Chapter 30

Bottomhole Pressures

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Introduction

The practice of using bottomhole pressure (BHP) to improve oil production and to solve petroleum engineering problems started in about 1930. Pressures in oil wells were first calculated from fluid levels and later by injecting gas into the tubing until the pressure became constant. The earliest BHP measurements were made with pressure bombs and with maximum-indicating or maximum-recording pressure gauges that did not have the accuracy, reliability, or durability now demanded. These early pressure measurements were occasional, or spot tests rather than systematic diagnostic engineering measurements.

BHP Instruments

The development of precision recording pressure gauges small enough in diameter to be run through tubing made it feasible to make BHP measurements in sufficient number to develop the science that now makes them indispensable to petroleum engineering. BHP now is determined with continuously recording pressure gauges, which are either self-contained or surface-recording.

Self-Contained Gauges

Mechanical self-contained pressure gauges are used universally. The pressure element and recording section are encased and sealed against external pressure except for an opening to communicate the pressure to the element. The entire instrument is run to the depth at which the pressure is to be measured, allowed to stabilize thermally, and then returned to the surface and the pressure determined from the chart. Modern pressure measurement systems incorporate force summing devices that convert energy into physical displacement or deformation. These force summing devices can take many forms, three of which are shown in Fig. 30.1. Although there are numerous mechanical self-contained pressure devices available (Table 30.1) only the most commonly used continuously recording BHP gauges are discussed fully. Regardless of the type of force summing device incorporated into the BHP gauge, whether physical displacement (piston elements) or deformation (bellows/bourdon tubes), the generated force is coupled to a recording device.

The Amerada pressure gauge has a helical bourdon tube as a pressure element that is of sufficient length to rotate the stylus the full inside circumference of the cylindrical chart holder without multiplication of movement. A clock moves the chart longitudinally. The gauge is made in both 1¼- and 1-in. diameters with a length of approximately 74 in. A vapor-pressure-type recording thermometer can be run in combination with this to obtain continuously recorded temperatures and allow correction of pressure measurements. This will also ensure that thermal stabilization has occurred.

The Humble gauge pressure element has a piston, which moves through a stuffing box against a helical spring in tension. Attached to the inner end of the piston is a stylus that records longitudinally on a chart in a cylindrical holder, which is rotated by a clock. The instrument is made in two sizes, with 1¼- and 15/16-in. OD's, and is approximately 60 in. long. Thermometer elements are available for both sizes.

Other recording gauges have been described in the literature, two of which were continuously recording, but they are no longer available on the market. The Gulf BHP gauge has a pressure element consisting of a long metallic bellows restrained by a double helical spring in tension. The recording mechanism is a cylindrical chart holder rotated by a clock. The USBM BHP gauge pressure element is a multiple-bellows type with a movement of about 0.6 in., which is multiplied through a rack and gears to about 5½ in. of stylus movement. The stylus records longitudinally on a cylindrical chart that is

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*The original chapter on this topic in the 1962 edition was written by C.V. Millikan.

TABLE 30.1—MECHANICAL RECORDING BHP GAUGES

	Amerada			Kuster					Johnston
	RPG-3	RPG-4	RPG-5	KPG	AK-1	K-2	K-3	Leutert	J-200
OD, in.	1.25	1	1.5	1.25	2.25	1	1.25	1.42	2.88
Length, in.	77	76	20	73	36	41	43	139	54
Type pressure element*	B	B	B	B	B	B	B	RP	P
Maximum pressure, psi**	25,000	25,000	20,000	30,000	30,000	20,000	20,000	10,000	20,000
Accuracy, %FS†	±0.2	±0.2	±0.25	±0.2	±0.25	±0.25	±0.25	±0.025	±0.25
Resolution, %FS†	±0.05	±0.056	±0.05	±0.05	±0.025	±0.05	±0.04	±0.005	NS
Maximum service temperature, °F	500	500	450	700	350	700	700	300	400
Maximum clock running time, hours	360	144	120	360	120	120	120	360	192

*B = bourdon tube, RP = Rotating piston, P = Piston.
**Normally, elements are available in several ranges.
†FS = Full scale, NS = Not stated.

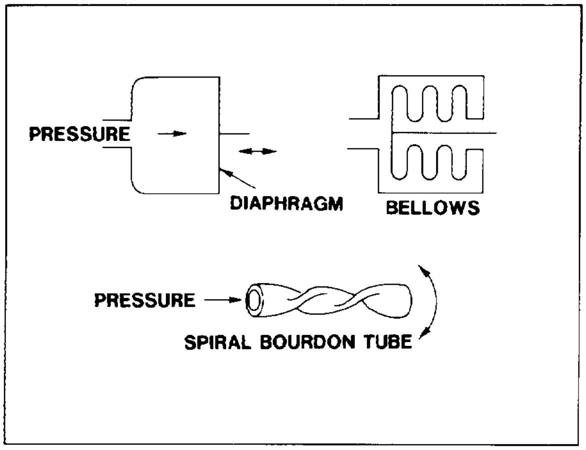

Fig. 30.1—Force summing devices.

rotated by a helical spring but controlled by a watch movement.

BHP gauges, although rugged and capable of service in severe conditions, must be considered precision instruments. Proper attention to adjustment, calibration, and operation is required to obtain consistently reliable and accurate pressure measurements. A comparison of the commonly used mechanical continuously recording BHP gauges is shown in Table 30.1.

Charts

Charts used in a BHP gauge are paper or metal. Paper charts have an abrasive coating and are marked by a brass or gold stylus. Metal charts, which are made of brass, copper, or aluminum, are generally preferred because they are not affected by humidity. Plain metal charts require a sharp pointed stylus. Coated metal charts are generally preferred because they produce less stylus friction. Black-coated charts are marked with a steel or jewel stylus, which burnishes the coated surface. White-coated charts are used with a brass or gold stylus. A finer line can be made on the black chart, but it is more difficult to read. A brass or gold stylus used with white-coated charts, paper, or metal, must be sharpened very frequently.

A small magnifying lens and steel scale with 0.01-in. divisions are most frequently used for reading charts with static pressure—i.e., where only one or two pressures readings are made on a chart. When a number of readings are to be made from a chart, it is advantageous to use one of the several available chart scanners. Some engineers have used microscopic comparators to read pressure deflection to 0.0001 in., but the inherent errors of a pressure element even under most careful handling are usually greater than the added accuracy of such precise measurement of the chart. New electronic chart scanners have improved the readability and accuracy of mechanical BHP gauges.

Calibration

Self-contained pressure gauges, like all pressure gauges used for precision work, must be calibrated on a deadweight tester at regular intervals. To obtain maximum accuracy, the pressure gauge is calibrated before a survey at the anticipated bottomhole temperature, (BHT), the survey conducted, and then the chart read using the presurvey calibration lines. New pressure elements should be calibrated frequently until they have become seasoned in service and their ability to retain calibration has been established. Before calibration, pressure equal to the maximum range of the element should be applied and released several times. The number of calibration points should be more on a new element, and two or more curves should be run as a check. The element should also be calibrated at the reservoir temperature at which the pressures are to be determined, or a temperature-correction factor should be determined to correct pressures measured at other than calibration temperature (Fig. 30.2). During calibration, the gauge should be tapped lightly to relieve residual friction in the moving parts of the element. Under normal operating conditions, pressure determination in a well should have an accuracy within a range of 0.2% of the maximum range of the element. The pressure element range should be selected to operate in the upper two-thirds range when at bottomhole conditions. Greater accuracy can be obtained by greater attention to details of calibration and the use of instruments that are well-seasoned by service. Pressure increase inside the gauge caused by an increase in temperature is considered only when extra effort is made to obtain precision pressures.

Temperature Effect

Temperature effect is an inherent property of metals and is present in all gauges, although for some alloys it is very small. Except for such alloys, temperature change

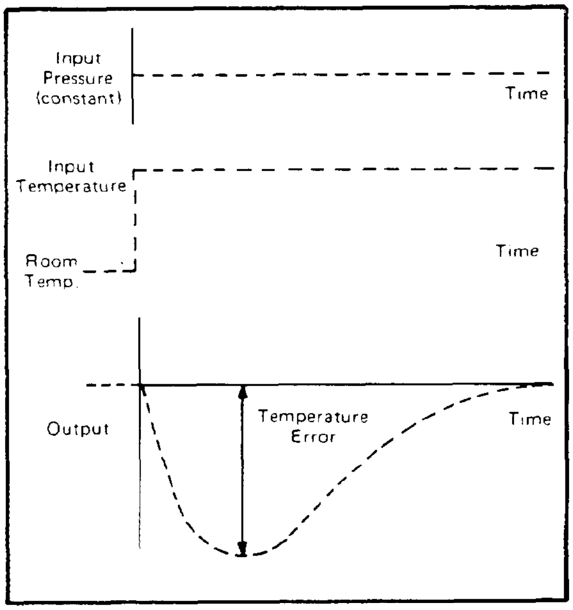

Fig. 30.2—Temperature effect on pressure gauges.

must be considered in pressure measurements. The preferred method is to calibrate the pressure element at the temperature of the reservoir in which pressures are to be measured. The calibration curve for most pressure elements is practically a straight line; therefore, a temperature-correction coefficient may be determined for a given pressure element and used to correct for temperatures other than the calibration temperature as follows. For a given pressure, preferably about three-fourths of the maximum for the element, determine the pressure deflection and the temperature. For the same pressure, determine the deflection at a higher temperature, preferably 100°F higher.

