FLOW/BUILDUP TEST REPORT

#1591
Copy 2 of 2

HOME PIERSON 07-16-02-29W1
SPEARFISH (1015 - 1021 mKB)
TEST DATE: DECEMBER 20 - JANUARY 4, 2000

Prepared for:

ANDERSON EXPLORATION LTD.

Prepared by:

PETRO MANAGEMENT GROUP LTD.

JANUARY 2000

#401, 100 - 4th Avenue S.W.
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January 19, 2000

ANDERSON EXPLORATION LTD.
1600, 324 - 8th Ave. S.W.
Calgary, Alta., T2P 2Z5

Attn.: Mr. Larry Sopko

HOME PIERSON 07-16-02-29W1
SPEARFISH (1015 - 1021 mKB)
FLOW/BUILDUP TEST
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As requested, a flow/buildup test analysis was performed on the subject well. A summary of the test data and the analysis results is attached. The report marked ORIGINAL contains the test data on a diskette, if available. Three copies of the report are attached.

Should you have any questions, please feel free to contact me at (403) 216-5101.

Yours truly,
Petro Management Group Ltd.

COPY (Original Signed) S. IBRAHIM

Saad Ibrahim, P. Eng.
Principal Engineer

Summary of Test Data and Results

Case Name : Finite Conductivity Fracture #1

Home Pierson 07-16-02-29W1

Spearfish (1015 - 1021 mKB)

Flow/Buildup Test

Test Date: Dec. 20 - Jan. 4, 2000

Model Parameters

Oil Permeability (k_o)	5.539 mD	Fracture Half Length (x_f)	9.32 m
Gas Permeability (k_g)	0.046 mD	Fracture Flow Capacity ($k_f w$)	141.946 mD.m
Water Permeability (k_w)	0.679 mD	Fracture Face Skin (sf)	0.010
Total Mobility ($[k/\mu]_t$)	6.66 mD/mPa.s	Skin Equivalent to Xf	-3.499
Total Transmisivity ($[kh/\mu]_t$)	17.99 mDm/mPa.s	Exterior Radius (r_e)	234.82 m
Wellbore Storage Constant Dim. (C_D)	423.25		

Formation Parameters

Net Pay (h)	2.70 m
Total Porosity (ϕ_t)	17.00 %
Oil Saturation (S_o)	0.60 %
Gas Saturation (S_g)	99.00 %
Water Saturation (S_w)	0.40 %
Wellbore Radius (r_w)	0.091 m
Formation Temperature (T)	42.0 °C
Formation Compressibility (c_f)	5.658e-7 kPa^{-1}
Total Compressibility (c_t)	5.136e-4 kPa^{-1}

Production and Pressure

$Q_t B_t$	9.539 m^3/d
Final Oil Rate	2.040 m^3/d
Final Gas Rate	0.130 $10^3 m^3/d$
Final Water Rate	1.540 m^3/d
Final Flowing Pressure (p_{wfo})	485.00 kPa
Final Measured Pressure	2042.74 kPa
Initial Pressure (p_i)	2042.74 kPa

Synthesis Results

Average Error	-0.25 %
Synthetic Initial Pressure (p_i)	3567.81 kPa
Extrapolated Pressure at Specified Time	3252.09 kPa
Pressure Drop Due To Skin (Δp_s)	14.11 kPa
Flow Efficiency (FE)	0.996
Damage Ratio (DR)	1.004

Fluid Properties

Oil Compressibility (c_o)	2.38433e-4 kPa^{-1}
Gas Compressibility (c_g)	5.16793e-4 kPa^{-1}
Water Compressibility (c_w)	4.56924e-7 kPa^{-1}
Oil Formation Volume Factor (B_o)	1.054
Gas Formation Volume Factor (B_g)	0.052080 m^3/m^3
Water Formation Volume Factor (B_w)	1.006
Oil Viscosity (μ_o)	3.690 mPa.s
Gas Viscosity (μ_g)	11.331 μPa.s
Water Viscosity (μ_w)	0.627 mPa.s
Solution Gas Ratio (R_s)	9 m^3/m^3
Oil Gravity (γ_o)	0.835
Gas Gravity (G)	0.650
PVT Reference Pressure (p_{PVT})	2042.74 kPa
Bubble Point Pressure (P_{bp})	2042.74 kPa

Forecasts

Specified Flowing Pressure (p_{wfs})	485.00 kPa
3 - Month Constant Rate	2.298 m^3/d
6 - Month Constant Rate	2.022 m^3/d
Specified Forecast Time	12.00 month
Forecast Constant Rate @ Current Skin	1.805 m^3/d
PI / II (Total Liquids - Actual)	1.28e-3 $m^3/d/kPa$
Forecast Constant Rate @ Skin=0	1.813 m^3/d
PI / II (Total Liquids - Ideal)	1.29e-3 $m^3/d/kPa$

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SUMMARY OF RESULTS

SUMMARY OF RESULTS

1. The average reservoir pressure (P_R) is 3 252 kPa.

2. The effective permeability to oil of the Spearfish formation is 5.5 mD.

3. The apparent wellbore skin factor of -3.5 and the fracture half length of 9.3 m confirm the effectiveness of the fracture treatment.

4. Production forecast sensitivity indicates that the well will start declining after approximately 11 months.

5. The IPR plot indicates a maximum theoretical stabilized oil rate (AOF) of 2.1 m^3/d.

6. Radius of investigation is approximately 21 m.

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TEST ANALYSIS

DISCUSSION

1. Test Overview:

The Home Pierson 07-16-02-29W1 is completed in the Spearfish formation at 1015 - 1021 mKB and is equipped with a 60.3 mm tubing. The well was fractured during the initial completion to improve productivity.

During the test, the well produced at an oil rate of 2.0m^3/d. Subsequently, the well was shutin for a 350 hour buildup period. The bottom hole pressures were calculated from the measurement of liquid levels, obtained from the Acoustic Wellsounder equipment by Otatco Inc. The oil gravity is 36 API. Other oil physical properties were calculated using various standard correlations.

2. Data Validation:

During the test, bottom hole pressures were measured using the Acoustic Wellsounder equipment.

The primary pressure derivative (PPD) plot was constructed for the measured pressures (Figure 1) as shown in the Section "Test Data Quality". The PPD showed only minor pressure anomalies. The PPD plot should be monotonically decreasing with time for valid buildup data. Pressure data was reported in absolute at MPP.

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TEST INTERPRETATION

1. Pressure Buildup Analysis:

Pressure buildup analysis was performed on the shut-in period. The reservoir parameters were provided by Anderson Exploration Ltd., as shown in the attached form "Summary of Test Data and Results". The final oil rate flow rate prior to shutting in the well was 2.0 m^3/d at a sandface flowing pressure of 485 kPa, as shown in the Strip Chart (Figure 2) in the section "Pressure Transient Analysis".

Both the Horner Plot and the pressure derivative analysis were used in the analysis, as discussed below, and results were later fine tuned using the pressure history match techniques of the test pressure data.

Wellbore storage regime was identified by the unit slope straight of the pressure derivative as shown in the Diagnostic Derivative Analysis plot (Figure 3) in the section "Pressure Transient Analysis". Bilinear flow regime, which confirms the effectiveness of fracture treatment, was identified by the 1/4 slope straight line of the pressure derivative. The flattening of the pressure derivative, of the late time data, confirms that radial flow was reached.

Radial flow analysis was performed to determine the reservoir parameters using the semi-log straight line drawn through the late time pressure data, as shown in the Horner plot (Figure 4). The extrapolation of the last data points yielded a P^* of 3 356 kPa. The (P^*) was corrected for the shape, areal extent of the reservoir and the location of the well to determine the average reservoir pressure of 3 341 kPa. The results of the Horner plot and the pressure derivative are summarized below:

	Horner	Derivative
Effective Permeability, mD	6.6	6.2
Reservoir Pressure, kPa	3 341	n/a
Apparent Skin Factor	-3.2	-3.3

Bi-linear flow analysis, using the Tandem Quad Root plot, was performed to evaluate the effectiveness of the hydraulic fracture treatment (Figure 5). The straight line drawn through the pressure data during bi-linear flow regime, concluded a fracture conductivity (k_f.w) of 33.2 mD.m.

2. Pressure History Match:

The preliminary results from the Horner analysis were used as starting parameters for pressure history matching of the test data. The best match of the test data was obtained, using the Finite Conductivity Fracture Model. The overlay of simulated analysis results on the real test data is presented in the cartesian, semi-log and log-log plots (Figures 6, 7 and 8), in the section "Pressure History Match". The parameters used to achieve the history match are as follows:

	History Match	
Reservoir Pressure, P_r	3 252	kPa
Effective Permeability, k	5.5	mD
Fracture conductivity, K_f.w	141.9	mD.m
Skin Factor, S	-3.5	
Fracture Half Length, X_f	9.3	m
Six-Month Stabilized Rate, q_s	2.0	$10^3 m^3/d$

3. Inflow Performance Relationship (I.P.R)

The Inflow Performance Relationship (I.P.R) was constructed using the Vogel equation, as shown in Figure 8, in the Section "I.P.R". The average reservoir pressure of 3 252 kPa and the test data were used to generate the I.P.R plot, at the current skin factor of -3.5. The well maximum theoretical oil rate is 2.1 m^3/d.

