Chevron et al Fort Liard M-25
Northwest Territories
SDL#99
Grid Area 60°30', 123°, 30'
Surface Location: M-25
Bottom Hole Location: L-26
Flow and Buildup Test: January 2000

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Attachments

Chevron et al Fort Liard M-25

Summary

The M-25 well was drilled and completed by Chevron from September 1999 to January 2000. The well was tested using a three-point flow after flow test followed by an extended flow and build-up. The objectives of the flow and buildup test were to assess the wellbore deliverability and confirm a minimum original gas in place (OGIP) in order to proceed with well tie in. The following is a summary of the information obtained from the flow and build-up test:

- Reservoir Permeability-Height is 3690 md*m. Skin is estimated at +12.
- The system was best modeled as a dual porosity system.
- Likely multiple reservoir boundaries were identified, with the first no-flow boundary at approximately 300-m from the wellbore.
- Initial reservoir pressure is estimated at 28007 kPaa at 3459.4 mKB MD (3132.6 m TVD or –2214.8 m TVDss).
- Probable estimates of the OGIP are:
    - P10 – 2803 $10^6 m^3$ (99 Bcf)
    - P50 – 5238 $10^6 m^3$ (185 Bcf)
    - P90 – 39473 $10^6 m^3$ (1394 Bcf)
- Sandface AOF is estimated to be 6890 10^3 m^3/d (243 MMcfd).
- Gauge failures were a problem (3 out of 8 gauges failed completely, none of the remaining 5 recorded data for the full build-up period) during the testing of M-25. An attempt to identify the connectivity of the nearby Chevron et al K-29 well to the M-25 well (by placing gauges in K-29 during the M-25 flow and build-up test) was also plagued by gauge failure. Both K-29 gauges failed outright and did not have pressure data stored when they were retrieved.

Overview

The M-25 wellbore was completed as an open hole completion. The 244.5 mm intermediate casing was landed at a measured depth of 3438 mKB and an open hole interval was drilled at a 36 to 39 degree angle through the Nahanni reservoir to a total depth of 3770 mKB. A permanent packer was set at 3421 mKB, with an 88.9 mm tailpipe at 3454 mKB. An 88.9 mm tubing string was stung into the permanent packer. The well was acid washed and squeezed for the entire open hole interval (75 m^3 15% HCl). After the acid stimulation the well was flowed back to clean-up for several hours. See attachment 1 for the wellbore schematic.

A static gradient was run, with the maximum depth obtained of 3569 mKB. A total of 8 Lee Tool LMR 16K pressure recorders were landed in the wellbore, with setting depths from 3440 to 3455 mKB. The first attempt to begin the flow after flow test at 280 10^3 m^3/d had to be aborted when the surface equipment began to plug with hydrates. The well was shut in to build back up to its initial pressure, and the hydrate plugs were cleared from the surface equipment and wellhead. After a short shut-in period, the well was re-opened, but at a higher initial rate. The well flowed at rates up to 780 $10^3 m^3/d$ from January 8th to January 11th, when the well was shut in for build-up. Total gas flared during the test and proceeding clean up was 2523.6 $10^3 m^3$.

The gauges were recovered January 25th. A production log, utilizing a tool string consisting of a full bore spinner, CCL, GR, temperature, and pressure measurement was then run. During the production log, 43 $10^3 m^3$ of gas was flared, bringing the total gas flared during the evaluation of M-25 to 2570 10^3 m^3 (90 mmcf).

A second static gradient was run February 28th to a maximum depth of 3557 mKB, and similar to the first static gradient run, indicated a gas gradient for the full run depth.

An attempt to obtain interference data from Chevron et. al. Ft. Liard K-29 was not successful due to gauge failures.

Section 1: Gauge Data

Figure 1 shows the final pressure measured by the five different pressure recorders that provided build-up data. The calibration of the gauges is apparently quite good, as the initial measured pressure range was 9 kPa for the 5 gauges. Table 1 highlights the gauge depths during the test, and Table 2 summarizes the pressure information from these gauges.

Figure 1: Comparison of Final Measured Pressure of Gauges

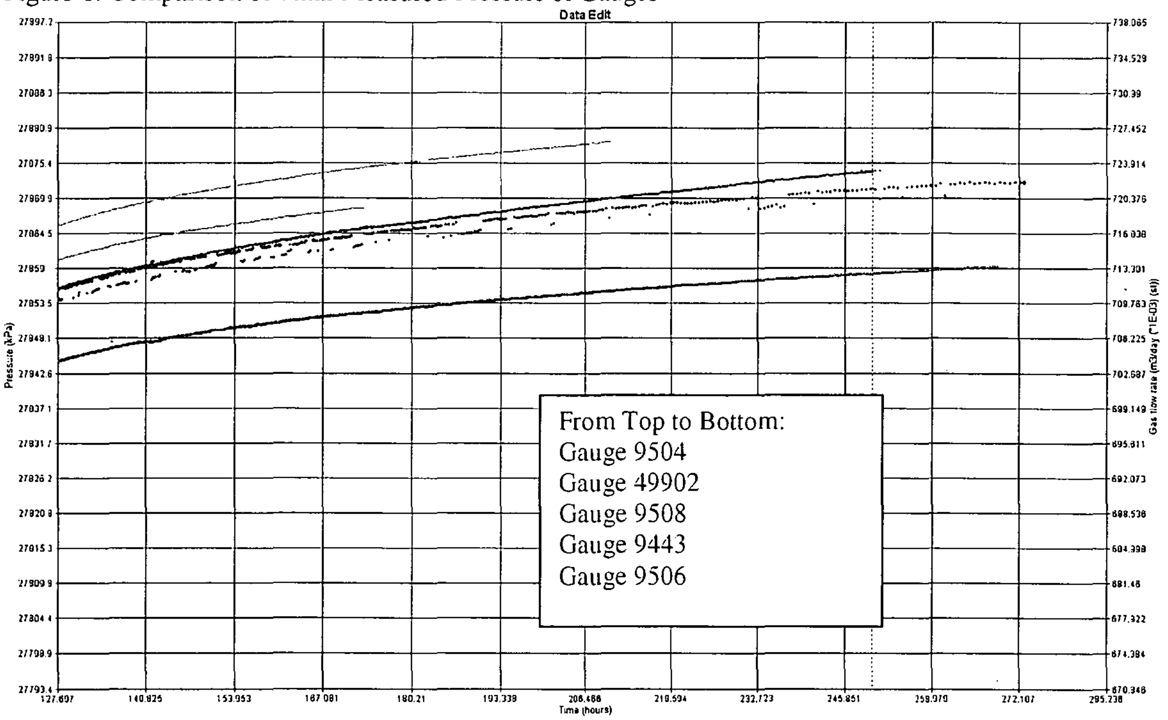


Table 1: Set Depth of the Gauges with Build-up Data

Gauge #	Measured Depth (mKB)	TVD (mKB)	TVDss (m)
9443	3442.9	3118.4	-2200.6
9506	3444.3	3119.6	-2201.8
9508	3445.8	3120.9	-2203.1
49902	3450.3	3124.8	-2207.0
9504	3453.5	3127.5	-2209.7

