Chapter 4
Production Packers

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Production Packers Classification and Objectives

Production packers generally are classified as either retrievable or permanent types. Packer innovations include the retrievable seal nipple packers or semipermanent type.

The packer isolates and aids in the control of producing fluids and pressures to protect the casing and other formations above or below the producing zone. All packers will attain one or more of the following objectives when they are functioning properly.

1. Isolate well fluids and pressures.
2. Keep gas mixed with liquids, by using gas energy for natural flow.
3. Separate producing zones, preventing fluid and pressure contamination.
4. Aid in forming the annular volume (casing/tubing/packer) required for gas lift or subsurface hydraulic pumping systems.
5. Limit well control to the tubing at the surface, for safety purposes.
6. Hold well servicing fluids (kill fluids, packer fluids) in casing annulus.

Once a tubing-packer system has been selected, designed, and installed in a well there are four modes of operation: shut-in, producing, injection, and treating. These operational modes with their respective temperature and pressure profiles have considerable impact on the length and force changes on the tubing-to-packer connections.

Tubing-To-Packer Connections

There are three methods of connecting a packer and a tubing string, and the tubing can be set in tension, compression, or left in neutral (no load on the packer, tension nor compression).

*Author of the chapter on this topic in the 1962 edition was W.B. Bleakley.

1. Tubing is latched or fixed on the packer, allowing no movement (retrievable packers). Tubing can be set either in tension, compression, or neutral.
2. Tubing is landed with a seal assembly and locator sub that allows limited movement (permanent or semipermanent packers only). Tubing can be set only in compression or neutral.
3. Tubing is stung into the packer with a long seal assembly that allows essentially unlimited movement (permanent packers only). Tubing is left in neutral and it cannot be set in tension or compression.

A retrievable packer is run and pulled on the tubing string on which it was installed. No special tubing trips are required. It has only one method of connection to the tubing — latched or fixed. The tubing can be set in tension, compression, or left in neutral. Tubing-length changes will result in force changes on the packer and tubing. In deep or high-temperature wells the rubber element may "vulcanize" and take on a permanent set, making release very difficult.

Permanent and semipermanent packers can be run on wireline or tubing. They have three methods of tubing connection: latched (fixed), landed (limited movement), or stung in with a long seal assembly (free movement). Special tools plus milling are needed to recover it from the well. When left for long periods of time without movement, the seal assembly and polished bore (in the packer) may stick together.

Packer Utilization And Constraints

Understanding uses and constraints of the different types of packers will clarify the factors to consider before selecting the best packer and will illustrate how they achieve their specific objectives.

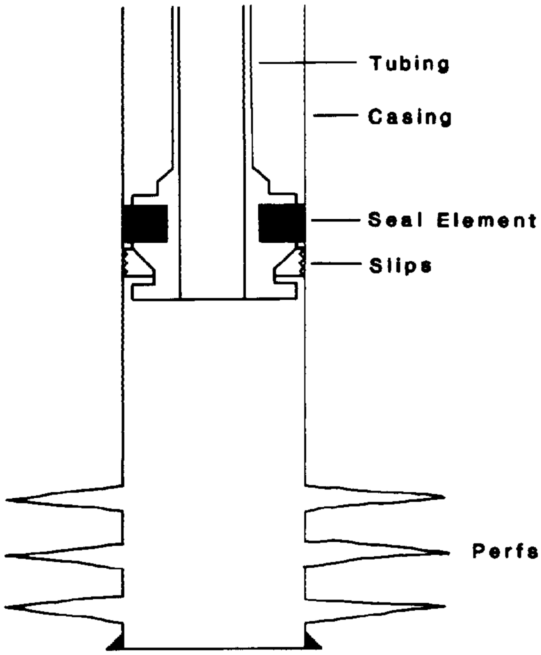

Fig. 4.1—Solid-head retrievable compression packer.

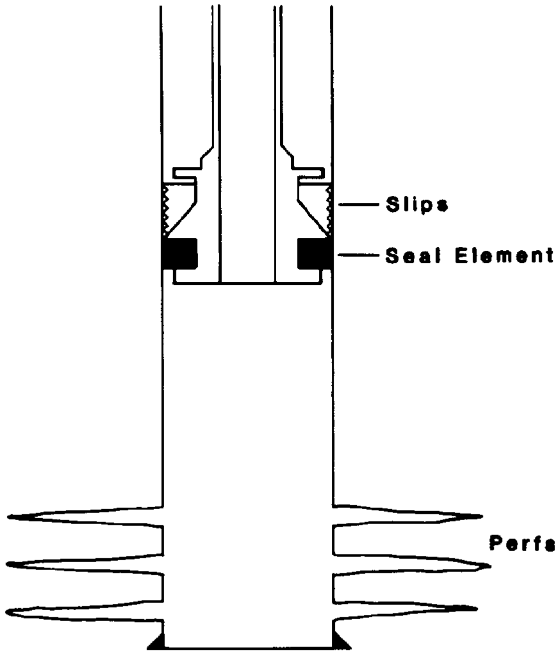

Fig. 4.2—Solid-head retrievable tension packer.

Retrievable Packers

Solid-Head Compression Packer. Retrievable compression (weight-set solid-head) packers are applied when annulus pressure above the packer exceeds pressure below the packer, as in a producing well with a full annulus. This situation precludes gas lift. Fig. 4.1 shows this type of packer.[1]

The constraints of a solid-head compression packer are:

1. Packer release can be hampered by high differential pressure across packer.
2. Packer may unseat if a change in the operational mode results in a tubing temperature decrease (tubing shortens).
3. Tubing may corkscrew permanently if a change in the operational mode results in a tubing temperature increase (tubing lengthens).

Solid-Head Tension Packer. Retrievable tension packers generally are used when pressure below the packer is greater than the annulus pressure above the packer, such as in an injection well or low-pressure and -volume treating (Fig. 4.2). These packers also are used in shallow wells where the tubing weight is insufficient to set a compression packer properly.

Constraints of the solid-head retrievable tension packer are:

1. Release is difficult with high differential pressure across the packer.
2. Tubing could part if a change in the operational mode results in a temperature decrease.
3. Packer could release if a change in the operational mode results in a temperature increase.

Isolation Packer. A retrievable isolation packer (Fig. 4.3) is used when two mechanically set packers are to be set simultaneously. It requires anchor pipe on the plugged back depth below it to use tubing weight to shear the pins that hold the packer in the unset mode. It can be used to isolate old perforations or a damaged spot in the casing temporarily. This packer is for temporary use only and should be retrieved as soon as its purpose is accomplished.

