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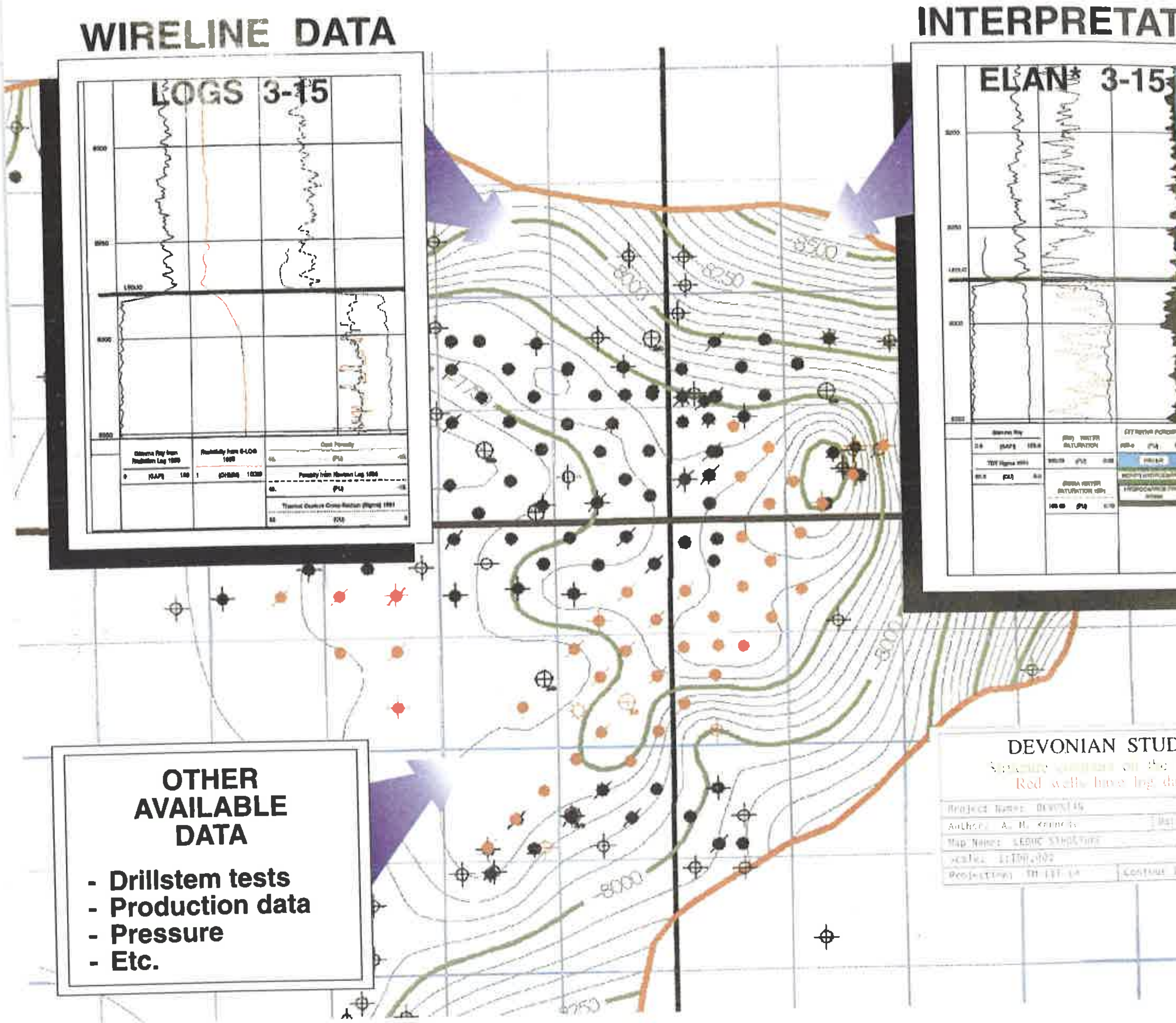