Then[1]

$$C_T=\frac{d_2-d_1}{d_1(T_2-T_1)}, \qquad (1)$$

where

C_T = temperature coefficient,
T_1 = lower temperature,
T_2 = higher temperature,
d_1 = deflection at T_1 for given pressure, and
d_2 = deflection at T_2 for same pressure.

The corrected deflection can be calculated as

$$d_c=\frac{d_o}{1+C_T(T_o-T_c)}, \qquad (2)$$

where

d_c = deflection at calibration temperature,
d_o = observed deflection,
T_c = calibration temperature, and
T_o = observed temperature.

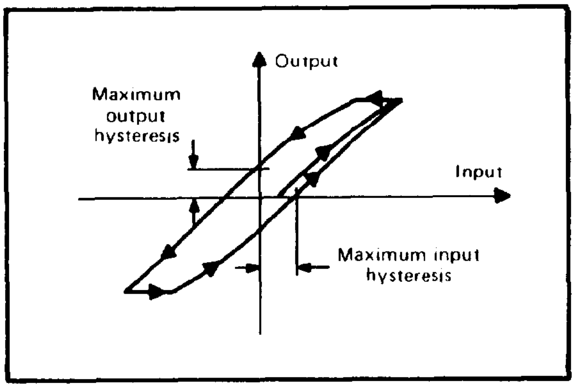

Fig. 30.3—Hysteresis.

If it is more convenient, pressure readings may be substituted for deflections in Eq. 2. Gauges with a steel pressure element usually have a temperature coefficient of about 0.0002 in./°F.

When the pressure gauge is run to the depth of the pressure determination, it should remain long enough to stabilize thermally, usually 15 to 20 minutes. If the instrument cannot remain long enough to reach temperature equilibrium, a maximum-indicating thermometer run in a closed container as part of the gauge will give a satisfactory reading for temperature correction.

Many BHP gauge elements are made of an alloy with a very low temperature coefficient such as Ni-Span C®, and a temperature correction may be neglected up to 200°F except where extra precautions are taken to obtain very precise pressure measurements. For temperatures above 200°F, most elements require a varying correction that can be determined only by actual calibration.

Hysteresis

Hysteresis is a characteristic of metals under strain that must be recognized in pressure gauges. Because of hysteresis, the calibration of a gauge made with increasing pressures will differ slightly from a calibration made with decreasing pressures (Fig. 30.3). If only static pressures are to be determined, a calibration at increasing pressure is satisfactory. When a flowing pressure starting from a static condition is to be determined, hysteresis may be of sufficient magnitude to take into account. To determine the hysteresis effect, the pressure element should be pressurized somewhat higher than the highest anticipated well pressure and released several times before running the calibration, first with increasing pressures, then with decreasing pressures. Flexing the element several times will substantially reduce the hysteretic effect and should be done each time just before the gauge is run into a well.[2]

Operating Equipment

The BHP gauge, a self-contained instrument, is run on a wireline and depth is measured by the line running in contact with a calibrated measuring wheel, which operates a counter. The most frequently used calibration of the measuring wheel is 2 ft/rev. When the contact of the line is tangent to the measuring wheel, the wheel

TABLE 30.2—WIRELINE TENSILE STRENGTHS AND WEIGHTS

	Tensile Strength (psi)	Nominal Tensile Strength (lbf)			
		Diameter Line (in.)			
		0.066	0.072	0.082	0.092
Plow steel	232,000	794	945	1,225	1,542
Stainless steel	170,000	582	692	898	1,130
Monel	150,000	513	611	792	997
	Nominal Weight per 1,000 ft of Line (lbm)				
Plow steel		11.4	14.0	18.0	22.6
Stainless steel		11.8	14.1	18.3	23.0
Monel		13.1	15.6	20.2	25.4

diameter in inches is $24/\pi$. When the contact is an arc of the wheel, the wheel diameter is $D=(24/\pi)-d$, where d is the diameter of the wireline. This applies if the greatest distance of the chord of the contact arc from the periphery of the wheel is greater than the diameter of the wireline. The measuring wheel diameter should be checked at reasonable intervals to maintain accuracy of depth measurements. A decrease in the diameter of the wireline caused by wear or by permanent stretch resulting from a hard pull will also cause errors in depth measurements.

The most common wirelines have diameters of 0.066, 0.072, 0.082, or 0.092 in. In areas having noncorrosive well fluids, plow steel lines are most satisfactory, but for corrosive conditions, stainless steel and Monel® lines are used. Both plow steel and stainless steel are subject to hydrogen embrittlement, but are satisfactory for short runs such as static-pressure tests, except under severe conditions. For an operation that requires the line to be in the hole under corrosive conditions for several hours, a Monel line should be used. Nominal tensile strengths of wire lines and their weights are given in Table 30.2.

Equipment for operating a wireline varies greatly. The most frequently used unit is a trailer-mounted reel driven by a 2- to 4-hp air-cooled gasoline engine. Power is transmitted to the reel by V-belt, through a disk clutch, or by hydraulic drive. On smaller equipment, an idler pulley permits the V-belt to serve as a clutch also. Braking may be by friction disk, brakeband, or hydraulic pump. When the equipment is used for a continuous program it may be mounted in a pickup truck, with housing to protect against the weather.

Pressure Bombs

Pressure bombs were used to some extent before recording pressure gauges small enough in diameter for oilwell use became available. They were usually made from tubing approximately 1½ in. in diameter with a small needle valve in the top and a ball and seat in the bottom to hold maximum pressure in the well. When the bomb was recovered, the pressure was determined by attaching a pressure gauge to the valve. The bomb had to be long enough to leave a volume of gas (or air) in the top to reduce the error of filling the bourdon tube of the pressure gauge. There was also substantial correction for temperature unless the bomb was raised to BHT before the pressure was read. An ordinary commercial maximum-indicating pressure gauge enclosed in a pressure-tight container was used occasionally, and in some cases a recording mechanism and clock were added. Such instruments were 3 in. or larger in diameter, which limited their use to wells without tubing.

Surface Recording Gauges

Surface recording pressure gauges can be used either permanently installed or wireline retrievable. All surface recording pressure gauges must be run on a single-

TABLE 30.3—SURFACE RECORDING BHP GAUGES

Pressure Measurement System	Amerada EMR-502 with EPG-512 Pressure/ Temperature Gauge	Lynes DMR-312 PTS-5K	Lynes DMR-314 PTX-5K	Sperry Sun	Johnston-Macco/ Schlumberger SSDR-1 Solid State Downhole Recorder	Johnston-Macco/ Schlumberger J-300 Accutronic Pressure Recorder	Amerada EPG-512 Pressure/Temperature Gauge	Lynes Conductor Wire Line Probe	Hewlett Packard 2813B Quartz Pressure Gauge	Johnston-Macco/Flopetrol Schlumberger DPTT
Dimensions and Weight										
OD, in	1.25	1.25	1.65	1.7	1.7	3	1.25	1.65	1.44	1.5
Length, in	85	50.5	60.75	108	150	76	13	28.5	39.38	44
Weight, lbm	3	8.5	10	NS	46 75 (with battery)	117 (with battery)	3	9.5	11	12
Pressure Channel										
Transducer type	capacitance	strain gauge	quartz crystal	bourdon tube	sputtered thin film strain gauge	sputtered thin film strain gauge	capacitance	quartz crystal	quartz crystal	sputtered thin film strain gauge
Calibrated range, psi	0 to 2,500 0 to 5,000 0 to 10,000	0 to 5,000 0 to 10,000	0 to 5,000 0 to 10,000	0 to 15,000	0 to 10,000	0 to 10,000	0 to 2,500 0 to 5,000 0 to 10,000	0 to 5,000 0 to 10,000	200 to 11,000	0 to 10,000
Operating range, psi	NS**	2 x FS	1 1 x FS	NS	1.5 x FS	1.5 x FS	NS	NS	1.1 x FS	1.5 x FS
Accuracy, %FS*	±0.09	±0.25	±0.05	±0.05	±0.04	±0 04	±0.09	±0.05	†	±0.04
Resolution, %FS*	±0.0004	±0 025	±0.006	±0.005	±0.0002	±0 0002	±0.0004	±0.001	±0.00009	±0.0002
Repeatability							±0.09% FS	NS	±0.4 psi	NS
Temperature Channel										
Range, °F	0 to 302	32 to 257	32 to 257	no temperature channel	32 to 302	32 to 302	0 to 302	32 to 257	no temperature channel	32 to 302
Accuracy	±0 1°F	±0.33% of reading	±0.33% of reading	no temperature channel	±0.5°F	±0.5°F	±0.1°F	±0.33% of reading	no temperature channel	±0.5°F
Resolution, °F	±0.01	±0.06	±0.25	no temperature channel	±0.10	±0.05	±0.01	±0 25	no temperature channel	±0.02
Power Supply and Signal Processor							GSC-501 gauge signal converter	DSR-300 digital surface recorder	Hewlett Packard 2816A pressure signal processor	SPRO test system
Environment										
Vibration	NS	NS	NS	NS	NS	±10G 10 to 60 Hz				
Shock	NS	NS	NS	NS	NS	200 G for 11 milliseconds (half-sine wave)				

*FS = Full scale.