Control-Head Compression Packer. The control-head retrievable compression packer (Fig. 4.4) has a bypass valve to alleviate the packer release problem resulting from excessive differential pressure. The valve is on top of the packer. It is opened, equalizing the pressure across the packer, by picking up the tubing without moving the packer. As with the solid-head packer, using tubing weight, this packer holds pressure from above only. It is not suitable for injection wells or low-volume and -pressure treating.

Constraints are: (1) the bypass or equalizing valve could open if an operational mode change results in a tubing temperature decrease, and (2) tubing could corkscrew permanently if an operational mode change results in a tubing temperature increase.

A control-head retrievable compression packer run with an anchor is basically a treating packer. It holds pressure from below without tubing weight because the anchor holds the packer and constrains its movement. Pressure across the packer is equalized through a valve operated by picking up on the tubing (Fig. 4.5). Temperature changes have the same effect as they have with the control-head compression packer without an anchor.

Control-Head Tension Packer. The control-head retrievable tension packer is released easily even if high

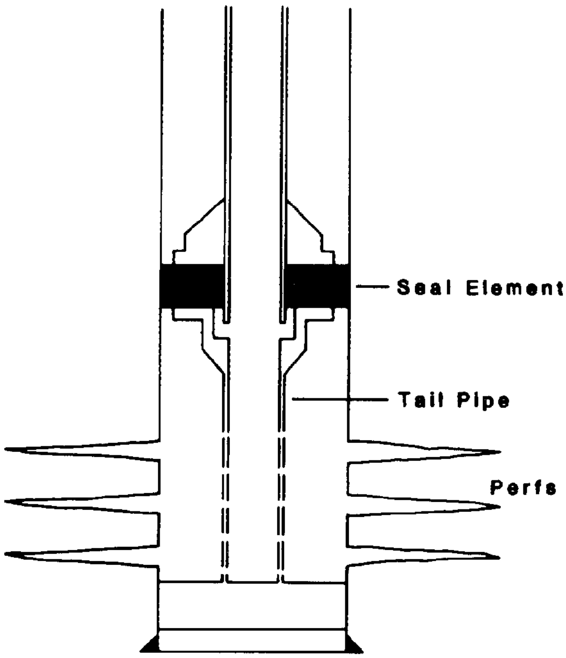

Fig. 4.3—Isolation packer is held in place with shear pins.

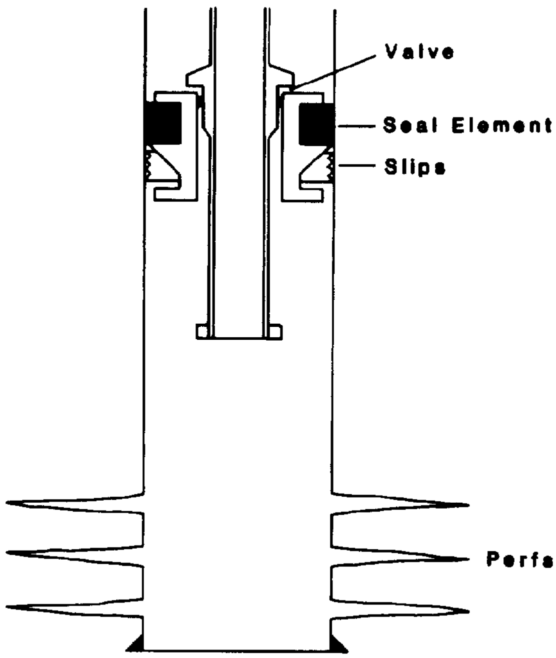

Fig. 4.4—Control-head compression packer employs a top equalizing valve.

differential pressure exists across the packer during normal operations. This pressure is equalized by a valve on top of the packer that is opened by lowering the tubing without moving the packer. This type packer holds pressure from below only, with tubing in tension, and is not suitable for wells with well servicing fluid in the annulus.

Constraints of a control-head tension packer are: (1) premature bypass valve opening could occur with a tubing temperature increase as the tubing elongates, and (2) tubing could part with a tubing temperature decrease as the tubing contracts.

Mechanically Set Packer. Mechanically set retrievable packers (Fig. 4.6) have slips above and below the seal element and can be set with either tension, compression, or rotation. Once the packer is set, the tubing can be left in tension, compression, or neutral mode. How the tubing is left is dictated by future operations to be performed. Careful planning of these subsequent operations is needed to neutralize temperature and pressure effects on the tubing and the equalizing valve.

The mechanically set retrievable packer is suitable for almost universal application, the only constraint being found in deep deviated wells where transmitting tubing movement will be a problem.

Hydraulic-Set Packer. The retrievable hydraulic-set packer (Fig. 4.7) also has slips above and below the packing element. It is set by applying the hydraulic pressure in the tubing to some preset level above hydrostatic pressure. Once the packer is set, the tubing may be put in limited tension, compression, or left neutral. The packer generally is released with tension-actuated shear pins. It is universally applicable, the only constraint being its high cost.

Common Constraint — All Latched Packers. Severe tubing length changes resulting from changing temperatures can develop sufficient forces to move the packer in the casing. This can happen in old corroded casing or in the harder grades of new casing such as P-110. The teeth on the slips "shave" the pipe, thus loosening their grip.

Permanent Packers

The polished sealbore packer (Fig. 4.8) is a permanent-type or semipermanent packer that can be set with precision depth control on conductor wireline. It also can be set mechanically or hydraulically on the tubing. A locator sub and seal assembly is attached to the bottom of the tubing and is stung into the polished bore receptacle of the packer. Isolation is achieved by the fit of the seals inside the polished bore.

This packer allows all three connection methods—fixed, limited movement, or free movement—that subsequent operations will dictate. It is ideal for wells subject to frequent workover because the tubing is retrieved easily.

Permanent packers are especially useful where tubing temperature may vary widely because the seals slide up and down in the polished bore. They can be retrieved by using a special tool on the end of the tubing in place of the seal assembly, but a round trip with the tubing is required.

There is one important constraint with this packer—if the tubing remains in a place for a long time at the same temperature and no movement occurs between the seals and the polished bore, the seals may stick to the polished bore surface, creating a tubing-retrieval problem.

The seal assembly length (Fig. 4.8) should allow sufficient free upward tubing movement during stimulation treatments and permit tubing weight slackoff to eliminate seal movements during the producing life of the well.

