DST DATA EVALUATION IN PRACTICE

by
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ABSTRACT

Originally Drill Stem Test (DST), as an evaluation tool, was only an indicator of type of fluid production.

Interest in the DST as a modern evaluation tool was revived when certain theoretical equations were proven as a means of calculating values for important formation parameters.

This paper is an example, the basic interpretation method, that will prepare the geologist and engineer for more sophisticated approaches that are sure to come. It is proposed of this paper to show how DST data might be used to make certain reservoir parameter determinations, in field works.

I. INTRODUCTION

Petroleum geologists and engineers have recognized that production data, such as formation pressure decline and buil-up curves, will yield information that may be used in certain exploration and exploitation studies. The senior engineer will point out many valid reasons why these data should be obtained as early as possible in the producing life of a reservoir.

Drill (DST) has long been accepted as the best and most economical means of completing a bore hole for a time being. Technological advances within the industry have introduced welltest methods, by which the engineer and geologist may take DST data and use them with reliance in formation evaluation studies. Due to the basic nature of DST as an evaluation tool, these data will be obtained at the most economical time

It is noted in the field of formation evaluation that DST is the only evaluation tool that obtains the reservoir parameters under dynamic conditions at a point early enough to enter into a decision regarding the disposition of each well.

II. DATA AVAILABLE FROM A WELL TEST

The data obtained from DST generally includes physical description of reservoir fluid, volume of recovery, flow times, shut-in time and a bottom hole pressure-time chart showing the well bore pressure measurements during the various tool manipulations. Reservoir characteristics that may be calculated from well test data are:

a. Permeability

The permeability calculated by a well test is the average effective permeability of the formation to the actual fluid produced. Well test is the only evaluation tool that gives a direct means of calculating effective permeability.

b. Well Bore Damage

Whether or not well bore damage has been incurred by mechanical drilling action is readily indicated by empirical calculations. Well bore damage can occur and impede fluid flow from formations. Low recovery on the test may be the result of damage rather than poor production characteristics. Well bore damage determinations can be made only from pressure fluctuations such as those induced by a DST.

c. Reservoir Pressure

It is possible to make mathematical determinations for the static reservoir pressure. This pressure value is useful as a substitute for a missing stabilized or static mechanical measurement (stabilized initial shut-in pressure reading) and as a check on other calculations.

d. Depletion

If a given reservoir is small enough that its total areal extent is effected by a normal DST, pressure depletion will occur and be detected by a properly conducted DST. If the relative small volume of fluid removed during a normal formation test causes pressure depletion, then an extremely small reservoir exists and experience has shown that it will not be commercial.

e. Radius of Investigation

Because there is physical removal of formation fluid during a DST, there will be a definite effect upon the formation for a determinable distance.

This distance is known as the radius of investigation of the test. This characteristic may be used indetermining spacing requirements and other volumetric calculations.

f. Barrier Indications

If a barrier or any other anomaly such as a fluid contact exists within the radius of investigation of the test, it may be reflected in the pressure analysis. Through other evaluation data and experience in interpretation it is often possible to determine the exact type of anomaly.

The science of petroleum reservoir engineering has been using fluid flow equations to describe flow of fluid through a porous media. These equations describe the relationship between characteristics of the formation, properties of the fluid moving through that formation and the result of this relationship on the amount of fluid moved when a certain force is applied. There are many different fluid flow equations, generally each derived from a specific set of conditions. The conditions that are assumed to be present during most formation tests are:

a. Radial Flow

This means that fluid flowing into the well bore from the formation is assumed to have come equally from all parts of the formation radiating out from the wellbore This assumption will hold true for most sandstone but falls down in fractured limestone.

b. Homogeneous Formation

This means that the formation is assumed to be horizontal and has the same and constant characteristics all through the length and the thickness of the particularzone under consideration. Thisassumption means that any values calculated will be average over the length and/or thickness.

c. Steady State Conditions

It assumes that during that portion of the pressure build-up curve used in the analysis that formation and fluid characteristics are approaching a point of equilibrium. The term of steady state also denotes the assumption that during flow, the rate and pressure drop causing flow were constant. Formation tests are most apt to deviate from this assumption.

d. Infinite Reservoir

It assumes that is no limit to the reservoir. It is recognized, that all reservoirs do have finite limits and that there is depletion. But, on the usual formation test, the amount of fluid removed during test is negligible when compared to the total amount available in the reservoir. As result the formation is approaching infinitely large or unlimited conditions as far as the test is concerned.

If the amount of fluid removed is significant then measurable depletion should occur and be seen on a properly run test. This significant amount is variable with the actual size of the reservoir and duration of the test.

e. Single Phase Flow

It assumes that only one type of formation fluid is flowing into the well bore. This means that if there is gas produced on a test of an oil bearing formation then it is assumed to be gas that came out of solution in the well bore or drill pipe.

If any liquid hydrcarbons are produced on a test of a gas formation then they are assumed to be condesation of gases within the drill pipe or well bore. Water production is assumed to be produced from another horizon.

