

**FINGAL 55B
DRILL STEM TEST
FINAL REPORT
“G UPPER & G LOWER” ZONE COAL SEAMS
OPEN HOLE INTERVAL
342.5 – 343.5 & 346.7 – 347.9 mGL
JUNE 10 – 11, 2007**

**Prepared for:
Pure Energy Resources Limited**



**Prepared by:
Focal Petroleum Engineering Pty Ltd.**

July 11, 2007

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Pure Energy Resources Limited
P.O. Box 952
SOUTH PERTH, WA 6951

Attention: Mr. Steve Beardsall

Dear Sir

Re: Fingal 55b Coal "G Upper & G Lower" Drill Stem Test Report

The following is a summary of the results obtained from the Drill Stem Test conducted from June 10 - 11, 2007 over the "G upper and G lower" Coals, open hole interval from circa 342.5 – 343.5 and 346.75 – 347.9 mGL.

The DST was conducted through the drillpipe and coring bit, using an off bottom inflatable packer. Prior to testing, 195 meters of water was displaced from the drillpipe with air to allow inflow from the reservoir to occur.

The test was comprised of a 60 minute flow period followed by a 15.5 hour buildup period (recorders left overnight). A low flow gas meter was used to measure the gas recovery and a fluid recorder in the drill pipe was used to establish daily water production volumes (bbl/day) from the inflow of water into the wellbore.

During the inflation of the isolation packers, a rapid increase in pressure was noted below the packer suggesting that the permeability within the test interval was low.

During the shut-in procedure (raising the drill string 70mm) for the downhole tool, a small drop in pressure was noted to start the buildup. This is likely the result of some upward movement by the packer, creating a small amount of suction in the wellbore.

Comments and Conclusions

- The pressure response observed during the flow and buildup periods suggested a reservoir with low flow capacity to water. Since the inflow from the reservoir was predominantly water, the test was analysed as a water well. The gas volume recovered was insignificant (< 1 cf) and was not used in the interpretation.
- The gross net pay of 6.9 ft (2.1 m) was obtained from the core samples (G upper 3.3 ft, G lower 3.6 ft). A default porosity of 2% was used for the interpretation.
- An average water rate of circa 1.5 bbl/d was calculated using the pressure increase from the inflow of water into the wellbore during the flow period.
- A reservoir pressure (P_i) of 371 psia was determined from the simulation. The subject reservoir is slightly under-pressured, with a reservoir gradient of 0.34 psi/ft.
- The pressure derivative indicated that wellbore storage was overcome by zero slope (near wellbore radial flow) about 12 minutes after shut-in. At about 1 hour after shut-in, the derivative began to follow a downward trend. At about six hours after shut-in, the derivative flattened a second time into zero slope (outer area radial flow) that remained for the duration of the test.
- Conventional analysis and Simulation were both conducted. The late-time zero slope of the pressure derivative was attributed to an increase in flow capacity (k and/or h) commencing about 15 feet away from the wellbore. Although there is about three meters separating the G seams, any indication of individual flow capacity was masked by the increase (three times) in total flow capacity. The buildup was simulated and matched using a radial composite model. The results compared well with the conventional analysis and have been quoted throughout this report.
- The positive skin value is considered moderate and is likely attributed to coal fines in the near wellbore region.

A summary of the Test Results is as follows:

Average Reservoir Pressure (Pr) @ 337.3 mGL 371 psia (simulation)

Apparent Skin Factor +2.3

Near Wellbore Zone

Average Permeability to Water 0.9 md

Flow Capacity to Water 6 md.ft

Radius of Investigation 16 ft

Outer Area Zone

Average Permeability to Water 3.1 md

Flow Capacity to Water 21.7 md.ft

Radius of Investigation 29 ft

If further clarification of the test interpretation is required, please contact the undersigned on (08) 94749622.

