

CHAPTER-3

RESERVOIR ROCK PROPERTIES

3.1 Porosity

Porosity is the ratio of void or pore volume to macroscopic or bulk volume; the rock or solid phase volume is the bulk volume less the pore volume. Porosity is a static property can be measured in the absence of flow. For most naturally occurring media the porosity is between 0.10 to 0.40 although on occasion values outside this range have been observed. Many times porosity is reported as a percent, but it should always be used in calculations as a fraction. From these typical values the rock “phase” clearly occupies the largest volume in any medium. The porosity of a permeable medium is a strong function of the variance of the local pore or grain size distribution, and a weak function of the average pore size itself for sandstones the porosity is usually determined by the sedimentological processes under which the medium was originally deposited. For carbonate media, on the other hand, the porosity is mainly the result of changes that took place after deposition.

The pore space as well as the porosity can be divided into an interconnected or effective porosity that is available to fluid flow and a disconnected porosity that is unavailable to fluid flow. Certain of the enhanced oil recovery processes exhibit behavior whereby some of the effective porosity (dead end pores) is shielded from the displacing agent. At the other end of the flow scale is the fracture porosity that expresses the fraction of the volume of a particular medium that is tied up in large-scale voids. In what follows, the word porosity references to a volume that is substantially larger than the smallest discrete feature in the rock.

The physical composition of a rock and the textural properties (geometric properties such as the sizes and shapes of the constituent grains, the manner of their packing) are what is important when discussing reservoir rocks and not so much the age of the rock. Fluids occupy the void space created throughout the beds between grains, called pore space or interstice mathematical form as:

$$\phi = V_p / V_b$$

$$\phi = (V_b - V_{ma}) / V_b$$

$$\phi = [V_b - (W / \rho_{ma})] / V_b$$

where: V_p : pore volume , V_b : bulk volume , V_{ma} : volume of matrix minerals , W : total weight of matrix minerals , ρ_{ma} : matrix mineral density

According to this definition, the porosity of porous materials could have any value, but the porosity of most sedimentary rocks is generally lower than 50%. The porosity's of petroleum reservoir range from 5% to 40% but most frequently are between 10% to 20%. Uniformity or sorting is the gradation of grains. If small particles of slit or clay are mixed with larger sand grains, the effective porosity will be considerably reduced. The highly cemented sandstones have low porosities, whereas the soft, unconsolidated rocks have high porosities. Compaction tends to close voids and squeeze fluid out to bring the mineral particles closer together, especially the finer-grained sedimentary rocks. This is the basic mechanism of primary migration of petroleum. Generally, porosity is lower in deeper, older rocks, but exceptions to this basic trend are common. With increasing overburden pressure, poorly sorted angular sand grains show a progressive change from random packing to closer packing. There is three method of packing. These are:

- a) Cubic,
- b) Hexagonal and
- c) Rhombohedral.

3.2 Methods of Packing Spheres and the Type of Porosity

3.2.1 Cubic Packing

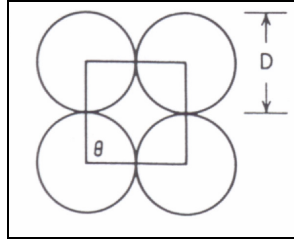


Figure 3-1 Cubic Packing

(Top row is directly above bottom row)

$$\theta = 90^\circ ; V_b = D^3 ; V_g = \pi D^3/6$$

$$\emptyset = (D^3 - \pi D^3/6) / D^3 = D^3 (1 - \pi/6) / D^3 = 0.476 = \mathbf{47.6 \%}$$

3.2.2 Hexagonal Packing

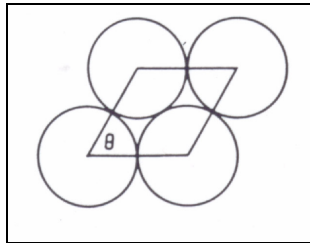


Figure 3-2 Hexagonal Packing.