A. *Draw Down Equation*

Using the conditions set above, a flow equation has been developed for radial flow in homogeneous and infinite reservoirs. This equation is known as the point source solution and as taken from Horner's paper, expressed inoil field terms:

$$Pf = Po + \frac{70.6Q\mu B}{kh}\left[Ei\left(\frac{-948.2r^{2}\phi\mu c}{kT}\right)\right] \quad ....(1)$$

By knowing the various formation and fluid characteristics this equation gives a means of calculating the formation pressure that will result if the fluid is flowed at rate Q for time T. By careful observation of all the available information on a typical formation test, enough data can be obtained to compute or find most of the components listed in equation (1).

Q is defined from the recovered volume at flow time T.

μ, B and c are defined from tables if the oil gravity and gas oil ratio are known. h and f is defined from electrical logs or sample analysis. Po can be measured by the leveled out initial shut-in build-up. Pf and k as unknowns.

B. ***Build-up Equation***

On investigation it was found that when flow is shut-in the formation pressure is allowed to build-up, then the wellbore becomes just another point in the reservoir. As a result of this phenomenon, any pressure recorded in the well bore, during build-up, is an image of the pressure recorded at any other arbitrary point in the reservoir. If some equation can be derived from a build-up that would state the reverse of equation (1) then there would be only parameter k is unknown.

Horner works on pressure build-up derived just such an equation from exactly the same conditions and assumptions listed earlier. In oil field units Horner's equation is:

$$Pf' = Po - \frac{162.6Q\mu B}{kh} Log \frac{T+\theta}{\theta} \quad \text{................ (2)}$$

where: Pf' = formation pressure during build-up, psig

T = time of flow, minutes

θ = time of shut-in, minutes

III. RESERVOIR PARAMETRES OBTAINED BY BUILD-UP ANALYSIS

A. ***Permeability***

Permeability determined by buil-up analysis is known as effective permeability. This value of permeability is the best permeability measurement possible because it is obtained at reservoir conditions.

B. ***Well Bore Damage***

One of the most valuable determinations to be made from test data is estimating the presence and magnitude of well bore damage. Well bore damage is defined as being a zone of reduced permeability immediately adjacent to well bore. It is generally the result of or caused by the mechanical action of drilling a hole into the formation. Well bore damage is also referred to as skin effect, skin damage, skin, etc.

To understand well bore damage it might help to look briefly at the various causes. Four common causes of damage are :

(1) Invasion of drilling fluid filtrate into the formation.

(2) Invasion of drilling solids into the formation.

(3) Bit damage.

(4) Production damage (relative permeability effects).

1. Drilling Fluid Invasion Damage

The invasion of drilling fluid into a formation occurs anytime, a formation has permeability and the drilling fluid has a fluid loss. This is a natural result of the physical characteristics of the properties involved. The drilling fluid has weight and naturally will develop a hydrostatic pressure.

In water base muds this fluid is water that has filtered through the mud cake, or filtrate water. The higher the water loss property of the mud, the greater the amount of filtrate water that tends to enter into the formation.

Some formation are not compatible to this foreign water and will react in an adverse manner. One type of reaction, as an example, is that a shaly sand is formed. This shaly sand formation exists only in exposure to a salt water solution.

A fresh water is injected and these shales that have always been salt water wet are exposed to fresh water for the first time. The shales tend to absorb the water and in the process swell. As a result of the swelling the opening that allow fluid passage (permeability) are reduced, and well bore damage is created.

2. Drilling Solids Invasion

Some formations will have natural openings large enough (high permeability) to permit the entrance of the mud solids. The difference in pressure between the drilling fluid hydroststic pressure and formation pressure may be large enough to wedge or pack these solids into the formation to such an extent that when the pressure differential is reversed in favour of the well bore, the wedge will not break.

As a result of this phenomenon the opening is closed to passage of fluid out of the formation and well bore damage is created.

3. Bit Damage

The mechanical chipping action of most rotary bits loosens the formation in front of the bit, the circulating drilling fluid washes these chips away. Quite often the bit chips away the formation faster then the mud can carry them away. When this occurs, the bit will continue to grinde the pieces into still finer particles.

These fine particles may then be small enough to be forced back into the natural openings of the formation, either by the pressure differential or more commonly by the pounding effect of the bit, and a wedge type of blockage may result as above.

The same pounding action of the bit can actually crush the matrix formation so that the natural openings are reduced in size. Either effect has the same end result in that well bore damaged is created.

4. Production Damage

The very act necessary for the production of fluid from formation, a pressure drop the driving force, can create conditions that induce a damage situation. One type of production damage is gas blockage. The pressure drop created by opening the test tool may be sufficient to cause gas to come out of solution within the reservoir.

The gas bubbles fill up and block the natural openings and a well bore damage effect is created. The end result of all these various forms of damage is to restrict rate of flow of formation fluid to some degree below that which normally might be expected for the existing reservoir and pressure drop conditions.

