

**FINGAL 55B**  
**DRILL STEM TEST**  
**FINAL REPORT**  
**“B” ZONE COAL SEAM**  
**OPEN HOLE INTERVAL 187.1-190.7 mGL**  
**JUNE 2, 2007**

**Prepared for:**  
**Pure Energy Resources Limited**



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

**July 11, 2007**

11 July 2007

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

**Attention: Mr. Steve Beardsall**

Dear Sir

***Re: Fingal 55b Coal "B" Drill Stem Test Report***

The following is a summary of the results obtained from the Drill stem test conducted on June 2, 2007 over the "B" Coals, open hole interval from circa 187.1-190.7 mGL.

The DST was conducted through the drillpipe and coring bit, using an off bottom inflatable packer. Prior to testing, circa 80 meters of water was displaced from the drillpipe with air to allow inflow from the reservoir to occur.

The test was comprised of a 15 minute flow period followed by a buildup period of 30 minutes. 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.

A pressure fall-off was observed prior to the subject test when the packers were inflated, and the reservoir was isolated from drill pipe.

**Comments and Conclusions**

- The pressure response observed during the flow and buildup periods suggested a reservoir with moderate to high flow capacity to water. Since the inflow from the reservoir was predominantly water, the test was analysed as water well. The gas volume recovered was insignificant (< 1 cf) and was not used in the interpretation.

- The net pay of 12.3 ft (3.75 m) was obtained from the core samples. A default porosity of 2% was used for the interpretation.
- A water rate of circa 18.6 bbl/d was calculated using the pressure increase from the inflow of water into the wellbore during the flow period.
- An initial estimated reservoir pressure ( $P_i$ ) of 218 psia was extrapolated from the late-time pressure fall-off data observed after the packers were inflated. The reservoir pressure of 217 psia was calculated from the simulation match and has been quoted throughout this report. The subject reservoir is slightly under-pressured with a reservoir gradient of 0.36 psi/ft.
- The pressure derivative indicated that wellbore storage was overcome by radial flow (zero slope) within the first minute of shut-in. After about three minutes of shut-in, the pressure derivative followed a short upward trend until returning to zero slope (radial flow) at about 10 minutes after shut-in. The late-time pressure derivative appeared to begin a slight upward trend.
- Conventional analysis and Simulation were both conducted. The best fit match was obtained using composite model with decreasing flow capacity (kh) away from the wellbore. It should be noted that although the radial composite model infers a reduction in kh away from the wellbore, the pressure derivative signature could also be the result of a multi-layered reservoir, and the outer zone of the composite system is representative of the major contributing layer in the wellbore. An outer, third zone (3-zone composite model) was incorporated into the match to return the reservoir pressure closer to the initial pressure estimated from the fall-off extrapolation. The results from the simulation were very comparable 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) @ 182.6 mGL      217 psia (simulation)**

**Apparent Skin Factor      +4**

**Zone/Layer 1**

**Average Permeability to Water      38 md**  
**Flow Capacity to Water      470 md.ft**  
**Radius of Investigation      17 ft**

**Zone/Layer 2**

**Average Permeability to Water      10 md**  
**Formation Flow Capacity to Water      123 md.ft**  
**Radius of Investigation      25 ft**

**Zone/Layer 3**

**Average Permeability to Water      8 md**  
**Formation Flow Capacity to Water      92 md.ft**  
**Radius of Investigation      50 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**