(Top row has been moved one radius to the right)

$$\theta = 60^\circ ; V_b = D^3 \sin 60^\circ = 0.866 D^3 ; V_g = \pi D^3/6$$

$$\emptyset = D^3 (0.866 - \pi/6) / D^3 = 0.395 = \mathbf{39.5 \%}$$

3.2.3 Rhombohedral Packing

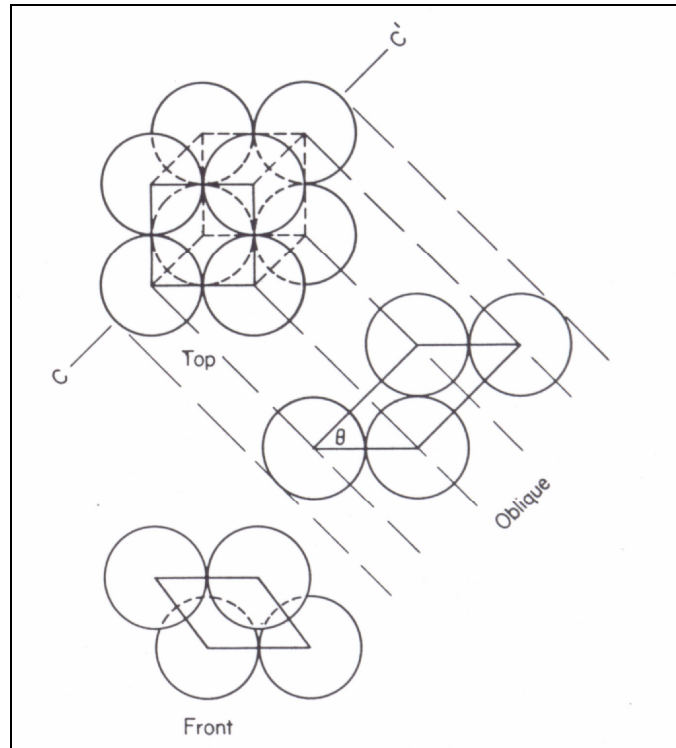


Figure 3-3 Rhombohedral Packing.

(Top row has been moved to left and forward one radius as shown in front view)

$$\theta = 45^\circ ; V_b = D^3 \sin 45^\circ = D^3 / 1.414 ; V_g = \pi D^3 / 6$$

$$\emptyset = D^3 (1/1.414 - \pi/6) / D^3 = 0.259 = \mathbf{25.9 \%}$$

As defined previously, porosity is a measure of the void space within a rock, and as such may be used to determine the quantity of fluid, which may be stored within that rock. Consider a bulk volume of rock with a surface area of one acre and a thickness of one foot. This constitutes basic rock volume measurements used in oil field calculations, an acre-foot. It is also standard practice to express all liquid volumes in terms of barrels.

1 acre = 43560 ft² ; 1 bbl = 42 gal = 5.615 cu ft ; 1 acre-ft = 43560/5.615 = 7758 bbl

It is then obvious that the pore space within a rock is equal to:

$$7758 \times \varnothing = V_p \text{ (bbl/acre-ft).}$$

Therefore volumetric equation of oil in place is:

$$N = (7758 \times \varnothing \times S_o) / B_o = [7758 \times \varnothing \times (1-S_w)] / B_o$$

N = tank oil in place, bbl/acre-ft; S_o = oil saturation; S_w = water saturation and B_o = oil formation volume factor.

3.2.4 Total Porosity

It is defined as the ratio of the volume of all the voids to the bulk volume. It is usually of less interest.

3.2.5 Effective Porosity

It is defined as the volume of the interconnected void or pore volume to the bulk volume of a material.

3.2.6 Primary Porosity

Porosity formed at the time sediment was deposited. The sedimentary rocks, which typically exhibit primary porosity, are the clastic (fragmental) rocks which are composed of erosional fragments from older beds. These are normally classified by grain size, although much looseness of terminology exists. Typical clastic rocks, which are common reservoir rocks are sandstones, conglomerates and oolitic limestones.

3.2.7 Secondary Porosity

Voids formed after the sediment was deposited. The magnitude, shape, size and interconnection of the voids bear no relation to the form of the original sedimentary particles. Porosity of this type has been divided into three classes based on the mechanisms of formation.

3.2.7.1 Solution Porosity

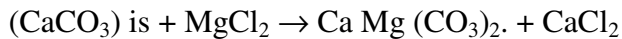
Voids formed by the solution of the more soluble portions of the rock in percolating surface and subsurface water containing carbonic and other organic acids.

3.2.7.2 Fractures, Fissures and Joints

Voids of this type are common in many sedimentary rocks and are formed by structural failure of the rock under loads caused by various forms of diastrophism such as folding and faulting.