Yours faithfully,

FOCAL PETROLEUM ENGINEERING PTY LTD

Ryan Gee

WELL TEST CONSULTANT

Terry Primeau

MANAGING DIRECTOR

LIST OF FIGURES

Figure 1 – Validata Plot

Figure 2 – Strip Chart

Figure 3 – Conventional Log-Log Plot

Figure 4 – Conventional Semi-Log Plot

Figure 5 – Conventional Results 1 – Near Wellbore Zone

Figure 6 – Conventional Results 2 – Outer Area Zone

Figure 7 – Simulation Match – Strip Chart

Figure 8 – Simulation Match – Log-Log Plot

Figure 9 – Simulation Match – Semi-Log Plot

Figure 10 – Simulation Results

Fingal 55B
June 10 - 11, 2007

Packer Depth @ 341.2 mGL
Formation: G upper & lower

Validata

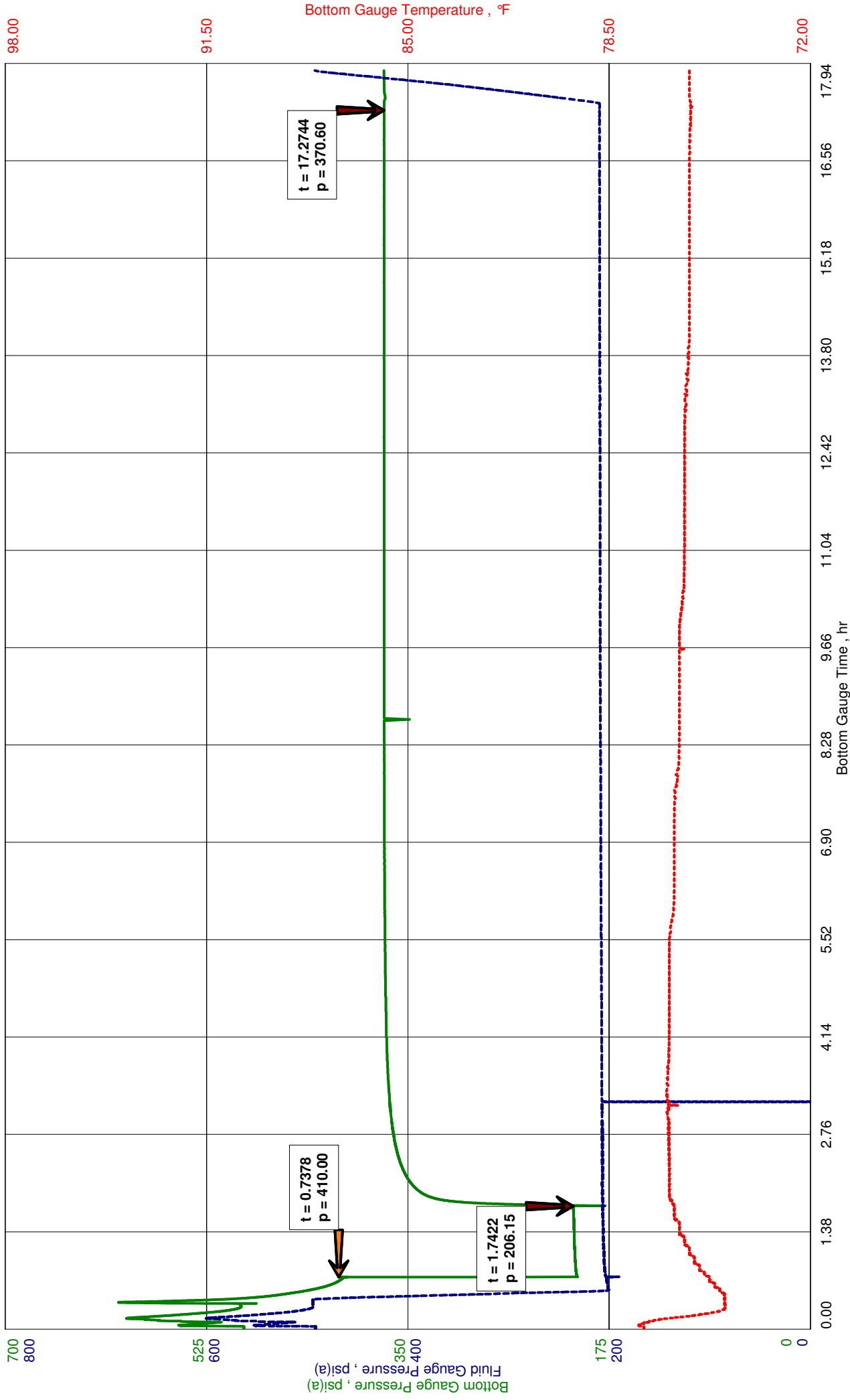
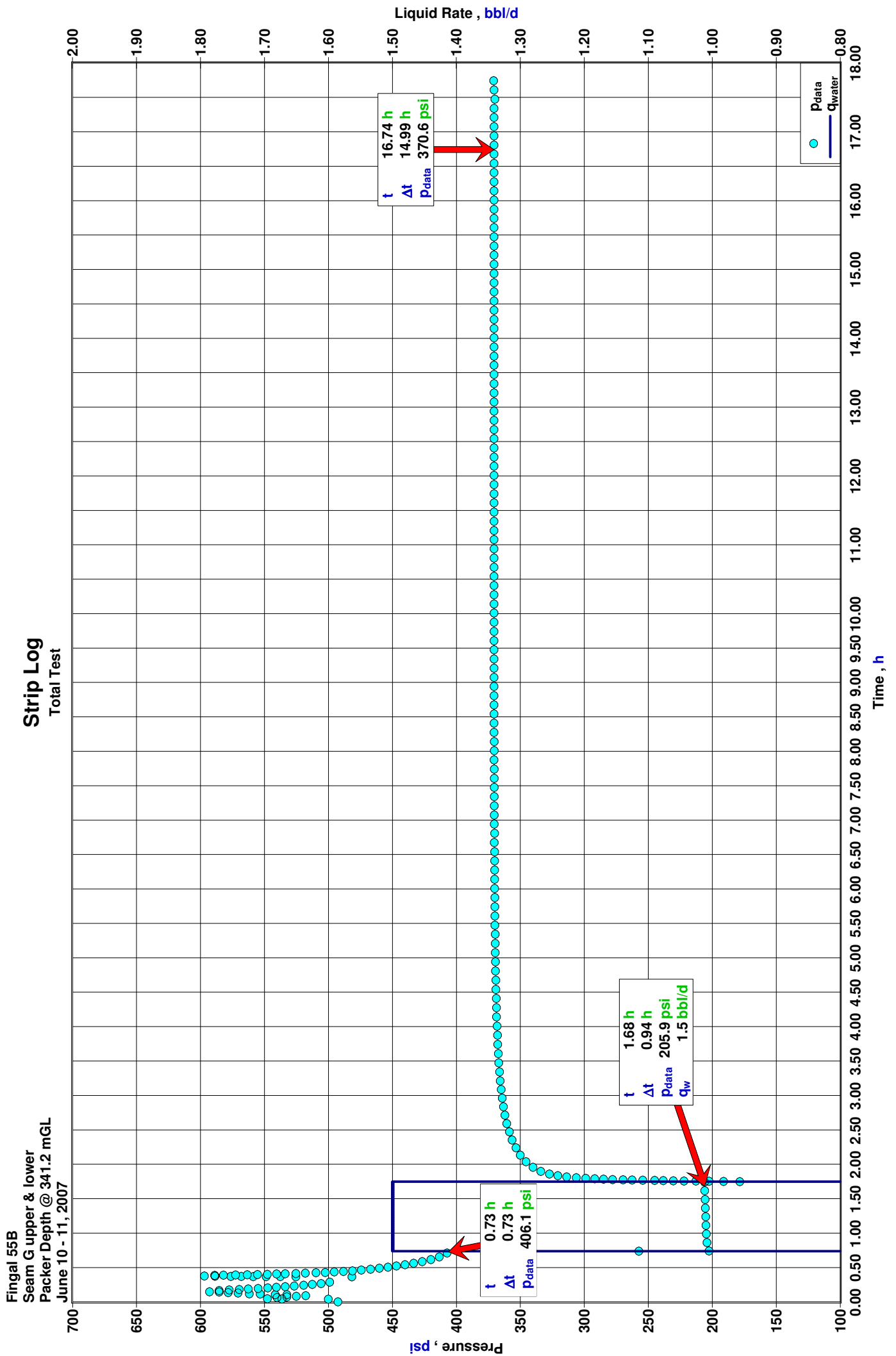


