WELL 7/8-3 NORWAY

DRILL STEM TEST REPORT

DECEMBER 1983

CNI DRILLING

SUBJECT	0007/803-64	
CHRONO		
DISTR.	ACTION	INFO
MGR		
SDE		

J.S. MacDonald

P.E.S. Houston.

WELL 7/8-3

SUMMARY OF TEST RESULTS

1. Drill Stem Test No 1

Date of Test	1st - 3rd December 1983.
Formation Type	Upper Jurassic Sandstone.
Perforated Interval	12 42 - 12 59 ft (3762 - 3767m)
Initial Flow Period.	7 mins
Initial Buildup	60 mins.
Final Flow Period	10hrs 10mins (610 mins)
Final Buildup	13 hrs 24 mins (804 mins)

Flow Period Results

Oil Flowrate (final 5hours)	1340 declining to 1275 BOPD.
Gas Flowrate	230 M SCF/D.
Gas - Oil - Ratio.	177 SCF/BBL
B.S.W.	1 %
Flowing BHP (final 5hours).	3788psig declining to 3736 psig.
Flowing WHP (final 5hours)	57 psig.
Flowing Pressure Gradient	0.299 psi/ft
Oil Gravity - specific	0.864
°API	32°
Gas Gravity	0.881
H_2S Content	0
CO_2 Content	5%

Pressure Buildup Analysis

Initial Formation Pressure (mid-perfs)	8602 psig ± 5 psi
Formation Pressure Gradient	0.701 psi/ft ± 0.001 psi/ft
Mud Weight Equivalent	13.48 ppg ± 0.02 ppg.
Formation Temperature (mid-perfs)	312 °F.
Temperature Gradient (ref mudline)	2.314 °F/100 ft
Permeability-Thickness	202 md-ft
Permeability	70 md (assuming contributing h = 3 ft).
Skin Effect.	-3.2
Productivity Index (actual)	0.27 bbl/d/psi
Radius of Investigation.	± 500 ft.

2. Drill Stem Test No. 2.

Date of Test	4th - 6th December 1983
Formation Type.	Upper Jurassic Sandstone.
Perforated Interval	12252 - 12272 ft (3734.5 - 3740.6 m)
Initial Flow Period	5 mins
Initial Buildup Period	40 mins.
Final Flow Period	9 hrs 17 mins (557 mins)
Final Buildup Period.	10 hrs 10 mins. (610 mins)

Flow Period Results.

Average Oil Flowrate	415 BOPD.
Gas Flowrate	Unable to measure
Gas- Oil Ratio	Unable to measure.
Flowing BHP final	4446 psig.
Flowing WHP	20 psig.
Flowing Pressure Gradient (final)	0.362 psi/ft.
Oil Gravity - Specific	± 0.884.
- ° API	28 - 29 ° API
Gas Gravity	Unable to measure
H_2S	0
CO_2.	4 %

Pressure Buildup Analysis.

Initial Formation Pressure (mid-perf)	8586 psig ± 5 psi
Formation Pressure Gradient	0.700 psi/ft ± 0.001 psi/ft
Mud Weight Equivalent	13.46 ppg ± 0.02 ppg.

Formation Temperature (mid-perfs)	310° F
Temperature Gradient (ref mudline)	2.313 °F / 100 ft
Permeability - thickness	346 md-ft
Permeability	23 md.
Skin Factor	+ 9
Drawdown Due to Skin	1957 psi
% DD Due to Skin	54 %.
Radius of Investigation	± 220 ft
P.I. (actual)	0.12 bbl/d/psi
P.I. (S=0)	0.30 bbl/d/psi.

WELL 7/8-3 NORWAY

DRILL STEM TEST NO. 1

DATE: 1ST - 3RD DECEMBER 1983

WELL 7/8-3
WELL DATA
DST NO 1

Well Location	57° 15' 31.2" N. 2° 32' 45.8" E.
Depth RKB (to MSL)	82 ft (25m)
Water Depth	266 ft (81m)
Total Depth	14174 ft. (4320m)
Plugback Depth	12457 ft (3797m)
Perforated Intervals	12342 - 12359 ft (3762 - 3767 m) 4" casing guns. 4 SPF. 90° phasing.
Mid-perforation Depth	12350 ft (3764.3 m)
Casing Size	7" 32# C95 Liner. Hanger at 11348 ft. Shoe at 12557ft
Test String	5" 19.5# Class 'G' drill pipe.
Test Packer	Dowell Positest Packer at 12285 ft (3744.5m)
Test Valve	Dowell Sleeve PCT valve at 12254 ft (3735m)
Cushion	Full seawater cushion.
Test String Volume	205 bbls.
Rathole Volume	1.0 bbls to top perforations; 1.4 bbls to bottom perforations

Mud

	MW	FV	PV	YP	pH	% Oil	CL^-
1. When drilled	14.5	58	28	17	10.1	4	12K
2. When perforated	14.2	55	27	9	11.3	1	17K.

Well 7/8-3

Diary of Events

D.S.T. No 1.

	Time	Event
er 1983	05-00	Perforate test interval from 12342-12359 ft (3762-3767 m) with 4" casing guns, 4SPF, 90° phasing.
	06-57	Start Sperry Sun gauge no 0346 (20000 psi element) with a 70hr clock and a 17hour start delay.
	06-58	Start Sperry Sun gauge no 0120 (10000 psi element) with a 70hr clock and a 17hour start delay.
	07-10	Start Dowell gauge no J-755 (14000 psi element) with a 96 hour clock.
	07-12	Start Dowell gauge no J-756 (14000 psi element) with a 48hour clock.
	08-00	Start picking up test tools.
	11-30	Pressure test tool string to 5000 psi. Run in hole. Fill test string with a seawater cushion whilst running in the hole.
	20-00	Function test EZ tree.
	21-56	Set packer at 12284 ft (3744.2 m).
	23-30	Rig up surface flowlines.
mber 1983	06-30	Pressure test surface equipment and test string: a) Test string, flohead and choke manifold to 7500 psi b) Separator to 1000 psi. c) Burner flowlines to 500 psi.
	06-54	Pressure up annulus to 1600 psi to open downhole test valve for the initial flow period.

Time	Event
06-55	Open well at surface on a 2" fixed choke size. Flowing seawater cushion. WHP = 0 psig.
07-01	Bleed off annulus pressure to shutin well for the initial buildup period.
07-04	Shutin at surface. ISIWHP = 0 psig.
08-01	FSIWHP = 0 psig.
08-01	Pressure up annulus to open downhole test valve for final flow period. Open for flow at surface on a 2" fixed choke.
10-25	Traces of gas at surface. FWHP = 1 psig.
10-30	Traces of oil at surface FWHP = 1 psig.
11-15	Increasing oil content in produced fluid. Flowing 45% seawater cushion and 55% oil. FWHP = 90 psig.
12-03	Change to 1" adjustable choke.
12-09	Change to 16/64" adjustable choke.
12-24	FWHP = 170 psig.
12-24	Change back to a 2" fixed choke. The wellhead pressure did not increase dramatically on the 16/64" choke size. The well is largely formation capacity limited. The flow will be through a 2" fixed choke and the separator will be used to control the backpressure. to the well.
12-45	Switch flow through the separator.
16-00	Take one set of separator oil and gas PVT samples for laboratory recombination.
16-40	Take second set of separator PVT samples.
18-00	By-pass separator.