3.2.7.3 Dolomitization

This is the process by which limestone (CaCO_3) is transformed into dolomite $\text{Ca Mg} (\text{CO}_3)_2$.



It has long been observed that dolomite is normally more porous than limestone. Dolomite crystals are always in a random packing. Consequently ground waters more readily percolate through dolomite, which has more and larger inter-crystalline voids, and attack more rock surface. Porosity formed by dolomitization is then due to solution effects enhanced by previous chemical change in limestone.

3.3 Porosity Determination Techniques

3.3.1 Buoyancy Technique (effective): The dry formation core sample is weighted and saturated with a wetting fluid. It is then immersed in the same wetting liquid and weighted. The reduction in weight is the buoyancy, which is the product of the matrix volume (plus unconnected pore volume) and the density of the saturating fluid. The bulk volume is measured by immersion in mercury, since mercury is a non-wetting fluid and it does not enter the pores at atmospheric pressure. The porosity is:

$$\phi = (V_b - V_{\text{ma}}) / V_b$$

3.3.2 Gas Expansion Method (effective): The dry sample is inserted in the sample chamber and both chambers are evacuated. The two valves isolating the expansion chamber are then closed, and an initial pressure P_1 is applied to the sample chamber. Then the valve on the left of the sample chamber is closed, and the valve between the sample chamber and the expansion chamber is opened. The pressure between the two chambers is allowed to equalise, pressure P_2 . Knowing bulk volume, volume of empty sample chamber (V_s) and volume of expansion chamber (V_e), the porosity can be found as:

$$\phi = V_p / V_b = [(P_1 - P_2)V_b + P_2V_e - (P_1 - P_2) V_s] / [(P_1 - P_2) V_b]$$

3.3.3 Pycnometer Method (total): The weight (W) of the cleaned and dried core sample is obtained by weighing the sample in air. The bulk volume (V_b) is measured by immersion of the sample in mercury. A representative portion of the sample is then crushed to individual grain size. The crushed sample is weighted and the volume is determined in a pycnometer by displacement of a non-wetting fluid. The grain density will be the weight of the crushed sample divided by its volume. The grain volume, or matrix volume of the original sample is calculated by dividing its weight by the grain density. The total porosity is then equal to the bulk volume minus the grain volume divided by the bulk volume.

$$\phi = (V_b - V_{ma}) / V_b$$

During sedimentation and lithification, some of the pore spaces initially developed became isolated from the other pore spaces by various diagenetic and catagenetic processes such as cementation and compaction. Thus, many of the pores will be interconnected, whereas others will be completely isolated. This leads to two distinct categories of porosity; namely total (absolute) porosity and effective porosity, depending upon which pore spaces are measured in determining the volume of these pore spaces. Absolute porosity is the ratio of the total void space in the sample to the bulk volume of the sample, regardless of whether or not those void spaces are

interconnected. Effective porosity is the ratio of the interconnected pore volume to the bulk volume. This porosity is an indication of the ability of a rock to conduct fluids, but it should not be used as a measure of the fluid conductivity of a rock.

3.4 Permeability

Permeability is also a basic permeable medium property that, unlike porosity, cannot be defined apart from fluid flow. We use it most commonly to estimate production/injection rates from which come estimates of economic lives. Permeability is the proportionality “constant” between the fluid flow rate and an applied pressure or potential gradient. The figure on the right illustrates this for flow of a single incompressible fluid. The last line of this figure is one for of Darcy’s law, which for single-phase, one-dimensional flow constitutes a definition of permeability. The other terms in the equation are the superficial velocity (the flow rate) and the fluid viscosity (μ).

Darcy’s law contains the superficial or Darcy velocity. This is the volumetric flow rate divided by the cross-sectional area normal to flow (q/A).