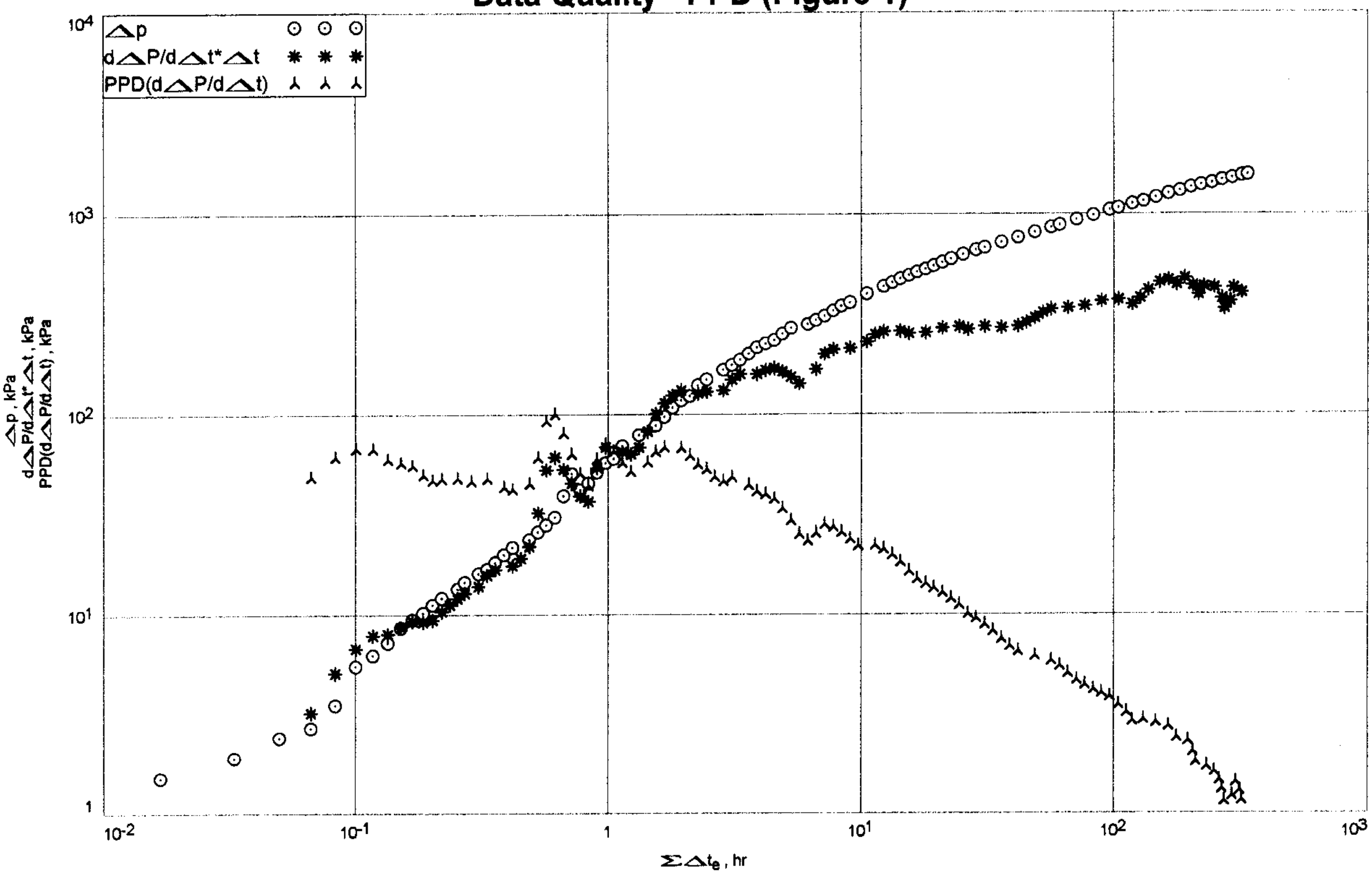
4. Production Forecast Sensitivity Analysis:

Production forecasts were generated for the well using the reservoir parameters obtained from the test history match. Sensitivity analysis was performed in attempt to maximize the oil recovery and to establish a reasonable gas production plateau. The bottom hole flowing pressure (BHFP) was used as a sensitivity parameter, and the various generated production forecasts are shown in Figure 9 in the section "Pressure History Match".

TEST DATA
QUALITY

Home Pierson 07-16-02-29W1
Spearfish (1015 - 1021 mKB)
Flow/Buildup Test
Test Date: Dec. 20 - Jan. 4, 2000

Data Quality - PPD (Figure 1)



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Home Pierson 07-16-02-29W1
Spearfish (1015 - 1021 mKB)
Flow/Buildup Test
Test Date: Dec. 20 - Jan. 4, 2000

	Time hr	Cum Time hr	Pressure kPa(a)	Gas Rate $10^3m^3/d$	Oil Rate m^3/d	Water Rate m^3/d
1	8000.0000	8000.0000	485.00	0.130	2.040	1.540
2	-0.0001	8000.0001	485.00	0.130	2.040	1.540
3	0.0169	8000.0169	486.50	0.000	0.000	0.000
4	0.0331	8000.0331	486.91			
5	0.0500	8000.0500	487.43			
6	0.0667	8000.0667	487.70			
7	0.0833	8000.0833	488.53			
8	0.1003	8000.1003	490.52			
9	0.1172	8000.1172	491.25			
10	0.1342	8000.1342	492.25			
11	0.1511	8000.1511	493.61			
12	0.1681	8000.1681	494.45			
13	0.1850	8000.1850	495.18			
14	0.2019	8000.2019	496.17			
15	0.2189	8000.2189	497.08			
16	0.2358	8000.2358	497.46			
17	0.2528	8000.2528	498.41			
18	0.2697	8000.2697	499.51			
19	0.2867	8000.2867	500.19			
20	0.3064	8000.3064	501.07			
21	0.3308	8000.3308	501.90			
22	0.3575	8000.3575	503.26			
23	0.3861	8000.3861	504.90			
24	0.4169	8000.4169	506.68			
25	0.4503	8000.4503	506.78			
26	0.4864	8000.4864	508.63			
27	0.5256	8000.5256	510.80			
28	0.5675	8000.5675	512.90			
29	0.6131	8000.6131	515.50			
30	0.6619	8000.6619	524.03			
31	0.7147	8000.7147	535.37			
32	0.7719	8000.7719	526.76			
33	0.8336	8000.8336	529.99			
34	0.9003	8000.9003	536.29			
35	0.9719	8000.9719	542.28			
36	1.0497	8001.0497	544.98			
37	1.1339	8001.1339	554.44			
38	1.2244	8001.2244	555.21			
39	1.3219	8001.3219	564.02			
40	1.4275	8001.4275	563.48			
41	1.5417	8001.5417	573.19			
42	1.6653	8001.6653	582.05			

Print Filter Used: Nth Line = 1.000

Home Pierson 07-16-02-29W1
Spearfish (1015 - 1021 mKB)
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	Time hr	Cum Time hr	Pressure kPa(a)	Gas Rate $10^3m^3/d$	Oil Rate m^3/d	Water Rate m^3/d
43	1.7975	8001.7975	592.90			
44	1.9408	8001.9408	602.60			
45	2.0956	8002.0956	608.36			
46	2.2639	8002.2639	624.89			
47	2.4444	8002.4444	634.43			
48	2.6392	8002.6392	638.58			
49	2.8508	8002.8508	651.86			
50	3.0761	8003.0761	661.96			
51	3.3211	8003.3211	672.94			
52	3.5861	8003.5861	686.38			
53	3.8736	8003.8736	701.51			
54	4.1825	8004.1825	711.46			
55	4.5158	8004.5158	720.31			
56	4.8781	8004.8781	737.77			
57	5.2669	8005.2669	755.64			
58	5.6867	8005.6867	762.76			
59	6.1417	8006.1417	768.45			
60	6.6314	8006.6314	781.14			
61	7.1631	8007.1631	794.84			
62	7.7339	8007.7339	814.60			
63	8.3500	8008.3500	833.53			
64	9.0156	8009.0156	848.56			
65	9.7339	8009.7339	857.26			
66	10.5100	8010.5100	885.13			
67	11.3475	8011.3475	894.24			
68	12.2486	8012.2486	919.12			
69	13.2308	8013.2308	938.78			
70	14.2861	8014.2861	961.54			
71	15.4236	8015.4236	979.01			
72	16.6653	8016.6653	998.06			
73	17.9892	8017.9892	1017.25			
74	19.4225	8019.4225	1037.43			
75	20.9703	8020.9703	1057.71			
76	22.6517	8022.6517	1079.74			
77	24.4631	8024.4631	1099.77			
78	25.3406	8025.3406	1110.96			
79	26.4164	8026.4164	1120.97			
80	28.5206	8028.5206	1142.03			
81	30.7936	8030.7936	1160.57			
82	33.2456	8033.2456	1185.54			
83	35.8956	8035.8956	1205.43			
84	38.7539	8038.7539	1225.74			

Print Filter Used: Nth Line = 1.000

Home Pierson 07-16-02-29W1
Spearfish (1015 - 1021 mKB)
Flow/Buildup Test
Test Date: Dec. 20 - Jan. 4, 2000

