilby Jurassic B Pool.

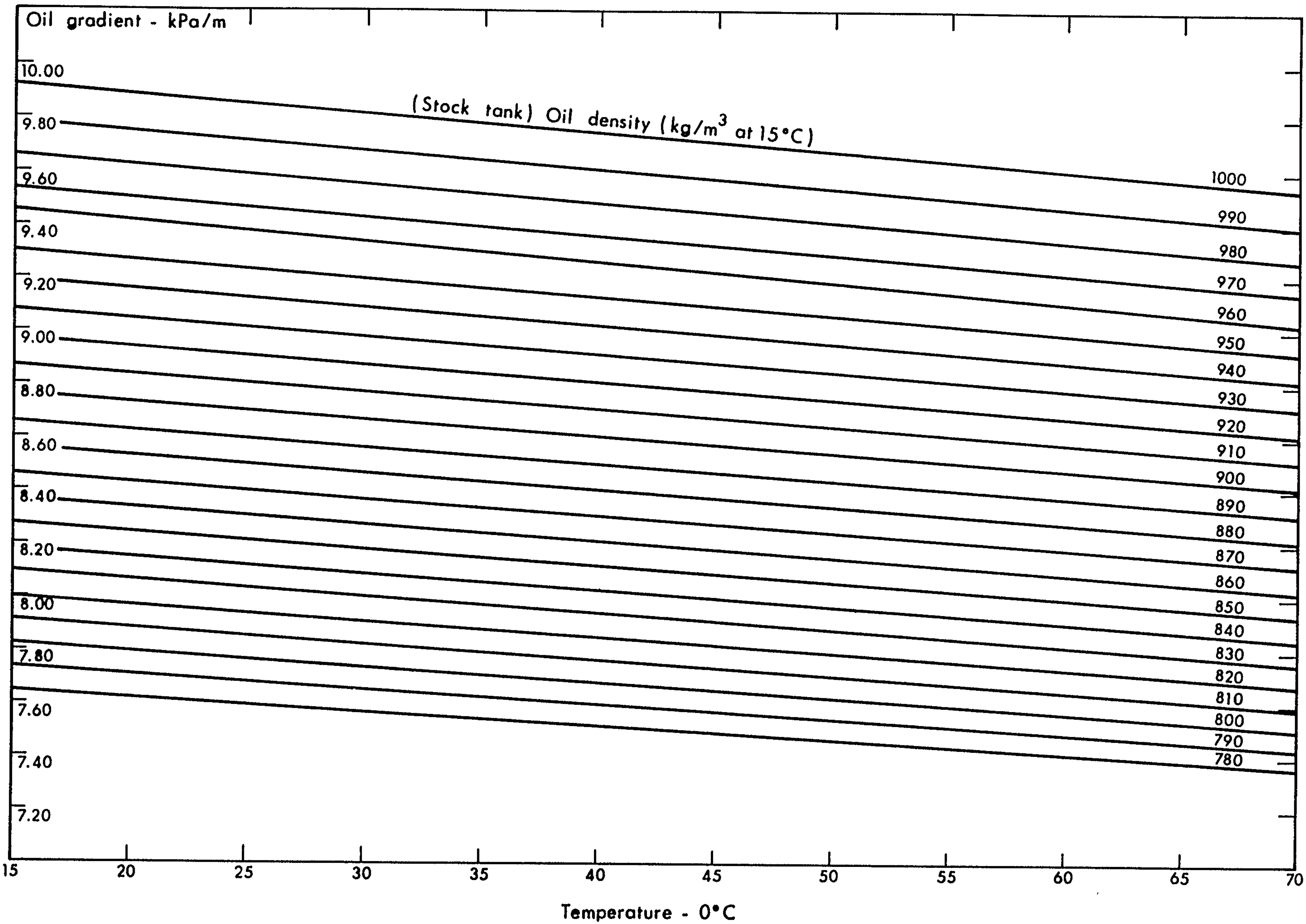

FIGURE 13 CHART FOR ESTIMATING PRESSURE GRADIENT OF GAS-FREE CRUDE OIL

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if these wells are shut in for several months, water-cuts can safely be neglected when calculations are performed, because most of the water will have settled and returned to the formation. An exception occurs when water and some heavy oils form a stable emulsion.