Table 2: Initial and Final Measured Pressure – Corrected to –2214.8 mTVDss

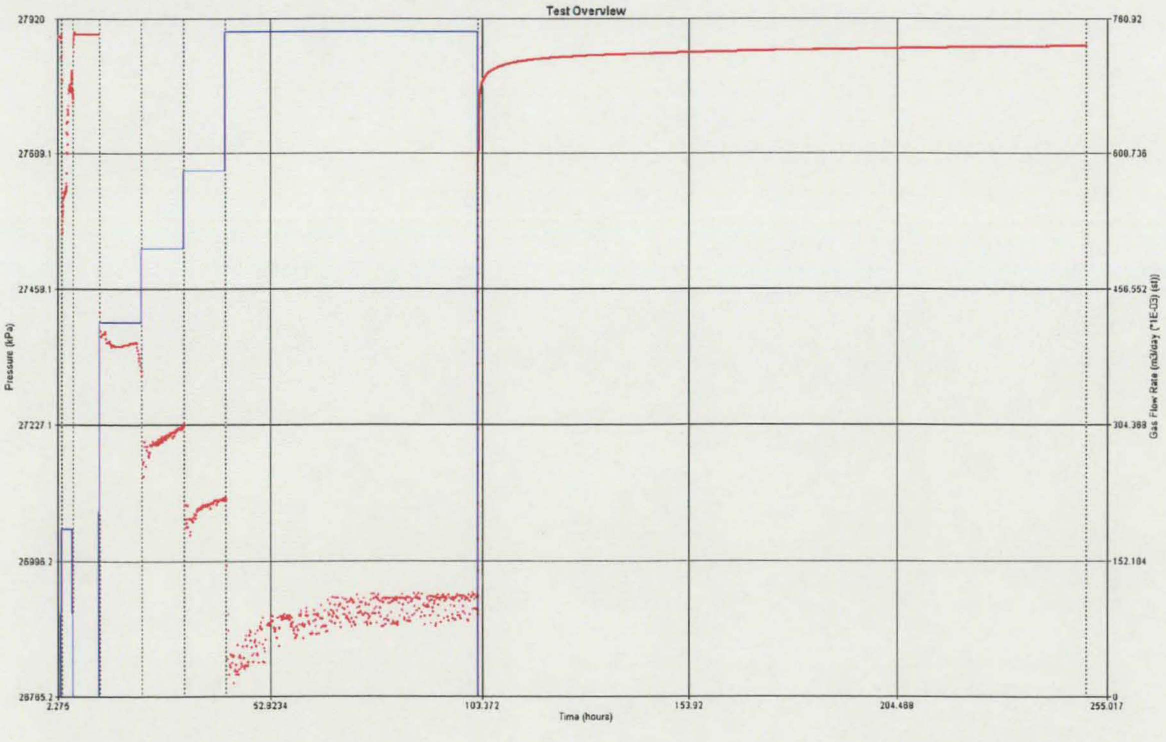
Gauge #	Measured Initial Pressure (kPaa)	Measured Final Pressure (kPaa)	Measured Depletion (kPa)	Build-up Data Available (hrs)
9443	28011	27989	22	151
9506	28002	27974	28	146
9508	28005	27986	19	155
49902	28008	27972	36	70
9504	28006	27978	28	107

The well was left shut in for approximately 328 hours after the flow test. The longest any of the gauges lasted was less than ½ of this shut in time (gauge 9508 lasted for 47% of the build-up time). At this time, the reason for the gauge failure is still unclear. Gauge 9508 was used for continued well transient analysis due to it having the most build-up data available.

Section 2: Test Data

Attachment 2 at the back of this report is a detailed sequence of events that occurred from the completion to the temporary suspension of the well. Figure 2 below is an overview of the flow and build-up test data from gauge 9508, with the average rate data from the flow periods superimposed on the pressure data.

Figure 2: Bottom Hole Pressure Data from Gauge 9508 with Rate



It is interesting to note that on the first three flow periods, the bottom hole pressure was increasing with time. On the extended flow period, this phenomenon was also noted at the beginning of the interval. This is likely due to the well 'cleaning up' with time, with more fluid being produced at the initial choke change setting due to the drop in bottom hole pressure. Figure 3 below supports this theory, showing the WGR with time during each flow period. Note that no water was measured during the first flow period. Figure 4 below shows the rate plotted with wellhead pressure and temperature.