Figure 1

Figure 2



Fingal 55B
Seam G upper & lower
Packer Depth @ 341.2 mGL
June 10 - 11, 2007

Diagnostic Analysis

Typecurve

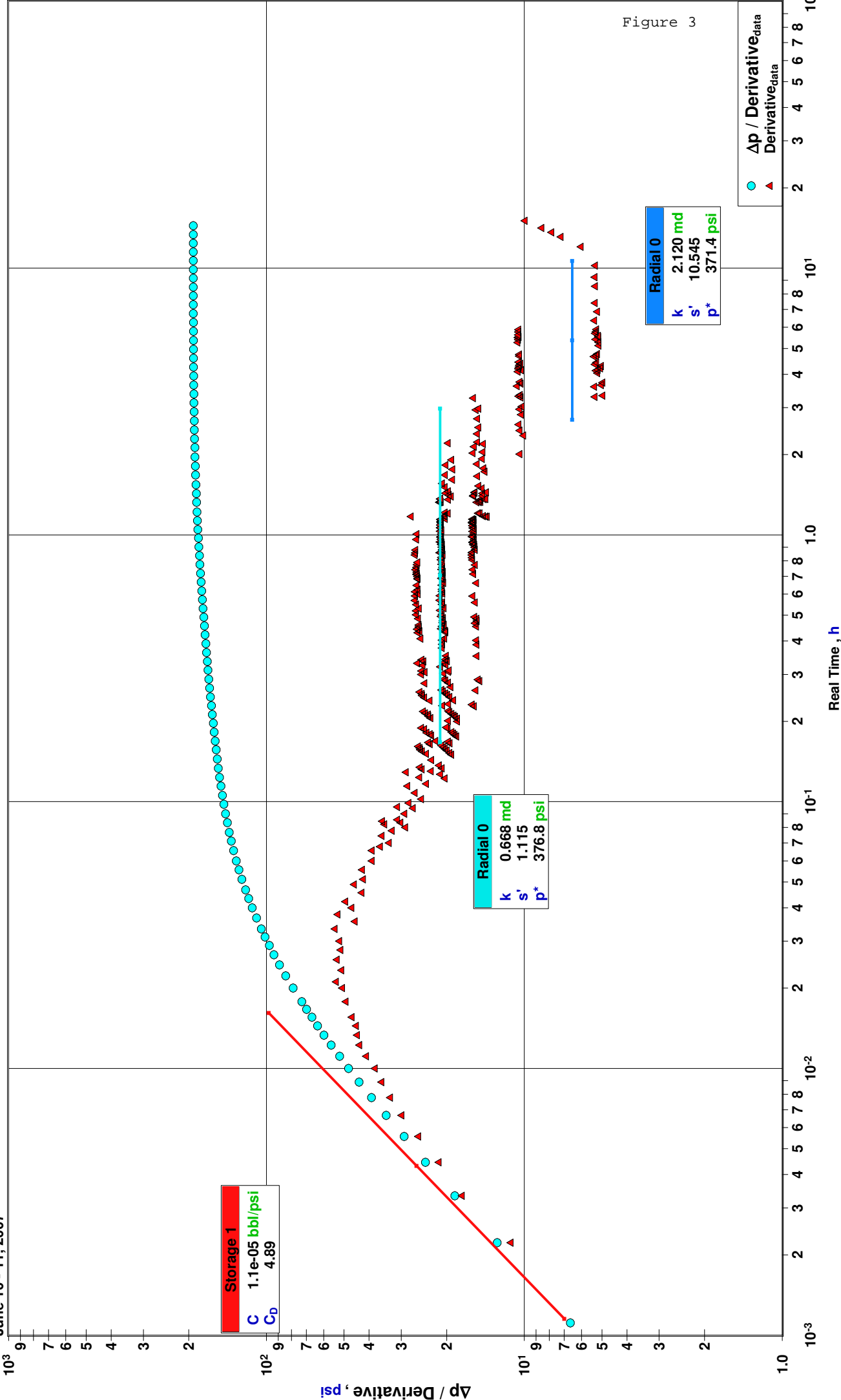
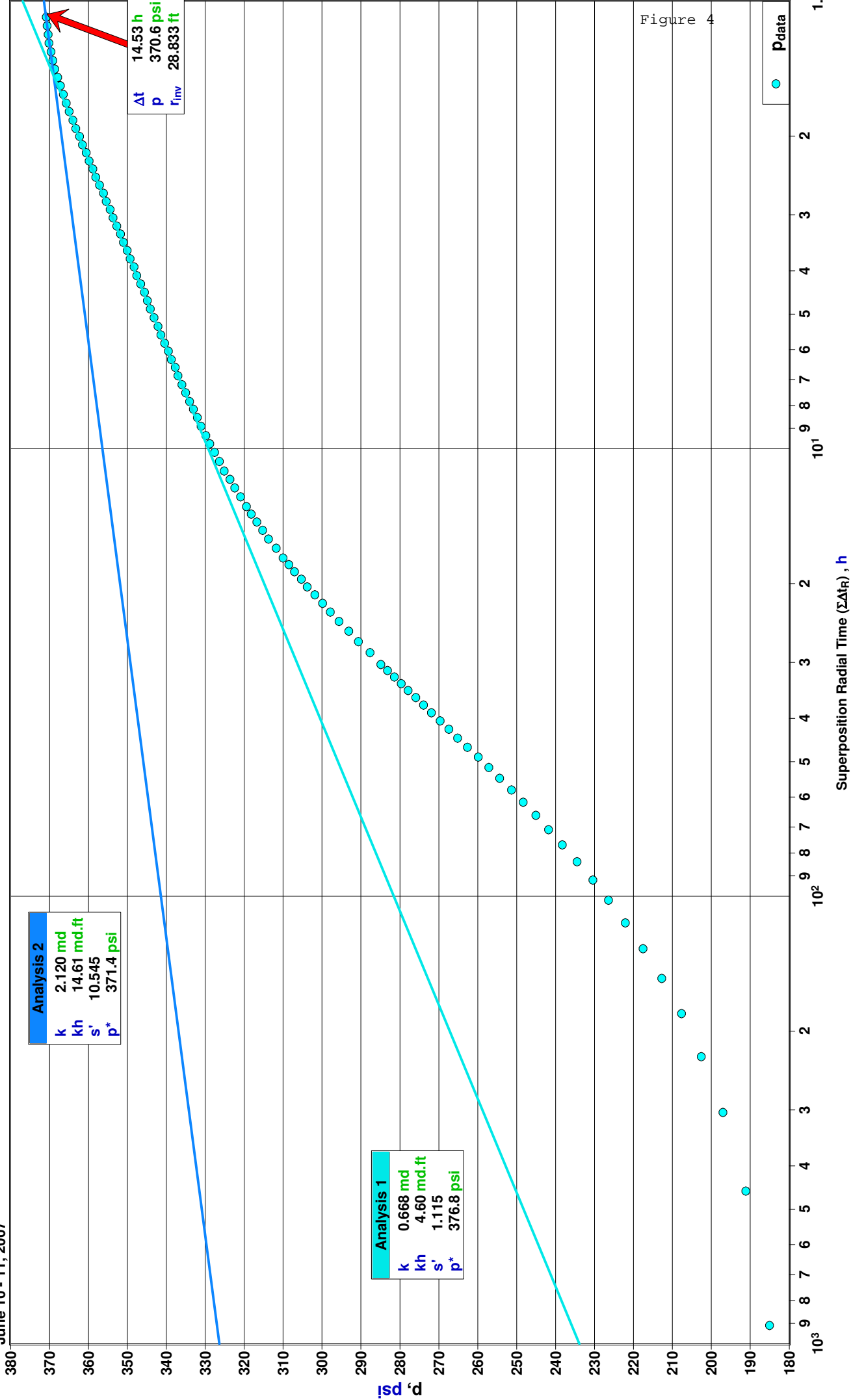


