SEL32/2003 July 2007 Annual Report

Appendix 2

Drill Stem Test Results

By

Focal Petroleum Engineering PTY LTD.

Fingal 41b DST Reports

1. Seam B
2. Seam C
3. Seam D
4. Seam F
5. Seam G upper & G lower

FINGAL 41B

DRILL STEM TEST

FINAL REPORT

"B" ZONE COAL SEAM

OPEN HOLE INTERVAL 301.9 – 306.5 mGL

JUNE 17 – 18, 2007

Prepared for:

Pure Energy Resources Limited

Prepared by:

Focal Petroleum Engineering Pty Ltd.

July 11, 2007

July 11, 2007

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

Attention: Mr. Steve Beardsall

Dear Sir

Re: Fingal 41b Coal "B" Drill Stem Test Report

The following is a summary of the results obtained from the Drill stem test conducted from June 17 to 18, 2007 over the "B" Coal, open hole interval from circa 301.85 – 306.5 mGL.

The DST was conducted through the drillpipe and coring bit, using an off bottom inflatable packer. Prior to testing, circa 295 meters of water were displaced from the drillpipe with air to allow inflow from the reservoir to occur.

The test was comprised of a 10 minute pre-flow and 30 minute initial shut-in period followed by a 30 minute main flow and a 14.5 hour main buildup (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 falloff in pressure was noted below the packer suggesting that the permeability within the test interval was high and that the reservoir is significantly under-pressured.

Comments and Conclusions

- The pressure response observed during the flow and buildup periods suggested a reservoir with very high 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 (< 5 cf) and was not used in the interpretation.

- The net pay of 9.2 ft (2.8 m) was obtained from the core samples. A default porosity of 2% was used for the interpretation.

- Average water rates of circa 33 bbl/d and 31 bbl/d were calculated using the pressure increase from the inflow of water into the wellbore during the pre-flow and main flow periods, respectively.

- An initial estimated reservoir pressure of 189 psia was extrapolated from the late-time pressure fall-off data observed after the packers were inflated. The best estimate of reservoir pressure (Pi) of 187 psia was calculated from the simulation and has been quoted throughout this report. The subject reservoir is significantly under-pressured with a reservoir gradient of 0.19 psi/ft.

- The pressure derivative indicated that wellbore storage was immediately overcome by a zero slope (radial flow) trend and remained for the duration of the buildup. The late-time derivative on the log-log plot appears to begin an upward trend. However, this trend is not evident on the semi-log plot and is likely a function of the gauge resolution as the buildup approaches reservoir pressure (average step increase of circa 0.2 psi).

- Conventional analysis and Simulation were both conducted. A good match of the entire data set was achieved using a Vertical model. The simulation compared very well with the conventional results and has been quoted throughout this report.

- The large positive skin value is attributed to coal fines in the near wellbore area as a result of the rapid depressurising of the reservoir during the DST.

A summary of the Test Results is as follows:

Average Reservoir Pressure (Pr) @ 296.5 mGL	**187**	**psia (simulation)**
Apparent Skin Factor	**+38**	
Average Permeability to Water	**179**	**md**
Flow Capacity to Water	**1645**	**md.ft**
Radius of Investigation	**135**	**ft**

If further clarification of the test interpretation is required, please contact the undersigned on (08) 9474 9622.

Yours faithfully,
FOCAL PETROLEUM ENGINEERING PTY LTD

Ryan Gee
WELL TEST CONSULTANT

Terry Primeau
MANAGING DIRECTOR

LIST OF FIGURES

Fingal 41B
June 17 - 18, 2007

Validata

Packer Depth @ 300.4 mGL
Formation: Seam B

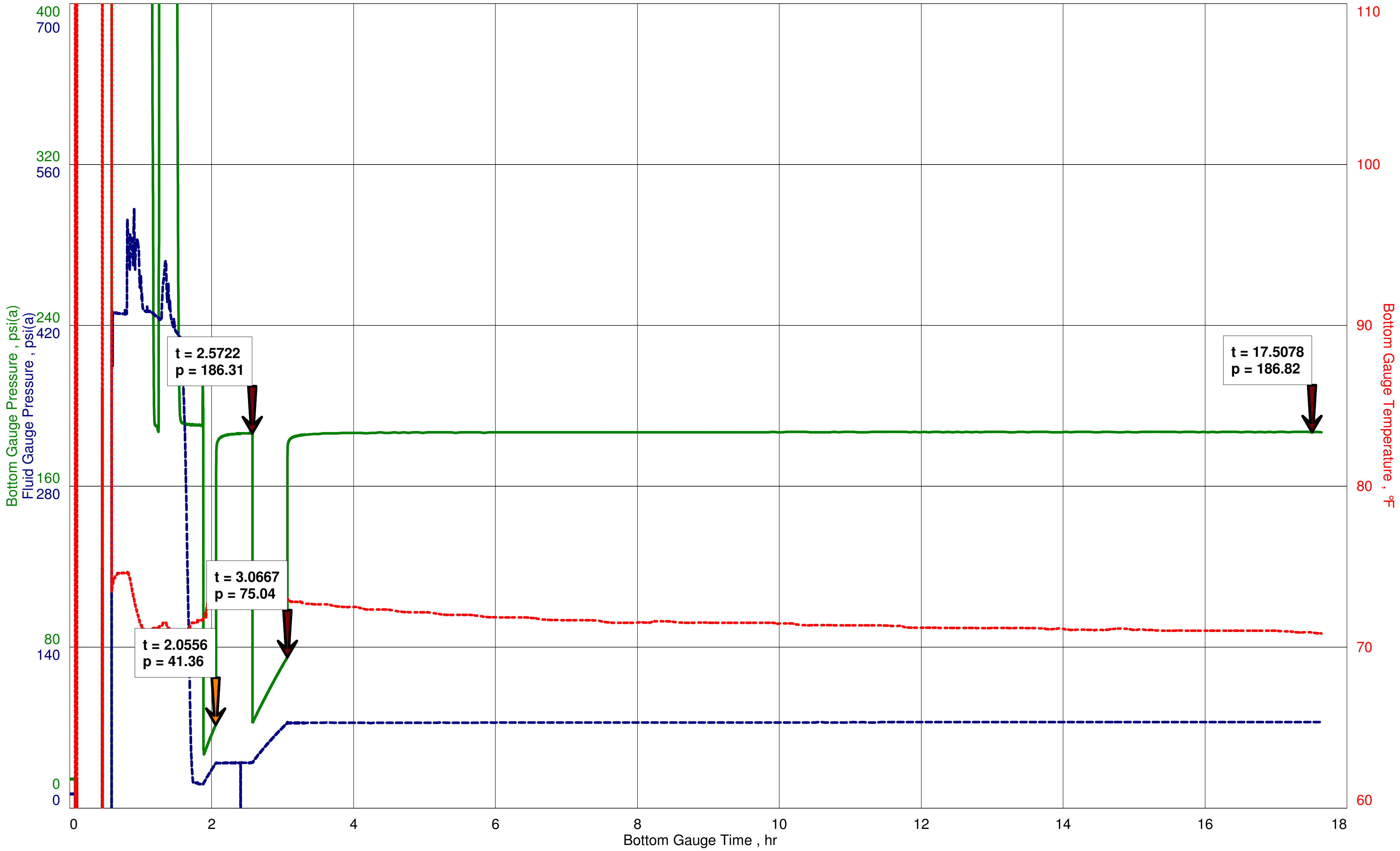
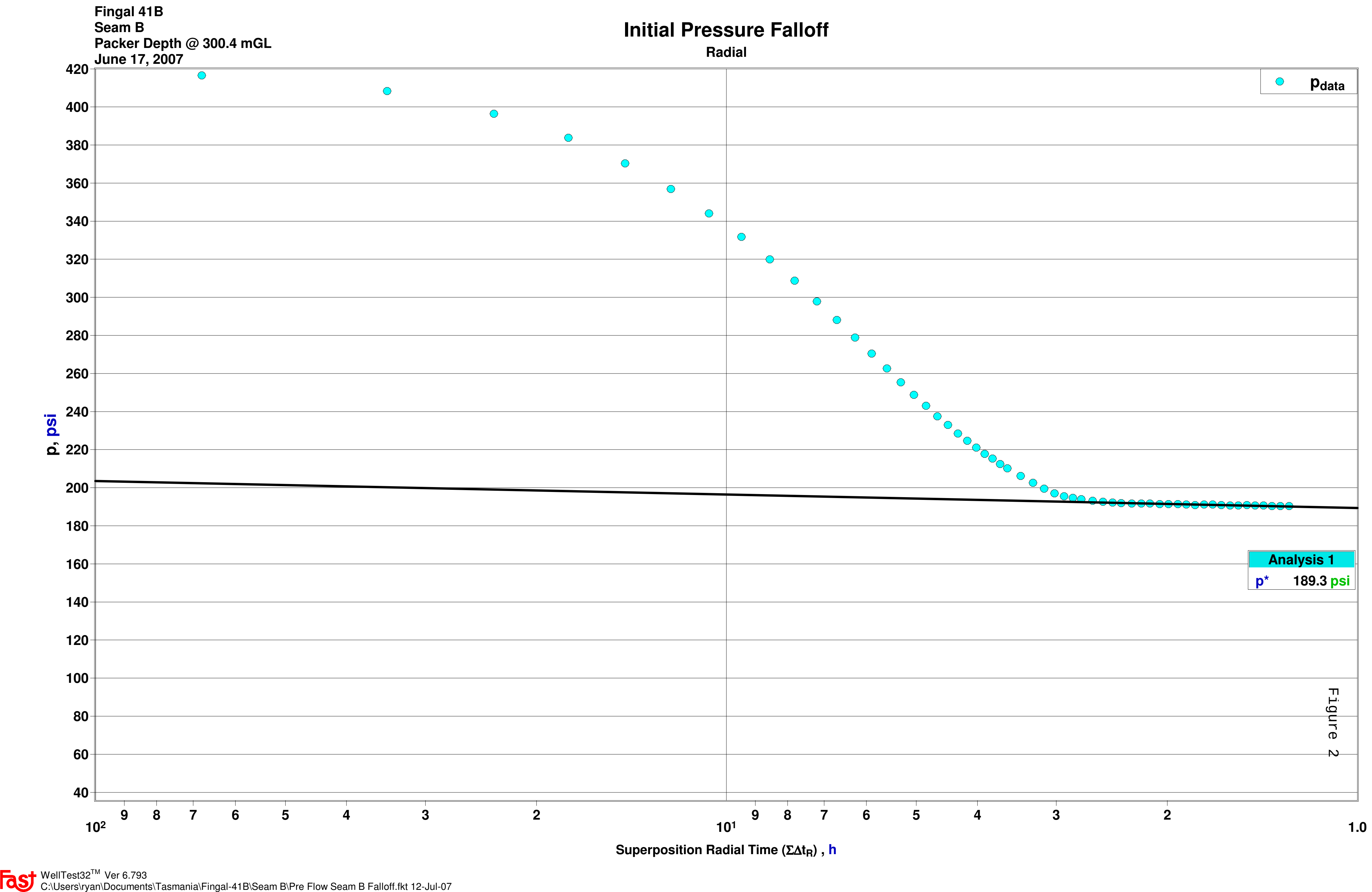


Figure 1



Fingal 41B
Seam B
Packer Depth @ 300.4 mGL
June 17, 2007
Initial Pressure Falloff
Radial
p, psi
Superposition Radial Time (ΣΔt_R) , h
p_data
Analysis 1
p* 189.3 psi
Figure 2
WellTest32™ Ver 6.793
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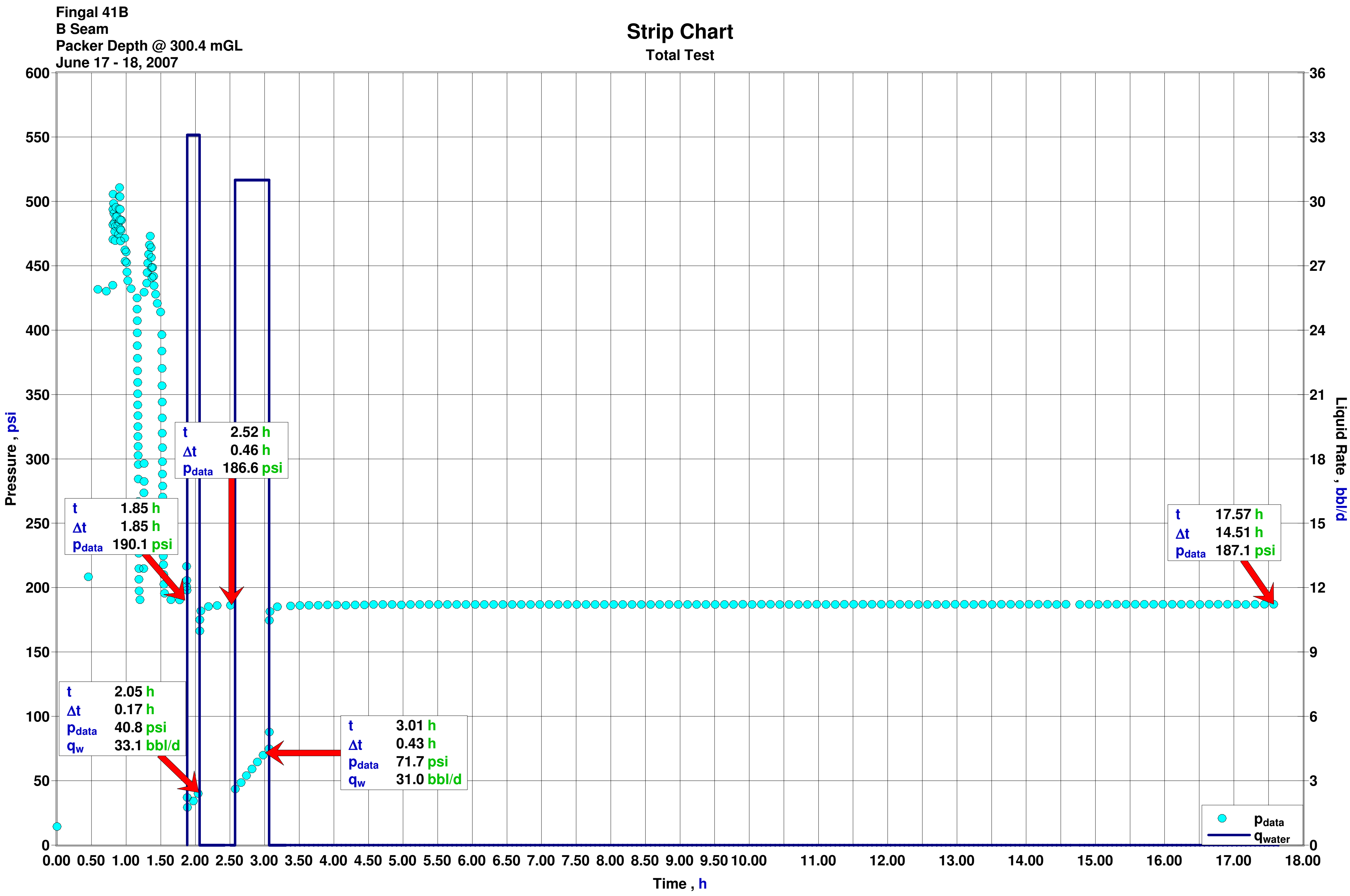

Figure 3

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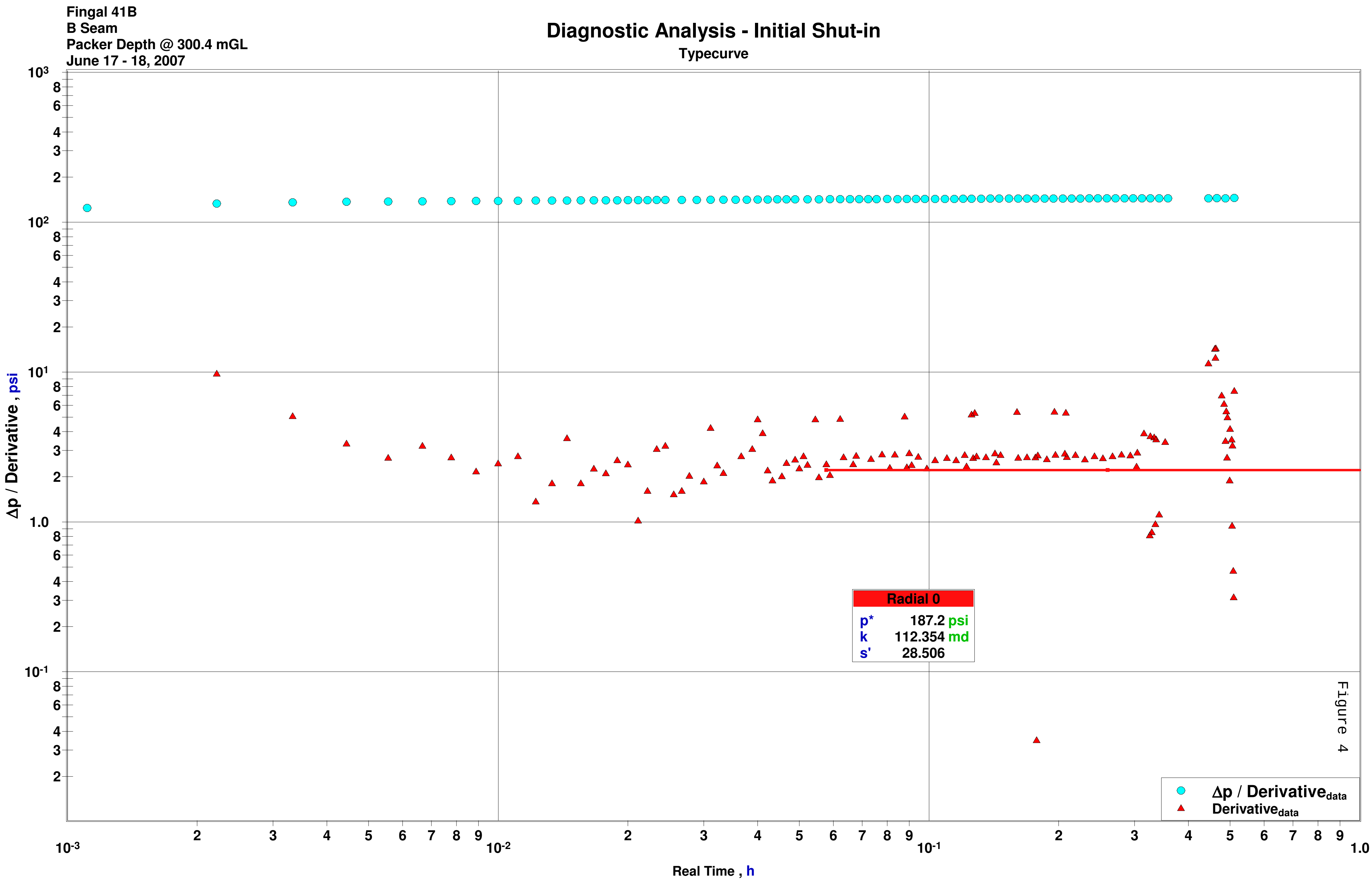

Figure 4

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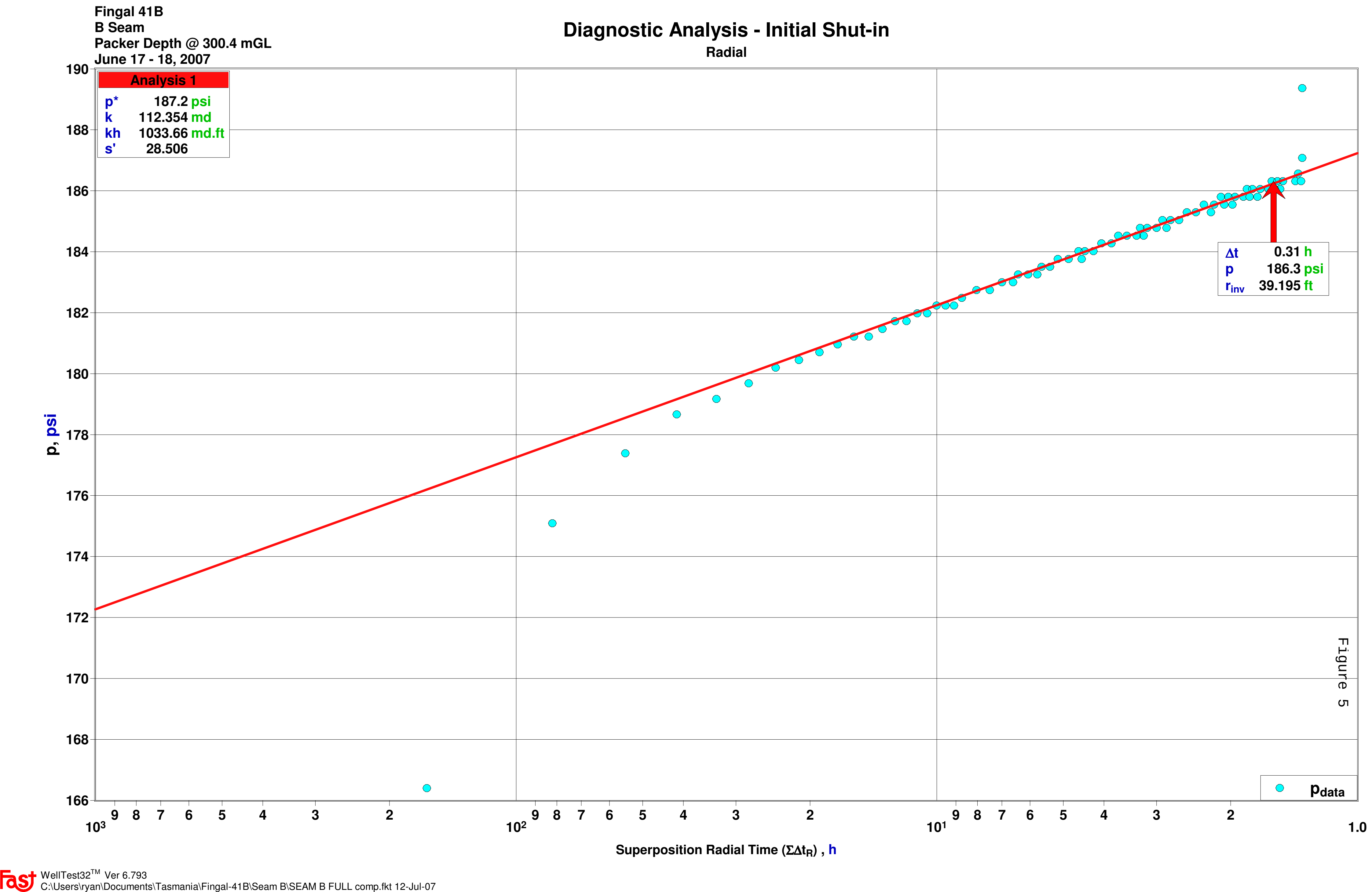

Fingal 41B
B Seam
Packer Depth @ 300.4 mGL
June 17 - 18, 2007
Diagnostic Analysis - Initial Shut-in
Radial
Analysis 1
p* 187.2 psi
k 112.354 md
kh 1033.66 md.ft
s' 28.506
Δt 0.31 h
p 186.3 psi
r inv 39.195 ft
p, psi
Superposition Radial Time (ΣΔtR) , h
pdata
Figure 5
WellTest32TM Ver 6.793
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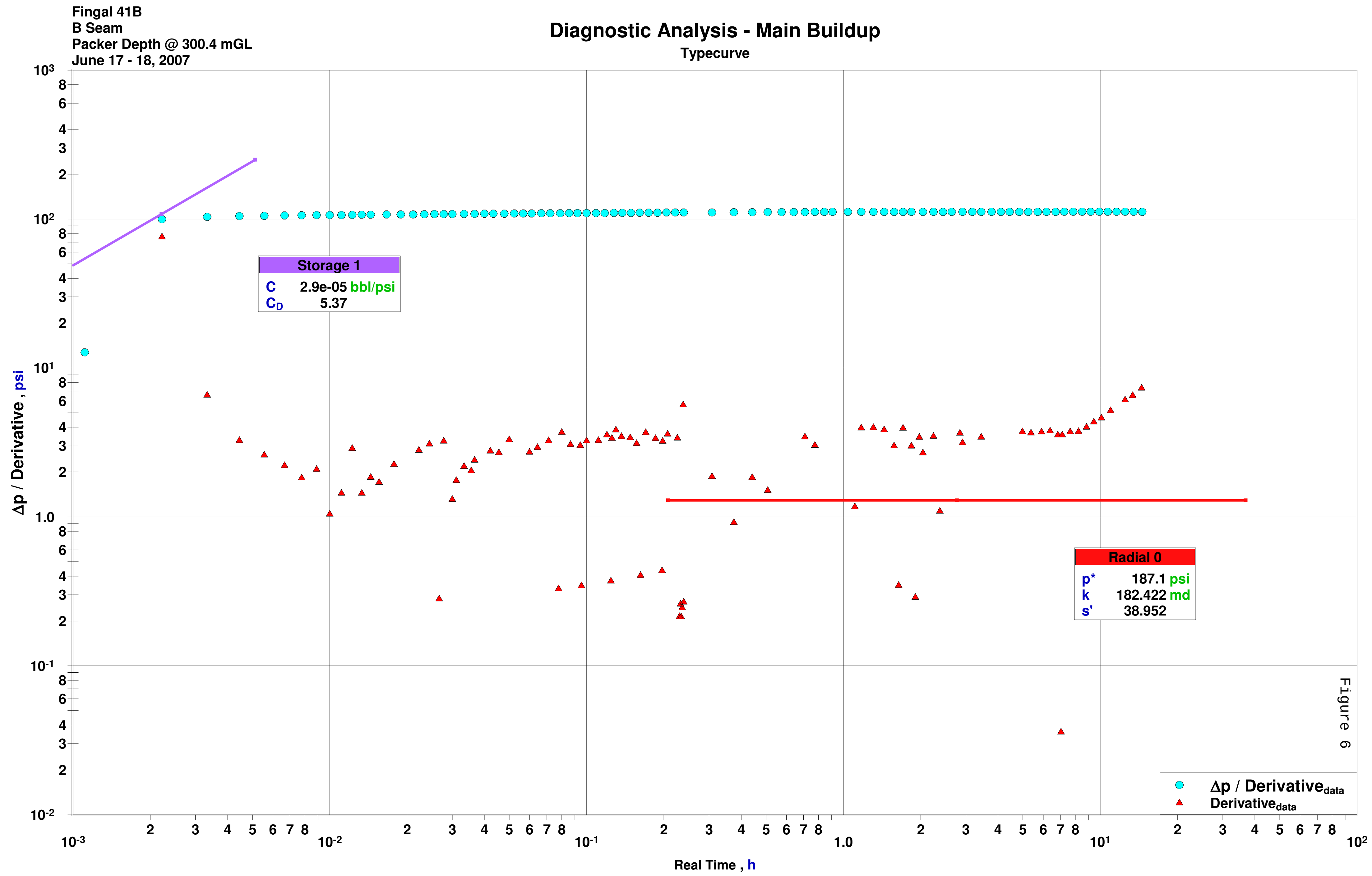

Figure 6

WellTest32TM Ver 6.793
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Fingal 41B
B Seam
Packer Depth @ 300.4 mGL
June 17 - 18, 2007

Diagnostic Analysis - Main Buildup
Radial

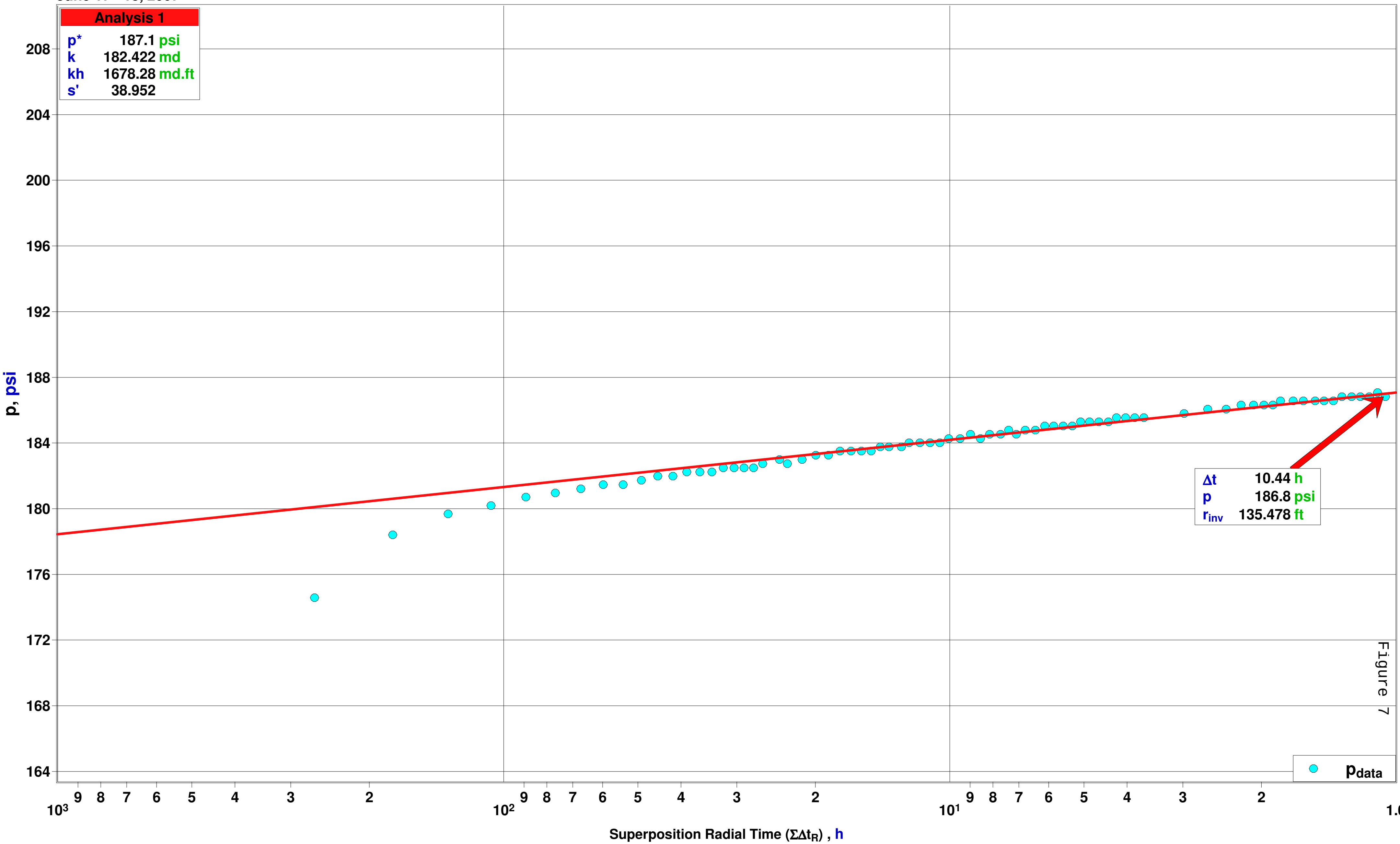

Figure 7

WellTest32™ Ver 6.793
C:\Users\ryan\Documents\Tasmania\Fingal-41B\Seam B\SEAM B FULL comp.fkt 13-Jul-07

Water Well Test - Buildup
Radial Flow Analysis

Fingal 41B	Packer Depth @ 300.4 mGL
B Seam	June 17 - 18, 2007

Analysis Results

Total Sandface Rate (q_tB_t)	30.989 bbl/d	Apparent Skin (s')	38.952
Semilog Slope (m)	2.88	Skin - Damage	38.952
Gas Permeability (k_g)	md	Skin - Inclination	
Oil Permeability (k_o)	md	Skin - Partial Penetration	
Water Permeability (k_w)	182.422 md	Pressure Drop Due to Skin (Δp_s)	97.38 psi
Flow Capacity (kh)	1678.283 md.ft	Damage Ratio (DR)	7.677
Total Mobility (k/μ_t)	190.38 md/cp	Flow Efficiency (FE)	0.130
Total Transmissivity(kh/μ_t)	1751.53 md.ft/cp		

Reservoir Parameters

Net Pay (h)	9.200 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)	71.0 °F
Formation Compressibility (c_f)	9.482e-6 psi^{-1}
Total Compressibility (c_t)	2.893e-4 psi^{-1}

Pressures

Initial Pressure (p_i)	187.00 psi
Extrapolated Pressure (p^*)	187.07 psi
Final Flowing Pressure (p_{wfo})	75.04 psi

Production and Times

Corrected Flow Time (t_c)	0.6844 hr
Cumulative Water Production	0.884 bbl
Final Water Rate	31.000 bbl/d

Fluid Properties

Water Compressibility (c_w)	3.28607e-6 psi^{-1}
Water Formation Volume Factor (B_w)	1.000
Water Viscosity (μ_w)	0.958 cp
Solution Gas Ratio (R_{sw})	0 scf/bbl
Specific Gravity (G)	1.000
Gas Gravity (G)	0.650
PVT Reference Pressure (p_{PVT})	187.00 psi

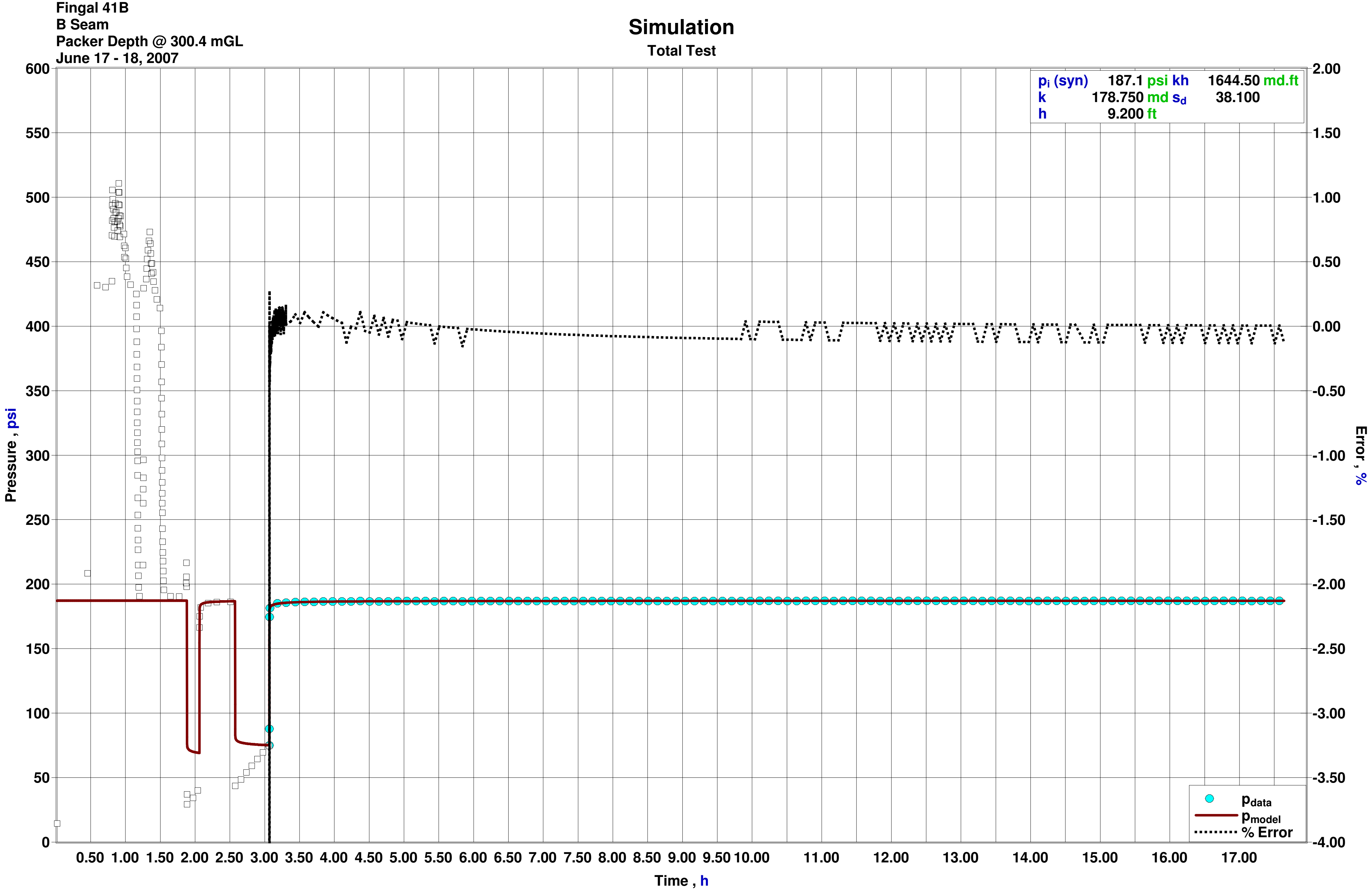

Figure 9

WellTest32TM Ver 6.793
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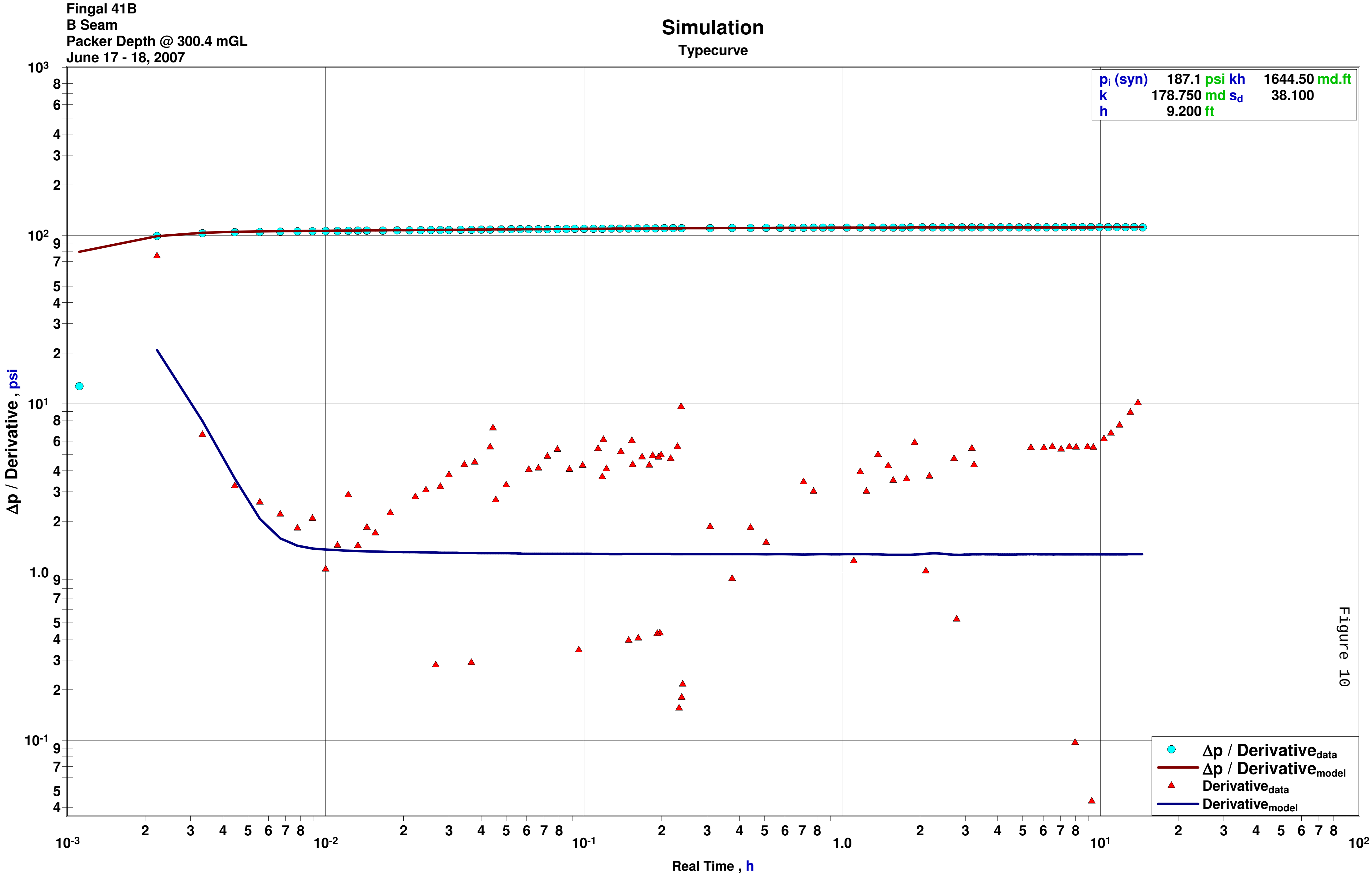