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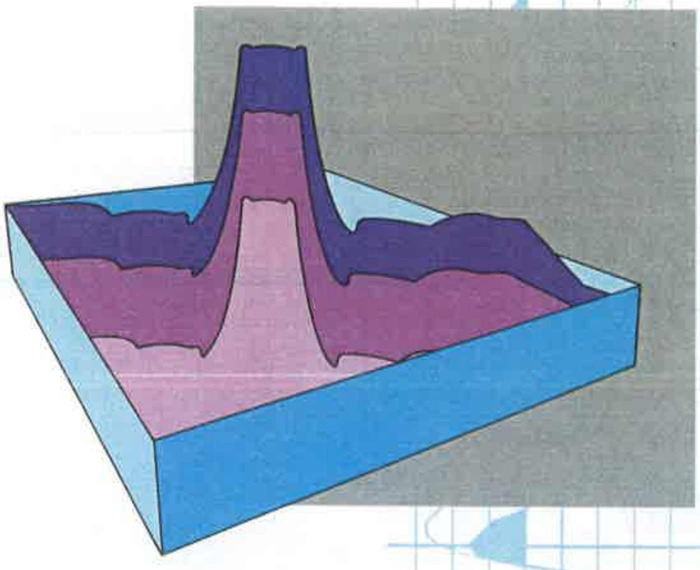

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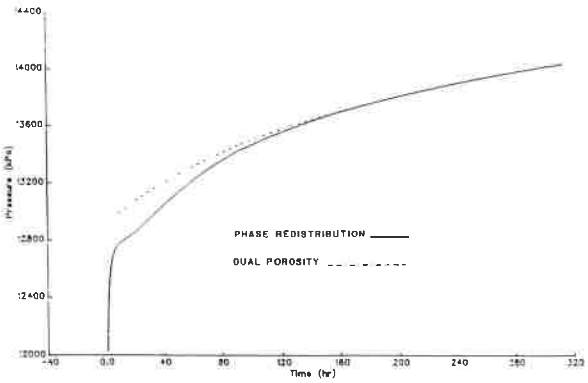

FIGURE 14. Comparison of dual porosity and phase redistribution strip chart.

Redistribution; Changing Wellbore Storage; Liquids Past Recorders; Liquid Influx; Gauge Malfunction; Wellbore and Near-Wellbore Cleanup; Geotidal, seismic, undetermined effects.

In a companion paper entitled: "How Wellbore Dynamics Affect Pressure Transient Analysis" Mattar and Santo[2] (1991) provide the theory and several examples to illustrate that the above effects can cause the PPD to increase, i.e. $d^2PPD/dt^2 > 0$.

To illustate the effects of Phase Redistribution in the wellbore, and its interaction with the reservoir, the model published by Fair[5] was implemented for drawdown and build-ups. The case shown in Figure 11 represents:

$C_D = 1000$, $s = 5$, $r_{eD} = 00$, $t_D = 10^6$
$C_{aD} = 500$
$C_{PD} = 5, 6.5, 7.1, 7.0$

Figures 11c and 11d clearly show the increasing PPD for the cases where phase redistribution is in effect. For the one curve where there is no phase redistribution, the PPD is continuously decreasing. The phenomenon of phase redistribution is purely a wellbore effect[6].

PPD as a Diagnostic

In all the cases presented, the authors have tried to model some extremely complex reservoirs, and in every case, have found that the primary pressure derivative — PPD — was continuously decreasing. However, as soon as wellbore effects were introduced increasing PPDs were observed.

As a very direct comparison of reservoir effects and wellbore effects and to demonstrate the power of the PPD as a diagnostic tool, we present Figures 12 and 13. Figure 12a represents a dual porosity reservoir with its characteristic "dip" in the derivative. Figure 13a shows a very similar "dip" in the derivative but the reservoir model is not a dual porosity system but a homogeneous reservoir with *Phase Redistribution in the Wellbore*. Figures 12a and 13a cannot be differentiated from each other, however, if we look at the PPD for each case the answer is plain and clear. This is shown in Figures 12b and 13b, which are the PPD corresponding to the "dual porosity" and Wellbore Phase Redistribution cases. The PPD for the dual porosity case shows a continuously decreasing PPD, whereas that for the Wellbore effect shows an Increase in the PPD! On a cartesian plot (strip chart), this would show up as an increasing trend in the build-up as show in Figure 2. In fact, Figure 14 shows an overlay of the pressure data for the models shown in Figures 12 and 13. In this case, the effect of the phase redistribution is very obvious. In actual test cases, the change in slopes is more subtle and can only be seen on a magnified scale.