Figure 3

Fingal 55B
Seam G upper & lower
Packer Depth @ 341.2 mGL
June 10 - 11, 2007

Diagnostic Analysis
Radial



Water Well Test - Buildup

Radial Flow Analysis

Fingal 55B

Packer Depth @ 341.2 mGL

Seam G upper & lower

June 10 - 11, 2007

Analysis Results

Total Sandface Rate ($q_t B_t$)	1.500 bbl/d	Apparent Skin (s')	1.115
Semilog Slope (m)	47.66	Skin - Damage	1.115
Gas Permeability (k_g)	md	Skin - Inclination	
Oil Permeability (k_o)	md	Skin - Partial Penetration	
Water Permeability (k_w)	0.668 md	Pressure Drop Due to Skin (Δp_s)	46.18 psi
Flow Capacity (kh)	4.601 md.ft	Damage Ratio (DR)	1.315
Total Mobility (k/μ_t)	0.74 md/cp	Flow Efficiency (FE)	0.760
Total Transmissivity(kh/μ_t)	5.12 md.ft/cp		

Reservoir Parameters

Net Pay (h)	6.890 ft
Total Porosity (ϕ_t)	2.00 %
Water Saturation (S_w)	95.00 %
Oil Saturation (S_o)	0.00 %
Gas Saturation (S_g)	5.00 %
Wellbore Radius (r_w)	0.30 ft
Formation Temperature (T)	75.9 °F
Formation Compressibility (c_f)	9.482e-6 psi ⁻¹
Total Compressibility (c_t)	1.566e-4 psi ⁻¹

Pressures

Initial Pressure (p_i)	371.00 psi
Extrapolated Pressure (p^*)	376.85 psi
Final Flowing Pressure (p_{wfo})	178.41 psi

Production and Times

Corrected Flow Time (t_c)	1.0100 hr
Cumulative Water Production	0.063 bbl
Final Water Rate	1.500 bbl/d

Fluid Properties

Water Compressibility (c_w)	3.24418e-6 psi ⁻¹
Water Formation Volume Factor (B_w)	1.000
Water Viscosity (μ_w)	0.899 cp
Solution Gas Ratio (R_{sw})	0 scf/bbl
Specific Gravity (G)	1.000
Gas Gravity (G)	0.650
PVT Reference Pressure (p_{pVT})	371.00 psi

Water Well Test - Buildup

Radial Flow Analysis

Fingal 55B

Packer Depth @ 341.2 mGL

Seam G upper & lower

June 10 - 11, 2007

Analysis Results

Total Sandface Rate ($q_t B_t$)	1.500 bbl/d	Apparent Skin (s')	10.545
Semilog Slope (m)	15.01	Skin - Damage	10.545
Gas Permeability (k_g)	md	Skin - Inclination	
Oil Permeability (k_o)	md	Skin - Partial Penetration	
Water Permeability (k_w)	2.120 md	Pressure Drop Due to Skin (Δp_s)	137.54 psi
Flow Capacity (kh)	14.609 md.ft	Damage Ratio (DR)	3.498
Total Mobility (k/μ_t)	2.36 md/cp	Flow Efficiency (FE)	0.286
Total Transmissivity(kh/μ_t)	16.25 md.ft/cp		

Reservoir Parameters

Net Pay (h)	6.890 ft
Total Porosity (ϕ_t)	2.00 %
Water Saturation (S_w)	95.00 %
Oil Saturation (S_o)	0.00 %
Gas Saturation (S_g)	5.00 %
Wellbore Radius (r_w)	0.30 ft
Formation Temperature (T)	75.9 °F
Formation Compressibility (c_f)	9.482e-6 psi ⁻¹
Total Compressibility (c_t)	1.566e-4 psi ⁻¹

Pressures

Initial Pressure (p_i)	371.00 psi
Extrapolated Pressure (p^*)	371.41 psi
Final Flowing Pressure (p_{wfo})	178.41 psi