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# Validata

Packer Depth @ 186.5 mGL  
Formation: Seam B

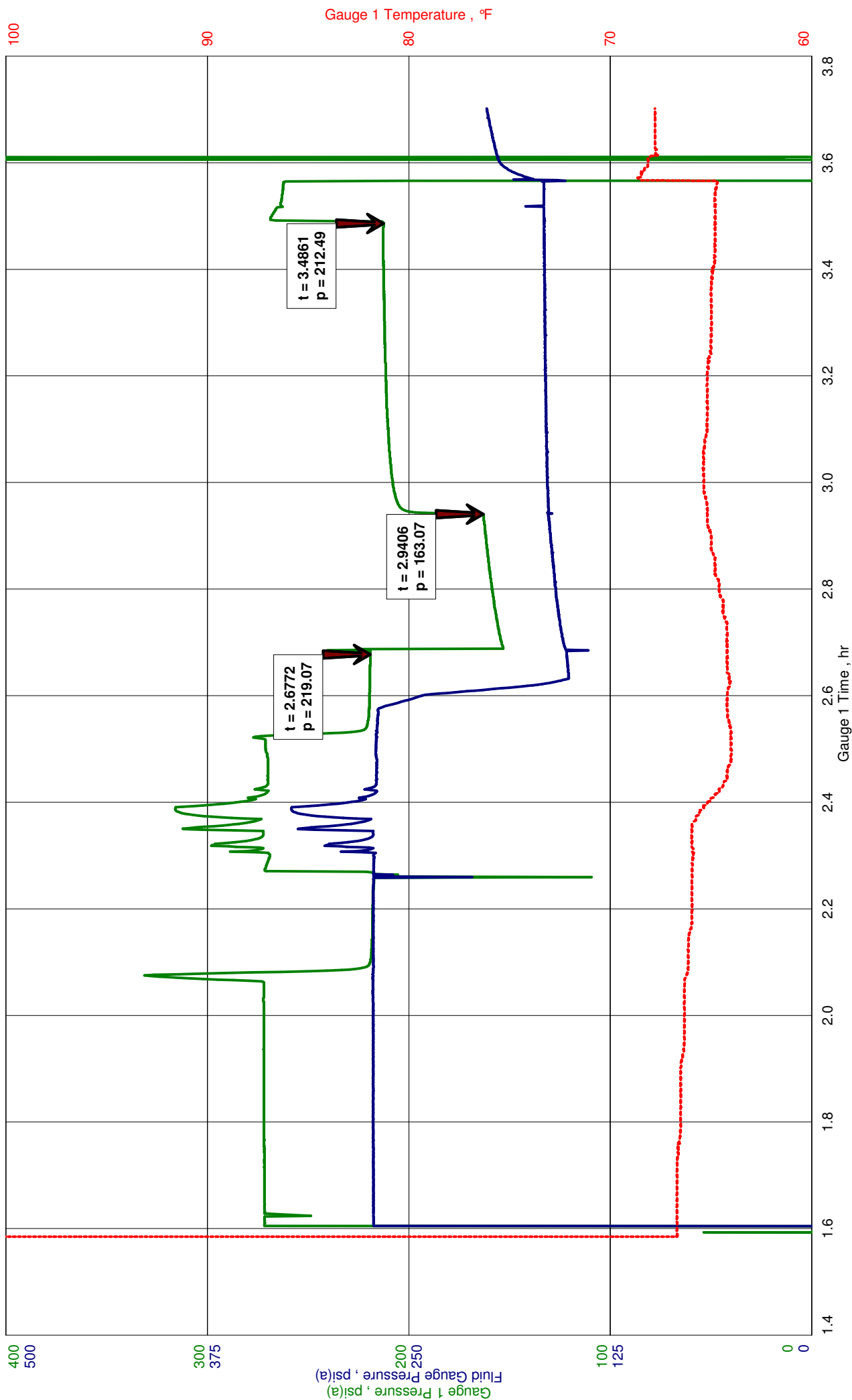
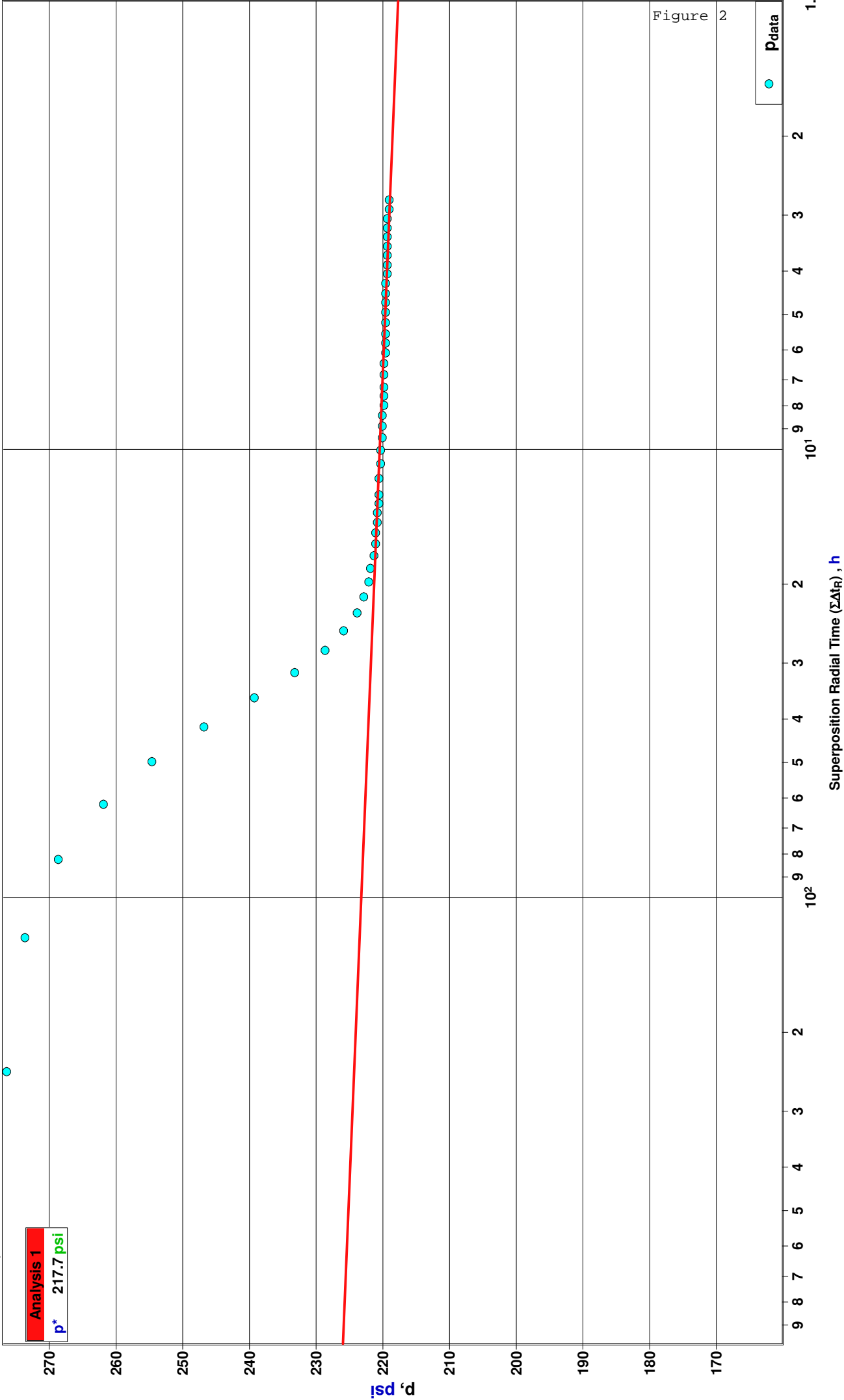