**NS = Not stated by manufacturer or available to author.

†Accuracy of HP 2813B if operating temperature is known: within 1.8°F: ±0.5 psi or ±0.025% of reading, whichever is greater; within 18°F: ±1.0 psi or ±0.1% of reading, whichever is greater; and within 36°F: ±5 psi or ±0.25% of reading, whichever is greater.

TABLE 30.4—SUMMARY OF TRANSDUCER CRITERIA

Sensor	Excitation	Output Level	Accuracy (%)	Pressure Range (psi)	Frequency Response (Hz)	Temperature Range and Effects (°F)	Shock and Vibration Sensitivity	Stability* (%/yr)	Life or Calibration Shift with Use*
Capacitive	AC-DC special	high level (5V) frequency/bridge	0.02	0.01 to 5,000	0 to > 100	0 to + 165	poor to good	0.05	$>10^7$ cycles with < 0.05% calibration shift
Differential transformer	AC special	high level (5V) phase demod/bridge	0.5	30 to 10,000	> 100	0 to + 165	poor	0.5	$>10^6$ cycles life
Force balance	AC line power	high level (5V) with servo	0.01	1 to 5,000	0 to < 5	40 to + 165 (0.01%/°F)	poor	0.05%/month	$>10^7$ cycles with < 0.5% calibration shift
Piezoelectric	DC amp and self-generating AC	medium level with amp	1	0.1 to 40,000	1 to > 100,000	− 450 to + 400 (0.01%/°F)	excellent	1	unmeasurable use effects
Potentiometer	AC-DC regulated	high level	1	5 to 10,000	0 to > 50	− 65 to + 300 (0.01%/°F)	poor	0.5	$<10^6$ cycles life
Strain gauge	AC-DC regulated								
Unbonded	10V AC-DC	low level 4 mV/V	0.25	0.5 to 40,000	0 to > 2,000	− 320 to + 600 (0.005%/°F over limited compensated range)	good	0.5	< 0.5% calibration shift after 10^5 cycles
Bonded foil	10V AC-DC	low level 3 mV/V	0.5	5 to 10,000	0 to > 1,000	− 65 to + 250 (0.01%/°F over limited compensated range)	very good	0.5	$>10^6$ cycles
Thin film	10V AC-DC	3 mV/V	0.25	15 to 10,000	0 to > 1,000	− 320 to + 525 (0.005%/°F over limited compensated range)	very good	0.05	$>10^6$ cycles with < 0.25% calibration shift
Diffused semiconductor	10 to 28 V DC	medium level 3 mV/V to 20 mV/V	0.25	15 to 5,000	0 to > 1,000	− 65 to 250 (0.005%/°F over limited compensated range)	very good	0.05	< 0.25% calibration shift after 10^6 cycles
Bonded bar semiconductor	10V AC-DC	medium level 3 mV/V to 20 mV/V	0.25	5 to 10,000	0 to > 1,000	− 65 to + 250 (0.01%/°F over limited compensated range)	very good	0.5	< 0.5% calibration shift after 10^6 cycles
Variable reluctance	AC special	40 mV/V	0.5	0.04 to 10,000	0 to > 1,000	− 320 to + 600 (0.02%/°F over limited compensated range)	very good	0.5	$>10^6$ cycles life
Vibrating wire and tube	AC special	high level and frequency	0.02	1 to 100	0 to > 100	− 65 to + 200 requires temperature control	poor	0.01	$>10^6$ cycles life
Vibrating quartz	AC special	high level and frequency	0.01	1 to 10,000	0 to > 100	0 to + 302	good	0.005	$>10^6$ cycles life

*Stability and calibration shift should be considered together.

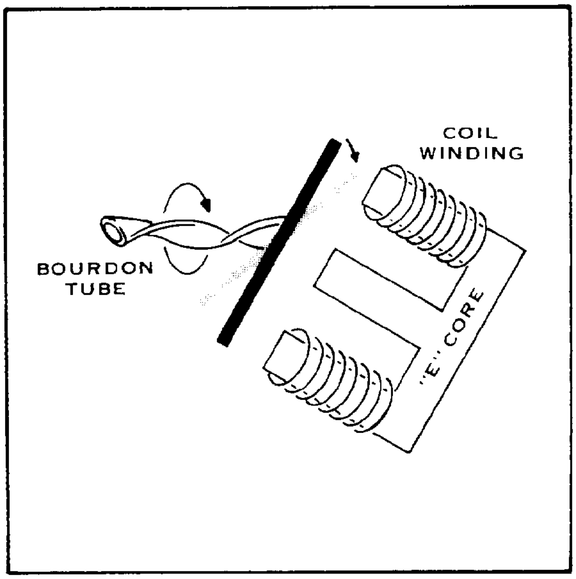

Fig. 30.4—'E'-Core transformer

conductor armored cable that carries a direct current from the surface to the transducer in the bottomhole instrument. Oscillating current returns through the same circuit from the transducer to surface instruments that determine and record its frequency. A transducer is any device that converts energy from one form to another. There is a large variety of transducers that allow nonelectrical variations to be converted into changes in resistance, current, voltage, capacitance, etc. Some examples are the strain gauge, thermistor, and the microphone. Readings are made at selected intervals of 1 second to 30 minutes or more. The frequency recorded in cycles per second is translated to pounds per square inch from a calibration curve. Table 30.3 shows a comparison of commonly used surface recording pressure gauges.

A permanently installed surface recording pressure gauge requires a gauge carrier or receiver and either a single conductor line or small diameter tubing (0.092 in.) strapped to the production tubing. The pressure gauge can be run with the tubing or by wireline retrievable, which sits in a gas lift mandrel or some other device to complete the circuit. The surface instruments may be connected permanently, or one set can be used to monitor BHP in several wells.

Modern precision pressure-measuring systems incorporate force summing devices that convert gas or liquid entry into physical displacement or deformation. The following sections discuss various concepts of pressure transducer technology shown in Table 30.4.[3]

Pressure Transducer Technology

Capacitive Transducer

In a capacitive transducer, a diaphragm is spaced evenly between capacitor plates. BHP causes displacement of the diaphragm and a change in capacitance. The advantages of a capacitive transducer are excellent frequency response, low hysteresis, good linearity, and excellent stability and repeatability. Disadvantages are high sensitivity to temperature variations and vibration.

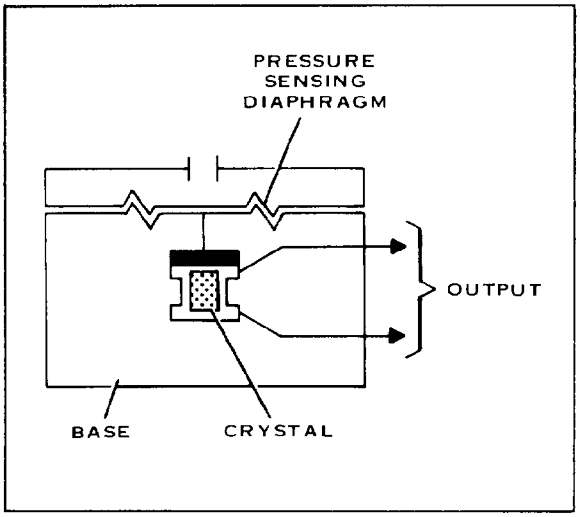

Fig. 30.5—Piezoelectric transducer.

Variable Inductance Transducer

In the variable inductance transducer, a flux linkage bar is mechanically linked to a spiral bourdon tube, diaphragm, or bellows (Fig. 30.1). The flux linkage bar is in the magnetic path of an E-core transformer (Fig. 30.4). Displacement of the flux linkage bar by pressure changes the E-core flux density resulting in a transformer output proportional to the pressure applied. The advantages are medium-level output and rugged construction. Disadvantages are a requirement for AC excitation, poor linearity, and susceptibility to stray magnetic fields.

Piezoelectric Transducer

The piezoelectric effect is the property exhibited by certain crystals of generating voltage when subjected to pressure (Fig. 30.5). When a strain is applied to an asymmetrical crystalline material such as barium, titanite, quartz, or rochell salt, an electrical charge is generated. When a piezoelectric crystal is connected to a diaphragm, bellows, or bourdon tube, the generated charge can be made proportional to the applied pressure. Advantages are very high frequency response (250 kHz), small size, rugged construction, and ability to accept large overpressures without damage. Disadvantages are temperature sensitivity, inability to make static measurements, and special electronics required.