Figure 10

WellTest32™ Ver 6.793
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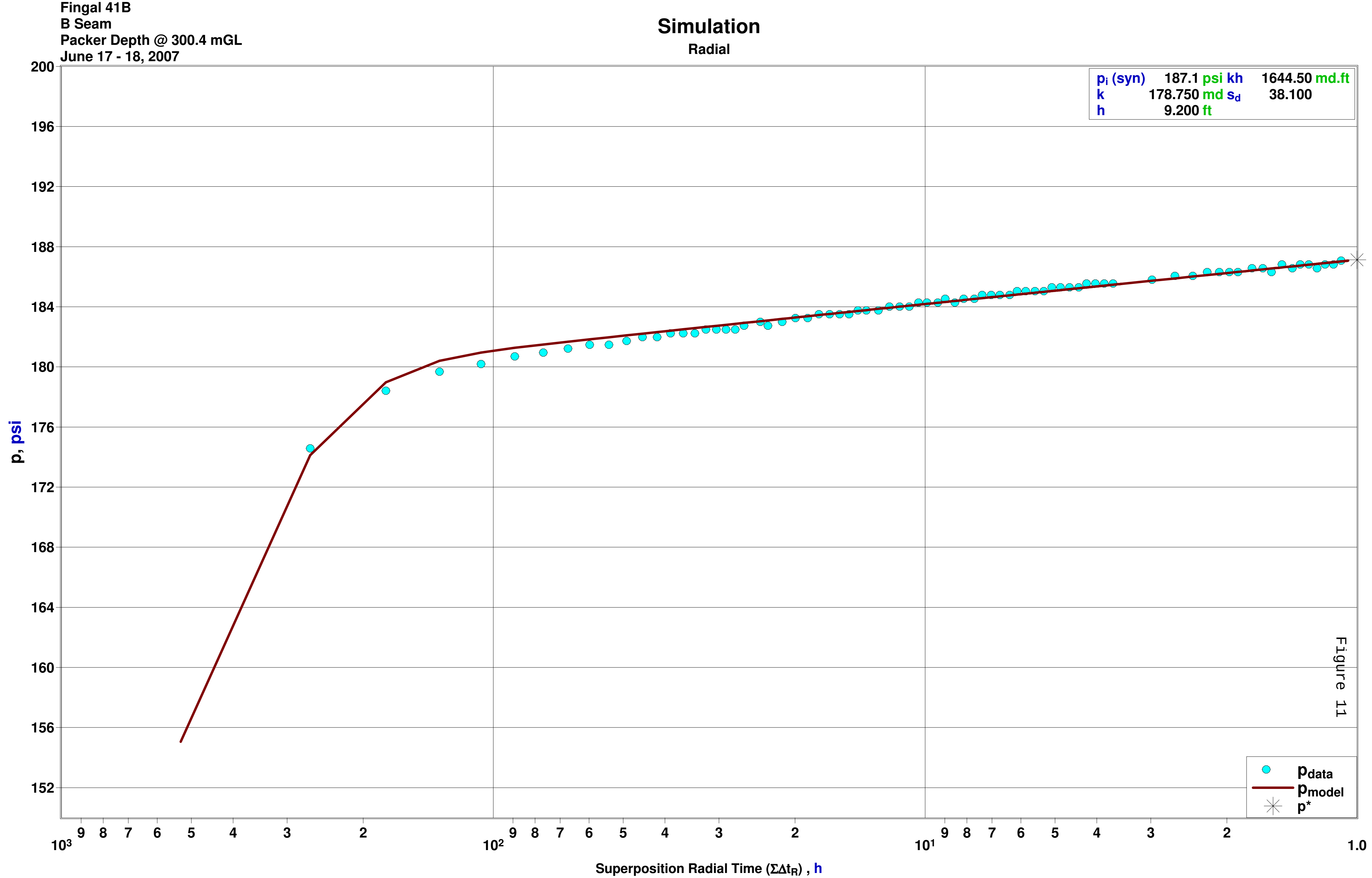

WellTest32™ Ver 6.793
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Figure 12

Vertical Water Well Model

Case Name : Simulation

Fingal 41B

B Seam

Packer Depth @ 300.4 mGL

June 17 - 18, 2007

Model Parameters

Water Permeability (k_w)	178.750 md
Gas Permeability (k_g)	md
Skin (s)	38.100
Total Mobility $(k/\mu)_t$	186.55 md/cp
Total Transmissivity $(kh/\mu)_t$	1716.27 md.ft/cp
Wellbore Storage Constant Dim. (C_D)	1.75

Reservoir Length (X_e)	1000000.000 ft
Reservoir Width (Y_e)	1000000.000 ft
Active Well At (X_w)	ft
Active Well At (Y_w)	ft

Formation Parameters

Net Pay (h)	9.200 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)	71.0 °F
Formation Compressibility (c_f)	9.482e-6 psi^{-1}
Total Compressibility (c_t)	2.893e-4 psi^{-1}

Fluid Properties

Water Compressibility (c_w)	3.28607e-6 psi^{-1}
Water Formation Volume Factor (B_w)	1.000
Water Viscosity (μ_w)	0.958 cp
Solution Gas Ratio (R_{sw})	0 scf/bbl
Specific Gravity (G)	1.000
PVT Reference Pressure (p_{PVT})	187.00 psi

Production and Pressure

Q_tB_t	30.989 bbl/d
Final Water Rate	31.000 bbl/d
Final Gas Rate	MMCF/D
Final Flowing Pressure (p_{wfo})	75.04 psi
Final Measured Pressure	186.82 psi
Cumulative Water Production	0.884 bbl

Synthesis Results

Average Error	0.24 %
Synthetic Initial Pressure (p_i)	187.13 psi
Extrapolated Pressure at Specified Time	187.13 psi
Pressure Drop Due To Skin (Δp_s)	97.13 psi
Flow Efficiency (FE)	0.133
Damage Ratio (DR)	7.495

Forecasts

Forecast Flowing Pressure (P_{flow})	75.04 psi
3 - Month Constant Rate Forecast @ Curr. Skin	28.347 bbl/d
6 - Month Constant Rate Forecast @ Curr. Skin	28.144 bbl/d
Forecast Flow Duration (t_{flow})	12.00 month
Constant Rate Forecast @ Curr. Skin	27.945 bbl/d
PI / II (Actual)	0.251 bbl/d/psi
Constant Rate Forecast @ Skin=0	127.716 bbl/d
PI / II (Ideal)	1.178 bbl/d/psi
Constant Rate Forecast @ Skin=-4	204.290 bbl/d

FINGAL 41B

DRILL STEM TEST

FINAL REPORT

"C" ZONE COAL SEAM

OPEN HOLE INTERVAL 328.1 – 330.8 mGL

JUNE 19, 2007

Prepared for:

Pure Energy Resources Limited

Prepared by:

Focal Petroleum Engineering Pty Ltd.

July 11, 2007

July 11, 2007

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

Attention: Mr. Steve Beardsall

Dear Sir

Re: Fingal 41b Coal "C" Drill Stem Test Report

The following is a summary of the results obtained from the Drill Stem Test conducted on June 19, 2007 over the "C" Coal, open hole interval from circa 328.1 – 330.8 mGL.

The DST was conducted through the drillpipe and coring bit, using an off bottom inflatable packer. Prior to testing, circa 260 meters of water were displaced from the drillpipe with air to allow inflow from the reservoir to occur.

The test was comprised of a 1.3 hour flow and a 2.1 hour buildup. 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 falloff in pressure was noted below the packer suggesting that the permeability within the test interval was high and that the reservoir is significantly under-pressured.

Comments and Conclusions

- The pressure response observed during the flow and buildup periods suggested a reservoir with very high 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 (< 2 cf) and was not used in the interpretation.

- The net pay of 5.2 ft (1.6 m) was obtained from the core samples. A default porosity of 2% was used for the interpretation.

- An average water rate of circa 4.8 bbl/d was calculated using the pressure increase from the inflow of water into the wellbore during the flow period.

- A reservoir pressure (Pi) of 223 psia was calculated from the simulation and has been quoted throughout the report. The subject reservoir is significantly under-pressured with a reservoir gradient of 0.21 psi/ft.

- The pressure derivative indicated that wellbore storage was overcome within the first minute of shut-in by a zero slope (radial flow) trend that remained for the duration of the buildup.

- Conventional analysis and Simulation were both conducted. The buildup was initially modelled with a vertical model, however the early time data was not well matched. A radial composite model was incorporated with an increasing (three times) flow capacity (kh) circa eight feet away from the wellbore region in order to match the early time data. The dominant outer region of the simulation (radial composite model) compared very well with the conventional results and has been quoted throughout this report.

- The large positive skin value is attributed to coal fines in the near wellbore area as a result of the rapid depressurising of the reservoir during the DST.

A summary of the Test Results is as follows:

Average Reservoir Pressure (Pr) @ 322.6 mGL	**223 psia (simulation)**
Apparent Skin Factor	**+8**
<u>Near Wellbore Zone</u>	
Average Permeability to Water	**12.3 md**
Flow Capacity to Water	**65 md.ft**
Radius of Investigation	**7.5 ft**
<u>Outer Area Zone</u>	
Average Permeability to Water	**33.5 md**
Flow Capacity to Water	**176 md.ft**
Radius of Investigation	**72 ft**

If further clarification of the test interpretation is required, please contact the undersigned on (08) 9474 9622.

Yours faithfully,
FOCAL PETROLEUM ENGINEERING PTY LTD

Ryan Gee
WELL TEST CONSULTANT

Terry Primeau
MANAGING DIRECTOR

focal
PETROLEUM ENGINEERING PTY LTD

LIST OF FIGURES

Fingal 41B
June 19, 2007

Validata

Packer Depth @326.5 mGL
Formation: Seam C

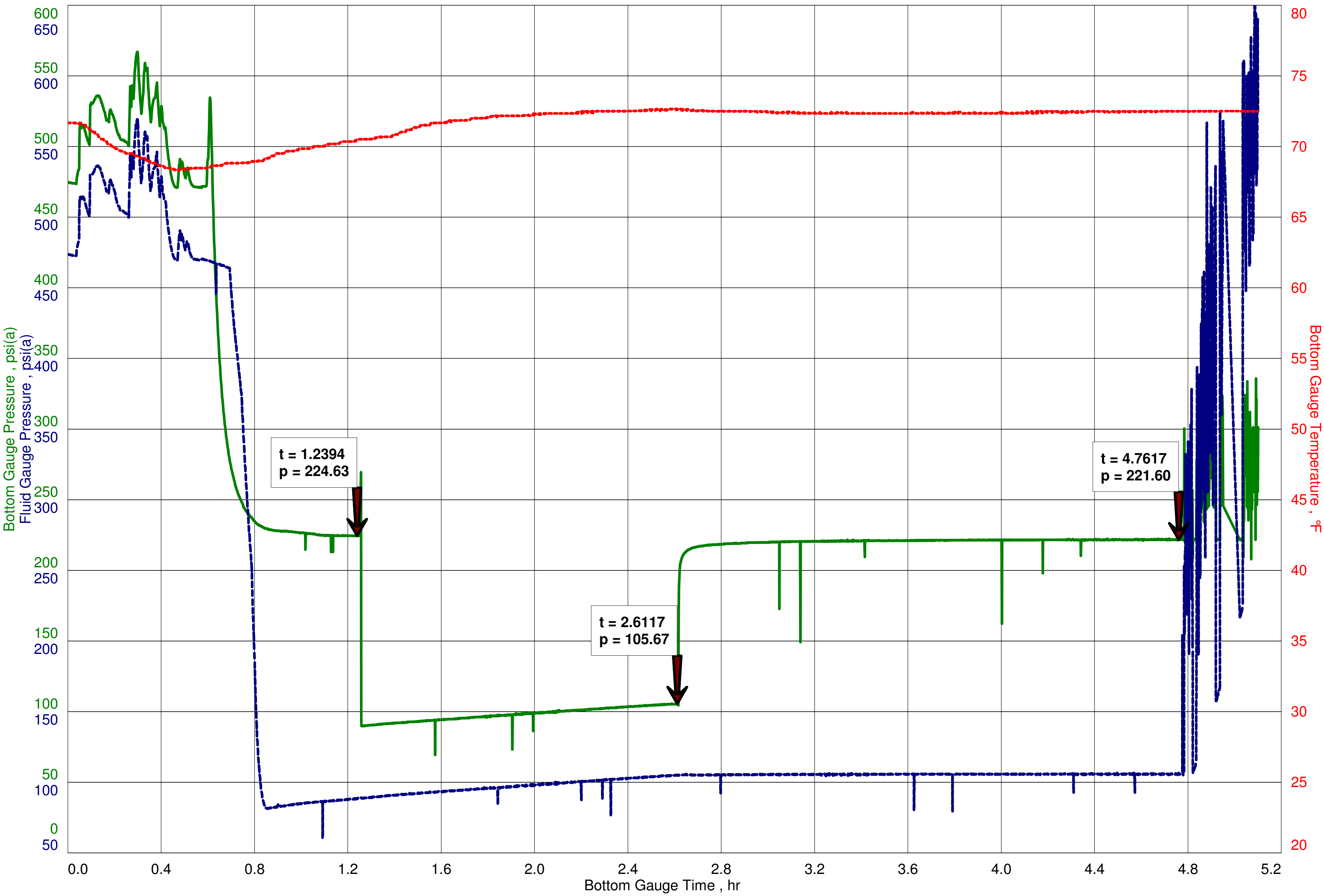

Figure 1

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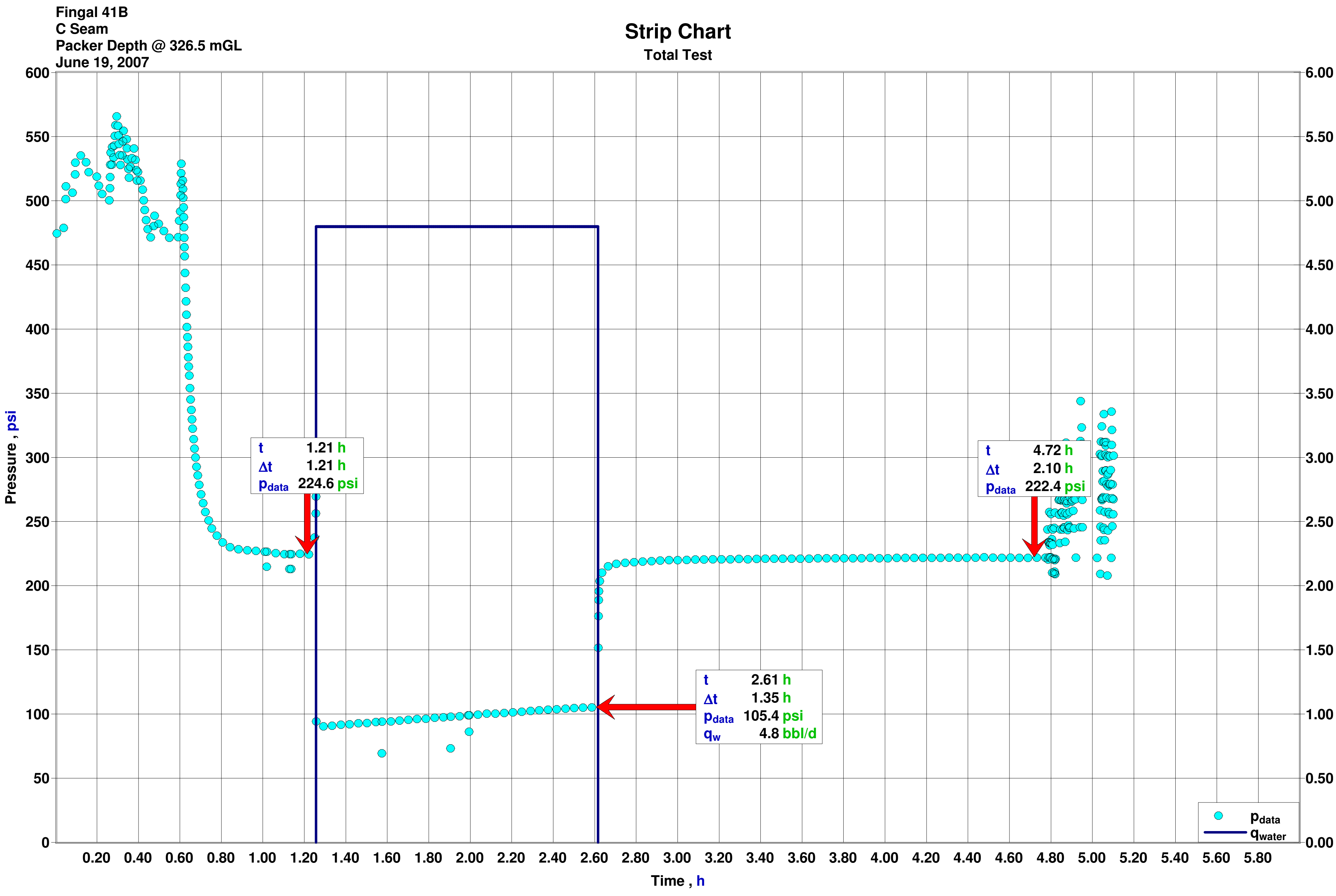

Figure 2

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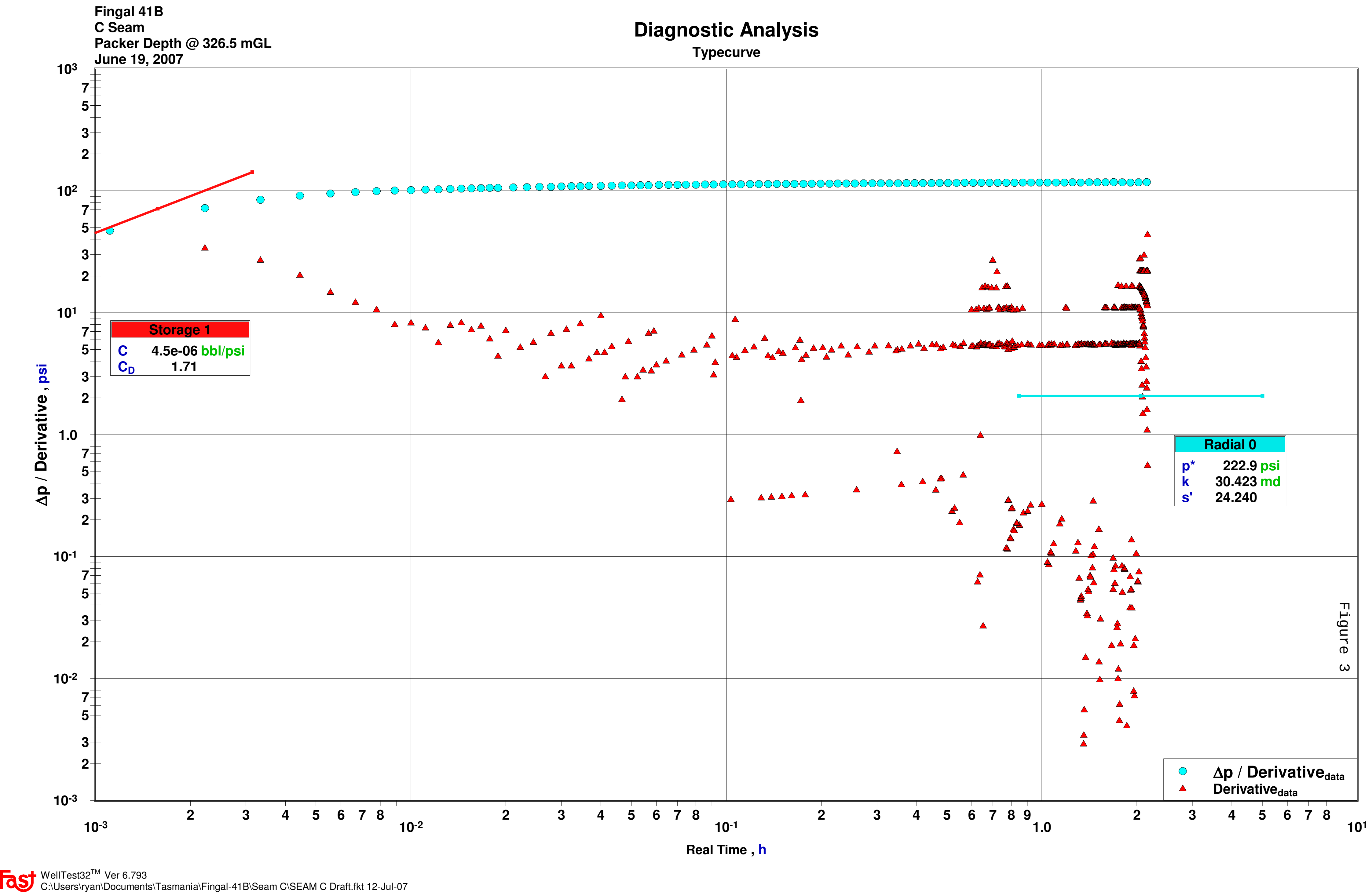

Fingal 41B
C Seam
Packer Depth @ 326.5 mGL
June 19, 2007
Diagnostic Analysis
Typecurve
Storage 1
C 4.5e-06 bbl/psi
CD 1.71
Radial 0
p* 222.9 psi
k 30.423 md
s' 24.240
Δp / Derivative , psi
Real Time , h
Δp / Derivative data
Derivative data
Figure 3
WellTest32TM Ver 6.793
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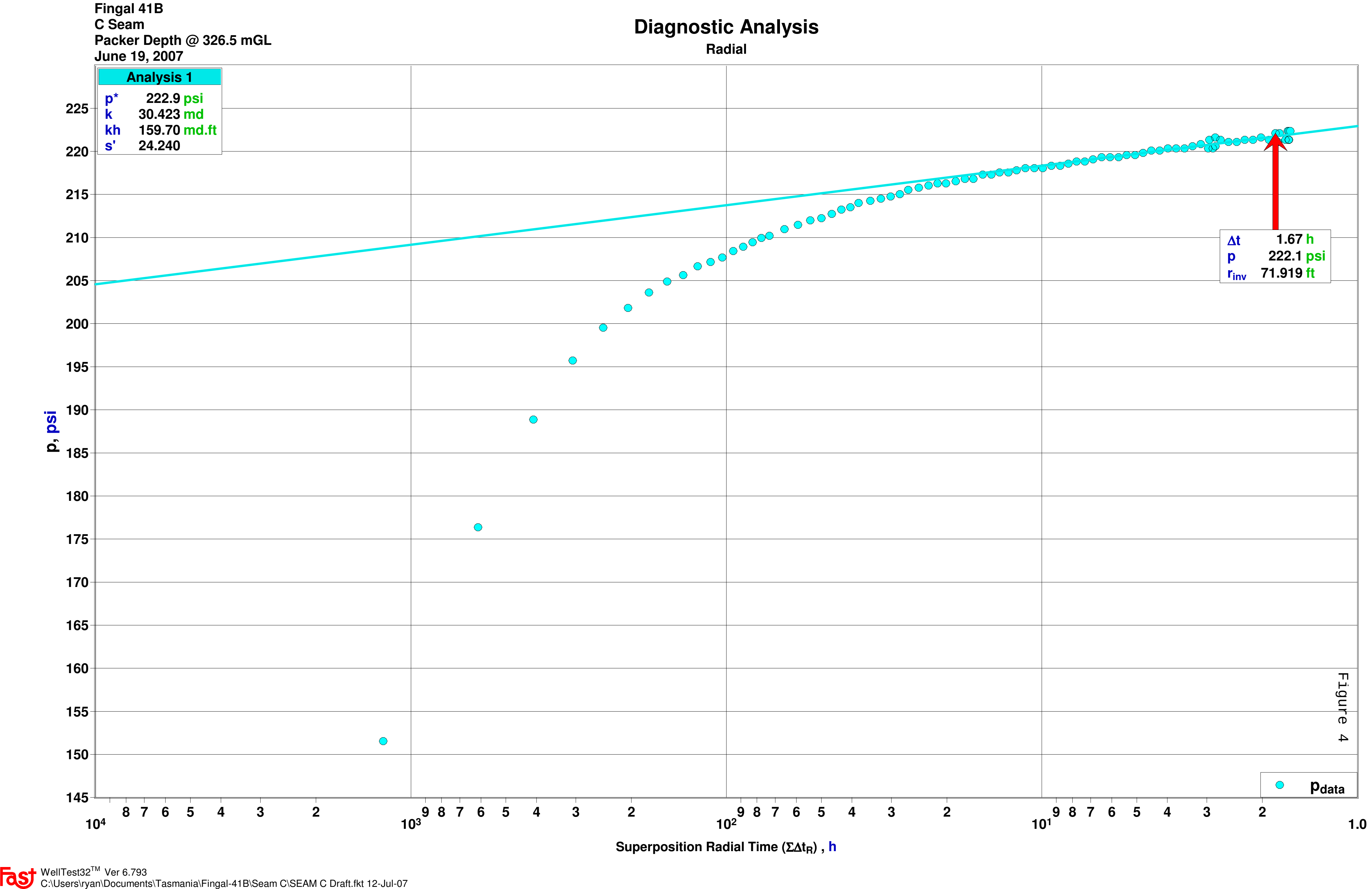

Fingal 41B
C Seam
Packer Depth @ 326.5 mGL
June 19, 2007
Diagnostic Analysis
Radial
Analysis 1
p* 222.9 psi
k 30.423 md
kh 159.70 md.ft
s' 24.240
Δt 1.67 h
p 222.1 psi
r_{inv} 71.919 ft
p, psi
Superposition Radial Time ($\Sigma\Delta t_R$) , h
p_{data}
Figure 4
WellTest32™ Ver 6.793
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Figure 5

Water Well Test - Buildup
Radial Flow Analysis

Fingal 41B	Packer Depth @ 326.5 mGL
C Seam	June 19, 2007

Analysis Results

Total Sandface Rate (q_tB_t)	4.799 bbl/d	Apparent Skin (s')	24.240
Semilog Slope (m)	4.59	Skin - Damage	24.240
Gas Permeability (k_g)	md	Skin - Inclination	
Oil Permeability (k_o)	md	Skin - Partial Penetration	
Water Permeability (k_w)	30.423 md	Pressure Drop Due to Skin (Δp_s)	96.69 psi
Flow Capacity (kh)	159.701 md.ft	Damage Ratio (DR)	5.619
Total Mobility (k/μ_t)	32.38 md/cp	Flow Efficiency (FE)	0.178
Total Transmissivity(kh/μ_t)	169.99 md.ft/cp		

Reservoir Parameters

Net Pay (h)	5.249 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)	72.5 °F
Formation Compressibility (c_f)	9.482e-6 psi^{-1}
Total Compressibility (c_t)	2.471e-4 psi^{-1}

Pressures

Initial Pressure (p_i)	222.00 psi
Extrapolated Pressure (p*)	222.92 psi
Final Flowing Pressure (p_{wfo})	104.37 psi

Production and Times

Corrected Flow Time (t_c)	1.3600 hr
Cumulative Water Production	0.272 bbl
Final Water Rate	4.800 bbl/d

Fluid Properties

Water Compressibility (c_w)	3.27519e-6 psi^{-1}
Water Formation Volume Factor (B_w)	1.000
Water Viscosity (μ_w)	0.939 cp
Solution Gas Ratio (R_{sw})	0 scf/bbl
Specific Gravity (G)	1.000
Gas Gravity (G)	0.650
PVT Reference Pressure (p_{PVT})	222.00 psi

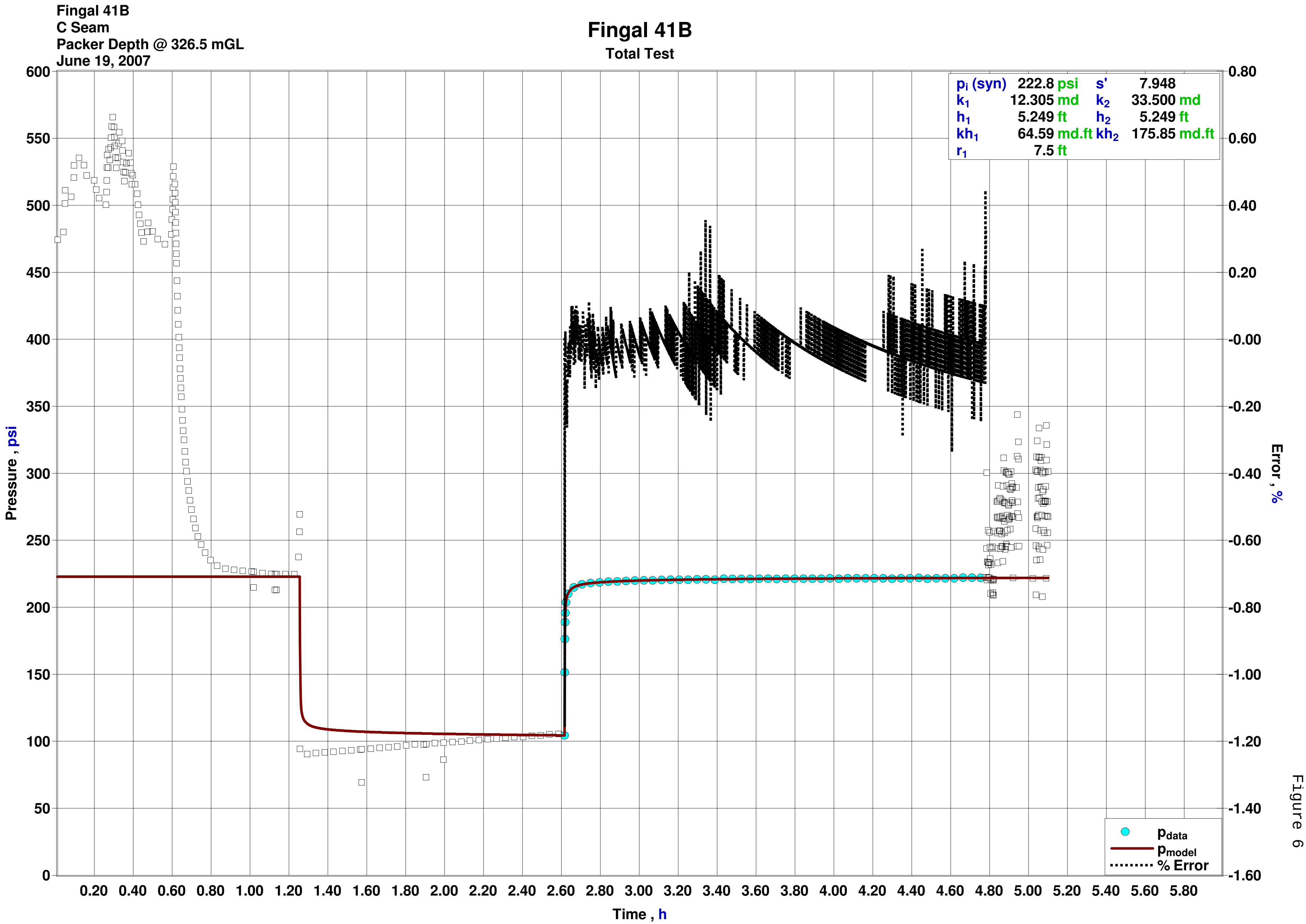

Figure 6

WellTest32™ Ver 6.793
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Fingal 41B
C Seam
Packer Depth @ 326.5 mGL
June 19, 2007

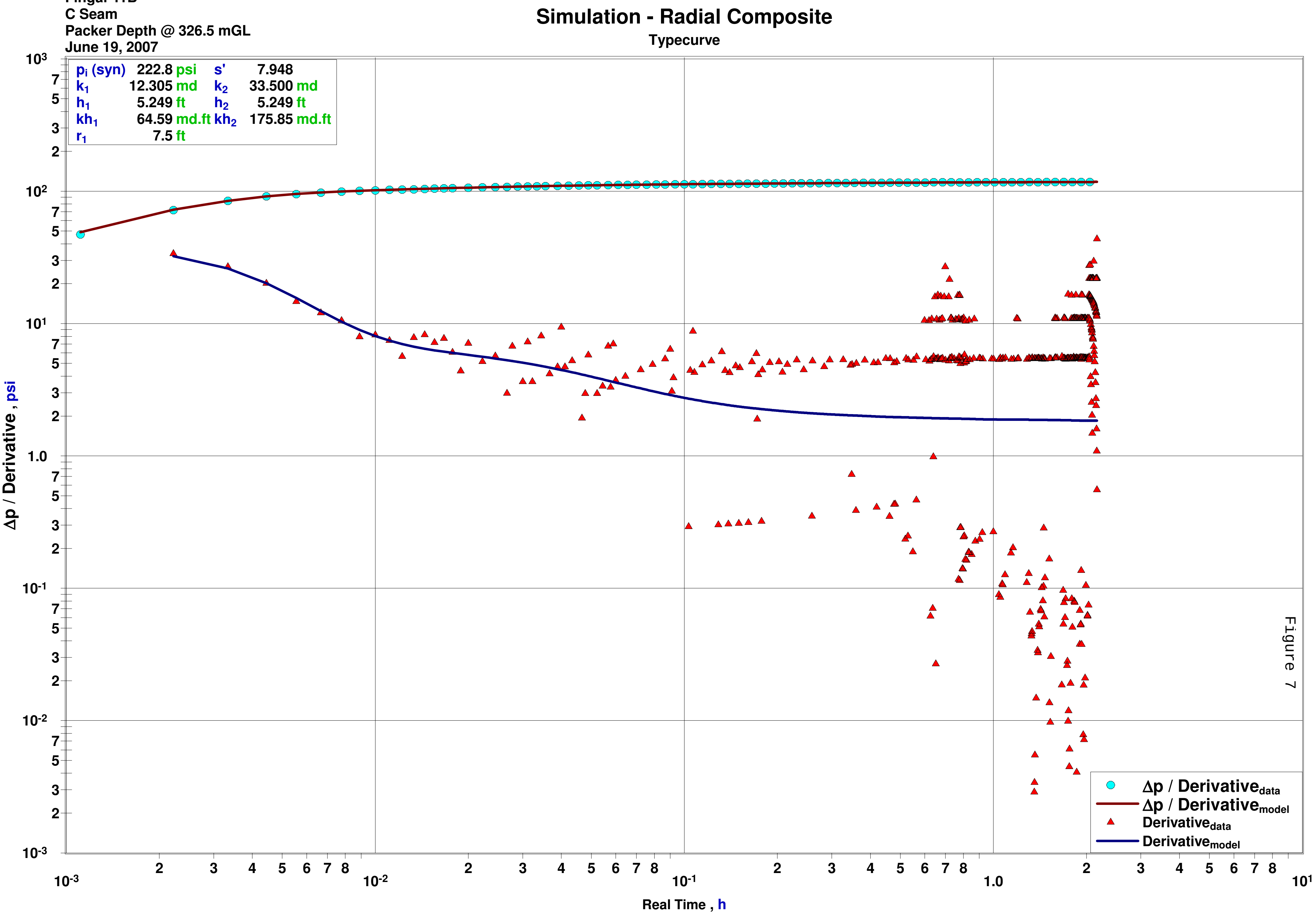

Figure 7

WellTest32™ Ver 6.793
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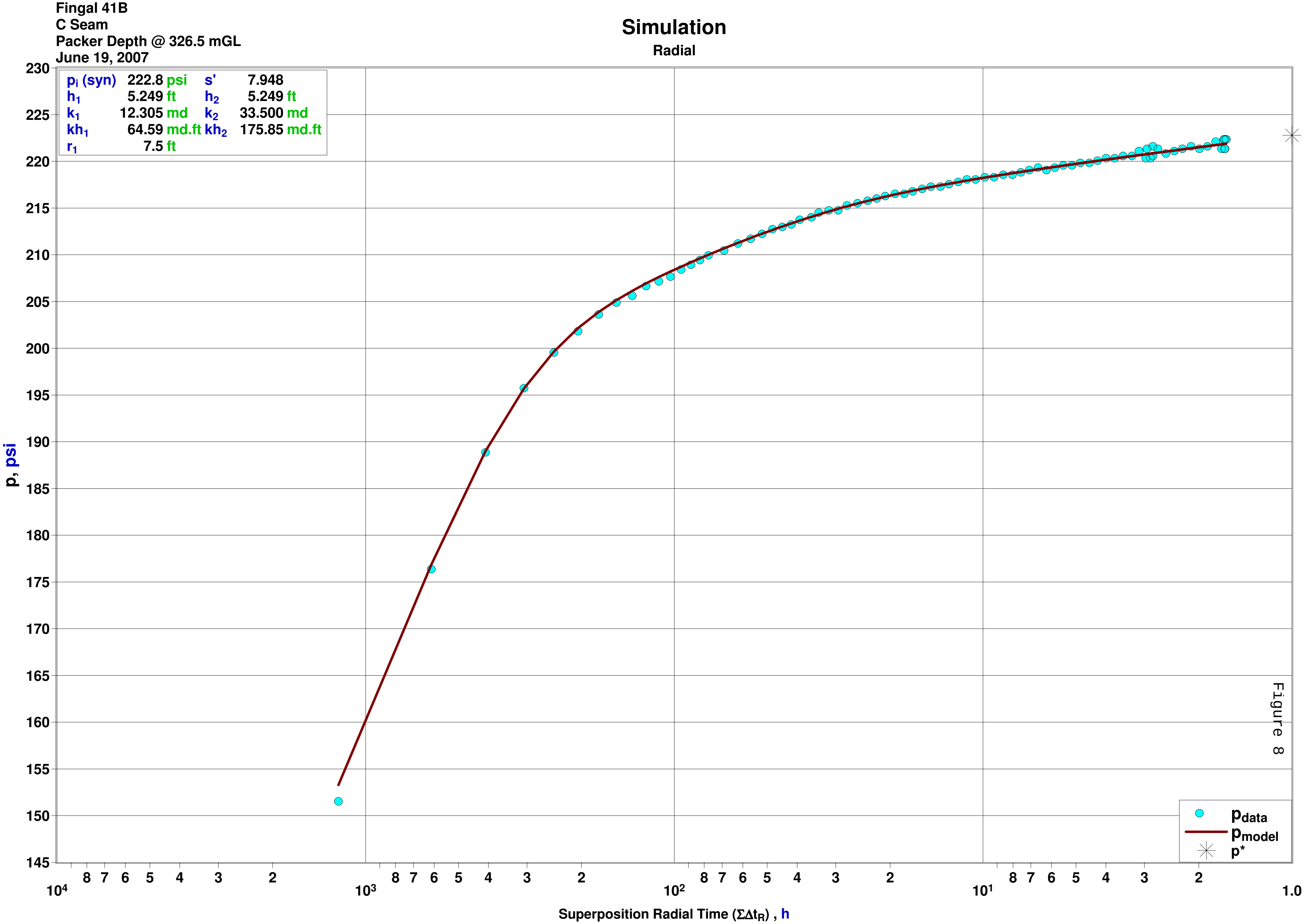

Figure 8

WellTest32™ Ver 6.793
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Composite Water Well Model

Case Name : Radial Composite

Fingal 41B

C Seam

Packer Depth @ 326.5 mGL

June 19, 2007

Model Parameters

Region 1

Total Mobility $(k/\mu)_t$	13.10 md/cp
Permeability $(k)_1$	12.305 md
Net Pay $(h)_1$	5.25 ft
Total Porosity $(\phi_t)_1$	2.00 %
Viscosity $(\mu)_1$	0.939 cp
Total Compressibility $(c_t)_1$	2.471e-4 psi^{-1}
Region Radius $(r)_1$	7.494 ft
Skin (s)	7.948

Region 2

Total Mobility $(k/\mu)_t$	35.66 md/cp
Permeability $(k)_2$	33.500 md
Net Pay $(h)_2$	5.25 ft
Total Porosity $(\phi_t)_2$	2.00 %
Viscosity $(\mu)_2$	0.939 cp
Total Compressibility $(c_t)_2$	2.471e-4 psi^{-1}
Region Radius $(r)_2$	ft

Apparent Wellbore Storage Dim. (C_{aD})	1.71
Wellbore Storage Constant Dim. (C_D)	1.20
Storage Pressure Param. Dim. (C_{pD})	

Formation Parameters

Gas Saturation (S_g)	5.00 %
Water Saturation (S_w)	95.00 %
Oil Saturation (S_o)	0.00 %
Wellbore Radius (r_w)	0.30 ft
Formation Temperature (T)	72.5 °F

Fluid Properties

Water Compressibility (c_w)	3.27519e-6 psi^{-1}
Oil Compressibility (c_o)	1.50000e-6 psi^{-1}
Gas Compressibility (c_g)	4.69021e-3 psi^{-1}
Water Formation Volume Factor (B_w)	1.000
Gas Formation Volume Factor (B_g)	0.011565 bbl/scf
Water Viscosity (μ_w)	0.939 cp
Gas Viscosity (μ_g)	0.0107 cp
Solution Gas Ratio (R_{sw})	0 scf/bbl
Specific Gravity (G)	1.000
PVT Reference Pressure (p_{PVT})	222.00 psi

Production and Pressure

Q_tB_t	4.799 bbl/d
Final Water Rate	4.800 bbl/d
Final Gas Rate	MMCF/D
Final Flowing Pressure (p_{wfo})	104.37 psi
Final Measured Pressure	301.34 psi
Cumulative Water Production	0.272 bbl

Synthesis Results

Average Error	0.05 %
Synthetic Initial Pressure (p_i)	222.78 psi
Extrapolated Pressure at Specified Time	222.78 psi
Pressure Drop Due To Skin (Δp_s)	78.33 psi
Flow Efficiency (FE)	0.338
Damage Ratio (DR)	2.955

Forecasts

Forecast Flowing Pressure (P_{flow})	104.37 psi
3 - Month Constant Rate Forecast @ Curr. Skin	4.312 bbl/d
6 - Month Constant Rate Forecast @ Curr. Skin	4.271 bbl/d
Forecast Flow Duration (t_{flow})	12.00 month
Constant Rate Forecast @ Curr. Skin	4.231 bbl/d
PI / II (Actual)	0.036 bbl/d/psi
Constant Rate Forecast @ Skin=0	10.151 bbl/d
PI / II (Ideal)	0.088 bbl/d/psi
Constant Rate Forecast @ Skin=-4	25.794 bbl/d

FINGAL 41B

DRILL STEM TEST

FINAL REPORT

"D" ZONE COAL SEAM

OPEN HOLE INTERVAL 355.7 – 364.5 mGL

JUNE 23 – 24, 2007

Prepared for:

Pure Energy Resources Limited

Prepared by:

Focal Petroleum Engineering Pty Ltd.