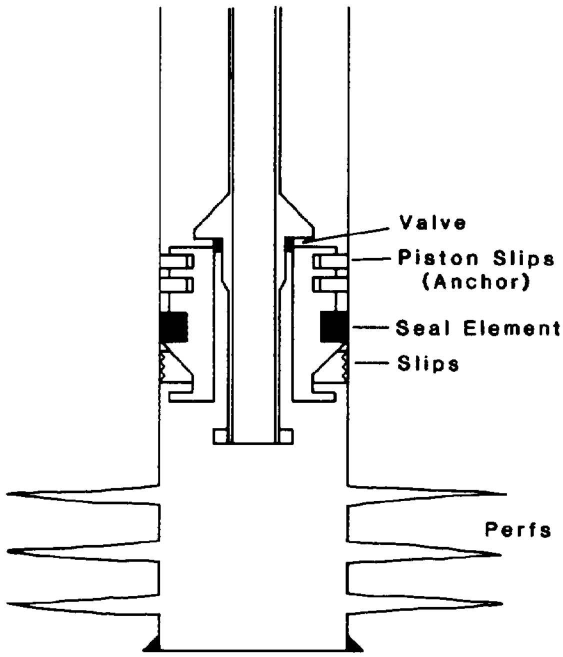

Fig. 4.5—Treating compression packer is held by an anchor containing piston slips.

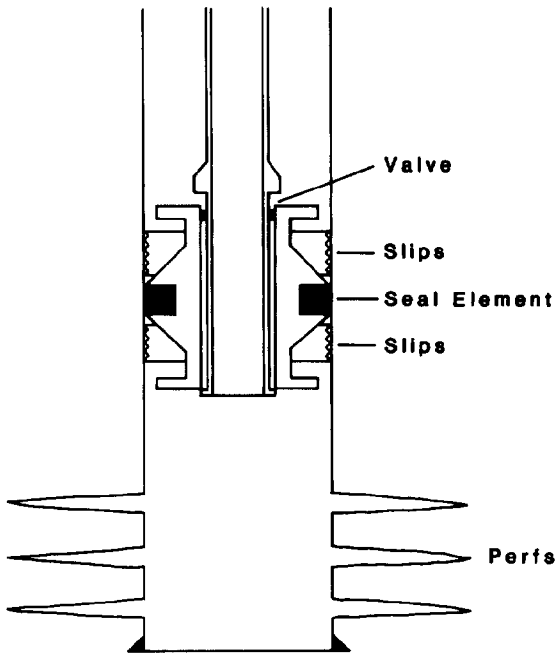

Fig. 4.6—Mechanically set dual-slip packer has slips above and below rubber element.

Considerations For Packer Selection

Packer selection requires an analysis of packer objectives for the anticipated well operations, such as initial completions, production stimulation, and workover procedures. Considering both current and future well conditions, the packer with the minimum overall cost that will accomplish the objectives should be selected. Initial investment and installation costs should not be the only criteria. Overall packer cost is related directly not only to retrievability and failure rate but to such diverse factors as formation damage during subsequent well operations or replacement of corkscrewed tubing.

Retrievability will be enhanced greatly by using oil or solid-free water rather than mud for the packer fluid. Frequency of packer failures may be minimized by using the proper packer for the well condition and by anticipating future conditions when setting the packer. Permanent packers are by far the most reliable and, when properly equipped and set, are excellent for resisting the high pressure differentials imposed during stimulation. They are used widely when reservoir pressures vary significantly between zones in multiple completions.

Weight-set tension types of retrievable packers will perform satisfactorily when the force on the packer is in one direction only and is not excessive.

Surface/Downhole Equipment Coordination

Setting a packer always requires surface action and in most cases either vertical or rotational movement of the tubing. Selection of the packer must be related to wellhead equipment. The well completion must be considered as a coordinated operation. The surface and downhole equipment must be selected to work together as a system to ensure a safe completion. This is especially true in high-pressure well applications.

Packer Mechanics

The end result of most packer setting mechanisms is to (1) drive a cone behind a tapered slip to force the slip into the casing wall and prevent packer movement, and (2) compress a packing element to effect a seal. Although the end result is relatively simple, the means of accomplishing it and subsequent packer retrieval varies markedly between the several types of packers.

Some packers involve two or more round trips, some require wireline time, and some eliminate trips by hydraulic setting. The time cost should be examined carefully, especially on deep wells using high-cost rigs. In some cases higher initial packer costs may be more than offset by the saving in rig time, especially offshore.

Corrosive Well Fluids

Materials used in the packer construction must be considered where well fluids contain CO_2 or H_2S in the presence of water or water vapor.

Sour Corrosion (Sulfide or Chloride Stress Cracking Corrosion). Even small amounts of H_2S with water produce iron sulfide corrosion and hydrogen embrittlement. The Natl. Assn. of Corrosion Engineers specifies that materials for H_2S conditions be heat-treated to only a maximum hardness of 22 Rockwell C to alleviate embrittlement. Hardness has no effect on iron sulfide corrosion, however. For critical parts where high strength is required, K-Monel® is resistant to both embrittlement and iron sulfide corrosion. Corrosion inhibitors may be required to protect exposed surfaces.

Sweet Corrosion ("Weight Loss" Corrosion). CO_2 and water cause iron carbonate corrosion, resulting in deep pitting. For ferrous materials, low-strength steels or cast

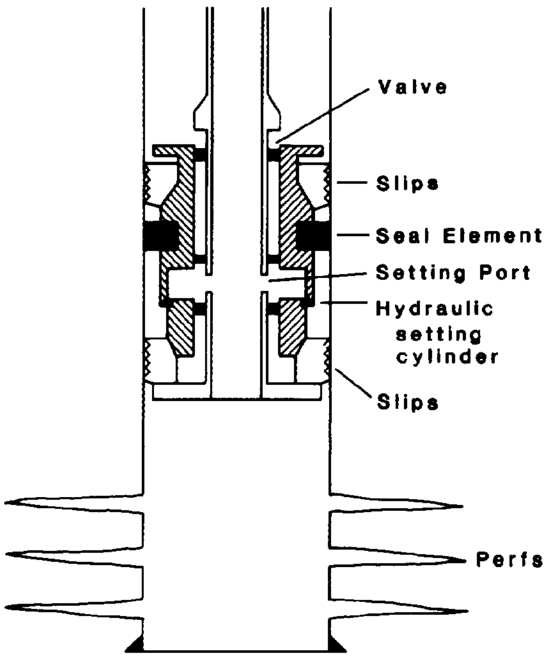

Fig. 4.7—Hydraulic packer is set by tubing pressure.