Hurst and van Everdingen presented empirical equations which showed the effect of the skin damage on pressure draw down. This effect was reflected as an additions of an empirical value to a normal fluid flow equation. One such presentation is as follows:

$$Pf = Po - \left[\frac{70.6Q\mu B}{kh}\left(\ln\frac{kT}{\phi\mu crw^2} - 8.80907 - 2S\right)\right] \quad ....(3)$$

where: S = an empirical dimensionless value for total skin effect present.
rw = radius of well bore, inches.

The skin effect, S, is solved using equation:

$$S = 1.151\left[\frac{(Po - Pf)kh}{162.6\phi\mu B} - \log\frac{kT}{\phi\mu crw^2} + 2.85\right] \quad ....(4)$$

$$if\ \frac{162.\phi\mu B}{kh} = M \quad .... (5)$$

By substituting equation (5), equation (4) may be further simplified as:

$$S = 1.151\left[\frac{Po - Pf}{M} - \log\frac{kT}{\phi\mu crw^2} + 2.85\right] \quad ....(6)$$

Equation (6) gives a means of solving for the dimesionless value S, denoting the skin effect or skin factor, using the pressure build-up data available from a properly conducted DST.

Starting with an empirical equation for solving the damage ratio, DR, can be developed. From equation (4), it is possible to show an expression of the theoretical rate of flow, QT, in relation to other formation and fluid characteristics affecting flow, when there is no damage, or S = 0, then:

$$QT = \frac{(Po - Pf)kh}{162.6\mu B[\log(kT/\phi\mu crw^2) - 2.85]} \quad ....(8)$$

By the same way, using equation a constant M, where:

$$M = \frac{162.6Q\mu B}{kh}$$

and by finishing equation (2), then it is possible to write

$$M = \frac{Po - Pf}{Log[(T+\theta)/\theta]} = \frac{162.6Q\mu B}{kh} \quad ....(9)$$

Then an expression may be made for the actual rate of flow QA, that is gauged from the DST, and its relation to the other factors that produced this rate of flow:

$$QA = \frac{Mkh}{162.6\mu B} \quad ....(10)$$

Substituting equation (8) and (9) into equation (4) yields

$$DR = QT/QT = \frac{\dfrac{(Po - Pf)kh}{162.6\mu B[\log(kT/\phi\mu crw^2) - 2.85}}{\dfrac{Mkh}{162.6\mu B}}$$

or,

$$DR = \frac{(Po - Pf)}{M[\log(kT/\phi\mu crw^2) - 2.85]} \quad ....(10)$$

This yields a rigorous solution to damage ratio (DR), if formation and fluid characteristics are known and can be used.

From equation (9) it was shown that a constant relation was generally established during a DST buil-up, where the constant is:

$$M = \frac{Po - Pf}{Log[(T+\theta)/\theta]} = \frac{162.6Q\mu B}{kh} \quad .... (11)$$

Recognizing that the pressure and time data are readily available from the DST pressure chart then it is fairly simple to solve for the constant once the steady state conditions are approached during the shut-in.

The best method to ascertain steady state conditions under present day testing procedures is to actually plot shut-in pressure, Pf', versus the dimensionless time function, log (T + q)/q). This will then show whether or not the straight line portion, representing steady state conditions has been reached.

5. Breakdown Pressure

This plot will be a graphical presentation of how formation shut-in pressure Pf', varies with respect to a dimensionlesstime function that varies with shut-intime These pressure and time data are obtained from what is generally referred to as a pressure breakdown. The pressure breakdown is simply a series of pressure reading at definite time increments, generally equal time distances.

Generally, from a breakdown plot data, can be established in tabular form (on Table 1)

Having this information in a tabular form it is then a simple manner to transpose it to graph paper.

Figure 1 shows results when data are plotted on standard coordinate paper. To make this plot, pressure readings in column 3 were plotted against logarithmic function of (T + q)/q), tabulated in column 5. To use standard coordinated paper it is necessary to make the additional step from column 4 to column 5.

The solution is good only if it is positively known that the selected points are in the steady state, or on the straight line portion of the plot. To ascertain that there is a straight line portion it is generally necessary to make a plot. If a plot is to be made, the easiest method to solve for the constant M is through the use of the graph, by using the equation:

$$M = \frac{P9 - P6}{\log\frac{T+\theta 6}{\theta 6} - \log\frac{T+\theta 9}{\theta 9}} \text{ psi/log cycle ...... (12)}$$

Points 6 and 9 fall into a straight line. This means that during this portion of the build-up, the formation was approaching a steady-state condition. For the most complete interpretatives study of DST data analysis, a plot of pressure versus time function should always be made.

IV. ANALYSIS PROCEDURE IN PRACTICE

To use this theory into practice by making some actual calculations of reservoir parameters. This section will utilize the pressure breakdown data and plot information given in the previous sections for these calculations. From the plot of Pressure Breakdowns, the value of the constant M is determined. Once this value is determined it can be put to work in the calculation of permeability and well bore damage.