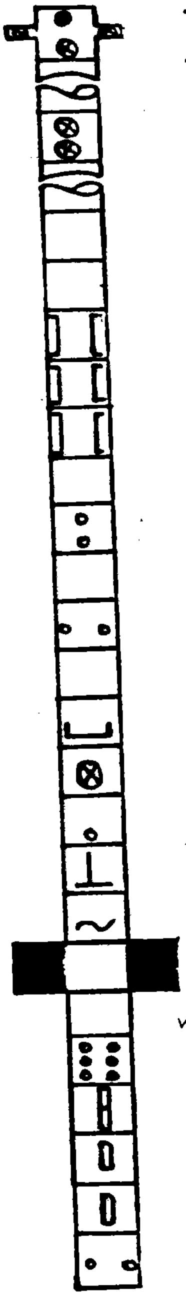
Time	Event.
18-03	Pressure up annulus to 3200 psi to try and shear closed the downhole test valve. The well was left open at surface to try and determi[ne] whether the downhole valve had indeed closed.
18-11	It was unclear whether or not the downhole valve had closed. Information upon retrieving the test tools indicate that the valve did not shear closed. The annulus pressure was however released at 18-11 to close the tool for the final buildup.
18-20	Shut in at surface. ISIWHP = 20 psig.
[...]ember 1983 06-30	FSIWHP = 139 psig.
07-19	Drop bar to shear impact sub.
07-35	Impact sub did not shear. There was no communication between the annulus and the drill pipe at this stage. It was therefore necessary to use annulus pressure to open the S.S.A.R.V. reverse sub. However at 1900 psi the annulus pressure dropped. It was later discovered, upon inspection of the downhole tools, that the bar had not sheared the impact sub reverse pins when it landed but it had weakened them sufficiently such that the annulus pressure sheared them. The ~~we~~ test string was then reversed out, recovering a full string of oil. Because the downhole test valve did not shear

Time	Event.
	closed permanently, the annulus pressure required to reverse out the test string caused the valve to open during the reverse out. This prevented a representative bottomhole PVT sample being caught in the tool.
09-55	Unseat packer and pull out of the hole.

END OF TEST.

D.S.T. NO. 1

TEST TOOLS LISTING



Description	O.D. (inches)	I.D. (inches)	Length (feet)	Depth (feet)	
Flohead	–	3.00	10.00	-30.31	
5" Drill Pipe	5.00	4.28	20.31 317.63	-20.31 0.00	Rotary
Sub-sea-test-tree	5.00	3.00	22.17 1.25	317.63 339.80	Wellhea
5" Drill Pipe	5.00	4.28	10720.51	341.05	
X-over	6.75	2.85	1.78	11061.56	
3½" Drill Pipe	3.50	2.76	276.27	11063.34	
Slip Joint (open)	5.00	2.25	28.18	11339.61	
Slip Joint (½-open)	5.00	2.25	25.68	11367.79	
Slip Joint (closed)	5.00	2.25	23.18	11393.47	
7 Stds Drill Collars	4.75	2.78	641.34	11416.65	
S.S.A.R.V.	5.00	2.25	8.46	12057.99	
1 Std Drill Collars	4.75	2.78	91.62	12066.45	
Impact Reverse Sub	4.75	2.25 (equiv.)	1.08	12158.07	
1 Std Drill Collars	4.75	2.78	91.62	12159.15	
Bar Catcher Sub	4.75	2.25 (equiv)	1.02	12250.77	
P.C.T. Valve	4.75	1.50 (equiv)	18.57	12251.79	
H.R.T.	4.75	1.50	4.27	12270.36	
Hydraulic Jars	5.00	2.25	6.50	12274.63	
Safety Joint	5.00	2.25	1.71	12281.13	
Positest Packer	5.75	2.25	1.15 1.95	12282.84 12284.00	Packer Rubber
X-over	4.75	2.25	0.82	12286.94	
Perforated Anchor	4.75	–	9.94	12287.76	
Sperry Sun Gauge Carrier	3.50	–	30.70	12297.70	
J-200 Gauge Carrier	5.00	–	6.96	12328.40	
J-200 Gauge Carrier	5.00	–	6.96	12335.36	
Ported Bullnose	4.75	–	1.90	12342.32	

Notes: 1. All depths are to top of tool joints. (drillers depths)
2. Loggers depths (perforated intervals) are 14ft deeper than drillers depths.

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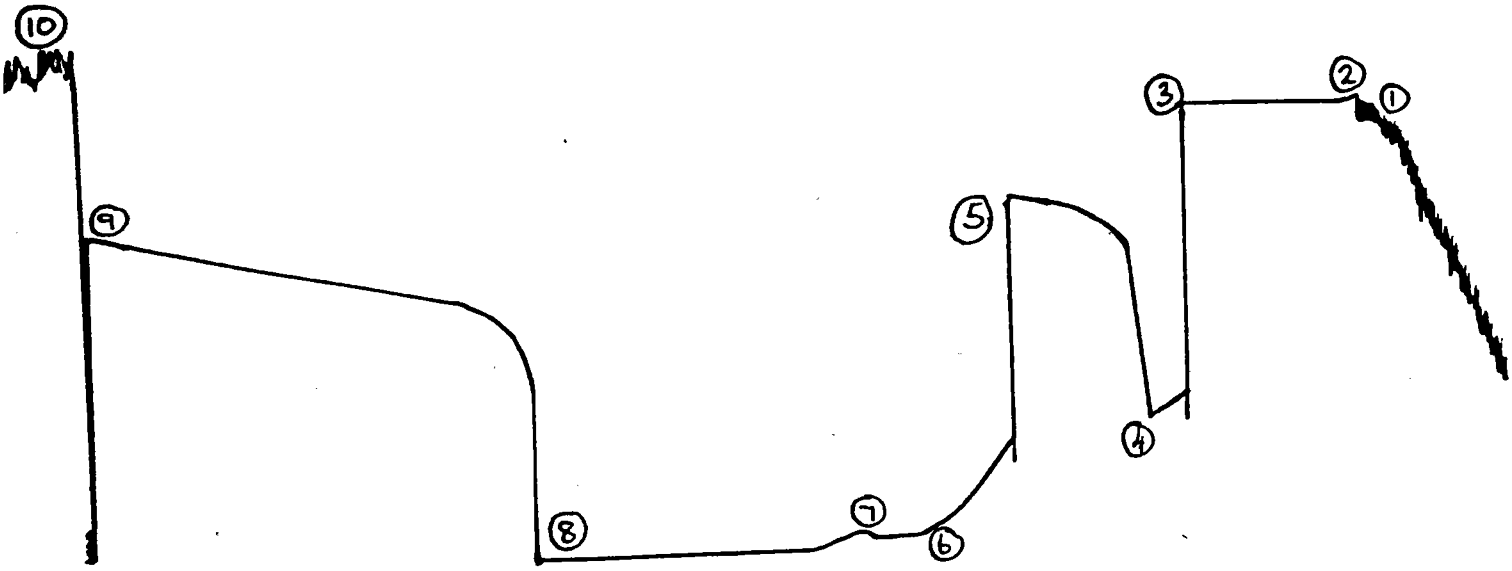
SCHEMATIC OF DOWNHOLE TEST CHART

D.S.T. No. 1.



Not to Scale.

nitial hydrostatic
set packer at 12284 ft.
Open downhole test valve for initial flow period.
Shutin downhole test valve for initial buildup period.
Open downhole test valve for final flow period.
Produced the full water cushion at surface. Now flowing clean oil.
Change to smaller choke size at surface. Decide to change back to a fully open 2" line
Shutin downhole test valve for final buildup period.
Opened downhole test valve whilst trying to open reversing subs.
Downhole test valve opened during reverse out.
Unseat packer.
Final hydrostatic.

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RECORD OF SAMPLES

D.S.T. No 1

A suite of separator PVT recombination samples and weathered oil samples were collected during the test. The downhole sample was not caught due to the test valve failing to shear closed after the final flow period. This resulted in the sample chamber opening during the reverse out and the sample being replaced by mud.

