Analysis of field data using Microsoft excel and MATLAB software to evaluate reservoir and well damage

ABSTRACT

Reservoir formation damage is a drop in a well's productivity caused by a decrease in reservoir rock permeability. To tackle this issue and maximize well production, obtained pressure build-up time data at a steady production rate from a vertical producing oil WELL 20A, was analysed to establish the wellbore and reservoir characteristics. A numerical well test simulator (Matlab) is used to simulate damage in the area close to the wellbore, a Microsoft Excel sheet and an analytical approach to calculate the impact of wellbore and reservoir factors such as skin, wellbore storage, and average reservoir permeability. In order to determine whether the numerical well test simulator was successful at performing pressure transient analysis on observed data, the findings from the analytical solutions using Microsoft Excel Sheet and numerical well test simulator Matlab were compared. Comparable outcomes for the permeability and skin values were obtained from the build-up test data analysis generated; hence, the negative skin values for wells 20A acquired after the analysis suggest that the formation is not damaged. This indicate that well 20A is not a candidate for workover operations.

1. Introduction

In the oil and gas industry, reservoir degradation is a challenging problem that can significantly decrease in fluid flow rates and retrieval from underground reservoirs [1,2]. Damage to wells and formations refers to many actions performed on wellbores in the course of drilling, production, workover, stimulation applications, and/or other attempts to boost gas or oil retrieval frequently result in formation damagethroughout the history of a well, from the initial drilling and wellbore completion to the production-induced depletion of a reservoir, Formation degradation could occur at any time. When a formation is exposed to a foreign fluid during operations like drilling, completion, workovers, or stimulations, formation damage may occur due tounfavorable wellbore fluid/formation fluid interactions. For the moment a well is generating less than its ideal productivity, remedial measures cannot be taken up to the time the fundamental cause of the issue has been identified.

Rarely, a thorough examination of the entire producing system may be needed. Several distinct probable reasons have been identified in connection with diverse downhole operations in the oil and gas wellbores by the several scholars who have researched the causes of formation damage [1,2,3,4,5,6,7,8,9,10].

Reservoir deterioration or destruction is frequently brought about by complicated processes that arise from interactions between many routes. In addition, the formation can be damaged in two ways: naturally and by artificial causes [1]. They can be more thoroughly characterized in accordance with the underlying biological, chemical, mechanical, and thermal sources of these mechanisms [1][2]. From the moment the drilling bits reach the formation up to the time the well is abandoned, there is a chance that the surrounding wellbore formation's permeability will be reduced or destroyed.

The zone is exposed to drilling fluids that could be harmful to the well's future productivity from the momentthe drilling bit hits the pay zone until the well is put into production. The type of drilling fluid and the pressure differential are crucial while drilling into the zone.A validated field test can help establish prevention or mitigation strategies for formation damage and provide scientific guidance. Over the past ten years, pressure transient testing theory and practice have made significant advancements, and numerous techniques and fixes have been proposed to examine diverse reservoirs. By inferring formation attributes from reservoir data, it is possible to determine a formation's capacity

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to produce reservoir fluids by studying well test and production data. Permeability, skin effect, and initial reservoir pressure are a few important characteristics that must be assessed.

1.1 Types of Reservoir and Well Damage

There are two types of formation damage mechanisms:

- Decreased permeability near wellbores
- Changes in near-wellbore relative permeability.

1.1.1 Decreased Permeability Near Wellbore

The reservoir properties of the near-wellbore zone are altered by some factors such as clay swelling and water saturation, which have a negative impact on well productivity/injectivity. Matrix acidizing is one method for restoring the reservoir features of the zone close to the wellbore. According to a literature analysis, the permeability of the near-wellbore zone decreases according to a clear rule due to formation damage, reaching its maximum reduction at the wellbore and returning to its original value as the distance from the wellbore increases.

1.1.2 Changes in Near Wellbore Relative Permeability

One may classify formation damage as damage to the area close to the wellbore (e.g., mud solids invasion, plugging). A zone of permeability alterations close to the wellbore (skin) occursdue tothe invasion the reservoir rock with alien fluid. The values for pertinent displacement and petrophysical parameters, as well as information on oil and water relative permeability, are obtained directly from the production records of oil and water wells.

1.2 Causes of Reservoir and Well Damages

Many authors have provided detailed descriptions of the different issues encountered in the field that obstruct the petroleum reservoir's ability to produce oil and gas. In porous media, there are several mechanisms by which formation damage takes place, chemical, mechanical, thermal and biological etc.