Potentiometric Transducer

This transducer is constructed by coupling the wiper of a multiturn potentiometer to an amplifying mechanical linkage to a diaphragm, bellows, or bourdon tube. Advantages are low-cost, high-level output and simple electronic circuits. Disadvantages are limited life, poor resolution, large hysteresis, and low frequency response.

Vibrating Wire Transducer

A thin wire is connected in tension to a diaphragm, bellows, or bourdon tube and is caused to vibrate under the influence of a magnetic field (Fig. 30.6). The wire's frequency of vibration is directly related to its tension.

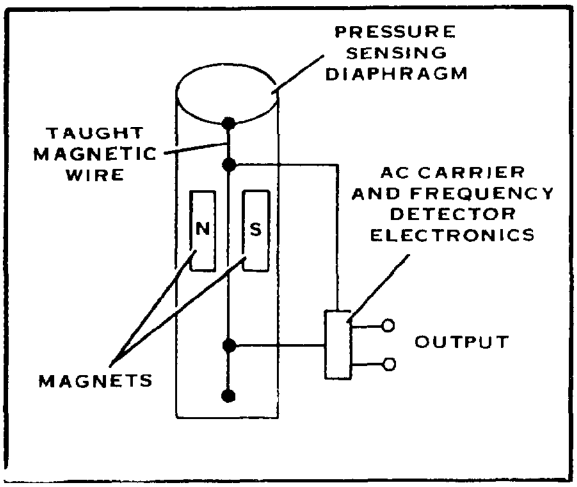

Fig. 30.6—Vibrating wire transducer.

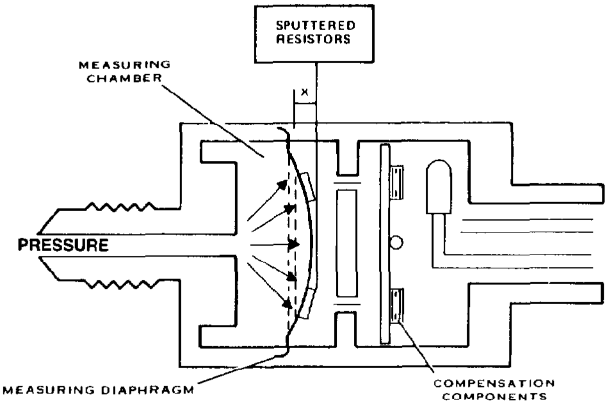

Fig. 30.7—Thin film strain gauge transducer.

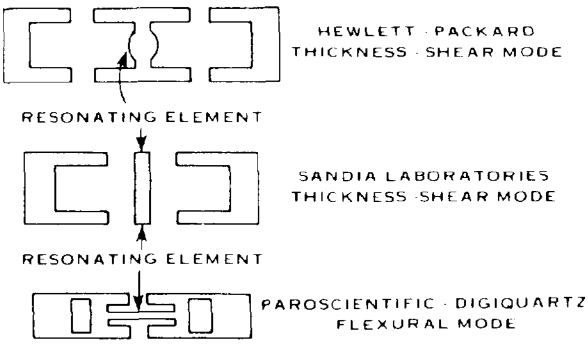

Fig. 30.8—Cross-sections showing different modes of motion of quartz crystals.

Advantages are very high accuracy, low hysteresis, and excellent long-term stability. Disadvantages are sensitivity to shock and vibration, temperature sensitivity, and additional electronics.

Strain Gauge Transducers

A strain gauge transducer is a strain-sensitive resistor mounted to a diaphragm, bellows, or bourdon tube. When pressure is applied, the resistor changes its physical length thereby causing change in resistance. This effect is expressed by

$$F_g = \frac{\Delta r/r}{\Delta L/L}, \qquad \text{(3)}$$

where

F_g = gauge factor,
Δr = change in resistance,
r = unstrained resistance,
ΔL = change in length, and
L = unstrained length.

There are four basic types of strain gauge transducers; unbonded wire, bonded foil, thin film, and semiconductor. A rule that applies to strain gauge transducers is the larger the gauge factor, the higher the output of the device. For unbonded wire, the gauge factor is four. Bonded foil and thin film (Fig. 30.7) have factors of two. For semiconductor transducers, the factor ranges from 80 to 150.

Vibrating Crystal Transducer

In vibrating crystal transducers, a crystal is forced by external electronic circuits to oscillate at its resonate frequency when external stress is applied to the crystal by mechanical linkage to the diaphragm, bellows, or bourdon tube. The resonate frequency of the crystal shifts in proportion to the stress. In at least one transducer of this type, the pressure is applied directly to the crystal itself. The vibrating crystal is usually manufactured out of quartz because of its excellent elastic properties, long-term stability characteristics, and ease of vibrational excitement. Fig. 30.8 shows various modes of motion of quartz crystal. Advantages are excellent accuracy, resolution, and long-term stability. Disadvantages are sensitivity to temperature and extremely high costs.

New technology is constantly evolving a new generation of surface recording pressure gauges that are more and more advantageous to the petroleum engineer and petroleum engineering problems.

Calculated BHP

BHP calculated from surface pressure and fluid level, although less accurate than measured pressure, is sufficient for many practical uses. In an open hole or open tubing, the fluid level can be determined by a float run on a measuring line.

In pumping wells, the fluid level can be determined by sound reflection. There are four types of commercial instruments available. These are the depthograph, echometer, sonoloy, and acoustical well sounder. Each of these instruments records sound reflection initiated by firing a blank shotgun shell or pistol cartridge or venting pressure into a chamber attached to the casing head. A sound reflection is received and recorded from each tubing collar. By counting the collar reflections and knowing the tubing tally, the depth to the fluid can be calculated. In deep wells, attenuation of the collar reflection makes accurate counting difficult. In some oil wells, usually those having considerable gas, a foaming condition makes the fluid level difficult to identify or may indicate a fluid level much higher than actual. A foaming condition is usually indicated when the fluid level changes several feet on tests made at short intervals of time. Fluid level can also be calculated from the time interval for the reflection to be received from the fluid level, but the variation in the speed of sound through gases of different compositions and the effect of temperature make the procedures more laborious and usually less accurate than the simpler method of counting collar reflections.

In calculating the pressure caused by the column of fluid, allowances should be made for gas in solution in the oil, which will reduce its specific gravity below that measured in the stock tank. This can reduce the gradient 5 psi/100 ft or more where much gas is in solution under high pressure. For wells producing water, it is customary to calculate the fluid head on a basis of a column of oil and water in the same ratio as normal production for the well, but this calculation is less reliable for low-capacity wells with high casinghead pressure and for pumping wells in which the pump is several hundred feet above the producing formation. If the surface pressure is low, the pressure caused by the weight of a column of gas may be too small to warrant consideration, but under high pressure it should be calculated and added to the hydrostatic head by the same equation used for calculating BHP in a gas well, where D is the depth of the fluid level.

Producing BHP of a pumping well that is sufficiently accurate for practical use may be calculated by shutting in the casing head until the gas pressure depresses the fluid level to the inlet of the pump, at which time fluid delivery is stopped. The casinghead pressure at that time, plus the head of the column of gas from the casing head to the pump inlet, plus the head of the column of liquid from the pump inlet to the producing formation is the producing BHP. A check of the determination should be made by releasing and controlling the pressure a few pounds less than the maximum pressure read and determining the rate of production under such conditions.

The BHP in a gas well can be calculated with an equation developed by Pierce and Rawlins[4]:

$$p_{ws}=(p_{wh})^{e^{0.0000347\gamma_g D}}, \quad \ldots\ldots\ldots\ldots (4)$$

where

p_{ws} = static BHP, psia,
p_{wh} = wellhead pressure, psia,
e = base, natural logarithms,
γ_g = specific gravity of gas (air=1), and
D = depth of well, ft.

This equation is based on an average temperature of the column of gas of 60°F. While the temperature gradient in a producing well is rarely a straight line, the average temperature at a depth below seasonal effect (20 to 30 ft) and at a depth of the pressure is sufficiently accurate for practical purposes. The equation can then be written[5]:

$$p_{ws}=(p_{wh})^{e^{\gamma_g D/(53.34T)}}$$

or

$$\log p_{ws}=\log p_{wh}+\frac{\gamma_g D}{122.82\bar{T}}, \quad \ldots\ldots\ldots\ldots (5)$$

where $\bar{T}$ is the average temperature in the borehole, °F+460.

Deviation of a gas from Boyle's law will affect the calculated BHP enough to be considered only in high pressure deep wells. USBM Monograph 7 presents the following equation.[5]

$$\frac{p_{wh}}{1+p_{ws}z}=\left(\frac{p_{wh}}{1+p_{wh}z}\right)^{e^{\gamma_g D/(53.34T)}} \quad \ldots\ldots\ldots\ldots (6)$$

where z is the deviation coefficient, deviation per psi expressed as a decimal.