Figure 3: Rate and WGR versus Time

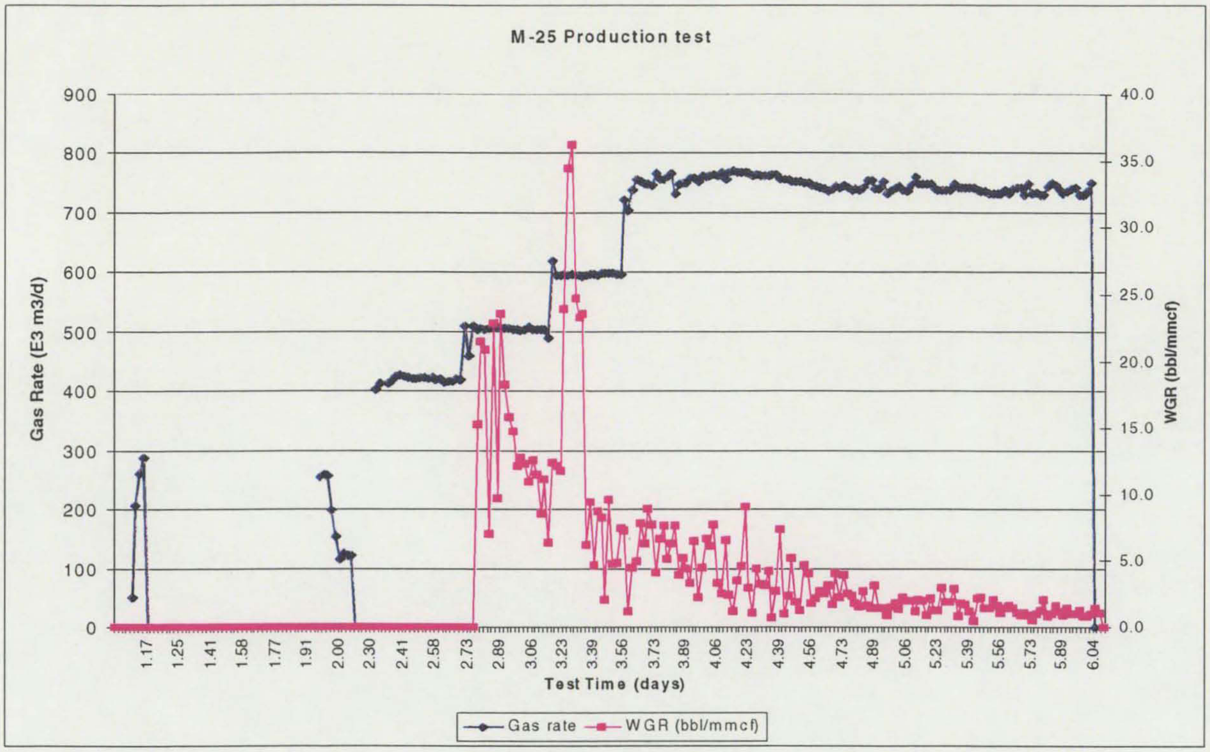
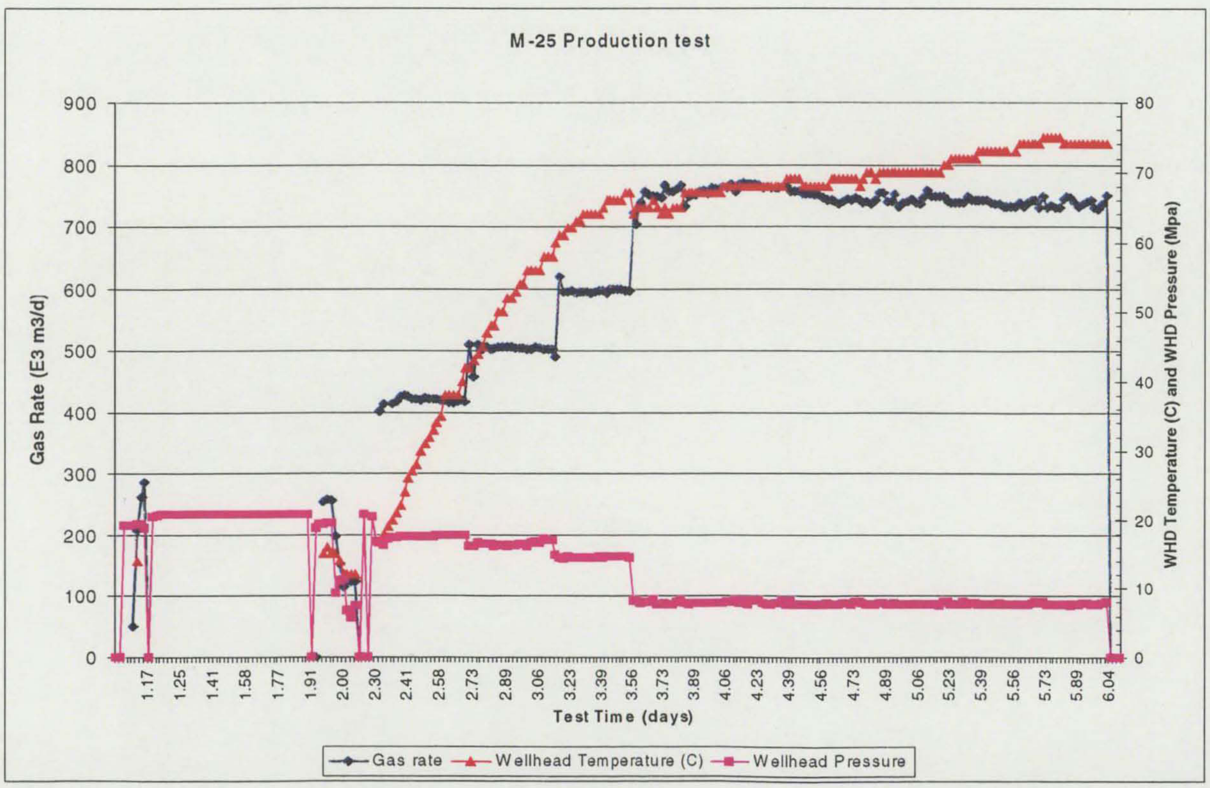


Figure 4: Rate, Wellhead Pressure and Temperature Versus Time



Section 3: Transient Evaluation

Evaluation Model

A dual porosity model was chosen as the appropriate model to use in the evaluation of the M-25 pressure transient. Open hole logs indicate the presence of natural fractures and a tight matrix rock, and the production log completed at the end of February identifies an inflow limited to a few discrete areas of the wellbore. These areas can be correlated to fractures identified on the open hole logs.

Another potential model for the evaluation is using a 'partial penetration' model to evaluate the transient. It is felt that the dual porosity model better reflects the current geologic model of the Ft. Liard Nahanni, and thus it was used to evaluate the transient.