(i) Mechanical Mechanism
- **Solid Plugging**
- Fine Migration

(ii) Chemical Mechanism
- Swelling of Clays
- Clay Deflocculation
- Saturation Changes

(iii) Biological Mechanisms
- Bacteria Plugging

(iv) Thermal Mechanism
- Wettability Alteration

1.3. Prevention of Reservoir and Well Damage

We can therefore alter operations, lessen the amount formation damage created close to the wellbore, which has an impact on hydrocarbon output. Understanding how different drilling, completion, and production processes may affect formation damage might help to dramatically reduce formation damage and enhance the well's capacity to produce fluids.

(i) Underbalanced Drilling

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Underbalanced drilling is both highly advised and frequently employed. Unbalanced drilling makes it possible for fracture fluids to enter the wellbore, preserving the fractures. If underbalanced drilling is not possible due to safety and legal constraints, bridging additives must be introduced ensuring that there are large enough particles in the mud system to span the fracture wall.

(ii) Drilling Fluid

The introduction of drilling fluids has reduced the risk of formation damage. In these applications, sized salt fluids and scaled calcium carbonate are the most often employed drilling fluids. For the sake of this application, both water-based and oil-based mud have been considered.

1.4 Treatment of Formation Damage

Acidizing

In order to increase well productivity, acid is introduced into the formation at a lower pressure than the formation breakdown pressure. This procedure is mostly employed to recover near-wellbore permeability during drilling, completion, or production after formation plugs. However,there are drawbacks, such as high rates of corrosion, clay sensitivity, and subsequently high acid consumption to create the suitable reservoir rock. Due of its thermal stability, retarded nature, an organic acid and low corrosion rate are combined with mud acid to address these shortcomings.

1.5 Importance of Mitigating Damage

Formation degradation can significantly lower production since a reservoir's ability to produce fluids is significantly impacted by near-wellbore permeability. Operators have researched damage processes and methods to stop or control them. As a result, operators can efficiently plan and execute operations related to drilling, completion, and production. The ultimate aims for operators are to reduce damage while boosting productivity.Additionally, techniques and technology for calculating formation damage will advance.

2. Materials and Methods

2.1 Materials

One potential well candidate, well 20A,has been chosen for this investigation. We will only use the well parameter and build-up data results specific to wells in our research. The three wells include: Well 20A.

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2.1.1 WELL 20A

WELL PARAMETERS

Table 1: Flow History for Well 20A

Tp	14
Q	366
Beta	1.5
Ct	6.00E-06

H	62
Phi	0.25
Yw	0.3
U	0.41
A	40
Phr	2260
Pwf	1240

Table 2: Build up Data for well 20A

Δt, hrs	SHUT IN PRESSURE	ΔP	(Tp+Δt)/Δt	LOG (Tp+Δt)/Δt
0.66	1465	225	22.21212	1.346590035
1	1650	410	15	1.176091259
1.5	1880	640	10.33333	1.014240439
2	1970	730	8	0.903089987
2.5	2040	800	6.6	0.819543936
3	2060	820	5.666667	0.753327667
4	2090	850	4.5	0.653212514
6	2110	870	3.333333	0.522878745
8	2120	880	2.75	0.439332694
10	2140	900	2.4	0.380211242
12	2180	940	2.166667	0.335792102
14	2205	965	2	0.301029996
20	2215	975	1.7	0.230448921
26	2225	985	1.538462	0.187086643

- **2.2 Methods**

In order to determine the PVT and reservoir data, as well as the reservoir and wellbore characteristics of a Niger Delta producing well. In contrast to a Microsoft Excel sheet, the well and reservoir properties were precisely evaluated using a numerical simulator (Matlab) and the standard method (analytical methods). On an Excel sheet, the data for the build-up pressure and time were plotted. As part of the build-up test, the vertical oil well's three flow regimes were determined, and reservoir and wellbore data were obtained

- **2.2.1 Numerical Solutions for Estimating Reservoir and Wellbore Parameters**

Matlab Source code for well 20A

```
clc
clear all
x = [29 22.21212121 15 10.33333333 8 6.6 5.666666667 4.5 3.333333333 2.75 2.4 2.166666667 2
1.7 1.538461538];
y = [1240 1465 1650 1880 1970 2040 2060 2090 2110 2120 2140 2180 2205 2215 2225];
scatter(x,y, 'DisplayName', 'MyData')
set(gca,'xscale','log')
set(gca,'yscale','linear')
hold on
```