Application of BHP

The importance of pressure analysis in projecting and enhancing the performance of producing oil and gas wells emphasizes the need for precision pressure measurement systems. Today's petroleum engineer must have sufficient information about the reservoir to adequately analyze current performance and predict and optimize future performance. More specifically, such pressures are a basic part of reservoir calculations, rate of equalization of pressures, interference tests for well spacing or rate of development, formation damage during completion, rework or workover operations, and indication of deposition of salts, sediments, or other restrictions at the wellbore. Other applications are design of downhole equipment for artificial lifting, efficiency of operation of such equipment, and evaluation of drillstem test (DST) information.

Static Pressure

Static pressure is the most frequent BHP measurement. Most such measurements are made as a pressure survey of a pool where the pressures in all wells are determined in a short period of time either by cooperation of the operators or by order of a conservation commission, usually as a result of a recommendation by the operators. Pressures are taken under reasonably uniform conditions after the wells have been shut in a specified length of time such as 24 or 48 hours, or longer, if the pressure buildup is at a slow rate. The pressures should be measured at or adjusted to a common data plane. In many pools, the pressures will not reach equilibrium in the specified shut-in time. However, if the pressures are determined for several surveys under the same conditions, the indicated rate of decline of the reservoir pressure should be reasonably accurate. Tests in representative wells which have been shut in long enough to reach pressure equilibrium will show the relation of the measured pressure to the actual reservoir pressure. Pressures in inactive wells may be used to confirm the actual pressure and the rate of decline.

Average Reservoir Pressure

The average reservoir pressure for a pool may be determined by arithmetically averaging the pressures of all wells. For some pools it is preferable to determine a weighted average by weighting each pressure by the productive thickness of the reservoir at that point. When for any reason the pressure cannot be determined in substantially all wells or where wells are irregularly spaced, a better average reservoir pressure is determined by recording the pressures, either actual or weighted, on a map of the area and drawing isobars from which the average pressure weighted for an area is determined by planimeter, grid system, or other means.

Static Pressure from Partial Buildup

Many low-permeability reservoirs require excessive shut-in time to reach static or equilibrium pressure. Several methods have been proposed for calculating the reservoir pressure from partial buildup of pressure. Muskat[6] proposed plotting log $(p_{ws}-p_t)$ vs. time, where p_{ws} is an estimated static BHP and p_t is the measured pressure at different times, p_{t_1}, p_{t_2}, p_{t_3}, etc. When plotted on semilog cross-sectional paper with pressure on the log scale, the selected p_{ws} is the static pressure when the plot is a straight line.

Arps and Smith[7] proposed plotting increments of pressure increase for uniform time periods against measured pressure on rectangular cross-sectional paper, and extrapolating the curve to intersect the zero line of the incremental-pressure scale, which gives the static pressure. Both the Arps and Smith and the Muskat methods are more commonly used in cases of rapid pressure buildup.

Miller *et al.*[8] presented an equation to calculate the static pressure from a partial buildup curve:

$$p_{ws}=p^*+\frac{(p_{sd}-\Delta\bar{p})q\mu B}{0.00708\,kh}, \qquad (7)$$

where

p_{ws} = static BHP, psi
p^* = last pressure on buildup curve, psi
p_{sd} = $\log_e(r_d/r_w)$ for constant pressure at radius of drainage, or
= $\log_e(r_d/r_w)-0.75$ when no influx across external boundary,
q = production rate at shut-in, B/D,
μ = reservoir fluid viscosity, cp,
B = formation volume factor for total fluid produced, RB/STB
k = permeability of reservoir, md,
h = effective thickness of reservoir, ft,
$\Delta\bar{p}$ = dimensionless pressure variable from curves (see Fig. 30.9),
Δp = $p_{wf}-p_{ws}$,
p_{wf} = BHP during buildup, psi,
p_{ws} = BHP at time of shut-in, psi, and
t = time after well was shut in, hours.

The value of p^* is determined by plotting the buildup pressure vs. the time on semilog paper, with time on the log scale. When afterflow is completed following shut-in, the points should fall on a straight line and p^* is the highest measured pressure lying on the straight line. This is the same straight line by which the slope, m, is determined in the equation for permeability from buildup pressures by the same authors and is discussed further under that topic.

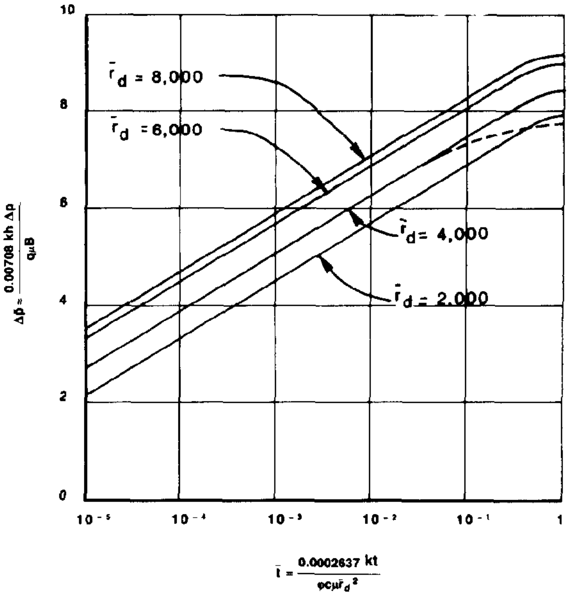

Fig. 30.9—Curves from which $\Delta\bar{p}$ is determined in the Miller *et al.* equation for calculating static pressure from buildup pressure curve. *Solid lines assume influx at* r_d and dotted line indicates direction of curves when no influx at r_d.

The straight line by which the slope m is determined comes from the middle time region of a Horner plot. Afterflow causes lack of development of the middle time region (with long periods of afterflow), early onset of boundary effects, and development of several false straight lines that could be mistaken for the middle time region. This makes the middle time region difficult for the buildup test analyst to recognize. Recognition of the middle time region is essential for successful buildup curve analysis based on Horner plot method. The line must be identified to estimate reservoir permeability, to calculate skin factor, and to estimate static drainage area pressure.

A log-log graph of the pressure change, $p_{ws}-p_{wf}$ (Δp), in a buildup test vs. shut-in time t presents a good estimation of where the straight line portion, or middle time region, begins (Fig. 30.10).[9] A log-log graph of pressure change $p_{ws}-p_{wf}$ vs. Δt[16] is an even more diagnostic indicator of the end of afterflow distortion. Fig. 30.11 shows a semilog plot of theoretical buildup test data. The use of type curves has greatly improved identification of the straight line portion of the buildup curve after wellbore storage effects have ended.

Horner[10] plotted buildup pressure vs. $(t+\Delta t)/\Delta t$ on semilog paper with $(t+\Delta t)/\Delta t$ on the log scale where t=total producing time since well completion, hours, and Δt=time since the well was closed in, hours. Extrapolation of the curve to a value of $(t+\Delta t)/\Delta t=1$ is the approximate static pressure.

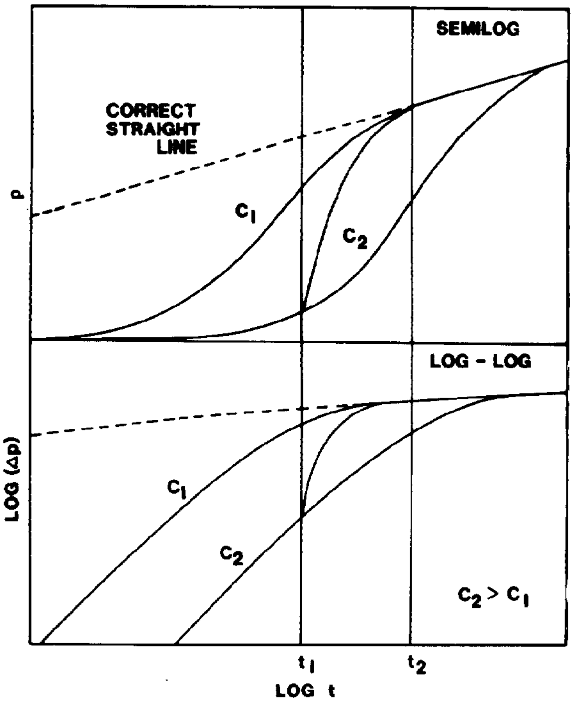

Fig. 30.10—Log-log vs. semilog plots.

The value of t is determined by dividing the cumulative production of the well by the rate of production per hour at the time the well is shut in. The uncertainty of the value of t increases with the age of the well. Experience indicates that using the time of the flow period before the well is shut in for the buildup test is often more reliable than using the total time since completion provided fully stabilized conditions exist both when the well is opened and when it is shut in.

Thomas,[11] with Horner's basic equation, preferred using the reciprocal of $(t+\Delta t)/\Delta t$ and therefore plotted pressure vs. $\Delta t/(t+\Delta t)$ on semilog paper with $\Delta t/(t+\Delta t)$ on the log scale, and extrapolated the curve to a value of $\Delta t/(t+\Delta t)=1$, which gives the approximate reservoir pressure.

