Provided by **Discovery Capital, L.L.C.**
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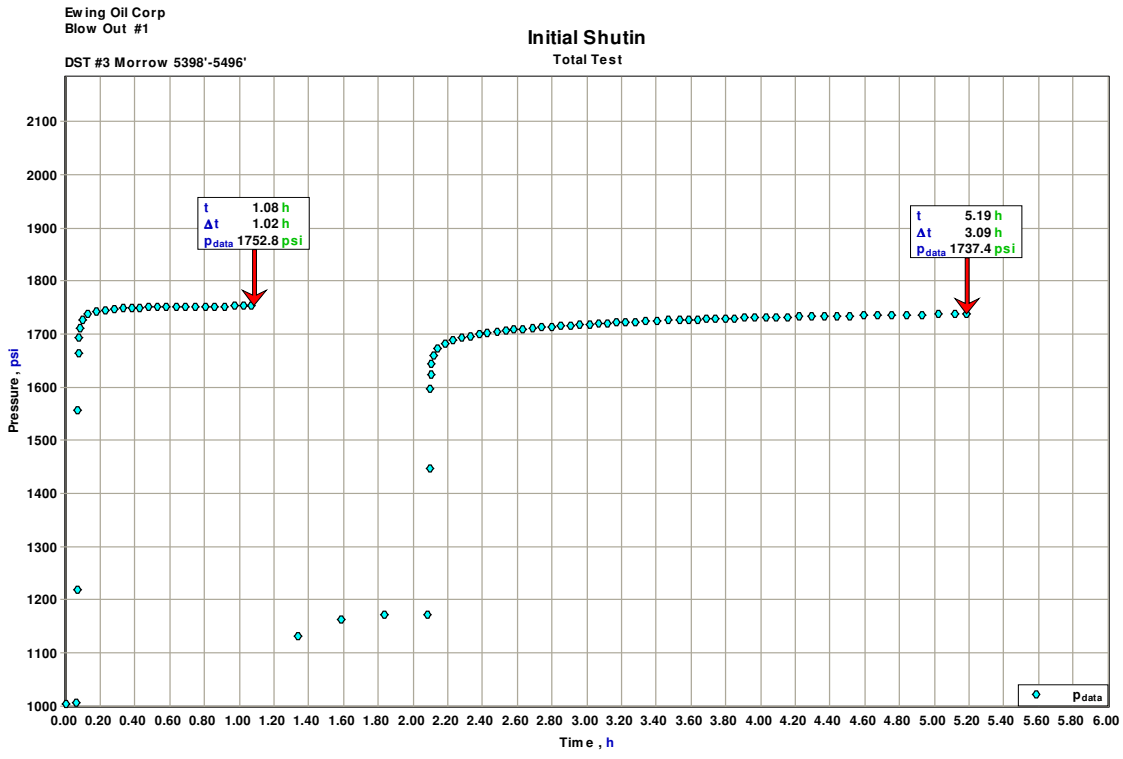
December 22, 2005

J.R. Ewing
Ewing Oil Corp
South Fork Ranch
Dallas, TX 75230

Dear J.R.:

As you requested I have reviewed the data acquired during DST #3 on the Blow Out #1, located in Big Gas Area Kansas. As you are aware this zone had an impressive flowrate during the test and the initial and final shutin pressures were virtually identical, indicating a very permeable zone. The following is my analysis.