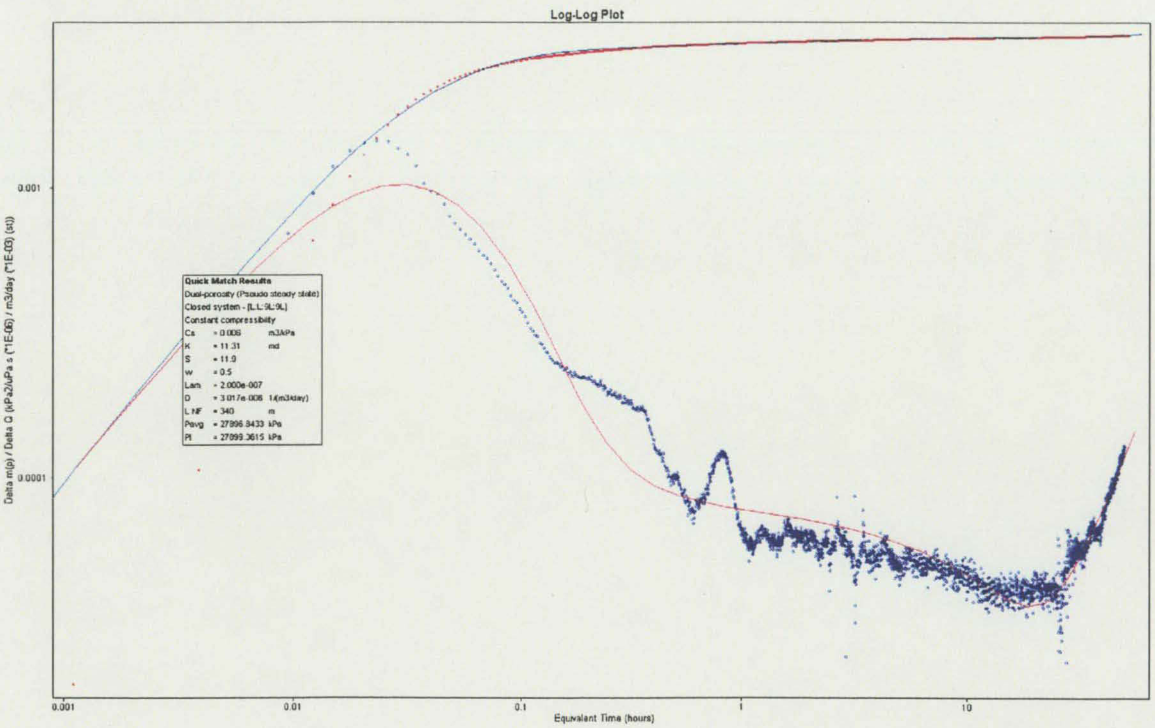
Permeability, Skin, and AOF

Utilizing the dual porosity model, and the input summarized in Attachment 3 of this report, the following results were obtained:

Permeability-Height – 3690 md-m
Darcy Skin - +12
Non-Darcy Skin Coefficient (D) – $3.0E^{-06}$ $1/(m^3/d)$

The estimate of permeability is based on simulation of output rather than direct measurement means. A second horizontal line on the Log-Log plot was not identified on the transient. It is hypothesized that this second horizontal line (which would highlight the combination of the fracture-matrix transmissibility) is masked by reservoir boundary indication on the transient. See Figure 5 below for the Log-Log plot.

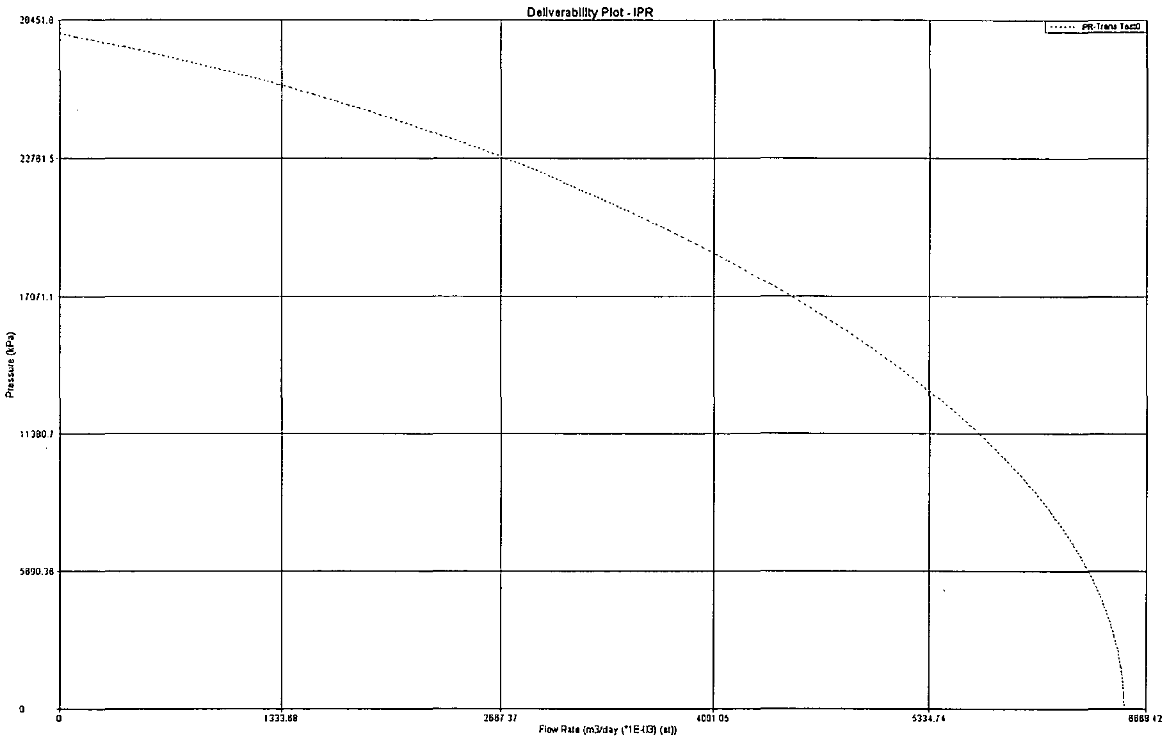
Figure 5: Log-Log Plot using Gauge 9508 Data



In high rate gas wells, total skin is made up of Darcy and non-Darcy skin effects. The 3-point flow after flow test was designed to allow for the determination of the non-Darcy skin effects. As noted above in Figure 2 and 3, the bottom hole pressure in the flow periods indicates that the non-Darcy effects were dynamic during the flow periods. Thus, it is impossible to model the non-Darcy effects accurately, and the coefficient D above should be taken as a 'best guess'. The inability to measure the non-Darcy effects puts in question the estimation of the Darcy skin factor, as well as the AOF estimate of the well.