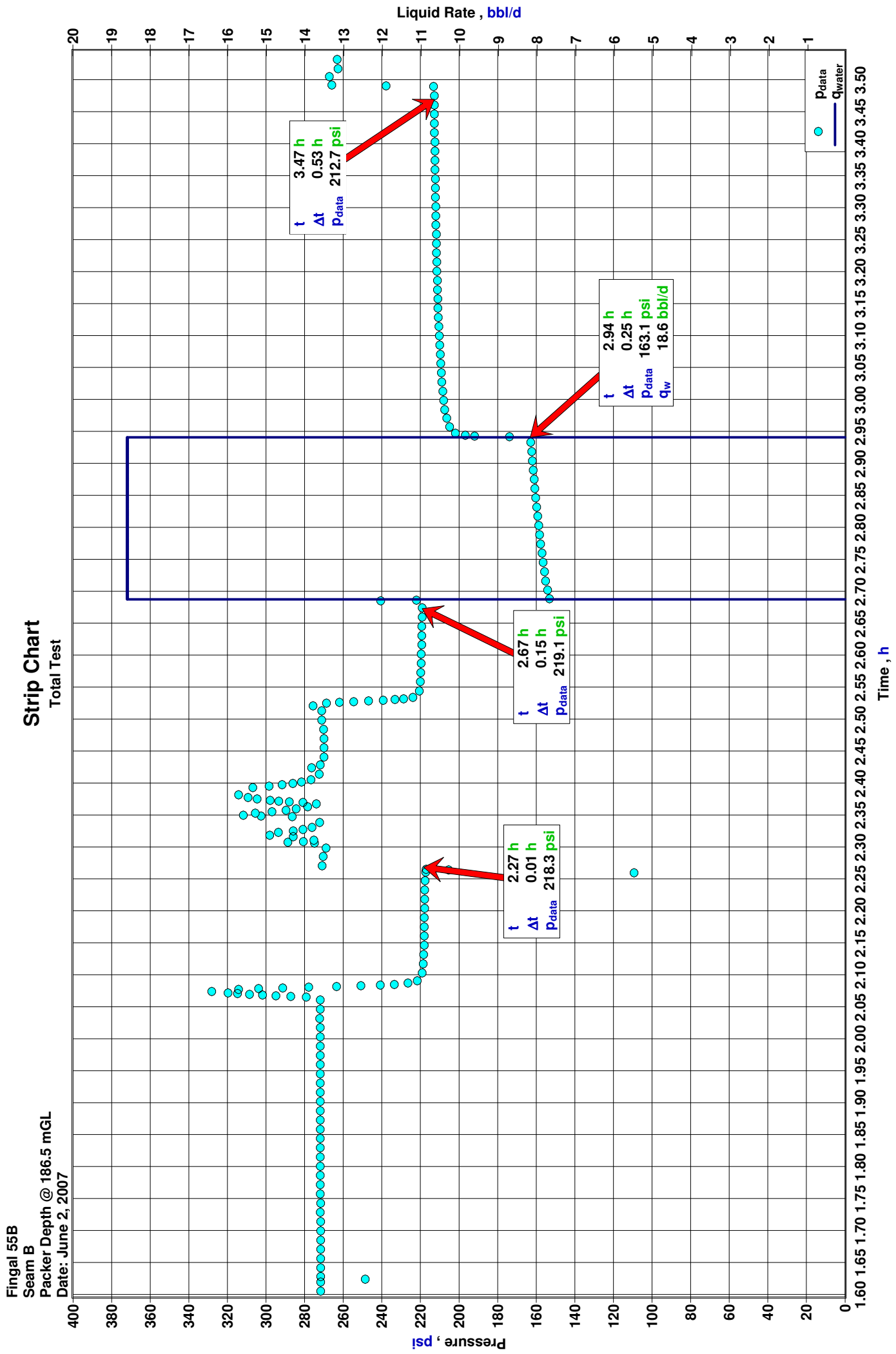
Figure 1

Fingal 55B  
Seam B  
Packer Depth @ 186.5 mGL  
Date: June 2, 2007

Pressure Falloff after setting Packer

Radial







Fingal 55B  