STRIP CHART

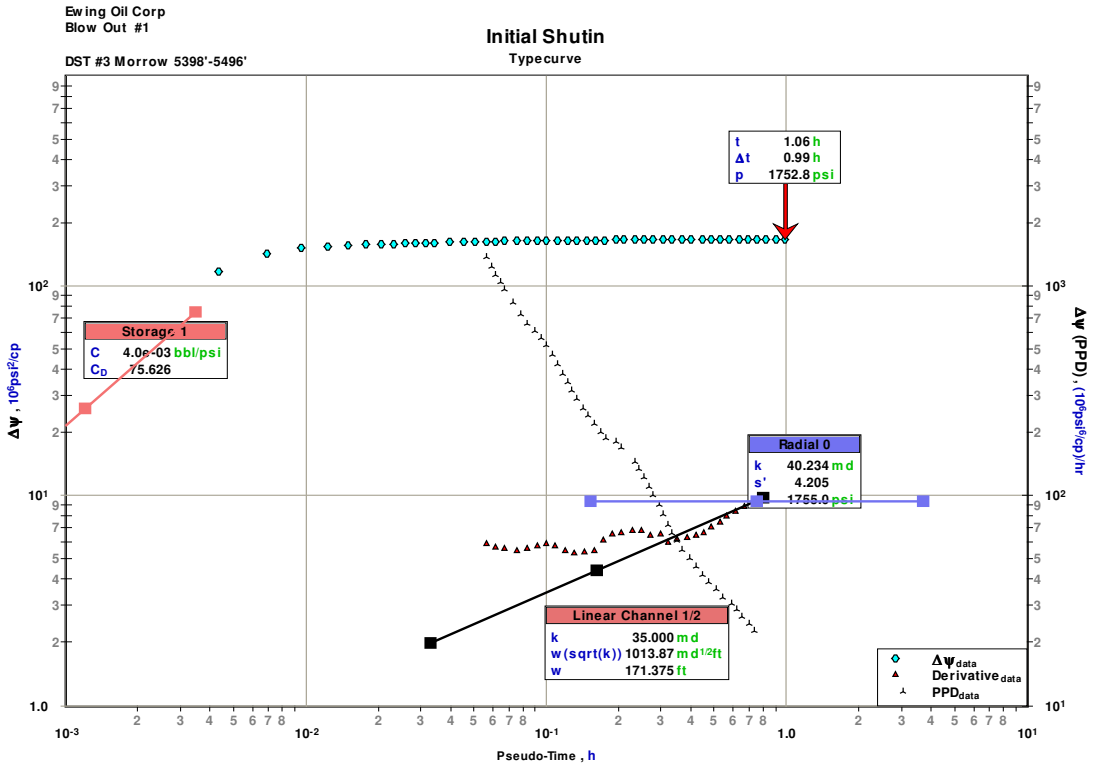


The short initial flow period allowed for almost complete buildup of the pressure to 1753 psia shown on the plot. This compares with a P_I of 1757 psia measured in the Offset # 1. This pressure drop is too small to attribute to the production from the Offset #1, although that is a distinct possibility/probability.

Notice pressure build up during the final flow period. In an ideal situation the bottomhole flowing pressure of a gas zone should decrease during flow. I suspect that a substantial blockage/skin problem is being cleaned up during this period, assuming that the choke size is not changing during the test.

The final build up was quick and with the same character as the initial. The final buildup pressure was 1538 psia, but the pressure was still building. No assumption of drainage can be made from the recorded data, a model must be constructed.

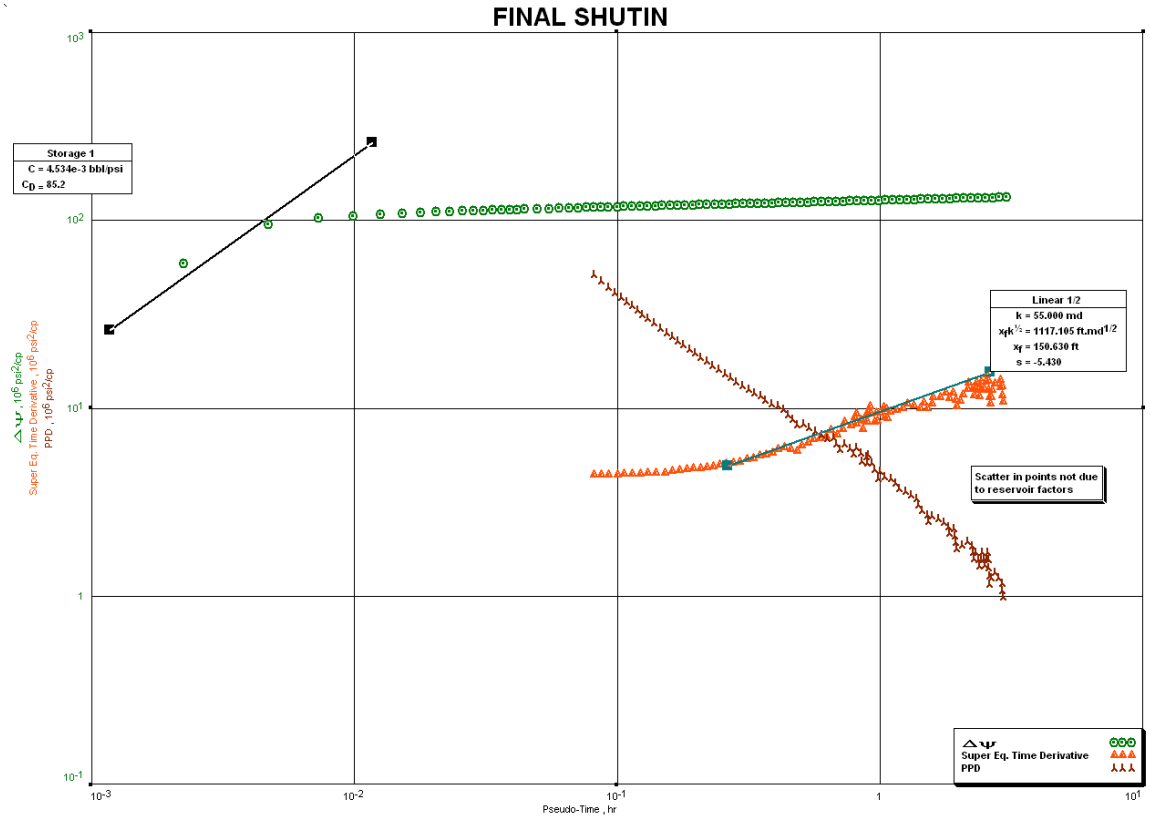
INITIAL SHUTIN



Although the Initial Shutin data should not be used for calculations, it can provide insight into the reservoir. In this case I can see that the dimensionless storage value C_D is small as expected from a DST. More importantly the Derivative curve shows a decidedly upward trend. I look to the Final Build up to see if these characteristics continue. This build in Derivative also indicates that the pressure is still building possibly to the P_i seen in the Offset #1.