The AOF of the well is estimated at 6890 $10^3 m^3/d$. Again, due to the inability to measure the non-Darcy skin effect, this estimate should be used with a degree of caution. See figure 6 below for the IPR curve of the well.

Figure 6: IPR (AOF) using Gauge 9508



<u>Dual Porosity Parameters and Reservoir Boundaries</u>

Estimates of the dual porosity parameters, w (omega) and Lam (Lambda) are detailed below. These estimates are dependent upon the results of the other near reservoir and boundary parameters calculated and assumed.

w – 0.5
Lam – 2 e-07

Utilizing the dual porosity model, it seems apparent that at least two reservoir boundaries are evident in the transient information. A best guess at the distance to the nearest boundary is ~ 350 m. The second boundary encountered was modeled the same distance from the well as the first. This summary is dependent on the reservoir model chosen and other reservoir parameters calculated, and is certainly not a unique solution to the transient information.

Section 4: Reservoir Pressure and OGIP Estimates

Due to test problems and gauge failures in M-25, the range of potential OGIP numbers calculated using the M-25 transient test are quite large. In doing material balance calculations using the depletion information, it is assumed that the initial pressure of the well is fully built up. Figure 7 and 8 below provide a close up look at the initial and final pressure information of gauge 9506. The initial pressure is still oscillating slightly, likely recovering from hydrate mitigation efforts that had been conducted. Despite this small problem, it is felt that the initial pressure is a good reflection of the initial pressure prior to the test. The final pressure was building at a rate of ~0.08 kPa/hr. This build rate manifests itself in the possible range of depletion and OGIP. Despite the uncertainty, the P10 (75% probability of the OGIP being larger than this number) is sufficient to continue development of the well and tie it in for commercial sales.