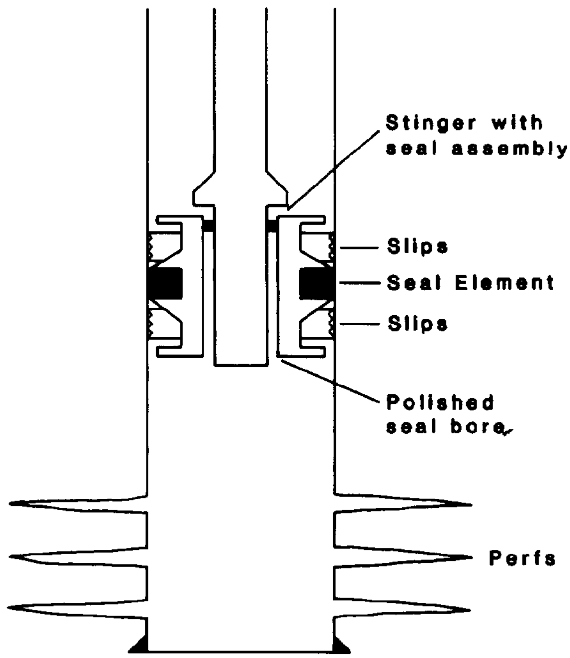

Fig. 4.8—Retrievable, permanent-type packer is made with polished sealbore.

iron are desirable to resist stress concentrations from pitting. Critical parts of production equipment can be made of stainless steel with 9% or higher chromium. Corrosion inhibitors may be required to protect exposed surfaces.

Bimetallic or galvanic corrosion resulting from contact of dissimilar metals should be considered. Usually this is not a problem, since steel is the anode, or sacrificial member, and the resulting damage is negligible because of the massive area of the steel compared with the less-active stainless of K-Monel.

Sealing Element

The ability of a seal to hold differential pressure is a function of the elastomer pressure, or stress developed in the seal. The seal stress must be greater than the differential pressure. In a packer sealing element, the stress developed depends on the packer setting force and the backup provided to limit seal extrusion.

The sealing element may consist of one piece or may be composed of multiple elements of different hardnesses. In a three-element packer, for example, the upper and lowermost elements are usually harder (abrasion resistant) than the center element. The center element seals off against imperfections in the casing, while the harder outside elements restrict extrusion and seal with high temperature and pressure differentials. Many packers also include metallic backup rings to limit extrusion.

Where H_2S or CO_2 is present, seal materials and temperature and pressure conditions must be considered carefully. Teflon® resists H_2S or chemical attack up to 450°F; but Teflon seal extrusion can be a problem. With controlled clearance and suitable metallic backup to prevent extrusion, glass-filled Teflon has performed satisfactorily to 450°F with a 15,000-psi differential pressure. Because of seal rigidity it may not perform well below 300°F. With temperatures below 250°F, Nitrile ® rubber can be used with metallic backup for static seals. The performance of Viton® seals becomes marginal at 300°F. A tubing-to-packer seal consisting of vee-type rings of Kalrez,® Teflon,® and Rylon® in sequence with metallic backup have been satisfactory (under limited movement) up to 300°F and 10,000-psi differential pressure.

Retrievability

Consideration of retrievability must combine several factors, relative to packer design and use. Retrievable packers are released by either straight pull or rotation. In a deviated hole, applied torque usually can develop more downhole releasing force than pull, although sometimes it also is necessary to manipulate the tubing up and down to transmit the torque to bottom.

The packer sealing element should prevent solids from settling around the slips. Usually the bypass on a control-head packer opens before the seal is released; this allows circulation to remove sand or foreign material.

High setting force is needed to provide a reliable seal under high differential pressures, but it should be recognized that the resulting seal extrusion can contribute to the retrieval problem. A jar stroke between release and pickup positions is an aid in packer removal.

The method of retracting and retaining slip segments is a factor in retrievability. Bypass area around the packer is also important. Where external clearance is minimized to promote sealing, the internal bypass area must be sufficiently large to prevent swabbing by the sealing element when pulling out of the hole.

Fishing Characteristics

A permanent packer must be drilled out to effect removal. This usually presents little problem because all material is millable. Some expensive variations of permanent packers provide for retrieval but retain the removable seal tube feature. Removal of stuck retrievable packers usually results in an expensive fishing operation because components are nondrillable and require washover milling. When selecting packers, consider the volume and type of metal that must be removed if drilled and the presence of rings or hold-down buttons that may act as ball bearings to milling tools.

Through-Tubing Operations

Packers with internal diameters equal to that of the tubing should be used to facilitate through-tubing operations. Also, tubing should be set to minimize or alleviate buckling where through-tubing operations are anticipated.

Purchase Price

Table 4.1 presents a range of packer cost indices. The most economical types are weight-set and tension packers. However, inclusion of a hydraulic hold-down with a compression packer will increase the initial cost from 20 to 100%. Multistring hydraulic-set packers are usually the most expensive and also require many accessories.

TABLE 4.1—COST COMPARISON OF PRODUCTION PACKERS

Packer Type	Tubing-Casing size (in.)	Typical Cost Index**
Compression	2×5½	1.00
Tension set	2×5½	0.925
Mechanical set	2×5½	1.54
Hydraulic set	2×5½	2.30
Dual	2×2×7	5.85
Permanent*	2×5½	1.85
Semipermanent*	2×5½	2.30

*Electric-line setting charge not included.
**Cost of simple compression packer = 1.00.

Tubing/Packer System

Advantages

By using a properly selected packer, well operations will be more efficient. Wireline pressure and logging operations will proceed faster and smoother. Longer flowing life will be achieved with the use of a packer through the optimal use of the gas energy.

The use of a packer in a gas well, with a tailpipe run below the perforations, will alleviate the problem of gas wells heading, loading up with water, and dying prematurely. (The water is produced continuously as a mist and is not allowed to build up over the perforations.)

This use of a packer and tail pipe will not control the natural water influx, but will keep the water moving along until such time as the available pressure is less than the pressure required to flow.

Where Packers Are Not Used

Packers are not run in rod-pumped wells, unless extraordinary circumstances such as dual completion call for one. Electric submersible pumped wells would not have a packer, except when used with uphole subsurface safety valves required by government safety regulations for offshore wells. Many naturally flowing, high-volume, sweet-crude wells are produced up the annulus without packers; a small tubing string is run to be used to kill (circulate) the well or for running certain logs or pressure gauges. Dry, sweet-gas wells often are produced up both the tubing and the annulus and have no packers.

Operational Well Modes

There are four modes of operation that any given well might experience: (1) shut-in; (2) producing (either liquids, gas, or a combination); (3) injecting (hot or cold liquids, or gases); or (4) treating (high, low, or intermediate pressures and volumes).