Pumping Wells

For pumping wells producing significant amounts of water, a fluid-level measurement should be taken when the well is producing. After a period of continuous production, most of the fluid above the pump will be clean oil, while below, the water-cut will be approximately equal to the producing water-cut. After any shut-in period, care must be taken in estimating the composition of liquids in the annulus. The fluid entering the wellbore after the well is shut in will have approximately the same water-cut as when the well was on production. However, depending upon the properties of the oil and length of the shut-in time, some or all of the water will settle out of the fluid above the well perforations. Thus, a knowledge of the well completion data is helpful when analysing pumping wells.

Further discussion of wells producing with a water-cut is not included in this report, because factors such as properties of the oil, shut-in time, and well completion are so different from well to well. The uncertainty in estimating the fluid gradient, therefore, often makes the AWS pressure surveys for high-water-cut wells subject to large errors.

6.6 SUMMARY

In summary, the oil gradient chart (Figure 10) can be used with reasonable confidence subject to the following precautions:

1 The wells to be surveyed by AWS means should be carefully selected, with preference given to those previously surveyed with a subsurface gauge, so that a history is available to assist the calculation.

2 The best oil density for determining the pressure gradient of the liquid in the annulus is obtained by running both a pressure-gauge survey and a fluid-level survey. The oil density for a well is "backed-out" using Figure 10, and can be applied to other wells in the vicinity. In the absence of such data, residual-oil density from an available PVT analysis should be used. Finally, if no PVT analysis is available, the residual-oil versus stock-tank density correlation shown in Figure 11 may be used.

3 The pressure gradient of the liquid in the annulus should be checked periodically with the gradient obtained from the gauge pressure surveys, to ensure that the proper oil density is used in the AWS calculations.

4 Adjustments should be made for abnormal conditions, since Figure 10 does not compensate for all conditions. However, the figure is helpful for gradient selection under average conditions.

7 CALCULATING STATIC SUBSURFACE PRESSURE

The previous sections define all the parameters required to calculate static subsurface pressure. The surface pressure is measured with a deadweight tester or calibrated dial gauge. The fluid level is determined from an AWS recording. The temperature gradient is calculated from the known or estimated subsurface temperature and the surface temperature using Figure 6. Finally, the pressure due to fluid columns (gas and oil) is determined by the methods discussed in sections 5 and 6.

Nomenclature

The complete procedure is illustrated by the following examples. The nomenclature used is as follows.

D_d = datum depth of well measured from casing flange, m
D_L = depth of fluid level, m
G_g = gas relative density
G_{po} = calculated pressure gradient of the oil column, kPa/m
G_{poe} = estimated pressure gradient of the oil column, kPa/m
G_{ro} = residual-oil density, kg/m^3
H_g = height of gas column, m
P_g = pressure due to the gas column, kPa
P_{gL} = pressure at the gas-oil interface, kPa
P_L = average fluid pressure, kPa
P_o = pressure due to the oil column, kPa
P_{sc} = surface-casing pressure, kPa
P_{ws} = static subsurface pressure at datum, kPa
T_G = temperature gradient, °C/m
T_L = average fluid temperature, °C
T_s = mean surface temperature, °C

7.1 EXAMPLE: GAS WELL

H_g = 1 465 m
P_{sc} (ga) = 10 685 kPa
(abs) = 10 790 kPa
T_G = 0.045 5°C/m
G_g = 0.73

From Figure 4, the pressure due to the gas column is 2 045 kPa.