July 11, 2007

PETROLEUM ENGINEERING PTY LTD
ABN 18 061 691 450

July 11, 2007

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

Attention: Mr. Steve Beardsall

Dear Sir

Re: Fingal 41b Coal "D" Drill Stem Test Report

The following is a summary of the results obtained from the Drill Stem Test conducted from June 23 – 24, 2007 over the "D" Coals, open hole interval from circa 355.7 – 364.45 mGL.

The DST was conducted through the drillpipe and coring bit, using an off bottom inflatable packer. Prior to testing, circa 310 meters of water were displaced from the drillpipe with air to allow inflow from the reservoir to occur.

The test was comprised of a one hour flow and a 14.5 hour buildup (recorders left downhole 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 falloff in pressure was noted below the packer suggesting that the reservoir is significantly under-pressured and that there is permeability within the formation.

Comments and Conclusions

- The pressure response observed during the flow and buildup periods suggested a reservoir with moderate 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 (< 2 cf) and was not used in the interpretation.

- A temperature anomaly was noted during the buildup from about 10.5 to 12.5 hours after shut-in. This has been attributed to the temperature recorder and not to a reservoir response. Furthermore, the pressure gauges did not indicate any similar behaviour at this time and all corresponding pressure data was used in the interpretation.

- The gross net pay of 9.8 ft (3 m) was obtained from the core samples (D upper section 4.5 ft, D lower section 5.3 ft). A default porosity of 2% was used for the interpretation.

- An average water rate of circa 9.3 bbl/d was calculated using the pressure increase from the inflow of water into the wellbore during the flow period.

- A reservoir pressure (Pi) of 252 psia was extrapolated from the late-time semi-log data. The subject reservoir is significantly under-pressured with a reservoir gradient of 0.22 psi/ft.

- The pressure derivative indicated that wellbore storage was overcome within the first minute of shut-in by radial flow (zero slope). The pressure derivative displayed some erratic behaviour (non-reservoir activity) during the course of the buildup, but returned to the initial radial flow trend. The non-reservoir activity has been attributed to wellbore effects including minor phase redistribution and liquid movement.

- Conventional analysis and Simulation were both conducted. A line was placed through the initial radial flow portion on the semi-log plot to determine permeability and skin. A second line of identical slope was placed through the late-time semi-log data to extrapolate reservoir pressure.

- 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) @ 351.6 mGL	**252**	**psia (semi-log)**
Apparent Skin Factor	**+2**	
Average Permeability to Water	**4.9**	**md**
Flow Capacity to Water	**48**	**md.ft**
Radius of Investigation	**34**	**ft**

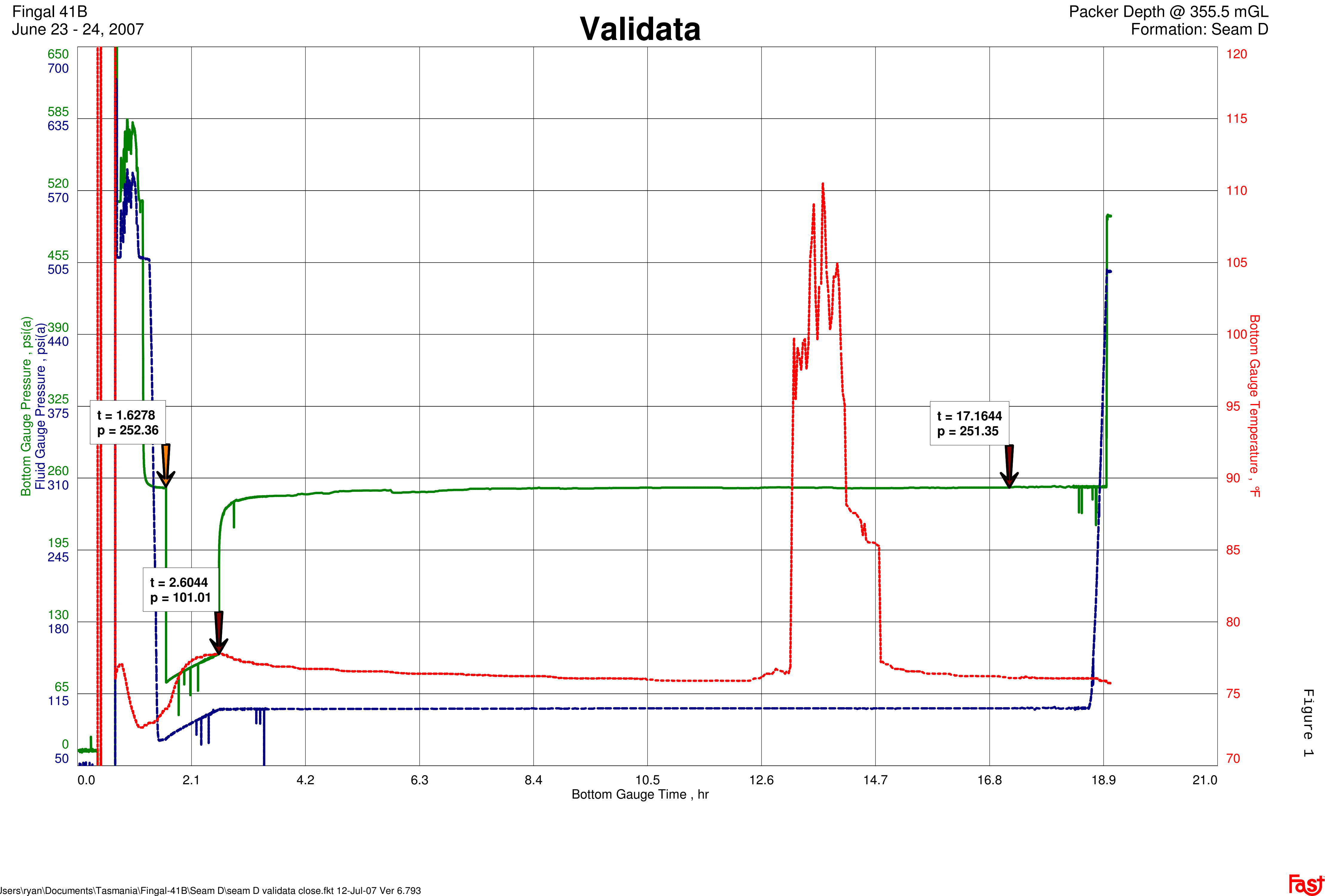
If further clarification of the test interpretation is required, please contact the undersigned on (08) 94749622.

Yours faithfully,
FOCAL PETROLEUM ENGINEERING PTY LTD

Ryan Gee
WELL TEST CONSULTANT

Terry Primeau
MANAGING DIRECTOR

LIST OF FIGURES



Fingal 41B
June 23 - 24, 2007
Validata
Packer Depth @ 355.5 mGL
Formation: Seam D
Bottom Gauge Pressure , psi(a)
Fluid Gauge Pressure , psi(a)
Bottom Gauge Temperature , °F
Bottom Gauge Time , hr
650
700
585
635
520
570
455
505
390
440
325
375
260
310
195
245
130
180
65
115
0
50
120
115
110
105
100
95
90
85
80
75
70
0.0
2.1
4.2
6.3
8.4
10.5
12.6
14.7
16.8
18.9
21.0
t = 1.6278
p = 252.36
t = 2.6044
p = 101.01
t = 17.1644
p = 251.35

Figure 1

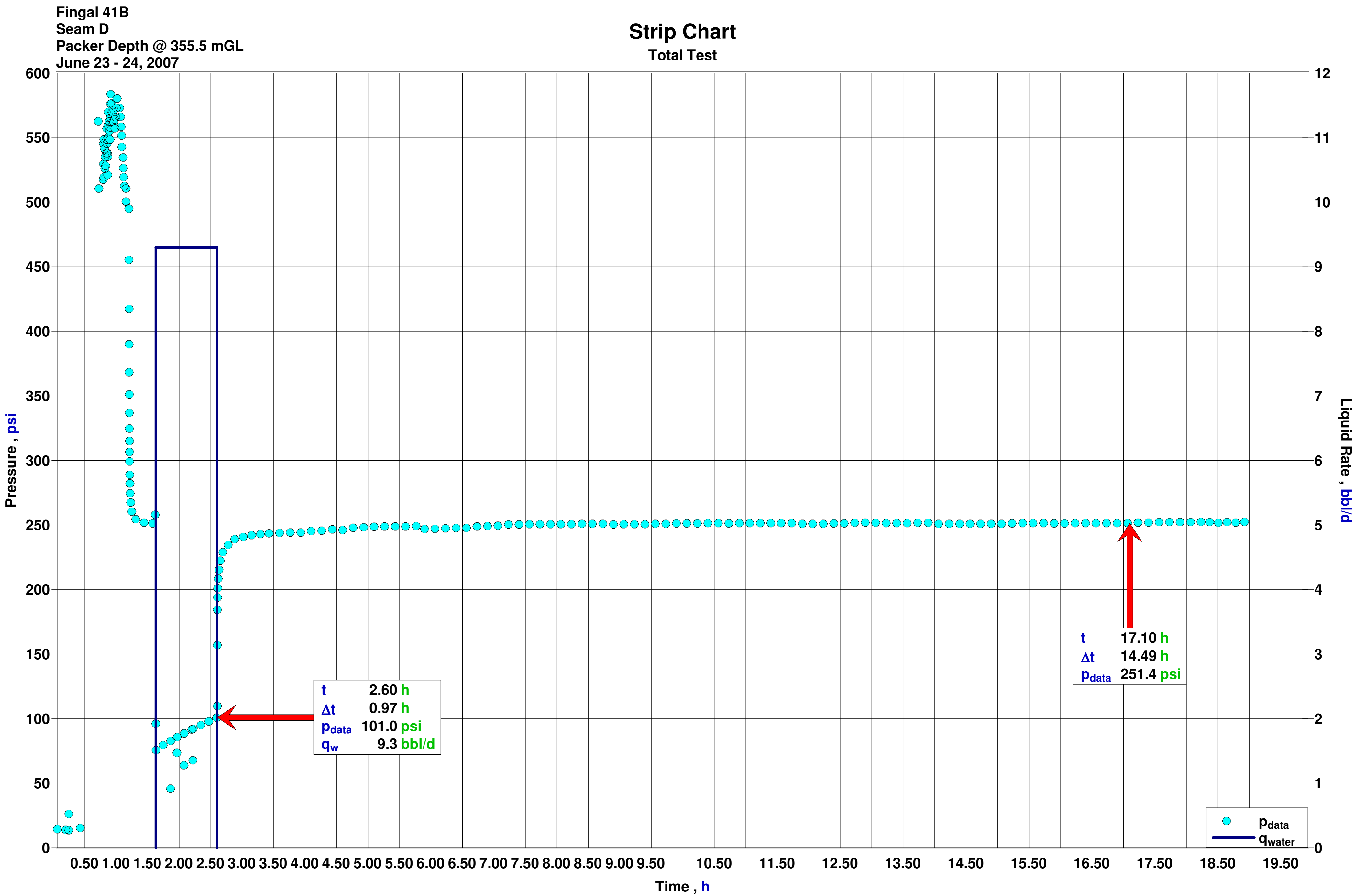


Figure 2

WellTest32TM Ver 6.793
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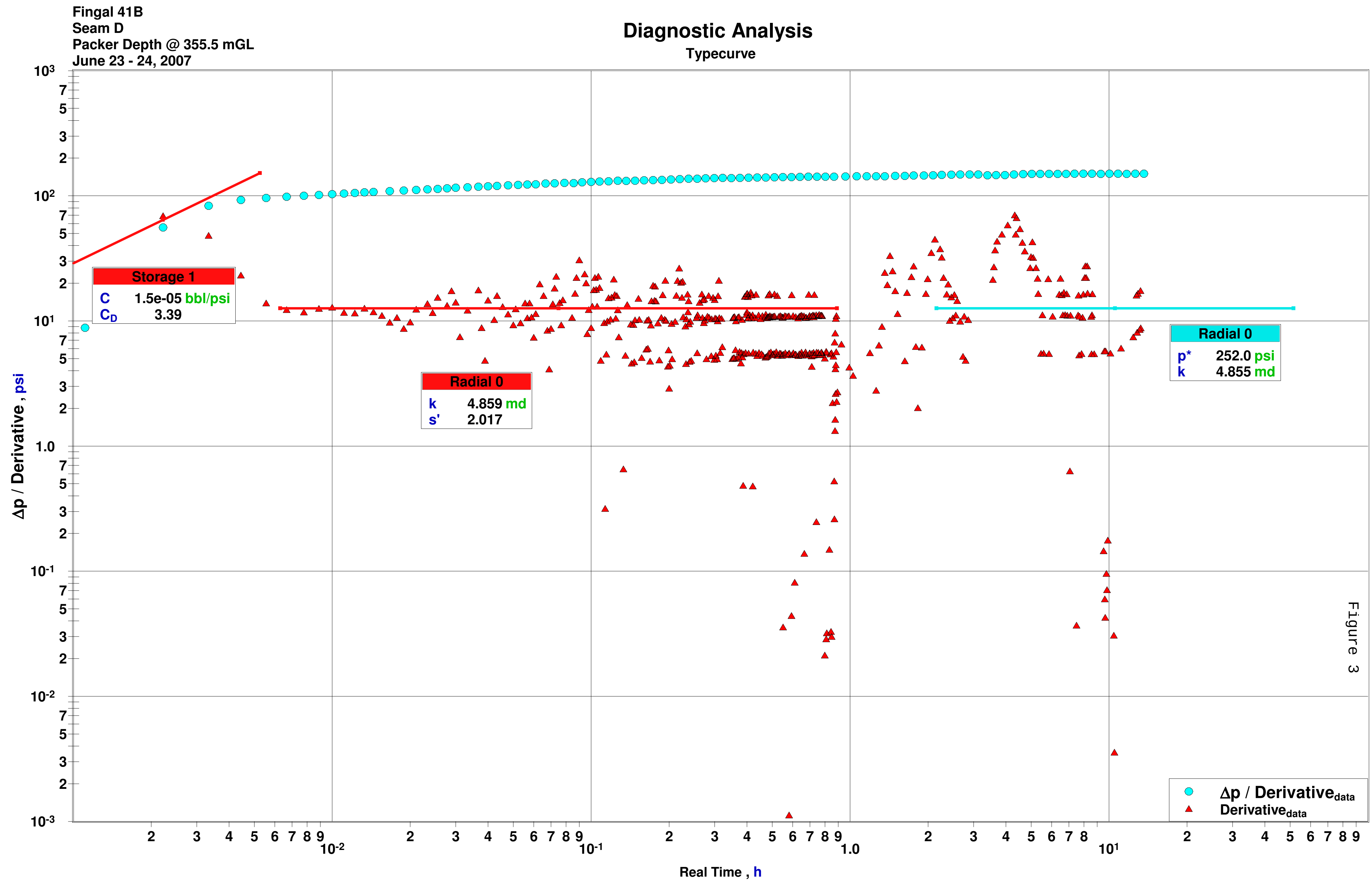

Figure 3

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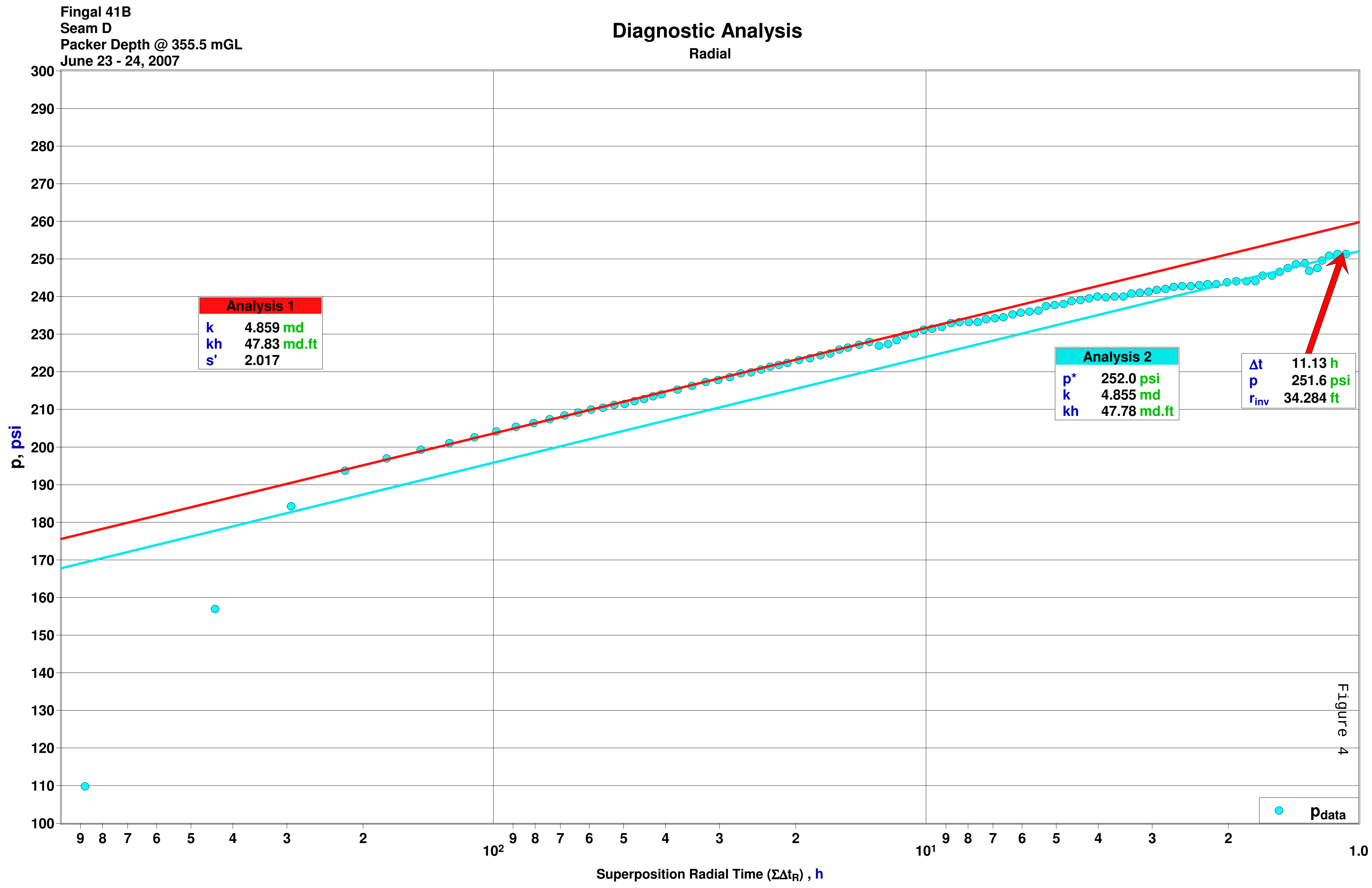

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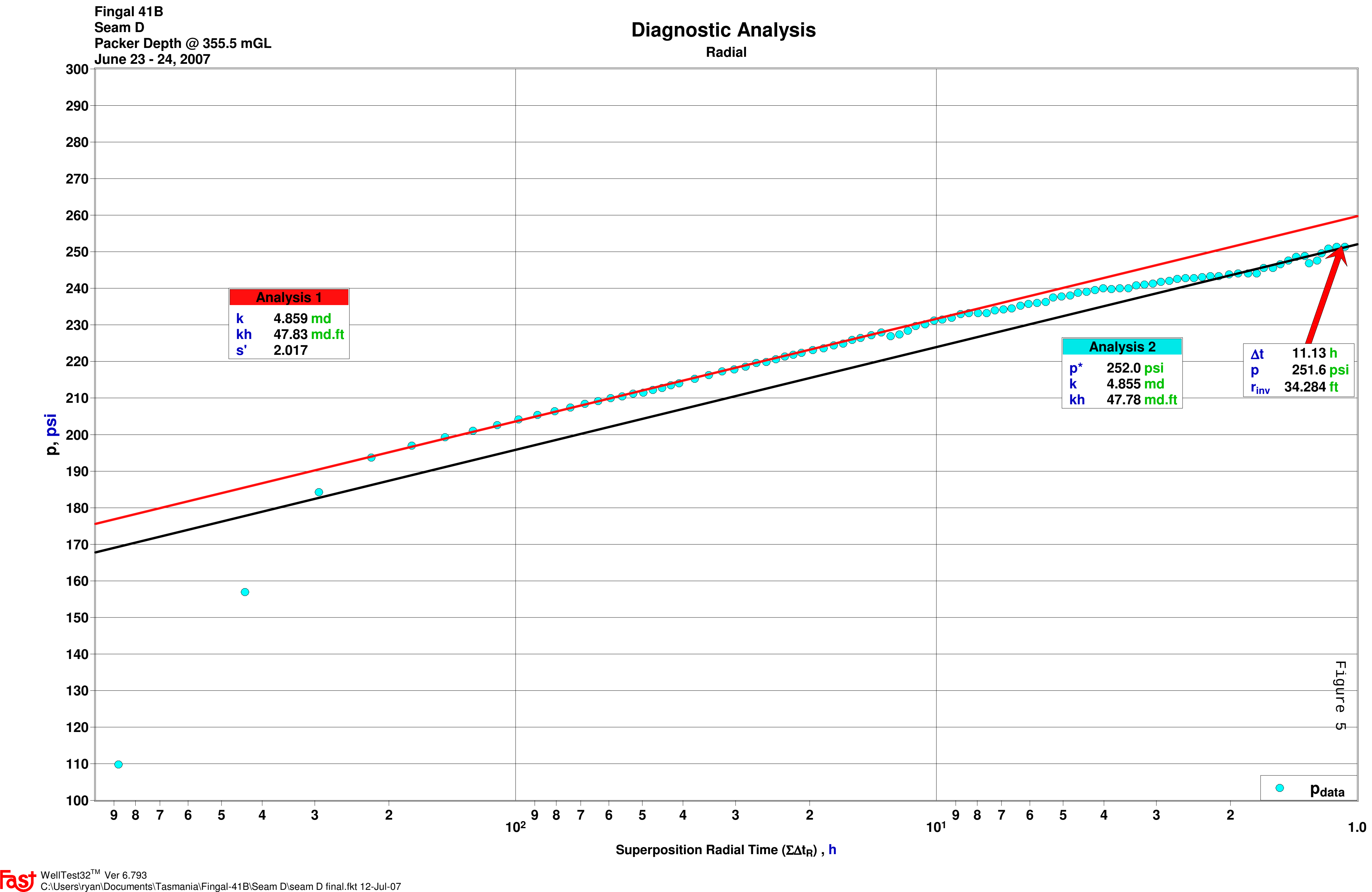
Fingal 41B
Seam D
Packer Depth @ 355.5 mGL
June 23 - 24, 2007
Diagnostic Analysis
Radial
Analysis 1
k 4.859 md
kh 47.83 md.ft
s' 2.017
Analysis 2
p* 252.0 psi
k 4.855 md
kh 47.78 md.ft
Δt 11.13 h
p 251.6 psi
r inv 34.284 ft
p, psi
Superposition Radial Time (ΣΔtR) , h
pdata
Figure 5
WellTest32TM Ver 6.793
C:\Users\ryan\Documents\Tasmania\Fingal-41B\Seam D\seam D final.fkt 12-Jul-07

Fingal 41B
Seam D
Packer Depth @ 355.5 mGL
June 23 - 24, 2007

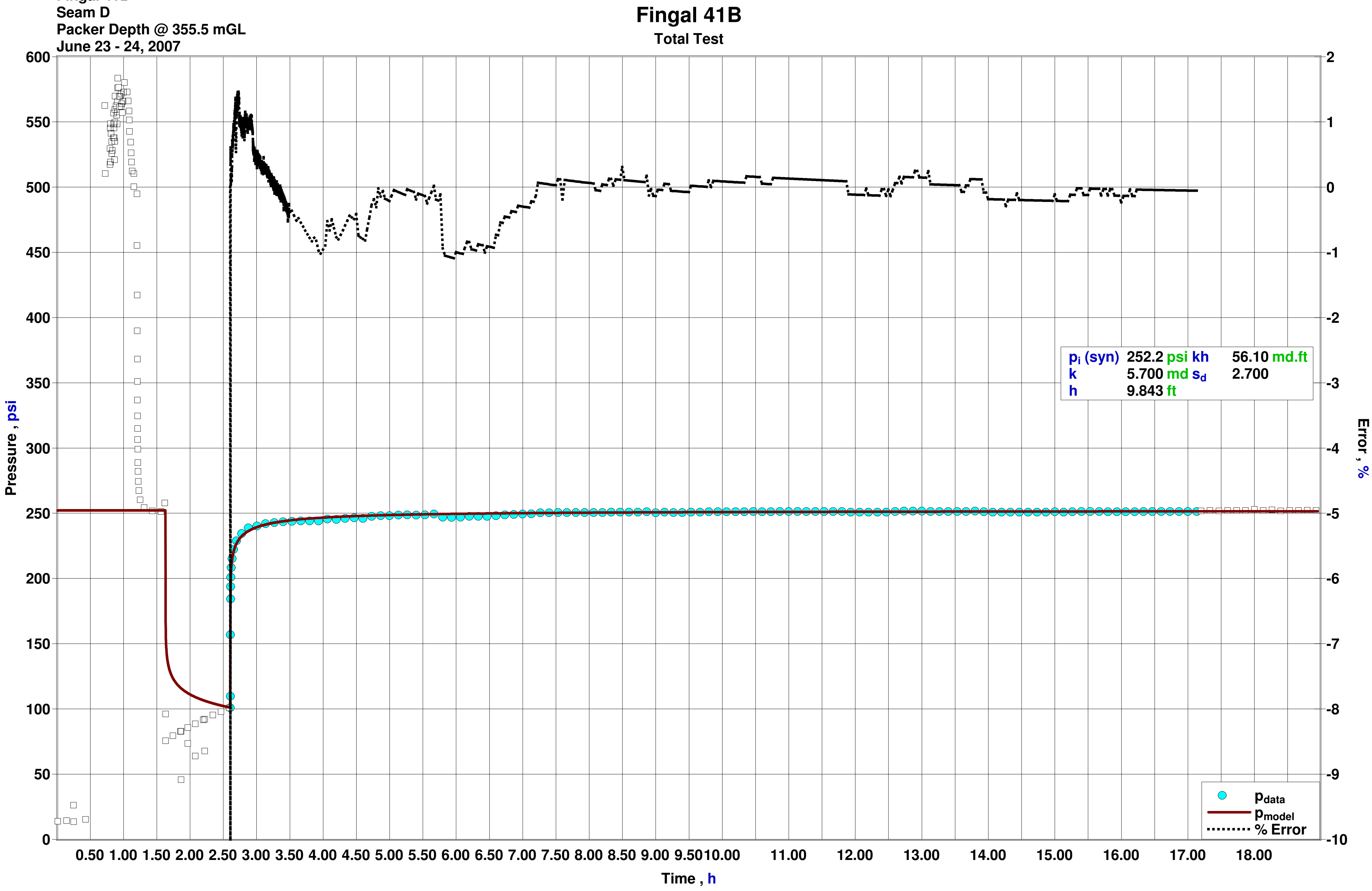

Figure 6

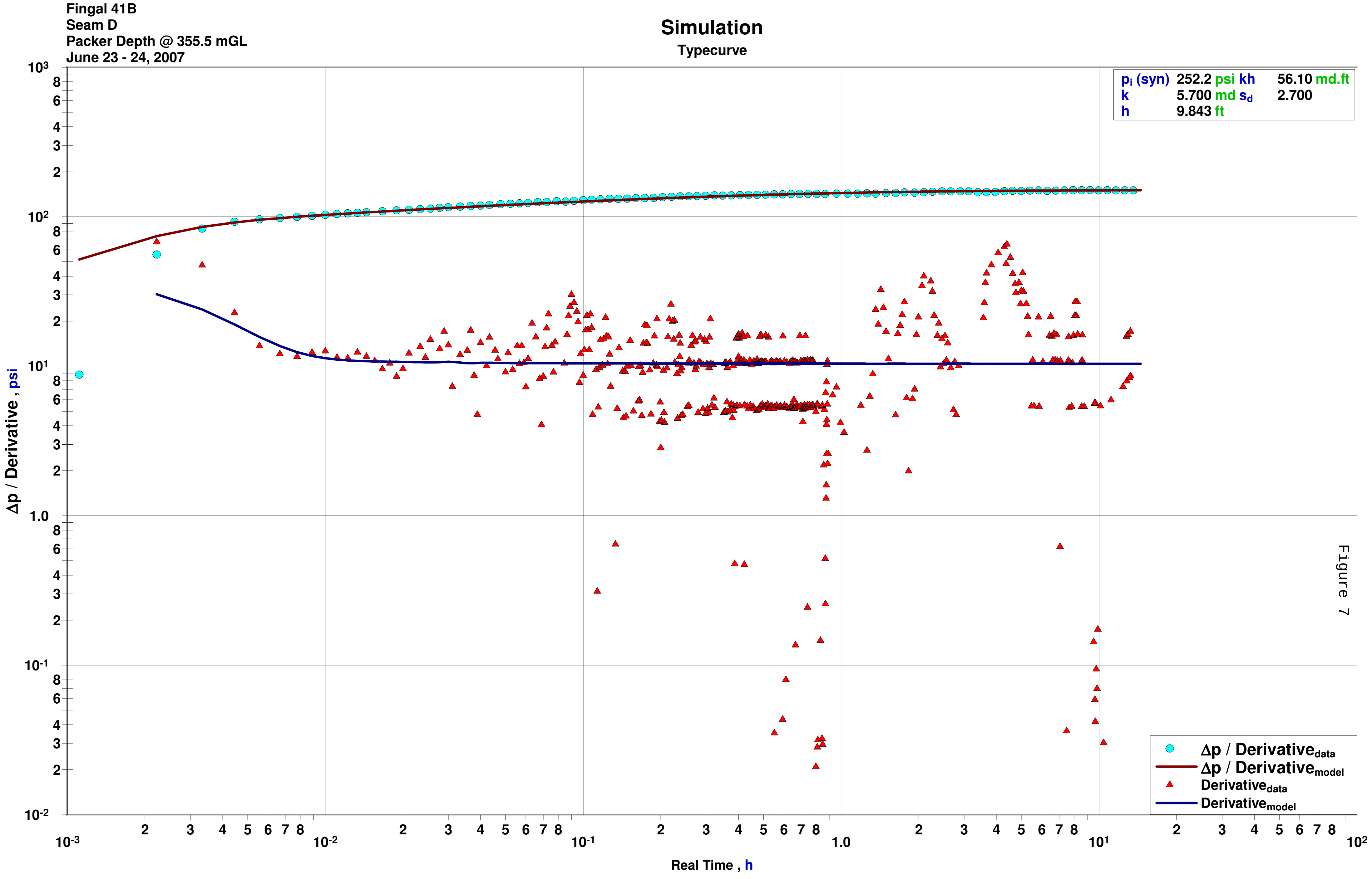

Figure 7

WellTest32™ Ver 6.793
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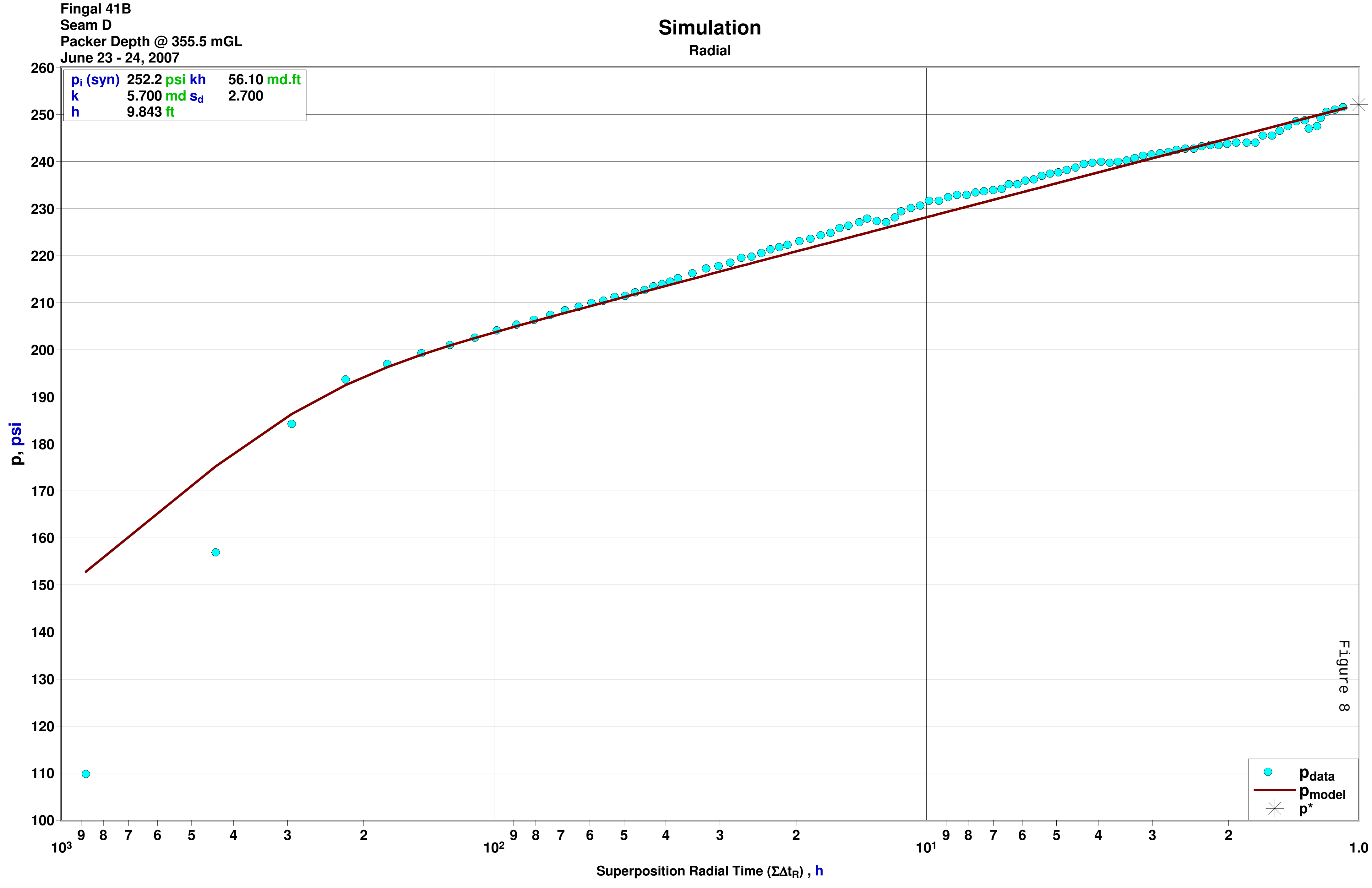

WellTest32™ Ver 6.793
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Vertical Water Well Model

Case Name : Simulation

Fingal 41B

Seam D

Packer Depth @ 355.5 mGL

June 23 - 24, 2007

Model Parameters

Water Permeability (k_w)	5.700 md
Gas Permeability (k_g)	md
Skin (s)	2.700
Total Mobility ($(k/\mu)_t$)	6.42 md/cp
Total Transmissivity ($(kh/\mu)_t$)	63.19 md.ft/cp
Wellbore Storage Constant Dim. (C_D)	1.20

Reservoir Length (X_e)	1000000.000 ft
Reservoir Width (Y_e)	1000000.000 ft
Active Well At (X_w)	ft
Active Well At (Y_w)	ft

Production and Pressure

Q_tB_t	9.303 bbl/d
Final Water Rate	9.300 bbl/d
Final Gas Rate	MMCF/D
Final Flowing Pressure (p_{wfo})	101.01 psi
Final Measured Pressure	251.85 psi
Cumulative Water Production	0.378 bbl

Formation Parameters

Net Pay (h)	9.843 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)	76.9 °F
Formation Compressibility (c_f)	9.482e-6 psi^{-1}
Total Compressibility (c_t)	2.201e-4 psi^{-1}

Synthesis Results

Average Error	0.45 %
Synthetic Initial Pressure (p_i)	252.16 psi
Extrapolated Pressure at Specified Time	252.16 psi
Pressure Drop Due To Skin (Δp_s)	56.12 psi
Flow Efficiency (FE)	0.629
Damage Ratio (DR)	1.591

Fluid Properties

Water Compressibility (c_w)	3.25199e-6 psi^{-1}
Water Formation Volume Factor (B_w)	1.000
Water Viscosity (μ_w)	0.888 cp
Solution Gas Ratio (R_{sw})	0 scf/bbl
Specific Gravity (G)	1.000
PVT Reference Pressure (p_{PVT})	251.93 psi

Forecasts

Forecast Flowing Pressure (P_{flow})	101.01 psi
3 - Month Constant Rate Forecast @ Curr. Skin	6.075 bbl/d
6 - Month Constant Rate Forecast @ Curr. Skin	5.891 bbl/d
Forecast Flow Duration (t_{flow})	12.00 month
Constant Rate Forecast @ Curr. Skin	5.719 bbl/d
PI / II (Actual)	0.039 bbl/d/psi
Constant Rate Forecast @ Skin=0	7.412 bbl/d
PI / II (Ideal)	0.051 bbl/d/psi
Constant Rate Forecast @ Skin=-4	13.197 bbl/d

FINGAL 41B

DRILL STEM TEST

FINAL REPORT

"F" ZONE COAL SEAM

OPEN HOLE INTERVAL 405 – 407.9 mGL

JUNE 27, 2007

Prepared for:

Pure Energy Resources Limited

Prepared by:

Focal Petroleum Engineering Pty Ltd.