Table 1
Pressure breakdown data

(1) Point	(2) Shut-in Time θ (form graphic)	(3) Pressure Pf' (from graphic)	(4) (T+ θ)/θ (calculated)	(5) (T+ θ)/θ (calculated)
1	5	965	(65+5)/5 = 14000	1.346
2	10	1215	(65+10)/10 = 7.500	0.875
3	15	1405	(65+5)/5 = 5.333	0.727
4	20	1590	(65+10)/20 = 4250	0.628
5	25	1685	(65+5)/25 = 3.600	0.556
6	30	1725	(65+10)/30 = 3.167	0.500
7	35	1740	(65+5)/35 = 2.857	0.455
8	40	1753	(65+10)/40 =2.625	0.419
9	45	1765	(65+5)/45 = 2.444	0.388

A. *Permeability*

Using equation (5) and solving for the general unknowns then we have:

$$\frac{kh}{\mu B}=\frac{162.6Q}{M} \quad (13)$$

kh/μB is called the tranmissibility factor. Transmissibility is defined as the ability of a given formation, represented by permeability, k, and thickness, h, to transmit a given fluid, represented by a viscosity, μ, and formation volume factor, B.

From test information, recovery and flow time, it is a simple process to compute rate of flow Q. Using equation 13, having values for Q and M, it is possible to solve for the transmissibility (kh/θB).

Example 1:

Using the test data on the Table 1 and given addition data that a recovery of 600 ft. of oil with 300 ft. of 3-1/2" ID drill colars and 4-1/2" FH 15# drill pipe. 35^o APIgravity oil and 47 MCF/day gas. Formation temperature of 120^o F, Packer at 4500'. TD-4550".

Solution:

1st solve for Q
600 ft total fluid
300 ft. DC (2-1/2" ID)
x 0.0061 bbl/ft. = 1.83 bbls.
300 ft. DP (4-1/2 15.5#)
x 0.0142 bbl/ft. = 4.26 bbls.
Total Recovery = 6.09 bbls.

Given flow time data was 65 minutes.

$$Q=\frac{V}{T}=\frac{6.09\,bbl}{65\,\text{min.}}x\frac{1440\,\text{min.}}{day}=135\,BOPD$$

Taking M from graphical solution in Figure 2 or 375 psi/log cycle.

$$Then,=\frac{kh}{\mu B}=\frac{162.6Q}{M}=\frac{162.6(135)}{375}=58.5\,md.\,ft/cp$$

Most generally, solving for the transmissibility is as far as it is possible to go on formation test, without additional information. If, for example, the company representative knows that the 50 ft test interval had only 10 ft of porosity (or net productive interval) then a value for formation thickness h has been given.

From the test data above, the oil gravity and gas recovery give sufficient information to go to available literature and find the values for viscosity, μ, and formation volume factor, B. In this case viscosity is found μ = 1.5 cp, and formation volume factor B = 1.15. It is then a simple matter to solve for permeability, k, using equation 13.