Seam B  
Packer Depth @ 186.5 mGL  
Date: June 2, 2007

# Diagnostic Analysis

Typecurve

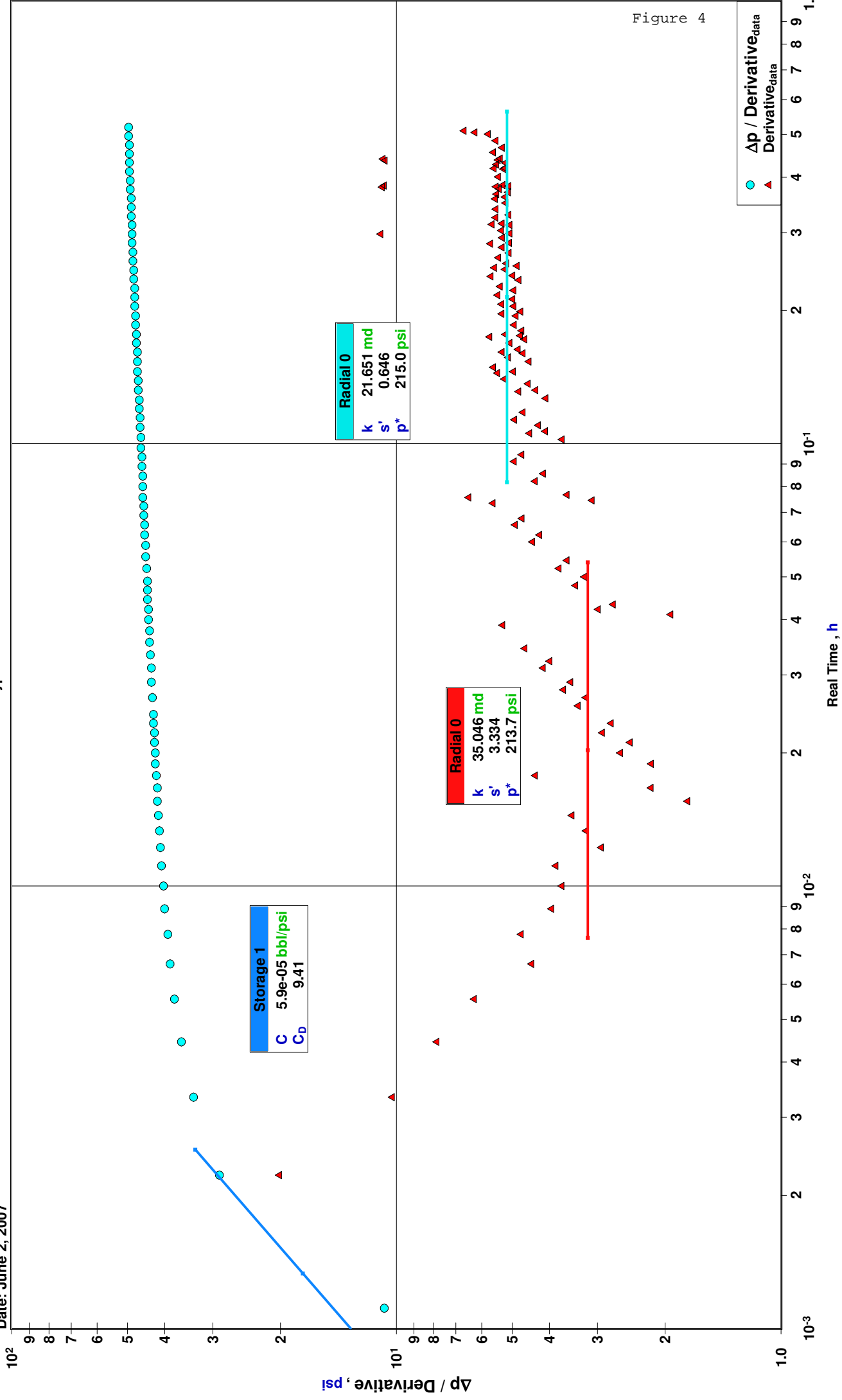
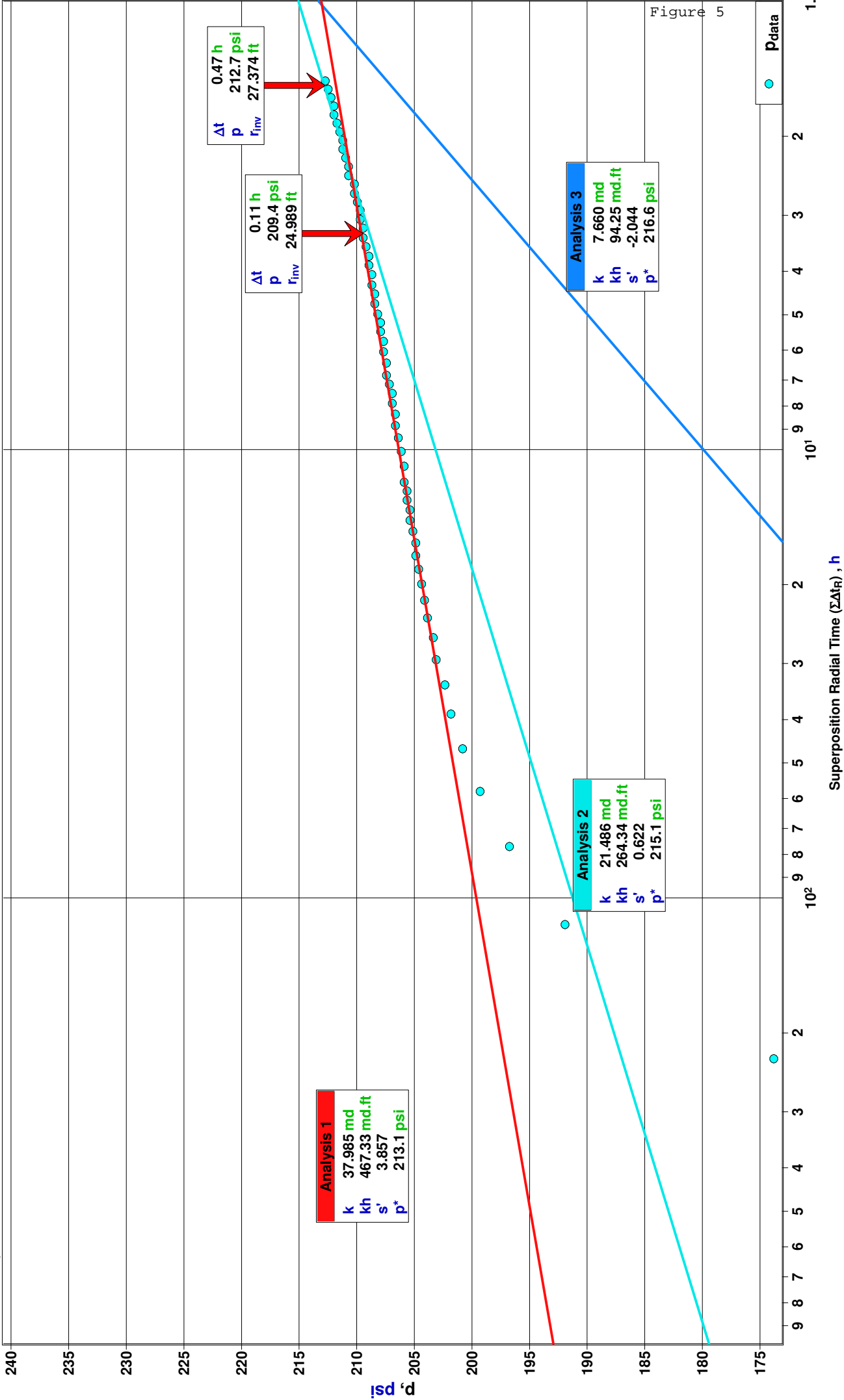