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```
grid on
box on
axis equal
%
Bp = polyfit(log10(x), y, 1);
Yp = polyval(Bp, log10(x));
Yp2 = 10.^(Yp);
m = (Bp(1));
%
plot(x, Yp, 'r', 'DisplayName', 'Fit');
text(20, 1800, strcat('Slope = ', num2str(Bp(1))), 'Interpreter', 'none');
legend
tp = input('enter the value of tp: ') %hrs
q = input('enter the value of q: ') %bbl/day
B = input('enter the value of B: ')
Ct = input('enter the value of Ct: ') %psi^-1
h = input('enter the value of h: ') %ft
phi = input('enter the value of phi: ')
rw = input('enter the value of rw: ')
mu = input('enter the value of mu: ')
A = input('enter the value of A: ')
P1hr = input('enter the value of P1hr: ')
Pwf = input('enter the value of Pwf: ')
%m = input('enter the value of m: ')
K = -(162.6*q*B*mu)/(m*h)
X = (P1hr-Pwf)/m
Y = K/(phi*mu*Ct*rw^2)
Z = log10(Y)
S = 1.1513*(X - Z + 3.23)
perm_pdt = K * h
Pressure_drop_skin = 0.87*m*S
if S < 0
disp("well is not damaged, well stimulation not required")
else
disp("well is damaged, well stimulation required")
end
```

- **2.2.2 Analytical Methods for Determining Wellbore and Reservoir Properties**

Calculating the wellbore storage coefficient

$\boldsymbol{C}$s= $\frac{q_s B}{24\Delta P}$ t

Where,

Δt =2 hr

ΔP = 110.01 psig

Q=366bbl/day

Cs = $\frac{366*1.5}{24*110.01} * 2$

Cs = 0.415871 bbl/psi

Analytical approach (Microsoft excel sheet) for caculating the slope (m)

Slope (m)= -673.33 psi/cycle

Estimating the average reservoir permeability (k) using analytical solution

k= $\frac{162.6q\beta\mu}{mh}$

substituting

k =$\frac{162.6*366*1.5*0.41}{673.33*62}$

k = 0.8767md

Calculating the permeability thickness product (kh) using analytical solution

Kh = $\frac{162.6*q*\beta*\mu}{m}$

Kh = $\frac{162.6*366*1.5*0.41}{673.33}$

Kh = 54.356 md.ft

Analytical methods for calculating the skin factor (s)

S = 1.1513*($\frac{pws\,1hr-pwf\,(\Delta t=0)}{m} - \log\frac{k}{\emptyset\mu Ct\,rw^{2}} + 3.23$)

S = 1.1513*($\frac{2260-1240}{-673.33} - \log\frac{0.8767}{0.25*0.41*6e-6*0.3^{2}} + 3.23$)

S = -5.711

Analytical methods for calculating the added pressure drop around the $\Delta p_{skin} = 0.87\ m\ s$

$\Delta p_{skin} = 0.87* -673.33*(-5.711)$

$\Delta p_{skin} = 3345.48$

3. Result and Discussion

For the purpose of this analysis, the horner's plot was used to determine reservoir parameters including effective permeability, skin factor, flow efficiency, and damage factor (ratio of damaged to undamaged wells). As shown below, three potential well candidates have been chosen for this investigation. A summary of results from three wells are stated below.