Even though the pressure was still building as shown by the Derivative, the magnitude of the build is very small. I have superimposed a Radial Flow solution in order to estimate Pi. As you can see P* is extrapolated to be about 1755 psia. I will assume this to be Pi.

FINAL SHUTIN



The data from the Final Shutin indeed reflects the characteristics seen in the Initial Shutin. The data quality is excellent as seen by the constant downward trend in the PPD curve. The scatter in the data at the end of the test is due to very small build up rate, not any sort of reservoir behavior.

The Derivative curve shows an upward trend with a slope of ½. This "Linear ½" slope can indicate either a Channel type drainage area or a fractured reservoir area. The geology of the Morrow obviously indicates that the former is a more logical conclusion. Based on these findings I will construct a reservoir model based on Channel type drainage.

In this model a long narrow reservoir is created. The inflection point on the plot above indicates that a barrier is encountered fairly close to the wellbore. Typically a DST from a gas well only looks a couple of hundred feet into the zone. This is due entirely to, and is a function of, the amount of gas withdrawn from the reservoir.

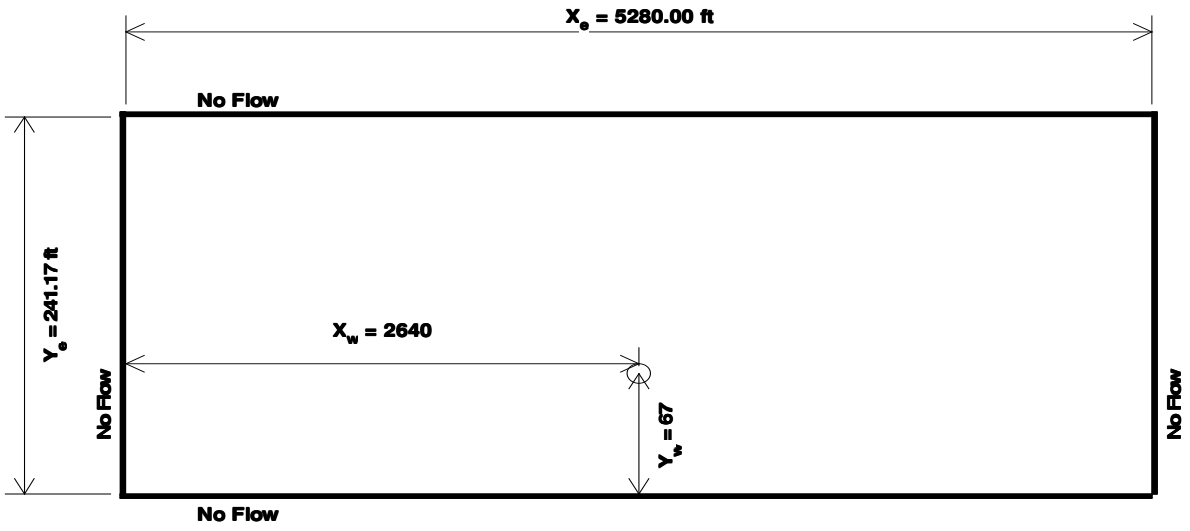
In the case of this well, the flow rate was high enough that we were able to see much further than is typical. The schematic below shows the reservoir dimensions calculated by the model. Although I believe that the width of the reservoir is in the correct order of magnitude, I cannot put any certainty into the length. Because the test was so short , I used and arbitrary length of one mile.

Vertical 2

k = 97.295 md
s = 8.899
GIP_{model} = 115 MMcf

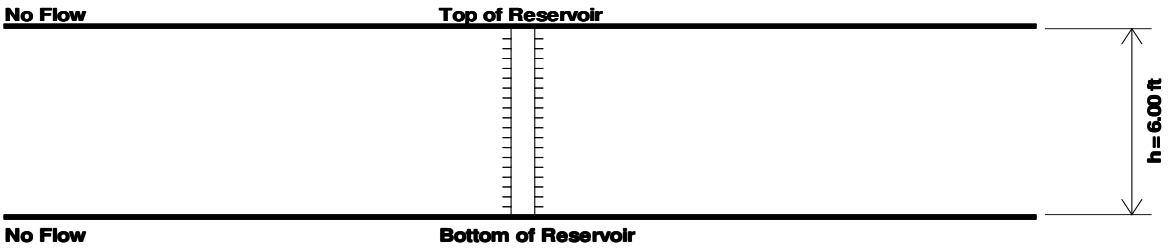
Plan View

(Not to scale)



Side View

(Not to scale)



Vertical Gas Well Model

Case Name : Channel Model

Daystar Petroleum

Saunders Trust A #1

Sec 26-31S-31W Seward Co. Ks

DST #3 Morrow 5398'-5496'

Model Parameters

Permeability (k)	97.295	md
Apparent Wellbore Storage Dim. (C_{aD})		
Wellbore Storage Constant Dim. (C_D)	50.00	
Storage Pressure Param Dim. (C_{pD})		
Skin (s)	8.899	
Turbulence Factor (D)	0.00	$(MMCF/D)^{-1}$

Reservoir Length (X_e)	5280.000	ft
Reservoir Width (Y_e)	241.166	ft
Active Well At (X_w)	2640.000	ft
Active Well At (Y_w)	67.493	ft