Figure 4

Fingal 55B  
Seam B  
Packer Depth @ 186.5 mGL  
Date: June 2, 2007

Diagnostic Analysis  
Radial



# Water Well Test - Buildup

## Radial Flow Analysis

Fingal 55B

Packer Depth @ 186.5 mGL

Seam B

Date: June 2, 2007

### Analysis Results

Total Sandface Rate ( $q_t B_t$ )	18.575 bbl/d	Apparent Skin ( $s'$ )	-2.044
Semilog Slope (m)	33.40	Skin - Damage	-2.044
Gas Permeability ( $k_g$ )	md	Skin - Inclination	
Oil Permeability ( $k_o$ )	md	Skin - Partial Penetration	
Water Permeability ( $k_w$ )	7.660 md	Pressure Drop Due to Skin ( $\Delta p_s$ )	psi
Flow Capacity (kh)	94.248 md.ft	Damage Ratio (DR)	0.468
Total Mobility ( $k/\mu_t$ )	7.35 md/cp	Flow Efficiency (FE)	2.137
Total Transmissivity( $kh/\mu_t$ )	90.42 md.ft/cp		

### Reservoir Parameters

Net Pay (h)	12.303 ft
Total Porosity ( $\phi_t$ )	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)	64.8 °F
Formation Compressibility ( $c_f$ )	9.482e-6 psi <sup>-1</sup>
Total Compressibility ( $c_t$ )	2.547e-4 psi <sup>-1</sup>

### Pressures

Initial Pressure ( $p_i$ )	215.24 psi
Extrapolated Pressure ( $p^*$ )	216.58 psi
Final Flowing Pressure ( $p_{wfo}$ )	163.07 psi