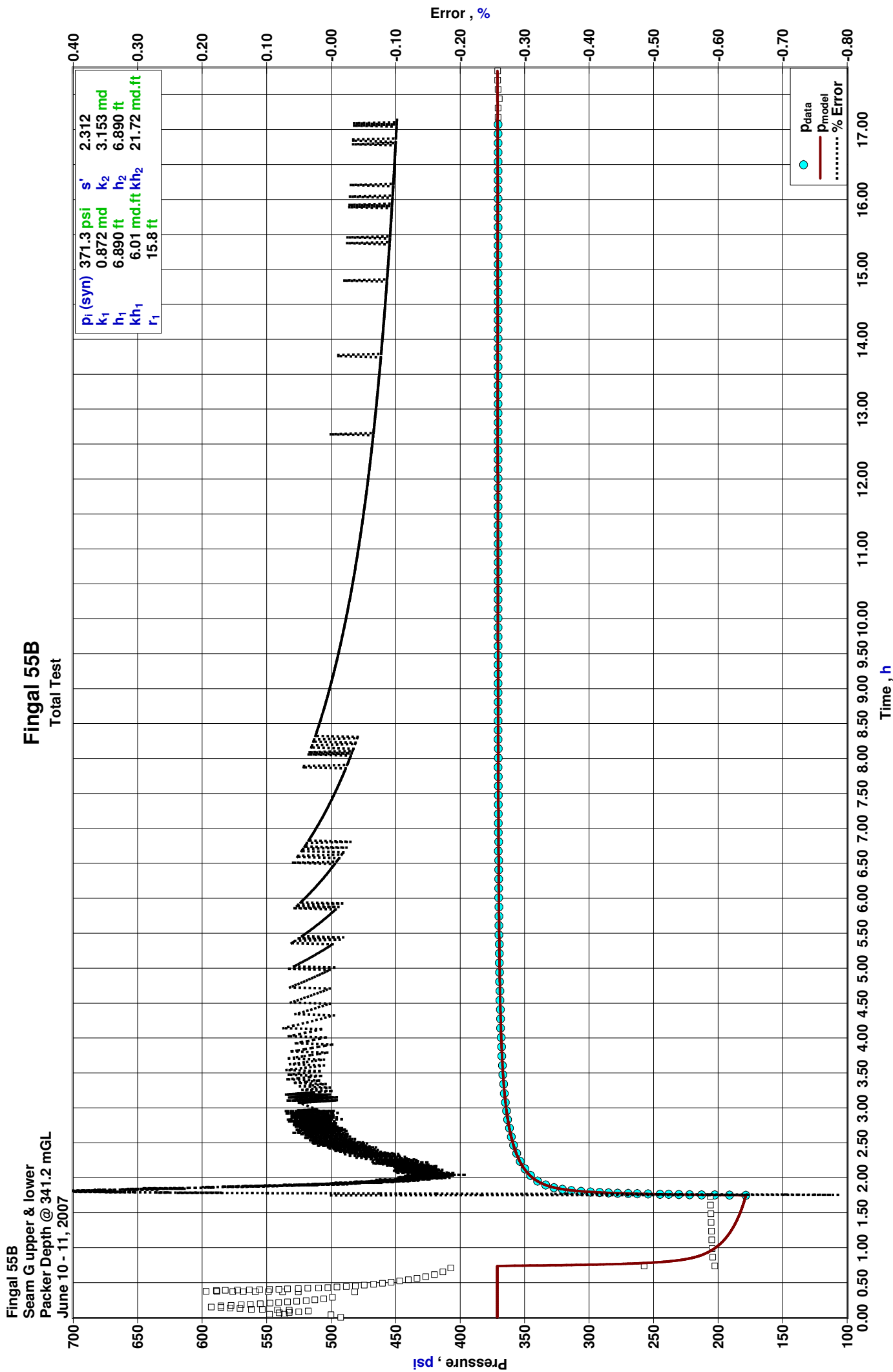
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Specific Gravity (G)	1.000
Gas Gravity (G)	0.650
PVT Reference Pressure (p_{pVT})	371.00 psi