Conclusion

1. Our hypothesis, "for a single rate drawdown or build-up, the PPD is continuously decreasing", has been demonstrated to be true for all the reservoir models discussed in this paper. The auth cannot envisage any reservoir models that violate this PPD princ
2. Before analyzing a well test, using sophisticated pressure tra ent analysis, one must make sure that the data being analyzed not have an increasing PPD. Where increasing PPD is obser that portion of the data is affected by Wellbore Dynamics and Reservoir characteristics.
3. Inconsistencies and discontinuities between various theore reservoir models were very quickly identified using the PPD meth
4. The PPD is a very simple and very effective diagnostic too is easy to apply either visually, graphically or computational
5. The PPD confirms the engineering intuition (gut feeling) the fastest response should occur at the earliest time. In other wo it makes sense from a physical perspective, and it is comfor that mathematics supports the concepts.
6. The PPD is a necessary (but not sufficient) tool in well test terpretation.

Acknowledgment

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NOMENCLATURE

C_{aD} = dimensionless apparent wellbore storage
C_D = dimensionless wellbore storage
C_{PD} = pressure parameter in phase redistribution model
FCD = dimensionless fracture conductivity
p = pressure
dp/dt = slope of pressure vs time plot on strip chart (cartesian c dinate scales)
PPD = Primary Pressure Derivative (equals absolute value of dp or dp/dΔt)
dp/dlog t = slope of semilog plot (pressure vs log time)
SLD = Semilog Derivative (equals dp/dlog t)
Δp_D = dimensionless drawdown pressure difference ($p_i - p_{wf}$
Δp_{DBU} = dimensionless build-up pressure difference ($p_{ws} - p_{wf}$
p_i = initial pressure
p_{wf} = flowing pressure
p_{ws} = shut-in pressure
t = flow time
Δt = shut-in time
t_D = dimensionless flow time
Δt_D = dimensionless shut time
r_D = dimensionless radius (r/r_w)
r_{eD} = dimensionless outer circular boundary (r_e/r_w)
x_{eD} = dimensionless single boundary (x_e/x_x)
y_{eD} = dimensionless single boundary (y_e/y_w)
s = skin effect
s_m = matrix skin
ω = storativity ratio
λ = interporosity flow coefficient
kh/u = transimissity
φch = storativity

Subscripts

1,2,3, refer to layers or zones

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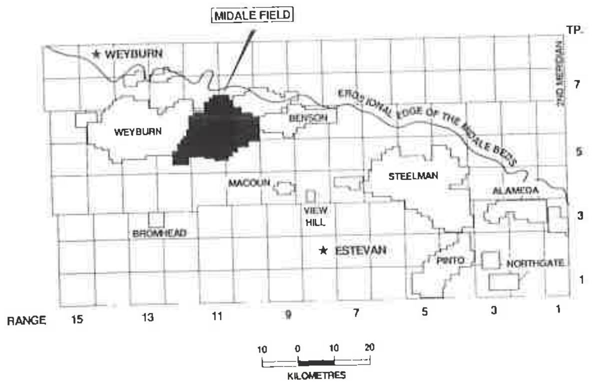

FIGURE 1. Location of the Midale field in southeastern Saskatchewan.

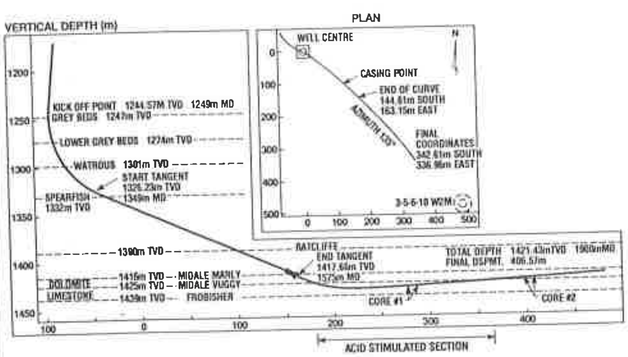

FIGURE 2. Plan and profile views of Shell Midale U EOR Horizontal C3-5-6-10W2M.

30% range. The Vuggy zone is a micro- to coarsely-crystalline fragmental limestone with a porosity typically between 8% and 15%. The Marly zone is typically laterally continuous and relatively homogeneous dolomite with very little stylolite development or vertical barriers to fluid flow[8]. However, some lateral facies changes from dolomite to limestone have been observed. The Vuggy zone is more laterally discontinuous and heterogeneous with sparry calcite and anhydrite cementation.