Hurst[12] plotted the buildup pressure vs. the shut-in time in minutes on semilog paper with time on the log scale. A straight line is drawn through the points and extrapolated to an intercept time value of 1. The slope is the value of pressure change in one log cycle. Expressing his equation in English units, the static pressure is calculated:

$$p_{ws}=b+m \log 625\, m, \quad \ldots\ldots\ldots\ldots\ldots\ldots (8)$$

where

p_{ws} = static BHP, psi,
m = slope of buildup curve, and
b = intercept of curve with time value of 1 minute.

Correct identification of the straight-line portion of the buildup curve is necessary for the interpretation of pressure buildup data. The straight-line portion of the curve is frequently masked by one or more factors, such as skin effect, afterflow, and the early onset of boundary effects. Chap. 35, "Well Performance Equations," addresses these problems.

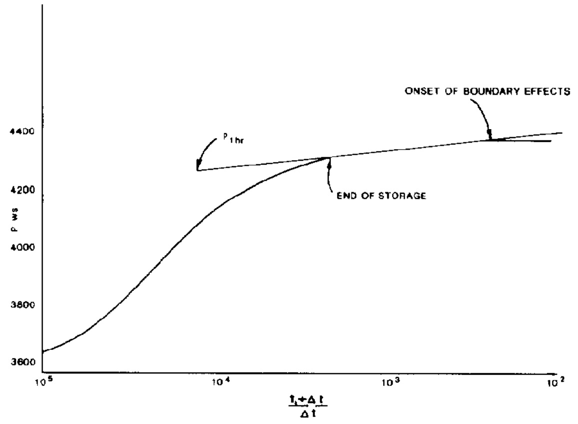

Fig. 30.11—Plot of typical buildup with afterflow.

The capacity of a well to produce can be estimated from the BHP drawdown on a flow test. For gas wells, the open-flow capacity is calculated by the procedure proposed in Ref. 5 except that both the static pressure and the flowing pressure are measured with a BHP gauge. Open-flow capacity of oil wells having large capacity and high pressure is rarely of value, and little work has been reported on such determinations. Theoretically, so long as single-phase flow maintains, the rate of flow should increase in proportion to the drawdown pressure. But, because of gas coming out of solution below the bubblepoint, turbulence in the flow, and borehole restrictions, the flow conditions change and the proportionality does not hold. Engineers who have investigated the problem usually consider that little increase will be obtained after the drawdown pressure is one-half the static pressure. For low-pressure wells, the rate of production will usually continue to increase until the flowing pressure is equal to or close to atmospheric pressure.

Productivity Index

PI is defined as the barrels of oil produced per day per pound decline in BHP. To determine the PI, a well is shut in until static or reservoir pressure is reached. The well then is opened and produced until the BHP and rate of production are stabilized. Since a stabilized pressure at surface does not necessarily indicate a stabilized BHP, the BHP should be recorded continuously from the time the well is opened. The PI is then

$$J=\frac{q_o}{p_{ws}-p_{wf}}, \quad \ldots\ldots\ldots\ldots\ldots\ldots (9)$$

where

J = PI, B/D-psi,
q_o = rate of oil production, B/D,
p_{ws} = static BHP, psi, and
p_{wf} = flowing BHP, psi.

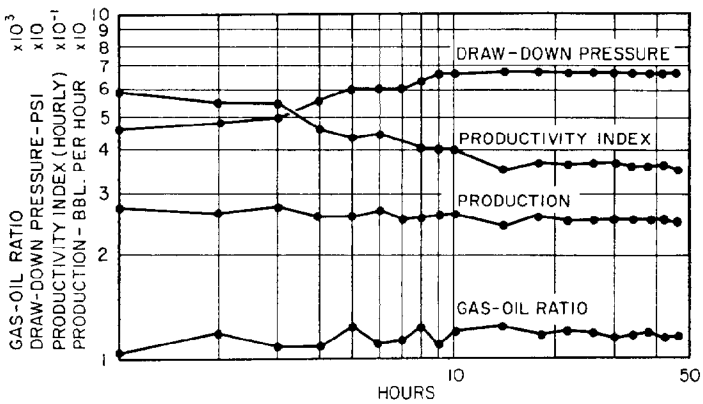

Fig. 30.12—Flow-test data on a well having a negligible transient or stabilization period.

Specific PI is defined as barrels of oil produced per day per pound decline in BHP per foot of effective reservoir thickness, and is expressed as

$$J_s=\frac{q_o}{(p_{ws}-p_{wf})h}, \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (10)$$

where J_s is the specific PI and h is the effective reservoir thickness, ft.

On a flow test the time required for a well to reach a stabilized BHP and rate of production, that is, the transient period, may require several hours or even days and occasionally several weeks. The duration of the transient period and the rate of the pressure decline and the PI decline during the transient period will indicate the quality of the reservoir. A short transient period indicates a high-quality reservoir, and a long transient indicates a low-quality reservoir which will have a comparatively low recovery of the amount of oil calculated to be in place. Reservoir quality is not related to the numerical value of the PI. The nature of the transient period is most conveniently expressed by plotting the productivity index by hours on log-log paper.

Typical well test data are presented in Figs. 30.12 through 30.15. The negligible transient period of the test shown in Fig. 30.12 indicates a high-quality reservoir from which relatively high recovery may be expected. The short transient period in the flow test in Fig. 30.13 indicates a comparatively high recovery of the original oil in place. In Fig. 30.14, the transient period is quite long but the continuous flattening of the slope of the PI curve indicates eventual stabilization. Fig. 30.15 is the flow test of a well in which the continuous decline in pressure, production, and PI shows that the flow will not stabilize and therefore the ultimate recovery will be lower than that reasonably expected from a consideration of the producing formation and its apparent productivity.

Flow tests and PI tests are conducted by other procedures. Some prefer to run the test at two or more different rates of flow. There is usually some difference in the PI at different rates, sometimes more than can be accounted for by inherent limitation of accuracy of pressure measurement and production gauging. Changing GOR or WOR will affect the relative permeability and therefore the PI. Calculating a PI based on total fluid mass instead of liquid production has given more consistent results in some pools.

Permeability

Permeability of the reservoir rock can be calculated from the PI. Wycoff *et al.*[13] used

$$k=\frac{q\mu B\log(r_d/r_w)}{0.003076\,h(p_{ws}-p_{wf})}$$

$$=325\,J_s\mu B\log\frac{r_d}{r_w}, \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots (11)$$

where

k = permeability, md,
r_d = radius of drainage area, ft,
r_w = wellbore radius, ft,
q = production rate, B/D,
μ = viscosity of produced fluid, cp,
B = formation volume factor, RB/STB,
h = effective reservoir thickness, ft,
p_{ws} = static BHP,
p_{wf} = flowing BHP, and
J_s = specific PI.

Permeability can be calculated from the buildup curve obtained when a producing well is shut in following a flow test. Muskat discussed this in 1937 and presented an equation in 1949.[14] The equation in commonly used units is

$$k=\frac{40.37\,md^2\mu B\log(r_d/r_w)}{h\gamma}, \quad \ldots\ldots\ldots\ldots\ldots (12)$$

where m=slope of log $(p_{ws}-p_{wf})$ vs. t, d=diameter of flow pipe, in., t=time, hours, since well was closed in, and other parameters are as previously defined.

The equation has limitations, but it may be helpful in cases of severe reservoir damage such as interpretation of DST buildup curves where recovery is low.

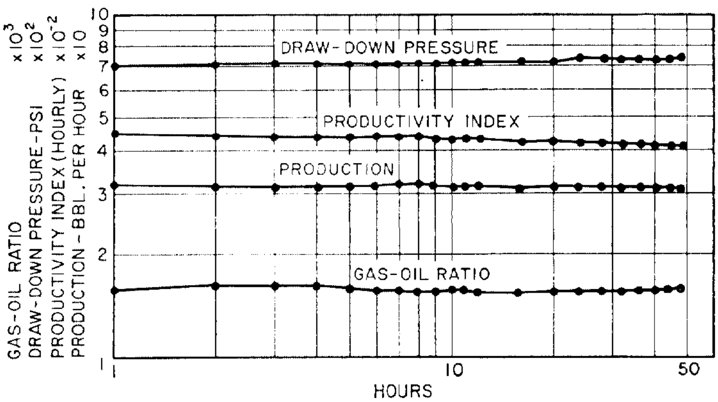

Fig. 30.13—Flow-test data on a well having a short transient period.

Miller *et al.*[8] calculated permeability from a BHP buildup curve with the equation

$$k_o=\frac{162.5 q_o \mu_o B_o}{hm}, \quad \ldots\ldots (13)$$

where

k_o = effective oil permeability, md,
k = permeability, md,
q_o = oil production rate, B/D,
μ_o = viscosity of reservoir oil, cp,
B_o = formation volume factor of oil, RB/STB,
h = effective reservoir thickness, ft, and
m = slope of buildup curve.