The following is a list of the samples caught and the conditions under which they were taken.

a. Separator Samples.

Type	Bottle Size	Bottle No.	Time Taken		Separator Sampling Data		
					Pressure psig	Temperature °F	Gas/Oil Rat Scf/Bbl.
OIL	700cc	83081909	12/2/83	16-00	45	56	175
GAS	20Ltr	A14761		16-00	45	56	175
OIL	700cc	8207321	12/2/83	16-40	45	56	178
GAS	20Ltr	A14716		16-40	45	56	178

b. Weathered Oil Samples.

1. 5 x 5 gallon weathered oil samples.
2. 1 x 55 gallon weathered oil sample.

Oil gravity = 0.864 at 60°F
= 32° API at 60°F.

b. Gas.

Gas gravity	=	0.881 at 60°F.
CO_2	=	5 %
H_2S	=	0

A cromatograph of the gas samples was carried out during the test. The analysis is given below. However the accuracy of the data is unknown due to the limited facilities on the rig.

Component	%.
C_1	72
C_2	9
C_3	10
iC_4	1
nC_4	3
CO_2	5

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FLOW PERIOD DATA
D.S.T. No. 1

Summary

The well was flowed for a 7 minute initial flow period followed by an initial buildup of 60 minutes. A final flow period of 10 hours 10 mins was then taken prior to a 13 hour 24 min final buildup. First traces of oil were seen at surface after 2.5 hours and the well was flowing 98 % oil after 3.5 hours. After clean oil was flowing at surface an attempt to choke back and increase the wellhead pressure in order to get critical flow to the separator was made. However a reduction from 2" to 16/64" only resulted in a wellhead pressure increase of about 100 psi. It was therefore decided to flow the well wide open (2" choke) at the wellhead and use the separator as the backpressure control to the well. The well was then flowed through the separator for 5.25 hours before shutting in downhole for the final buildup. A detailed tabulation of the flow data is provided.

Fluid Properties.

The following is a summary of the fluids recovered and their properties.

a. Oil.

The oil recovered was dark, black and sweet with no traces of H_2S. There did not appear to be any significant wax content to the oil.

D.S.T. No. 1

Time	Bottomhole	Wellhead		Separator		Oil	Gas	Gas-Oil Ratio	BSW	Remarks.
	Pressure psig	Pressure psig	Temperature °F	Pressure psig	Temperature °F	Flowrate BOPD	Flowrate MSCF/D	SCF/BBL	%	
12/2/83										
08-01	Open downhole test valve for final flow period. Open at surface on 2" choke.									Flowing cushion.
08-30	5185	2	52	-	-	1322	0	0	100	Flowing cushion.
09-00	5028	2	56	-	-	1318	0	0	100	Flowing cushion.
09-30	4877	2	61	-	-	1280	0	0	100	Flowing cushion
10-00	4721	1	65	-	-	1293	0	0	100	Flowing cushion
10-30	4561	1	70	-	-	1343	-	-	99	Trace of oil
11-30	4000	42	74	-	-	-	-	-	2	Clean oil.
12-00 → 12-30	Changing surface choke sizes. Decide to remain with a 2" fixed choke and control well with the separator pressure. This will allow maximum flowrates.									
12-45	Switch flow through separator.									
13-30	3788	55	67	40	57	1417	232	164	2	Flowing oil.
14-00	3782	56	67	40	59	1346	232	173	2	
14-30	3776	57	67	45	60	1340	229	171	2	
15-00	3769	57	67	45	62	1285	229	178	1	
15-30	3753	57	67	45	62	1358	229	169	1	
16-00	3755	57	67	45	62	1308	228	175	0	
16-30	3746	57	67	45	62	1294	228	176	1	
17-00	3740	57	67	45	62	1277	228	179	1	
17-30	3738	59	67	50	62	1288	230	179	1	
18-00	3736	59	67	50	62	1252	226	180	1	
18-00	By-pass separator.									
18-11	Shutin downhole test valve for final buildup.									
	Recovered a full string of oil upon reverse out									

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COMPARISON OF BOTTOM HOLE PRESSURE GAUGES

D.S.T. No. 1

Gauge No.	SS 0346	SS 0120	J-755	J-756
Gauge Element	20000 psi.	10000 psi	14000 psi	14000 psi
Clock (hrs)	70	70	96	48
Depth (ft RKB)	12308	12317	13330	13337
Initial Hydrostatic	* 1.	* 1	9190	9266
Initial Flow	5656-5382	5499-5416	5585-5456	5575-5446
Initial Buildup	8551	8550	8613	8620
Second Flow	—	—	—	—
Second Buildup	—	—	—	—
Final Flow * 2.	3792-3677	3790-3669 *3	3819-3747	3821-3758
Final Buildup	8135	* 3	8147	8152
Final Hydrostatic	9035	* 3	9115	9082.
Temperature	312°F	310°F	310°F	302°F

Notes:

1. The delay time set in the Sperry Sun gauges prevented the initial hydrostatic from being recorded.
2. The pressures recorded here are for the final 5 hours of the flow period.
3. The Sperry Sun gauge no 0120 malfunctioned during the final flow period and stopped during the final buildup. This was due to the excessive bottomhole temperatures experienced.

WELL 7/8-3

PRESSURE BUILDUP ANALYSIS

D.S.T. No. 1

The following are the parameters used for the pressure buildup analysis of drill stem test no. 1. The pressure data is taken from the Sperry Sun gauge no. 03.6 at 12308 ft.

P^*	= 8586 psig ± 5 psi	(from Horner Buildup Plot - Fig 1)
P_{1hr}	= 7070 psig.	(from Horner Buildup Plot - Fig 2)
P_{wf}	= 3750 psig.	(from pressure data).
μ_o	= 0.9 cp.	(from correlation charts)
B_o	= 1.21 res bbls/bbl.	(.. .. ..)
C_o	= 5×10^{-6} vol/vol/psi	(.. .. ..)
C_w	= 4.6×10^{-6} vol/vol/psi	(.. .. ..)
C_f	= 4×10^{-6} vol/vol/psi	(.. .. ..)
C_t	= 8.8×10^{-6} vol/vol/psi	
ϕ	= 0.12	(from electric logs)
S_w	= 0.40	(.. .. ..)
r_w	= 0.35 ft	
q_{oil}	= 1300 BOPD	
m	= 1140 psi/cycle.	(from Horner Buildup Plot - Fig 2)

1. Initial Formation Pressure

p^* = 8586 psig ± 5 psi

Gauge depth = 12308 ft

Mid-perforation depth = 12350 ft

Assume fluid beneath tool valve is 100% oil after the initial flow.

Liquid gradient (32° API oil) = 0.374 psi/ft

Initial Formation Pressure (at mid-perfs) = 8586 + (12350 - 12308) 0.374

= **8602 psig ± 5 psig**

Formation Pressure Gradient (reference MSL) $= \frac{8602}{12350 - 82}$

= **0.701 psi/ft ± 0.001 psi/ft**

Mud Weight Equivalent = **13.48 ppg ± 0.02 ppg.**

2. Formation Temperature

Maximum recorded temperature = 311 °F (average of 3 readings)

Gauge depth = 12318 ft (average of 3 readings)

Mid-perforation depth = 12350 ft

a. Assume average seafloor temperature is 34°F.

Temperature Gradient (reference mudline) $= \frac{311 - 34}{12318 - 348}$

= **2.314 °F/100 ft**

b. Assume mean annual surface temperature is 50° F.

$$\text{Temperature Gradient (reference MSL)} = \frac{311 - 50}{12318 - 82}$$

$$= 2.133 \text{ °F}/100 \text{ ft}$$

Assuming case a.