Reservoir Properties

Beliveau, Kaldi and others[4-9] have previously described the reservoir and petrophysical properties of the Midale Beds. Table 1 summarizes petrophysical data obtained from within the Marly and Vuggy zones of the three Midale horizontal wells. In Midale horizontal C3-5-6-10W5 well two Marly zones were intersected. A 17 m section of Marly at the heel of the well between 1577 m and 1594 m (measured depth) had 7 m of net pay averaging 26% porosity. Only two natural fractures were identified from a wellbore imaging log which was run over this interval. Between 1594 m and 178 m a total of 108 m of pay were identified with an average porosi of 11%. A total of 236 natural fractures were identified over th interval from the FMS log. At the toe of the well a 100 m sectio of Marly with 51 m of net pay had an average porosity of 27% and a total of 69 fractures.

In comparison with the two other horizontal wells in the Mida unit, the Vuggy zone is somewhat more naturally fractured an possesses a higher water saturation than the Vuggy encountered the other two wells.

Based on pressure surveys taken prior to the stimulation trea ment the reservoir pressure at the heel of the C3-5-6-10W2 horizon well was expected to be 7.9 MPa (5.6 kPa/m equivalent) and 12 MPa (8.9 kPa/m equivalent) near the toe of the well. Pressu anomalies, with gradients equivalent to or greater than 10 kPa/ are possible along portions of the well which have not seen appre able reservoir pressure drawdown and are receiving pressure su port from injector wells.

Natural Fractures

A ubiquitous feature of the Midale reservoir is a strongly oriente naturally occurring vertical fracture system. Previous core stud and pressure transient pulse testing have shown that the entire fi is traversed by a dominant fracture set with an average orientati of N48°E which gives rise to an average field wide horizontal perm ability anisotropy of between 25 and 30[5,6]. Typically the Vug zone (limestone) is the most fractured and possesses vertical a near-vertical, open, partially and totally cemented fractures w heights of several centimetres up to 5 m. The Marly dolomit less fractured as a whole. There is considerable variation in the sp ing, size and conductivity of the natural fractures as suggested Table 1.

Evaluation of natural fractures observed in the core revealed t most were open or partially open and would be considerably m conductive to fluid than the surrounding matrix. It is difficul determine the actual average in situ fracture aperture from w bore imaging logs, however, Luthi and Souhaite[10] reported so success in resolving relative aperture distributions by examining t conductive anomalies. Figure 3 is an example of an image show near vertical natural fractures intersecting the horizontal well

The two rose diagrams in Figure 4 show the strike and dip di tion for a total of 308 natural fractures detected on the wellb imaging log in the Marly and Vuggy zones of the Midale horiz tal C3-5-6-10W2 well. Note the relatively narrow natural frac strike distribution which has a mean azimuth of 051 degrees as d mined with circular statistics[11]. The rose diagram showing the direction suggests an almost symmetrical distribution of the about the predominate fracture strike azimuth. The fractures toward the northwest and southeast and typically vary betwee degrees and 90 degrees. An important point to note is the abs of a conjugate or orthogonal set of secondary fractures. The l would be difficult to detect with a horizontal well drilled per dicular to the major fracture trend, unless the orthogonal frac were quite closely spaced. The origin of this dominant struc fabric is not entirely certain although it is possible that both and regional tectonic events, and reservoir quality may have significant factors in their formation. Nearly all of the frac

TABLE 1. Petrophysical summary — Midale Horizontal wells

Well	Zone	Penetration (m) Gross	Penetration (m) Net	Porosity (%)	Wellbore Imaging Log No. of Fractures	Wellbore Imaging Log Density Fractures/m
C9-23-6-11W2	Marly	179	112	22	28	0.16
	Vuggy	93	35	13	87	0.94
C3-5-6-10W2	Marly 1	17	7	26	2	0.12
	Vuggy	186	108	11	236	1.27
	Marly 2	100	51	27	69	0.69
C3-14-6-11W2	Marly 1	35	13	27	3	0.09
	V	57	56	16	63	1.11