From Figure 5, the correction required to allow for the temperature gradient is −110 kPa. Therefore, the pressure due to the gas column is 1 935 kPa, and:

P_{ws} (ga) = 10 685 + 2 045 − 110
= 12 620 kPa

7.2 EXAMPLE: OIL WELL

D_L = 460 m
P_{sc} (ga) = 3 445 kPa
T_G = 0.038 3°C/m
T_s = 1.7°C
G_g = 0.75
G_{ro} = 837 kg/m^3
D_d = 1 525 m

Procedure

1 Measure surface-casing pressure using a deadweight tester or dial gauge.

2 Determine pressure due to the gas column using procedure in Example 7.1.

3 Determine pressure due to the oil column.

4 Calculate the static subsurface pressure at datum.

Calculations:

1 Measured P_{sc} = 3 445 kPa.

2 From the procedure shown in Example 7.1, pressure doe to the gas column (P_g) is 179 kPa.

3 Calculate the pressure due to the oil column, as follows:

First, to determine from Figure 10 the pressure gradient of the oil column (G_{po}), calculate

gas-fluid interface pressure (P_{gL})
average fluid temperature (T_L)
average fluid pressure (P_L)

Calculate P_{gL}:

$$P_{gL}\ (ga) = 3\ 445 + 179$$
$$= 3\ 624\ \text{kPa}$$

Calculate T_L:

$$T_L = T_s + T_G \left(\frac{D_d - D_L}{2} + D_L\right)$$

$$= 1.7 + 0.038\ 3 \left(\frac{1\ 525 - 460}{2} + 460\right)$$

$$= 39.7^{o}C$$

Calculate P_L:

Assume the pressure gradient of the oil column (G_{poe}) to be 7.46 kPa/m:

$$P_L\ (ga) = P_{gL} + \left(\frac{D_d - D_L}{2}\right) G_{poe}$$

$$= 3\ 624 + \left(\frac{1\ 525 - 460}{2}\right)\ 7.46$$

$$= 7\ 596 \text{ kPa}$$

From Figure 10, the calculated pressure gradient (G_{po}) is 7.24 kPa/m.

Since G_{poe} differs from G_{po} by more than 0.10 kPa/m, choose a new value of G_{poe} and repeat the calculation of the average liquid pressure (P_L):

Let G_{poe} = 7.24 kPa/m
Re-calculate the average liquid pressure (P_L):

$$P_L\ (ga) = 3\ 624 + \left(\frac{1\ 525 - 460}{2}\right)\ 7.24$$

$$= 7\ 479 \text{ kPa}$$

From Figure 10, the calculated oil gradient (G_{po}) is now 7.22 kPa/m.

Since G_{poe} and G_{po} differ by 0.10 kPa/m or less, use 7.22 kPa/m for G_{po}.

Next, determine the pressure due to the oil column (P_o):

$$P_o\ (ga) = (D_d - D_L)\ G_{po}$$
$$= (1\ 525 - 460)\ 7.22$$
$$= 7\ 689\ kPa$$

4 Calculate the static subsurface pressure at datum (P_{ws}), as follows:

$$P_{ws}\ (ga) = P_{sc} + P_g + P_o$$
$$= 3\ 445 + 179 + 7\ 689$$
$$= 11\ 313\ kPa$$

7.3 EXAMPLE: GAS-FREE OIL WELL

D_L = 305 m
P_{sc} (ga) = 0 kPa
P_g (ga) = 0 kPa
P_{gL} (ga) = 0 kPa
T_G = 0.034 6°C/m
T_s = 2.8°C
G_{ro} = 870 kg/m^3
D_d = 1 525 m

Calculate the average liquid temperature (T_L):

$$T_L = T_s + T_G \left\{\frac{D_d - D_L}{2} + D_L\right\}$$

$$= 2.8 + 0.034\ 6 \left\{\frac{1\ 525 - 305}{2} + 305\right\} = 34.5°C$$

From Figure 13 the calculated oil gradient (G_{po}) is 8.42 kPa/m.