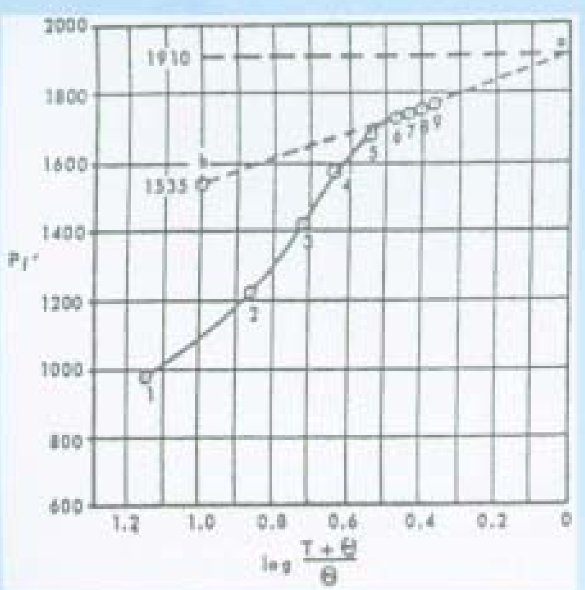


Figure 1
Plot of pressure breakdown data on standard coordinate paper

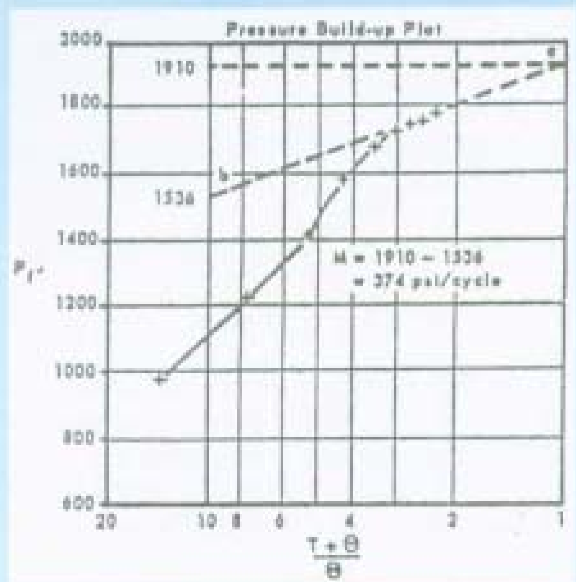


Figure 2
Plot of pressure breakdown data on semi-log paper

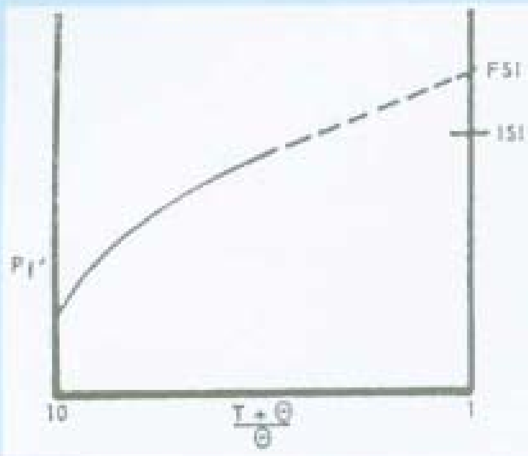


Figure 3
Plot of mathematical pressure reading

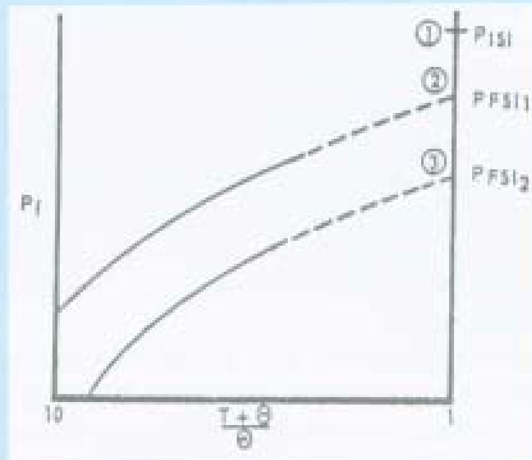


Figure 4
Comparison of the mechanical and mathematical pressure reading measurement

Table 2
Summary of calculated DST Data

Estimated Damage Ratio, EDR		4.23
Estimated Damage Ratio, EDR	:	4223 psig
Slope of Shut-in Curve, M	:	54 psi/log cycle
Productivity Index, PI	:	1.32 bbl/day/psi
Radius of Investigation, ri	:	138 ft
Effective Transmissibility, kh/μB	:	4280 md.ft/cp
Flow Rate Oil, Q		1422 bbl/day
Gas Oil Ratio, GOR		1500 CF/bbl
k (effective to oil), k	:	150 md

$$\frac{kh}{\mu B}=58.5 \rightarrow k=\frac{58.5\mu B}{h}=\frac{58.5(1.5)(1.15)}{10}=10.1md$$

When the fluid flowing is gas it is standard practice to report recovery as a rate of flow in cubic feet per day (CFPD) or in thousands of cubic feet per day (MCFPD). The following equation for transmissibility was developed using rate of flow Q in MCFPD.

$$\frac{kh}{\mu Z}=\frac{1637QgTf}{Mg} \qquad (14)$$

where: Z = gas deviation factor
Mg = build-up constant for gas

$$=\frac{Po^2-Pf^2}{\log(T+\theta)/\theta}$$

Assume that the previous test produced gas. The plot in Figure 5 is for such a test using the breakdown and plotting pressure squared as discussed above.
From this plot and the resulting slope solution, Mg, the transmissibility calculation would be:

Example 2: Given test data in table 1 having a recovery of 1500 MCFPD, and formation temperature of 140^o F.

Solution for Mg:

$Mg = P1^2 - P10^2 = 3{,}570{,}000 - 2{,}383{,}000$
$= 1{,}187{,}000\ psi^2/logcycle$
$Tf = {}^oF + 460 = 140 + 460 = 600^oR$
$Qg = 1500\ MCFPD$

$$\frac{kh}{\mu Z}=\frac{1637QgTf}{Mg}=\frac{1637(1500)(600)}{1{,}187{,}000}$$
$$=1240md.ft/cp$$

The effective permeability to gas would then be computed in the same manner as before. From measurements or local information a specific gravity of the gas (Air = 1.0) may be obtained. Knowing the specific gravity, formation temperature and pressure then values for viscosity and deviation may be obtained from the literature. In this case viscisity μ = 0.019 cp and gas deviation factor Z = 0.79, so that: kh/μB = 1240, then k:

$$k = \frac{1240(0.019)(0.79)}{10} = 1.9\,md$$

B. ***Well Bore Damage, EDR***

The determination of the existence of well bore damage and the extent of its influence is made through the use of the EDR equation 15, such as:

$$EDR = \frac{Po - PF}{M(5.5 + \log T - 2.85)} = \frac{Po - PF}{M(\log T + 2.65)} \quad \text{.........(15)}$$

An example of the use of this equation given below, using the test data presented in Table 1.

Example 3: Given, actual rate of flow Q =135 BOPD, maximum reservoir pressure Po = 1910 psig, final flow pressure PF = 350 psig, slope constant M = 375 psi/log cycle, flow time T = 650 minutes.