The usual mode of operation is only one of the factors that need to be considered when selecting a particular type of packer to be used in a well. Subsequent operations and their pressures and temperature changes are likely to be extremely important to packer utilization success.[2,3] Typical temperature-vs.-depth profiles are illustrated in Fig. 4.9. These profiles are similar to those measured in wells operating in one of four modes: shut-in, production, injection, or treatment.

Fig. 4.9a depicts a typical geothermal gradient, with the temperature increasing with depth to the bottomhole temperature (BHT). Every time a well is shut in, the operating temperature profile will begin to move toward the shape of the natural geothermal profile.

Producing well temperature profiles for both gas and oil are shown in Fig. 4.9b. The wellhead temperature of an oil well will be somewhat less than BHT. The amount of cooling as crude flows to the surface will depend on several factors: (1) the relative amount of oil and water, (2) the specific heats of the oil and water, (3) the flow rate, (4) the gas/liquid ratio, and (5) the vertical flow pressure drop that controls gas liberated and attendant cooling effect.

The temperature profile of a gas well may have a wellhead temperature lower than ambient. In any case the wellhead temperature of a gas well will depend on the BHT, the flow rate, the pressure drop in the tubing, the specific heat of the gas, and other factors.

Injection temperature profiles can be quite varied (Fig. 4.9c). The profile will depend on such factors as the nature of the injection fluid (liquid or gas), the rate of injection, and the injected fluid temperature (cold liquid or gas, hot gas or liquid, or even steam). The liquids injected will tend to have little heat loss down the tubing, while the gas injected will tend to pick up or lose heat to approach the BHT.

While treating is simply a special case of the injection mode, and it is temporary in nature, it is considered important enough to be discussed separately. As with the liquid injection profile, the treating liquid will not pick up any appreciable amount of heat as it moves down the tubing and the treating temperature profile is essentially vertical (Fig. 4.9d).

As illustrated in some examples later, the important thing about these profiles is not their shape but how much the shape and temperature change from one operational

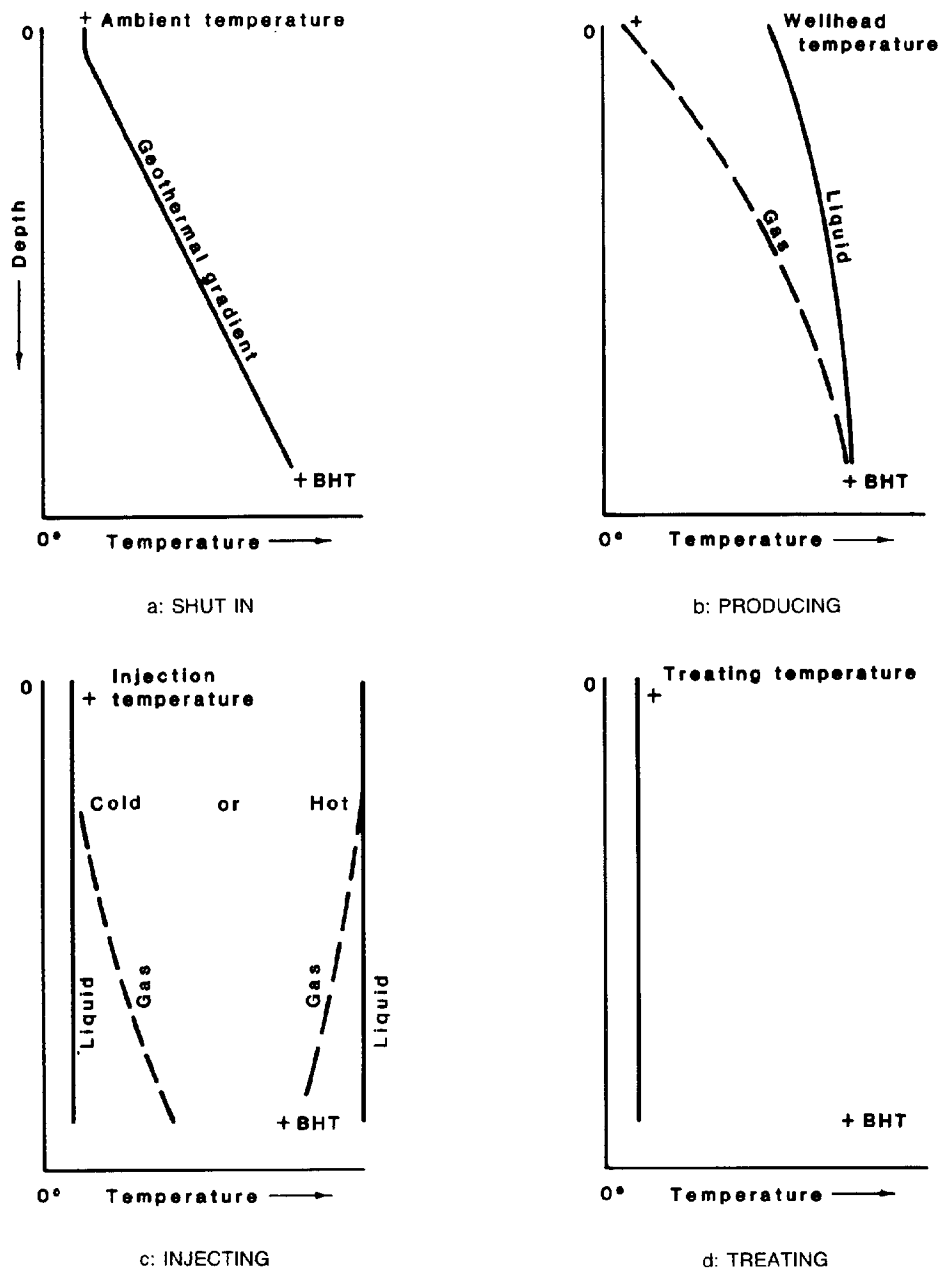

Fig. 4.9—Temperature profiles for four possible modes of oil and gas wells: a. Shut-in, b. Producing, c. Injecting, d. Treating.

mode to another, and how those temperature changes affect the tubing and packer system. It is strongly recommended that anticipated temperature profiles of each operational mode be drawn accurately when planning various steps of any completion or major workover.