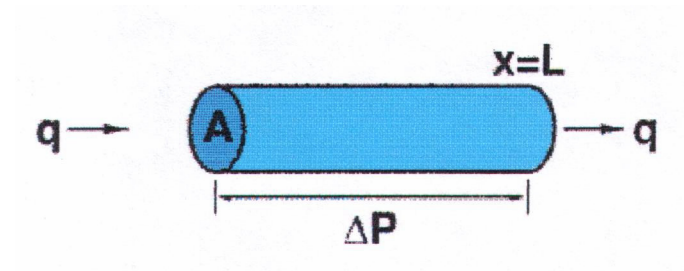


Figure 3-4 Permeability Measurement

The unit of permeability in the empirical equation is the Darcy and the dimension is (L^2). It is usually too large to be convenient in hydrocarbon reservoirs. The milidarcy (10^{-3} Darcy) is therefore used. The practical range of permeability values is from 0.1 milidarcy (md) to several darcies. Generally the permeability is termed as :

Poor if; $k < 1$,
 Fair if; $1 < k < 10$,
 Moderate if; $10 < k < 50$,
 Good if; $50 < k < 250$,
 Very good if; $k > 250$.

The factors affecting the magnitude of permeability are: Shape and size of grain sizes, cementation, fracturing and solution. In order to develop flow equation, the following assumptions should be made:

- Flow is horizontal, laminar and linear,
- Isothermal conditions exist
- Steady state flow conditions exist
- The flowing fluid saturate the pore rock space

The physical concept of the Darcy is enhanced by a dimensional analysis of Darcy's equation. This is accomplished by resolving the quantities into three basic dimension of mass (M), length (L) and time (t), and solving for the dimension of permeability (k).

$$k = (q \mu L) / (A \Delta P)$$

q = flow rate (cm^3/sec), A = cross sectional area (cm^2), ΔP = pressure difference across the sample (atm), μ = viscosity (cp), L = length of the sample (cm) and, k = permeability (Darcy).

To illustrate some features of the permeability definition more clearly, write Darcy's law as:

q = flow rate (L^3/t), A = cross sectional area (L^2), ΔP = pressure difference across the sample (M/Lt^2), μ = viscosity (M/Lt), L = length of the sample (L) and, k = permeability (L^2).

$$k = (q \mu L) / (A \Delta P)$$

$$k = [(\text{L}^3/\text{t}) (\text{M}/\text{Lt}) \text{L}] / [(\text{L}^2) (\text{M}/\text{Lt}^2)]$$

$$k = \text{L}^2$$

This simple form of Darcy's law is as important for what it does *not* say as it is for what it does say. For example, if we increase the rate q , we find that the pressure drop ΔP increase; k is not a function of either flow rate or ΔP . Doubling (for example) the fluid viscosity results in a doubling of ΔP and no change in k . Permeability is not a function of the fluid viscosity, nor, indeed, of the fluid identity. Increasing L for the same ΔP results in a decrease in q so that k is again unchanged. Permeability is not a function of the size of the sample. We say that k is an *intrinsic* function of the medium, or rather of the medium's properties.

In truth, all of the above negations are only approximately true. k does depend on the fluid identity, water vs. oil, or fresh water vs. brine, in many cases. Similarly, k also depends on the scale of the measurement L . That is why we use the term *absolute* permeability with caution. When k depends on rate or ΔP , the phenomena are referred to as non-Darcy effects. Such deviations are important in many cases, but we shall continue the exposition for the ideal case to focus on rock properties.

The term "absolute" permeability is used when the porous rock is 100% saturated with a single fluid, such as oil, gas or water. When two or more fluids are present, the permeability is called "*effective*" permeability (k_o , k_g , k_w). Because fluids interfere each other during their movement, the sum of effective permeabilities will always be less than the absolute permeability. The ratio of effective permeability of one phase during multiphase flow to the absolute permeability is the "*relative*" permeability to that phase (k_{ro} , k_{rg} , k_{rw}).

Petroleum reservoirs can have primary and secondary permeability. Primary permeability is originated at the time of deposition and lithification (hardening) of sedimentary rocks. Secondary one is resulted from the alteration of the rock matrix by compaction, cementation, fracturing and solution.

3.5 Fluid Saturations

In most oil-bearing formations, it is believed that the rock was completely saturated with water prior to the invasion and trapping of petroleum. The less dense hydrocarbons are considered to migrate to positions of hydrostatic and dynamic equilibrium. Thus displacing water from the interstices of the structurally high part of the rock. The oil will not displace all the water, which originally occupied these pores. To determine the quantity of hydrocarbons accumulated in a porous rock formation, it is necessary to determine the fluid saturation (oil, water and gas) of the rock material.