	Time hr	Cum Time hr	Pressure kPa(a)	Gas Rate $10^3m^3/d$	Oil Rate m^3/d	Water Rate m^3/d
85	41.8622	8041.8622	1245.52			
86	45.1978	8045.1978	1265.41			
87	48.8206	8048.8206	1291.07			
88	52.6769	8052.6769	1312.25			
89	56.8728	8056.8728	1337.83			
90	61.4353	8061.4353	1365.28			
91	66.3269	8066.3269	1391.91			
92	71.6144	8071.6144	1419.35			
93	77.3561	8077.3561	1441.08			
94	83.5186	8083.5186	1466.87			
95	90.1728	8090.1728	1498.98			
96	97.3353	8097.3353	1526.48			
97	105.1436	8105.1436	1552.31			
98	111.1439	8111.1439	1576.99			
99	113.5186	8113.5186	1584.43			
100	119.5189	8119.5189	1602.08			
101	122.5686	8122.5686	1610.83			
102	128.5689	8128.5689	1625.95			
103	132.3936	8132.3936	1637.55			
104	138.3939	8138.3939	1656.49			
105	142.9436	8142.9436	1672.10			
106	148.9439	8148.9439	1687.70			
107	154.3353	8154.3353	1701.39			
108	160.3356	8160.3356	1717.73			
109	166.6686	8166.6686	1741.37			
110	172.6689	8172.6689	1758.30			
111	179.8186	8179.8186	1769.76			
112	185.8189	8185.8189	1787.18			
113	194.2019	8194.2019	1806.79			
114	200.2022	8200.2022	1818.87			
115	206.2025	8206.2025	1837.06			
116	209.5686	8209.5686	1843.11			
117	215.5689	8215.5689	1854.08			
118	221.5692	8221.5692	1862.99			
119	226.3686	8226.3686	1871.54			
120	232.3689	8232.3689	1882.74			
121	238.3692	8238.3692	1894.02			
122	244.5353	8244.5353	1909.20			
123	250.5356	8250.5356	1909.30			
124	256.5358	8256.5358	1925.21			
125	263.8853	8263.8853	1936.26			
126	269.8856	8269.8856	1947.68			

Print Filter Used: Nth Line = 1.000

	Time hr	Cum Time hr	Pressure kPa(a)	Gas Rate $10^3m^3/d$	Oil Rate m^3/d	Water Rate m^3/d
127	275.8858	8275.8858	1954.59			
128	281.8861	8281.8861	1962.76			
129	285.0519	8285.0519	1962.38			
130	291.0522	8291.0522	1974.48			
131	297.0525	8297.0525	1976.25			
132	303.0528	8303.0528	1987.06			
133	307.9186	8307.9186	1991.71			
134	313.9189	8313.9189	1998.48			
135	319.9192	8319.9192	2009.54			
136	325.9194	8325.9194	2019.98			
137	332.2853	8332.2853	2025.92			
138	338.2856	8338.2856	2031.66			
139	344.2858	8344.2858	2036.86			
140	350.2861	8350.2861	2042.74			

Print Filter Used: Nth Line = 1.000

PRESSURE TRANSIENT ANALYSIS

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Spearfish (1015 - 1021 mKB)
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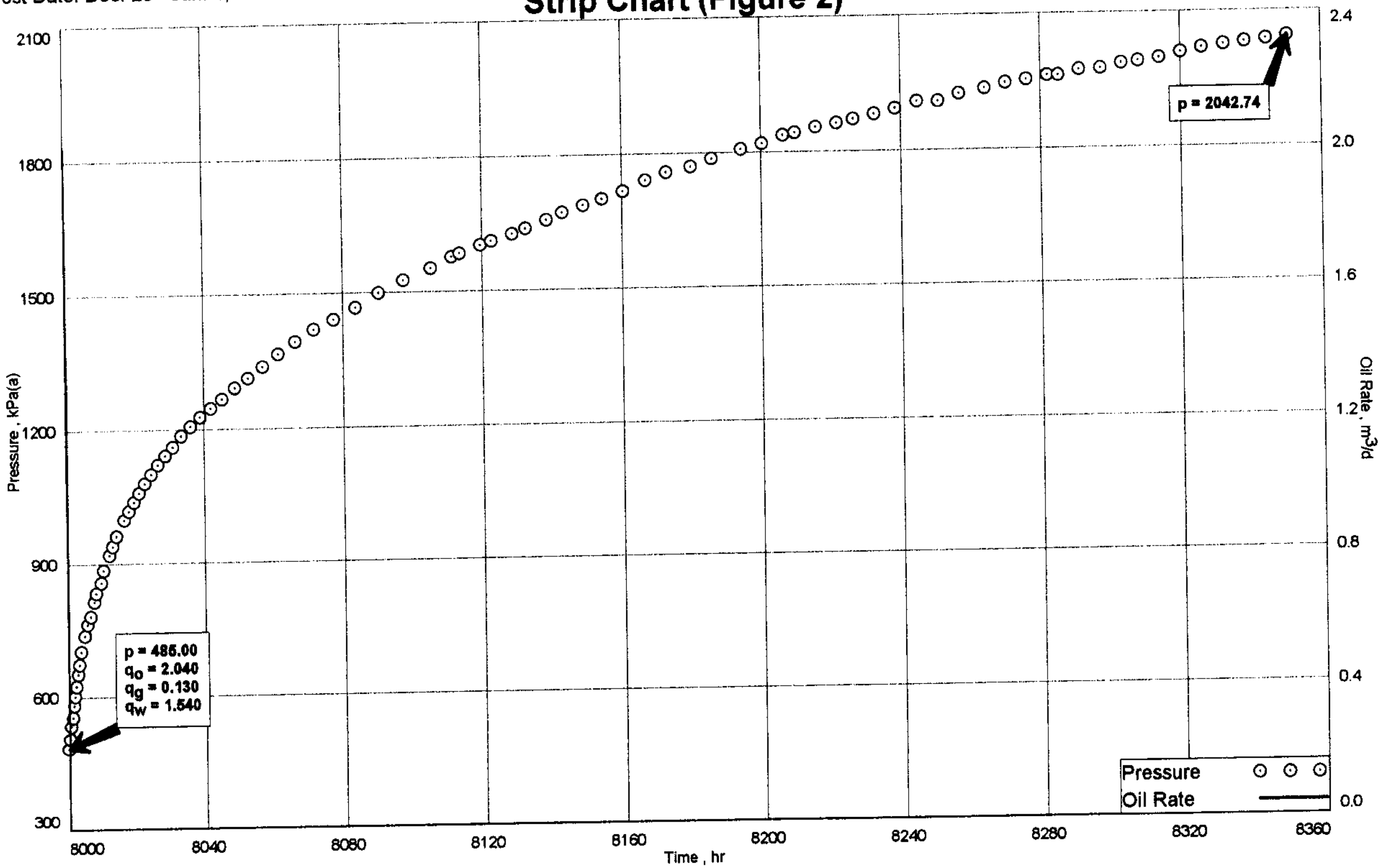
Strip Chart (Figure 2)



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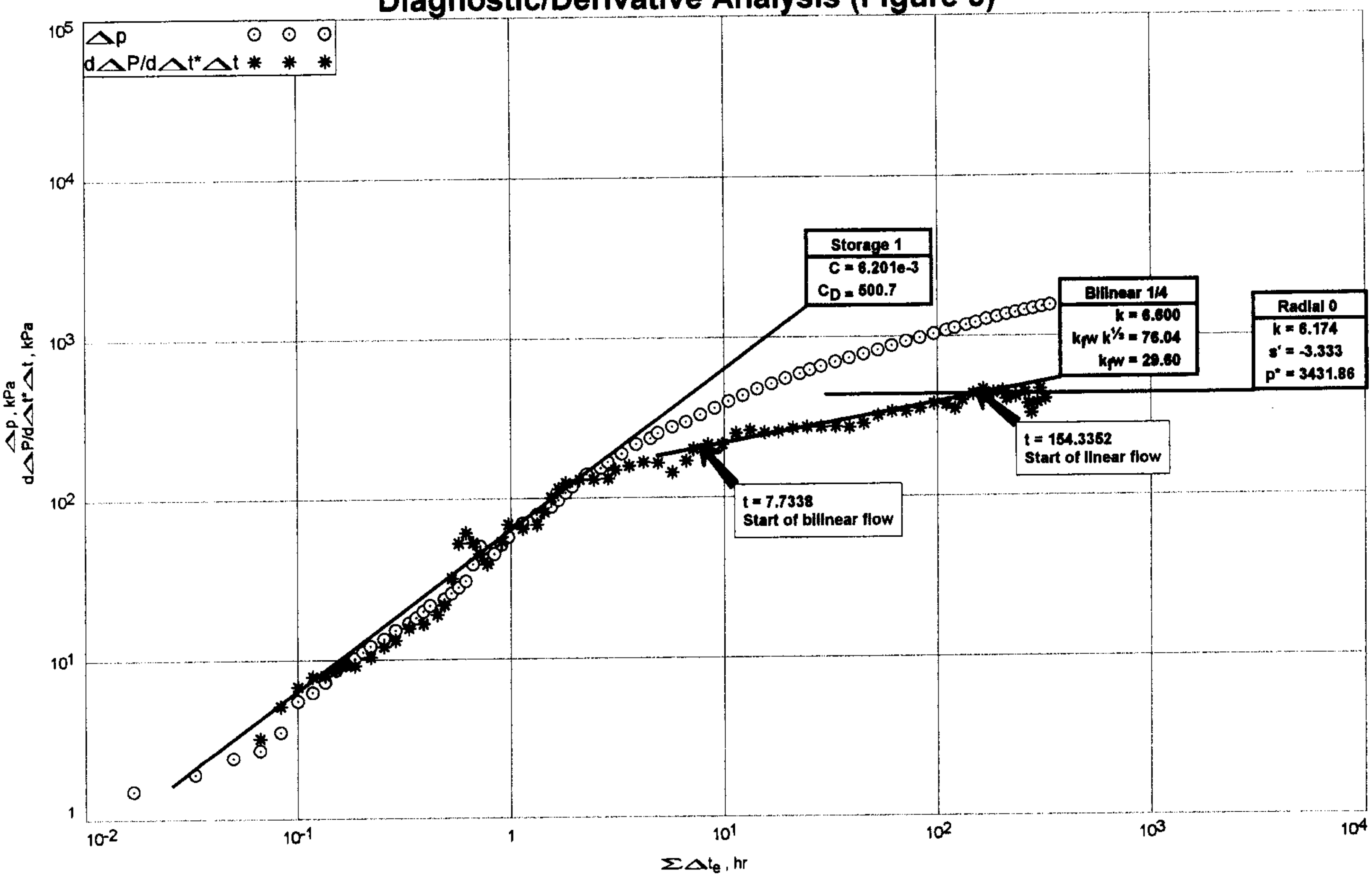
Diagnostic/Derivative Analysis (Figure 3)