July 11, 2007

ABN 18 061 691 450

July 11, 2007

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

Attention: Mr. Steve Beardsall

Dear Sir

Re: Fingal 41b Coal "F" Drill Stem Test Report

The following is a summary of the results obtained from the Drill Stem Test conducted on June 27, 2007 over the "F" Coal, open hole interval from circa 405 – 407.9 mGL.

The DST was conducted through the drillpipe and coring bit, using an off bottom inflatable packer. Prior to testing, circa 345 meters of water was displaced from the drillpipe with air to allow inflow from the reservoir to occur.

The test was comprised of a one hour flow and a 35 minute shut-in period. The fluid recorder observed a negligible (zero) increase in pressure during the flow period, indicating no measurable inflow from the reservoir. Immediately after shut-in, the bottomhole pressures began to decline indicating the reservoir pressure was lower than the 55 meters of hydrostatic head in the drill pipe. Therefore, the test was terminated after only 35 minutes of shut-in and based on discussions with Pure personnel, a re-test of the F seam was not conducted. The following report is a qualitative analysis of the F seam.

During the inflation of the isolation packers, a long and slow falloff in pressure was noted below the packer suggesting that the permeability within the test interval is low and that the reservoir is extremely under-pressured.

Comments and Conclusions

- The pressure response observed during the initial falloff and shut-in period suggested a reservoir with low flow capacity to water. A water injection rate was incorporated into the flow period in order to provide some qualitative analysis of the data.

- The net pay of nine ft (2.9 m) was obtained from the core samples. A default porosity of 2% was used for the interpretation.

- The last measured pressure during the shut-in period was 62.8 psia at recorder run depth (RRD). The minimum estimate of reservoir pressure (Pi) of 49.1 psia was extrapolated from the late-time semi-log plot. These pressures are the range for reservoir pressure of the F seam. The subject zone is extremely under-pressured with a formation gradient between 0.037 and 0.048 psi/ft.

- The pressure derivative suggested that wellbore storage was overcome by what appears to be fracture flow (half slope trend) effects that lasted for the duration of the test. This could be attributed to a small fracture created in the very near wellbore area as a result of the over balance pressure of the hydrostatic column (circa 580 psi) in the wellbore during drilling.

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

Fingal 41B
June 27, 2007

Validata

Packer Depth @ 404.7 mGL
Formation: Seam F

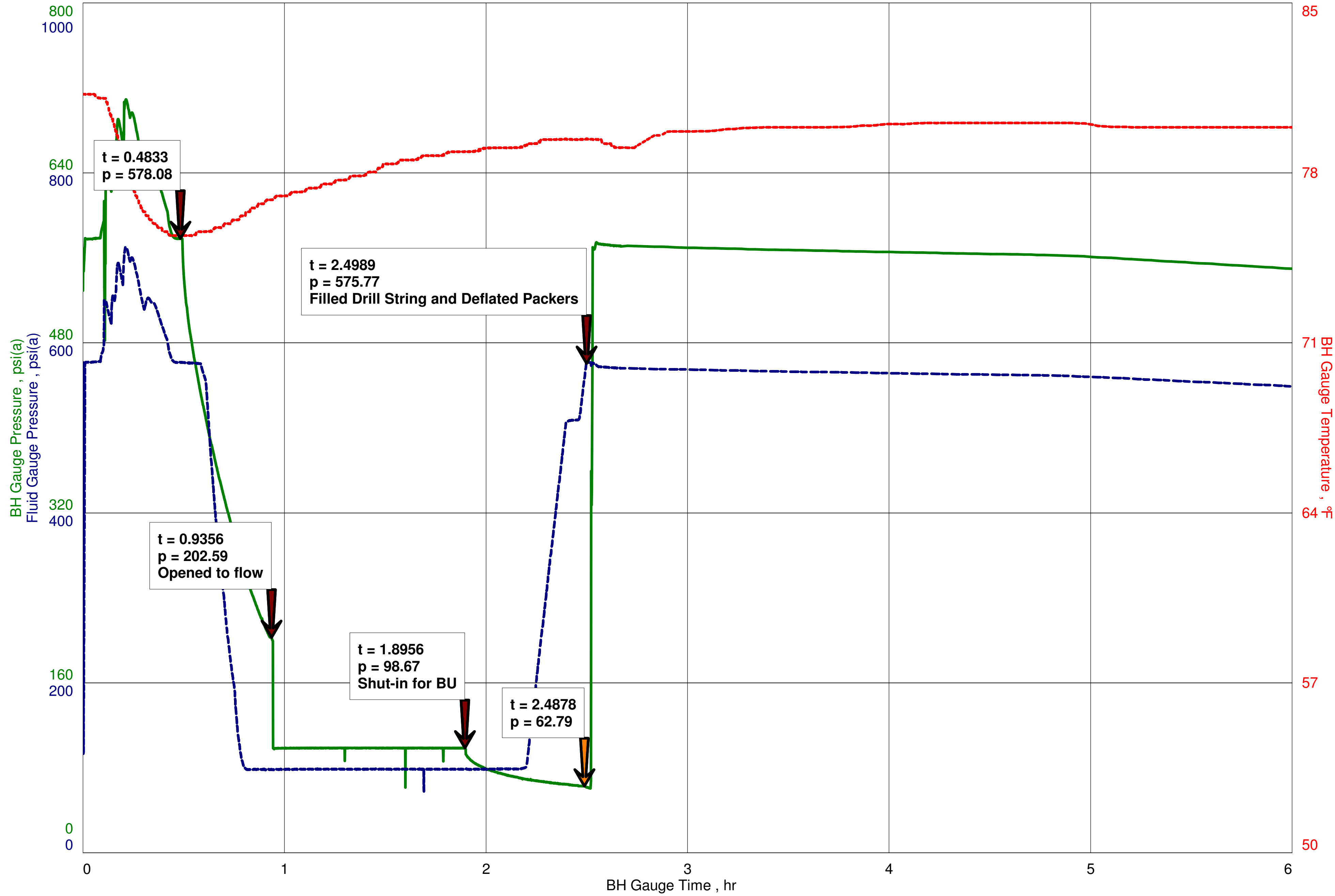

Figure 1

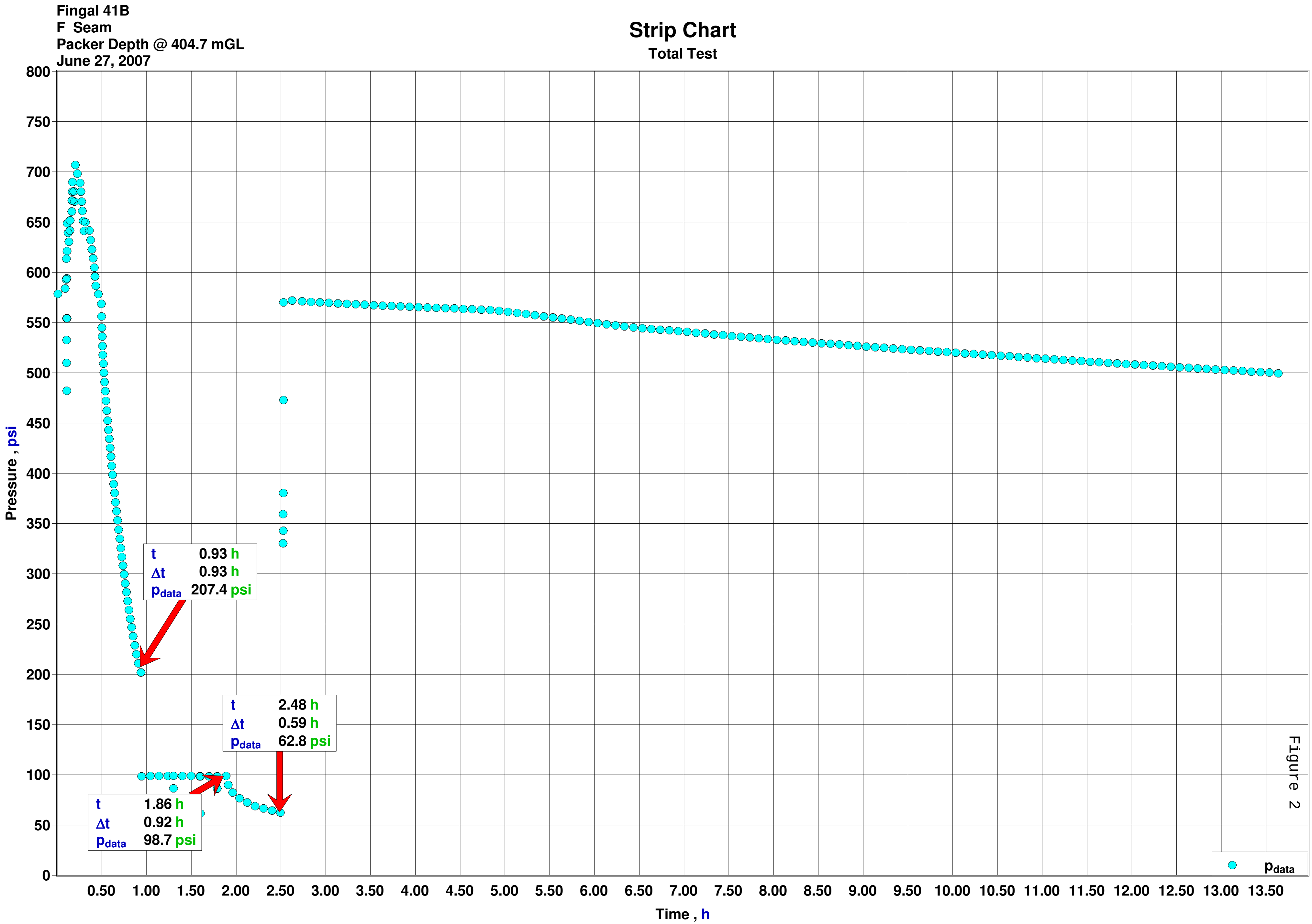

Figure 2

WellTest32™ Ver 6.793
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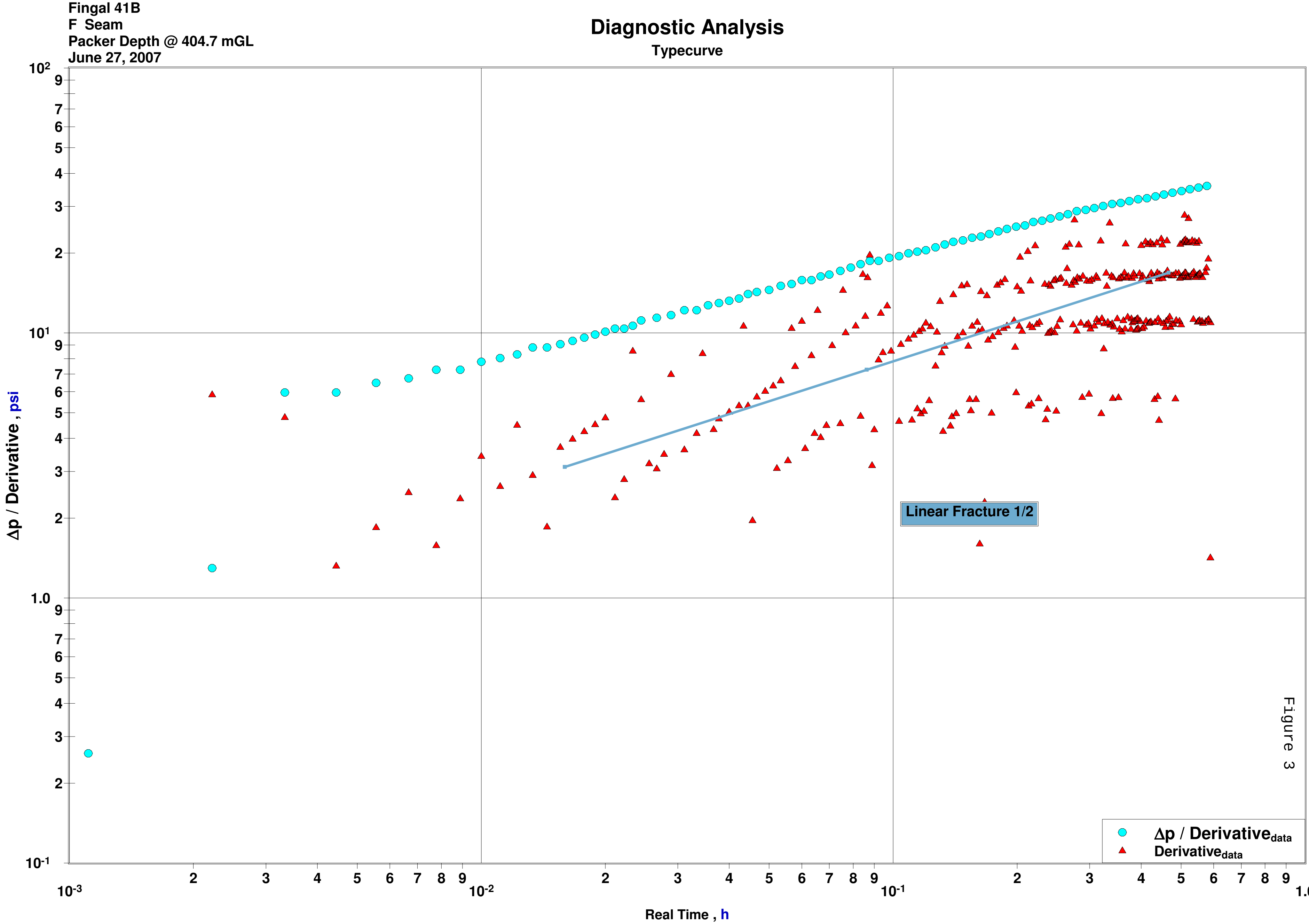

Figure 3

WellTest32™ Ver 6.793
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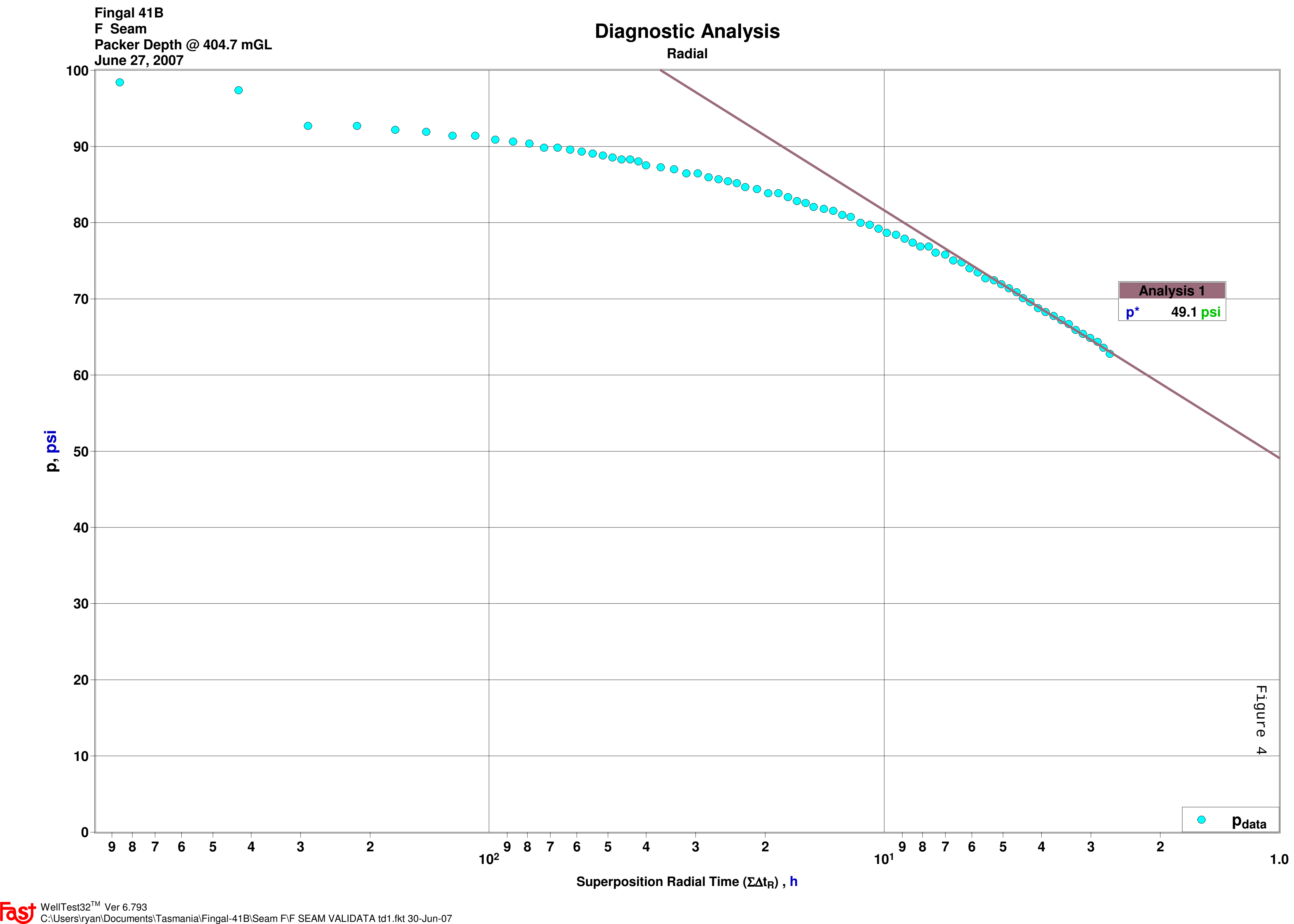

Fingal 41B
F Seam
Packer Depth @ 404.7 mGL
June 27, 2007
Diagnostic Analysis
Radial
Analysis 1
p* 49.1 psi
p, psi
Superposition Radial Time (ΣΔtR) , h
pdata
Figure 4
WellTest32TM Ver 6.793
C:\Users\ryan\Documents\Tasmania\Fingal-41B\Seam F\F SEAM VALIDATA td1.fkt 30-Jun-07

FINGAL 41B
DRILL STEM TEST
FINAL REPORT
"G UPPER & G LOWER" ZONE COAL SEAMS
OPEN HOLE INTERVAL
453.7 – 455.1 & 462.6 – 463.6 mGL
JULY 1, 2007

Prepared for:

Pure Energy Resources Limited

PURE

ENERGY RESOURCES LIMITED

Prepared by:

Focal Petroleum Engineering Pty Ltd.

July 11, 2007

focal

PETROLEUM ENGINEERING PTY LTD

PETROLEUM ENGINEERING PTY LTD
ABN 18 061 691 450

July 11, 2007

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

Attention: Mr. Steve Beardsall

Dear Sir

Re: Fingal 41b 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 July 1, 2007 over the "G upper and G lower" Coals, open hole interval from circa 453.65 – 455.1 and 462.58 – 463.64 mGL

The DST was conducted through the drillpipe and coring bit, using an off bottom inflatable packer. Prior to testing, circa 345 meters of water was displaced from the drillpipe with air to allow inflow from the reservoir to occur.

The test was comprised of a one hour flow and a 1.5 hour buildup. 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 sharp increase in pressure followed by a long, slow falloff was noted below the packer suggesting that the reservoir has low permeability and is significantly under-pressured.

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 was the result of some upward movement by the packer, creating a small amount of suction in the wellbore.

The buildup data used in the well test analysis was truncated circa 15 minutes prior to the end of the downhole shut-in. It appeared that the late-time data was influenced by non-reservoir activity that has been attributed to the commencement of operations to pull the gauges out of hole. This did not affect the overall interpretation of the test.

Comments and Conclusions

- The pressure response observed during the flow and buildup periods suggested a reservoir with very 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 7.9 ft (2.4 m) was obtained from the core samples (G upper 4.8 ft, G lower 3.1 ft). A default porosity of 2% was used for the interpretation.

- An average water rate of circa 0.5 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 of 273 psia was extrapolated from the late-time pressure fall-off data observed after the packers were inflated. The reservoir pressure (Pi) of 273 psia was also determined from the simulation match of the buildup and has been quoted throughout the report. The subject reservoir is significantly under-pressured with a reservoir gradient of 0.19 psi/ft.

- The pressure derivative indicated that wellbore storage dominated the entire buildup. For the purposes of this report, it was assumed that the late-time data was approaching radial flow (zero slope).

- Conventional analysis and Simulation were both conducted. The conventional estimates for permeability and skin were used to initiate the simulation match. An excellent match was obtained using a vertical model and the results have been quoted throughout this report. However, it should be noted that the match was non-unique and acceptable matches could also be obtained using other reservoir models and parameters. Therefore, these results should be used with some caution.

- The negative skin value is considered low and could be attributed to a slightly improved wellbore condition, or small natural fractures observed in the G upper section of core.

A summary of the Test Results is as follows:

Average Reservoir Pressure (Pr) @ 449.4 mGL	**273**	**psia (simulation)**
Apparent Skin Factor	**-1.3**	
Average Permeability to Water	**0.06**	**md**
Flow Capacity to Water	**0.5**	**md.ft**
Radius of Investigation	**3**	**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

focal
PETROLEUM ENGINEERING PTY LTD

LIST OF FIGURES

Fingal 41B
July 1, 2007

Validata

Packer Depth @ 453.3 mGL
Formation: Seam G upper & G lower

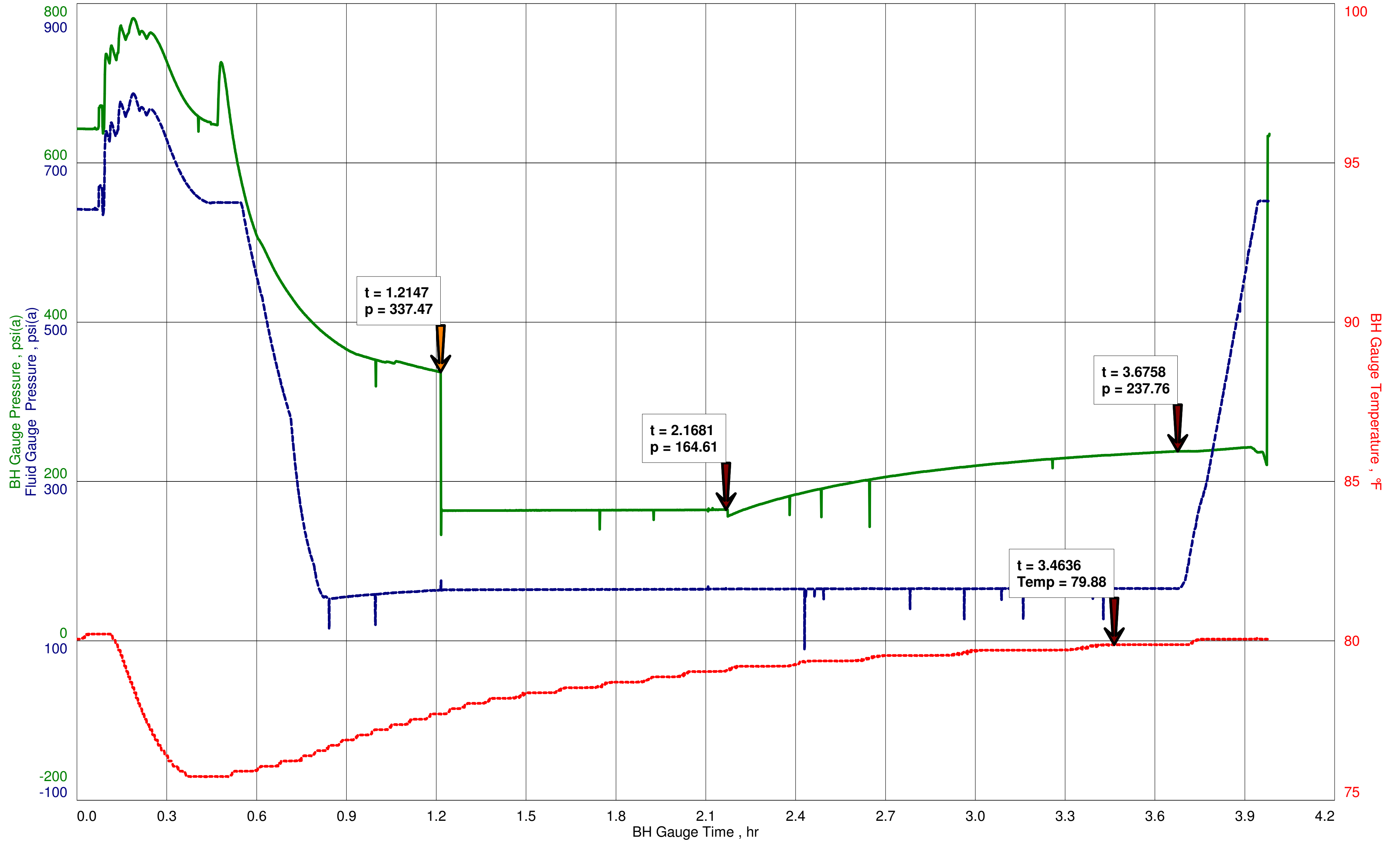

Figure 1

Fingal 41B
July 1, 2007

Packer Depth @ 453.3 mGL
Formation: Seam G upper & G lower

Validata (Late-Time Data)

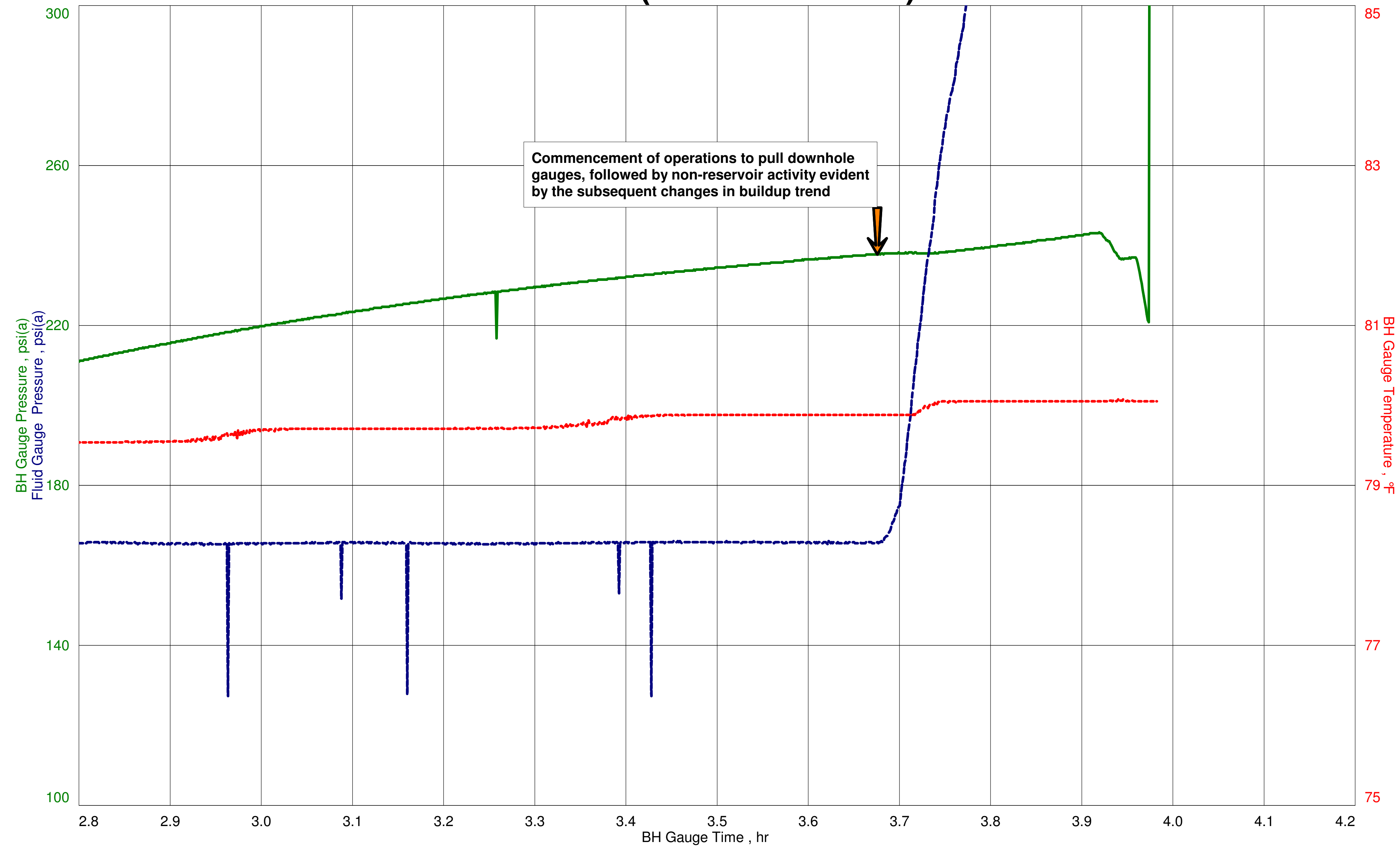

Figure 2

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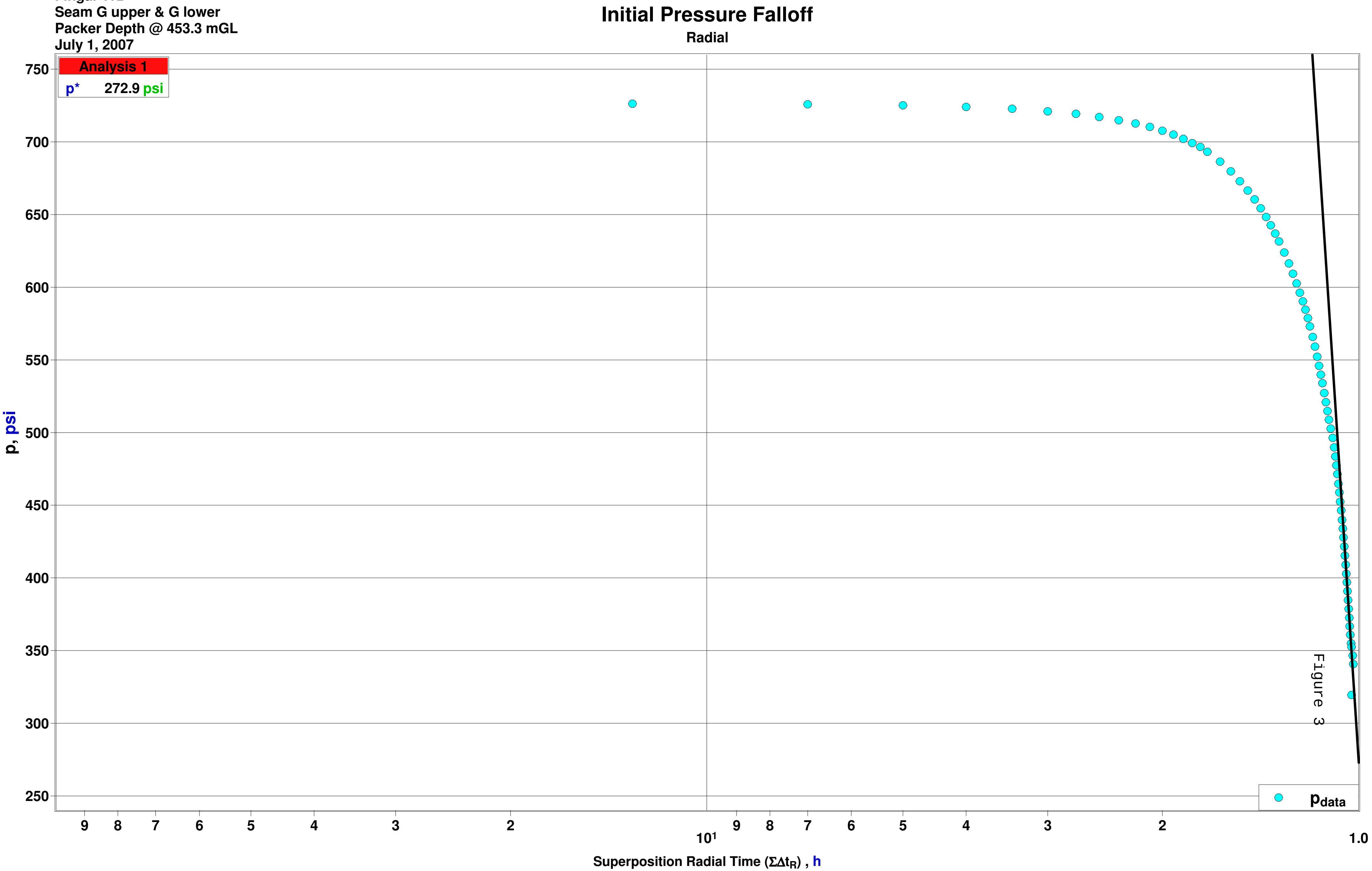
Fast

Fingal 41B
Seam G upper & G lower
Packer Depth @ 453.3 mGL
July 1, 2007



WellTest32TM Ver 6.793
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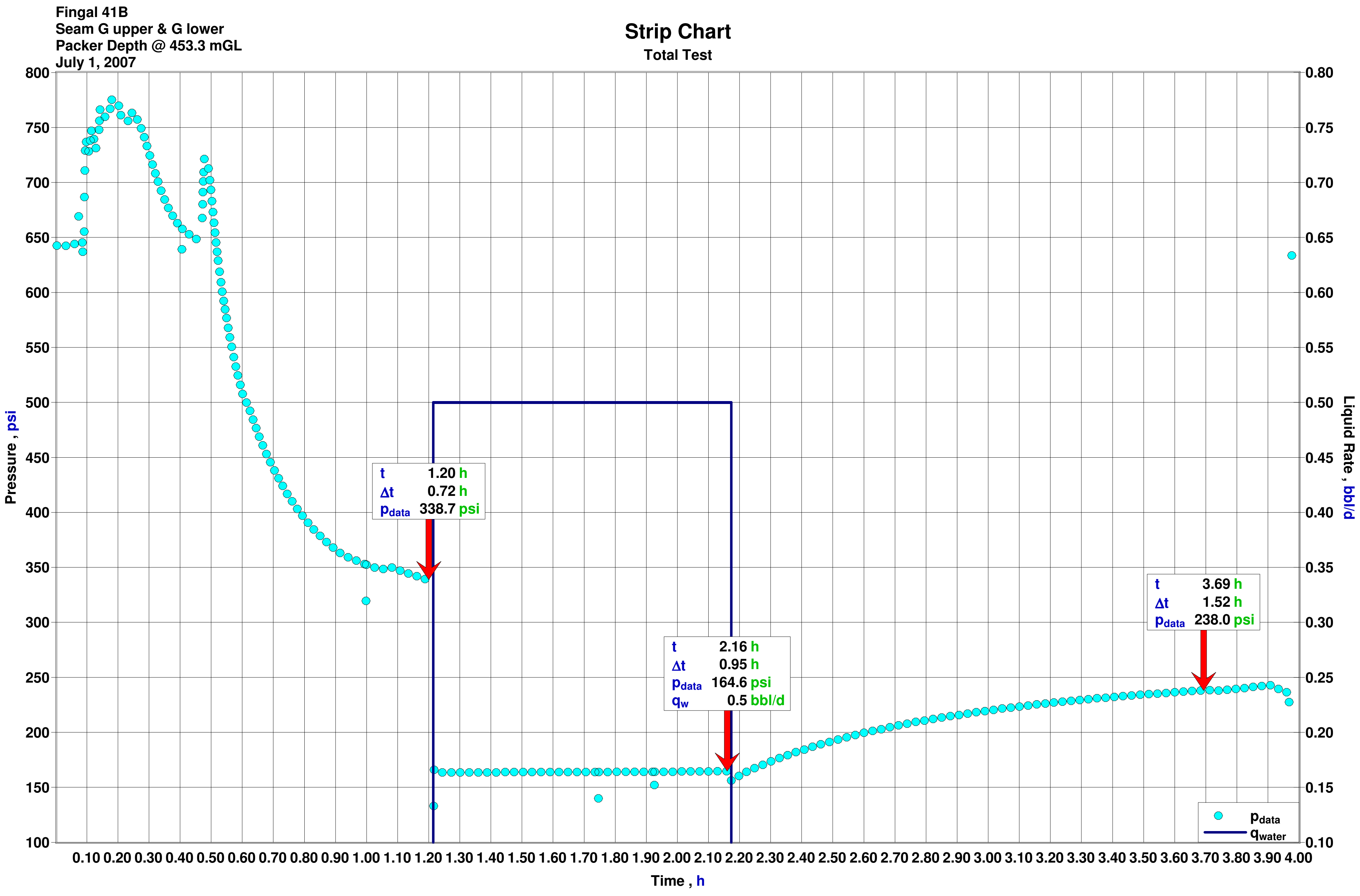