In order to measure values of original rock saturations, there have been essentially three methods devised. These methods involve either the evaporation of the fluids in the rock or the leaching out of the fluids in the rock by extraction with a solvent. One of the most popular means of measuring the initial saturations is the *retort* method. This method takes a small rock sample and heats the sample so as to vaporize the water and the oil, which is condensed and collected in small receiving vessel. Before retorts can be used, calibration curves must be prepared on various gravity fluids to correct for the losses from cracking and coring with the various applied temperatures. The retort is a rapid method for the determination of fluid saturations, and utilizing the correction yields satisfactory results. It gives both the water and oil volumes, so that the oil and water saturations can be calculated from the following equations:

$$S_w = \text{water volume,cc} / \text{pore volume,cc}$$

$$S_o = \text{oil volume,cc} / \text{pore volume,cc}$$

$$S_g = 1 - S_o - S_w$$

The other method of determining fluid saturations is by extraction with a solvent. Modified ASTM method or a centrifuge method can accomplish extraction. From this analysis the water saturation can be determined by the following equation:

$$S_w = \text{water volume} / \text{pore volume}$$

The oil saturation is an indirect determination. It is necessary to note the weight of the core sample prior to extraction. Then, after the core has been cleaned and dried, the sample is weighted again. The oil saturation as a fraction of pore volume is given as:

$$S_o = (\text{wt of wet core} - \text{wt of dry core} - \text{wt of water}) / [(\text{pore vol.}) (\text{oil density})]$$

The last method of determining the water saturation is to use centrifuge. The values of water and oil saturations are calculated using the below equations for the ASTM extraction method.

$$S_w = \text{water volume,cc} / \text{pore volume,cc}$$

$$S_o = \text{oil volume,cc} / \text{pore volume,cc}$$

$$S_g = 1 - S_o - S_w$$

3.6 Compressibility

The porosity of sedimentary rocks has been shown to be a function of the degree of compaction of the rock. Apart from the effect of compaction on grain arrangements, rocks are also compressible. In rocks, three types of compressibility can be observed. These are:

- rock matrix compressibility
- rock bulk compressibility
- pore compressibility

Compressibility can be defined as the fractional change in volume of the rock material with a unit change in pressure.

$$C_r = (1/V_r) (\partial V_r / \partial P)$$

V_r : volume of the rock and $(\partial V_r / \partial P)$ = change in volume with pressure

The unit of compressibility is psi^{-1} .

3.7 Subsurface Pressure

It is readily seen in Darcy equation that fluid movement from a reservoir rock to a well bore can take place only if a pressure differential can be established between the reservoir and the well. This requires that the fluids in the rock can be confined under an elevated pressure. Fortunately, it is the general case to find such a condition prevailing. In general the elevated pressures encountered with depth are due to one or two causes:

- Hydrostatic pressure* is imposed by the weight of fluid which fills the voids of the rocks,
- Formation pressure* is the pressure of the fluids in the pores of subsurface formations,
- Overburden pressure* due to the weight of the rocks and their fluid content existing above the reservoir.

It is more common to find subsurface pressures varying as a linear function of depth with a gradient close to the hydrostatic gradient of fresh to moderately saline water. Departures from this behavior, both higher and lower are considered abnormal.

3.7.1 Hydrostatic Pressure

Hydrostatic pressure is the pressure that a column of fluid of a given weight (density) and given vertical height exerts. In oil field, it is usually measured in units of psi (pounds per square inch).

$$P_h = 0.052 \times MW \times D$$

where: P_h = hydrostatic pressure, psi, MW = mud weight, ppg and D = depth, ft.

3.7.2 Formation Pressure

Formation pressure is the pressure of the fluids in the pores of subsurface formations. This pressure is found to increase with depth. Under normal conditions, formation pressure at any depth will be roughly equivalent to hydrostatic pressure generated by a column of formation water from surface to that depth.

Normal formation pressure gradient: 0.433 psi/ft - 0.5 psi/ft

Most common value is 0.465 psi/ft.

$$P_f = 0.052 \times \rho_w \times D$$

where: P_f = formation pressure, psi, ρ_w = water density, ppg and D = depth, ft.

3.7.3 Overburden Pressure

It is the pressure due to the weight of overlying sediments.

$$P_{ob} = 0.052 \times \rho_s \times D$$

where: P_{ob} = overburden pressure, psi, ρ_s = bulk density of overlying sedimentary rock, ppg and D = depth, ft.

On the average, the value is 1 psi/ft.