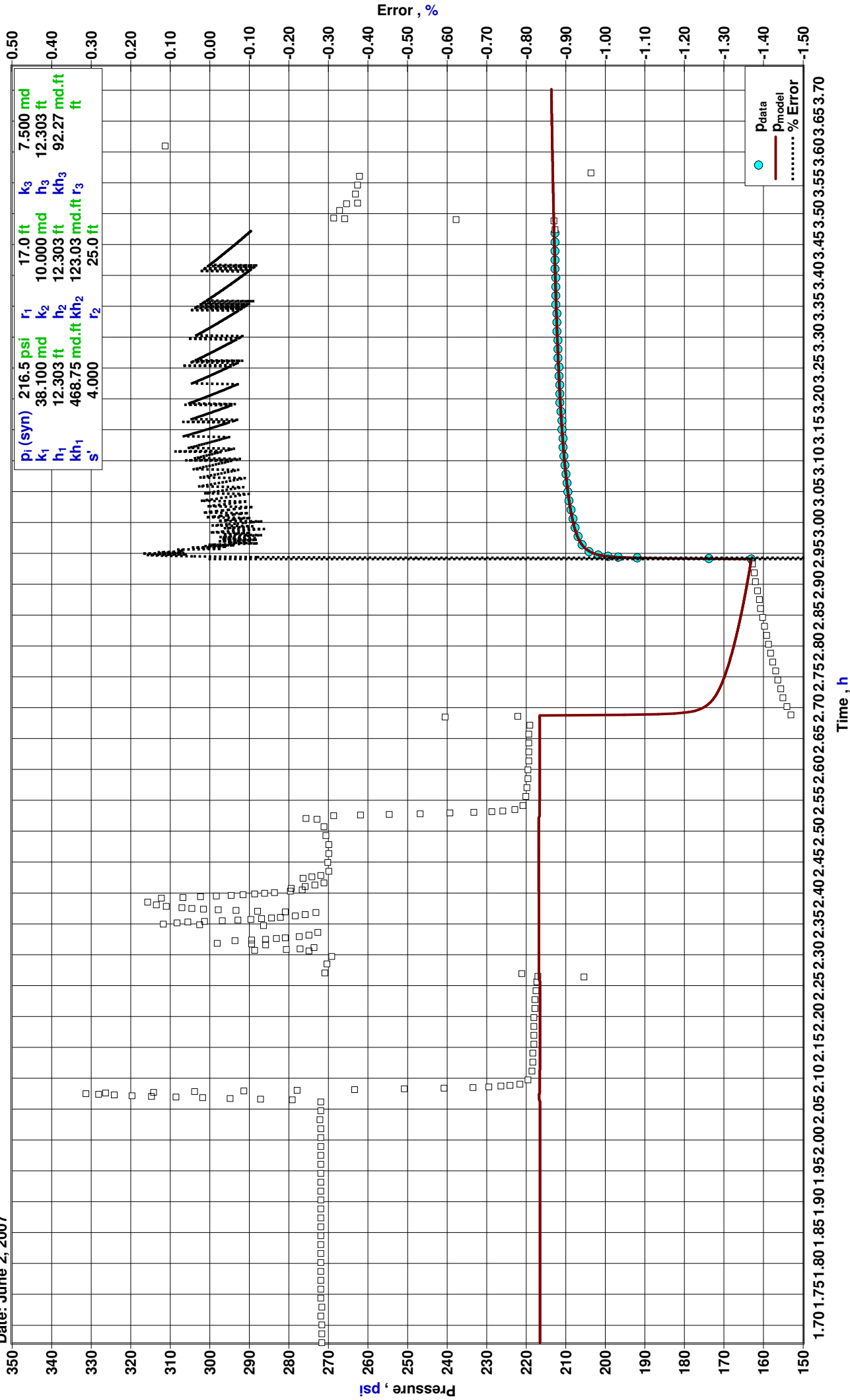
### Production and Times

Corrected Flow Time ( $t_c$ )	0.2518 hr
Cumulative Water Production	0.195 bbl
Final Water Rate	18.600 bbl/d

### Fluid Properties

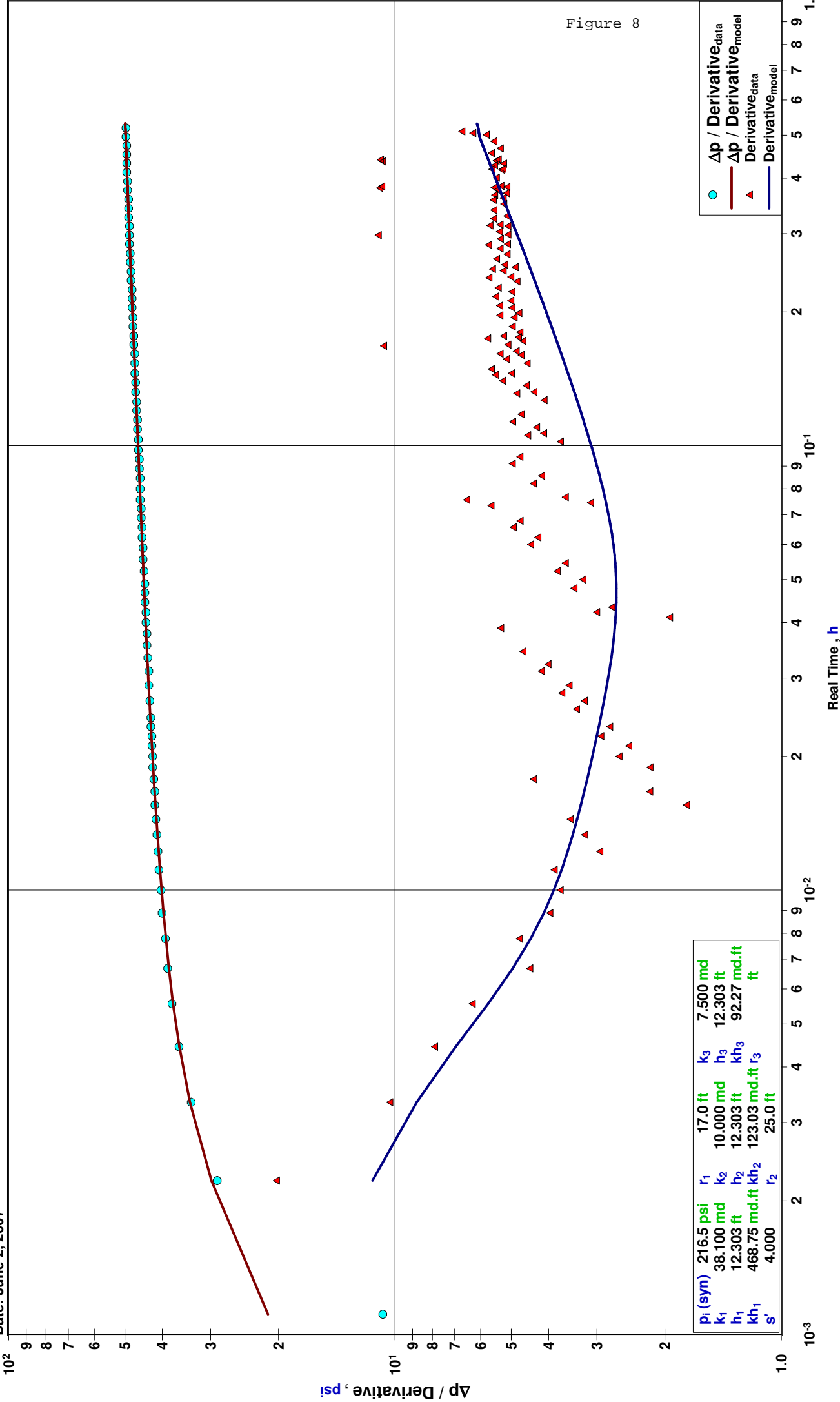
Water Compressibility ( $c_w$ )	3.31501e-6 psi <sup>-1</sup>
Water Formation Volume Factor ( $B_w$ )	0.999
Water Viscosity ( $\mu_w$ )	1.042 cp
Solution Gas Ratio ( $R_{sw}$ )	0 scf/bbl
Specific Gravity (G)	1.000
Gas Gravity (G)	0.650
PVT Reference Pressure ( $pp_{VT}$ )	215.24 psi