Formation Parameters

Net Pay (h)	6.000	ft
Total Porosity (Φ_t)	15.00	%
Gas Saturation (S_g)	77.00	%
Water Saturation (S_w)	23.00	%
Oil Saturation (S_o)	0.00	%
Wellbore Radius (r_w)	0.33	ft
Formation Temperature (T)	120.0	°F
Formation Compressibility (c_f)	4.109e-6	psi^{-1}
Total Compressibility (c_t)	4.853e-4	psi^{-1}

Fluid Properties

Gas Gravity (G)	0.685	
N_2	6.91	%
H_2S	0.00	%
CO_2	0.13	%
Critical Pressure (P_c)	658.72	psi
Critical Temperature (T_c)	367.73	R
PVT Reference Pressure (p_{PVT})	1752.80	psi
Gas Compressibility (c_g)	6.23976e-4	psi^{-1}
Gas Compressibility Factor (z)	0.825	
Gas Viscosity (μ_g)	0.0157	cp
Gas Formation Volume Factor (B_g)	0.001370	bbl/scf

Production and Pressure

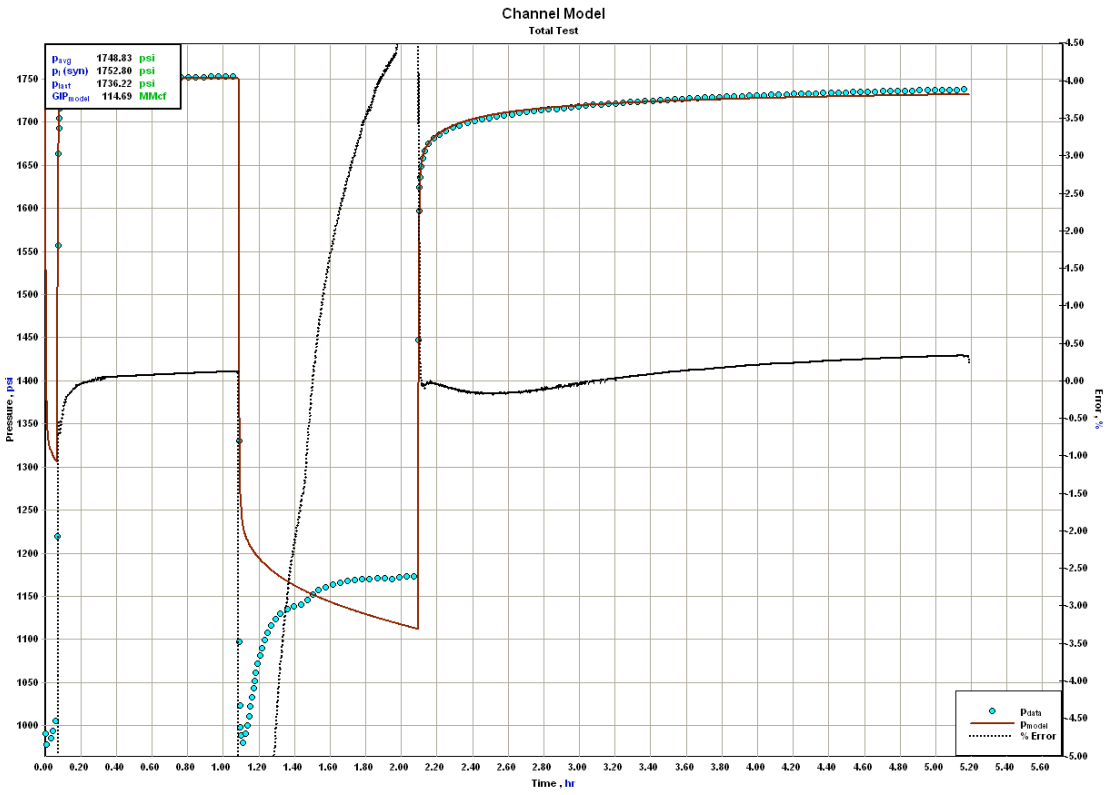
Final Gas Rate	6.500	MMCF/D
Cumulative Gas Production	0.288	MMCF
Final Measured Pressure	1736.22	psi

Synthesis Results

Average Error	-0.70	%
Synthetic Initial Pressure (p_i)	1752.80	psi
Average Reservoir Pressure	1748.83	psi
Pressure Drop Due To Skin (Δp_s)	380.87	psi
Flow Efficiency (FE)	0.402	
Damage Ratio (DR)	2.488	

Forecasts

Forecast Flowing Pressure (P_{flow})	1172.81	psi
3 - Month Constant Rate Forecast @ Curr. Skin	0.357	MMCF/D
6 - Month Constant Rate Forecast @ Curr. Skin	0.187	MMCF/D
Forecast Flow Duration (t_{flow})	12.00	month
Constant Rate Forecast @ Curr. Skin	0.096	MMCF/D
Constant Rate Forecast @ Skin=0	0.097	MMCF/D
Constant Rate Forecast @ Skin=-4	0.098	MMCF/D