3.8 Subsurface Temperature

Since the earth is assumed to contain a molten core, it is logical to assume that temperature should increase with depth. This temperature-depth relationship is commonly a linear function of the following form:

$$T_D = T_s + \alpha D$$

T_D = temperature of the reservoir at any depth; T_s = average surface temperature α = temperature gradient (degree/ft) and D = depth, ft.

3.9 Example Problems:

1. How much oil exists in the following field?

Area of field = 640 acres; Average sand thickness = 20 ft; $\varnothing = 20\%$; $S_w = 30\%$, $B_o = 1.20$

$$N = [7758 (0.20) (1 - 0.30)] / 1.20 = 905.1 \text{ bbl/acre-ft}$$

$$N = 905.1 \times 640 \times 20 = \mathbf{11.6 \times 10^6 \text{ bbl}}$$

2. What is the porosity of the following rock sample?

Bulk volume = 9.9 cc ; Weight of dry sample in air = 20 gr ; Sand grain density = 2.67 gr/cc.

$$\text{Grain volume} = 20 / 2.67 = 7.5 \text{ cc}$$

$$\varnothing = [(V_b - V_g) / V_b] \times 100 = [(9.9 - 7.5) / 9.9] \times 100 = \mathbf{24.2\%}$$

3. What is the porosity of the following rock sample?

Clean, dry weight of sample = 311 gr; Weight of sample with pores completely filled with

1.05 sp.gr. brine = 331 gr ; $d_{\text{core}} = 4 \text{ cm}$; Length of core = 10 cm.

$$V_b = \pi \times r^2 \times h = \pi \times 2^2 \times 10 = 40\pi$$

$$V_p = (331 - 311) / 1.05 = 19.05 \text{ cc}$$

$$\varnothing = (19.05 / 40\pi) \times 100 = \mathbf{15.1\%}$$

4. What is the porosity of the following rock sample?

Bulk volume = 9 cc ; Dry weight in air = 18.8 gr ; Weight saturated in air = 21.2 gr ; density of water = 1.02 gr/cc.

$$V_p = (21.2 - 18.8) / 1.02 = 2.35 \text{ cc}$$

$$\varnothing = (2.35 / 9) \times 100 = \mathbf{26.2 \%}$$

5. A cylindrial core sample was subjected to the following linear flow test. Find the permeability in md.

$$L = 20 \text{ cm} ; \mu = 2 \text{ cp} ; d = 4 \text{ cm} ; q = 100 \text{ cc/hour} ; \Delta P = 3 \text{ atm.}$$

$$k = [(q \times \mu \times L) / A \times \Delta P] = [(100/3600) \times 2 \times 20] / [(\pi \times 2^2) \times 3] = \mathbf{29.4 \text{ md}}$$

6. A cylindrial core sample was subjected to the following linear flow test. Find the permeability in md.

$$L = 10 \text{ cm} ; \mu = 1 \text{ cp} ; r = 2 \text{ cm} ; q = 30 \text{ cc/min} ; \Delta P = 3.40 \text{ atm.}$$

$$k = [(q \times \mu \times L) / A \times \Delta P] = [(30/60) \times 1 \times 10] / [(\pi \times 2^2) \times 3.40] = \mathbf{117 \text{ md}}$$

7. What is the pressure at a depth of 13000 ft with a mud weight of 14 ppg.

$$MW = 14 \text{ ppg and Depth : 13000 ft}$$

$$P_h = 0.052 \times MW \times D$$

$$P_h = 0.052 \times 14 \times 13000$$

$$P_h = \mathbf{9464 \text{ psi}}$$

8. What is the formation pore pressure at a depth of 4000 ft with a if the formation water density is of 9 ppg.

$\rho_w = 9$ ppg and Depth : 4000 ft

$$P_f = 0.052 \times \rho_w \times D$$

$$P_f = 0.052 \times 9 \times 4000$$

$$P_f = \mathbf{1872 \text{ psi}}$$

9. Find the temperature at a depth of 5000 ft when the average surface temperature is 75 F and the temperature gradient is 1.5 F/100 ft.

$T_s = 75$ F, $\alpha = 1.5$ F/100 ft (degree/ft) and $D = 5000$ ft.

$$T_D = T_s + \alpha D$$

$$T_D = 75 + (1.5 \text{ F/100 ft}) \times 5000$$

$$T_D = \mathbf{150 \text{ F}}$$