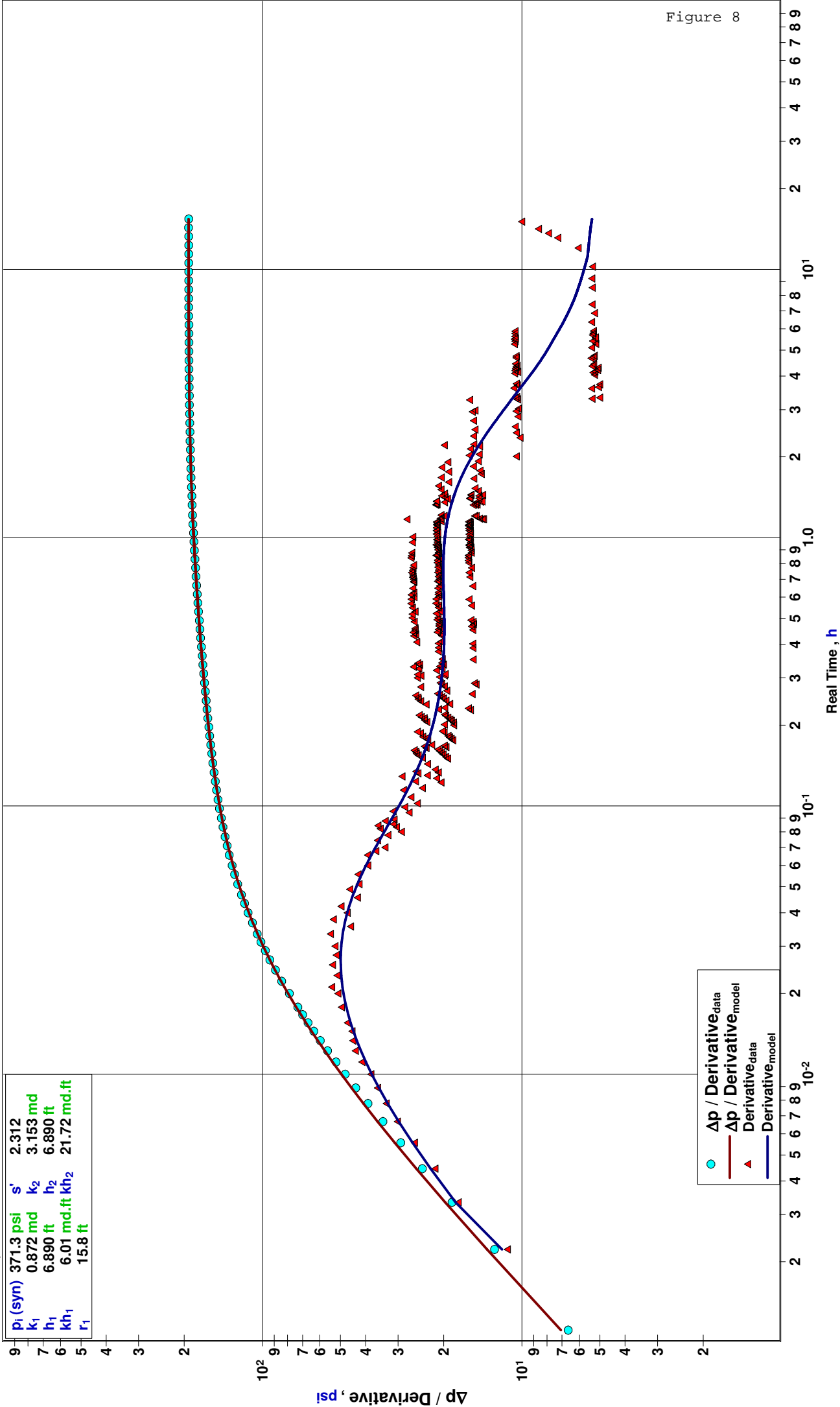
Figure 7



Fingal 55B
Seam G upper & lower
Packer Depth @ 341.2 mGL
June 10 - 11, 2007

p_i (syn)	371.3 psi	s'	2.312
k_1	0.872 md	k_2	3.153 md
h_1	6.890 ft	h_2	6.890 ft
kh_1	6.01 md.ft	kh_2	21.72 md.ft
r_1	15.8 ft		