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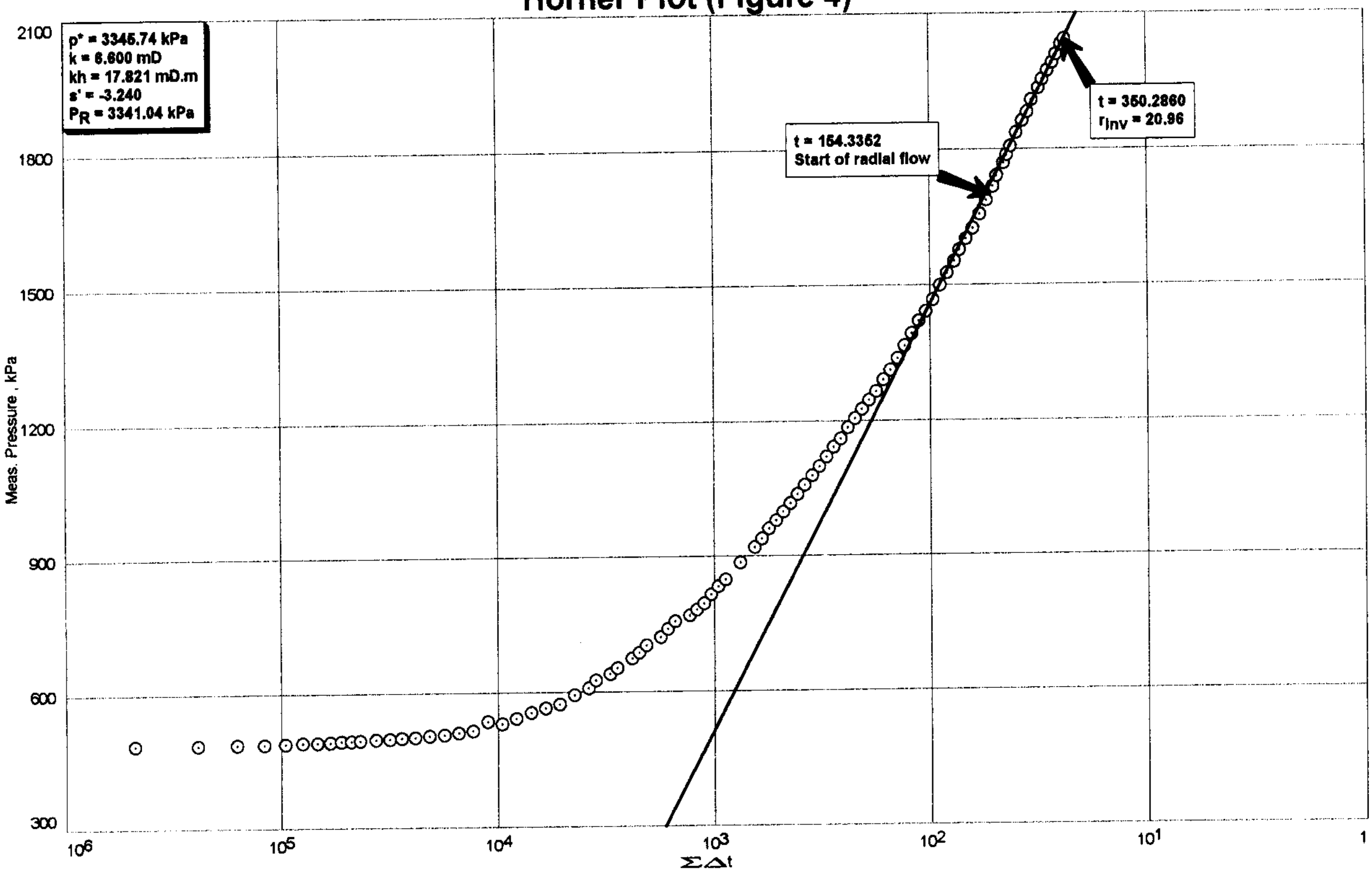
Horner Plot (Figure 4)



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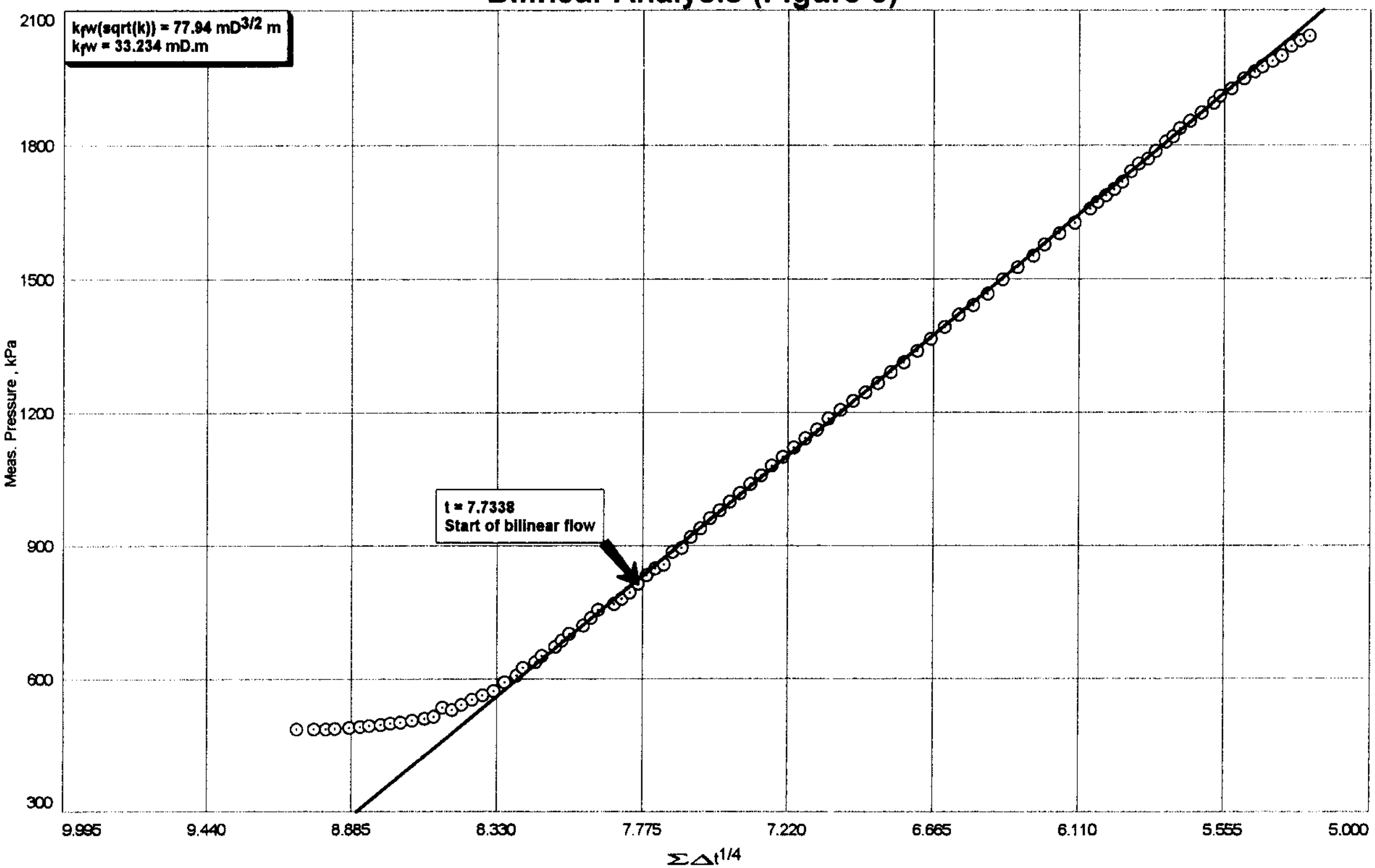
Bilinear Analysis (Figure 5)



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PRESSURE
HISTORY
MATCHING

Finite Conductivity Fracture Oil Well Model

Case Name : Finite Conductivity Fracture #1

Home Pierson 07-16-02-29W1

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Forecasts

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6 - Month Constant Rate	2.022 m^3/d
Specified Forecast Time	12.00 month
Forecast Constant Rate @ Current Skin	1.805 m^3/d
PI / II (Total Liquids - Actual)	1.28e-3 $m^3/d/kPa$
Forecast Constant Rate @ Skin=0	1.813 m^3/d
PI / II (Total Liquids - Ideal)	1.29e-3 $m^3/d/kPa$