Figure 7 – Initial Pressure Data from Gauge 9506

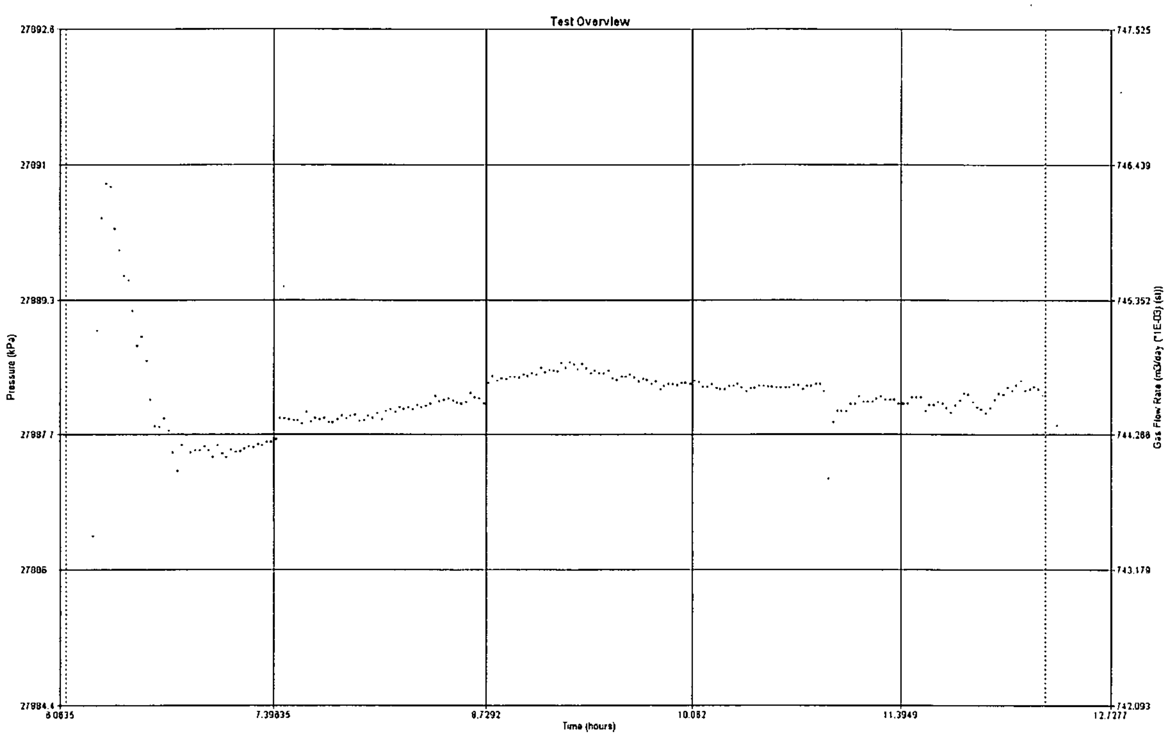


Figure 8 – Final Pressure Data from Gauge 9506

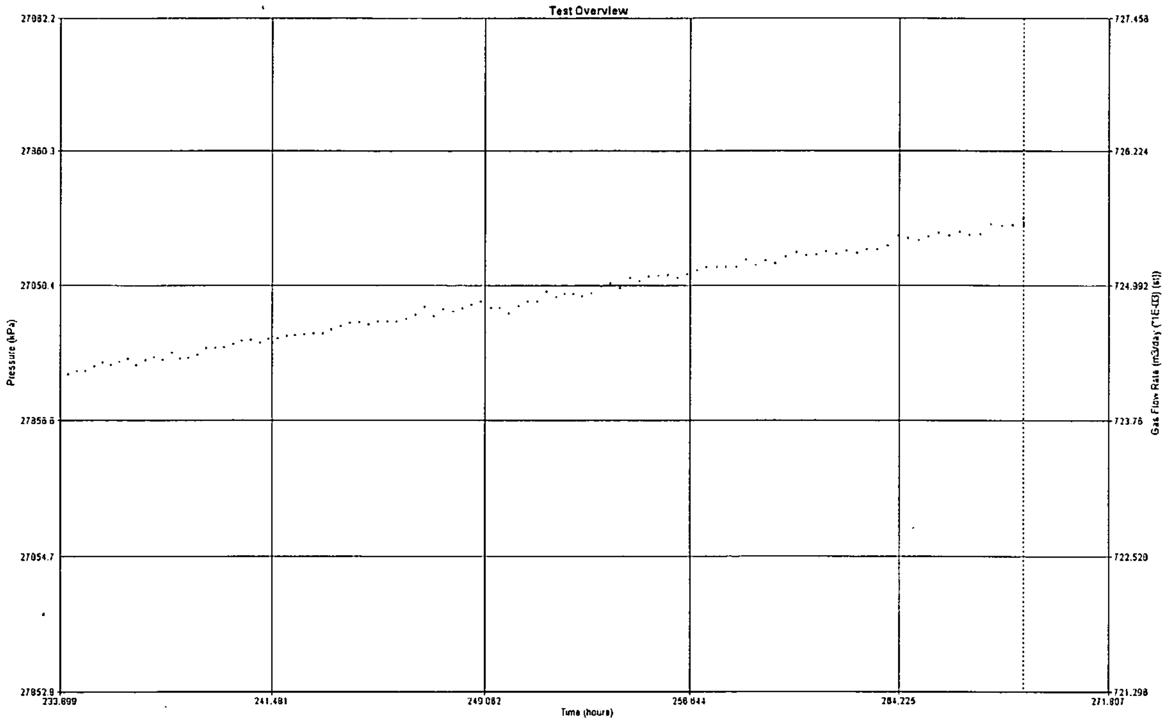


Table 2 previously highlighted the measured initial, final pressures, and thus measured depletion of the various gauges.

The initial reservoir pressure was taken as the arithmetic average of the initial pressures from the five gauges, all corrected to the same TVD depth (-2214.8m TVDss). To correct to absolute pressure, 90 kPa was used. A gradient of 1.85 kPa/m was used to correct the gauges to the TVD reference depth. Initial reservoir pressure is assumed to be 28007 kPaa. The initial reservoir pressure at the offset K-29 well was estimated to be 28003 kPaa at the same TVDss depth.

The data from Table 2 is useful to frame the lower end of the OGIP estimate. Gauge 9506, with its relatively long build-up time was chosen to represent the higher end of the measured depletion (and thus the lower OGIP estimate, the P10). This measured depletion was 28 kPa, and the P10 OGIP estimate is 2803 10^6m^3 (99 Bcf).

The P90 (a 25% probability the OGIP is greater than this number) estimate is based upon a simulated pressure response matching a rectangle 700 m wide and greater than 10 km long. This simulated response indicates that the bottom hole pressure would continue to increase until the pressure stabilized at 2 kPa depletion. The P90 OGIP estimate is 39473 10^6m^3 (1394 Bcf).

The P50 (50% probability the OGIP is greater than this number) depletion and OGIP estimate is based upon the arithmetic average of the P10 and P90 reservoir depletion. The arithmetic average of 28 and 2 kPa is 15 kPa. The P50 OGIP estimate is 5238 10^6m^3 (185 Bcf). The OGIP calculations are included in the attachments.

The two static gradients measured could not be used for reservoir pressure determination due to significant build up rates still being measured on the gauges when they were finished. On the January 7th static gradient, after one hour on bottom the pressure reading of the two gauges was building at 0.41 kPa/hr and 3.25 kPa/hr. On the February 28 static gradient, after one hour on bottom the two gauges were building at 4.64 kPa/hr and 7.16 kPa/hr. The static gradient information is included in the Attachments.