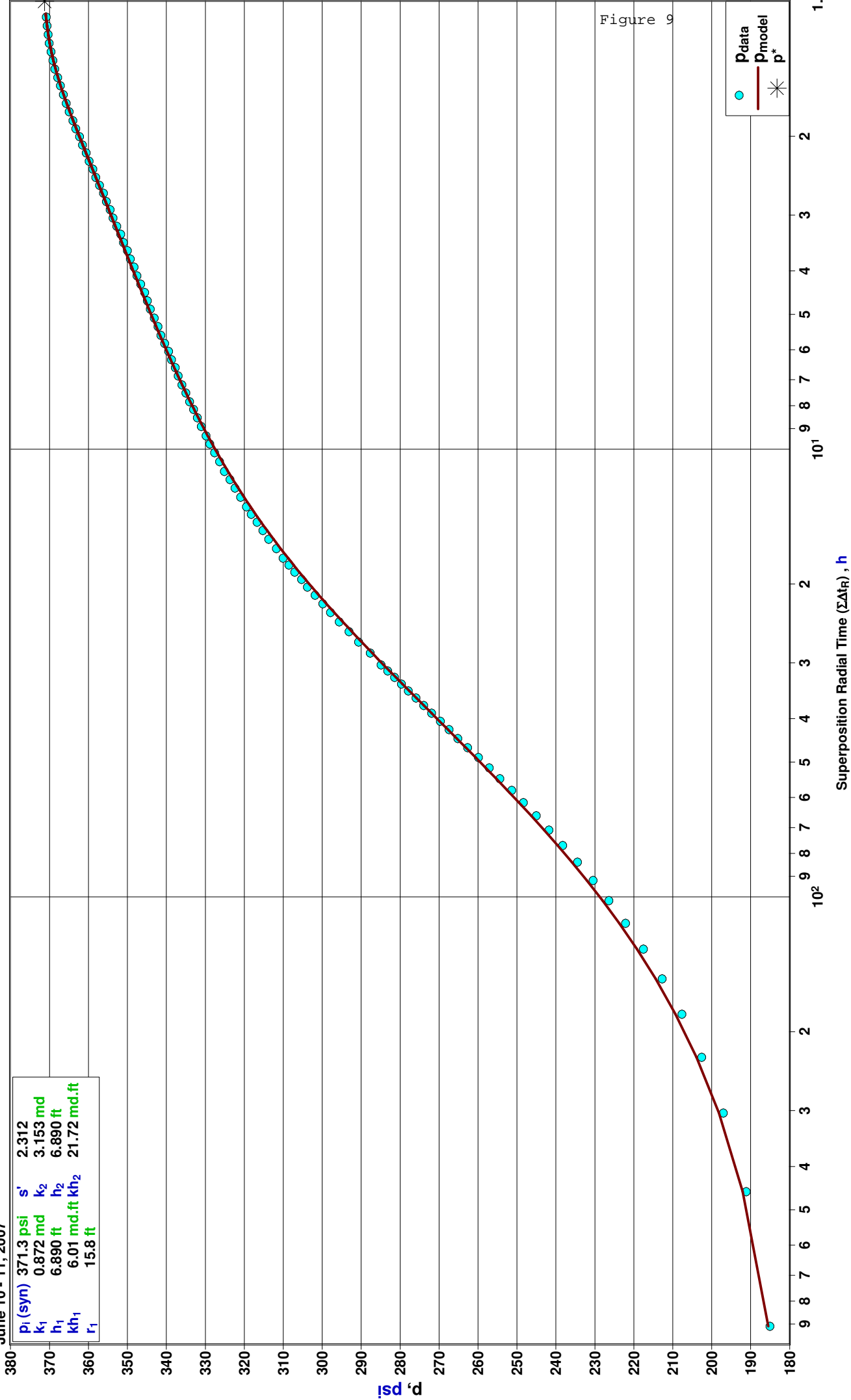
Simulation Typecurve



Fingal 55B
Seam G upper & lower
Packer Depth @ 341.2 mGL
June 10 - 11, 2007

p_i (syn)	371.3 psi	s'	2.312
k_1	0.872 md	k_2	3.153 md
h_1	6.890 ft	h_2	6.890 ft
kh_1	6.01 md.ft	kh_2	21.72 md.ft
r_1	15.8 ft		

Simulation
Radial



Composite Water Well Model

Case Name : Composite 2

Fingal 55B

Seam G upper & lower

Packer Depth @ 341.2 mGL

June 10 - 11, 2007

Model Parameters

Formation Parameters

Region 1

Region 2

Total Mobility (k/μ) _t	0.97 md/cp	Total Mobility (k/μ) _t	3.51 md/cp	Gas Saturation (S_g)	5.00 %
Permeability (k) ₁	0.872 md	Permeability (k) ₂	3.153 md	Water Saturation (S_w)	95.00 %
Net Pay (h) ₁	6.89 ft	Net Pay (h) ₂	6.89 ft	Oil Saturation (S_o)	0.00 %
Total Porosity (ϕ) ₁	2.00 %	Total Porosity (ϕ) ₂	2.00 %	Wellbore Radius (r_w)	0.30 ft
Viscosity (μ) ₁	0.899 cp	Viscosity (μ) ₂	0.899 cp	Formation Temperature (T)	75.9 °F
Total Compressibility (c_t) ₁	1.566e-4 psi ⁻¹	Total Compressibility (c_t) ₂	1.566e-4 psi ⁻¹		
Region Radius (r) ₁	15.810 ft	Region Radius (r) ₂	100.000 ft		
Skin (s)	2.312				

Fluid Properties

Apparent Wellbore Storage Dim. (C_{aD})	4.89	Water Compressibility (c_w)	3.24418e-6 psi ⁻¹
Wellbore Storage Constant Dim. (C_D)	4.33	Oil Compressibility (c_o)	1.50000e-6 psi ⁻¹
Storage Pressure Param. Dim. (C_{pD})		Gas Compressibility (c_g)	2.88021e-3 psi ⁻¹

Production and Pressure

$Q_t B_t$	1.500 bbl/d
Final Water Rate	1.500 bbl/d
Final Gas Rate	MMCF/D
Final Flowing Pressure (p_{wfo})	178.41 psi
Final Measured Pressure	370.85 psi
Cumulative Water Production	0.063 bbl

Water Formation Volume Factor (B_w)	1.000
Gas Formation Volume Factor (B_g)	0.006784 bbl/scf
Water Viscosity (μ_w)	0.899 cp
Gas Viscosity (μ_g)	0.0110 cp
Solution Gas Ratio (R_{sw})	0 scf/bbl
Specific Gravity (G)	1.000
PVT Reference Pressure (p_{pVT})	371.00 psi

Synthesis Results

Forecasts

Average Error	0.07 %	Forecast Flowing Pressure (P_{flow})	178.41 psi
Synthetic Initial Pressure (p_i)	371.28 psi	3 - Month Constant Rate Forecast @ Curr. Skin	1.221 bbl/d
Extrapolated Pressure at Specified Time	371.28 psi	6 - Month Constant Rate Forecast @ Curr. Skin	1.206 bbl/d
Pressure Drop Due To Skin (Δp_s)	72.94 psi	Forecast Flow Duration (t_{flow})	12.00 month
Flow Efficiency (FE)	0.622	Constant Rate Forecast @ Curr. Skin	1.191 bbl/d
Damage Ratio (DR)	1.608	PI / II (Actual)	0.006 bbl/d/psi
		Constant Rate Forecast @ Skin=0	1.705 bbl/d
		PI / II (Ideal)	0.009 bbl/d/psi
		Constant Rate Forecast @ Skin=-4	5.639 bbl/d