The slope m can be determined most conveniently by plotting BHP against time in hours on semilog paper, with time on the log scale. The initial part of the curve is affected by the afterflow into the wellbore, and the last part of the buildup curve may be too flat and therefore unreliable because of interference of drainage areas or limited reservoir. The calculation is simplified by extrapolating the buildup curve to encompass one complete cycle of the log scale. The slope is then the difference in the pressure reading at the beginning and at the end of the cycle.

The part of the curve representing the slope of the buildup curve is usually evident, but occasionally interferences and irregularities in the reservoir make the slope uncertain. We consider that if the value

$$m=\frac{0.0002637kt}{\phi c_L r_d{}^2 \mu}, \quad \ldots\ldots (14)$$

where

k = permeability, md,
t = time, hours, from closed in to end of straight-line portion,
ϕ = porosity, fractional,
c_L = liquid compressibility, psi^{-1},
μ = viscosity, cp,
r_d = drainage radius, ft,

falls to the range 10^{-1} to 10^{-2}, the slope m is proper and the calculated value of k is valid. This tacitly assumes that the values of the other factors are known and that the conditions exist for which the equation was derived. A valid calculation of permeability from buildup curves requires stabilized conditions of pressure and rate of production at the time the well is closed in.

These equations for calculating permeability are based on liquid single-phase flow. When a small amount of free gas is produced with the liquid, adjustment by the relative permeability will give an acceptable answer. When gas only is produced from the reservoir, the equations for permeability are as follows.

Radial flow equation:

$$k=\frac{q_g \mu_g T_R z \log(r_d/r_w)}{0.00306h(p_{ws}{}^2-p_{wf}{}^2)}. \quad \ldots\ldots (15)$$

Pressure buildup[15]:

$$k=\frac{1{,}637 q_g \mu_g T_R z}{hm_g}, \quad \ldots\ldots (16)$$

where

k = permeability, md,
q_g = rate of production, Mcf/D at 14.7 psi and 60°F,
μ_g = viscosity of reservoir gas, cp,
T_R = reservoir temperature, °F+460,
z = gas deviation factor, reservoir conditions,
h = effective reservoir thickness, ft,
p_{ws} = static BHP, psia,
p_{wf} = flowing BHP, psia,
r_d = drainage radius,
r_w = wellbore radius, and,
m_g = slope of pressure buildup curve, $p_w{}^2$ vs. log t, where t=time after shut-in, hours, p_w=BHP at t.

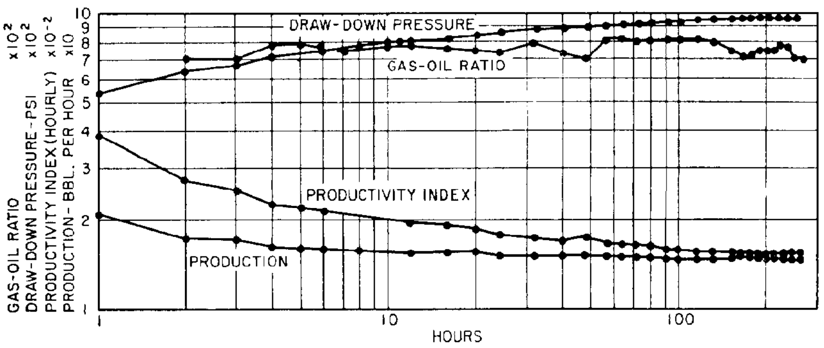

Fig. 30.14—Flow-test data on a well having a long but finite transient period.

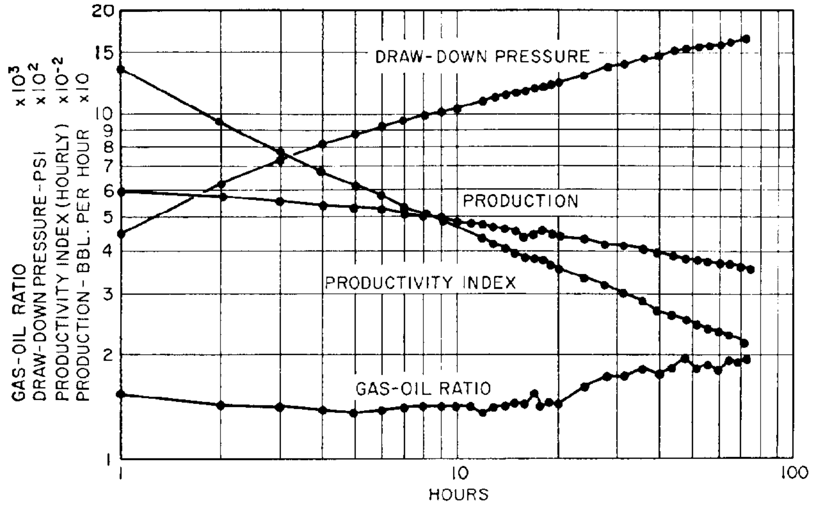

Fig. 30.15—Flow-test data on a well having a very long transient period.

Permeability Damage

The permeability of the reservoir adjacent to the borehole is frequently reduced by the invasion of drilling mud, water blocking by invasion of filtrate water from drilling fluid or other source, swelling of clay particles, or deposition of salts or wax. Blinding or partial clogging of screens or perforations will give a similar effect. A substantial restriction of flow can be observed on the BHP chart by the straight-line buildup until near the maximum pressure instead of the normal exponential shaped curve. On the other hand, permeability adjacent to the borehole may be increased as a result of acidizing, fracturing, or shooting.

The amount of damage or improvement to the permeability adjacent to the borehole is determined by comparing the permeability calculated from flow test with the permeability calculated from the buildup and is expressed as the productivity ratio:

$$F_P=\frac{k_j}{k_b} \quad \text{.............................} (17)$$

where

F_P = productivity ratio,
k_j = permeability calculated from productivity index, and
k_b = permeability calculated from buildup pressure.

Substituting the equated expressions of k_j and k_b and simplifying:

$$F_p=\frac{2m\log(r_d/r_w)}{p_{ws}-p_{wf}}. \quad \text{......................} (18)$$

A fractional F_P indicates restricted flow at the borehole and an F_P greater than unity indicates better permeability at the borehole, usually the result of stimulation.

Dolan *et al.*[16] presented an empirical equation to determine "damage factor" that does not involve the use of the amount of production. It is of particular value for interpretation of drillstem test charts that have an acceptable buildup but negligible fluid recovery. His equation expressed as productivity ratio is

$$F_P=\frac{\Delta p}{0.183(p_{ws}-p_{wf})}, \quad \text{...................} (19)$$

where

F_P = productivity ratio,
p_{ws} = static BHP,
p_{wf} = flowing BHP, and
Δp = slope of plot of p vs. $\log(t+\Delta t/\Delta t)$,

where

t = time well was open, minutes,
Δt = time after well was shut in, minutes, and
p = pressure at $t+\Delta t$.

Hurst[12] has developed equations for calculating restrictions to flow through the reservoir adjacent to the borehole, which they have called "skin effect." Expressed in oilfield units, these equations are

for oil:

$$p_s = m\left[\frac{(p_t - p_{wf})}{m} - \log\left(\frac{q_o B_o}{10.4 m h \phi c_o r_w^2}\right)\right] \qquad \text{.......... (20)}$$

and for gas:

$$p_s = m_g\left[\frac{(p_t - p_{wf})}{m_g} - \log\left(\frac{q_g z T_R}{2.063 \phi h m_g c_g \bar{p} r_w^2}\right)\right], \qquad \text{.......... (21)}$$

where

p_s = pressure loss due to skin effect, psi,
p_{ws} = static BHP, psi,
p_{wf} = flowing BHP, psi,
p_t = well pressure 1 hour after shut-in, psi,
q_o = production rate for oil, B/D,
q_g = production rates for gas, Mcf/D at 14.7 psia and 60°F,
B_o = formation volume factor of oil, RB/STB,
z = compressibility factor (gas deviation factor),
h = effective reservoir thickness, ft,
T_R = reservoir temperature, °F+460,
ϕ = porosity reservoir rock, fraction,
c_o = compressibility of reservoir oil, psi^{-1},
r_w = borehole radius, ft,
m = slope, p_t vs. $\log t$, and
m_g = slope p_t^2 vs. $\log t$, where p_t is the well pressure at time t and t is time after well shut-in, hours.

Positive values of p_s indicate damage and negative values of p_s indicate improvement of permeability adjacent to the wellbore in terms of pressure loss due to skin effect.

It is usually difficult to delineate specific heterogeneities from well test results only because different heterogeneities may cause the same or similar well test response. A higher degree of confidence is achieved when the interpretation of test results is confirmed by geological and geophysical evidence of heterogeneities.

Linear discontinuities, faults, and barriers affect a pressure buildup behavior and are manifested by a second straight line, the slope of which is double the initial straight line. For a well near a linear fault, drawdown testing can be used to estimate reservoir permeability and skin factor in the usual fashion, as long as wellbore storage effects do not mask the initial straight-line section. If the well is very close to the fault, the initial straight-line section may end so quickly that it will be masked by wellbore storage.