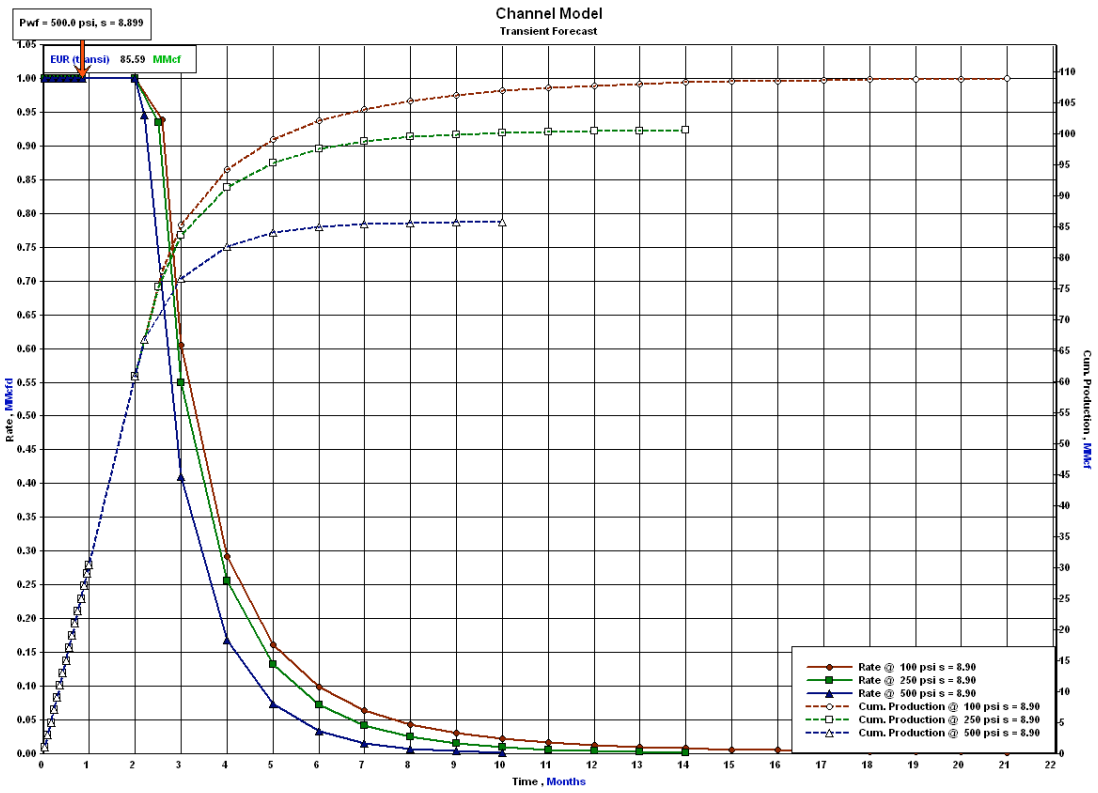
The plot shows the results of the model superimposed over the recorded data. As you can see the model results differ from the actual by less than 0.5% over the entire test. As the data is extrapolated backwards the **calculated** $P_{I(syn)}$ is equal to the **measured** P_I.

Notice that the flowing bottomhole pressure of the model (red line) is decreasing while the recorded data is increasing, this is the cleaning up I discussed earlier. Because the model fits so well during both of the shutin periods I feel that it is representative of the permeability, skin and boundaries of the reservoir.

The extrapolated pressure of 1749 psia, P_{avg}, is too close to Pi to make any conclusions as to the reserves in place, as calculated from the pressure drop. The volumetric calculation of reserves in place may be valid however. I always hesitate to make reserve estimates from DST data, but in this case the fit of the data is very sensitive to the width of the reservoir and the position of the well within it. I would not be surprised if the OGIP is close to the value shown on the plot above of 115 MMcf.

FORECAST

Using the above noted parameters I was able to forecast the well's future production against three different backpressures. This plot is on the next page, and should be useful in estimating the effectiveness of compression. As with all high perm reservoirs, compression makes a significant difference in flowrates. Unfortunately, with the limited reservoir I have constructed the ultimate recovery is not significantly changed.



CONCLUSIONS

- The recorded DST data was of excellent quality and represented reservoir behavior
- The initial reservoir pressure extrapolated to 1755 psia, virtually the same as that seen in the offsetting well.
- The test was too short to measure a pressure drop for reserve calculations
- The reservoir appears to have a long narrow Channel type geometry
- This is a high perm (100md) reservoir with high skin damage
- The shape of the reservoir will limit the OGIP

Thank you, for the opportunity to review this test for you. Please call after you have received this report so that we may discuss any question that may arise. I am providing this report in a .pdf format without the full size attachments. Please feel free to print as many copies as you need. A bound report will follow that has full size attachments.