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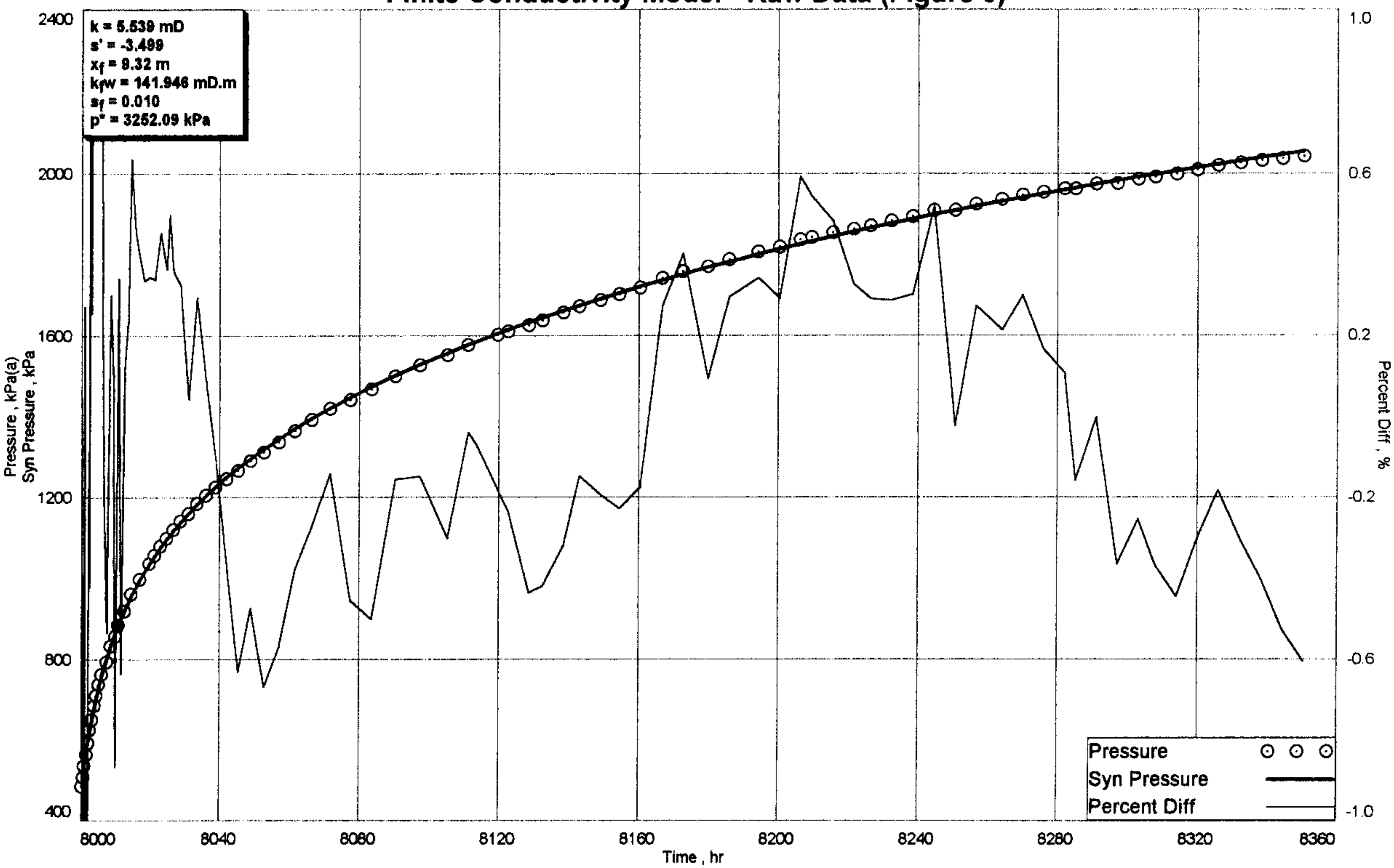
Test Date: Dec. 20 - Jan. 4, 2000

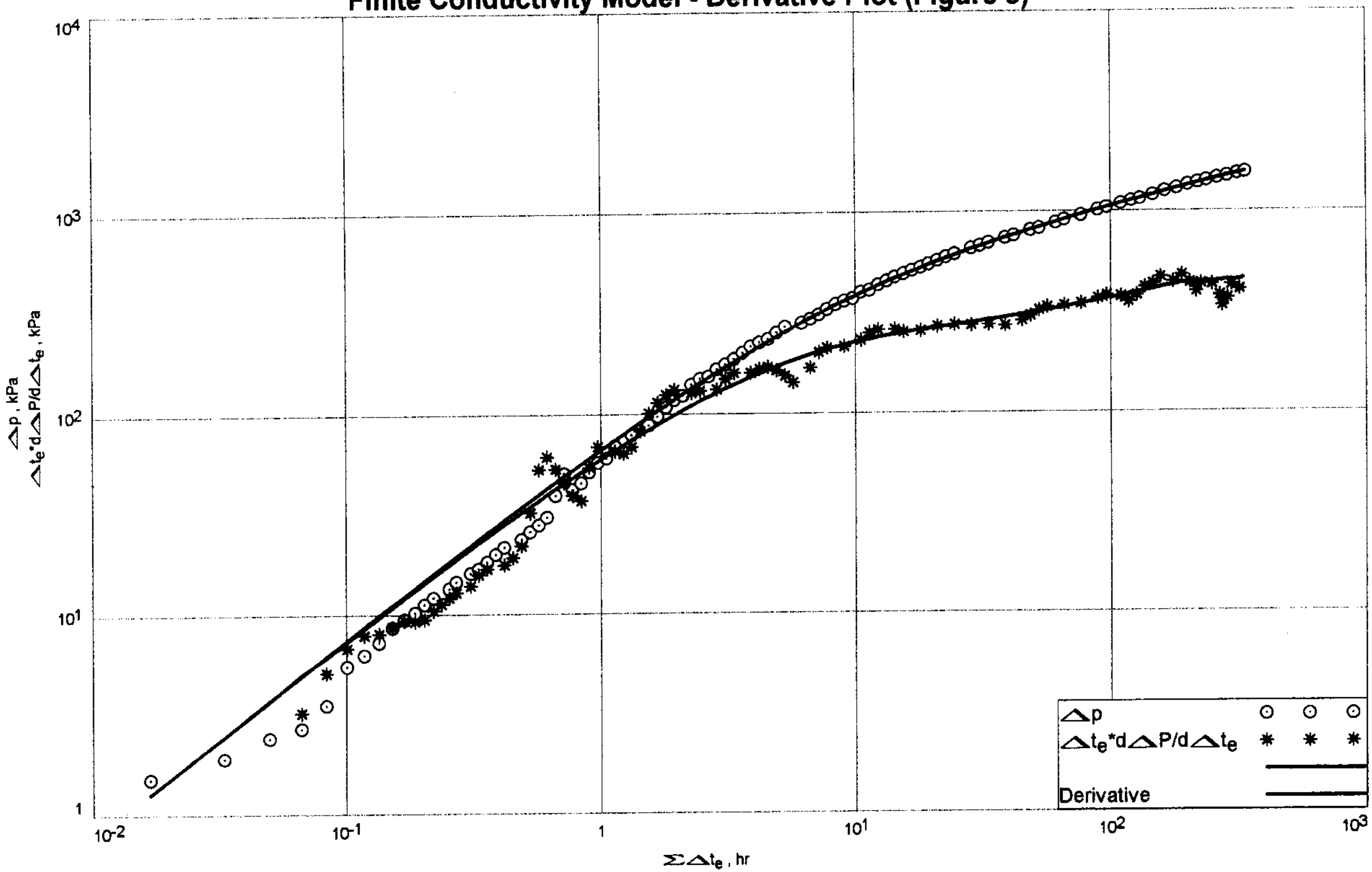
Finite Conductivity Model - Raw Data (Figure 6)



PMG

Home Pierson 07-16-02-29W1
Spearfish (1015 - 1021 mKB)
Flow/Buildup Test
Test Date: Dec. 20 - Jan. 4, 2000

Finite Conductivity Model - Derivative Plot (Figure 8)