As the drawdown proceeds and the pressure at the producing well falls below the initial semilog straight line, the following equation indicates that p_{wf} vs. $\log t$ plot will have a second straight line portion with a slope double that of the initial straight line.

$$p_{wf} = 2(m \log t + p_{1\text{hr}}) + p_i + m\left[0.86859s + \log\left(\frac{4L^2}{r_w^2}\right)\right], \qquad \text{.......... (22)}$$

where

$$m = \frac{-162.5 q_o \mu_o B_o}{kh},$$

$p_{1\text{hr}}$ = pressure on straight-line portion of semilog plot one hour after beginning a transient test, psi,
p_i = initial reservoir pressure, psi,
s = skin effect, and
L = distance to a linear discontinuity, ft.

However, the simple occurrence of a doubling slope in a transient test does not guarantee the existence of a linear boundary near the well.

To estimate the distance to a linear discontinuity, we use the intersection time, t_x, of the two straight line segments of the drawdown curve. The following equation applies for drawdown testing.[17]

$$L = 0.01217\sqrt{\frac{k_o t_x}{\phi c_t \mu_o}}, \qquad \text{.......... (23)}$$

where c_t is compressibility of the total system, psi^{-1}. The effects of reservoir heterogeneities and method of determining them are discussed in Chap. 26.

Lifting Equipment

BHP measurements are valuable to the engineer for determining the size and type of artificial lift to install and to monitor the efficiency of such equipment.

The efficiency of a gas lift depends, among other factors, on the pressure at the depth of gas injection. From the flowing pressure or PI, the pressure can be calculated for a given rate of production and after a gas lift is in operation. Knowing the PI, the producing efficiency can be calculated from the rate of production. The change in pressure gradient in a well being gas lifted will determine the point at which gas is entering the flow string, which is of interest where multiple flow or unloading valves are installed.

The PI is used to determine the amount of fluid available to be pumped from a well and therefore the size of the pump that should be run and the depth at which it should be set. After a well has been on the pump for some time and declined in production, the question frequently arises as to whether the productivity of the well has declined or the pumping equipment has decreased in efficiency. The correct condition can be determined by measuring the static and producing pressures, either with a bottomhole gauge or from fluid-level calculation by sound reflections as described previously. If fluid-level determinations are known to be unreliable for a given pool or are proved uncertain in a given well because of fluctuating fluid-level by several determinations, a BHP gauge should be run. Many operators have successfully run a pressure gauge in the annulus between the tubing and casing. During such runs the wireline will sometimes wrap around the tubing or the gauge will wedge between the tubing and casing. It can usually be released by starting the pumping equipment, but sometimes it is necessary to move in a pulling unit to lift the tubing to free the gauge. Many operators use an eccentric tubing head to position the tubing against one side of the casing instead of its normal central position and thus minimize chances of the gauge's becoming hung up in the annulus. The BHP gauge can be run on the rods in most wells by attaching it, preferably rigidly, to the standing valve. A pressure gauge under these conditions is subject to severe vibrations resulting from both the vibration of the pumping equipment and a "water-hammer" effect from the liquid at the pump level.

Drillstem Tests

The most common use of BHP gauges in a drilling well is in evaluating DST's. Pressure gauges were first used to determine that the valve functioned properly and was open during the test. Subsequently the pressure information has become important. The detailed pressure information obtained on a DST can be used to determine the productivity of the formation by calculating the PI from the amount of fluid recovered during the test and the static and drawdown pressures. A more recent use has been to confirm indicated productivity from the buildup after the valve is closed. It is not unusual to have a very poor recovery of fluid and obtain a good buildup curve such as can be obtained only when the producing capacity is much better than indicated by the quantity of fluid recovered. The permeability can be calculated from the buildup curve. While subject to a high probable error because of the short time of the test and usually high reservoir damage adjacent to the borehole, it is sufficient to indicate whether further testing may be warranted.

Mud Weight

The pressure at the depth of a DST, before seating the packer and also after the test is completed and the packer unseated, permits calculating the average weight of mud in the hole and is used to verify mud weight as measured by routine tests.

Nomenclature

b = intercept of curve with time value of 1 minute

B = formation volume factor for total fluid produced

B_o = formation volume factor of oil

c_L = liquid compressibility

c_o = compressibility of reservoir oil

c_t = compressibility of the total system

C_g = gas compressibility

C_T = temperature coefficient

d = diameter of flow pipe

d_c = deflection of calibration temperature

d_o = observed deflection

d_1 = deflection at T_1 for given pressure

d_2 = deflection at T_2 for same pressure

D = depth of well

e = base, natural logarithms

F_g = gauge factor

F_P = productivity ratio

h = effective reservoir thickness

J = PI

J_s = specific PI

k = permeability of reservoir

k_b = permeability calculated from buildup pressure

k_j = permeability calculated from productivity index

k_o = effective permeability of oil

L = distance to a linear discontinuity and unstrained length

ΔL = change in length

m = slope of buildup curve, p_t vs. log t or slope of $\log(p_{ws}-p_{wf})$ vs. t

m_g = slope of pressure buildup curve, $p_w{}^2$ vs. log t

p = pressure at $t+\Delta t$

Δp = slope of plot of p vs. log $t+\Delta t/\Delta t$ or $\Delta p=p_{wf}-p_{ws}$

$\widetilde{\Delta p}$ = dimensionless factor from curves (see Fig. 30.9)

p^* = last pressure on buildup curve

p_i = initial reservoir pressure

p_s = pressure loss due to skin effect

p_{sd} = log e r_d/r_w for constant pressure at radius of drainage or log e $(r_d/r_w)-0.75$ when no influx across external boundary

p_t = well pressure 1 hour after shut-in

p_w = BHP at t

p_{wf} = flowing BHP

p_{wh} = wellhead pressure

p_{ws} = static BHP

p_{1hr} = pressure on straight-line portion of semilog plot one hour after beginning a transient test

q = production rate at shut-in
q_g = rate of production
q_o = rate of oil production
r = unstrained resistance
Δr = change in resistance
r_d = drainage radius
r_w = wellbore radius
s = skin effect
t = time
t = time from closed in to end of straight-line portion of buildup curve
Δt = time after well was shut in
t_x = intersection time of the two straight line segments of the drawdown curve
$\bar{T}$ = average temperature in the borehole
T_c = calibration temperature
T_o = observed temperature
T_R = reservoir temperature
T_1 = lower temperature
T_2 = higher temperature
z = compressibility factor (gas deviation factor)
γ_g = specific gravity of gas (air=1)
μ = viscosity of produced fluid
μ_g = viscosity of reservoir gas
μ_o = viscosity of reservoir oil
ϕ = porosity reservoir rock

Key Equations in SI Metric Units

$$p_{ws}=p_{wh}\exp(1.139\times10^{-4}\gamma_g D). \qquad (4)$$

$$\log p_{ws}=\log p_{wh}+\frac{\gamma_g D}{67.37\bar{T}}. \qquad (5)$$

$$\frac{p_{ws}}{1+p_{ws}z}=\frac{p_{wh}}{1+p_{wh}z}\exp\left(\frac{\gamma_g D}{29.26\bar{T}}\right). \qquad (6)$$

$$p_{ws}=p^*+\frac{(p_{sd}-\Delta\bar{p})q\mu B}{2\pi hk}. \qquad (7)$$

$$k=\frac{q\mu B\log\left(\frac{r_d}{r_w}\right)}{2\pi h(p_{ws}-p_{wf})}=\frac{J_s\mu B\log\left(\frac{r_d}{r_w}\right)}{2\pi}. \qquad (11)$$

$$k=\frac{44{,}330\ md^2\mu B\log\left(\frac{r_d}{r_w}\right)}{h\gamma}. \qquad (12)$$

$$k_o=\frac{q_o\mu_o B_o}{5.4575hm}. \qquad (13)$$

$$m=\frac{kt}{\phi c_L r_d{}^2\mu}. \qquad (14)$$

$$k=\frac{254.359q_g\mu_g T_R z\log\left(\frac{r_d}{r_w}\right)}{h(p_{ws}{}^2-p_{wf}{}^2)}. \qquad (15)$$

$$k=\frac{127.2q_g\mu_g T_R z}{hm_g}. \qquad (16)$$

$$p_s=m\left[\frac{p_t-p_{wf}}{m}-\log\left(\frac{0.412q_oB_o}{\phi mhc_or_w{}^2}\right)\right]. \qquad (20)$$

$$p_s=m_g\left[\frac{p_t-p_{wf}}{m_g}-\log\left(\frac{142.817q_gzT_R}{\phi hm_gc_gr_w{}^2\bar{p}}\right)\right]. \qquad (21)$$

$$L=\sqrt{\frac{kt_x}{1.781\phi c_t\mu_o}}, \qquad (23)$$

where
p's are in Pa,
D is in m,
γ_g is in kg/m^3,
T is in K,
μ is in Pa·s,
h is in m,
k is in m^2,
q is in m^3/s,
r's are in m,
t is in s, and
c's are in m^3/m^3.

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