Figure 4

WellTest32™ Ver 6.793
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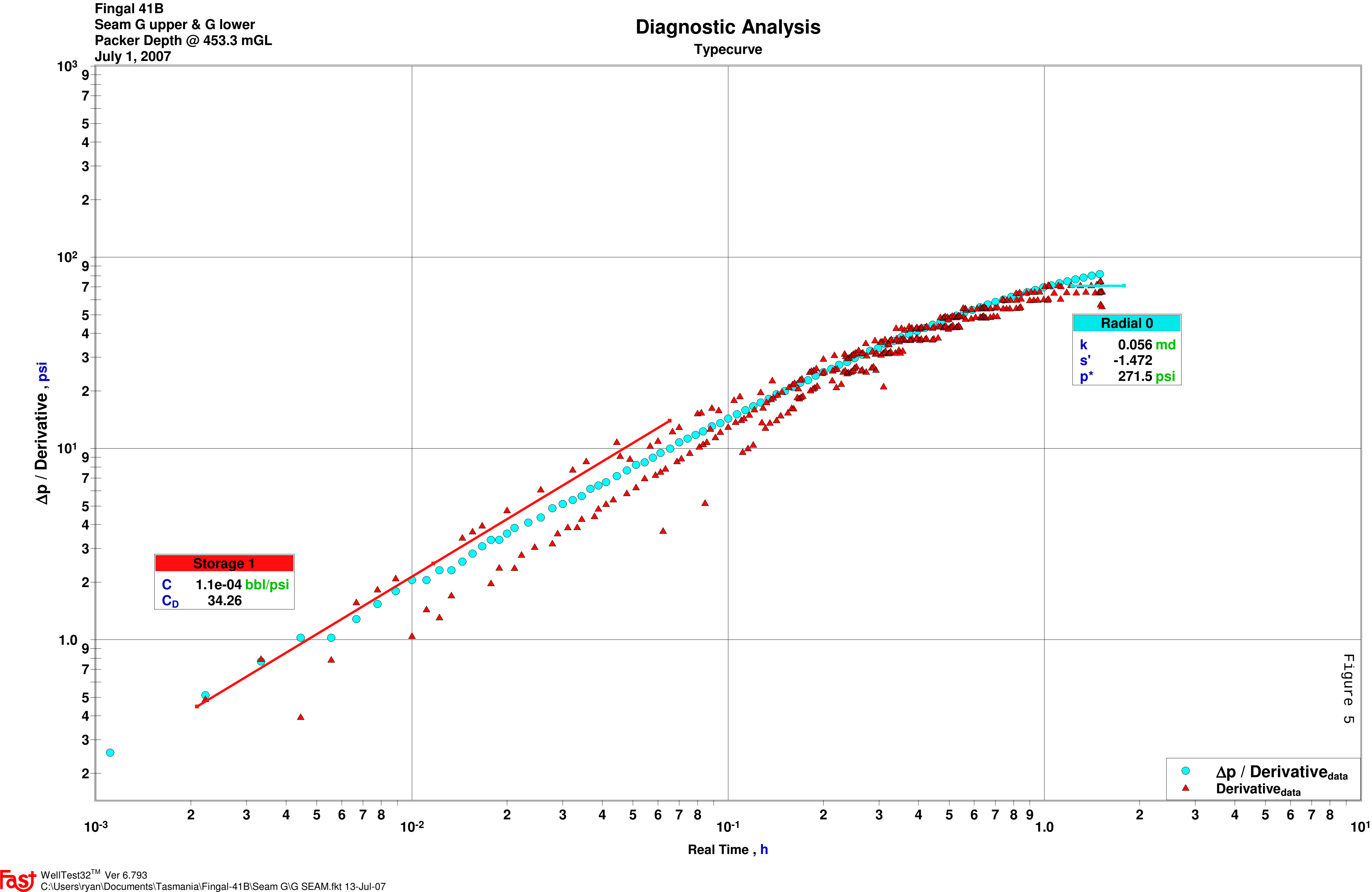
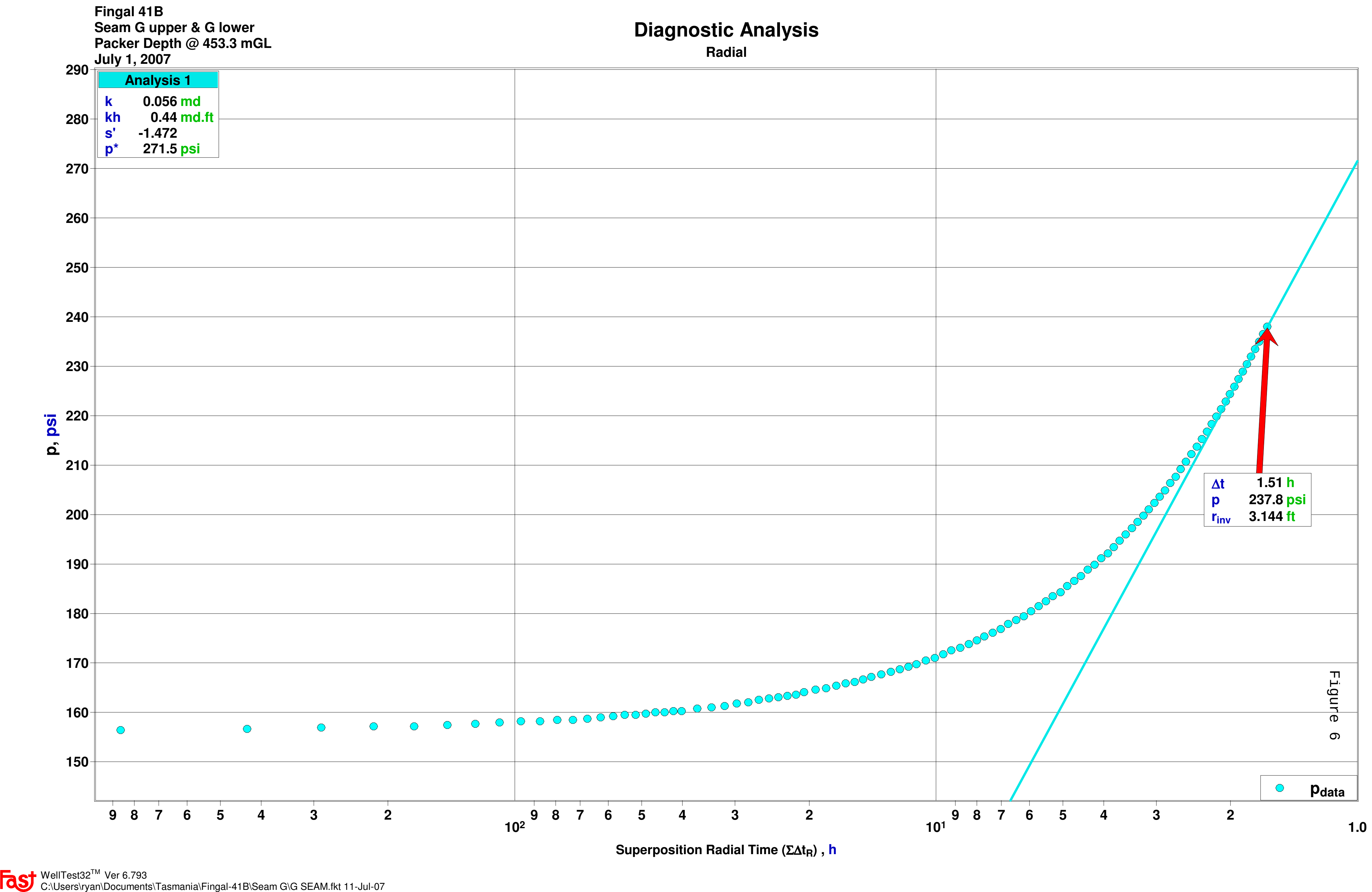

Fingal 41B
Seam G upper & G lower
Packer Depth @ 453.3 mGL
July 1, 2007
Diagnostic Analysis
Typecurve
Δp / Derivative , psi
Real Time , h
Storage 1
C 1.1e-04 bbl/psi
CD 34.26
Radial 0
k 0.056 md
s' -1.472
p* 271.5 psi
Δp / Derivative data
Derivative data
WellTest32TM Ver 6.793
C:\Users\ryan\Documents\Tasmania\Fingal-41B\Seam G\G SEAM.fkt 13-Jul-07

Figure 5



Fingal 41B
Seam G upper & G lower
Packer Depth @ 453.3 mGL
July 1, 2007
Diagnostic Analysis
Radial
Analysis 1
k 0.056 md
kh 0.44 md.ft
s' -1.472
p* 271.5 psi
Δt 1.51 h
p 237.8 psi
r_inv 3.144 ft
p, psi
Superposition Radial Time (ΣΔt_R) , h
p_data
Figure 6
WellTest32™ Ver 6.793
C:\Users\ryan\Documents\Tasmania\Fingal-41B\Seam G\G SEAM.fkt 11-Jul-07

Water Well Test - Buildup
Radial Flow Analysis

Fingal 41B

Seam G upper & G lower

Packer Depth @ 453.3 mGL

July 1, 2007

Analysis Results

Total Sandface Rate (q_tB_t)	0.500 bbl/d	Apparent Skin (s')	-1.472
Semilog Slope (m)	157.05	Skin - Damage	-1.475
Gas Permeability (k_g)	md	Skin - Inclination	
Oil Permeability (k_o)	md	Skin - Partial Penetration	
Water Permeability (k_w)	0.056 md	Pressure Drop Due to Skin (Δp_s)	psi
Flow Capacity (kh)	0.443 md.ft	Damage Ratio (DR)	0.381
Total Mobility (k/μ_t)	0.07 md/cp	Flow Efficiency (FE)	2.626
Total Transmissivity(kh/μ_t)	0.52 md.ft/cp		

Reservoir Parameters

Net Pay (h)	7.874 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)	79.9 °F
Formation Compressibility (c_f)	9.482e-6 psi^{-1}
Total Compressibility (c_t)	2.000e-4 psi^{-1}

Pressures

Initial Pressure (p_i)	280.00 psi
Extrapolated Pressure (p*)	271.49 psi
Final Flowing Pressure (p_{wfo})	156.16 psi

Production and Times

Corrected Flow Time (t_c)	0.9562 hr
Cumulative Water Production	0.020 bbl
Final Water Rate	0.500 bbl/d

Fluid Properties

Water Compressibility (c_w)	3.23639e-6 psi^{-1}
Water Formation Volume Factor (B_w)	1.001
Water Viscosity (μ_w)	0.855 cp
Solution Gas Ratio (R_{sw})	0 scf/bbl
Specific Gravity (G)	1.000
Gas Gravity (G)	0.650
PVT Reference Pressure (p_{PVT})	280.00 psi

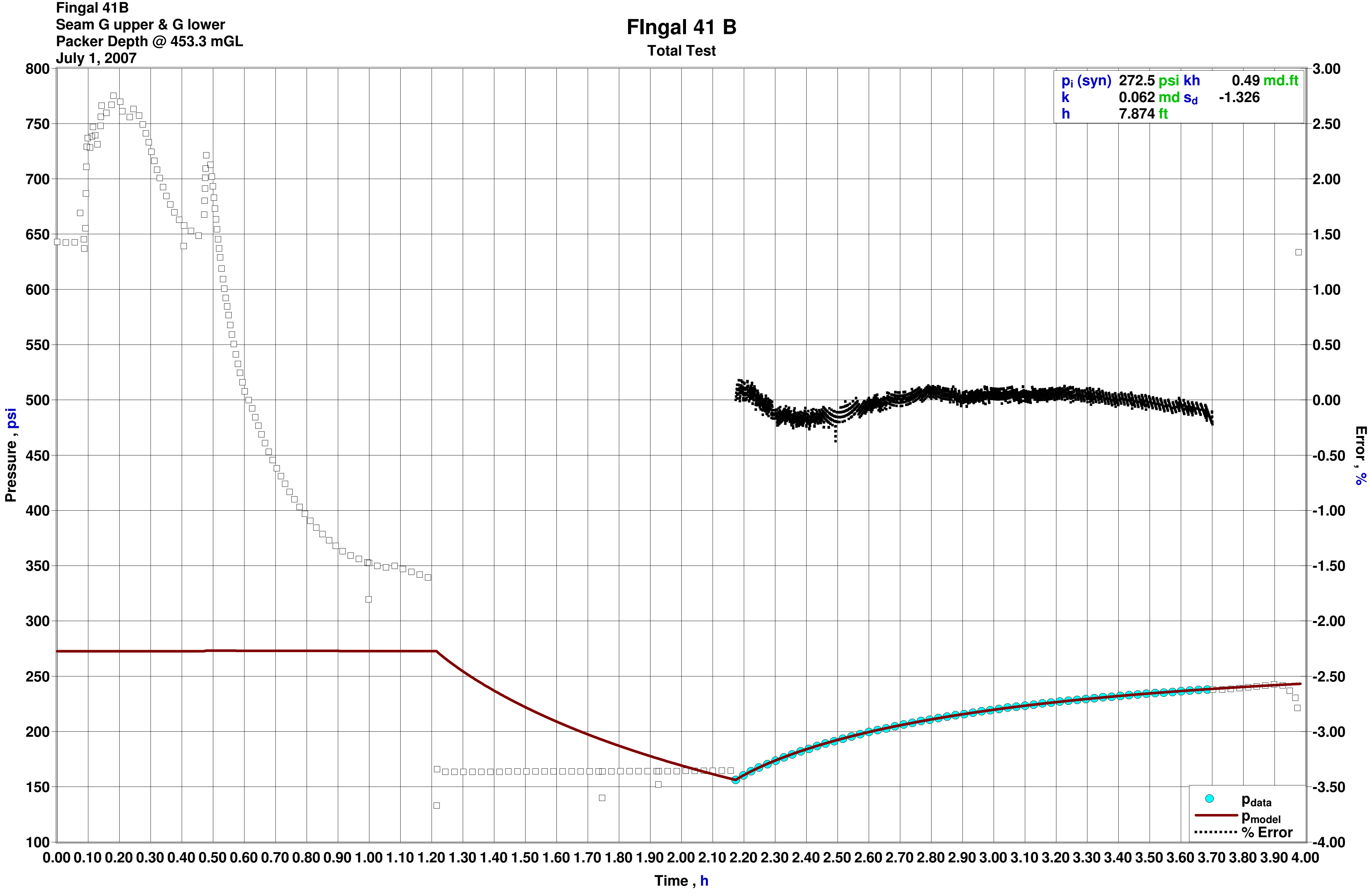
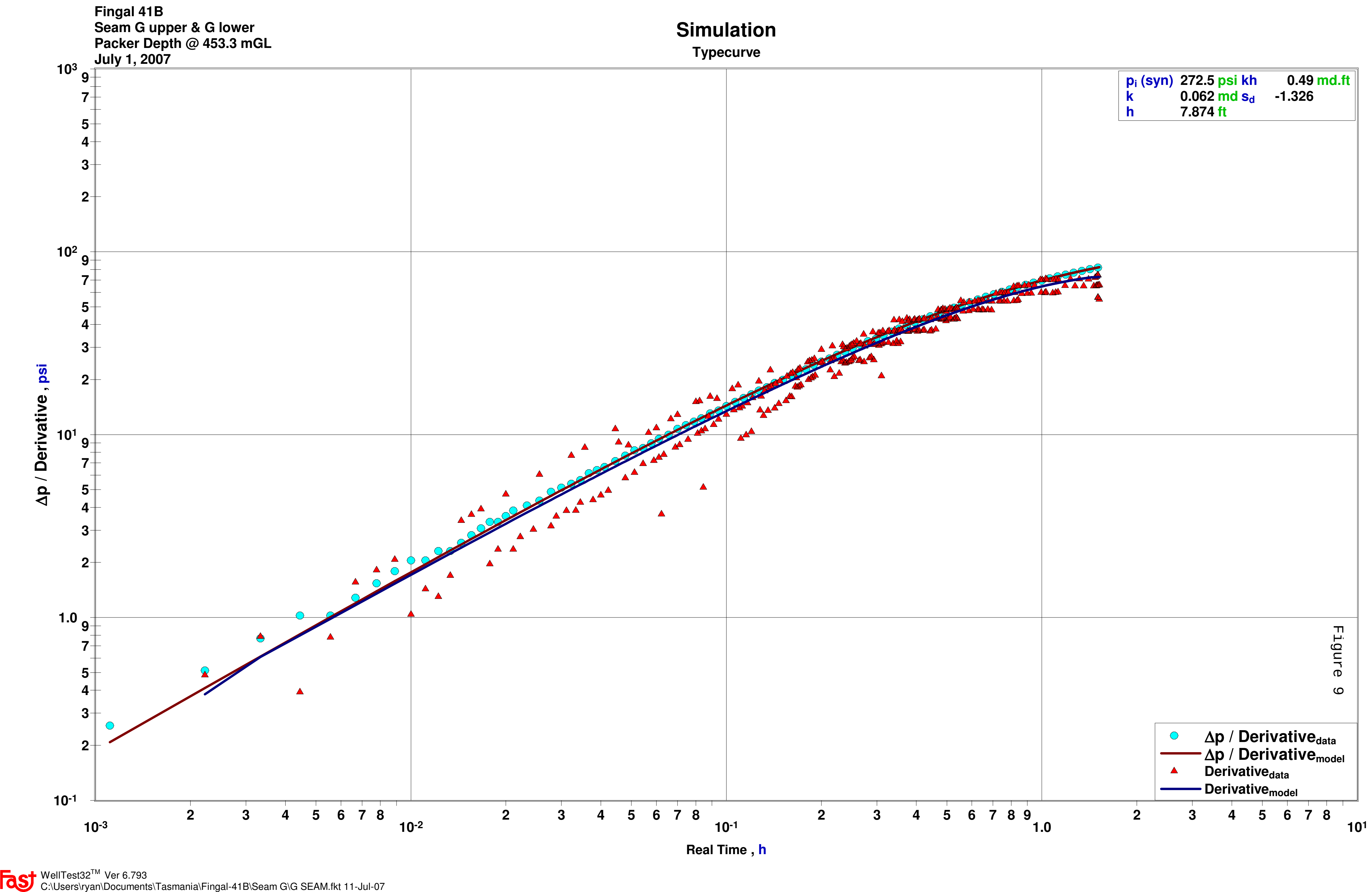


Figure 8

WellTest32™ Ver 6.793
C:\Users\ryan\Documents\Tasmania\Fingal-41B\Seam G\G SEAM.fkt 11-Jul-07



Fingal 41B
Seam G upper & G lower
Packer Depth @ 453.3 mGL
July 1, 2007
Simulation
Typecurve
pi (syn) 272.5 psi kh 0.49 md.ft
k 0.062 md sd -1.326
h 7.874 ft
Δp / Derivative , psi
Real Time , h
Δp / Derivativedata
Δp / Derivativemodel
Derivativedata
Derivativemodel
Figure 9
WellTest32TM Ver 6.793
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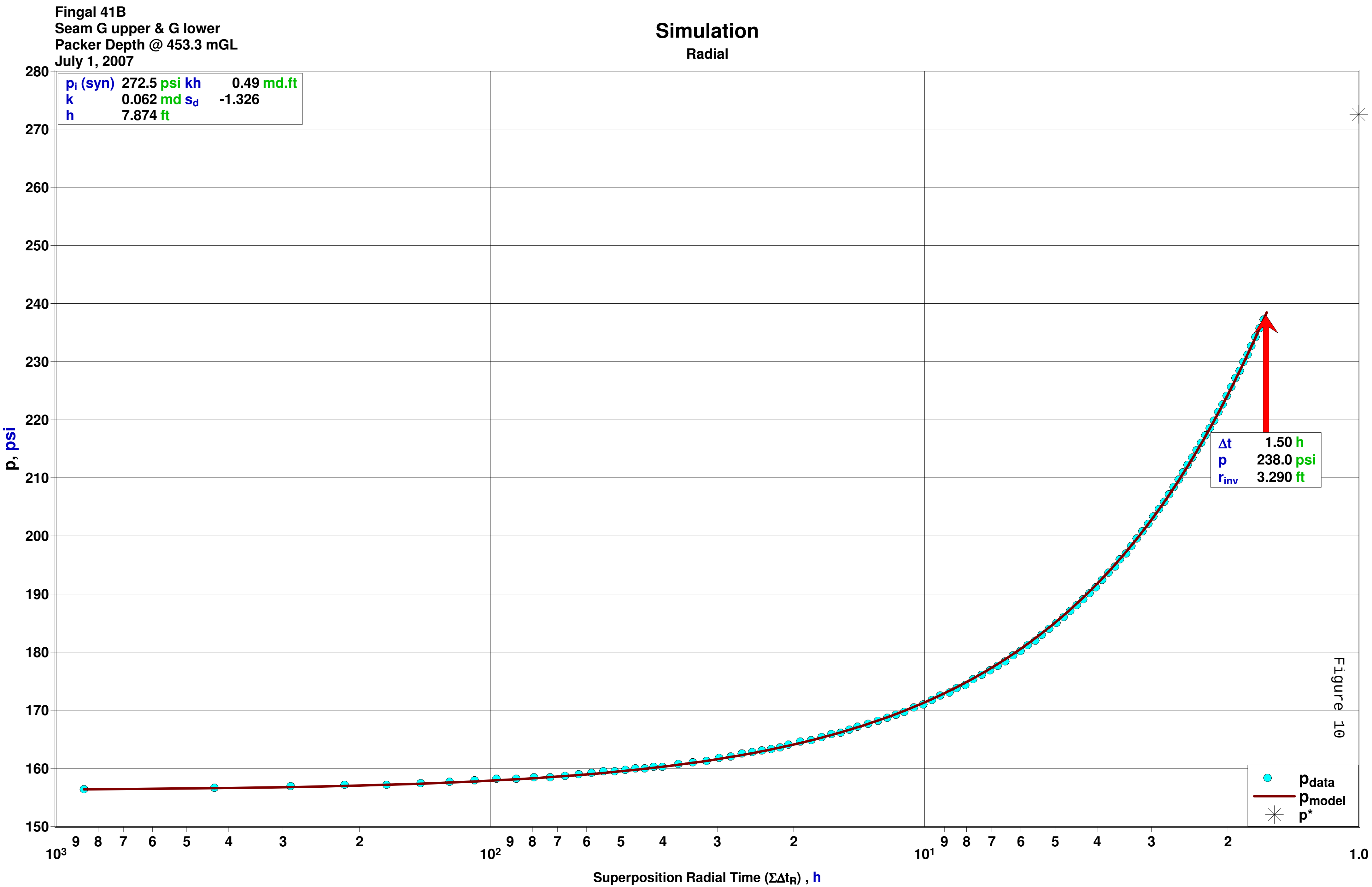

WellTest32[TM] Ver 6.793
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Vertical Water Well Model

Case Name : Simulation

Fingal 41B

Seam G upper & G lower

Packer Depth @ 453.3 mGL

July 1, 2007

Model Parameters

Water Permeability (k_w)	0.062 md
Gas Permeability (k_g)	md
Skin (s)	-1.326
Total Mobility $(k/\mu)_t$	0.07 md/cp
Total Transmissivity $(kh/\mu)_t$	0.57 md.ft/cp
Wellbore Storage Constant Dim. (C_D)	25.03

Reservoir Length (X_e)	1000000.000 ft
Reservoir Width (Y_e)	1000000.000 ft
Active Well At (X_w)	ft
Active Well At (Y_w)	ft

Formation Parameters

Net Pay (h)	7.874 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)	79.9 °F
Formation Compressibility (c_f)	9.482e-6 psi^{-1}
Total Compressibility (c_t)	2.000e-4 psi^{-1}

Fluid Properties

Water Compressibility (c_w)	3.23639e-6 psi^{-1}
Water Formation Volume Factor (B_w)	1.001
Water Viscosity (μ_w)	0.855 cp
Solution Gas Ratio (R_{sw})	0 scf/bbl
Specific Gravity (G)	1.000
PVT Reference Pressure (p_{PVT})	280.00 psi

Production and Pressure

Q_tB_t	0.500 bbl/d
Final Water Rate	0.500 bbl/d
Final Gas Rate	MMCF/D
Final Flowing Pressure (p_{wfo})	156.16 psi
Final Measured Pressure	636.34 psi
Cumulative Water Production	0.020 bbl

Synthesis Results

Average Error	0.07 %
Synthetic Initial Pressure (p_i)	272.54 psi
Extrapolated Pressure at Specified Time	272.53 psi
Pressure Drop Due To Skin (Δp_s)	psi
Flow Efficiency (FE)	1.424
Damage Ratio (DR)	0.702

Forecasts

Forecast Flowing Pressure (P_{flow})	156.16 psi
3 - Month Constant Rate Forecast @ Curr. Skin	0.096 bbl/d
6 - Month Constant Rate Forecast @ Curr. Skin	0.090 bbl/d
Forecast Flow Duration (t_{flow})	12.00 month
Constant Rate Forecast @ Curr. Skin	0.084 bbl/d
PI / II (Actual)	0.001 bbl/d/psi
Constant Rate Forecast @ Skin=0	0.068 bbl/d
PI / II (Ideal)	0.001 bbl/d/psi
Constant Rate Forecast @ Skin=-4	0.161 bbl/d

Fingal 55b DST Reports

1. **Seam B**

2. **Seam D**

3. **Seam F**

4. **Seam G upper & G lower**

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

ABN 18 061 691 450

Reservoir Engineering & Simulation Well Testing Oil & Gas Property Evaluation

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 (Pi) 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**	
<u>Zone/Layer 1</u>		
Average Permeability to Water	**38**	**md**
Flow Capacity to Water	**470**	**md.ft**
Radius of Investigation	**17**	**ft**
<u>Zone/Layer 2</u>		
Average Permeability to Water	**10**	**md**
Formation Flow Capacity to Water	**123**	**md.ft**
Radius of Investigation	**25**	**ft**
<u>Zone/Layer 3</u>		
Average Permeability to Water	**8**	**md**
Formation Flow Capacity to Water	**92**	**md.ft**
Radius of Investigation	**50**	**ft**

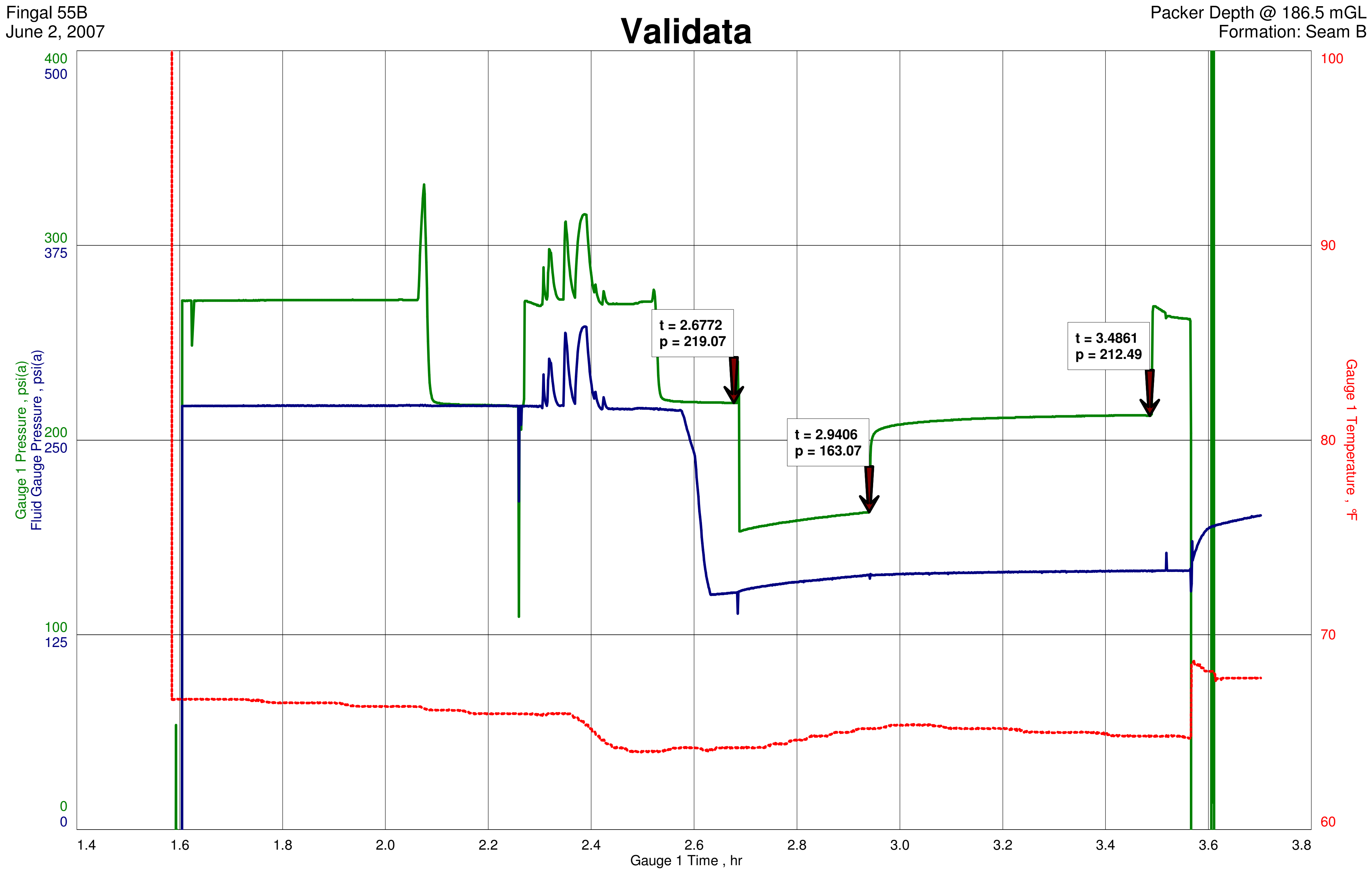
If further clarification of the test interpretation is required, please contact the undersigned on (08) 94749622.

Yours faithfully,
FOCAL PETROLEUM ENGINEERING PTY LTD

Ryan Gee
WELL TEST CONSULTANT

Terry Primeau
MANAGING DIRECTOR

LIST OF FIGURES



Fingal 55B
June 2, 2007
Validata
Packer Depth @ 186.5 mGL
Formation: Seam B
t = 2.6772
p = 219.07
t = 2.9406
p = 163.07
t = 3.4861
p = 212.49
Gauge 1 Pressure , psi(a)
Fluid Gauge Pressure , psi(a)
Gauge 1 Temperature , °F
Gauge 1 Time , hr
400
500
300
375
200
250
100
125
0
0
100
90
80
70
60
1.4
1.6
1.8
2.0
2.2
2.4
2.6
2.8
3.0
3.2
3.4
3.6
3.8

Figure 1

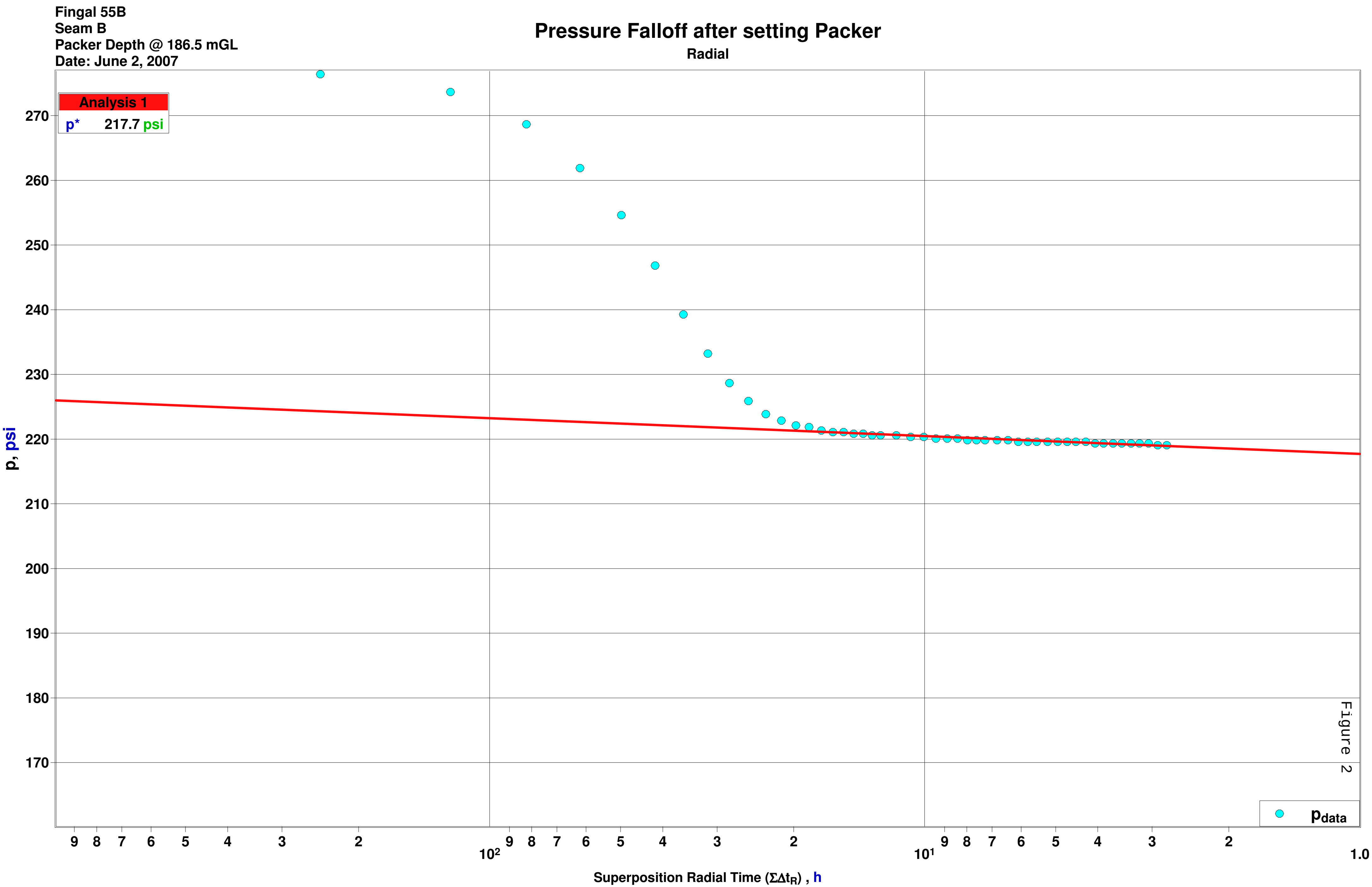


Figure 2

WellTest32™ Ver 6.793
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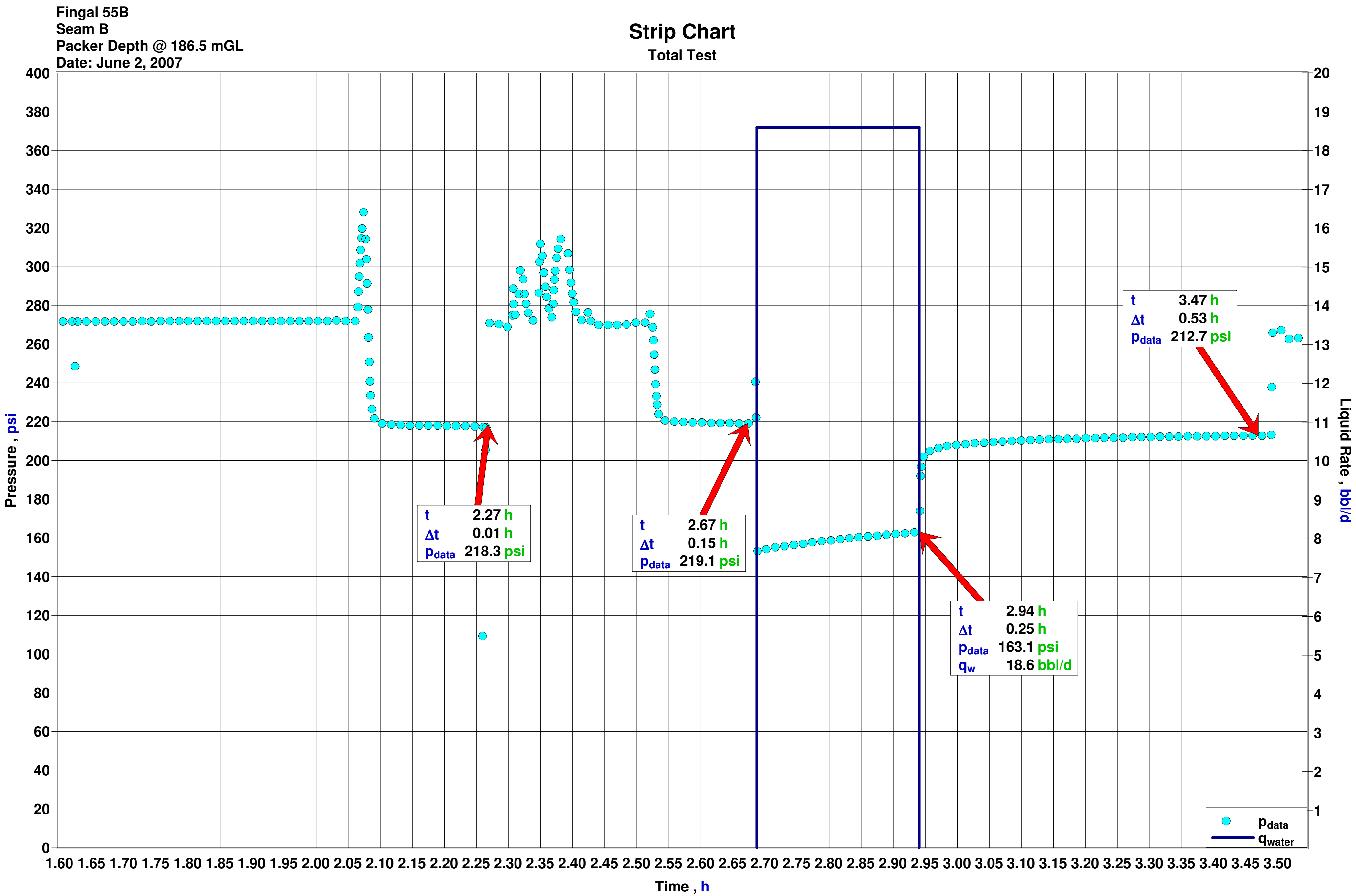

Figure 3

WellTest32TM Ver 6.793
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Fingal 55B
Seam B
Packer Depth @ 186.5 mGL
Date: June 2, 2007

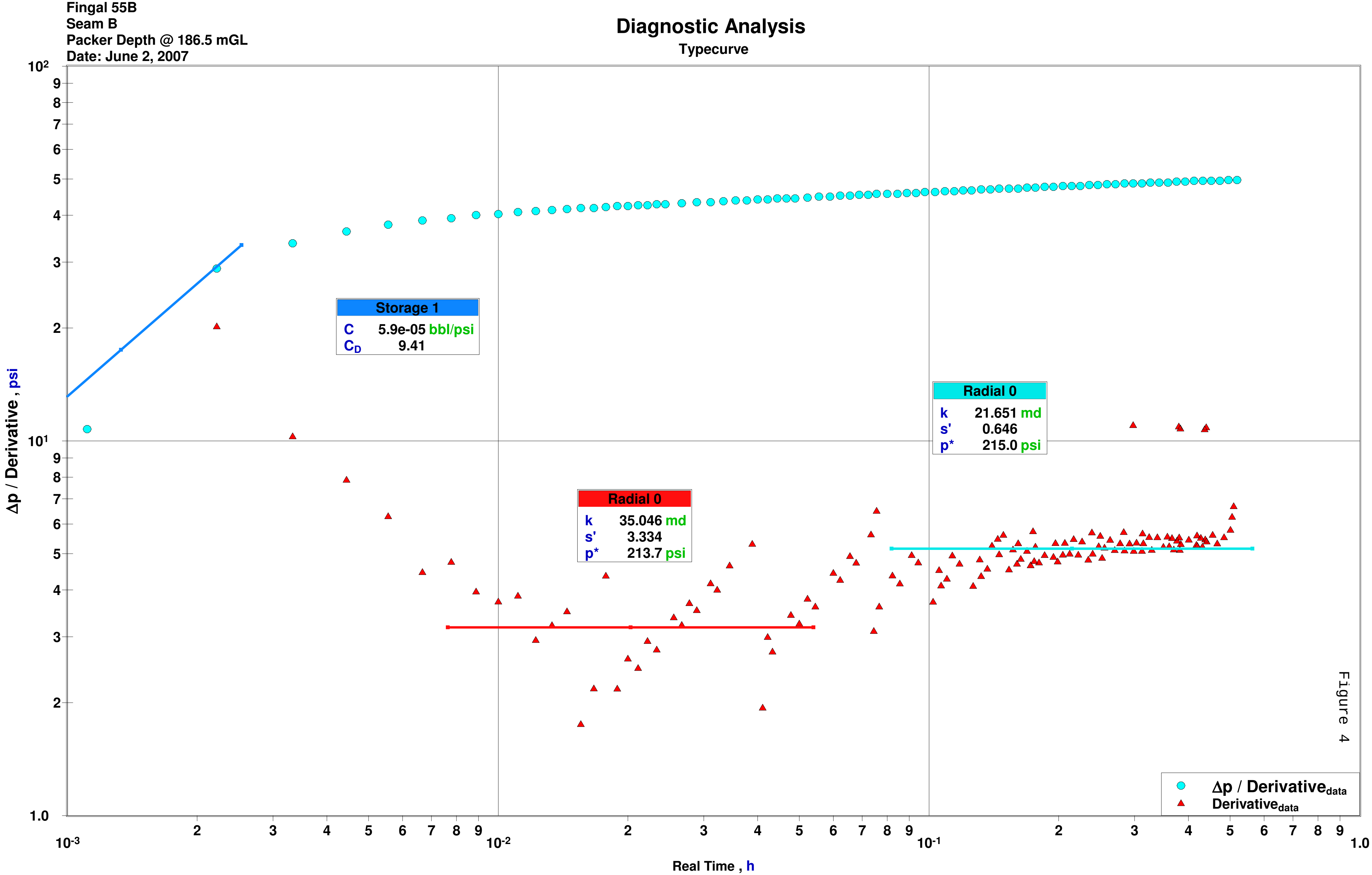

Figure 4

WellTest32TM Ver 6.793
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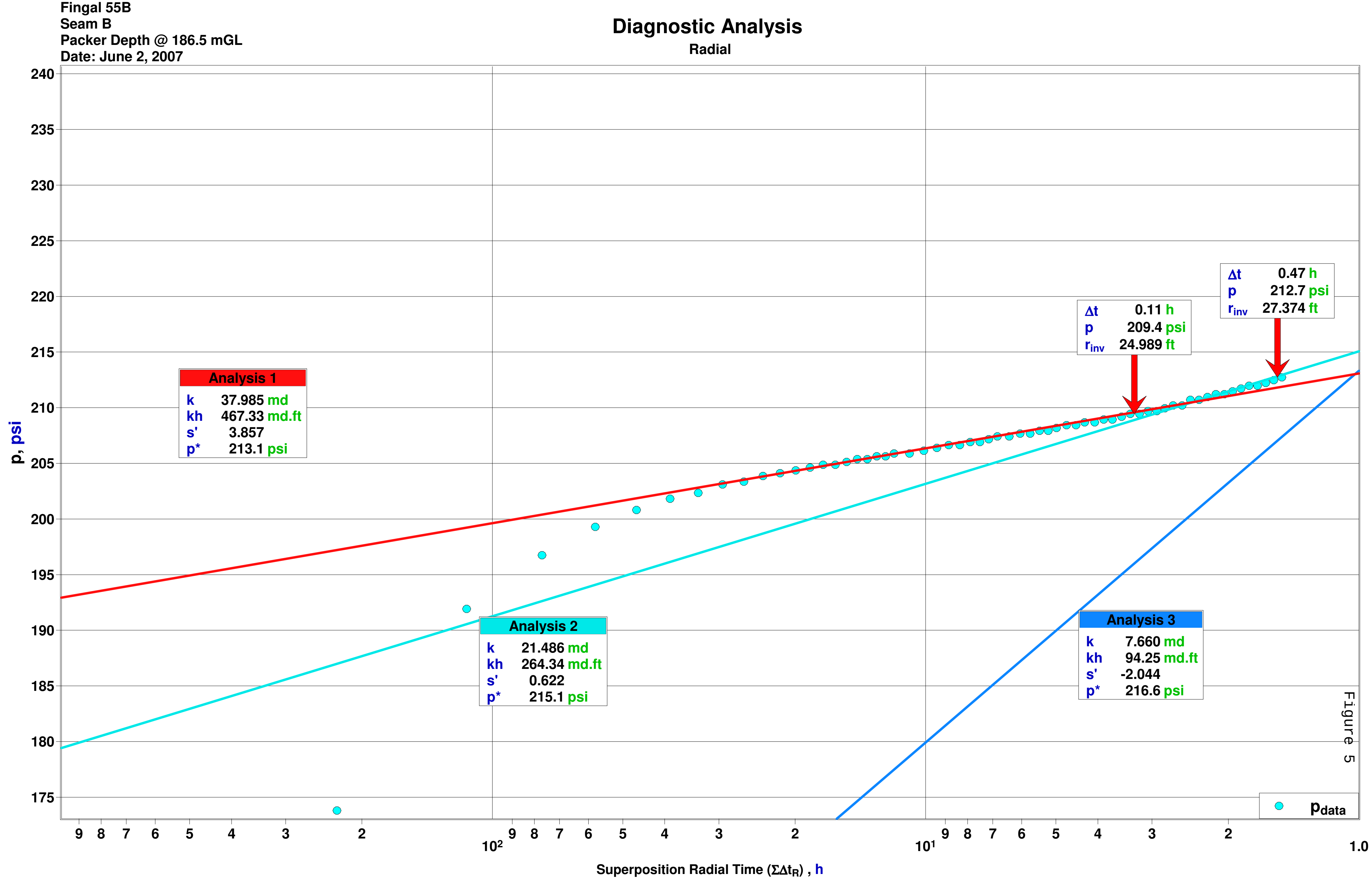