Solution :

$$EDR = \frac{Po - PF}{M(\log T + 2.65)} = \frac{1910 - 350}{375(\log 65 + 2.65)}$$

$$= \frac{1560}{375(1.813 + 2.65)} = 0.93$$

An example of DR calculations, using the same hypothetical test and data, can be calculated using equation 10 as follows:

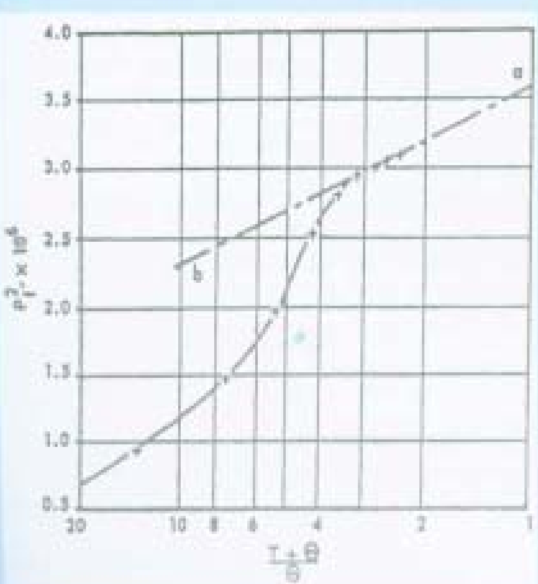
$$DR = \frac{(Po - Pf)}{M\left[\log(kT / \phi\mu c r w^2) - 2.85\right]}$$

$$DR = \frac{1910 - 350}{375[\log(0.1)(65)/(0.1)(1.5)(8.4x10^{-6})(4.5)^2 - 2.85]}$$

$$\frac{1560}{375(7.4269 - 2.85)} = 0.91$$

The estimated damage ratio value of 0.93 compares very favourable to the actual, empirically calculated value of 0.91. Experience has shown that this will be the case in most all instances. Only in those cases where the actual values for the formation and fluid characteristics are known and a value for a formal presentation is necessary, will it be worth the time to make the empirical calculation.

Since a damage ratio (whether DR or EDR) value of 1 denoted no damage then the above example shows that there was no damage present during the test. The rate of flow indicated Q =135 BOPD, is the maximum rate that can be expected under these test conditions.