1a*	1770.0	1765.8	1429.3	6	1.4	300	9313	4.8	12.6	1.8	26.9	18.8	19.1	13.3	17.1	12.0
1b	1770.0	1765.8	1429.3	6	1.4	300	7315	11.4	13.3	4.9	na	na	25.7	18.0	20.0	14.0
2	1765.8	1761.6	1429.3	9	2.1	300	2610	9.4	10.5	4.9	24.8	17.3	23.7	16.6	20.0	14.0
3	1761.6	1757.4	1429.5	6	1.4	300	2406	6.7	12.2	3.4	26.5	18.5	21.0	14.7	18.5	12.9
4	1757.4	1753.2	1429.7	7	1.7	300	2217	11.0	11.9	3.6	na	na	25.3	17.7	18.7	13.1
5	1753.2	1749.0	1429.8	5	1.2	300	1305	9.5	11.2	3.4	na	na	23.8	16.6	18.5	12.9
6	1749.0	1744.5	1429.9	9	2.0	300	1800	12.0	13.0	3.9	na	na	26.3	18.4	19.0	13.3
7	1744.5	1740.0	1430.1	9	2.0	300	1998	7.8	8.5	4.6	na	na	22.1	15.4	19.7	13.8
8	1740.0	1735.5	1430.3	2	0.4	300	2251	9.5	10.1	2.9	24.4	17.0	23.8	16.6	18.0	12.6
9	1735.5	1731.0	1430.4	6	1.3	300	1993	8.4	11.8	3.9	26.1	18.2	22.7	15.9	19.0	13.3
10a	1731.0	1726.5	1430.5	5	1.1	300	2005	9.8	10.5	3.9	na	na	24.1	16.8	19.0	13.3
10b*	1731.0	1726.5	1730.6	5	1.1	40	252	6.4	7.1	4.3	na	na	23.9	13.8	22.6	13.0
11	1726.5	1722.0	1730.7	6	1.3	300	2245	7.7	12.2	2.7	29.7	17.1	25.2	14.5	21.0	12.1
12	1722.0	1717.5	1430.5	8	1.8	300	2016	8.5	15.2	4.2	29.5	20.6	22.8	15.9	19.3	13.5
13	1717.5	1713.0	1431.1	3	0.7	300	2758	8.5	16.2	3.6	30.5	21.3	22.8	15.9	18.7	13.1
14	1713.0	1708.5	1431.4	3	0.7	300	2341	9.5	13.0	4.9	27.3	19.1	23.8	16.6	20.0	14.0
15	1708.5	1704.0	1431.7	4	0.9	300	2058	6.5	14.3	3.7	28.6	20.0	20.8	14.5	18.8	13.1
16	1704.0	1699.5	1432.1	4	0.9	300	2036	8.3	14.0	2.9	28.3	19.8	22.6	15.8	18.0	12.6
17	1699.5	1695.5	1432.4	3	0.8	300	2766	7.5	10.5	3.4	na	na	21.8	15.2	18.5	12.9
18	1665.0	1660.9	1433.9	4	1.0	300	2028	7.5	16.5	3.2	30.9	21.5	21.9	15.2	18.3	12.8
19	1660.9	1656.8	1433.9	1	0.2	300	2016	8.3	15.9	2.9	30.3	21.1	22.7	15.8	18.0	12.6
20	1656.8	1652.8	1433.9	3	0.8	300	2533	7.8	15.6	3.7	30.0	20.9	22.2	15.5	18.8	13.1
21	1652.8	1648.8	1433.9	2	0.5	300	2001	8.3	11.6	3.7	na	na	22.7	15.8	18.8	13.1
22	1648.8	1644.7	1433.8	3	0.7	300	2096	7.8	16.6	2.9	31.0	21.6	22.2	15.5	18.0	12.6
23	1644.7	1640.5	1433.8	3	0.7	300	1281	8.0	16.7	3.3	31.1	21.7	22.4	15.6	18.4	12.8
24	1640.5	1636.6	1433.8	7	1.8	300	3018	8.2	16.6	3.8	31.0	21.6	22.5	15.7	18.9	13.2
25	1636.6	1632.8	1433.7	8	2.1	300	3364	8.0	10.6	6.5	na	na	22.4	15.8	21.6	15.1
26	1632.8	1628.9	1433.6	2	0.5	300	2087	7.5	14.8	2.9	29.2	20.3	21.9	15.3	18.0	12.6
27a	1628.9	1625.0	1433.3	3	0.8	300	1500	8.0	13.8	3.3	28.2	19.7	22.4	15.6	18.4	12.8
27b*	1628.9	1625.0	1433.3	3	0.8	300	1350	8.0	14.0	3.3	28.4	19.8	22.4	15.6	18.4	12.8
			Number of Acid Fracs	27	27	27	27	27	27	27	19	19	27	27	27	27
			Mean	4.9	1.14	300	2446	8.3	13.2	3.6	28.6	19.8	22.8	15.8	18.8	13.1
			Standard Deviation	2.4	0.56	0	1449	1.4	2.4	0.9	2.1	1.6	1.5	1.0	0.9	0.6