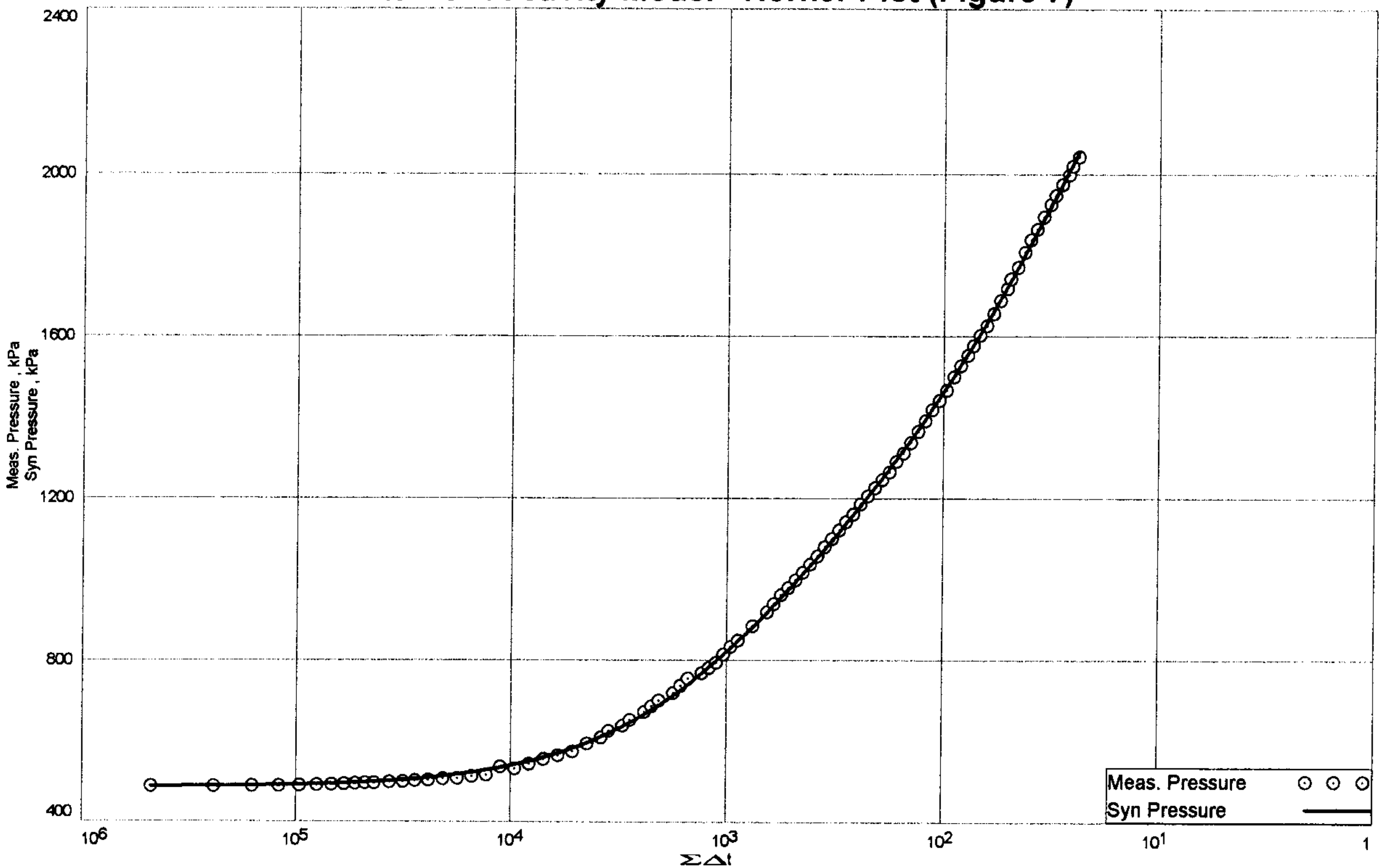


PMG

C:\Data\WellTest\anderson\Pierson\07160229.FKT 07-Jan-00 Ver 2.305

Home Pierson 07-16-02-29W1
Spearfish (1015 - 1021 mKB)
Flow/Buildup Test
Test Date: Dec. 20 - Jan. 4, 2000

Finite Conductivity Model - Horner Plot (Figure 7)

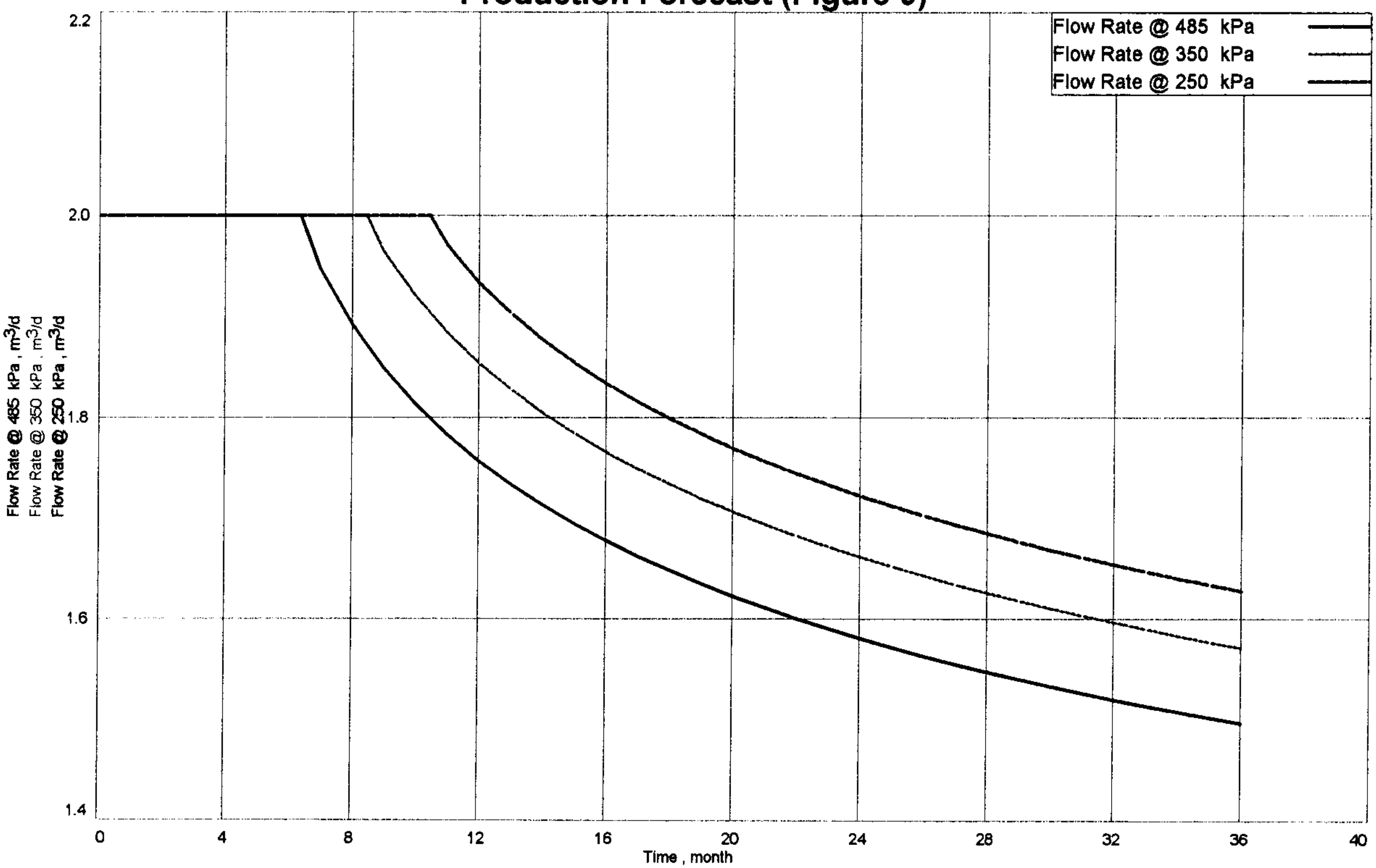


C:\Data\WellTest\anderson\Pierson\07160229.FKT 07-Jan-00 Ver 2.305

P M G

Home Pierson 07-16-02-29W1
Spearfish (1015 - 1021 mKB)
Flow/Buildup Test
Test Date: Dec. 20 - Jan. 4, 2000

Production Forecast (Figure 9)



I.P.R.

Inflow Performance Relationship
(I.P.R.)

Home Pierson 07-16-02-29W1
Spearfish (1015 - 1021 mKB)

Flow/Buildup Test
Test Date: Dec. 20 - Jan. 4, 2000

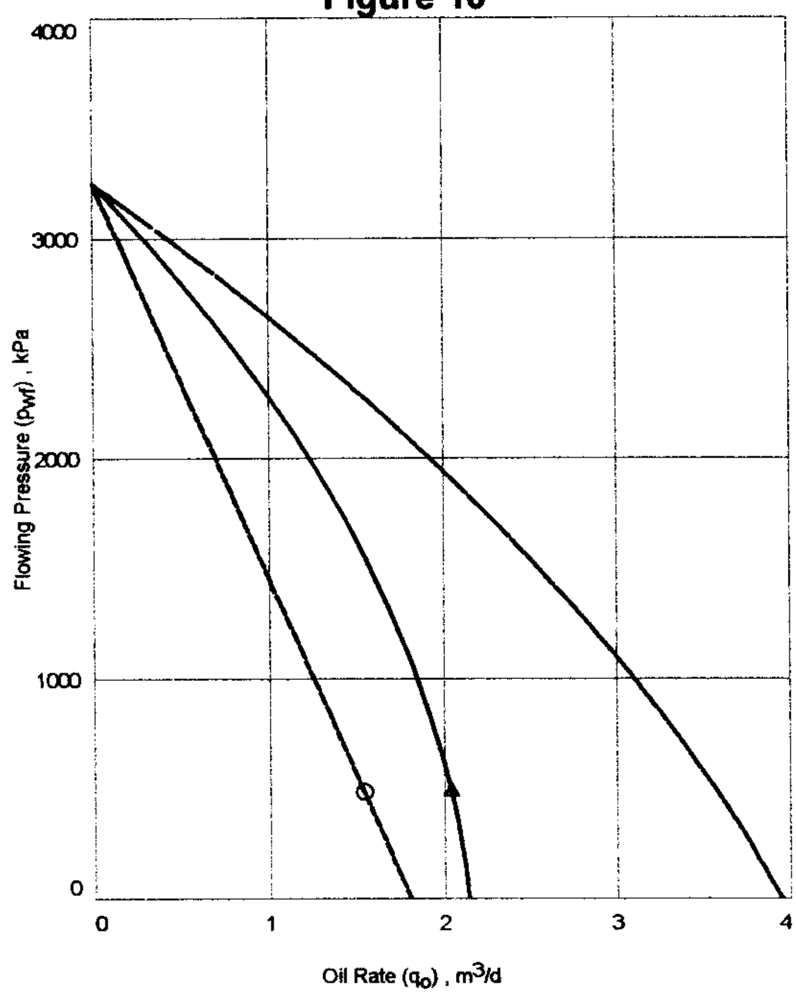
Test Data

Reservoir Pressure (p_R)	3253.00	kPa
Bubble Point Pressure (p_{bp})		kPa
Test Pressure (p_{wf})	485.00	kPa
Oil Test Rate (q_o)	2.040	m^3/d
Water Test Rate (q_w)	1.540	m^3/d

Results

Maximum Oil Rate	2.142	m^3/d
Maximum Water Rate	1.810	m^3/d
Maximum Total Rate	3.952	m^3/d