F[illegible]
Plot of breakdown test data

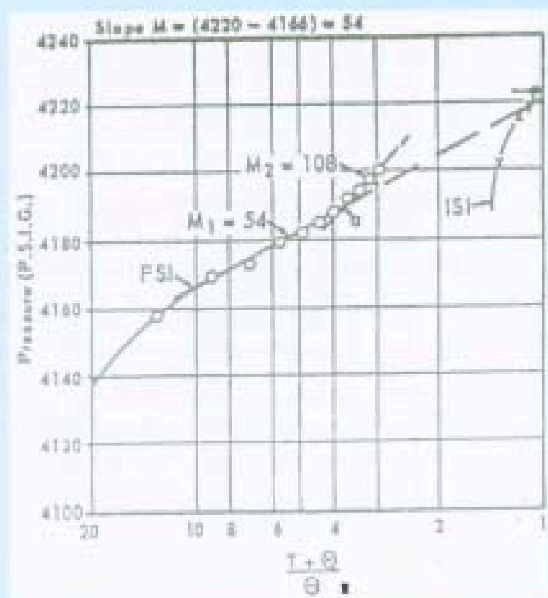


Figure 6
Horner's plot data

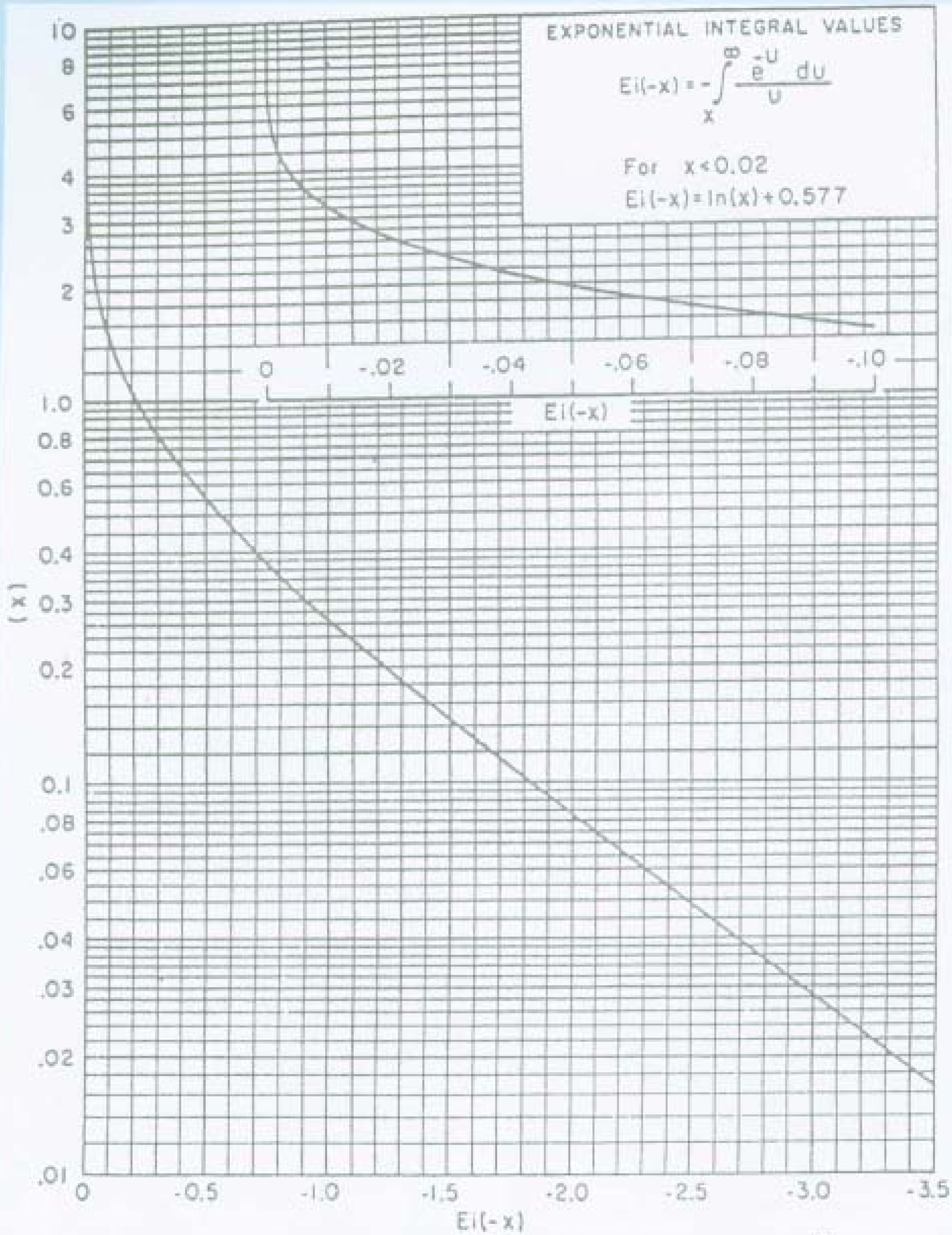


Figure 7
Exponential Integral values

The following is an example where damage is indicated:

Example 4: Given rate of flow Q = 38 BOPD, maximum reservoir pressure Po = 1788 psig, final flow pressure PF = 188 psig, slope constant M = 149 psi/log cycle, and flow time T = 120 minutes.

Solution:

$$EDR = \frac{Po - PF}{M\,(\log T + 2.65)} = \frac{1788 - 188}{149(\log 120 + 2.65)}$$

$$= \frac{1600}{149(2.08 + 2.65)} = 2.41$$

$$Then, QT = Q \; x \; EDR = 38 \, x \, 2.41 = 91\,BOPD$$

The difference between 38 BOPD and 91 BOPD may well mean the difference between a commercial well and a non-commercial well. In the days before DST data analysis, the rate of flow of 38 BOPD would have been taken at face value as being the maximum rate of flow available.

If this were a fairly deep well, say 10,000 ft, then as a pumping well this might not be considered a commercial well and conceivable plugged and abandoned, but with a potential of 91 BOPD it is probably commercial.

For gaseous flow, can be calculated using equation:

$$EDR = \frac{Po^2 - PF^2}{Mg(\log T + 2.65} \quad \text{.........................} (16)$$

It is pointed out that a low rate of production is generally caused by one of three things:

- low permeability
- high well bore damage
- combination of both

The properly run formation test will generally provide adequate data to calculate both of these characteristics. Judgment a knowledge of the local area will assist in helping to properly evaluate the test and formation from this point.

By proper application of complete test evaluation over long range exploration and development programs any operator can see a definite monetary savings.

C. *Radius of Investigation, ri*

When no anomalies are detected in the plot and there are no depletion indications, some of the radius of investigation (ri) equations that have been presented in various papers are:

(1) van Poollen and Craft Hawkins proposed to estimate radius of investigation in oil field can be used equation (oil field unit):

ri = [(kT)/fμc 40]^0.5 .... (17)

where T = flow time in days

(2) Maler proposes equation (oil field unit) :

ri = 4.63 (kT)^0.5 ....(20)

where T = flow time in minutes

As may be seen from these equations, there is very definite resemblance between these four equations, primarily:

(1) Higher the permeability and longer the time of flow is held, the larger the area of influence by test.

(2) Greater the porosity or storage capacity of the formation the smaller the area of influence.

(3) Higher the fluid viscosity and compressibility, the smaller the area of influence.

The following is example in calculating ri.

Example-5: Given, permeability k = 10.1 md, time of open flow periods T = 65 minutes, porosity (lab. or log data) f = 0.1, fluid viscosity μ = 1.5 cp, formation compressibility c = 8.4 x 10^-6 (lab.data).