Fig. 4.10 shows the pressure profiles of the four modes of well operation. Fig. 4.10a illustrates a typical shut-in well with well servicing fluid in the wellbore. The slope of the profile and the height to which the fluid level rises on the depth scale (and in the wellbore) will depend on the average reservoir pressure, $\bar{p}_R$, and the gradient of the well servicing fluid. Fig. 4.10b shows the profiles of typical producing oil and gas wells. A liquid injection profile (Fig. 4.10c) is similar to the shut-in profile, the difference being that the bottomhole injection pressure, $(p_i)_{bh}$, is greater than the average reservoir pressure, $\bar{p}_R$. The wellhead pressure, p_{wh}, can have any value, from a vacuum to several thousand psi. The gas injection profile may have a reverse slope on it or may have a normal but steep slope, depending on the rate, tubing size, and bottomhole injection pressure.

The treating pressure (Fig. 4.10d) is a special temporary case of the injection profile. The bottomhole treating pressure, $(p_t)_{bh}$, often will be greater than the injection pressure, especially in a fracturing job. The surface pressure will be constrained by the burst strength of the

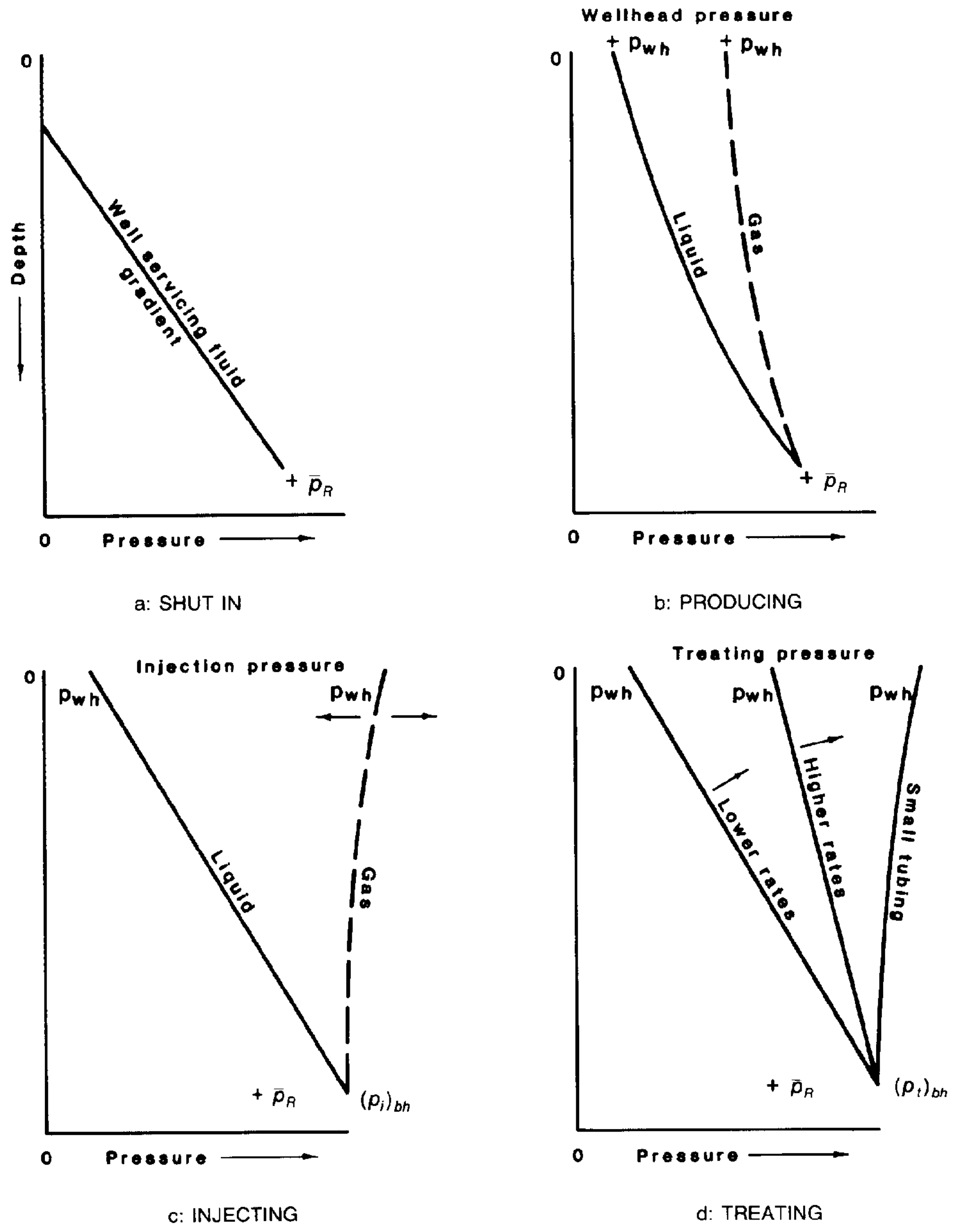

Fig. 4.10—Pressure profiles for four possible operational modes of oil and gas wells: a. Shut-in b. Producing c. Injecting d. Treating.

tubing and casing, and safety considerations. The slope of the pressure profile will depend on the tubing size, the treating rates, and the treating pressure downhole, $(p_t)_{bh}$.

It is recommended that pressure profiles of each operational mode be drawn for each step of a completion or major workover. As the examples will point out, the importance of pressure changes from one well mode to another and their effects on the tubing and packer system cannot be overemphasized.

Tubing Response Characteristics

Changing the mode of a well (producer, injector, shut-in) causes changes in temperature and pressures inside and outside the tubing. Depending on (1) how the tubing is connected to the packer, (2) the type of packer, and (3) how the packer is set, temperature and pressure changes will effect the following.

1. Length variation in the tubing string will result if the seals are permitted to move inside a permanent polished seal-bore packer.

2. Tensile or compressive forces will be induced in the tubing and packer system if tubing motion is not permitted (latched connection).

3. A permanent packer will be unsealed if motion is permitted (tubing contraction) and the seal assembly section is not long enough.

4. Unseating of a solid-head tension (or compression) packer will occur if it is not set with sufficient strain (or weight) to compensate for tubing movement.

5. The equalizing valve will open prematurely on control-head packers (tension or compression).

The net result of any of these five events could reduce the effectiveness of the downhole tools and/or damage the tubing, casing, or even the formations open to the well. Failure to consider length and force changes may result in costly failures of such operations as squeeze cementing, acidizing, fracturing, and other remedial operations. Formation damage may result. In addition, the tubing string could be corkscrewed or parted.

Potential length changes under extreme conditions determine the length of seals necessary to remain packed-off with a polished seal-bore packer. Potential induced forces need to be calculated to prevent tubing damage, unseating packers, or opening equalizing valves.

The two major factors that tend to lengthen or shorten the string (movement permitted) are[4,5] (1) temperature effect and (2) pressure effects—piston, ballooning, and buckling effects.