Figure 10



Flowing Pressure kPa	Oil Rate m^3/d	Water Rate m^3/d	Total Rate m^3/d
0.00	2.142	1.810	3.952
300.00	2.088	1.643	3.731
485.00*	2.040	1.540	3.580
600.00	2.005	1.476	3.481
900.00	1.892	1.309	3.201
1200.00	1.751	1.142	2.893
1500.00	1.580	0.975	2.555
1800.00	1.380	0.808	2.189
2100.00	1.151	0.641	1.793
2400.00	0.893	0.475	1.368
2700.00	0.606	0.308	0.914
3000.00	0.289	0.141	0.430
3253.00	0.000	0.000	0.000

Note : * Test Point
** Bubble Point
Oil IPR based on Vogel's Equation.
(Quadratic Curve Factor=0.2)

EQUATIONS

and

NOMENCLATURE

(METRIC UNITS)

BASIC TIME FUNCTIONS

Flow Time	t
Shut-In Time	Δt
Horner Time	$\frac{t + \Delta t}{\Delta t}$
Superposition Time	$t_n = \sum_{j=1}^{n} \frac{q_j - q_{j-1}}{q_n} \log(t - t_{j-1})$
	$\Delta t_n = \sum_{j=1}^{n} \frac{q_j}{q_n} \log \frac{t_n + \Delta t - t_{j-1}}{t_n + \Delta t - t_j}$
Equivalent Time	$\Delta t_e = \frac{t \cdot \Delta t}{t + \Delta t}$
Root Time	$\sqrt{t}$
	$\sqrt{\Delta t}$
Tandem Root Time	$\sqrt{t + \Delta t} - \sqrt{\Delta t}$

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BASIC TIME FUNCTIONS (cont'd)

Quad Root Time	$\sqrt[4]{t}$
	$\sqrt[4]{\Delta t}$
Tandem Quad Root Time	$\sqrt[4]{t+\Delta t} - \sqrt[4]{\Delta t}$

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TYPECURVES - DIMENSIONLESS VARIABLES

$$\Delta p_D = \frac{(kh/\mu)_t \ \Delta p}{141.2 \ q_t \ B_t}$$

$$t_D = \frac{2.637E{-4}(k/\mu)_t \ t}{\phi c r_w^2}$$

$$\frac{t_D}{C_D} = 0.000295 \ (\frac{kh}{\mu})_t \frac{t}{C}$$

$$C_D e^{2s} = \frac{0.8936 \ C \ e^{2s}}{\phi c h r_w^2}$$

$$t_{DA} = \frac{2.637E{-4} \ (k/\mu)_t \ t}{\phi c A}$$

$$t_{Dxf} = \frac{2.637E{-4} \ (k/\mu)_t \ t}{\phi c x_f^2}$$

$$(k_f w)_D = \frac{k_f w}{k x_f}$$

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McKINLEY ANALYSIS

Wellbore Capacity

$$F = \left(\frac{\Delta p\ F}{qB}\right)\left(\frac{qB}{\Delta p}\right)$$

Alpha

$$\alpha = \frac{F}{5.615}$$

Note: Alpha is the same as C

Wellbore Storage Constant
Compressible Fluid

$$C = c_{ws} V_{ws}$$

Wellbore Storage Constant
Changing Liquid Level

$$C = \frac{cross\text{-}sectional\ area}{5.615\ liquid\ gradient}$$

Transmissivity

$$\frac{kh}{\mu} = \left(\frac{\mathrm{T}}{F}\right) F$$

Pressure Drop Skin

$$\Delta p_s = \left[1 - \frac{kh_{(wellbore)}}{kh_{(formation)}}\right] \Delta p_{(departure)}$$

Flow Efficiency

$$FE = \frac{p^* - p_{wf} - \Delta p_s}{p^* - p_{wf}}$$

SEMILOG ANALYSIS

Transmissivity

$$\left(\frac{kh}{\mu}\right)_t = \frac{162.6\ q_t\ B_t}{m}$$

Permeability

$$k = \frac{162.6\ q_o\ B_o\ \mu_o}{mh}$$

Skin Factor

$$s' = 1.151\left[\frac{p_{ws} - p_{wfo}}{m} - \log\frac{t\Delta t}{t+\Delta t} - \log\left(\frac{(k/\mu)_t}{\phi_t c_t r_w^2}\right) + 3.23\right]$$

Pressure Drop due to Skin

$$\Delta p_s = 0.869\ ms'$$

Flow Efficiency

$$FE = \frac{\bar{p}_R - p_{wfo} - 0.869\ ms'}{\bar{p}_R - p_{wfo}}$$

Damage Ratio

$$DR = \frac{1}{FE}$$

Radius of Investigation

$$r_{inv} = \sqrt{\frac{(k/\mu_t)\ t}{948\phi_t c_t}}$$

Time to Stabilization

$$t_s = \frac{\phi\ c\ A}{2.637E\text{-}4\ (k/\mu)_t}(t_{DA})_{pss}$$

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SEMILOG ANALYSIS (cont"d)

Stabilized Rate

$$q_s = \frac{p_i - p_{wfo}}{\frac{162.6\ B_o}{(k/\mu)_o\ h}\left(\log\left(\frac{4A}{1.781\ r_w^2 C_A}\right) + \frac{4\pi (t_{DA})_{pss}}{2.303} + \frac{2s'}{2.303}\right)}$$

Productivity Index

$$P\ I = \frac{q}{\bar{p}_R - p_{wfo}}$$

MBH Average Pressure

$$\bar{p}_R = p^* - \frac{m}{2.303}\ (MBH\ function)$$

DIETZ Average Pressure

$$(\Delta t)_{\bar{p}_R} = \frac{\phi\ c_t\ A}{2.637E{-4}\ C_A (k/\mu)_t}$$

LINEAR ANALYSIS

Fracture half-length

$$x_f = \frac{4.064\ q_t\ B_t}{mh(\phi c k/\mu)_t^{1/2}}$$

Channel width

$$W = \frac{8.128\ q_t\ B_t}{mh(\phi c k/\mu)_t^{1/2}}$$

Skin Factor

$$s = \ln \frac{2\ r_w}{x_f}$$

BI-LINEAR ANALYSIS

Fracture Conductivity

$$k_f w = \left[\frac{44.1\ qB\mu}{mh(\phi\mu c k)^{1/4}}\right]^2$$

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NOMENCLATURE

Symbol	Description	Metric (SI)	Field
a	LIT flow equation coefficient	-	-
A	drainage area	m^2	ft^2
AOF	absolute open flow potential (gas)	$10^3 m^3/d$	MMcfd
b	LIT flow equation coefficient	-	-
B	formation volume factor	-	-
c	compressibility	kpa^{-1}	psi^{-1}
c_{ws}	compressibility of wellbore fluids	kpa^{-1}	psi^{-1}
C	wellbore storage/unloading constant	m^3/kPa	bbl/psi
C	simplified flow equation coefficient	-	-
C_A	shape factor	-	-
C_{aD}	apparent wellbore storage constant	-	-
C_D	dimensionless wellbore storage constant	-	-
C_{pD}	storage pressure parameter	-	-
DR	damage ratio	-	-
F	wellbore capacity (McKinley)	m^3/kPa	ft^3/psi
FE	flow efficiency	-	-
G	relative density (gas)	-	-
GOR	gas-oil ratio	m^3/m^3	ft^3/bbl
h	net pay	m	ft
k	permeability	mD	md
$k_{(x,y,z)}$	permeability in the x,y,z direction	mD	md
k_f	fracture permeability	mD	md
$k_f w$	fracture conductivity	mD.m	md.ft
kh	flow capacity	mD.m	md.ft
k/μ	mobility	-	-
kh/μ	transmissivity	-	-

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Symbol	Description	Metric (SI)	Field
L	length of horizontal well	m	ft
L_e	effective length of horizontal well	m	ft
m	slope of transient plots	-	-
n	simplified flow equation coefficient	-	-
p	pressure	kPa	psia
p_{bp}	bubble point pressure	kPa	psia
p_c	gas pseudo-critical pressure	kPa	psia
p_i	initial pressure	kPa	psia
p_R	average reservoir pressure	kPa	psia
p_{tf}	flowing wellhead pressure	kPa	psia
p_{ts}	shut-in wellhead pressure	kPa	psia
p_{wf}	flowing sandface pressure	kPa	psia
P_{wfo}	final flowing pressure	kPa	psia
p_{ws}	shut-in sandface pressure	kPa	psia
p^*	extrapolated pressure	kPa	psia
Δp_D	dimensionless pressure	-	-
Δp	pressure drop	kPa	psi
PI	productivity index	$m^3/d/kPa$	bbl/d/psi
q	flow rate - gas - liquid	$10^3 m^3/d$ m^3/d	MMcf/d bbl/d
q_j	j^{th} flow rate	m^3/d	bbl/d
q_n	n^{th} flow rate	m^3/d	bbl/d
q_s	stabilized rate - gas - liquid	$10^3 m^3/d$ m^3/d	MMcf/d bbl/d
r_e	external radius	m	ft
r_{inv}	radius of investigation	m	ft
r_w	wellbore radius	m	ft
R_s	solution gas ratio	m^3/m^3	ft^3/bbl