na not applicable
*water injected

kPa/m) measured in these two minifracs are reflective of the high pressure drawdown which was present in the vicinity of these production wells at the time of the test. The single formation leakoff test result from C3-5 is probably an overestimate of the S_{Hmin} gradient because the test was made in a cement contaminated section of strata not oriented in a principal stress direction. Furthermore, formation leakoff tests only indicate the point at which the formation begins to accept fluid, which is not necessarily the same as the far field minimum stress[18].

In summary, the orientations of the horizontal in situ stresses are not known with much certainty in the vicinity of Midale horizontal C3-5-6-10W2. A single Anelastic Strain Relaxation test, the regional model of northeast-southwest compressional stresses and the strongly oriented natural fracture orientation suggest that the S_{Hmax} direction, in the Midale beds, is likely between 045 degrees and 065 degrees. Horizontal stress magnitudes are less certain, although a reasonable estimate of the S_{Hmin} gradient at this locality is 14 kPa/m based on the reduced reservoir pressure.

Acid Stimulation Treatment

Rationale

The initial production from the Midale C3-5 horizontal well was disappointing. Gross fluid rates were less than half of what was anticipated and the oil cut was almost negligible. Pressures and production data indicated that some type of formation damage had occurred — likely drilling fluid invasion during hole cleaning when the filter cake was removed. A decision was made to try and acid wash the wellbore with 30 m³ of 15% nitrified HCl acid using 38 mm coiled tubing. This stimulation, although not selective, was the most economic option for removing the presumed wellbore face damage. Production rates improved marginally after this work but the oil cut remained unchanged indicating that the well could possibly benefit from a selective stimulation.

The well was shut-in while an openhole selective program was prepared for the fracture dominated Vuggy zone. It was believed that the Vuggy section or heel of the well should produce oil because the nearby vertical wells produce oil from the same zone at low water cuts. Because the Vuggy zone has a high concentration of fractures it was believed that drilling particulates had invaded the fractures, thus impairing production. The selective stimulation treatment was therefore designed using retarded acid to penetrate the formation and where possible partially cemented fractures to a depth of at least two metres from the wellbore.

Operational Aspects

Selective stimulation of the openhole section of Midale horizontal C3-5 was performed with centralized inflatable straddle packers separated by a 4.3 m long joint of 73 mm tubing. This configuration as detailed in Figure 6 was run on conventional 73 mm tubing to the desired depth. The advantage of the inflatable straddle packer assembly lies in its ability to unseat, move location and reseat. The fact that it is a hydraulic tool allows operation in highly deviated and horizontal wells. An additional advantage in using the stimulation fluid, acid, as the working fluid is the minimization of disruptions and the potential for acid dilution or contamination.

The Midale horizontal C3-5 workover marked the first reported application of inflatable stimulation packers in a horizontal openhole completion. Furthermore the entire job (27 sets) was completed without a tool failure or leakage around the packer elements. This performance was largely due to seating the tool in areas of the original 171 mm hole that were not enlarged by the acid wash.

The 15% HCl acid formulation was chemically retarded for application in the Vuggy limestone. Laboratory testing had shown that unretarded acid spent too quickly to obtain the desired penetration. The selected retarder gave a threefold increase in the reaction time. In addition to the retarder, the acid package included a corrosion inhibitor, surfactants, a dispersant, and anti-sludge and iron control agents.

Pressure/Rate Behaviour

Surface treatment pressures and injection rates during these sequential acid stimulations were recorded at one-second intervals on a PC-based data acquisition system. Data files were subsequently written to diskette for later analysis and plotting at an expanded scale. Table 3 summarizes the pressure and injection rate data for each stimulated interval. The measured depth, true vertical depth, number of natural fractures identified on the wellbore imaging log, the fracture density, the average injection rate and total acid or water volume per squeeze are given in this compilation. Tubing head and other calculated pressures are also given in this table and will be described later.

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