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Water Well Test - Buildup
Radial Flow Analysis

Fingal 55B

Seam B

Packer Depth @ 186.5 mGL

Date: June 2, 2007

Analysis Results

Total Sandface Rate (q_tB_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 (Δp_s)	psi
Flow Capacity (kh)	94.248 md.ft	Damage Ratio (DR)	0.468
Total Mobility (k/μ_t)	7.35 md/cp	Flow Efficiency (FE)	2.137
Total Transmissivity(kh/μ_t)	90.42 md.ft/cp		

Reservoir Parameters

Net Pay (h)	12.303 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)	64.8 °F
Formation Compressibility (c_f)	9.482e-6 psi^{-1}
Total Compressibility (c_t)	2.547e-4 psi^{-1}

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^{-1}
Water Formation Volume Factor (B_w)	0.999
Water Viscosity (μ_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 (p_{PVT})	215.24 psi

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

Fingal 55B

Total Test

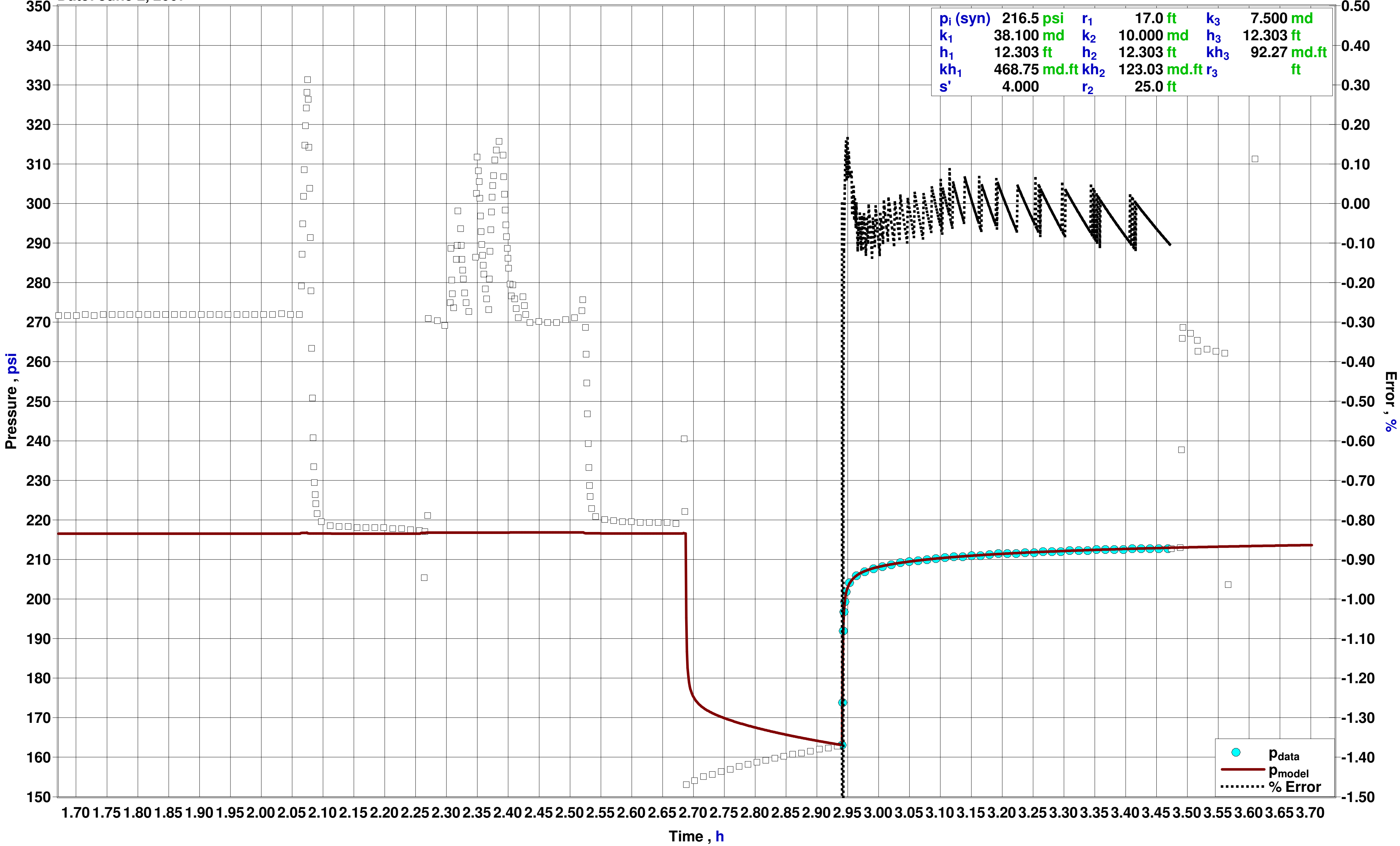

Figure 7

WellTest32[TM] Ver 6.793
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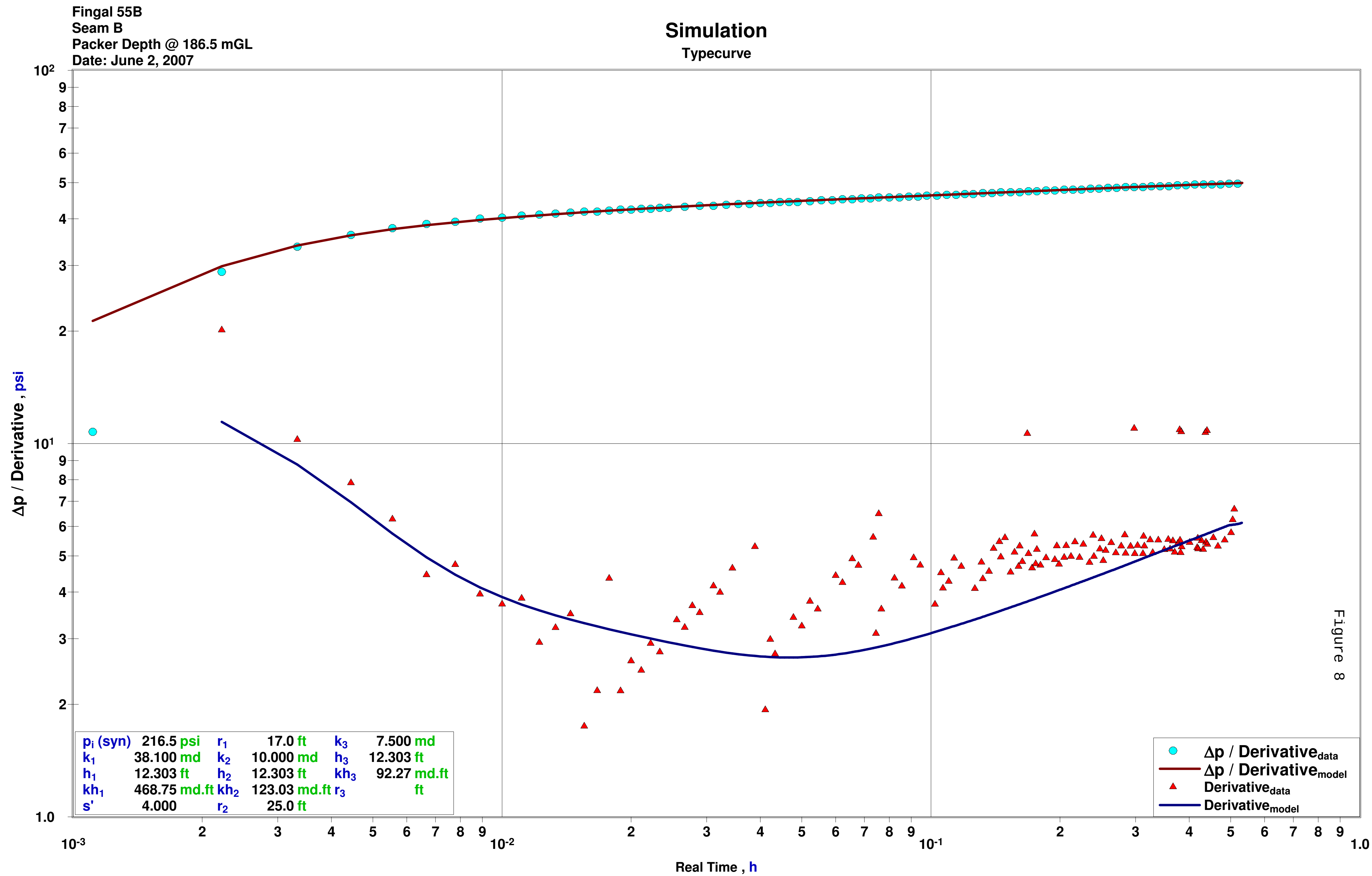

Figure 8

WellTest32™ Ver 6.793
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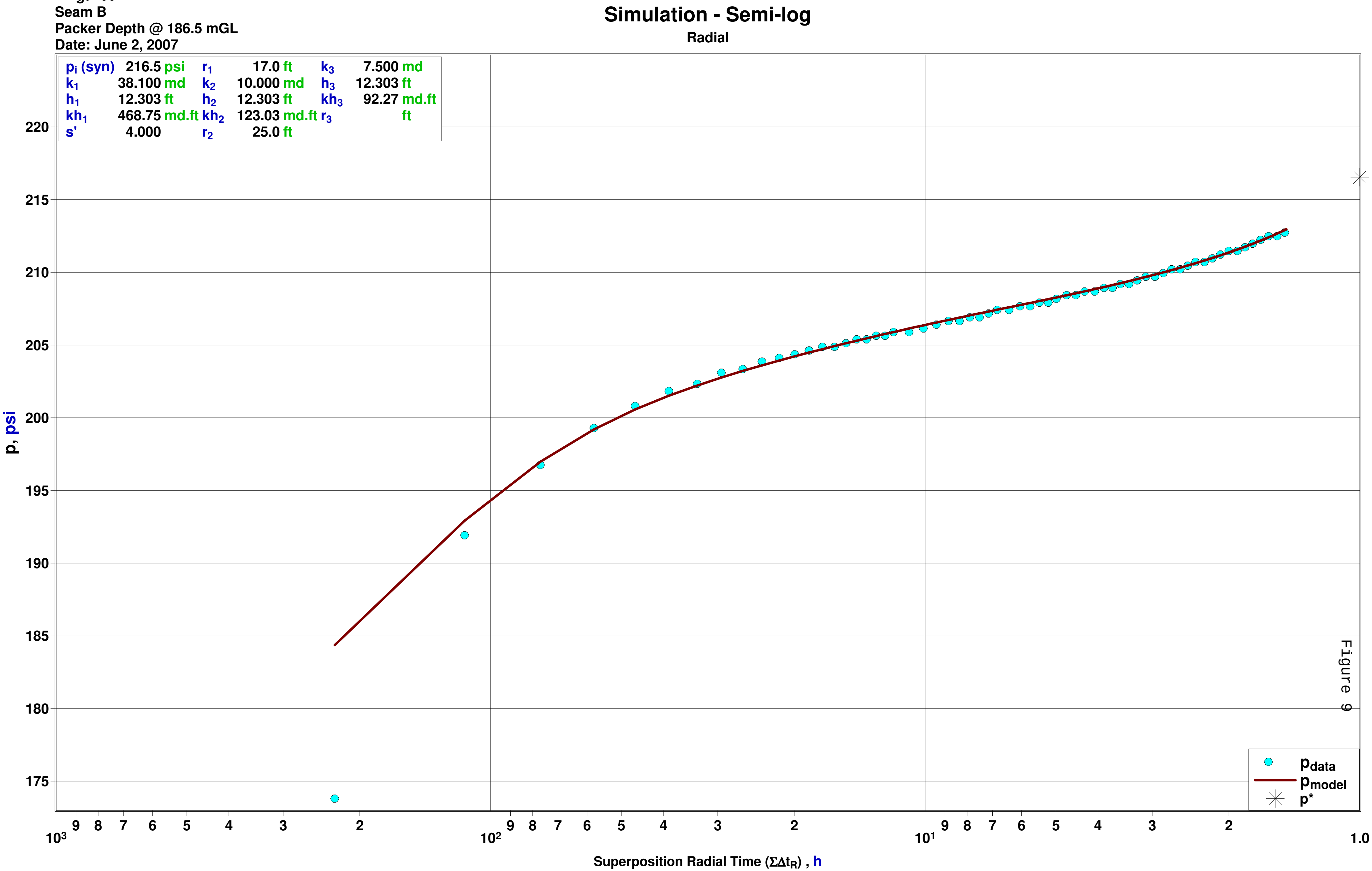
Fingal 55B
Seam B
Packer Depth @ 186.5 mGL
Date: June 2, 2007



Composite Water Well Model

Case Name : Composite 7

Fingal 55B

Seam B

Packer Depth @ 186.5 mGL

Date: June 2, 2007

Model Parameters

	Region 1	Region 2	Region 3
Total Mobility $(k/\mu)_t$	36.55	9.59	Total 7.20 md/cp
Permeability (k)	38.100	10.000	7.500 md
Net Pay (h)	12.30	12.30	12.30 ft
Total Porosity (ϕ_t)	2.00	2.00	2.00 %
Viscosity (μ)	1.042	1.042	1.042 cp
Total Compressibility (c_t)	2.547e-4	2.547e-4	2.547e-4 psi^{-1}
Region Radius (r)	17.000	25.000	1000.000 ft
Skin (s)	4.000		

Apparent Wellbore Storage Dim. (C_{aD})	0.00
Wellbore Storage Constant Dim. (C_D)	3.90
Storage Pressure Param. Dim. (C_{pD})	

Formation Parameters

Gas Saturation (S_g)	5.00 %
Water Saturation (S_w)	95.00 %
Oil Saturation (S_o)	0.00 %
Wellbore Radius (r_w)	0.30 ft
Formation Temperature (T)	64.8 °F

Fluid Properties

Water Compressibility (c_w)	3.31501e-6 psi^{-1}
Oil Compressibility (c_o)	1.50000e-6 psi^{-1}
Gas Compressibility (c_g)	4.84114e-3 psi^{-1}
Water Formation Volume Factor (B_w)	0.999
Gas Formation Volume Factor (B_g)	0.011747 bbl/scf
Water Viscosity (μ_w)	1.042 cp
Gas Viscosity (μ_g)	0.0106 cp
Solution Gas Ratio (R_{sw})	0 scf/bbl
Specific Gravity (G)	1.000
PVT Reference Pressure (p_{PVT})	215.24 psi

Production and Pressure

Q_tB_t	18.575 bbl/d
Final Water Rate	18.600 bbl/d
Final Gas Rate	MMCF/D
Final Flowing Pressure (p_{wfo})	163.07 psi
Final Measured Pressure	-900.98 psi
Cumulative Water Production	0.195 bbl

Synthesis Results

Average Error	0.06 %
Synthetic Initial Pressure (p_i)	216.54 psi
Extrapolated Pressure at Specified Time	216.54 psi
Pressure Drop Due To Skin (Δp_s)	23.29 psi
Flow Efficiency (FE)	0.564
Damage Ratio (DR)	1.772

Forecasts

Forecast Flowing Pressure (P_{flow})	163.07 psi
3 - Month Constant Rate Forecast @ Curr. Skin	5.724 bbl/d
6 - Month Constant Rate Forecast @ Curr. Skin	5.404 bbl/d
Forecast Flow Duration (t_{flow})	12.00 month
Constant Rate Forecast @ Curr. Skin	5.119 bbl/d
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

FINGAL 55B

DRILL STEM TEST

FINAL REPORT

"D" ZONE COAL SEAM

OPEN HOLE INTERVAL 239.0 – 246.1 mGL

JUNE 5, 2007

Prepared for:

Pure Energy Resources Limited

Prepared by:

Focal Petroleum Engineering Pty Ltd.

July 11, 2007

focal PETROLEUM ENGINEERING PTY LTD
ABN 18 061 691 450

July 11, 2007

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

Attention: Mr. Steve Beardsall

Dear Sir

Re: Fingal 55b Coal "D" Drill Stem Test Report

The following is a summary of the results obtained from the drill stem test conducted on June 5, 2007 over the "D" Coals, open hole interval from circa 239.0 – 246.05 mGL.

The DST was conducted through the drillpipe and coring bit, using an off bottom inflatable packer. Prior to testing, circa 120 meters of water was displaced from the drillpipe with air to allow inflow from the reservoir to occur.

The test was comprised of a 23 minute flow period followed by a buildup period of 60 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.

During the inflation of the isolation packers, a rapid increase in pressure followed by a slow fall-off was noted below the packer, suggesting that the permeability within the test interval was very low.

During the shut-in procedure (raising the drill string 70mm) for the downhole tool, a sharp drop in pressure was noted to start the buildup. This was the result of some upward movement by the packer, creating a small amount of suction in the wellbore. For the purpose of this report, the drawdown data was corrected to match the start of the buildup.

Comments and Conclusions

- The pressure response observed during the flow and buildup periods suggested a reservoir with very 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 net pay of 9.0 ft (2.75 m) was obtained from the core samples. A default porosity of 2% was used for the interpretation.

- A water rate of circa 0.3 bbl/d was calculated using the pressure increase from the inflow of water into the wellbore during the flow period.

- A reservoir pressure (Pi) of 268 psia was extrapolated from the late-time semi-log data. The subject reservoir is slightly under-pressured with a reservoir gradient of 0.35 psi/ft.

- The pressure derivative indicated wellbore storage was overcome by the start of radial flow (zero slope) at about 20 minutes after shut-in. The pressure derivative then followed an upward trend for an additional 20 minutes before returning to the initial radial flow trend. This non reservoir response has been attributed to a shift in the liquid level in the wellbore.

- Conventional analysis and Simulation were both conducted. A line was placed through the initial radial flow portion on the semi-log plot to determine permeability and skin. A second line of identical slope was placed through the late-time semi-log data to extrapolate reservoir pressure.

- 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) @ 234.4 mGL	**268**	**psia (semi-log)**
Apparent Skin Factor	**+3.3**	
Average Permeability to Water	**0.2**	**md**
Flow Capacity to Water	**1.8**	**md.ft**
Radius of Investigation	**4**	**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

Fingal 55B
June 5, 2007

Validata Plot

Packer Depth @ 238.3 mGL
Formation: Seam D

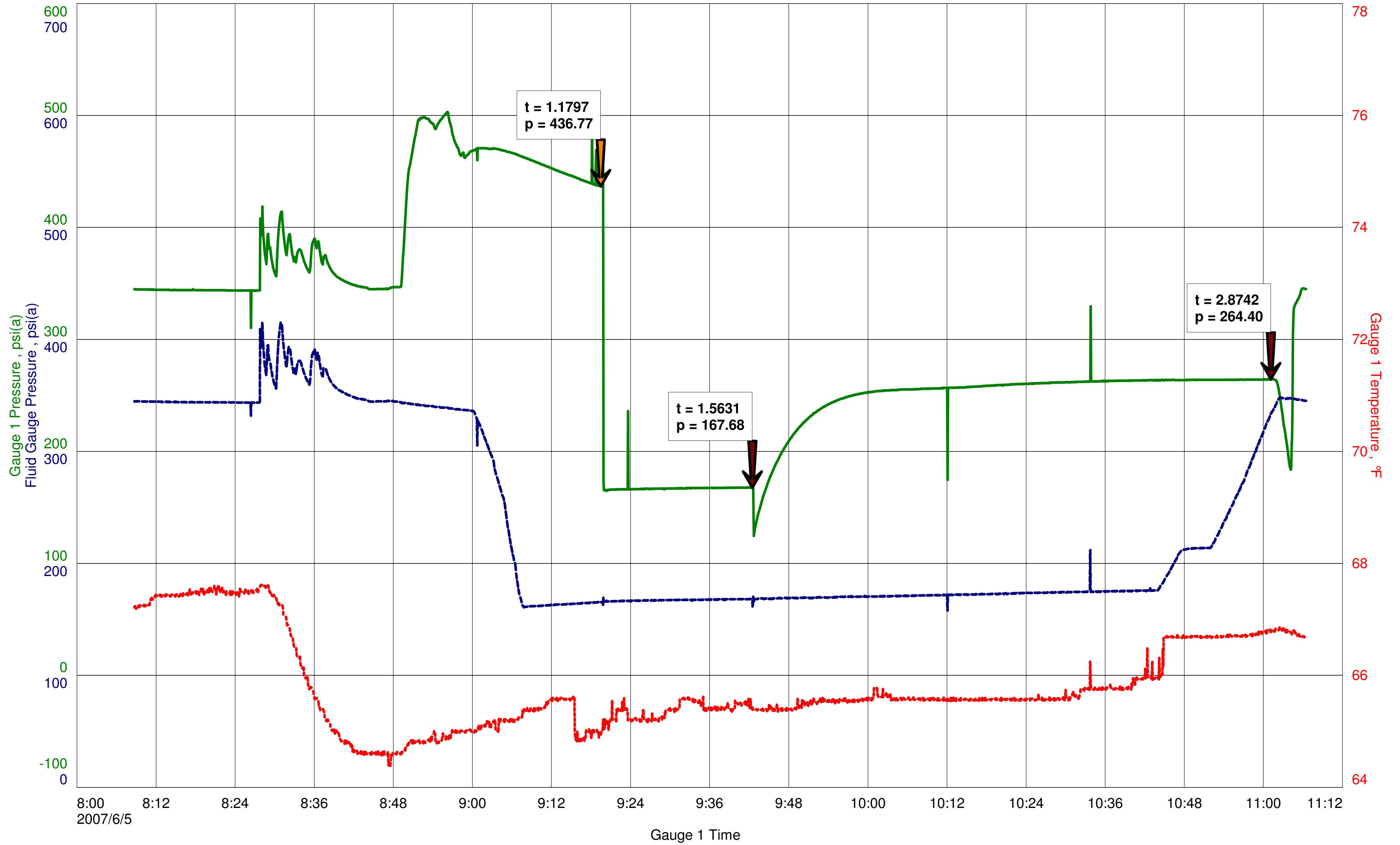


Figure 1

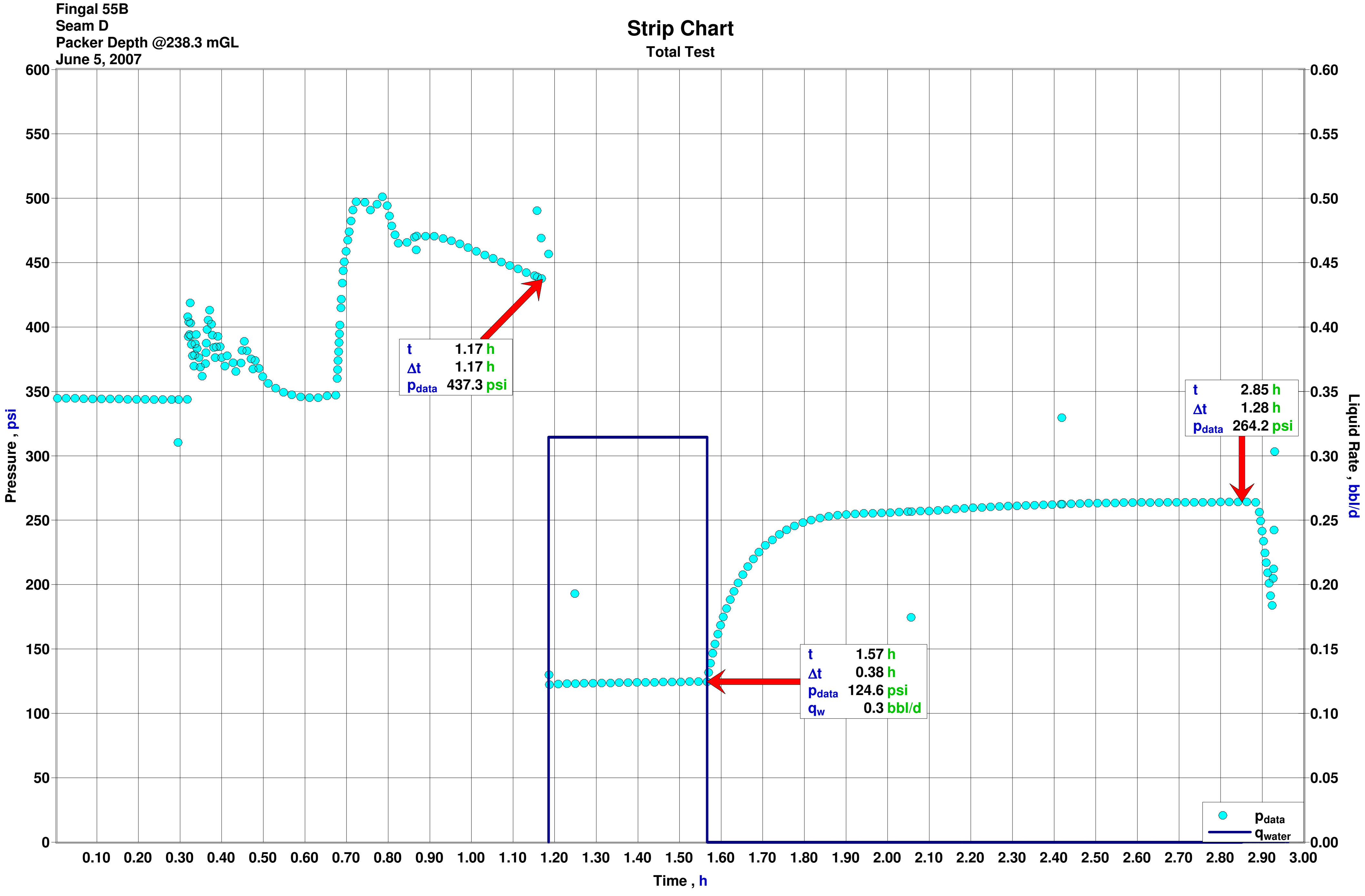


Figure 2

WellTest32™ Ver 6.793
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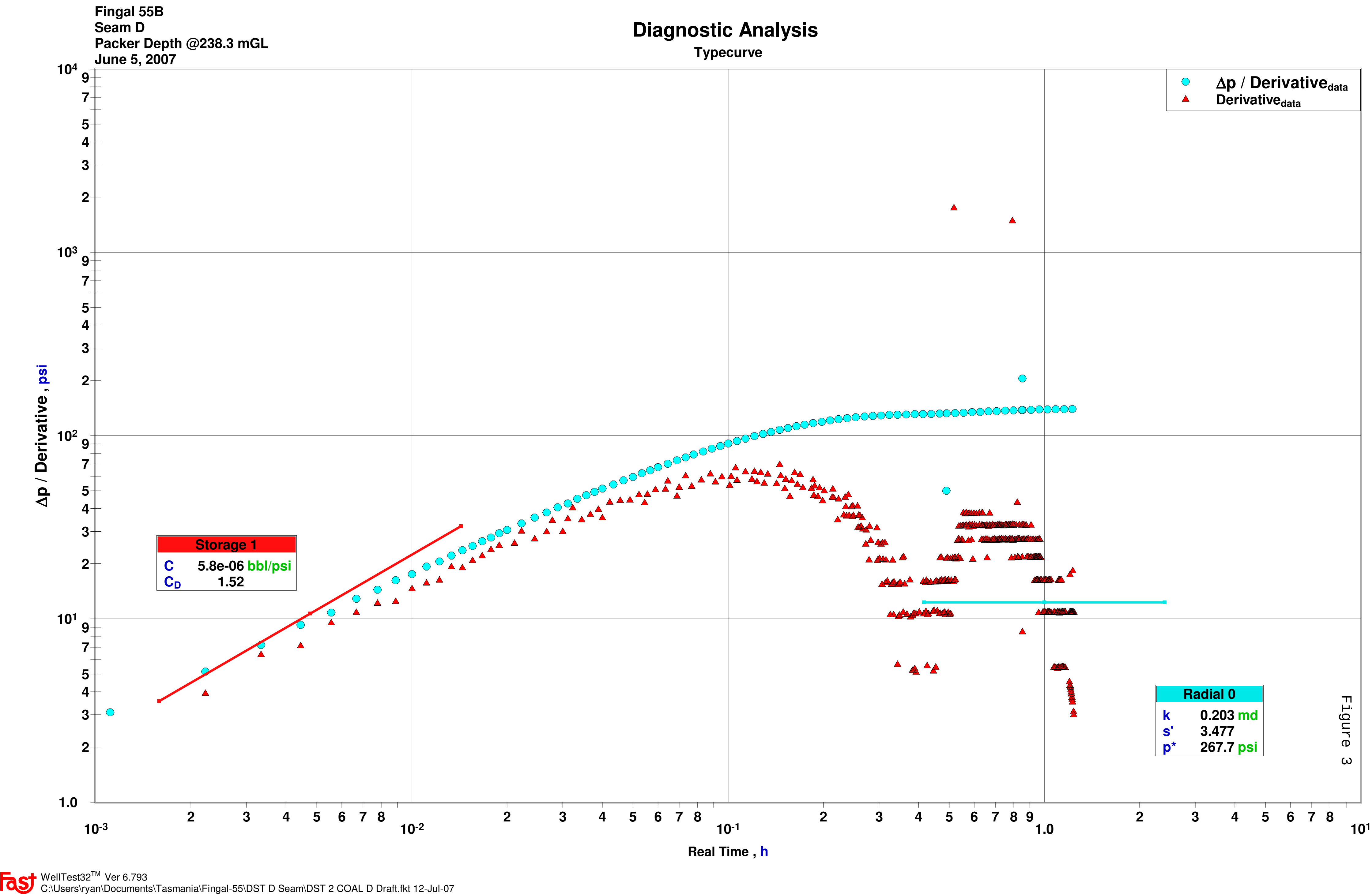

Fingal 55B
Seam D
Packer Depth @238.3 mGL
June 5, 2007
Diagnostic Analysis
Typecurve
Δp / Derivative_data
Derivative_data
Storage 1
C 5.8e-06 bbl/psi
C_D 1.52
Radial 0
k 0.203 md
s' 3.477
p* 267.7 psi
Δp / Derivative , psi
Real Time , h
WellTest32TM Ver 6.793
C:\Users\ryan\Documents\Tasmania\Fingal-55\DST D Seam\DST 2 COAL D Draft.fkt 12-Jul-07

Figure 3

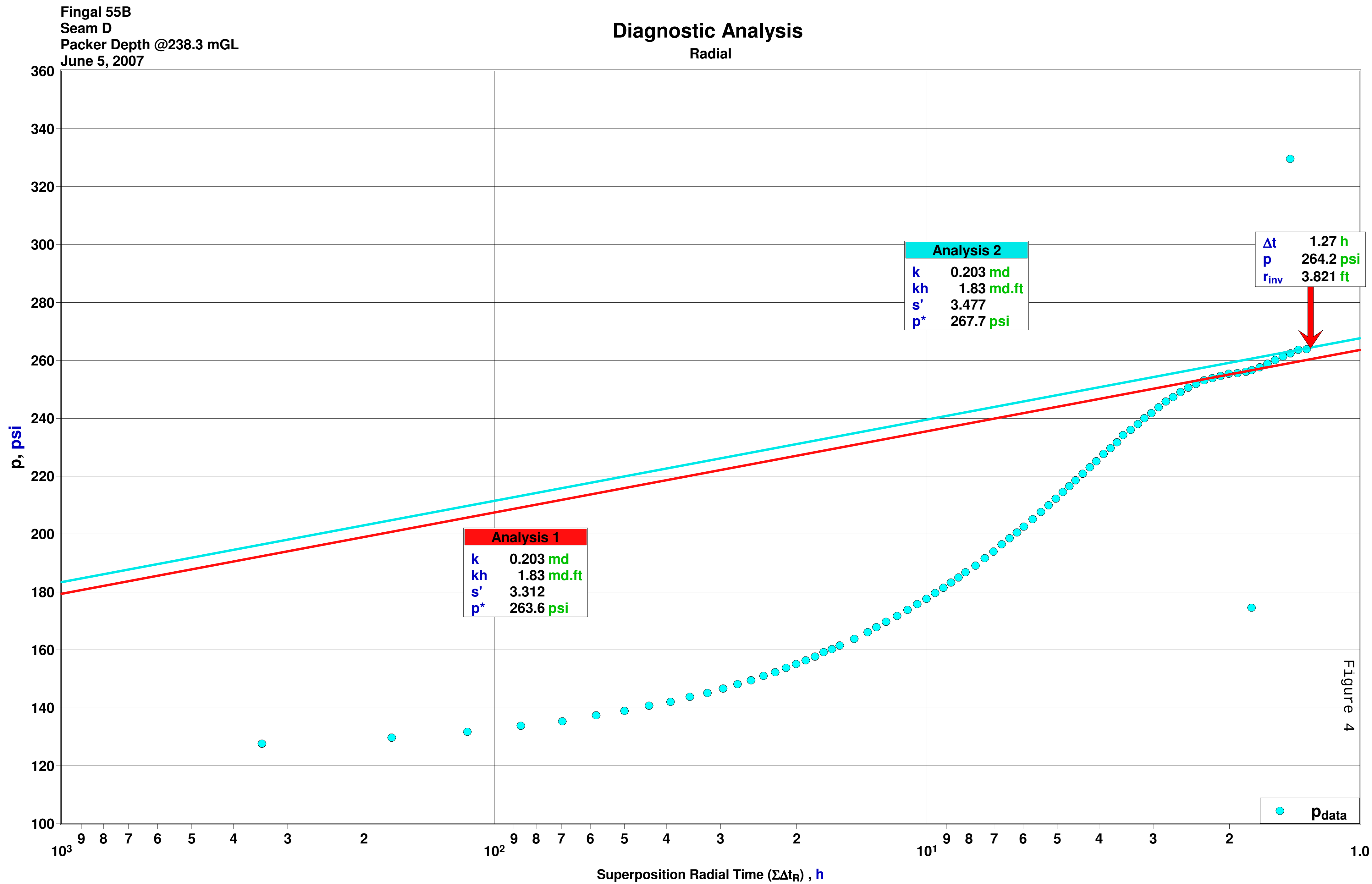

Figure 4

WellTest32[TM] Ver 6.793
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Water Well Test - Buildup
Radial Flow Analysis

Fingal 55B	Packer Depth @238.3 mGL
Seam D	June 5, 2007

Analysis Results

Total Sandface Rate (q_tB_t)	0.314 bbl/d	Apparent Skin (s')	3.477
Semilog Slope (m)	28.08	Skin - Damage	3.477
Gas Permeability (k_g)	md	Skin - Inclination	
Oil Permeability (k_o)	md	Skin - Partial Penetration	
Water Permeability (k_w)	0.203 md	Pressure Drop Due to Skin (Δp_s)	84.84 psi
Flow Capacity (kh)	1.827 md.ft	Damage Ratio (DR)	2.525
Total Mobility (k/μ_t)	0.20 md/cp	Flow Efficiency (FE)	0.396
Total Transmissivity(kh/μ_t)	1.82 md.ft/cp		

Reservoir Parameters

Net Pay (h)	9.022 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)	67.5 °F
Formation Compressibility (c_f)	9.482e-6 psi^{-1}
Total Compressibility (c_t)	2.109e-4 psi^{-1}