Sincerely,

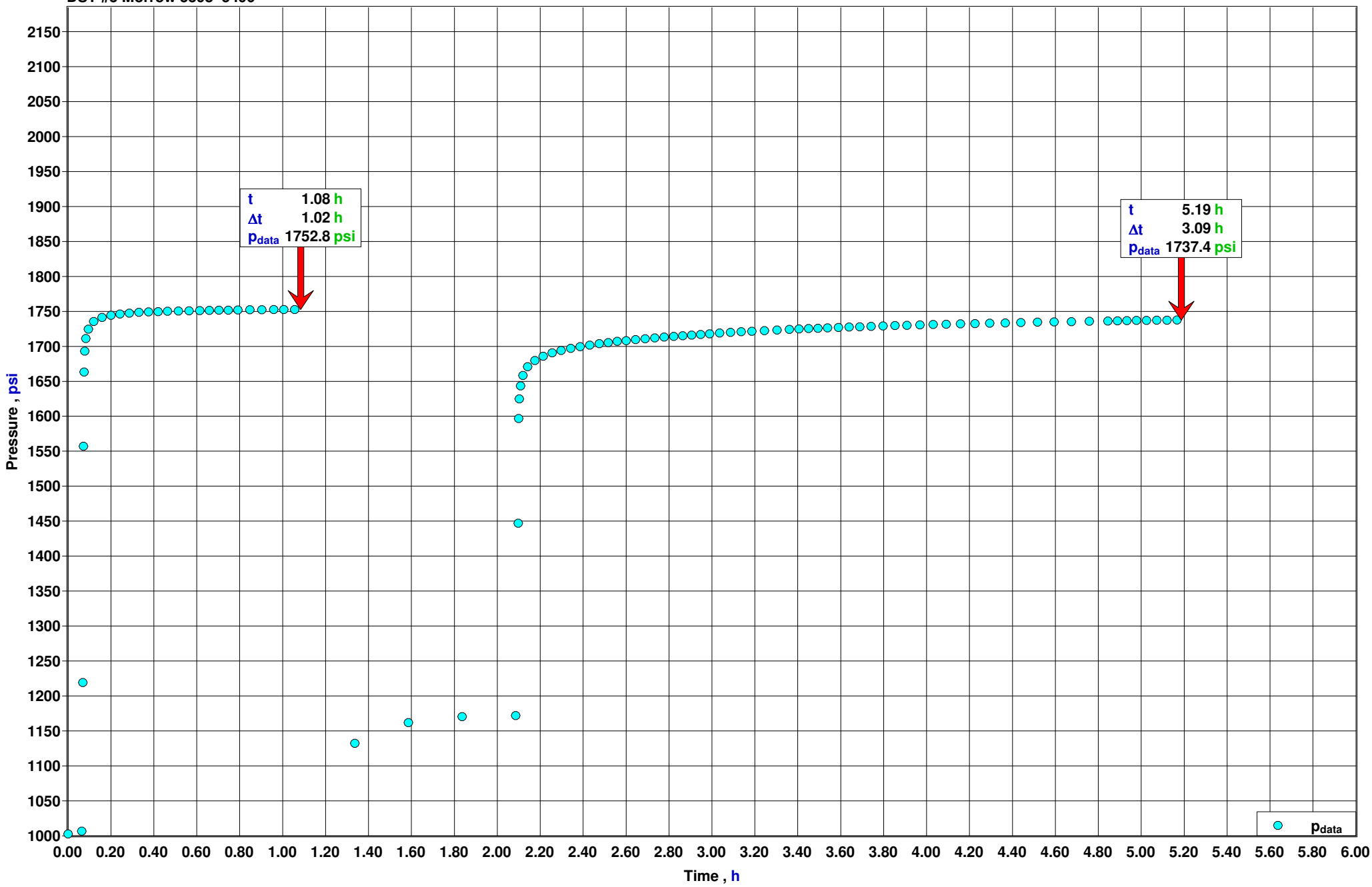
William M. Johnson
Managing Partner

Ewing Oil Corp
Blow Out #1

DST #3 Morrow 5398'-5496'