Symbol	Description	Metric (SI)	Field
s	skin factor	-	-
s'	apparent skin factor	-	-
S	saturation (oil, gas, water)	-	-
t	time	hr	hr
t_D	dimensionless time	hr	hr
t_a	pseudo-time	hr	hr
t_{DA}	dimensionless time (based on drainage area)	hr	hr
t_{Dxf}	dimensionless time (based on fracture 1/2 length)	hr	hr
t_n	n^{th} flow period, or superposition time	-	-
Δt	shut-in time	hr	hr
Δt_a	shut-in pseudo-time	hr	hr
Δt_e	equivalent time	hr	hr
$(t_{DA})_{pss}$	dimensionless time at pseudo-steady state	-	-
t_s	time to stabilization	hr	hr
T	temperature	K	°R
T_c	gas pseudo-critical temperature	K	°R
V_{ws}	wellbore volume - gas - liquid	m^3 m^3	ft^3 bbl
W	channel width	m	ft
w	fracture width	m	ft
x_e	length of reservoir	m	ft
x_f	fracture half-length	m	ft
x_o	x -location of observation well	m	ft
x_w	x- location of centre of active well	m	ft
y_e	width of reservoir	m	ft
y_o	y- location of observation well	m	ft
y_w	y- location of centre of active well	m	ft
Z	gas compressibility factor	-	-
z_w	z-location of centre of active well	m	ft

Symbol	Description	Metric (SI)	Field
α	wellbore storage/unloading constant	m^3/kPa	bbl/psi
μ	viscosity - gas - liquid	$\mu Pa.s$ mPa.s	cp cp
λ	inter-porosity flow coefficient	-	-
T	transmissivity (McKinley)	mD.m/mPa.s	md.ft/cp
ϕ	porosity	-	-
Ψ	pseudo-pressure	$kPa^2/\mu Pa.s$	$psia^2/cp$
ω	storativity ratio	-	-

Subscripts

D	dimensionless
DA	dimensionless based on area
Dxf	dimensionless based on fracture half -length
f	formation or flowing
g	gas
i	initial
o	oil
R	reservoir
s	shut-in, skin, stabilized or storage
t	total, transient, or wellhead (tubing head)
w	water or wellbore (sandface)
ref	evaluated at reference pressure

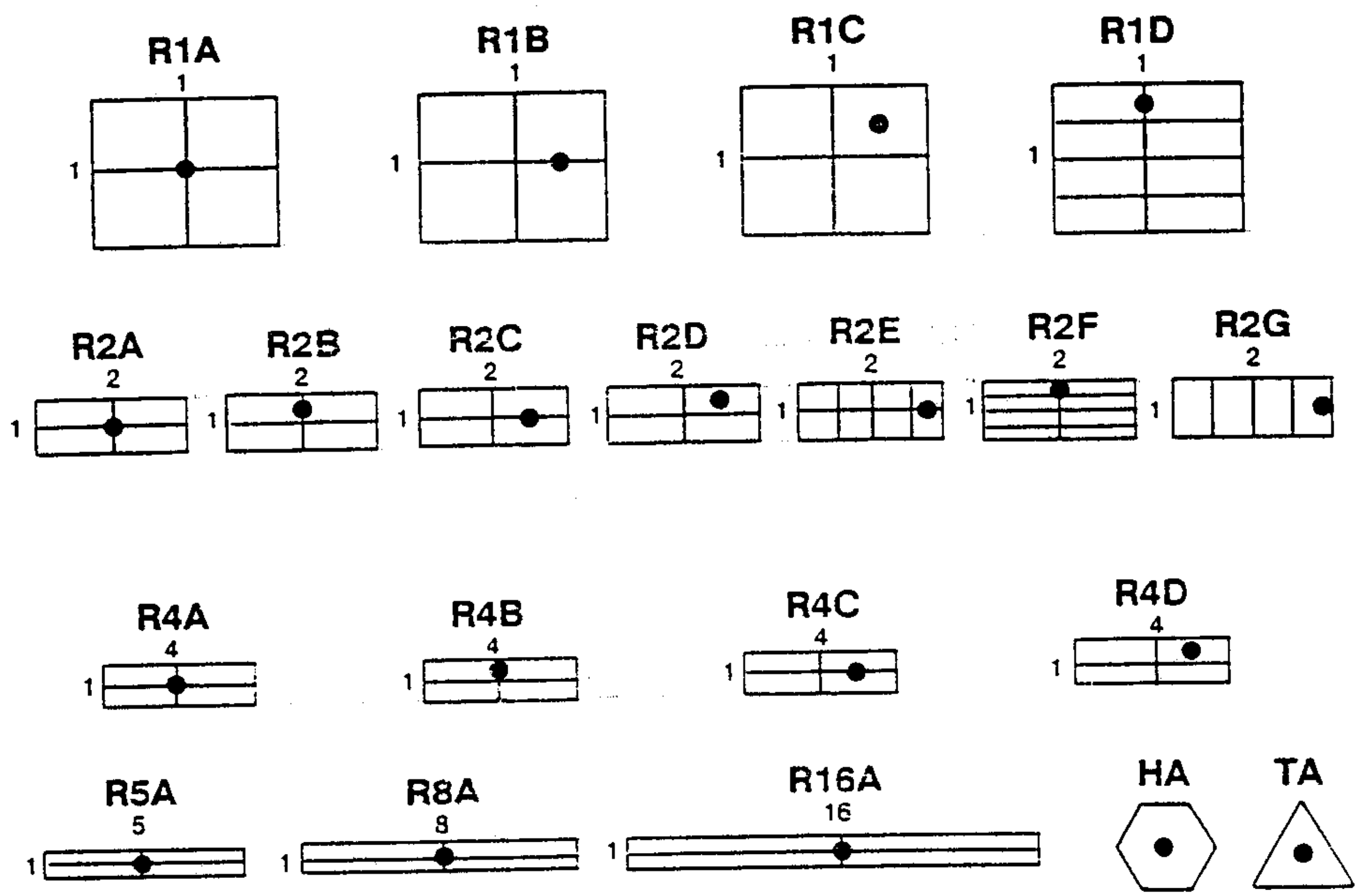
Superscripts

-	average

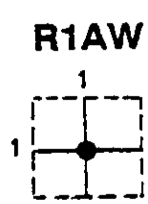
DIETZ SHAPE CODES

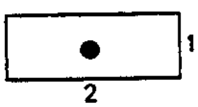
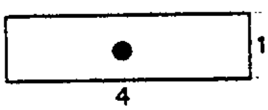
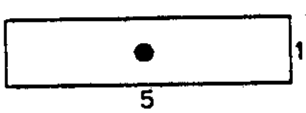
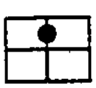
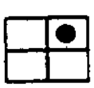
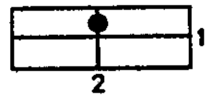
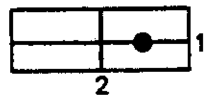
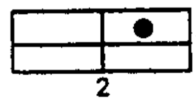
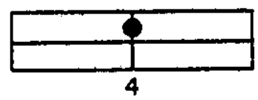
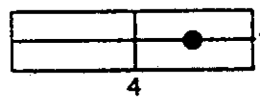
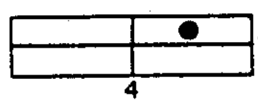
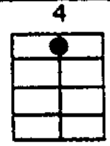
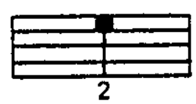
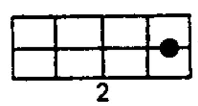
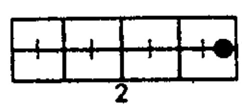
AVERAGE RESERVOIR PRESSURE - MBH CORRECTIONS

NO FLOW OUTER BOUNDARY



CONSTANT PRESSURE OUTER BOUNDARY



	$\ln C_A$	C_A	STABILIZED CONDITIONS FOR t_{DA} >
IN BOUNDED RESERVOIRS			
	3.45	31.6	0.1
	3.43	30.9	0.1
	3.45	31.6	0.1
	3.32	27.6	0.2
	3.30	27.1	0.2
	3.09	21.9	0.4
	3.12	22.6	0.2
	1.68	5.38	0.7
	0.86	2.36	0.7
	2.56	12.9	0.6
	1.52	4.57	0.5
	2.38	10.8	0.3
	1.58	4.86	1.0
	0.73	2.07	0.8
	1.00	2.72	0.8
	-1.46	0.232	2.5
	-2.16	0.115	3.0
	1.22	3.39	0.6
	1.14	3.13	0.3
	-0.50	0.607	1.0
	-2.20	0.111	1.2
	-2.32	0.098	0.9
IN WATER DRIVE RESERVOIRS			
	2.95	19.1	0.1
IN RESERVOIRS OF UNKNOWN PRODUCTION CHARACTER			
	3.22	25	0.1

PSEUDO-STEADY STATE SHAPE FACTORS FOR VARIOUS RESERVOIRS

FROM DIETZ (1965)

PMG

UNITS CONVERSION AND PREFIXES

METRIC (SI) UNIT	FIELD UNIT	DIVIDED BY
$10^3 m^3/d$	MMcfd	2.817 399 E+01
kPa	psia	6.894 757 E+00
mD	md	9.869 233 E-01
mD.m	md.ft	3.008 142 E-01
m	ft	3.048 E-01
m^3	bbl (35 Imp gal) (42 US gal)	1.589 873 E-01
Pa.s	cp	1.0 E+03
°C	°F	(°F-32)5/9 E+00
K	°R	5/9 E+00
m^2	section (640 acres)	2.589 988 E+06
ha	section (640 acres)	2.589 988 E+02
m^3	gallon (Imp)	4.546 09 E-03
m^3	gallon (US)	3.785 412 E-03
$m^3/10^3 m^3$	bbl/MMcf	5.643 052 E-03

Standard conditions: Metric (SI) 15°C, 101.325 kPa
Field 60°F, 14.65 psia

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