Pressures

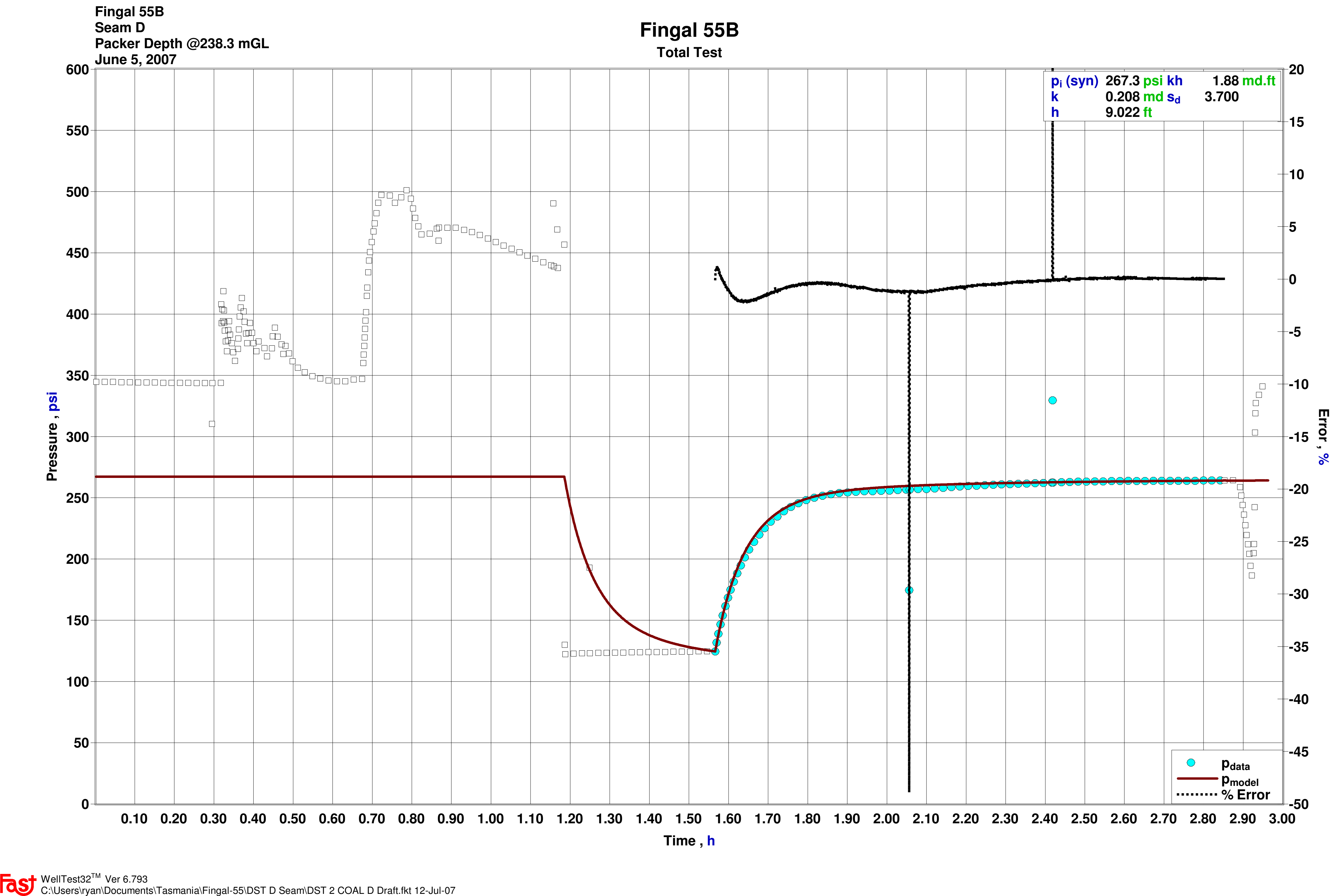
Initial Pressure (p_i)	265.00 psi
Extrapolated Pressure (p*)	267.65 psi
Final Flowing Pressure (p_{wfo})	124.53 psi

Production and Times

Corrected Flow Time (t_c)	0.3811 hr
Cumulative Water Production	0.005 bbl
Final Water Rate	0.314 bbl/d

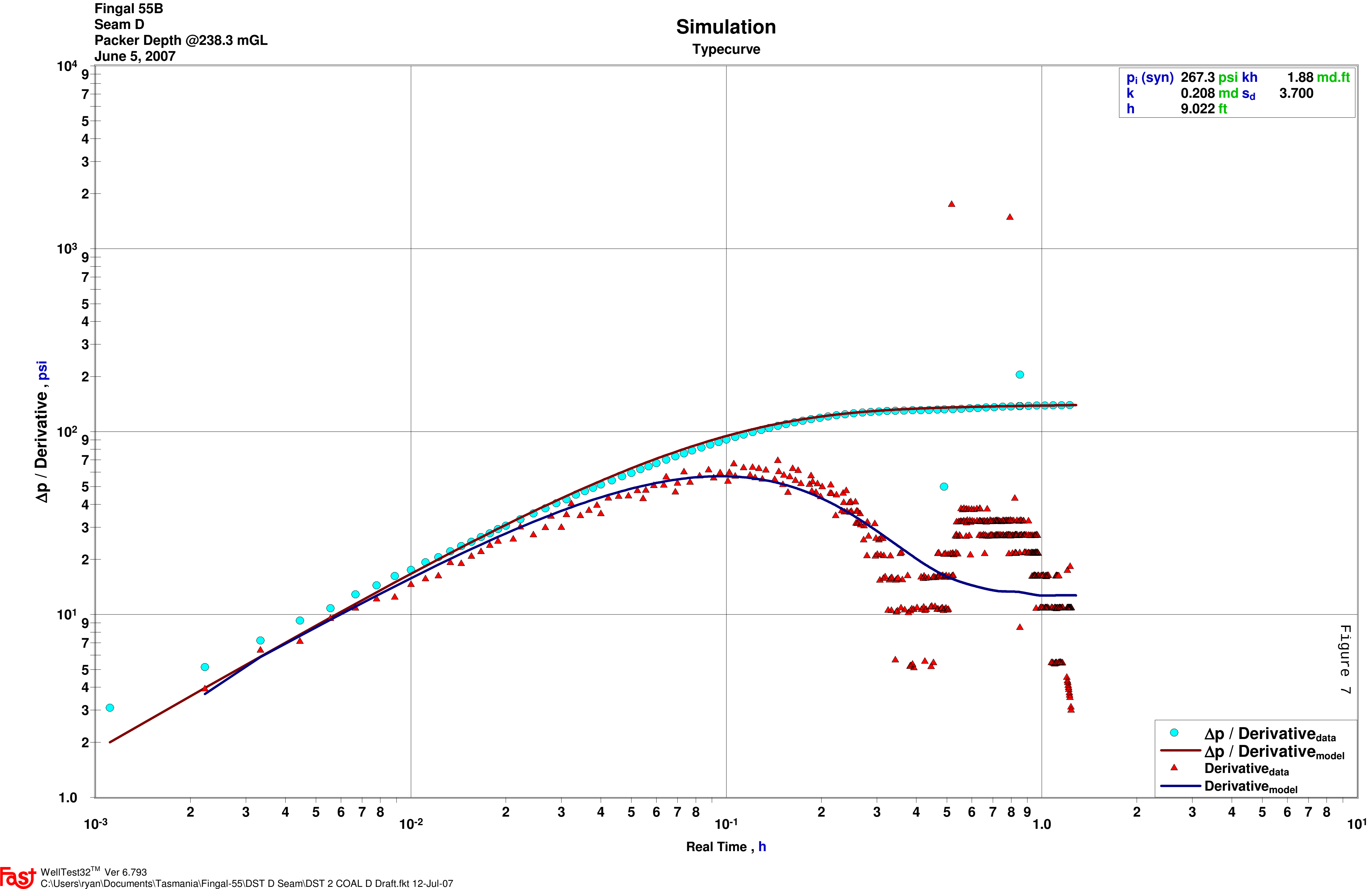
Fluid Properties

Water Compressibility (c_w)	3.29556e-6 psi^{-1}
Water Formation Volume Factor (B_w)	0.999
Water Viscosity (μ_w)	1.005 cp
Solution Gas Ratio (R_{sw})	0 scf/bbl
Specific Gravity (G)	1.000
Gas Gravity (G)	0.650
PVT Reference Pressure (p_{PVT})	265.00 psi



Fingal 55B
Seam D
Packer Depth @238.3 mGL
June 5, 2007
Fingal 55B
Total Test
p_i (syn) 267.3 psi kh 1.88 md.ft
k 0.208 md s_d 3.700
h 9.022 ft
Pressure , psi
Error , %
Time , h
p_{data}
p_{model}
% Error
WellTest32TM Ver 6.793
C:\Users\ryan\Documents\Tasmania\Fingal-55\DST D Seam\DST 2 COAL D Draft.fkt 12-Jul-07

Figure 6



Fingal 55B
Seam D
Packer Depth @238.3 mGL
June 5, 2007
Simulation
Typecurve
p_i (syn) 267.3 psi kh 1.88 md.ft
k 0.208 md s_d 3.700
h 9.022 ft
Δp / Derivative , psi
Real Time , h
Δp / Derivative$_{data}$
Δp / Derivative$_{model}$
Derivative$_{data}$
Derivative$_{model}$
Figure 7
WellTest32TM Ver 6.793
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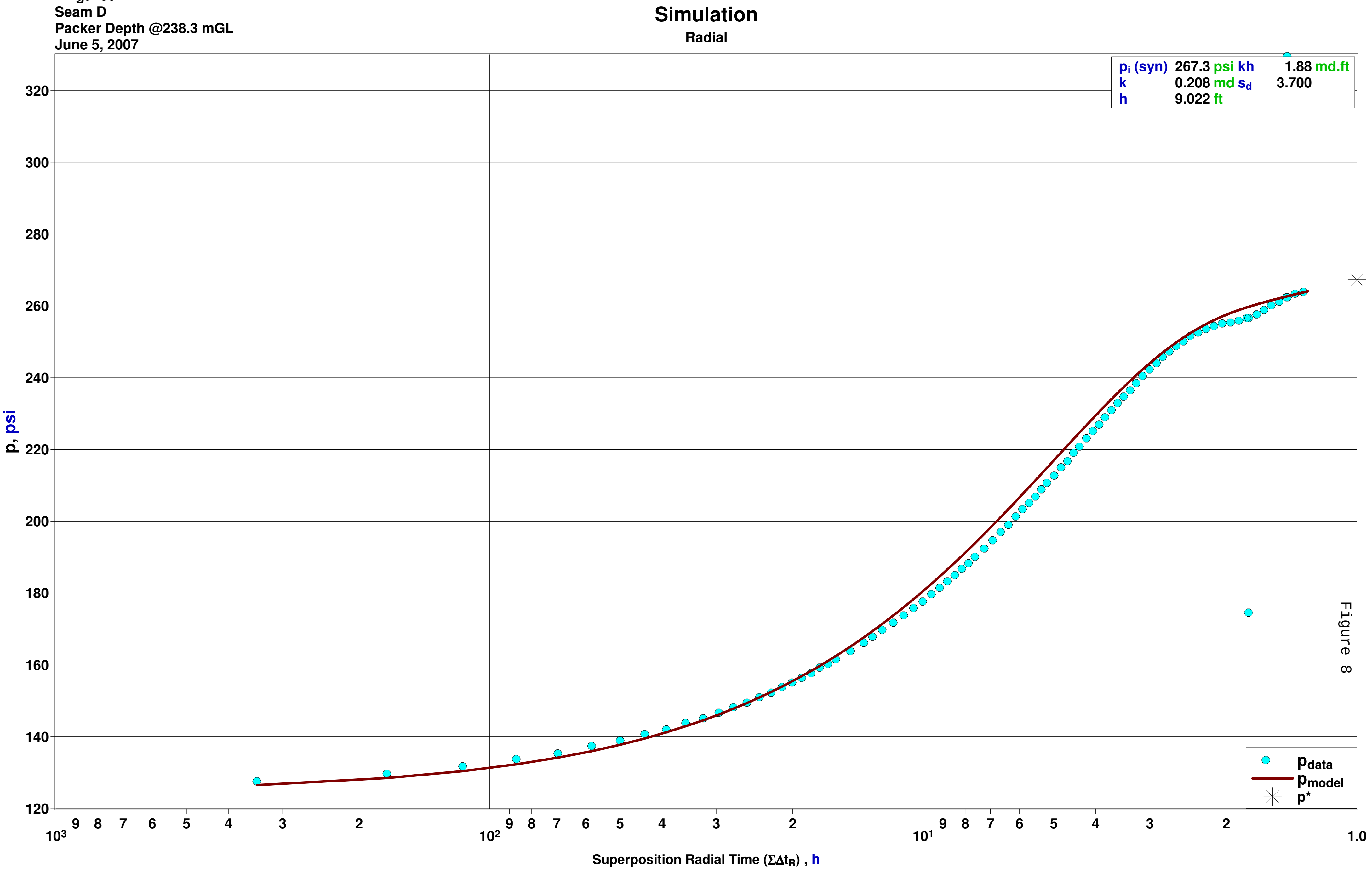
Fingal 55B
Seam D
Packer Depth @238.3 mGL
June 5, 2007



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Vertical Water Well Model

Case Name : Simulation

Fingal 55B

Seam D

Packer Depth @238.3 mGL

June 5, 2007

Model Parameters

Water Permeability (k_w)	0.208 md
Gas Permeability (k_g)	md
Skin (s)	3.700
Total Mobility $(k/\mu)_t$	0.21 md/cp
Total Transmissivity $(kh/\mu)_t$	1.87 md.ft/cp
Wellbore Storage Constant Dim. (C_D)	1.83

Reservoir Length (X_e)	1000000.000 ft
Reservoir Width (Y_e)	1000000.000 ft
Active Well At (X_w)	ft
Active Well At (Y_w)	ft

Formation Parameters

Net Pay (h)	9.022 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)	67.5 °F
Formation Compressibility (c_f)	9.482e-6 psi^{-1}
Total Compressibility (c_t)	2.109e-4 psi^{-1}

Fluid Properties

Water Compressibility (c_w)	3.29556e-6 psi^{-1}
Water Formation Volume Factor (B_w)	0.999
Water Viscosity (μ_w)	1.005 cp
Solution Gas Ratio (R_{sw})	0 scf/bbl
Specific Gravity (G)	1.000
PVT Reference Pressure (p_{PVT})	265.00 psi

Production and Pressure

Q_tB_t	0.314 bbl/d
Final Water Rate	0.314 bbl/d
Final Gas Rate	MMCF/D
Final Flowing Pressure (p_{wfo})	124.53 psi
Final Measured Pressure	345.10 psi
Cumulative Water Production	0.005 bbl

Synthesis Results

Average Error	0.64 %
Synthetic Initial Pressure (p_i)	267.27 psi
Extrapolated Pressure at Specified Time	267.27 psi
Pressure Drop Due To Skin (Δp_s)	85.78 psi
Flow Efficiency (FE)	0.399
Damage Ratio (DR)	2.506

Forecasts

Forecast Flowing Pressure (P_{flow})	124.53 psi
3 - Month Constant Rate Forecast @ Curr. Skin	0.181 bbl/d
6 - Month Constant Rate Forecast @ Curr. Skin	0.175 bbl/d
Forecast Flow Duration (t_{flow})	12.00 month
Constant Rate Forecast @ Curr. Skin	0.170 bbl/d
PI / II (Actual)	0.001 bbl/d/psi
Constant Rate Forecast @ Skin=0	0.255 bbl/d
PI / II (Ideal)	0.002 bbl/d/psi
Constant Rate Forecast @ Skin=-4	0.551 bbl/d

FINGAL 55B

DRILL STEM TEST

FINAL REPORT

"F" ZONE COAL SEAM

OPEN HOLE INTERVAL 297.5 – 298.9 mGL

JUNE 7, 2007

Prepared for:

Pure Energy Resources Limited

PURE
ENERGY RESOURCES LIMITED

Prepared by:

Focal Petroleum Engineering Pty Ltd.

July 11, 2007

focal
PETROLEUM ENGINEERING PTY LTD

PETROLEUM ENGINEERING PTY LTD
ABN 18 061 691 450

July 11, 2007

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

Attention: Mr. Steve Beardsall

Dear Sir

Re: Fingal 55b Coal "F" Drill Stem Test Report

The following is a summary of the results obtained from the Drill stem test conducted on June 7, 2007 over the "F" Coals, open hole interval from circa 297.5 – 298.9 mGL.

The DST was conducted through the drillpipe and coring bit, using an off bottom inflatable packer. Prior to testing, 184 meters of water was displaced from the drillpipe with air to allow inflow from the reservoir to occur.

The test was comprised of a 63 minute flow period followed by a 70 minute buildup period. 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 followed by a slow fall-off 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 sharp drop in pressure was noted to start the buildup. This was 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 net pay of 4.6 ft (1.4 m) was obtained from the core samples. A default porosity of 2% was used for the interpretation.

- An average water rate of circa 2.6 bbl/d was calculated using the pressure increase from the inflow of water into the wellbore during the flow period.

- The reservoir pressure (Pi) of 339 psia was calculated from the simulation. The subject reservoir is slightly under-pressured with a reservoir gradient of 0.35 psi/ft.

- The pressure derivative indicated that wellbore storage was immediately overcome by a linear flow (half slope) trend until about three minutes after shut-in. The derivative then begins to bend over and follow a downward trend until about 20 minutes after shut-in, where it flattens into radial flow (zero slope) for the duration of the test.

- Conventional analysis and Simulation were both conducted. It is suspected that the rapid increase in pressure during packer inflation likely created a small fracture in the very near wellbore area, as evident by the early time half slope (fracture flow effects). However, since the mini fracture did not penetrate very far into the damaged, near wellbore zone, for the purposes of this analysis, it was modelled using changing wellbore storage. The simulation compared very well with the conventional results and has 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) @ 292.9 mGL	**339 psia (simulation)**
Apparent Skin Factor	**+4.3**
Average Permeability to Water	**2.8 md**
Flow Capacity to Water	**12.9 md.ft**
Radius of Investigation	**22 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

focal
PETROLEUM ENGINEERING PTY LTD

LIST OF FIGURES

Fingal 55B
June 7, 2007

Validata

Packer Depth @ 296.8 mGL
Formation: F Seam

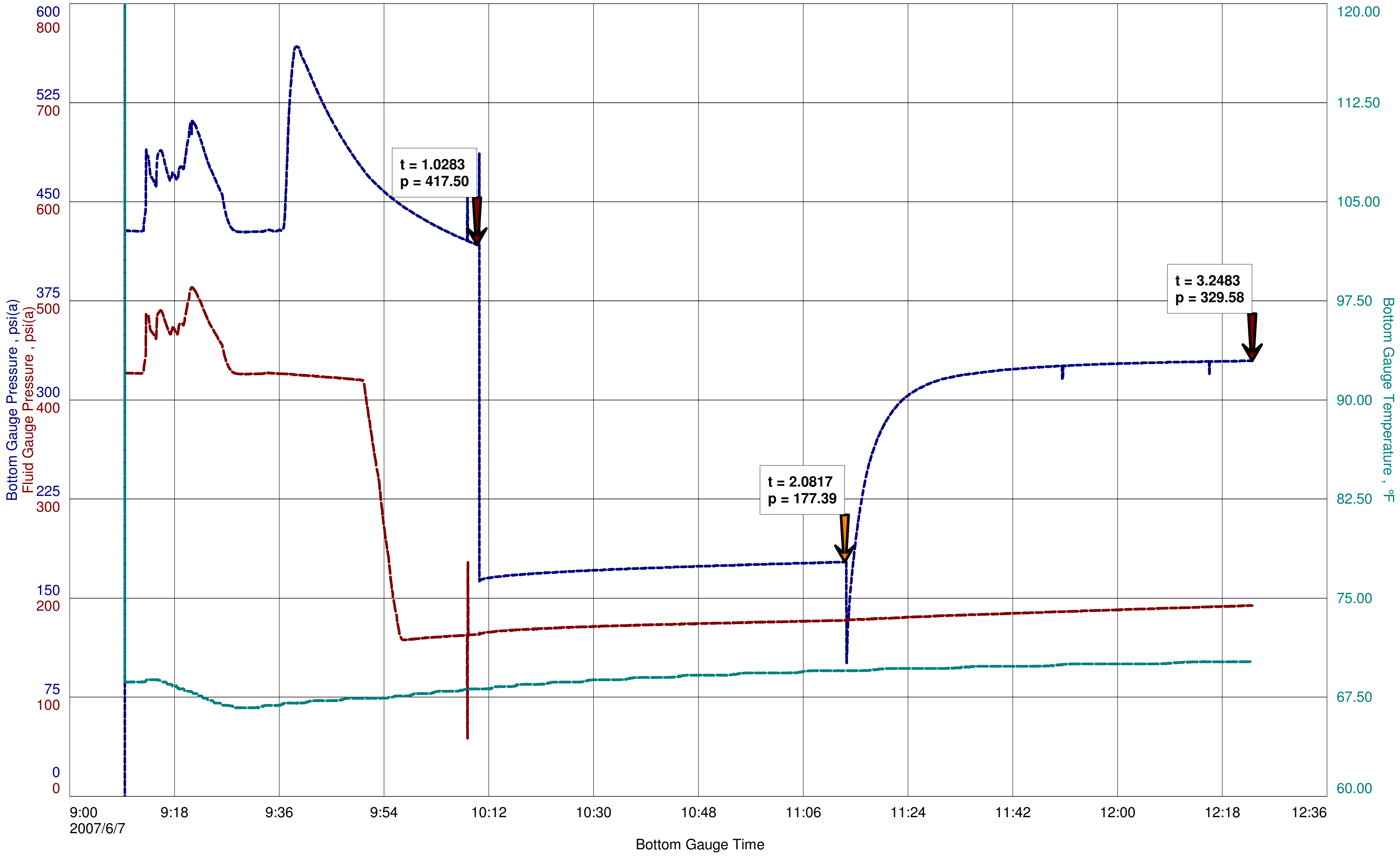

Figure 1

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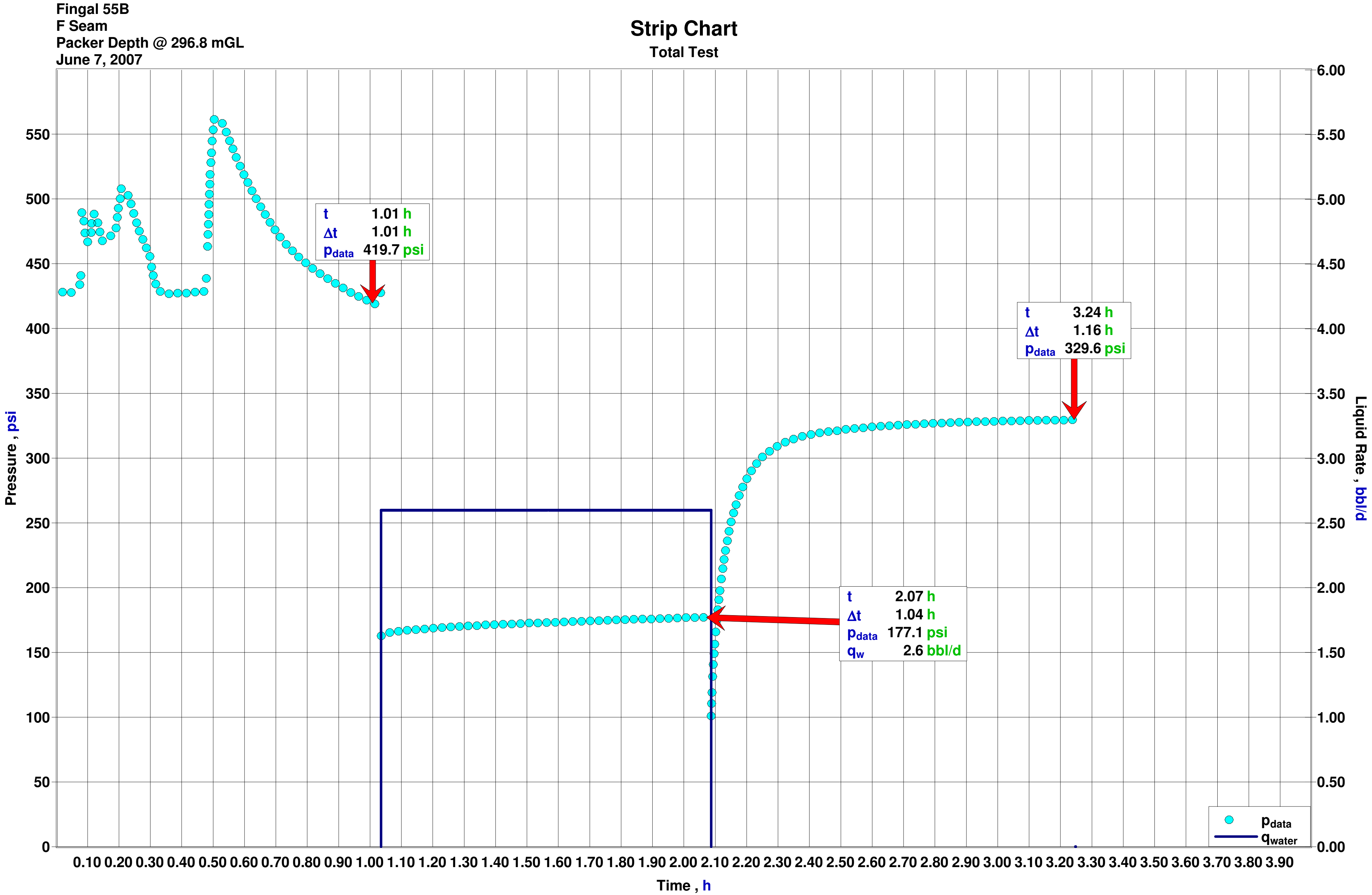

Figure 2

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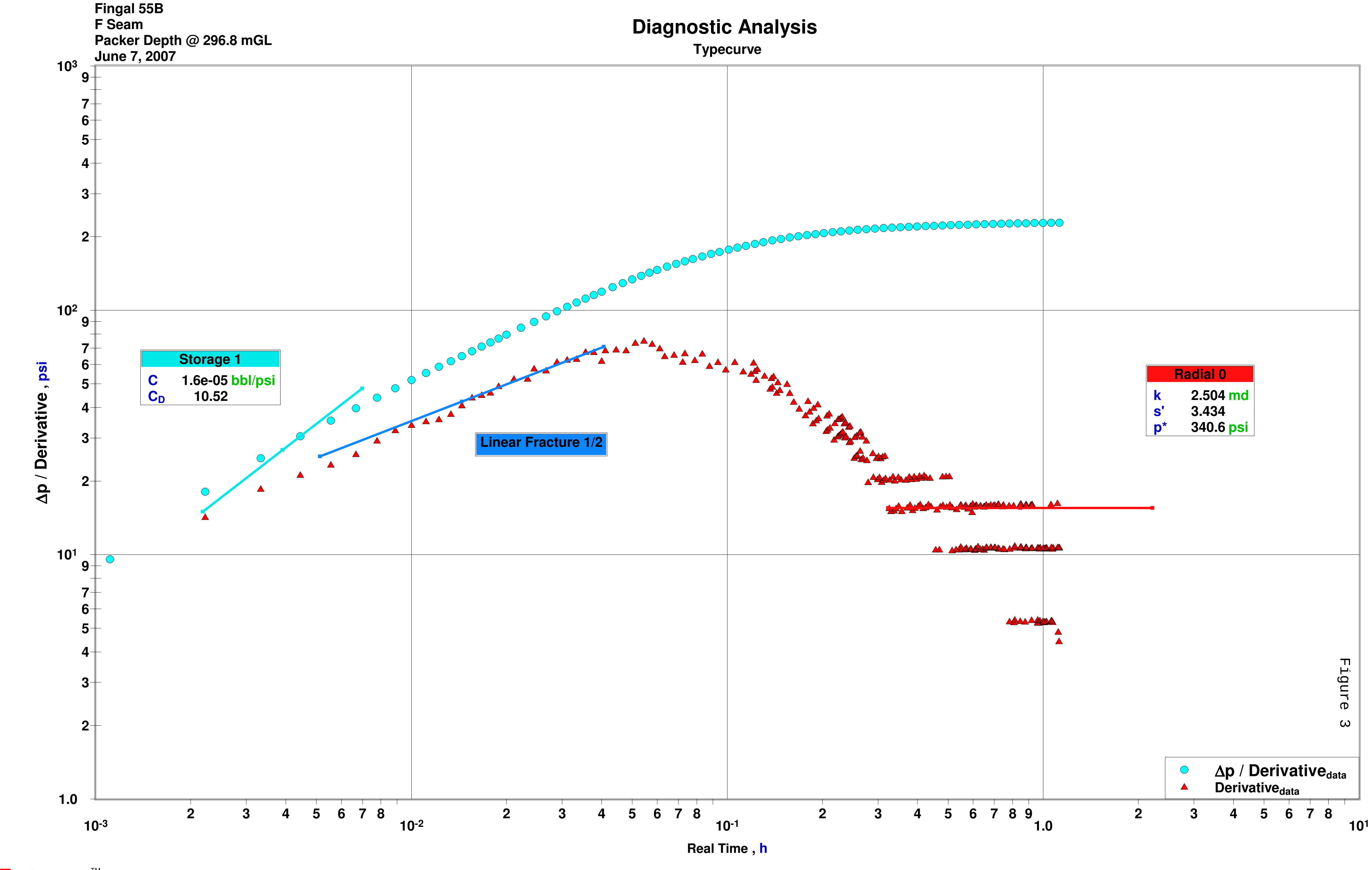

Figure 3

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Fingal 55B
F Seam
Packer Depth @ 296.8 mGL
June 7, 2007

Diagnostic Analysis

Radial

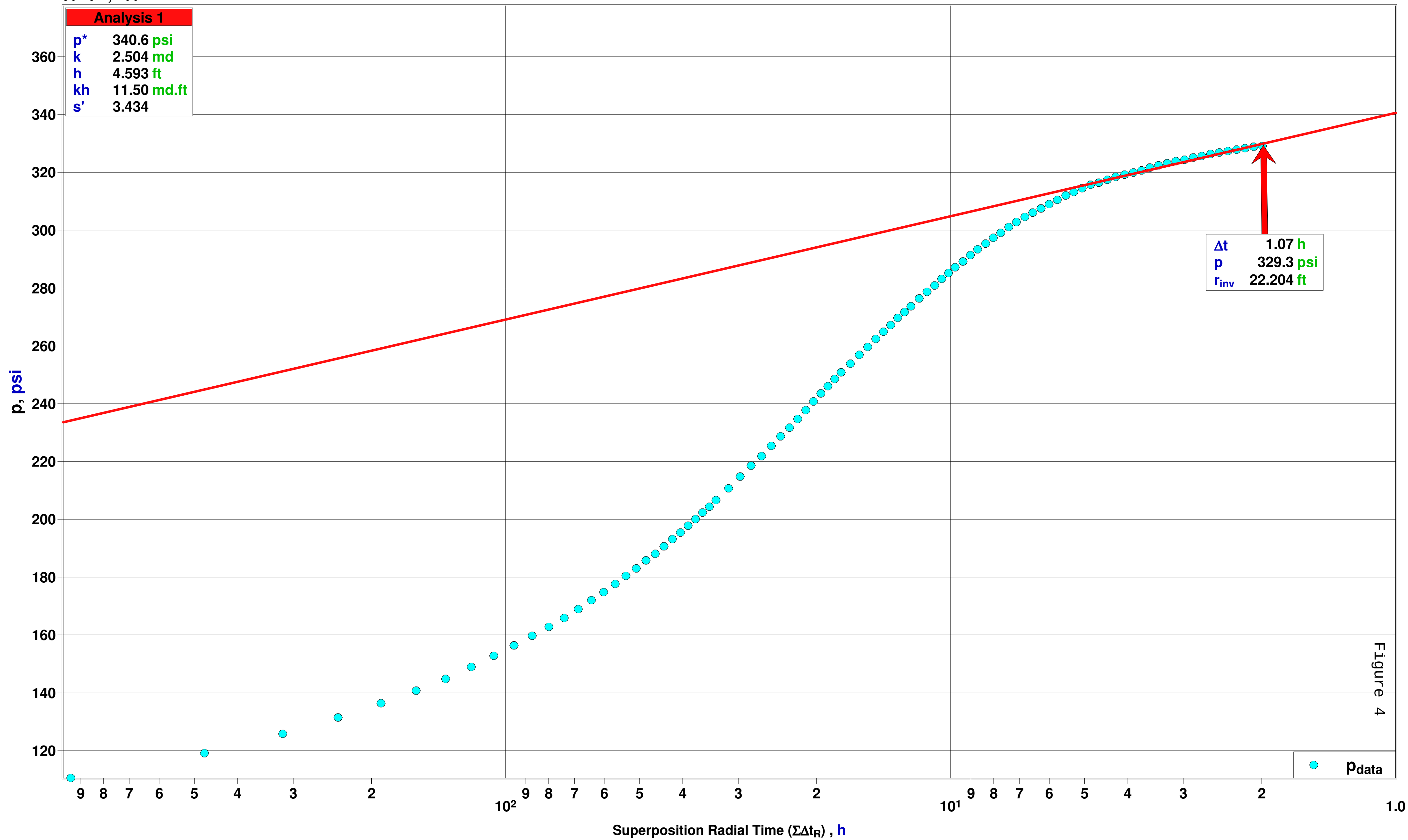

Figure 4

WellTest32™ Ver 6.793
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Water Well Test - Buildup
Radial Flow Analysis

Fingal 55B	Packer Depth @ 296.8 mGL
F Seam	June 7, 2007

Analysis Results

Total Sandface Rate (q_tB_t)	2.597 bbl/d	Apparent Skin (s')	3.434
Semilog Slope (m)	35.75	Skin - Damage	3.434
Gas Permeability (k_g)	md	Skin - Inclination	
Oil Permeability (k_o)	md	Skin - Partial Penetration	
Water Permeability (k_w)	2.504 md	Pressure Drop Due to Skin (Δp_s)	106.68 psi
Flow Capacity (kh)	11.501 md.ft	Damage Ratio (DR)	1.806
Total Mobility (k/μ_t)	2.57 md/cp	Flow Efficiency (FE)	0.554
Total Transmissivity(kh/μ_t)	11.81 md.ft/cp		

Reservoir Parameters

Net Pay (h)	4.593 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)	69.8 °F
Formation Compressibility (c_f)	9.482e-6 psi^{-1}
Total Compressibility (c_t)	1.692e-4 psi^{-1}

Pressures

Initial Pressure (p_i)	340.00 psi
Extrapolated Pressure (p*)	340.60 psi
Final Flowing Pressure (p_{wfo})	101.01 psi

Production and Times

Corrected Flow Time (t_c)	1.0522 hr
Cumulative Water Production	0.114 bbl
Final Water Rate	2.600 bbl/d

Fluid Properties

Water Compressibility (c_w)	3.27591e-6 psi^{-1}
Water Formation Volume Factor (B_w)	0.999
Water Viscosity (μ_w)	0.974 cp
Solution Gas Ratio (R_{sw})	0 scf/bbl
Specific Gravity (G)	1.000
Gas Gravity (G)	0.650
PVT Reference Pressure (p_{PVT})	340.00 psi

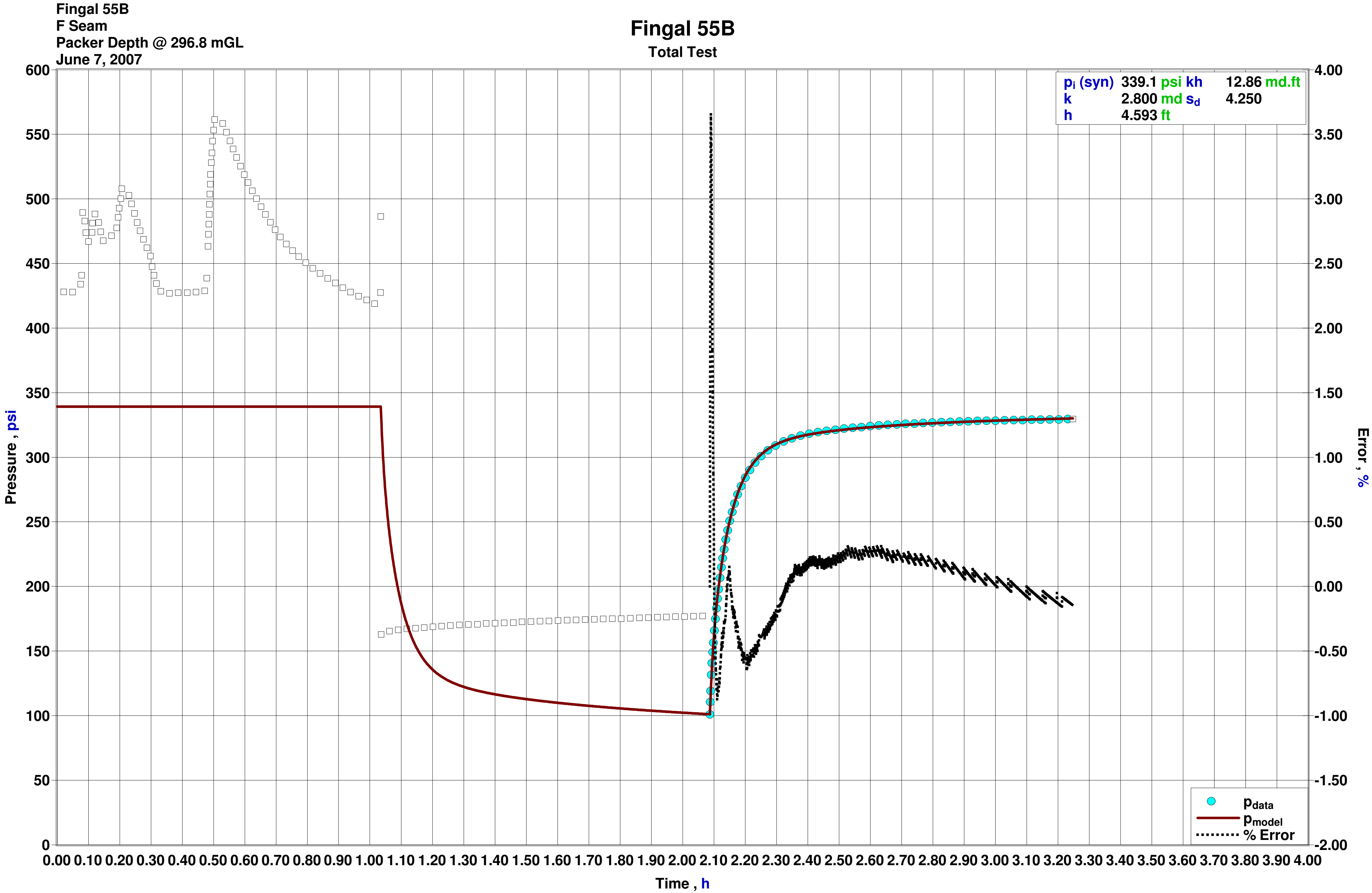

Figure 6

WellTest32™ Ver 6.793
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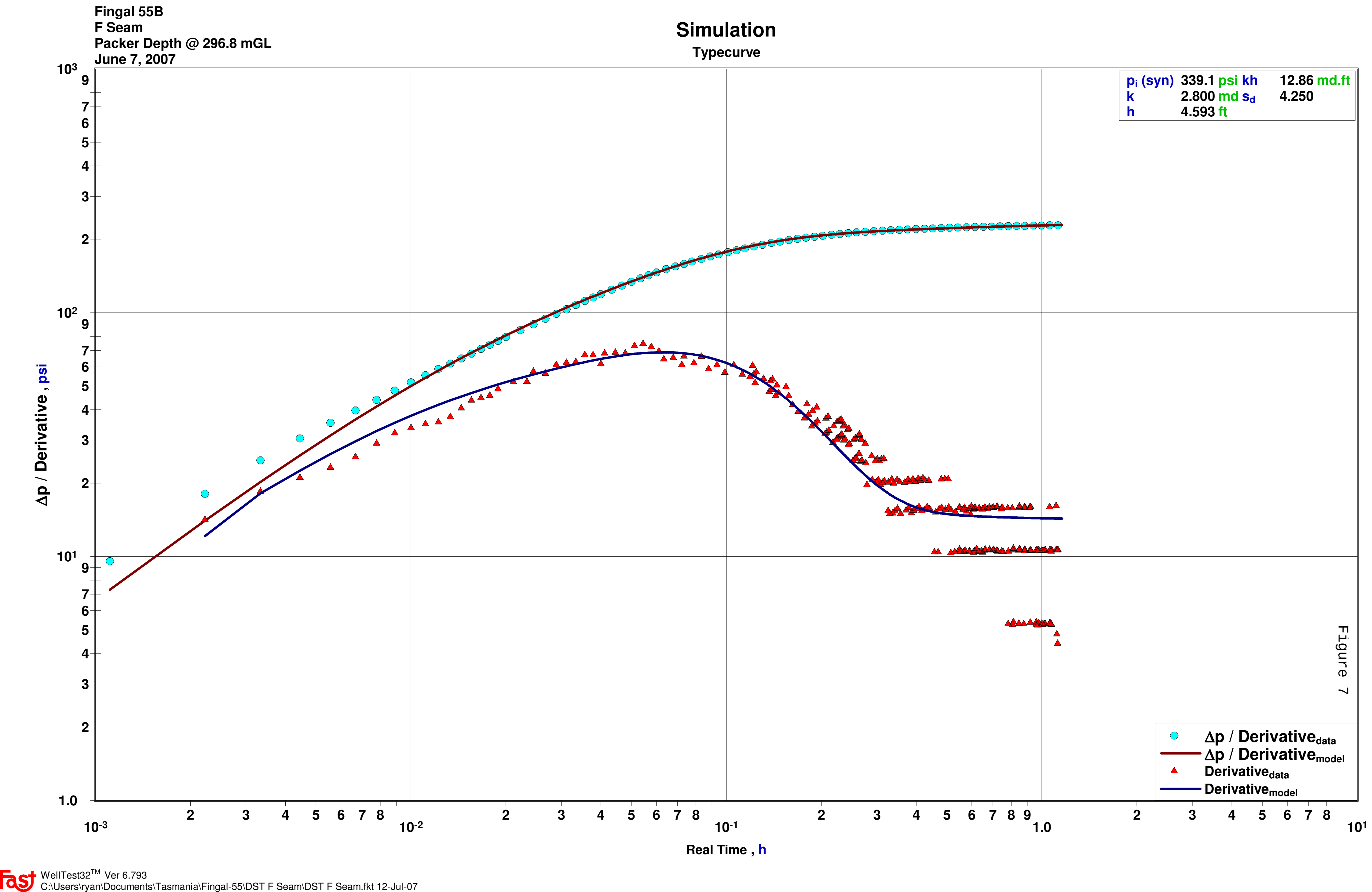
Fingal 55B
F Seam
Packer Depth @ 296.8 mGL
June 7, 2007
Simulation
Typecurve
p_i (syn) 339.1 psi kh 12.86 md.ft
k 2.800 md s_d 4.250
h 4.593 ft
Δp / Derivative , psi
Real Time , h
10^{-3}
10^{-2}
10^{-1}
1.0
10^{1}
10^{3}
10^{2}
10^{1}
Δp / Derivative$_{data}$
Δp / Derivative$_{model}$
Derivative$_{data}$
Derivative$_{model}$
WellTest32™ Ver 6.793
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Figure 7