Fingal 55B  
Seam B  
Packer Depth @ 186.5 mGL  
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Fingal 55B  
Seam B  
Packer Depth @ 186.5 mGL  
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Simulation  
Typecurve

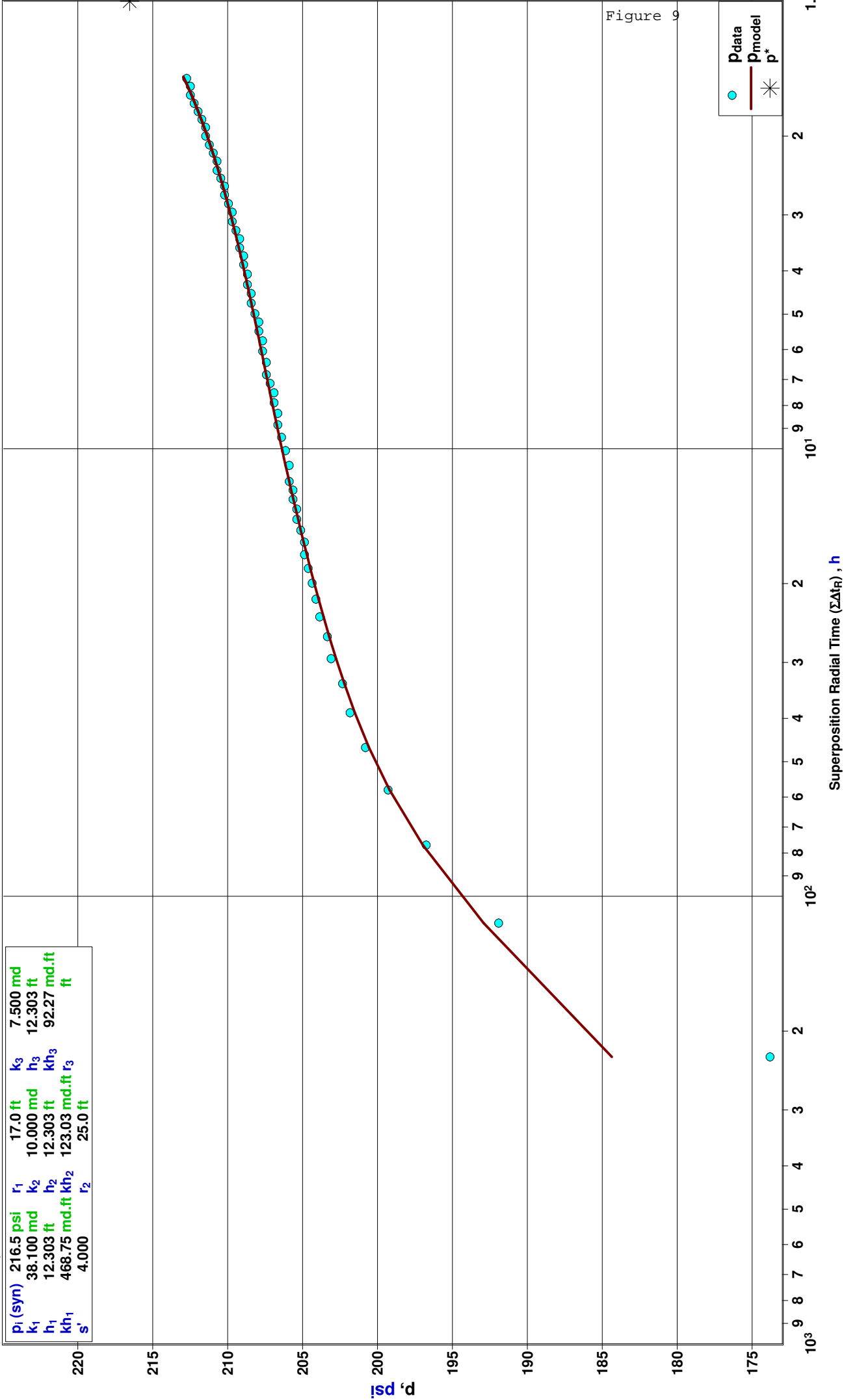


Fingal 55B  
Seam B  
Packer Depth @ 186.5 mGL  
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Simulation - Semi-log

Radial

$P_i$ (syn)	216.5 psi	$r_1$	17.0 ft	$k_3$	7.500 md
$k_1$	38.100 md	$k_2$	10.000 md	$h_3$	12.303 ft
$h_1$	12.303 ft	$h_2$	12.303 ft	$kh_3$	92.27 md.ft
$kh_1$	468.75 md.ft	$kh_2$	123.03 md.ft	$r_3$	ft
$s'$	4.000	$r_2$	25.0 ft		



# Composite Water Well Model

Case Name : Composite 7

Fingal 55B  
Seam B

Packer Depth @ 186.5 mGL  
Date: June 2, 2007

## Model Parameters

## Formation Parameters

	Region 1	Region 2	Region 3		
Total Mobility ( $k/\mu$ ) <sub>t</sub>	36.55	9.59	Total 7.20 md/cp	Gas Saturation (S <sub>g</sub> )	5.00 %
Permeability (k)	38.100	10.000	7.500 md	Water Saturation (S <sub>w</sub> )	95.00 %
Net Pay (h)	12.30	12.30	12.30 ft	Oil Saturation (S <sub>o</sub> )	0.00 %
Total Porosity ( $\phi$ ) <sub>t</sub>	2.00	2.00	2.00 %	Wellbore Radius (r <sub>w</sub> )	0.30 ft
Viscosity ( $\mu$ )	1.042	1.042	1.042 cp	Formation Temperature (T)	64.8 °F
Total Compressibility (c <sub>t</sub> )	2.547e-4	2.547e-4	2.547e-4 psi <sup>-1</sup>		
Region Radius (r)	17.000	25.000	1000.000 ft		
Skin (s)	4.000				

## Fluid Properties

Apparent Wellbore Storage Dim. (C <sub>aD</sub> )	0.00	Water Compressibility (c <sub>w</sub> )	3.31501e-6 psi <sup>-1</sup>
Wellbore Storage Constant Dim. (C <sub>D</sub> )	3.90	Oil Compressibility (c <sub>o</sub> )	1.50000e-6 psi <sup>-1</sup>
Storage Pressure Param. Dim. (C <sub>pD</sub> )		Gas Compressibility (c <sub>g</sub> )	4.84114e-3 psi <sup>-1</sup>

## Production and Pressure

Q <sub>t</sub> B <sub>t</sub>	18.575 bbl/d
Final Water Rate	18.600 bbl/d
Final Gas Rate	MMCF/D
Final Flowing Pressure (p <sub>wfo</sub> )	163.07 psi
Final Measured Pressure	-900.98 psi
Cumulative Water Production	0.195 bbl

Water Formation Volume Factor (B <sub>w</sub> )	0.999
Gas Formation Volume Factor (B <sub>g</sub> )	0.011747 bbl/scf
Water Viscosity ( $\mu_w$ )	1.042 cp
Gas Viscosity ( $\mu_g$ )	0.0106 cp
Solution Gas Ratio (R <sub>sw</sub> )	0 scf/bbl
Specific Gravity (G)	1.000
PVT Reference Pressure (pp <sub>VT</sub> )	215.24 psi

## Synthesis Results

## Forecasts

Average Error	0.06 %	Forecast Flowing Pressure (P <sub>flow</sub> )	163.07 psi
Synthetic Initial Pressure (p <sub>i</sub> )	216.54 psi	3 - Month Constant Rate Forecast @ Curr. Skin	5.724 bbl/d
Extrapolated Pressure at Specified Time	216.54 psi	6 - Month Constant Rate Forecast @ Curr. Skin	5.404 bbl/d
Pressure Drop Due To Skin ( $\Delta p_s$ )	23.29 psi	Forecast Flow Duration (t <sub>fLOW</sub> )	12.00 month
Flow Efficiency (FE)	0.564	Constant Rate Forecast @ Curr. Skin	5.119 bbl/d
Damage Ratio (DR)	1.772	PI / II (Actual)	0.101 bbl/d/psi
		Constant Rate Forecast @ Skin=0	5.818 bbl/d
		PI / II (Ideal)	0.116 bbl/d/psi
		Constant Rate Forecast @ Skin=-4	7.058 bbl/d