Formation Temperature (at mid-perfs) = $\underline{\underline{312 \text{ °F}}}$

3. Permeability - Thickness (kh).

$$kh = \frac{162.6 \; q_{oil} \; \mu_o \; B_o}{m}$$

$$kh = \underline{\underline{202 \text{ md-ft}}}$$

Based on the results of the core analysis it is reasonable to assume that the ~~total~~ majority of the production came from a 3 ft thick layer. The average permeability for this layer (assuming h = 3 ft) would therefore be approximately 70 md.

k = 70 md assuming contributing h = 3 ft.

This high permeability layer within a low permeability zone acts like a fracture in terms of the pressure buildup response. This explains the upward curvature in the final buildup plot (Figure 2) and also the high negative skin factor. This skin factor is a pseudo-skin effect due the ~~similarity of~~ fracture type effect.

4. Skin Factor.

$$S = 1.151 \left\{ \frac{P_{1hr} - P_{wf}}{m} - \log \frac{k}{\phi \mu C_t r_w^2} + 3.23 \right\}$$

$$\underline{\underline{S = -3.2}}$$

Effective Wellbore Radius $= r_w e^{-s}$

$$\underline{\underline{r_{we} = 8.6 \text{ ft}}}$$

5. Radius of Investigation.

The radius of investigation equation is being used assuming a high permeability streak of 100 md

$$r_{inv} = \frac{1}{2} \sqrt{\frac{0.00105 \; kt}{\phi \; \mu \; C_t}}$$

$$\underline{\underline{= \pm 500 \text{ ft}}}$$

6. Productivity Index

$$P.I. (\text{actual}) = \frac{q}{P_i - P_{wf}}$$ (at end of flow period)