Initial Shutin

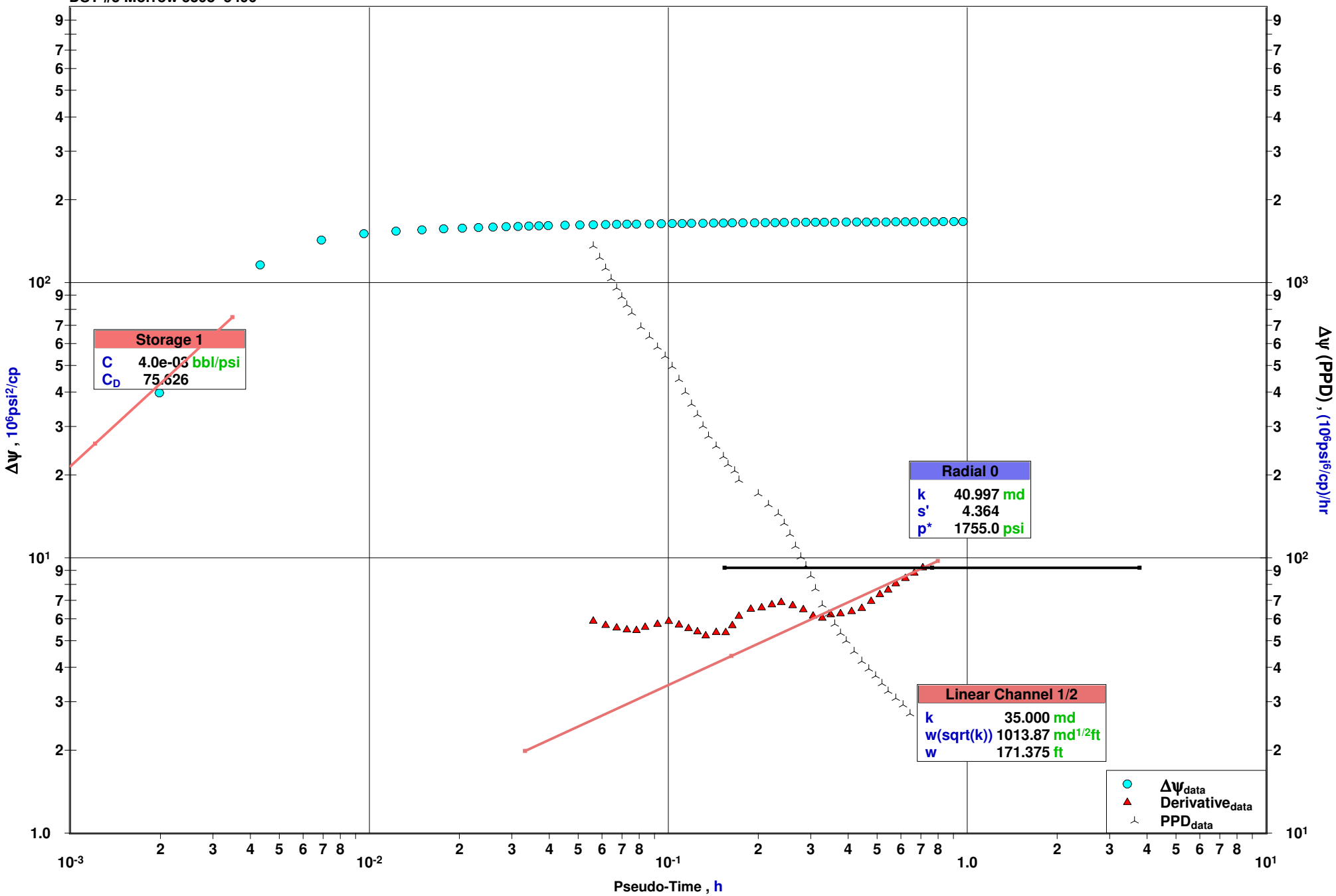
Total Test



Blowout #1
Seward Co. Ks
DST #3 Morrow 5398'-5496'