Buckling will only shorten the tubing string. The other factors may shorten or lengthen the tubing string. If motion is prevented, tension or compression forces are induced. It is important to understand and remember the direction of action of the length and force changes. It is equally important to remember that a string of tubing landed in any packer is initially in a neutral condition, except for any subsequent mechanical strain or set-down weight applied by the rig operator. After the tubing is landed, the factors that cause changes in length or force are always the result of a change in temperature and pressure.

Temperature Effect

Thermal expansion or contraction causes the major length change in the tubing.

$$\Delta L_t = 8.28\times 10^{-5}\times L_t \times \Delta\bar{T}, \quad \text{(1)}$$

where

ΔL_t = change in tubing length, ft,
L_t = tubing length, ft, and
$\Delta\bar{T}$ = change in average temperature, °F.

Length changes are calculated readily if the average temperature of the tubing can be determined for the initial condition and then again for the next operation and the next, etc. The average string temperature in any given operating mode is one-half the sum of the temperatures at the top and at the bottom of the tubing. The $\Delta\bar{T}$ is the difference between the average temperatures of any two subsequent operating modes.

If the motion is constrained, forces will be induced as a result of the temperature change. The temperature-induced force is

$$F = 207\times A_{tw}\times \Delta\bar{T}, \quad \text{(2)}$$

where

F = force (tensile or compressive, depending on direction of T), lbf, and
A_{tw} = cross-sectional area of the tubing wall, sq in.

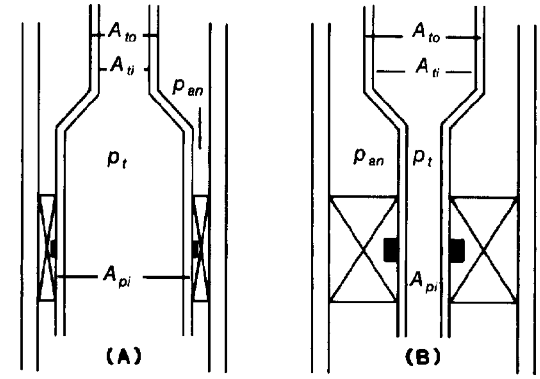

Fig. 4.11—Tubing and packer systems, illustrating various areas and pressures necessary for movement or force calculations.

In most cases, the temperature effect provides the major length or force change when changing from one operational mode to another.

Piston Effect

The length change or force induced by the piston effect is caused by pressure changes inside the annulus and tubing at the packer, acting on different areas (Fig. 4.11). The force and length changes can be calculated as follows.

$$F = \underset{\text{(tubing)}}{\Delta p_t(A_{pi}-A_{ti})} - \underset{\text{(annulus)}}{\Delta p_{an}\,(A_{pi}-A_{to})} \quad \text{(3)}$$

and

$$\Delta L_t = \frac{12L_t}{EA_{tw}}[\Delta p_t(A_{pi}-A_{ti})-\Delta p_{an}(A_{pi}-A_{to})], \quad \text{(4)}$$

(pressure acting on differential area)

where

E = modulus of elasticity, psi (30×10^6 for steel),
A_{pi} = area of packer ID, sq in.,
A_{ti} = area of tubing ID, sq in.,
A_{to} = area of tubing OD, sq in.,
Δp_t = change in tubing pressure at packer, psi, and
Δp_{an} = change in annulus pressure at packer, psi.

Note that the length change, ΔL_t, is a product of L/EA_{tw} and the piston force (Eq. 3). The piston force is the sum of two pressures acting on two areas—one for the tubing and one for the annulus. Fig. 4.11a shows that for a large bore packer, annulus pressure causes downward force while tubing pressure causes an upward force. For a small bore packer this situation is reversed (Fig. 4.11b). The force greatest in magnitude will determine the resulting direction of action. An accurate schematic of the tubing and packer bore for each case should be made for proper determination of areas, forces, and the resulting direction of action.

TABLE 4.2—TUBING CONSTANTS FOR USE IN DETERMINING BUCKLING MOVEMENT CAUSED BY PRESSURE DIFFERENTIALS

OD (in.)	W_t (lbm/ft)	A_{to} (sq in.)	A_{ti} (sq in.)	A_{tw} (sq in.)	I (in.^{4})	F_{oi}^2
1.660	2.40	2.164	1.496	0.668	0.195	1.448
1.900	2.90	2.835	2.036	0.799	0.310	1.393
2.000	3.40	3.142	2.190	0.952	0.404	1.434
2$\frac{1}{16}$	3.40	3.341	2.405	0.936	0.428	1.389
2$\frac{3}{8}$	4.70	4.430	3.126	1.304	0.784	1.417
2$\frac{7}{8}$	6.50	6.492	4.680	1.812	1.611	1.387
3$\frac{1}{2}$	9.20	9.621	7.031	2.590	3.885	1.368

Tubing OD (in.)	Weight (lbm/in.)	W_{ft} and W_{fd} (lbm/in.)	$W_t+W_{ft}-W_{fd}$ 7.0* 52.3**	8.0 59.8	9.0 67.3	10.0 74.8	11.0 82.3	12.0 89.8	13.0 97.2	14.0 104.7	15.0 112.2	16.0 119.7	17.0 127.2	18.0 134.6
1.660	$W_t=0.200$	W_{ft}	0.045	0.052	0.058	0.065	0.071	0.078	0.084	0.091	0.097	0.104	0.110	0.116
		W_{fd}	0.065	0.075	0.084	0.094	0.103	0.112	0.122	0.131	0.140	0.150	0.159	0.169
1.900	$W_t=0.242$	W_{ft}	0.062	0.070	0.079	0.088	0.097	0.106	0.115	0.123	0.132	0.141	0.150	0.159
		W_{fd}	0.086	0.098	0.110	0.123	0.135	0.147	0.159	0.172	0.184	0.196	0.209	0.221
2.000	$W_t=0.283$	W_{ft}	0.066	0.076	0.085	0.095	0.104	0.114	0.123	0.133	0.142	0.152	0.161	0.171
		W_{fd}	0.095	0.109	0.122	0.136	0.150	0.163	0.177	0.190	0.204	0.218	0.231	0.245
2$\frac{1}{16}$	$W_t=0.283$	W_{ft}	0.073	0.083	0.094	0.104	0.114	0.125	0.135	0.146	0.156	0.167	0.177	0.187
		W_{fd}	0.101	0.116	0.130	0.145	0.159	0.174	0.188	0.202	0.217	0.231	0.246	0.260
2$\frac{3}{8}$	$W_t=0.392$	W_{ft}	0.095	0.108	0.122	0.135	0.149	0.162	0.176	0.189	0.203	0.217	0.230	0.243
		W_{fd}	0.134	0.153	0.172	0.192	0.211	0.230	0.249	0.268	0.288	0.307	0.326	0.345
2$\frac{7}{8}$	$W_t=0.542$	W_{ft}	0.142	0.162	0.182	0.203	0.223	0.243	0.263	0.284	0.304	0.324	0.344	0.364
		W_{fd}	0.196	0.225	0.253	0.281	0.309	0.337	0.365	0.393	0.421	0.450	0.478	0.506
3$\frac{1}{2}$	$W_t=0.767$	W_{ft}	0.213	0.243	0.274	0.304	0.335	0.365	0.395	0.426	0.456	0.487	0.517	0.548
		W_{fd}	0.291	0.333	0.365	0.416	0.458	0.500	0.541	0.583	0.625	0.666	0.708	0.749

*lbm/gal.
**lbm/cu ft.