Calculate the static subsurface pressure at datum:

$$P_{ws}\ (ga) = P_{gL} + G_{po}\ (D_d - D_L)$$

$$= 0.0 + 8.42\ (1\ 525 - 305)$$

$$= 10\ 300\ \text{kPa}$$

8 VERIFYING STATIC SUBSURFACE PRESSURE

8.1 COMPARISON WITH GAUGE PRESSURE SURVEYS

Table 5 (p. 58) compares the pressures obtained during the June 1967 gauge pressure survey for the Pembina Cardium Pool with the corresponding pressures based on the Board's interpretation of AWS charts. The AWS survey was run in conjunction with the regular gauge pressure survey. As can be seen from the table, excellent agreement between the two methods was obtained. The AWS survey was performed according to the procedures outlined in this guide.

8.2 COMPARISON WITH RESIDUAL-OIL DENSITIES

An alternative method of verifying the accuracy of AWS static subsurface calculations involves the comparison of residual-oil densities obtained by applying Figure 10, in reverse, with those obtained from PVT analyses. A check on the accuracy of surveys in the Zama Field was done using 42 pools having sufficient PVT analyses. The pressure gradient, temperature, fluid pressure, and gas-oil interface pressure from about 100 gauge pressure surveys were used to calculate the residual-oil densities from Figure 10. Table 6 (p. 59) shows good agreement between the two methods of determining the residual-oil density for each pool. Over 75 per cent of the pools considered had a density difference of less than 5.5 kg/m^3.

TABLE 5 COMPARISON OF AWS AND GAUGE PRESSURES FOR VARIOUS WELLS
1967 Pembina Cardium Pressure Survey
kPa

Surface Pressure	Gauge Pressure	AWS Pressure
11 280	13 142	13 149
7 998	12 156	12 273
9 280	10 804	10 784
10 363	12 115	12 115
10 411	12 115	12 170
10 260	11 853	11 846
10 301	11 873	11 894
9 722	11 232	11 211
9 722	11 239	11 211
8 253	9 543	9 522
8 302	9 619	9 584
565	7 847	7 826
6 012	6 723	6 730
6 330	7 405	7 447
6 633	7 447	7 405
8 129	9 536	9 522
11 170	15 941	15 962

TABLE 6 COMPARISON OF OIL DENSITIES FROM FIGURE 10 WITH THOSE FROM PVT ANALYSES

Difference in Density kg/m^3	Number of Pools	Total %	Cumulative Total %
0 - 2.5	20	47.6	47.6
3.0 - 5.5	12	28.6	76.2
6.0 - 8.0	5	11.9	88.1
8.5 - 10.5	4	9.5	97.6
10.5 +	1	2.4	100.0

The following example shows the sensitivity of AWS pressure calculations to the density of residual oil (Table 7, P. 60).

D_L = 460 m

P_{gL} (ga) = 2 070 kPa

P_L (ga) = 6 065 kPa

T_G = 0.049 2°C/m

T_s = -1.7°C

T_L = 45.6°C

D_d = 1 465 m

TABLE 7 VARIATION OF STATIC SUBSURFACE OIL PRESSURE WITH RESIDUAL-OIL DENSITY

Case No.	Density of Residual Oil (G_{ro}) kg/m^3	Static Subsurface Oil Pressure Calculated Gradient (G_{po}) kPa/m	Total due to 1005-m Column (P_o) kPa	Difference in Total due to G_{ro} Variation (P_o) kPa
1	880	8.166	8212	-
2	875	8.080	8129	83
3	870	7.985	8032	97
4	865	7.861	7908	124

The example shows that an error of 5 kg/m^3 in the residual-oil density results in a corresponding error of about 100 kPa/m in the static subsurface pressure.

Applying the results from the above example to the data for the 42 Zama pools in Table 6 (p. 59) enables us to conclude that the use of residual-oil densities from PVT analyses for pressure calculations would result in the following computational error:

1 Approximately 50 per cent of the calculated gauge fluid pressures would have errors of less than 70 kPa.

2 Approximately 80 per cent of the calculated gauge fluid-column pressures would have errors of less than 105 kPa.

3 Approximately 98 per cent of the calculated gauge fluid-column pressures would have errors of less than 205 kPa.

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