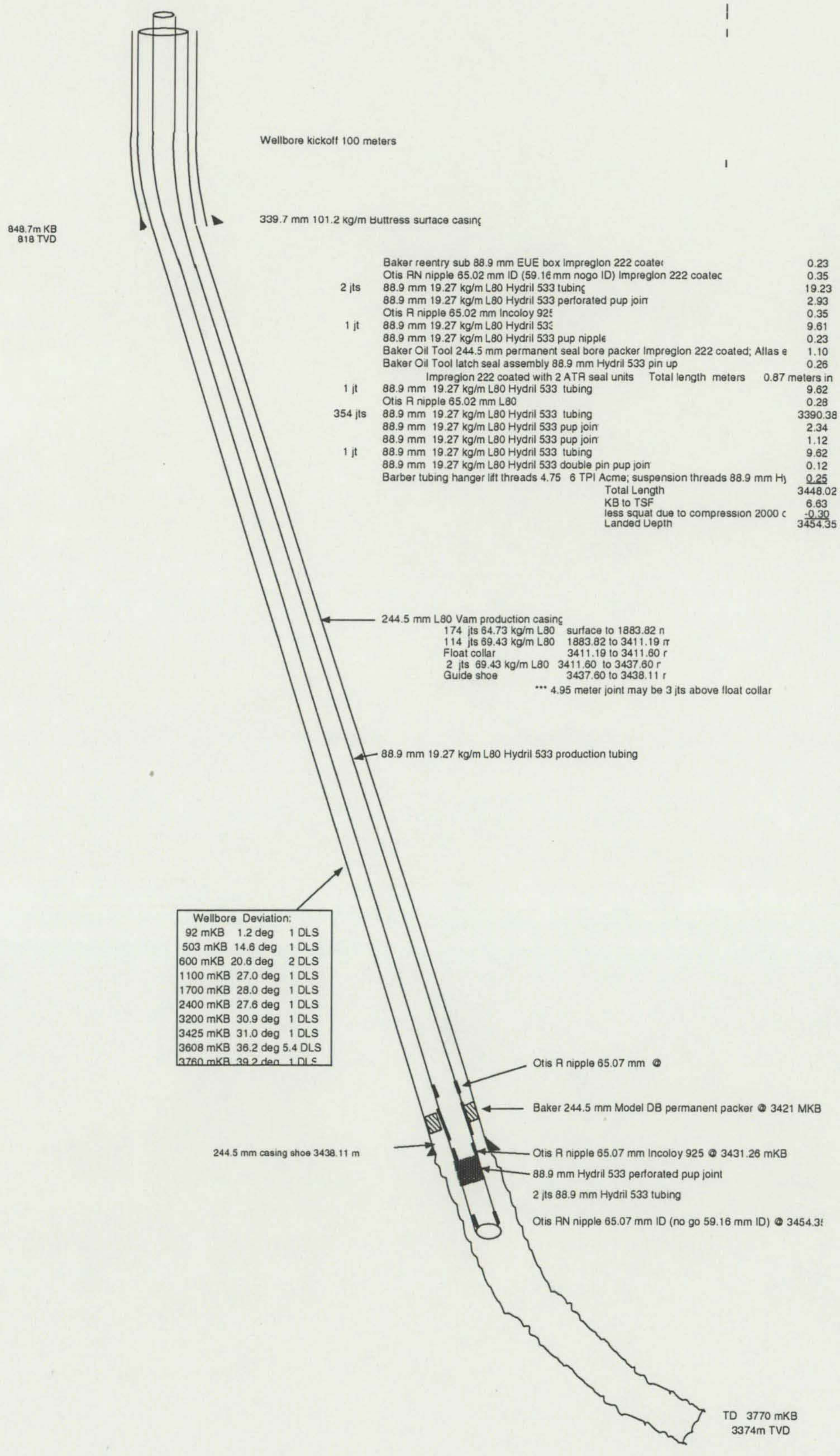
Chevron Canada Resources

Chevron etal Liard M-25
Wellbore Diagram

Wellbore

Chevron

Ground	?
KB Elev	917.80
KB to GL	7.20
KB to CF	7.31
KB to TSF	6.63



	Baker reentry sub 88.9 mm EUE box Impreglon 222 coate	0.23	3454.12
	Otis RN nipple 65.02 mm ID (59.16 mm nogo ID) Impreglon 222 coatec	0.35	3453.77
2 jts	88.9 mm 19.27 kg/m L80 Hydril 533 tubing	19.23	
	88.9 mm 19.27 kg/m L80 Hydril 533 perforated pup join	2.93	
	Otis R nipple 65.02 mm Incoloy 925	0.35	3431.26
1 jt	88.9 mm 19.27 kg/m L80 Hydril 533	9.61	
	88.9 mm 19.27 kg/m L80 Hydril 533 pup nipple	0.23	
	Baker Oil Tool 244.5 mm permanent seal bore packer Impreglon 222 coated; Allas e	1.10	3420.32
	Baker Oil Tool latch seal assembly 88.9 mm Hydril 533 pin up	0.26	
	Impreglon 222 coated with 2 ATR seal units Total length meters	0.87 meters in	0.26 meters o
1 jt	88.9 mm 19.27 kg/m L80 Hydril 533 tubing	9.62	
	Otis R nipple 65.02 mm L80	0.28	3410.16
354 jts	88.9 mm 19.27 kg/m L80 Hydril 533 tubing	3390.38	
	88.9 mm 19.27 kg/m L80 Hydril 533 pup join	2.34	
	88.9 mm 19.27 kg/m L80 Hydril 533 pup join	1.12	
1 jt	88.9 mm 19.27 kg/m L80 Hydril 533 tubing	9.62	
	88.9 mm 19.27 kg/m L80 Hydril 533 double pin pup join	0.12	
	Barber tubing hanger lift threads 4.75 6 TPI Acme; suspension threads 88.9 mm Hy	0.25	
	Total Length	3448.02	
	KB to TSF	6.63	
	less squat due to compression 2000 c	-0.30	
	Landed Depth	3454.35	

Attachment 2
M-25 – Sequence of Events

December 21, 1999 – commence completion operations.
December 22 – set permanent packer at 3421 mKB, circulate fluid above packer from mud to inhibited water.
December 24 – land 3.5 inch test tubing string in 2500 daN compression. Test annulus to 21 MPa.
January 3, 2000 – move on sit with test equipment.
January 4 – rig up test equipment.
January 5 – rig up coiled tubing. RIH to TD (3770 mKB), use nitrified water to lift drilling mud from well. Drilling mud decreased with time, and burnable gas returns gradually increased. Begin to pump only N2, water and mud returns decreased to negligible.

January 6
Hoist coiled tubing out of hole.
1:40 to 2:20 - Flow well pre-stimulation for 40 minutes. Rate estimated at 300 e3m3/d at 18.8 MPa surface pressure.
2:20 to 14:35 - Run in hole with coiled tubing to packer tail pipe bottom (3454 mKB). Perform 75 m3 15% HCl acid wash displacing acid with small H2O spacer and then N2. Displace acid in three trips across formation face (tailpipe to TD, TD to tailpipe, tailpipe to TD).
14:35 to 16:00 - Flow well for 1 hour while hoisting coiled tubing, recover all N2 then burnable gas at 200 E3m3/d. No spent acid recovered.
16:00 to 20:00 - Shut in well, pull coil tubing, rig out. SITP 19.1 MPa,
20:00 to 21:15 - Open well to 210 e3m3/d (TP 19.2 MPa), increase rate to 290 e3m3/d. Flow well on clean up for 1.25 hours. Shut in well for initial pressure.

January 7
3:00 to 8:15 – RIH with slickline, perform static gradient. Maximum depth obtained 3569 mKB. Stay on bottom for one hour, well still increasing at 14 kPa/hr.
8:15 to 14:00 – RIH and set 8 LMR gauges in the tailpipe of the tubing. Rig out slickline.
15:00 to 17:40 – begin to flow well on first rate, hydrate problems. Rate started at 264 e3m3/d at TP 19.5 MPa, reduced to 125 e3m3/d at TP of 7.5 MPa. Shut well in to clear hydrates at surface. SITP increases and stabilizes at 20.8 MPa.

January 8
0:00 to 10:00 – Open well up on rate #1, 11.1 mm choke, TP 17.4 MPa increasing to 17.7 MPa, rate between 425 e3m3/d and 435 e3m3/d.
10:00 to 20:00 – Open well up to rate #2, 14.3 mm choke, TP 18 MPa increasing to 21.5 MPa, rate between 523 e3m3/d and 515 e3m3/d.
20:00 – Open well up to rate #3, 18.25 mm choke, TP 14.6 MPa relatively steady, rate between 630 e3m3/d and 615 e3m3/d.

January 9
0:00 to 6:00 – continue to flow well on rate #3.
6:00 to 24:00 – Open well to rate #4, choke wide open, TP 8.3 MPa to 7.8 MPa, rate between 720 e3m3/d and 780 e3m3/d.

January 10
Continue to flow well on rate #4, choke wide open, TP 7.8 to 8.0 MPa, rate between 780 e3m3/d and 755 e3m3/d.

January 11
0:00 to 18:00 – continue to flow well on rate #4, choke wide open, TP 7.8 to 8.0 MPa, rate between 750 e3m3/d and 770 e3m3/d.
18:00 – shut well in for build-up, set BPV in tubing hanger.