Initial Shutin

Typecurve

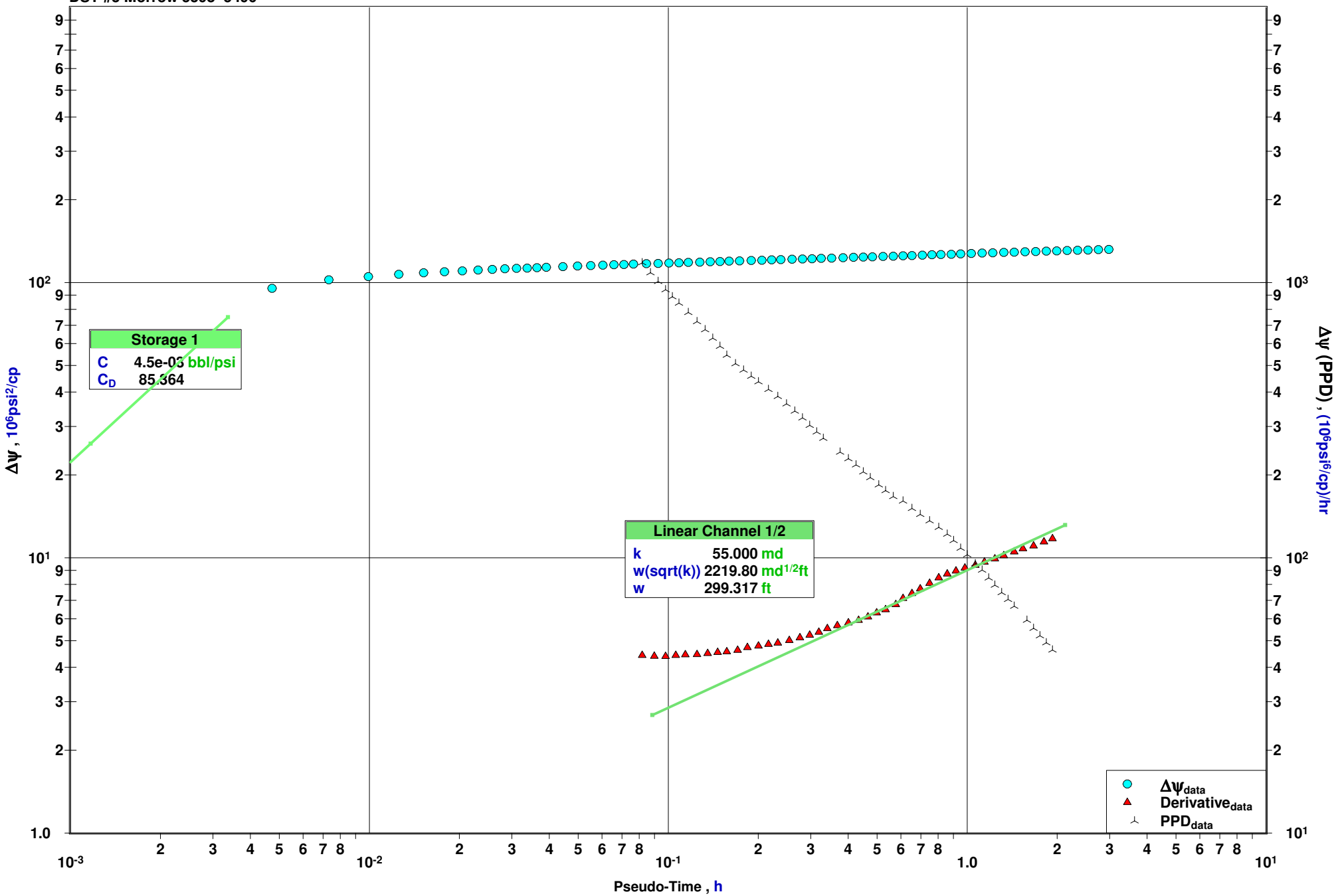


Ewing Oil Corp
Blow Out #1

DST #3 Morrow 5398'-5496'

Final Shutin

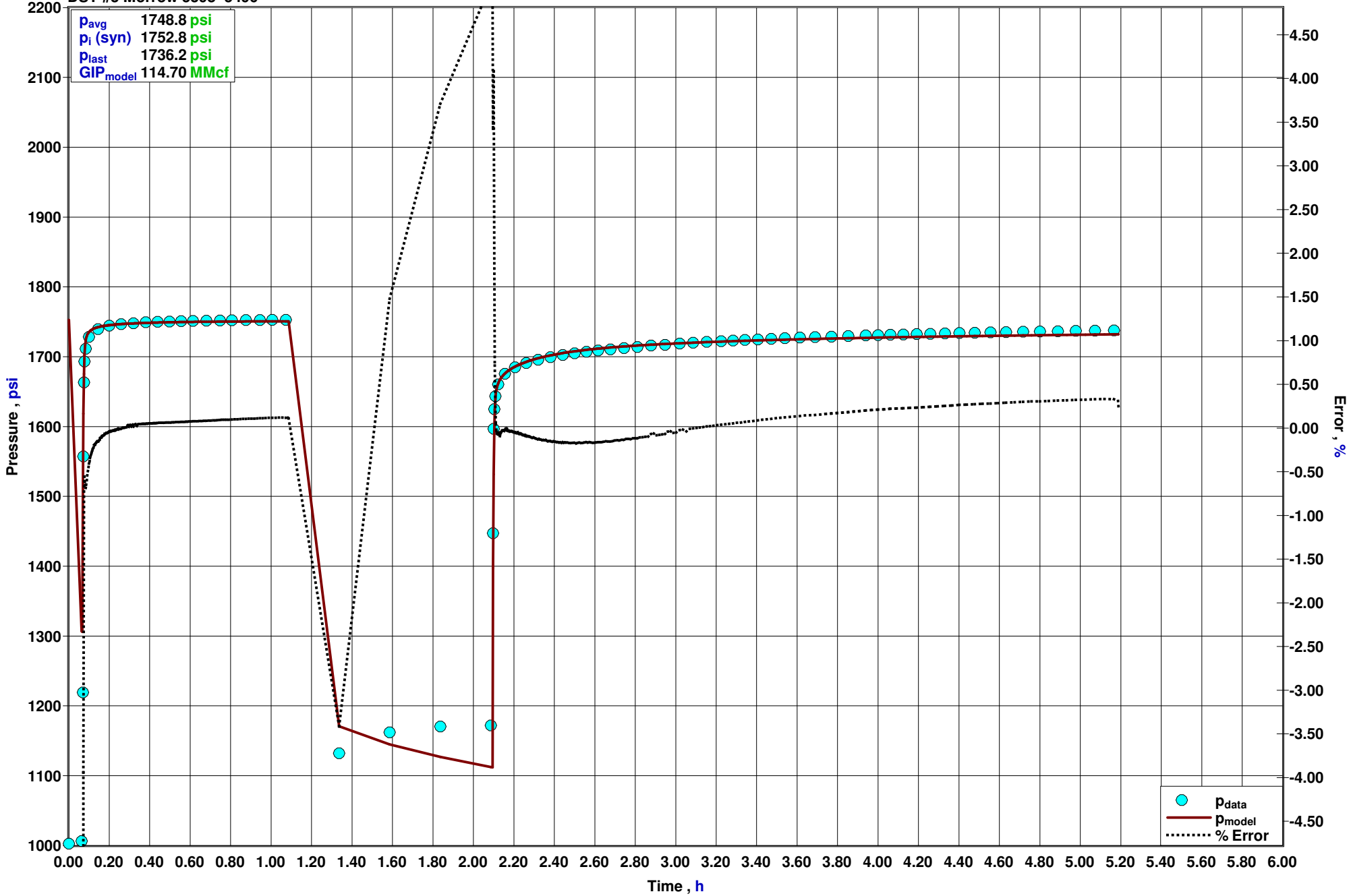
Typecurve



Ewing Oil Corp
Blow Out #1

DST #3 Morrow 5398'-5496'

Channel Model
Total Test



Ewing Oil Corp
Blow Out #1

DST #3 Morrow 5398'-5496'

Channel Model
Typecurve