$$\underline{\underline{= 0.27 \text{ bbl/d/psi.}}}$$

WELL 7/8-3

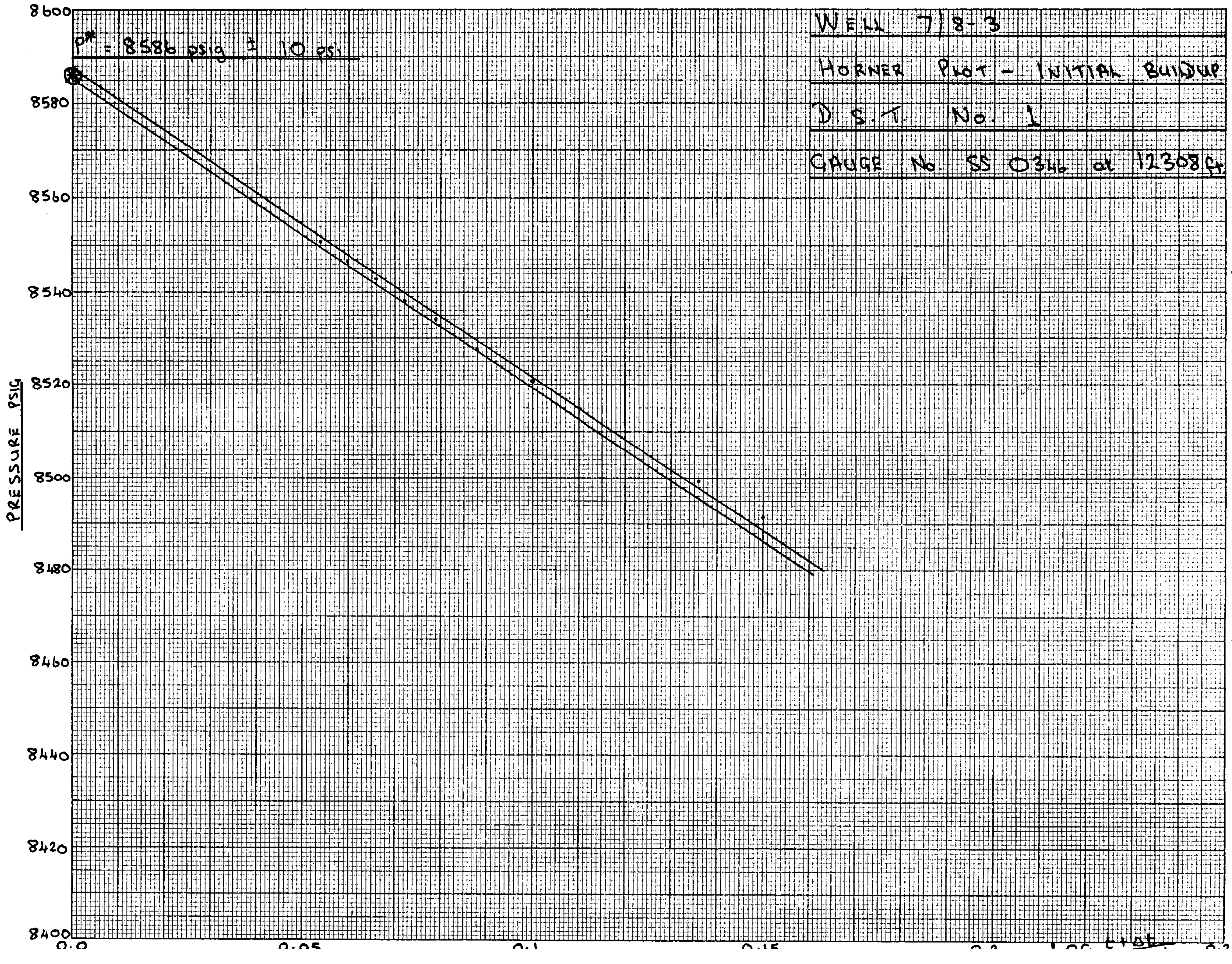
PRESSURE BUILD-UP DATA

D.S.T. No. 1

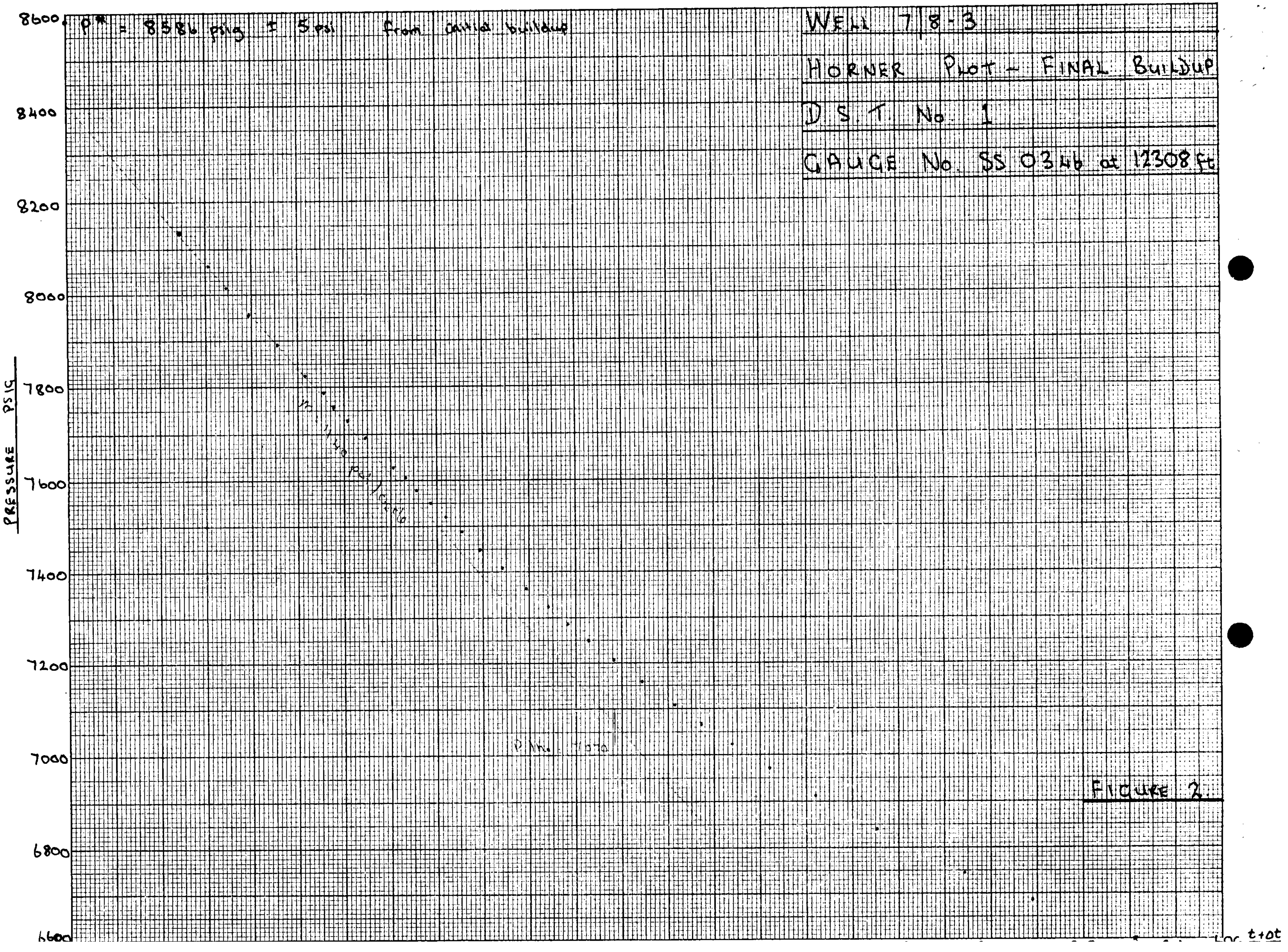
Gauge # Sperry Sun 0346 at 12308 ft.

	Δt mins.	$\log \frac{t^* + \Delta t}{\Delta t}$	Pressure psi
ial Buildup	1	0.903	8192.37
7mins.	3	0.523	8306.56
	5	0.380	
	7	0.301	8415.78
	9	0.250	
	11	0.214	
	13	0.187	
	15	0.166	
	17	0.150	8491.34
	19	0.136	8499.34
	23	0.115	
	27	0.100	8520.84
	31	0.088	8527.57
	35	0.079	8534.07
	39	0.072	8538.81
	43	0.066	8542.82
	47	0.060	8546.57
	53	0.054	8550.85
al Buildup	1	2.786	6450.96
610 mins.	3	2.310	6596.37
	5	2.090	6683.49
	7	1.945	6746.21
	11	1.752	6839.28
	15	1.620	6911.44
	19	1.520	6970.16
	23	1.440	7021.41
	27	1.373	7065.72
	31	1.315	7106.53
	37	1.243	7158.40
	43	1.181	7205.77
	49	1.129	7249.19
	55	1.082	7286.27

Δt mins.	$\log \frac{t^{*} + \Delta t}{\Delta t}$	Pressure psi.
61	1.041	7321.28
69	0.993	7362.46
79	0.941	7408.18
89	0.895	7449.50
99	0.855	7487.13
109	0.819	7520.07
119	0.787	7550.78
129	0.758	7578.34
139	0.731	7604.62
149	0.707	7628.42
159	0.685	7651.24
179	0.644	7691.94
199	0.609	7727.79
219	0.578	7759.62
239	0.551	7788.54
269	0.514	7826.46
299	0.483	7860.44
329	0.455	7890.94
369	0.424	7924.52
409	0.396	7955.08
449	0.373	7982.66
499	0.347	8011.76
549	0.325	8037.88
599	0.305	8061.89
659	0.285	8086.03
719	0.267	8108.20
803	0.245	8134.88



WELL 7/8-3
HORNER PLOT - INITIAL BUILDUP
D.S.T. No. 1
GAUGE No. SS 0346 at 12308 ft.
P* = 8586 psig ± 10 psi
PRESSURE PSIG
8600
8580
8560
8540
8520
8500
8480
8460
8440
8420
8400



WELL 7/8-3
HORNER PLOT - FINAL BUILDUP
D.S.T. No. 1
GAUGE No. SS 0346 at 12308 ft
p* = 8586 psig ± 5 psi from initial buildup
PRESSURE PSIG
8600
8400
8200
8000
7800
7600
7400
7200
7000
6800
6600

FIGURE 2.

WELL 7/8-3 - NORWAY

DRILL STEM TEST NO. 2

DATE: 4TH - 6TH DECEMBER 1983

WELL 7/8-3
WELL DATA
DST NO 2

Well Location	57° 15' 31.2" N. 2° 32' 45.8" E.
Depth RKB (to MSL)	82 ft (25m)
Water Depth	266 ft (81m)
Total Depth	14174 ft (4320m)
Plugback Depth	12278 ft (3742.4m)
Perforated Intervals	12252- 12272 ft (3734.5 - 3740.6m) 4" casing guns. 4 SPF. 90° phasing.
Mid-perforation Depth	12262 ft (3737.5 m)
Casing Size	7" 32# C95 liner. Hanger at 11348ft. Shoe at 12557f
Test String	5" 19.5# Class 'G' drill pipe.
Test Packer	Dowell Positest Packer at 12189 ft. (3715.3m)
Test Valve	Dowell PCT at 12159 ft. (3706.1m).
Cushion	Full seawater cushion.
Test String Volume	203 bbls.
Rathole Volume	1.5 bbls to top perforations; 2.1 bbls to bottom perforations.

Mud	MW	FV	PV	YP	pH	% Oil	CL⁻
1. When drilled	14.5	58	28	17	10.1	4	12K
2. When perforated	14.2	55	27	9	11.5	1	17K

WELL 7/8-3

DIARY OF EVENTS

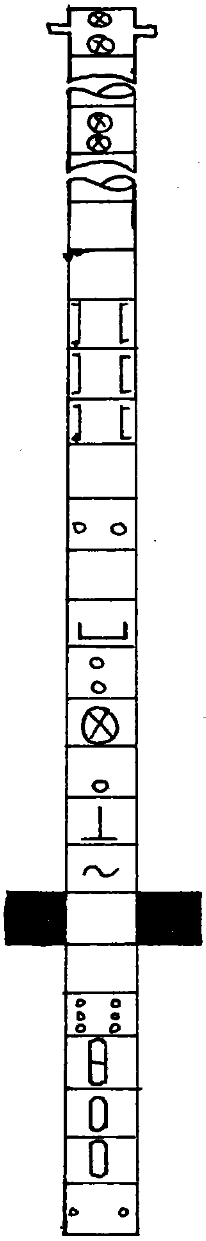
D.S.T. No. 2

te	Time	Event
December 1983	21-30	Perforate test interval from 12252- 12272 ft (3734.5 - 3740.5 m) with 4" casing guns, 4SPF, 90° phasing.
	22-45	Start Dowell gauge no J-755 with a 96 hr clock.
	22-46	Start Dowell gauge no J-756 with a 48 hr clock.
	22-47	Start Sperry Sun gauge no 0346 with a 70 hr clock and an 8.5 hr start delay.
	22-52	Start Sperry Sun gauge no 0341 with a 70 hr clock and an 8.5 hr start delay.
	23-00	Start picking up test tools.
' December 1983	01-30	Pressure test bottomhole test assembly to 5000 psi.
	11-00	Function test sub-sea-test-tree.
	12-14	Set packer at 12189 ft. (3715.3 m).
	13-10	Rig up and pressure test surface flowlines. a. Test string to 7500 psi b. Choke manifold to 7500 psi c. Separator to 1000 psi.
	13-28.	Pressure up annulus to open downhole test valve for initial flow period.
	13-33	Bleed off annulus to shutin downhole test valve for initial buildup period.
	14-13	Pressure up annulus to open downhole test valve for final flow period.
	14-14	Open well for flow on a 2" fixed choke.

te	Time	Event
December 1983	19-10	Traces of gas at surface. FWHP= 15 psig.
	19-15	Traces of oil at surface. FWHP= 15 psig.
	23-30	Pressure up annulus to shear the downhole test valve closed.
	23-33	Bleed off annulus pressure. S.S.A.R.V reverse sub opened.
	23-40	Start to reverse out test string.
December 1983	00-30	Well killed. Wait on buildup.
	09-40	Unseat packer. End of buildup.
	09-50	Circulate hole.
	12-55	Pull out of hole.