Ballooning and Reverse Ballooning

Internal pressure swells or balloons the tubing and causes it to shorten. Likewise, pressure in the annulus squeezes the tubing, causing it to elongate. This effect is called "reverse ballooning." The ballooning and reverse ballooning length change and force are given by

$$\Delta L_t=2.4\times 10^{-7}\times L_t\frac{\Delta \bar{p}_t-F_{oi}{}^2\Delta\bar{p}_{an}}{F_{oi}{}^2-1} \quad \ldots\ldots\ldots (5)$$

and

$$F=0.6(\Delta\bar{p}_t A_{ti}-\Delta\bar{p}_{an}A_{to}), \quad \ldots\ldots\ldots\ldots\ldots\ldots (6)$$

where

$\Delta\bar{p}_t$ = change in average tubing pressure from one mode to another, psi,
$\Delta\bar{p}_{an}$ = change in average annulus pressure from one mode to another, psi, and
F_{oi} = ratio of tubing OD to ID (Ref. 5 uses R).

Buckling Effects

Tubing strings tend to buckle only when p_t is greater than p_{an}. The result is a shortening of the tubing; the force exerted is negligible. The tubing length change is calculated using

$$\Delta L_t=\frac{r^2 A_{pi}{}^2(\Delta p_t-\Delta p_{an})^2}{8EI(W_t+W_{ft}-W_{fd})}, \quad \ldots\ldots\ldots\ldots\ldots\ldots (7)$$

where

r = radial clearance between tubing OD, d_{to}, and casing ID, d_{ci}, $=(d_{ci}-d_{to})/2$, in.,
I = movement of inertia of tubing about its diameter$=\pi/64(d_{to}{}^4-d_{ti}{}^4)$, in.^{4},
W_t = weight of tubing, lbm/in.,
W_{ft} = weight of fluid in tubing, lbm/in., and
W_{fd} = weight of displaced fluid, lbm/in.

Buckling only shortens the tubing and in most wells it will be the smallest constraint. For use with the radial and inertia calculations, values for A_{to}, A_{ti}, A_{tw}, I, F_{oi}, and $(W_t+W_{ft}-W_{fd})$ can be found, for most tubing sizes, in Table 4.2.

The net or overall length change (or force) is the sum of the length change (or forces) caused by the piston, ballooning, and temperature effects. The direction of the length change for each effect (or action of the force) must be considered when summing them. It follows that for a change in conditions, the motion (or force) created by one effect can be offset, or enhanced, by the motion (or force) developed by some other effect.

Moseley[6] presented a method for graphically determining the length and force changes (Eqs. 5 through 7). This method is particularly useful on a fieldwide basis where wells have the same size tubing, casing and packers.

When planning the sequential steps of a completion or workover, care should be taken to consider the temperatures and pressures in each step, once the tubing and packer system becomes involved. By careful selection of packer bore and use of annulus pressures, one or a combination of pressure effects could be employed to offset the adverse length or force change of another effect.

Combination Tubing/Packer Systems

Uniform completions have been discussed previously (i.e., a single tubing and casing size). Hammerlindl[7] presented a method for solving problems with combination completions. His paper in particular covered two items not covered by Lubinski *et al.*[4] He includes a direct mathematical method for calculating forces in uniform completions where tubing movement is not permitted and a method for handling hydraulic packers set with the wellhead in place. A combination completion consists of (1) more than one size of tubing, (2) more than one size of casing, (3) two or more fluids in the tubing and/or annulus, or (4) one or more of these.

Tubing/Packer Forces on Intermediate Packers

Intermediate packers are an integral part of the tubing string. Examples are dual packers in the long string or selective completion packers. The packer-to-tubing force on the intermediate packer is needed so that wells can be treated through the completion system. Without proper design, it is possible to shear the release mechanism in the intermediate packer(s), which could result in an expensive failure of the completion or workover.

Hammerlindl[8] wrote an extension on his[7] and Lubinski's[4] earlier works that developed a theory required to solve for the intermediate packer-to-tubing forces. The calculation procedure regarding pressure effects requires working the problem from the lowest packer to the surface in stages. The first stage is the tubing between the bottom and second packer. The second stage is the tubing between the second and third packer (or the surface, if there are only two packers). The procedures are the standard ones for uniform completions. The only changes are those to determine the changes in length as a result of applied forces on the intermediate packers; also the actual and fictitious force calculation procedure is modified. Interested readers are referred to Hammerlindl's 1980 paper[9] for additional information on the nebulous fictitious force of Lubinski *et al.*[4]

Key Equations in SI Metric Units

$$\Delta L_t = 1.4935\times10^{-5} L_t \times \Delta\bar{T} \quad \ldots\ldots\ldots\ldots (1)$$

$$F = 741.934 A_{tw} \times \Delta\bar{T} \quad \ldots\ldots\ldots\ldots (2)$$

$$\Delta L_t = \frac{3.6576 L_t}{E A_{tw}}[\Delta\bar{p}_t(A_{pi}-A_{ti}) - \Delta p_{an}(A_{pi}-A_{to})]. \quad \ldots\ldots\ldots\ldots (4)$$

$$\Delta L_t = 7.3\times10^{-8}\times L_t \frac{\Delta\bar{p}_t - F_{oi}^{\,2}\Delta\bar{p}_{an}}{F_{oi}^{\,2}-1} \quad \ldots\ldots\ldots (5)$$

Since Table 4.2 is not available in SI metric units, Eq. 7 is solved in English units (inches) and the result is converted to SI metric units (meters).

where

ΔL_t and L_t are in m,
ΔT is in °C,
F is in N,
A's are in m^2,
p's are in kPa, and
E is in 30×10^6 psi.

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