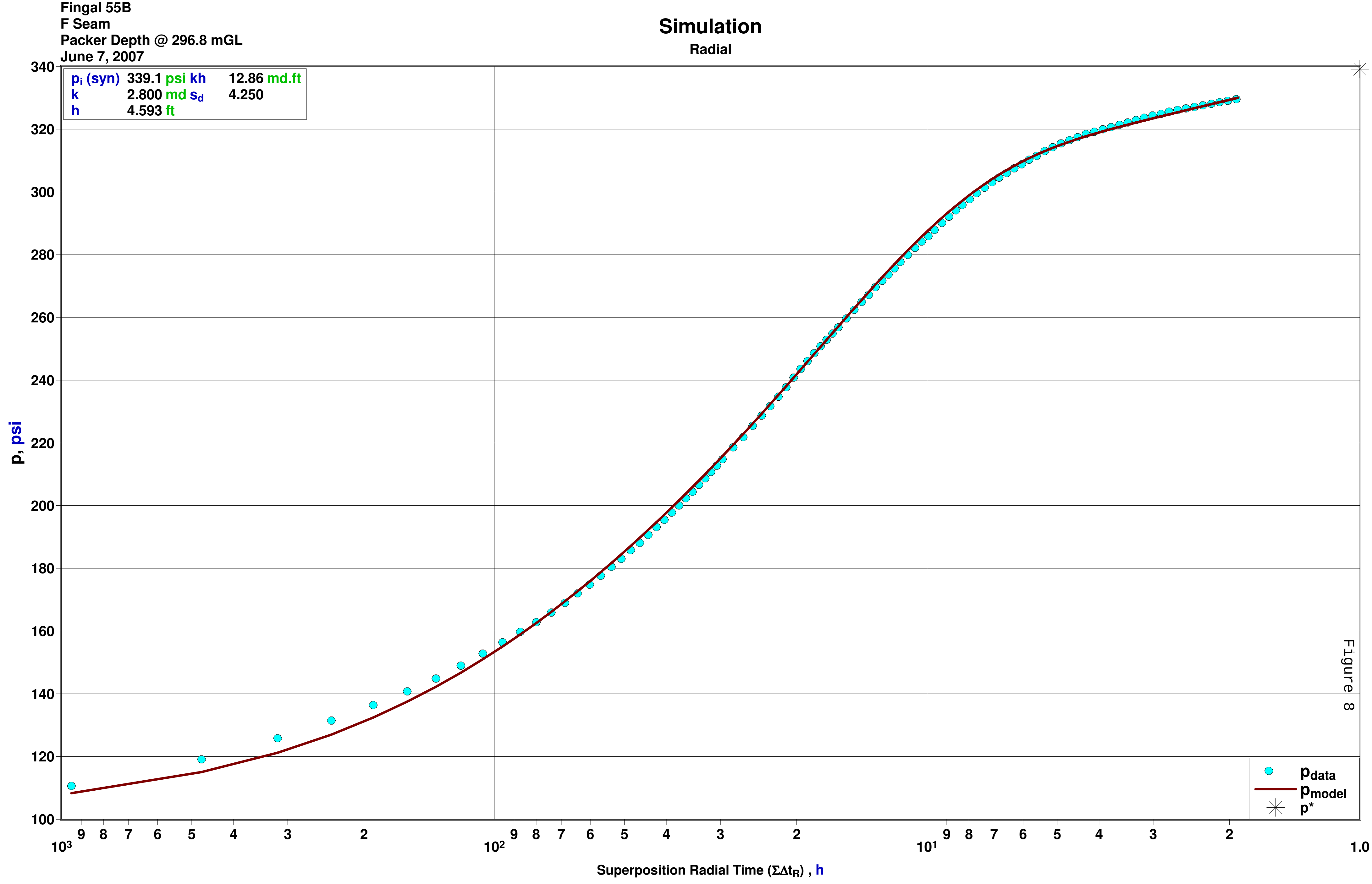

Figure 8

WellTest32[TM] Ver 6.793
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Vertical Water Well Model

Case Name : Radial Homogenous Simulation

Fingal 55B	Packer Depth @ 296.8 mGL
F Seam	June 7, 2007

Model Parameters

Water Permeability (k_w)	2.800 md
Gas Permeability (k_g)	md
Skin (s)	4.250
Total Mobility $(k/\mu)_t$	2.88 md/cp
Total Transmissivity $(kh/\mu)_t$	13.21 md.ft/cp
Wellbore Storage Constant Dim. (C_D)	3.93

Reservoir Length (X_e)	1000000.000 ft
Reservoir Width (Y_e)	1000000.000 ft
Active Well At (X_w)	ft
Active Well At (Y_w)	ft

Formation Parameters

Net Pay (h)	4.593 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)	69.8 °F
Formation Compressibility (c_f)	9.482e-6 psi^{-1}
Total Compressibility (c_t)	1.692e-4 psi^{-1}

Production and Pressure

Q_tB_t	2.597 bbl/d
Final Water Rate	2.600 bbl/d
Final Gas Rate	MMCF/D
Final Flowing Pressure (p_{wfo})	101.01 psi
Final Measured Pressure	329.58 psi
Cumulative Water Production	0.114 bbl

Synthesis Results

Average Error	0.21 %
Synthetic Initial Pressure (p_i)	339.14 psi
Extrapolated Pressure at Specified Time	339.14 psi
Pressure Drop Due To Skin (Δp_s)	117.91 psi
Flow Efficiency (FE)	0.505
Damage Ratio (DR)	1.981

Fluid Properties

Water Compressibility (c_w)	3.27591e-6 psi^{-1}
Water Formation Volume Factor (B_w)	0.999
Water Viscosity (μ_w)	0.974 cp
Solution Gas Ratio (R_{sw})	0 scf/bbl
Specific Gravity (G)	1.000
PVT Reference Pressure (p_{PVT})	340.00 psi

Forecasts

Forecast Flowing Pressure (P_{flow})	101.01 psi
3 - Month Constant Rate Forecast @ Curr. Skin	1.797 bbl/d
6 - Month Constant Rate Forecast @ Curr. Skin	1.748 bbl/d
Forecast Flow Duration (t_{flow})	12.00 month
Constant Rate Forecast @ Curr. Skin	1.702 bbl/d
PI / II (Actual)	0.007 bbl/d/psi
Constant Rate Forecast @ Skin=0	2.519 bbl/d
PI / II (Ideal)	0.011 bbl/d/psi
Constant Rate Forecast @ Skin=-4	4.595 bbl/d

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

PURE
ENERGY RESOURCES LIMITED

Prepared by:

Focal Petroleum Engineering Pty Ltd.

July 11, 2007

focal
PETROLEUM ENGINEERING PTY LTD

PETROLEUM ENGINEERING PTY LTD
ABN 18 061 691 450

Reservoir Engineering & Simulation Well Testing Oil & Gas Property Evaluation

July 11, 2007

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 (Pi) 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**
<u>Near Wellbore Zone</u>	
Average Permeability to Water	**0.9 md**
Flow Capacity to Water	**6 md.ft**
Radius of Investigation	**16 ft**
<u>Outer Area Zone</u>	
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

focal
PETROLEUM ENGINEERING PTY LTD

LIST OF FIGURES

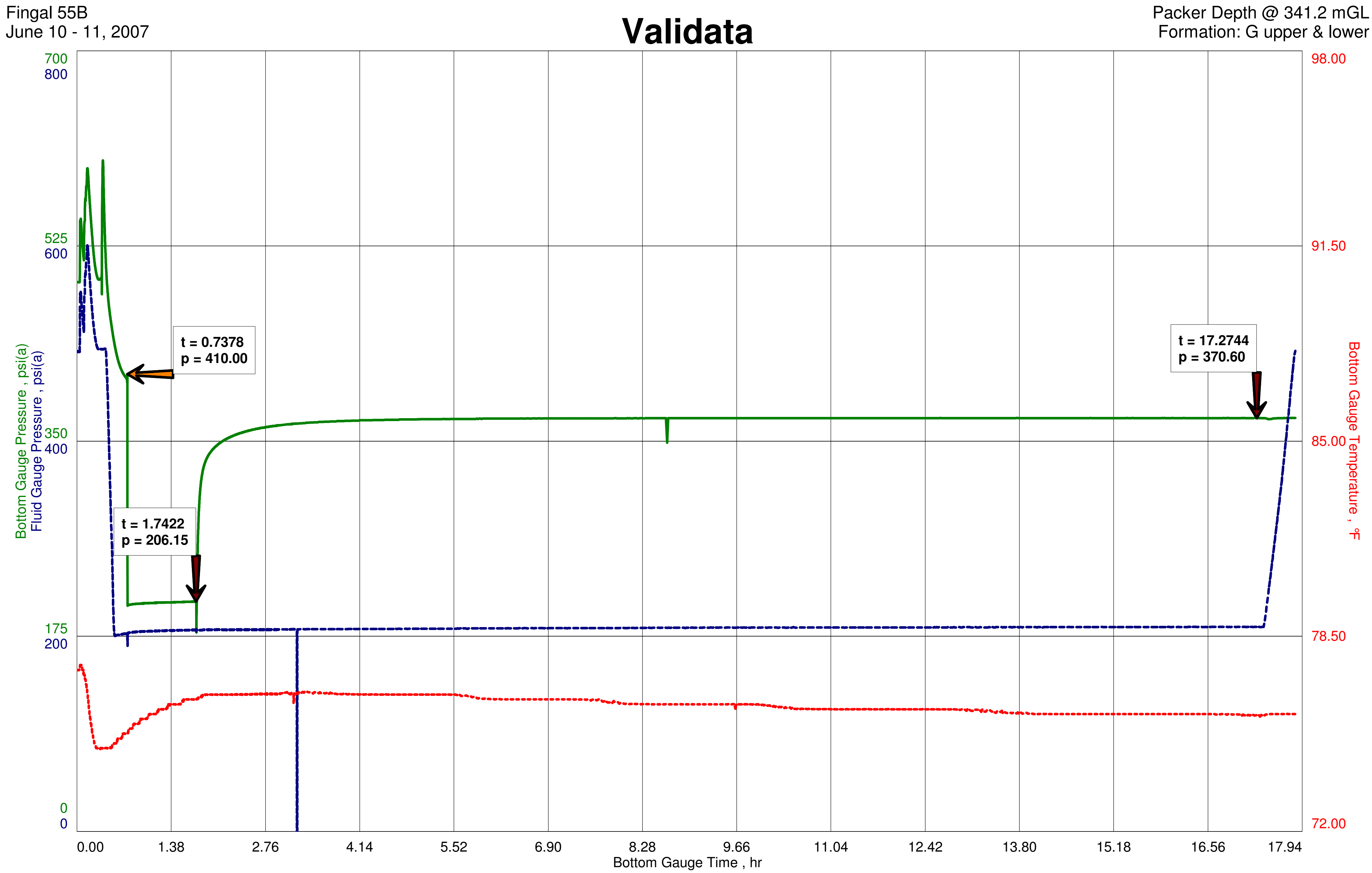

Figure 1

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Fast

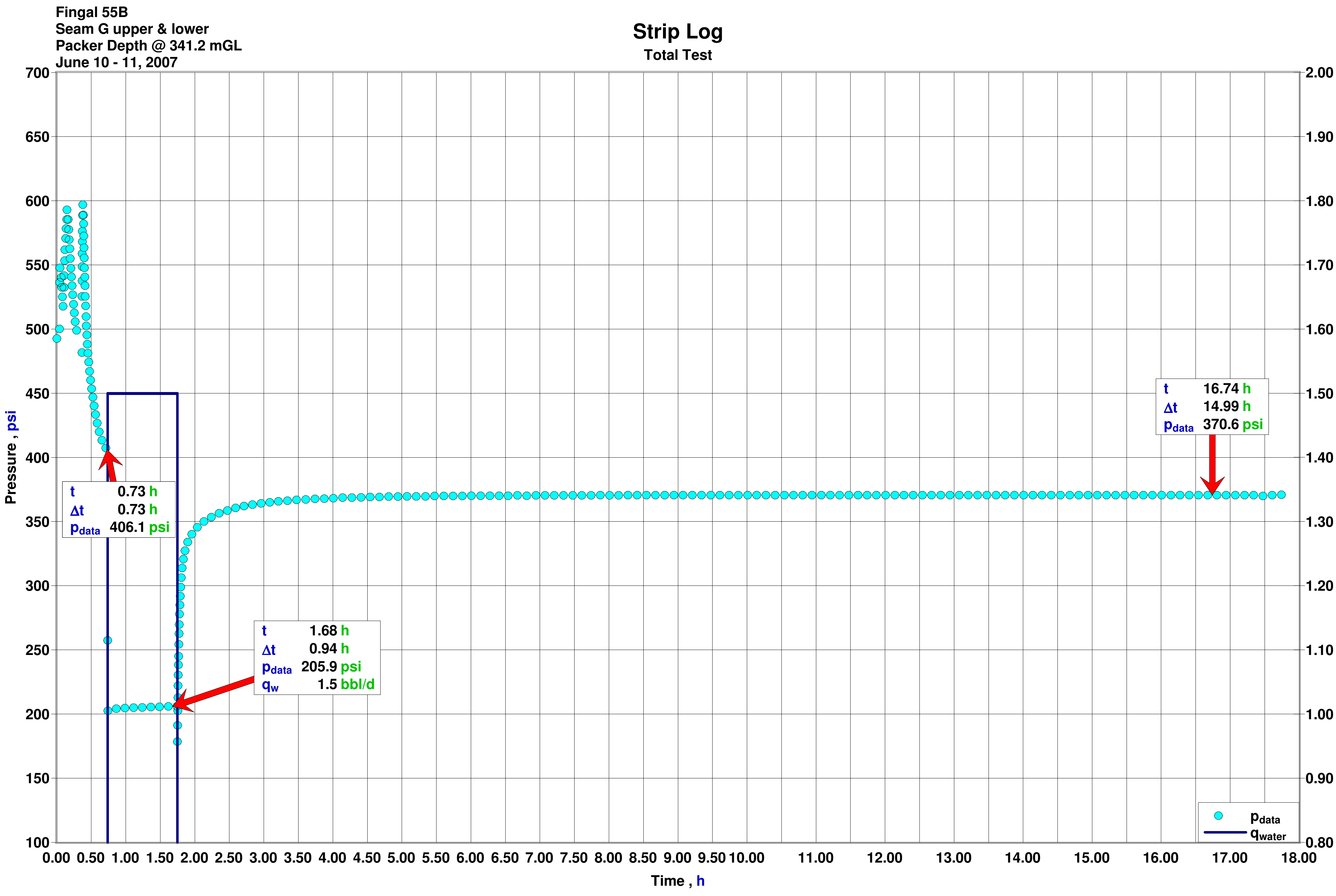

Figure 2

WellTest32™ Ver 6.793
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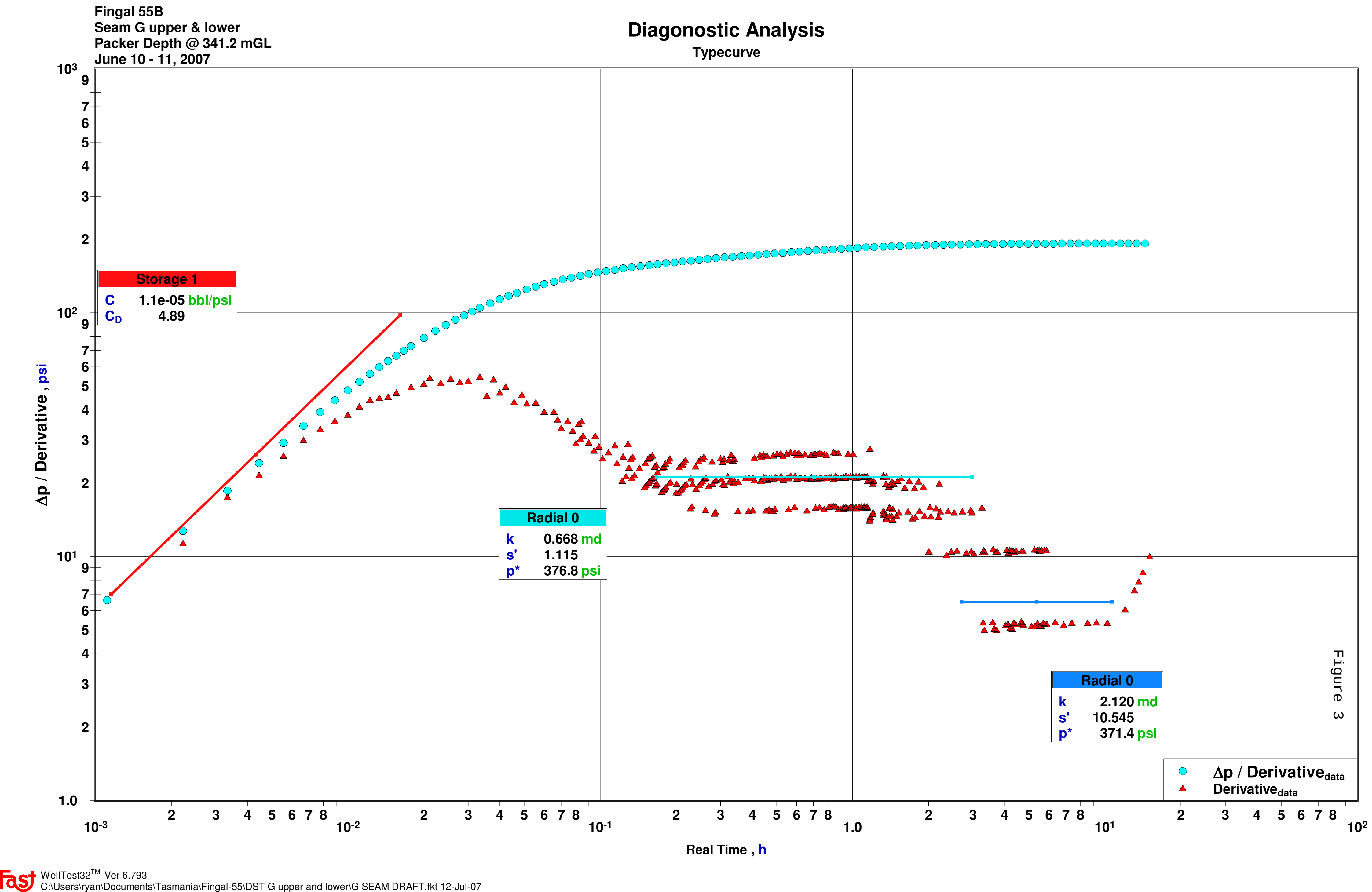

Fingal 55B
Seam G upper & lower
Packer Depth @ 341.2 mGL
June 10 - 11, 2007
Diagonostic Analysis
Typecurve
Storage 1
C 1.1e-05 bbl/psi
CD 4.89
Radial 0
k 0.668 md
s' 1.115
p* 376.8 psi
Radial 0
k 2.120 md
s' 10.545
p* 371.4 psi
Δp / Derivative , psi
Real Time , h
Δp / Derivative data
Derivative data
Figure 3
WellTest32TM Ver 6.793
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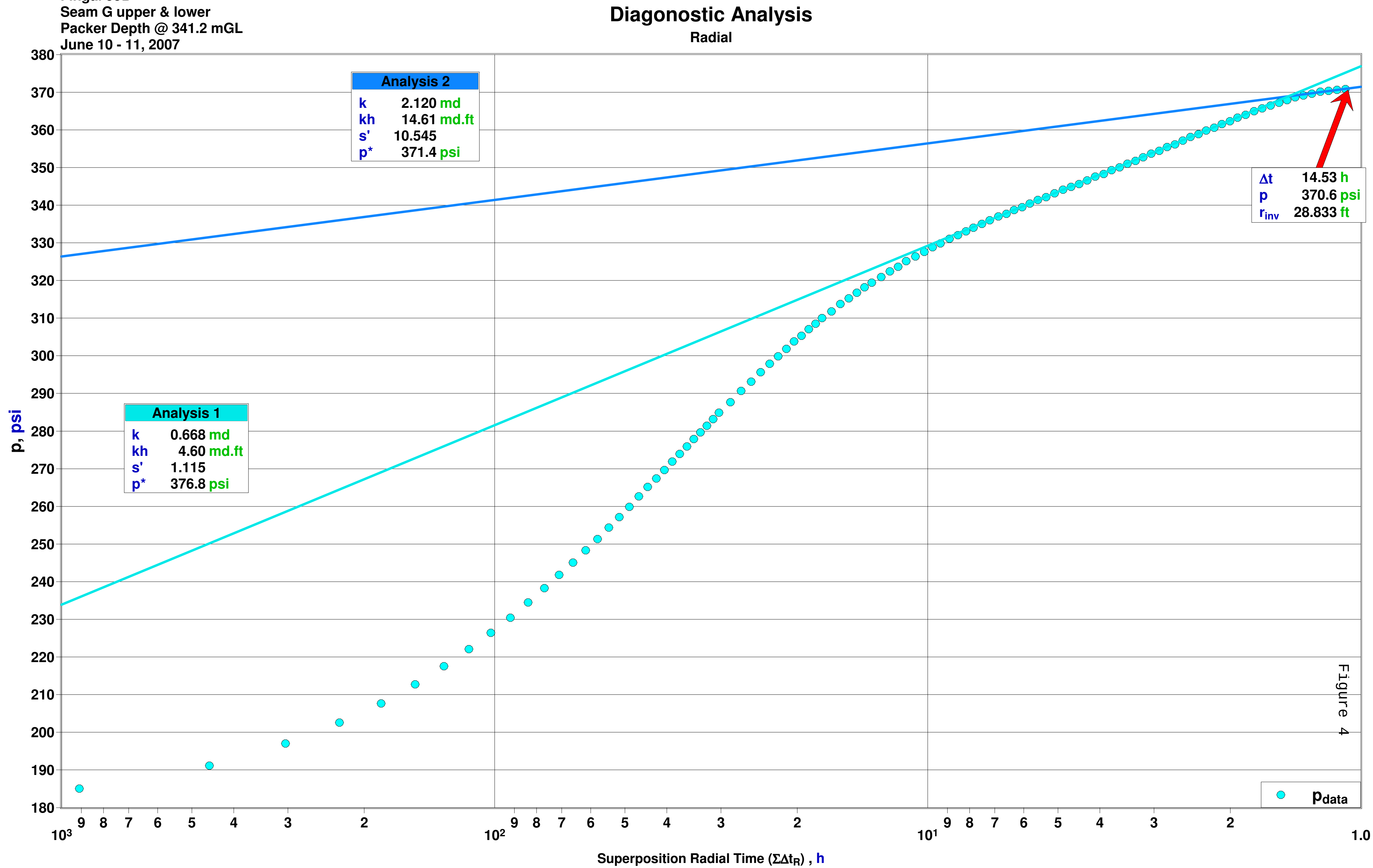
Fingal 55B
Seam G upper & lower
Packer Depth @ 341.2 mGL
June 10 - 11, 2007



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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_tB_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

Seam G upper & lower

Packer Depth @ 341.2 mGL

June 10 - 11, 2007

Analysis Results

Total Sandface Rate (q_tB_t)	1.500 bbl/d
Semilog Slope (m)	15.01
Gas Permeability (k_g)	md
Oil Permeability (k_o)	md
Water Permeability (k_w)	2.120 md
Flow Capacity (kh)	14.609 md.ft
Total Mobility (k/μ_t)	2.36 md/cp
Total Transmissivity(kh/μ_t)	16.25 md.ft/cp

Apparent Skin (s')	10.545
Skin - Damage	10.545
Skin - Inclination	
Skin - Partial Penetration	
Pressure Drop Due to Skin (Δp_s)	137.54 psi
Damage Ratio (DR)	3.498
Flow Efficiency (FE)	0.286

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

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

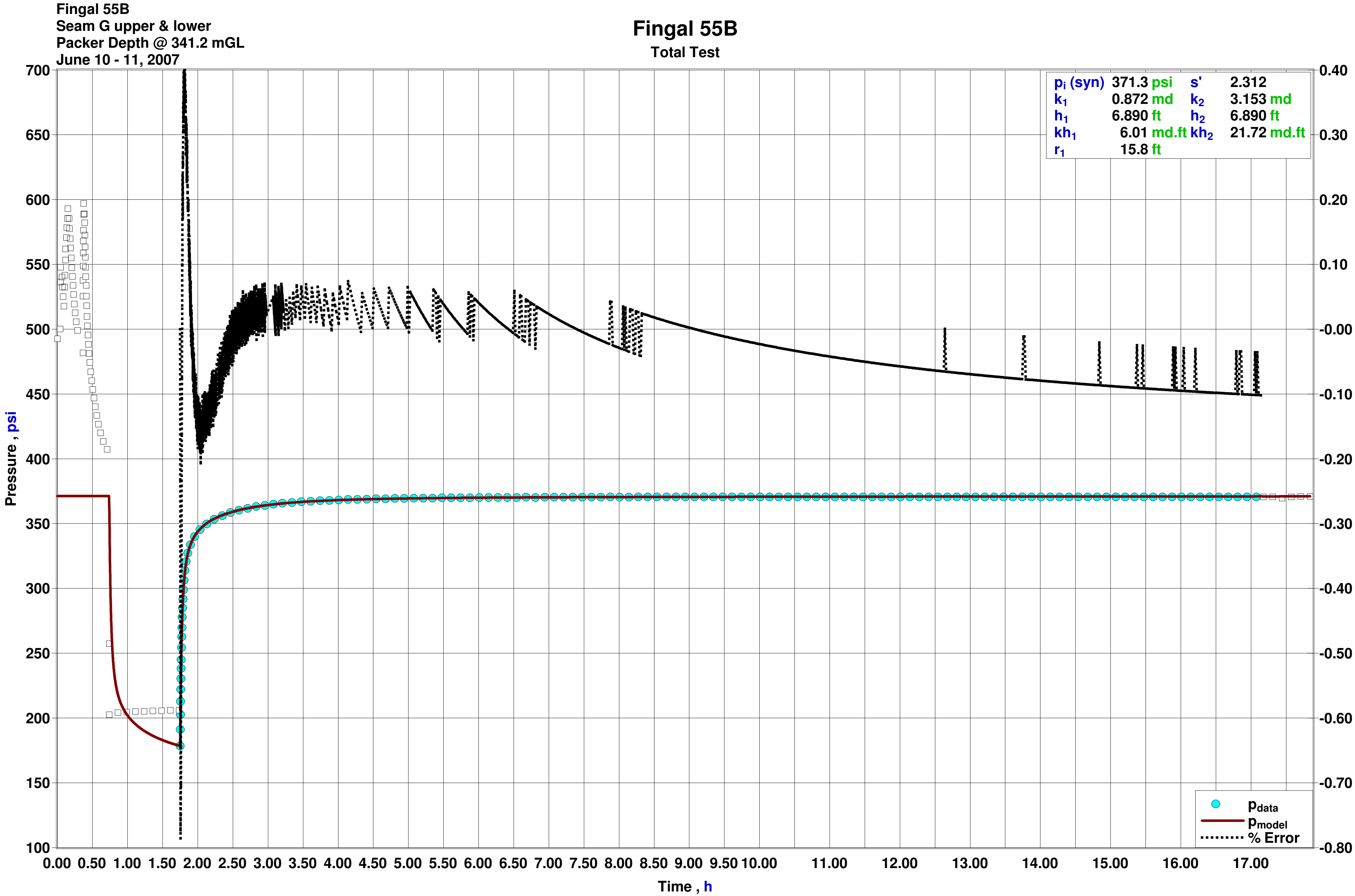

Figure 7

WellTest32™ Ver 6.793
C:\Users\ryan\Documents\Tasmania\Fingal-55\DST G upper and lower\G SEAM DRAFT.fkt 12-Jul-07

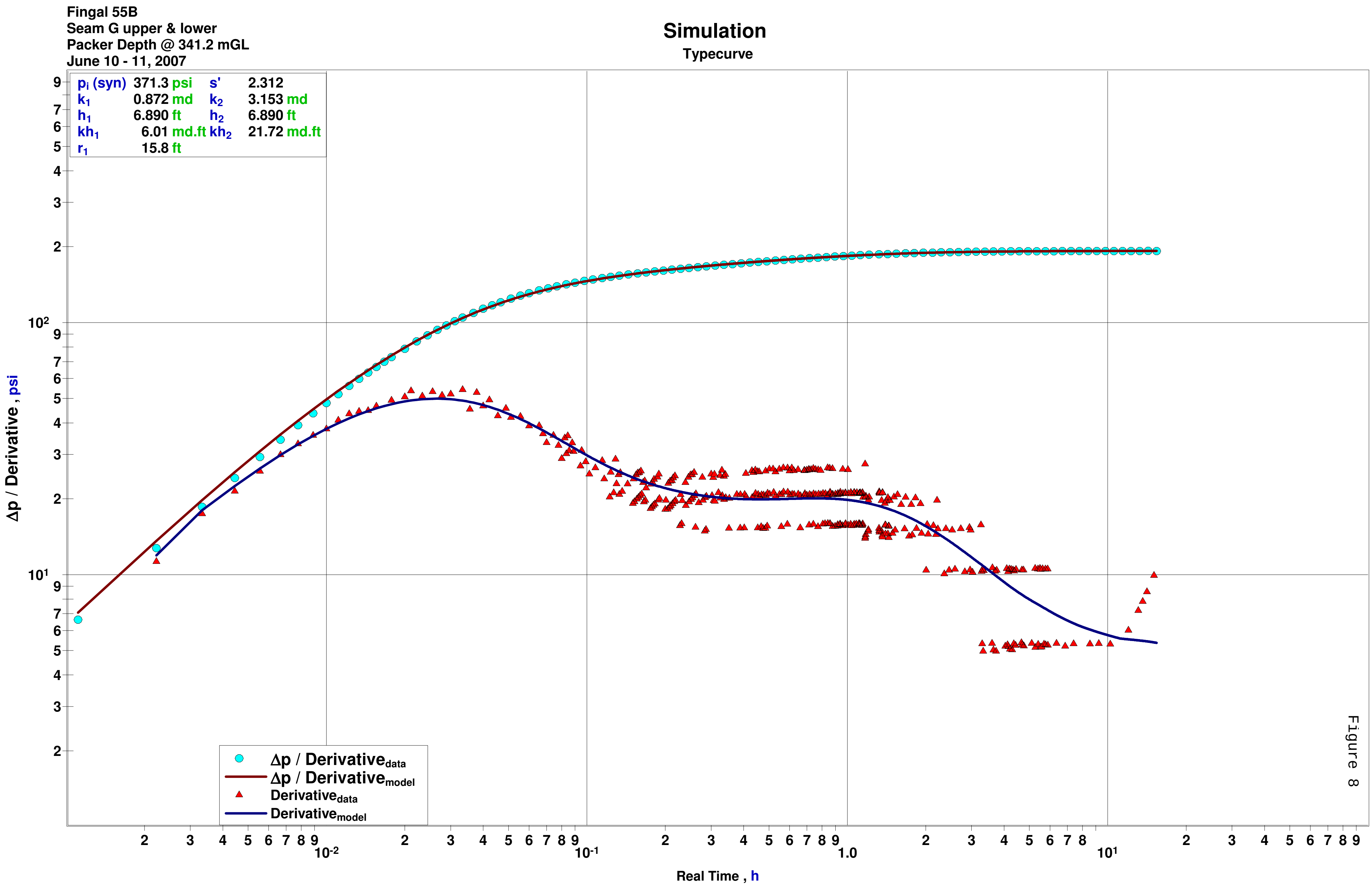

Figure 8

WellTest32™ Ver 6.793
C:\Users\ryan\Documents\Tasmania\Fingal-55\DST G upper and lower\G SEAM DRAFT.fkt 12-Jul-07

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

Simulation

Radial

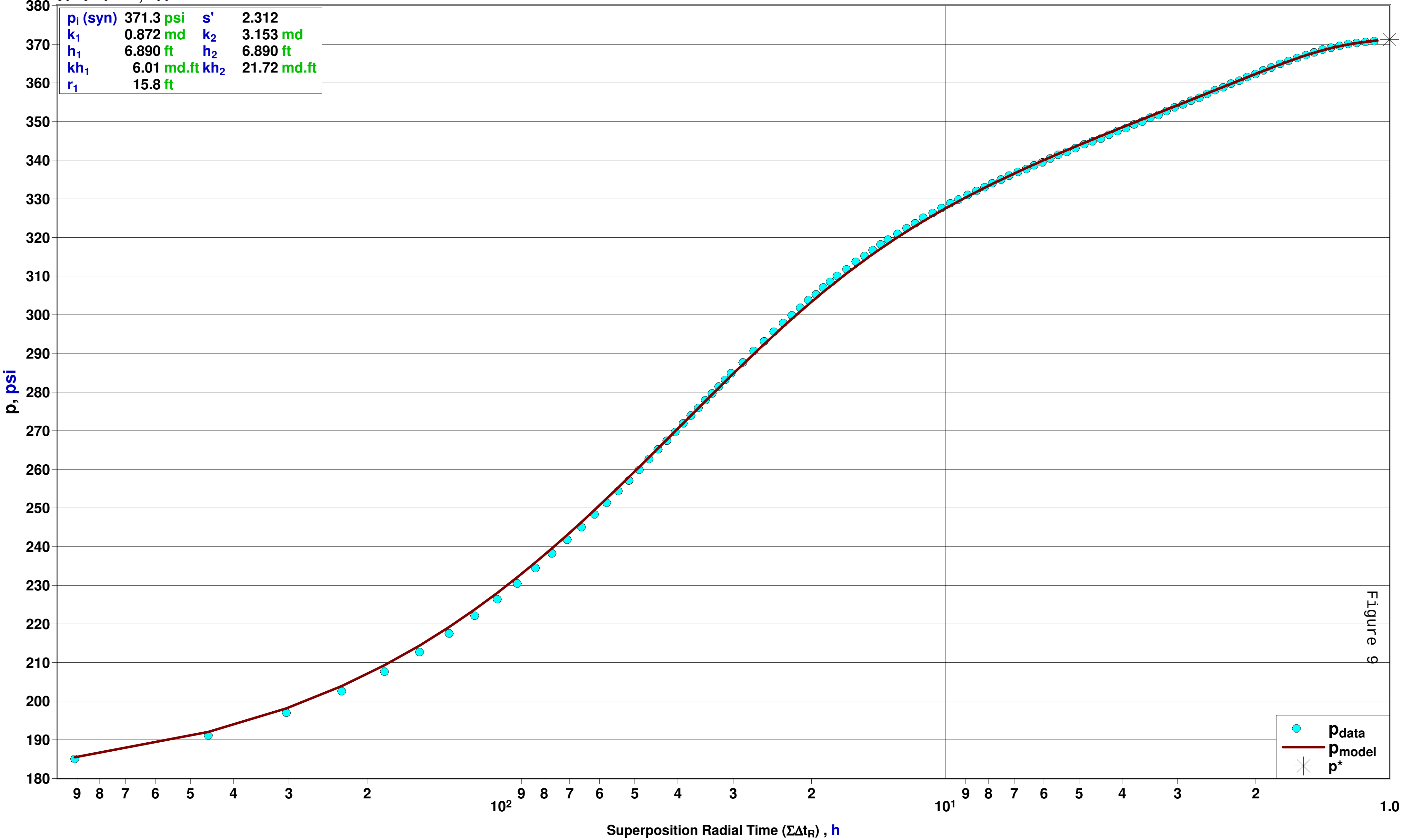

Figure 9

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

Region 1

Total Mobility $(k/\mu)_t$	0.97 md/cp
Permeability $(k)_1$	0.872 md
Net Pay $(h)_1$	6.89 ft
Total Porosity $(\phi_t)_1$	2.00 %
Viscosity $(\mu)_1$	0.899 cp
Total Compressibility $(c_t)_1$	1.566e-4 psi^{-1}
Region Radius $(r)_1$	15.810 ft
Skin (s)	2.312

Region 2

Total Mobility $(k/\mu)_t$	3.51 md/cp
Permeability $(k)_2$	3.153 md
Net Pay $(h)_2$	6.89 ft
Total Porosity $(\phi_t)_2$	2.00 %
Viscosity $(\mu)_2$	0.899 cp
Total Compressibility $(c_t)_2$	1.566e-4 psi^{-1}
Region Radius $(r)_2$	100.000 ft

Apparent Wellbore Storage Dim. (C_{aD})	4.89
Wellbore Storage Constant Dim. (C_D)	4.33
Storage Pressure Param. Dim. (C_{pD})	

Formation Parameters

Gas Saturation (S_g)	5.00 %
Water Saturation (S_w)	95.00 %
Oil Saturation (S_o)	0.00 %
Wellbore Radius (r_w)	0.30 ft
Formation Temperature (T)	75.9 °F

Fluid Properties

Water Compressibility (c_w)	3.24418e-6 psi^{-1}
Oil Compressibility (c_o)	1.50000e-6 psi^{-1}
Gas Compressibility (c_g)	2.88021e-3 psi^{-1}
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

Production and Pressure

Q_tB_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

Synthesis Results

Average Error	0.07 %
Synthetic Initial Pressure (p_i)	371.28 psi
Extrapolated Pressure at Specified Time	371.28 psi
Pressure Drop Due To Skin (Δp_s)	72.94 psi
Flow Efficiency (FE)	0.622
Damage Ratio (DR)	1.608

Forecasts

Forecast Flowing Pressure (P_{flow})	178.41 psi
3 - Month Constant Rate Forecast @ Curr. Skin	1.221 bbl/d
6 - Month Constant Rate Forecast @ Curr. Skin	1.206 bbl/d
Forecast Flow Duration (t_{flow})	12.00 month
Constant Rate Forecast @ Curr. Skin	1.191 bbl/d
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