END OF TEST.

WELL 7/8-3
TEST TOOLS
DST NO 2

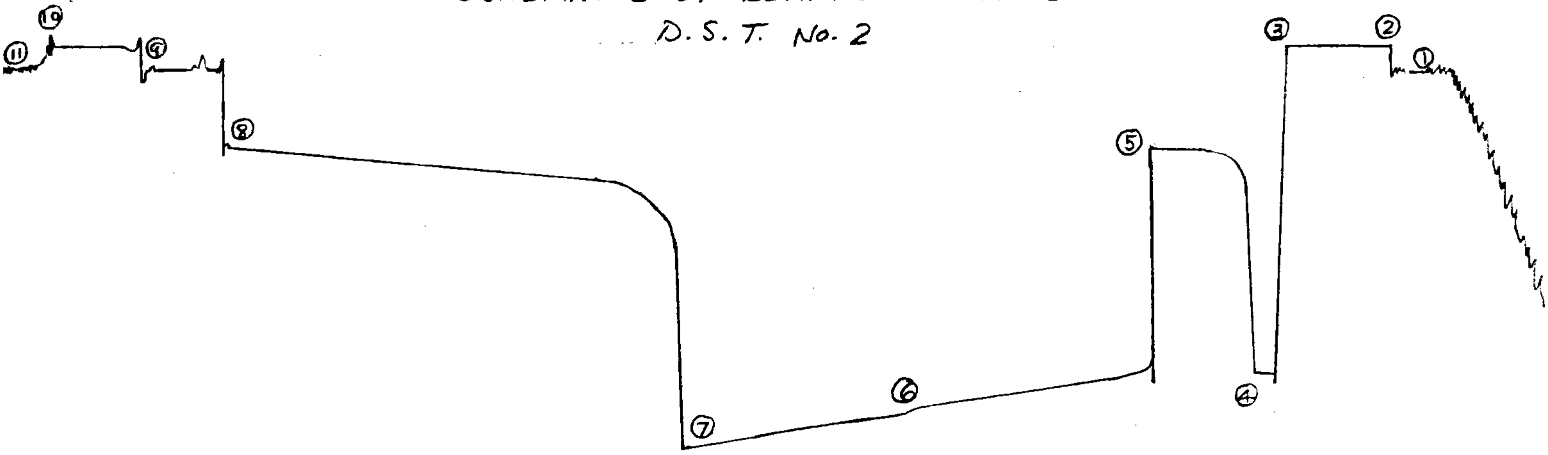


Description	O.D. (inches)	I.D. (inches)	Length (feet)	Depth (feet)
Flohead	—	3.00	10.00	-30.31
5" Drill Pipe	5.00	4.28	20.31 317.63	-20.31 Roto 0.00
Sub-Sea-Test-Tree	5.00	3.00	22.17 1.25	317.63 Well 339.80
5" Drill Pipe	5.00	4.28	10625.99	341.05
X-over	6.25	2.85	1.78	10967.04
3½" Drill Pipe	3.50	2.76	276.27	10968.82
Slip Joint (open)	5.00	2.25	28.18	11245.09
Slip Joint (½ open)	5.00	2.25	25.68	11273.27
Slip Joint (closed)	5.00	2.25	23.18	11298.95
8 Stds Drill Collars	4.75	2.78	732.96	11322.13
Impact Reverse Sub	4.75	2.25 (equiv)	1.08	12055.09
1 Std Drill Collars	4.75	2.78	91.62	12056.17
Bar Catcher Sub	4.75	2.25 (equiv)	1.02	12147.79
S.S.A.R.V	5.00	2.25	8.46	12148.81
P.C.T. Valve	4.75	2.25	18.57	12157.27
H.R.T.	4.75	2.25	4.27	12175.84
Hydraulic Jars	5.00	2.25	6.50	12180.11
Safety Joint.	5.00	2.25	1.71	12186.61
Positest Packer	5.75	2.25	1.15 2.95	12188.32 Pack 12189.47 Rubb
X-over	4.75	2.25	0.82	12192.42
Perforated Anchor	4.75	-	9.94	12193.24
SperrySun Gauge Carrier	3.50	-	30.70	12203.18
J-200 Gauge Carrier	5.00	-	6.96	12233.88
J-200 Gauge Carrier	5.00	-	6.96	12240.84
Ported Bullnose	4.75	-	1.90	12247.80

Notes: 1. All depths are drillers depths to top of tool joints.
2. Loggers depths are ± 14 ft deeper than drillers depths.

SCHEMATIC OF DOWNHOLE TEST CHART

D.S.T. No. 2



Not to Scale

1. Initial hydrostatic
2. Set packer at ft.
3. Open downhole test valve for initial flow period.
4. Shutin downhole test valve for initial buildup period.
5. Open downhole test valve for final flow period.
6. Oil begins to surface - mix with cushion water.
7. Shutin downhole test valve for final buildup period.
8. Open downhole reverse sub.
9. Circulation begins.
10. Unseat packer.
11. Final hydrostatic.

WELL 7/8-3

COMPARISON OF BOTTOM HOLE PRESSURE GAUGES

D.S.T. No. 2.

Gauge No.	SS 0346	SS 0341	J-755	J-756
Gauge Element	20000 psi	20000 psi	14000 psi	14000 psi
Clock (hrs)	70	70	96	48
Depth (ft RKB)	12213	12222	12235	12242
Initial Hydrostatic	9030	9032	9123	9068
Initial Flow	5473-5470	5499-5484	5511	5509
Initial Buildup	8522	8520	8555	8554
Second Flow	-	-	-	-
Second Buildup	-	-	-	-
Final Flow	5442-4446	5452-4441	5525-4465	5534-4467
Final Buildup	8521	8517	8538	8527
Final Hydrostatic	8980	8977	9027	8997
Temperature	307 °F	309 °F	309 °F	312 °F

Notes:

WELL 7/8-3

RECORD OF SAMPLES.

D.S.T. No. 2.

Due to the low flowrate produced by the well it was not possible to flow hydrocarbons through the separator during the test. Therefore no separator PVT recombination samples or gas samples were able to be taken. However a single phase bottomhole sample was collected from the downhole test tools, and several weathered oil samples were also collected from the reverse out. Based on the BSW figures recorded on the samples from the reverse out it is probable that the weathered oil samples are slightly contaminated with the seawater cushion. A record of the samples collected and an analysis of the fluid is given below.

a. Record of Samples.

1. Downhole PVT Samples

2. Weathered Oil Samples.

1 x 55 gallon weathered oil sample.

4 x 5 gallon weathered oil sample.

b. Analysis of Recovered Fluids.