3.1 Result

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- **3.1.1 Analytical Solution for Estimating Reservoir and Wellbore Parameters.**

Graph of Shut in Pressure Against Horner's Time

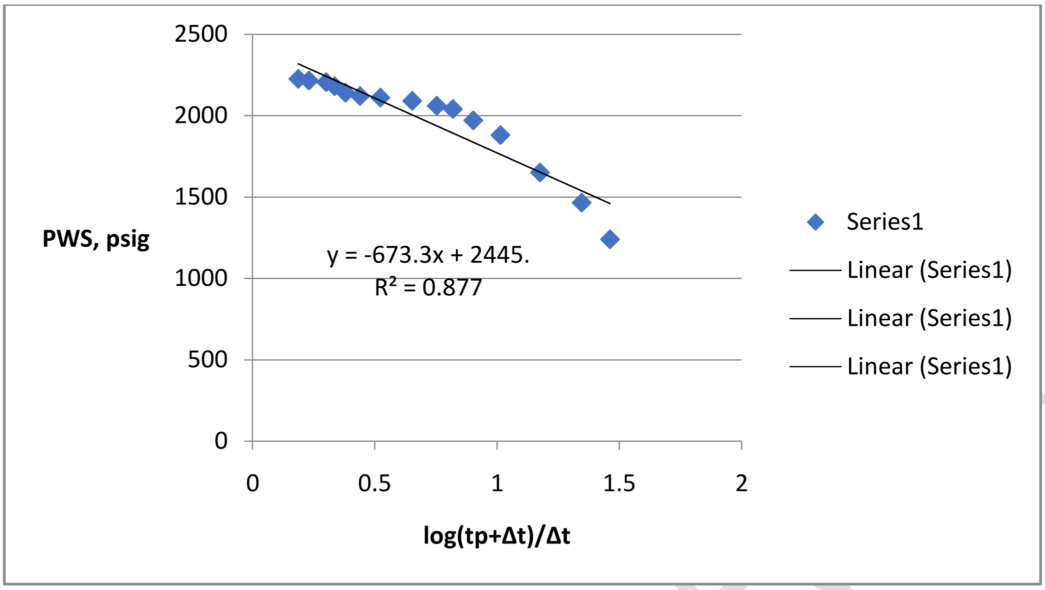

FIGURE 1: BUILD UP DATA FOR WELL 20A

- **3.1.2Numerical Solutions for Estimating Reservoir Parameters**

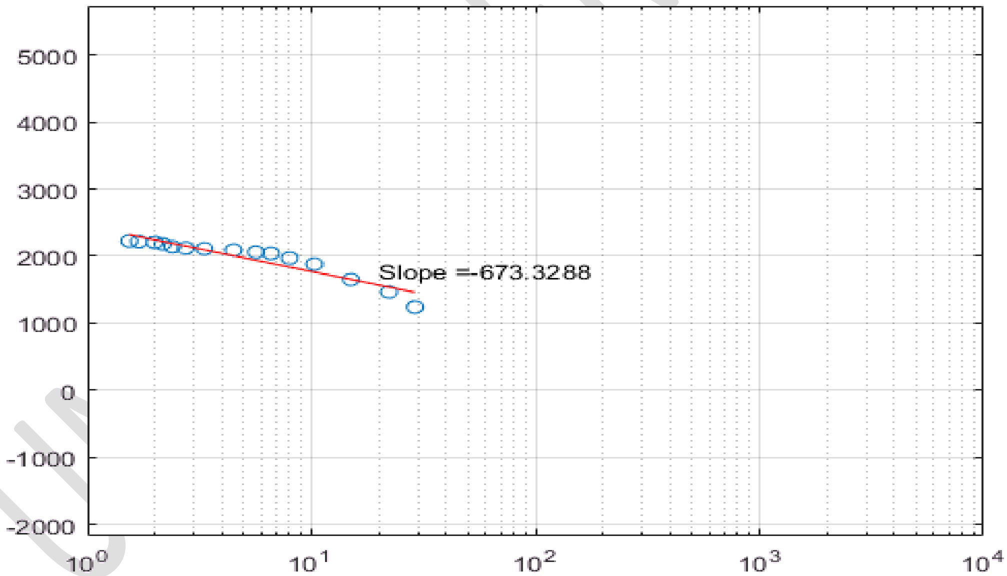

FIGURE 2: Plot of PwsAgaints (Tp+Δt)/Δt for Well 20A using matlab.

3.1.3 Comparison of the Results from Numerical and Analytical Solutions.

Table 3.Comparison ofNumerical and Analytical Solutions

RESERVOIRAND WELLBORE PARAMETERS	NUMERICAL STIMULATION USING MATLAB	ANALYTICAL SOLUTION USINGMICROSOFT EXCEL SHEET
permeability, k	0.8767	0.877
Permeability thickness product, kh	54.356	54.356
Skin(s)	-6.314	-5.711
C	0.61000	0.415871

3.2 Discussion

The findings for well 20A make it clear that there is no damage to the oil well. The vertical well is not an appropriate candidate for workover jobs because of a negative skin factor discovered in this case study. In comparison to the skin value (S= -5.711) procured when utilizing analytical methods with a Microsoft Excel sheet, and Matlab provides an estimate of skin value (S = -6.314). The average permeability values (0.877mD and 0.8767mD) still procured after numerical and analytical analysis are due to the test being conducted in a formation with a low degree of permeability. Also, relative permeability product obtained using Matlab is (54.356) and the one obtained using Microsoft excel is (54.356), this shows high relative permeability product. The results of the two analyses utilized to estimate reservoir property were similar.

4. Conclusion

This study looks closely at the idea of formation damage, as well as its mechanism and diagnosis. For the analysis of the build-up test to identify formation damage (skin factor), the Horner's plot was used. Calculation and computation of skin factors, damage ratio, permeability, permeability thickness product, and wellbore coefficient are used to determine whether any type of damage occurred in any of the study wells.Well 20A shows that the formation is not damaged. Results obtained with matlab and the outcomes obtained with the Microsoft excel sheet are the same.

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