January 24
Move on and rig up slickline to pull recorders.

January 25
8:45 – pull BPV from tubing hanger.
10:15 – first four recorders on surface.
13:30 – second set of recorders on surface.

January 26
Perform production log.
February 28
Run static gradient. Maximum depth obtained 3557 mKB.
February 29
Displace well gas into formation with N2. Run and set RX plug in R nipple at 3421 mKB. Pressure test of tubing unsuccessful.
March 1
Run in hole with slickline, replace prong in nipple. Pressure test tubing with N2. Temporary suspension complete.

Reservoir Description
Fluid type : Gas
Well orientation : Vertical
Number of wells : 1
Number of layers : 1

Layer Parameters Data

	Layer 1
Formation thickness	324.00 m
Average formation porosity	0.055
Water saturation	0.17
Gas saturation	0.83
Formation compressibility	9.0380e-7 kPa-1
Total system compressibility	2.6141e-5 kPa-1
Layer pressure	27894.0002 kPa
Temperature	152.0000 deg C

Well Parameters Data

	Well 1
Well radius	0.11 m
Distance from observation to active well	0.0000 m
Wellbore storage coefficient	6.0000e-3 m3/kPa
Well offset - x direction	0.00 m
Well offset - y direction	0.00 m

Fluid Parameters Data

	Layer 1
Gas gravity	0.7668 sp grav
Water-Gas ratio	0.0000 m3/m3
Water salinity	0.0000 ppm
Check Pressure	2.7900e4 kPa
Check Temperature	152.0000 deg C
Gas density	175.84801 kg/m3
Initial gas viscosity	21.2179 uPa.s
Gas formation volume factor	5.3610e-3 m3/m3 (st)
Water density	922.38396 kg/m3
Water viscosity	0.16181 mPa.s
Water formation volume factor	1.08308 m3/m3
Initial Z-factor	0.99812
Initial Gas compressibility	3.0286e-5 kPa-1
Water compressibility	5.8333e-7 kPa-1

Layer 1 Correlations
Ug Correlation : Carr et al

Layer Boundaries Data
Layer 1 Boundary Type : Parallel faults
L1 Boundary : No-flow
L3 Boundary : No-flow

Attachment 4

M-25 Pressure Transient - OGIP Calculations

Gp=G-(G/Ei-((G/Ei)*(cwSwc+cf)(deltaP)/(1-Swc)-WeBw)E
or Cumulative Gas Production=GIIP-Gas Remaining in Reservoir

Assume the water and pore compressibility's are negligible in comparison to that of gas and that the reservoir temperature remains constant then,
p/Z=pi/zi(1-Gp/G)/(1-WeBwEi/G)

WeBw/(G/Ei) represents the fraction of HCPV invaded by water
if no water influx, then
p/Z=pi/zi(1-Gp/G)
or to calculate G

G=(Gp*pi/Zi)/(pi/zi-p/z)

where		metric	
Gp - gas produced (bscf)	0.0881	2495	E3m3
Pi - initial pressure (psia)	4062	28006.8	kPaa
Zi - initial compressibility factor	0.977121	(Note - z calculated using PREOS)	
P10 - current pressure (psia)	4058	27978.8	kPaa
z - current compressibility factor	0.977011		

"P10" OGIP =	99	bcf, where G=OGIP

P50 - current pressure (psia)	4060	27991.8	kPaa
z - current compressibility factor	0.977062		

"P50" OGIP =	185	bcf, where G=OGIP

P90 - current pressure (psia)	4062	28004.8	kPaa
z - current compressibility factor	0.977113		

"P90" OGIP =	1394	bcf, where G=OGIP

Attachment 5
Gradient Information

7-Jan Post Transient Test

#9453

depth mCF	depth TVDm	Press (kPag)	Gradient (kPa/mKB)	Gradient (kPa/mTVD)
-1.5	5.8	20633.09		
498.5	502.8	22067.8	2.87	2.89
998.5	957.8	23285.98	2.44	2.68
1498.5	1402.5	24368.88	2.17	2.44
1998.5	1845.2	25340.98	1.94	2.20
2498.5	2289.9	26246.27	1.81	2.04
2998.5	2738.8	27119	1.75	1.94
3498.5	3172	27925.38	1.61	1.86
3544.5	3209.4	28021.42	2.09	2.57
3560.4	3221.7	28067.52	2.90	3.75

#9454

depth mCF	depth TVDm	Press (kPag)	Gradient (kPa/mKB)	Gradient (kPa/mTVD)
0	7.31	20630.4		
500	504.2	22075.82	2.89	2.91
1000	959.1	23292.61	2.43	2.67
1500	1403.8	24372.11	2.16	2.43
2000	1846.5	25340.43	1.94	2.19
2500	2291.2	26243.84	1.81	2.03
3000	2740.2	27085.11	1.68	1.87
3500	3173.3	27920.25	1.67	1.93
3546	3210.6	28029	2.36	2.92
3561.9	3222.9	28075.76	2.94	3.80

28-Feb Post Transient Test

#9453

depth mCF	depth TVDm	Press (kPag)	Gradient (kPa/mKB)	Gradient (kPa/mTVD)
-1.5	5.8	20906.7		
998.5	957.8	23551.64	2.64	2.78
1998.5	1845.2	25486.07	1.93	2.18
2998.5	2738.8	27122.23	1.64	1.83
3198.5	2914.8	27475.88	1.77	2.01
3398.5	3086.7	27791.49	1.58	1.84
3448.5	3129.5	27884.63	1.86	2.18
3498.5	3172	27970.04	1.71	2.01
3548.5	3212.5	28047.36	1.55	1.91
3555.5	3217.9	28051.64	0.61	0.79

#9454

depth mCF	depth TVDm	Press (kPag)	Gradient (kPa/mKB)	Gradient (kPa/mTVD)
0	7.31	20908.39		
1000	959.1	23556.24	2.65	2.78
2000	1846.5	25481.13	1.92	2.17
3000	2740.2	27115.64	1.63	1.83
3200	2916.1	27481.11	1.83	2.08
3400	3087.9	27798.01	1.58	1.84
3450	3130.8	27890.33	1.85	2.15
3500	3173.3	27974.88	1.69	1.99
3550	3213.7	28050.12	1.50	1.86
3557	3219.1	28056.88	0.97	1.25