1. Oil Analysis.

The produced oil is dark black and sweet with no measurable H_2S. There is a possibility that the oil contains a small percentage of wax although it is difficult to tell on site.

However the oil has a measured specific gravity of 0.905 at 60°F which is equivalent to a 26° API oil. This is much lower than the 32° API gravity from dst no 1. There is a 10-15% water cut in the samples which if removed will increase the gravity to 28-29°API. It is unusual to have such different gravities between test intervals unless they were separate reservoirs. A more accurate analysis of the samples will be carried out in town.

2. Gas Analysis.

Due to the low flowrates and the inability of the well to be flowed through the separator it was not possible to collect any gas samples. Therefore no gravity or compositional data is available. However there was 4% CO_2 and 0 ppm H_2S detected. at the choke manifold.

3. Water Analysis

All the recovered water is seawater cushion having 20-25000 ppm chlorides. There was no evidence of any formation water production.

FLOW PERIOD DATA
D.S.T. No 2.

Time	Bottomhole Pressure psig.	Wellhead Pressure psig	Wellhead Temp. °F	Flowrate BFPD	BSW %	Cumulative Oil Produced Bbls.	Cumulative Cushion Produced Bbl	Remarks.
5 Dec. 1983								
14-13	Pressure up	annulus to	open	downhole test	valve for	final flow	period.	
14-30		15	45	520	100	-	5.4	Flowing seawater cushion (Cl = 24k ppm)
15-00		13	45	415	100	-	14.1	
15-30		13	45	380	100	-	20.8	
16.00		16	45	380	100	-	28.8	
16-30		16	45	374	100	-	36.6	
17-00		16	45	387	100	-	44.7	
17-30		15	46	393	100	-	52.9	
18-00		16	46	399	100	-	61.2	
18-30		16	46	393	100	-	69.4	
19-00		17	47	387	100	-	77.4	
19-30		15	47	406	85	0.3	85.6	Small percent of oil at surface
20-00		15	47	425	85	1.6	93.1	
20-30		14	47	551	75	3.6	104.5	Increasing oil cut and water cushion.
21-00		15	47	486	70	-	-	
21-30		16	47	372	65	7.1	112.6	
22-00		16	47	456	65	10.4	118.8	
22-30		19	47	450	52	14.9	123.7	
23-00		20	47	393	58	18.3	128.5	
23-30		20	47	418	62	21.6	133.9.	
23-30	Pressure	up annulus	to	shear	downhole test valve		closed.	

Notes: 1. An additional 4 bbls of water cushion was produced during the initial flow period.

REVERSED RECOVERIES

D.S.T. No 2.

Sample No.	No of Strokes	Volume since start of reverse bbls.	Depth from which sample recovered ft	BSW %	Cum. Oil from reverse out bbls		Cum Water from reverse out bbls		Remarks
1	100	13.1	725	70	4.0	4.0	9.1	9.1	Mostly water cushion (seawater Cl^- = 25K) with traces of oil.
2	200	26.2	1450	65	4.6	8.6	8.5	17.6	
3	300	39.3	2175	56	5.8	14.4	7.3	24.9	
4.	400	52.4	2900	43	7.5	21.9	5.6	30.5	Increasing oil cut with some rathole mud on seawater cushion.
5	500	65.5	3625	24	10	31.9	3.1	33.6	
6	600	78.6	4350	20	10.5	42.4	2.6	36.2	
7	700	91.7	5075	14	11.3	53.7	1.8	38.0	Fairly clean oil mixed with a small percentage of seawater cushion.
8	800	104.8	5800	14	11.3	65.0	1.8	39.8	
9	900	117.9	6525	14	11.3	76.3	1.8	41.6	
10	1000	131.0	7250	12	11.5	87.8	1.6	43.2	
11	1100	144.1	7975	8	12.1	99.9	1.0	44.2	
12	1200	157.2	8700	8	12.1	112.0	1.0	45.2	
13	1300	170.3	9425	10	11.9	123.9	1.2	46.4	
14	1400	183.4	10150	9	12.0	135.9	1.1	47.5	
15	1500	196.5	10875	15	11.1	147.0	2.0	49.5	
16	1570	203.0	12150	15	5.5	152.5	1.0	50.5	
17	1575	-	-	99		-		-	Reverse out is complete. Mud from annulus

1. Initial Formation Pressure

p^*	$= 8568$ psig $\pm$ 5 psi
Gauge depth	$= 12293$ ft
Mid-perforation depth	$= 12262$ ft

Assume fluid beneath test valve is 100% oil after the initial flow

Liquid gradient (29° API oil)	$= 0.375$ psi/ft
Initial Formation Pressure (at mid-perfs)	$= 8586$ psig $\pm$ 5 psig.
Formation Pressure Gradient (reference MSL)	$= \frac{8586}{12350-82}$
	$= 0.700$ psi/ft $\pm$ 0.001 psi/ft
Mud Weight Equivalent	$= 13.46$ ppg $\pm$ 0.02 ppg.

2. Formation Temperature

Maximum recorded temperature	$= 309$ °F
Gauge depth	$= 12235$ ft
Mid-perforation depth	$= 12262$ ft

a. Assume average seafloor temperature is 34°F.

Temperature Gradient (reference mudline)	$= \frac{309-34}{12235-348}$
	$= 2.313$ °F/100ft

b. Assume mean annual surface temperature is 50°F.

Temperature Gradient (reference MSL) $= \frac{309-50}{12318-82}$

$= 2.117\ ^\circ F / 100\ ft$

Assuming case a.

Formation Temperature (at mid-perfs) $= 310\ ^\circ F$

=

3. Permeability - Thickness (kh).

$$kh = \frac{162.6\ q_{oil}\ \mu_o\ B_o}{m}$$

$$kh = 346\ md\text{-}ft$$

Assuming contributing $h = 15\ ft$

$$k = 23\ md.$$

4 Skin Factor.

$$S = 1.151 \left\{ \frac{P_{1hr} - P_{wf}}{m} - \log \frac{k}{\phi\ \mu\ C_t\ r_w^2} + 3.23 \right\}.$$

$$S = +9$$

Drawdown due to skin

$$DD = 0.87\ m\ S = 1957\ psi.$$

Percentage of drawdown due to skin $= \dfrac{\Delta P_{skin}}{DD}$

$= \cancel{}\ 54\%$.

5. Radius of Investigation.

$$r_{inv} = \frac{1}{2}\sqrt{\frac{0.00105\ kt}{\phi\ \mu\ C_t}}$$

$= \pm 220$ ft.