Solution: Radius of investigation can be determined using equation 17:

(1) ri = [kT/40 fμc]^0.5
= [(10.1)(65)/(1440)]/(0.1)(1.5)(8.4x10^-6)(40)^0.5
= 95 ft

Using the same value in equation 20:

(2) ri = 4.63 (kT)^0.5
ri = 4.63 [(10.1)(65)]^0.5 = 119 ft.

From the value given, it can be noticed that the two solutions give fair correlation in the answers. The primary cause of the difference is believed to be in the use of an empirical value such as the 4.63 rather than actual (or even estimated) value for the diffusivity factor, k/fμc. The porosity, f, and fluid compressibility, c, can have large variations from one formation and fluid to another, and can have a very large effect on the radius of influence of a given pressure drop.

D. *Barrier Determination, ra*

By knowing the pertinent formation and fluid characteristics and having a Horner plot that shows some type of anomaly then the distance to that anomaly may be approximated by substituting in the following equation for solving ra.

When an anomaly is detected then equation below, would be used to estimate the distance to the anomaly:

$$-Ei\left[\frac{-3793\, ra^2\, \phi\mu c}{kT}\right] = 2.303 \log \frac{T\ \theta a}{\theta a} \quad .....(21)$$

where: ra = distance to anomaly in feet

T = flow time in hours

qa = shut-in time at intercept point of two slopes describing anomaly, hours

Example-6: Using the DST information and pressure data given with figure-6.

Q = 1422 BOPD (45^o API @ 60^oF)
T = 120 min. = 2 hours
GOR = 1500 cu.ft/bbl
M1 = 54 psi/log cycle
From Standing : μ = 0.25 ; B = 1.81
c = 20.8 x 10^-6
From Micro Log : h = 13'
From Sonic Log : f = 14%

Solution:

From equation 13:

$$\frac{kh}{\mu B} = \frac{162.6\, Q}{M} = \frac{162.6\ (1422)}{54} = 4820\ md.ft/cp$$

$$k = \frac{4280\, \mu B}{h} = \frac{4280\ (0.25)\ (1.81)}{13} = 150\ md$$

From slope intercept on Horner plot (Figure 6)

$$\frac{T + \theta a}{\theta a} = 3.75$$

Using equation 21:

$$-Ei\left[\frac{-3793\ ra^2\ \phi\mu c}{kT}\right]$$

$$-Ei\left[\frac{-3793\, ra^2\, (0.14)(0.25)(20.8\,x10\text{^}-6)}{150\ (2)}\right] = 2.303 \log 3.75$$

$$-Ei[(-9.204\, x19\text{^}-6)\, ra^2] = 1.322$$

Then from exponential table or exponential plot, Figure-7,

x = 0.176 = (9.204 x 10^-6) ra²
ra = (19122)^0.5 = 138 ft

These calculations suggest that there is a sealing barrier approximately 138 ft, from the well bore. Subsequent drilling of three more wells in this area yielded subsurface geological data that showed a fault to be present approximately 175 ft, from this well.

V. CONCLUSIONS

A DST can give a considerable amount of information concerning a particular geological horizon, generally at a time early enough to have effect upon the economic life and potential of the well. If conducted properly a DST will normally gives:

(1) The fluid content of the particular horizon under test, and indicated rate of flow under measureable well bore conditios.

(2) The maximum, or static, reservoir pressure at the time of the test.

(3) The average effective permeability, through transmissibility calculations, of the formation to the reservoir fluid produced.

(4) The detection and gross effect of well bore damage.

(5) If occuring within the radius of influence the DST will detectbarriers, fluid phase changes (gas to liquid), permeability pinch out, etc. and the approximate distance to these anomalies from the well bore.

These parameters may be calculated from DST data if DST is conducted in the proper manner. The observation of a few simple rules of thumb will help conduct a DST in the proper manner. The calculations are simple enough that they may be made with only basic material at hand and the resulting answers are reliable.

The caution is made, however that no one evaluation tool is complete in itself and all evaluation tools give data that must be analysed and interpreted by individuals. Interpretations can and do vary from one person to the next.

SYMBOLS

A = cross sectional area, sq.cm.
B = formation volume factor, vol./vol.
c = fluid compressibility, vol./vol./psi
dp/ds = pressure gradient, atm./cm.
h = formation thickness, ft
k = permeability, md
kh = flow capacity, md ft
kh/μB = transmissibility factor, md ft/cp

M = Horner plot slope constant (liquid), psi/logcycle
Mg = Horner plot slope constant (gas), psi^2/log cycle
P = pressure, psig
Pf = formation pressure at flow time T, psig
Pf' = formation buildup presure at shut-in time θ, psig
Po = maximum reservoir pressure, psig
q = fluid flow rate, cc/sec.
Q = fluid flow rate, STBOPD
r = radius to pressure poit Pf, ft
rw = radius of well bore, inches
S = skin factor, fractional
T = flow time, min.,hr. or day
V = fluid velocity, cm/sec.
μ = fluid viscosity, cp
ϕ = porosity, fractional
θ = shut-in time, min., hr., days

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