6. Actual Productivity Index.

$$P.I.(act.) = \frac{q_{avg.}}{P_i - P_{wf\ avge}}$$

$= 0.12$ bbl/d/psi

7. Productivity Index $(s = 0)$

$$P.I.(s=0) = \quad = \frac{0.00708\ kh}{\mu\ B\ (\ln \frac{r_e}{r_w} - \frac{1}{2})}$$

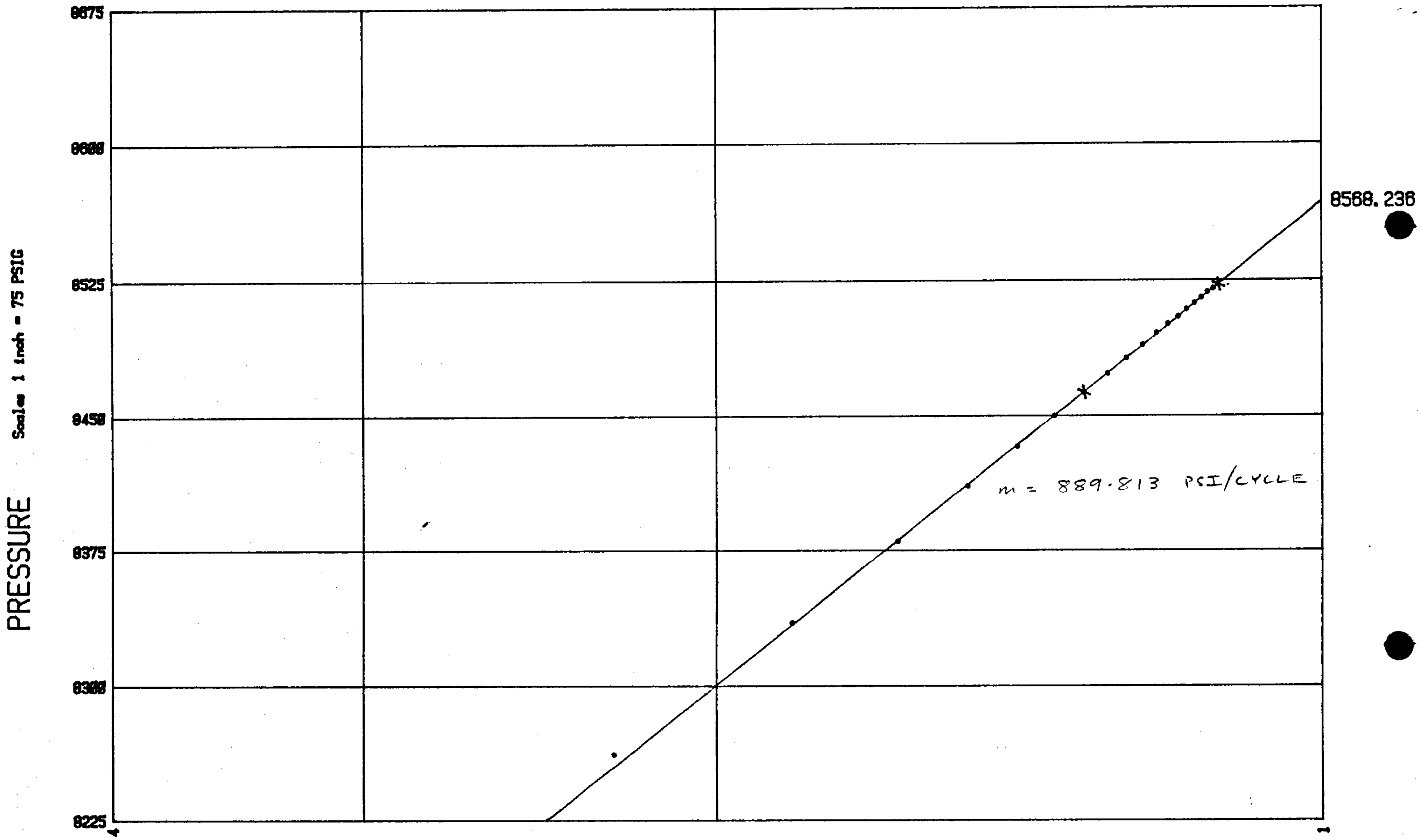
$= 0.30$ bbl/d/psi.

CONOCO NORWAY INC.
7/8-3
WILDCAT

NL Sperry-Sun, Inc.
HORNER PLOT

04 DECEMBER 1983

MKIIIA 348-1004
D04200



T = .08333 hours

(T+dT)/dT

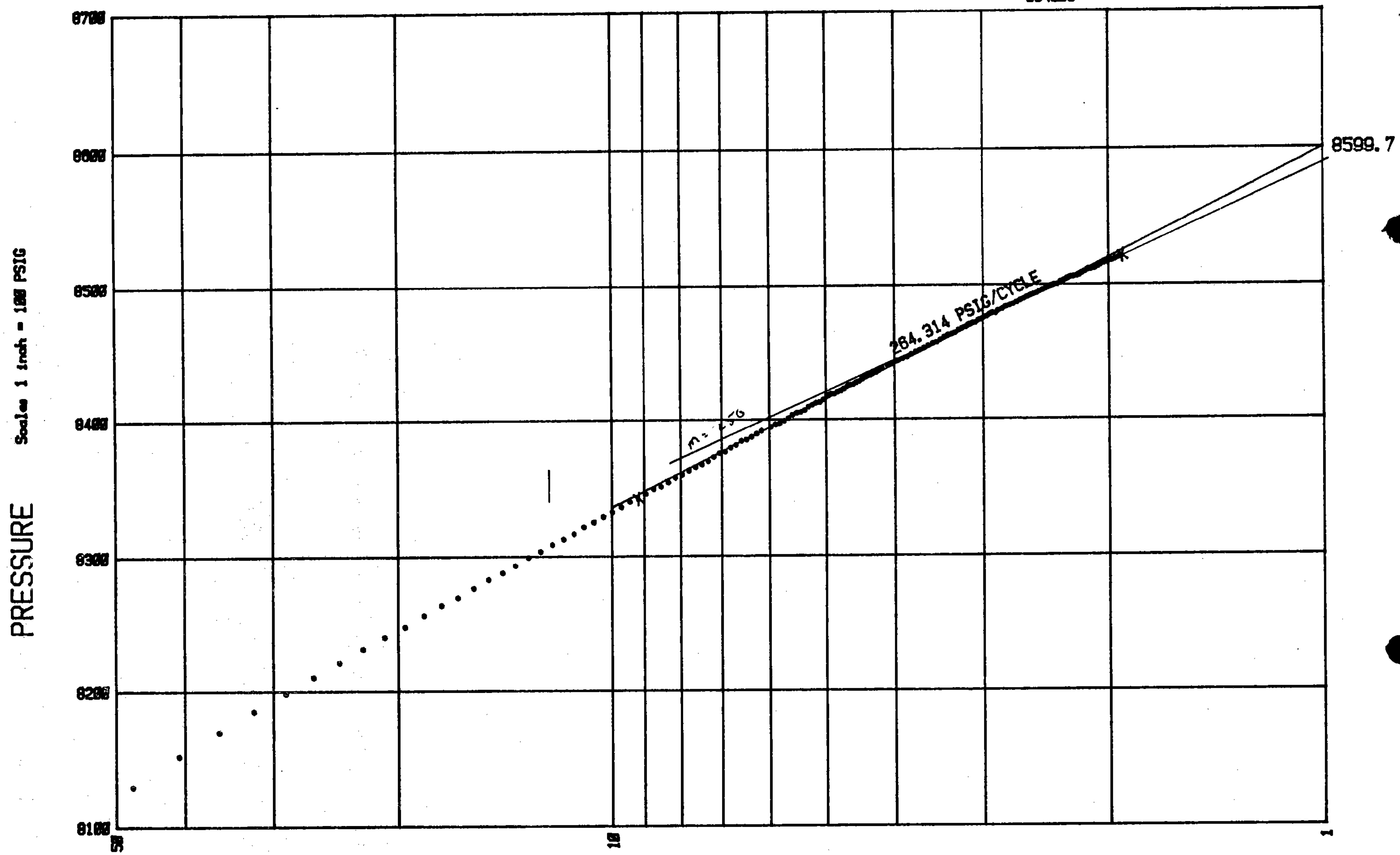
SHUT-IN TIME = 885 mins.
FINAL DELTA TIME = 925 mins.

CONOCO NORWAY INC.
7/8-3
WILDCAT

NL Sperry-Sun, Inc.
HORNER PLOT

04 DECEMBER 1983

MKIIIA 340-1004
D0420B



T = 9.28333 hours

(T+dT)/dT

SHUT-IN TIME = 1481 mins.
FINAL DELTA TIME = 2091 mins.