Reductions in the Productivity of Oil and Low Permeability Gas Reservoirs Due to Aqueous Phase Trapping

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Abstract

Many hydrocarbon bearing reservoirs exhibit the potential for significant productivity reductions due to adverse relative permeability effects associated with the retention of invaded aqueous fluids. These fluids could include water-based drilling mud filtrates, completion fluids, fracture fluids, workover fluids, kill fluids or stimulation fluids (including spent acid).

This paper identifies potential mechanisms behind phase trapping and identifies particular reservoir types which tend to be susceptible to this type of formation damage, most notably low initial water saturation gas reservoirs and strongly oil-wet oil reservoirs. Laboratory techniques to investigate the severity of aqueous trapping and various remedial techniques are described, and two field case studies illustrating the potential for permeability impairment due to invasive aqueous trapping are presented. One case study describes a series of wells completed in the Paddy formation and the second in the Cadomin formation in the Deep Basin area of central Alberta (both gas producing zones). Laboratory case studies documenting the phenomenon of aqueous phase trapping in strongly oil-wet porous media are also presented.

Introduction

Oil and gas bearing formations are potentially susceptible to many different types of formation damage(1-6). In this paper we are exclusively concerned with damage associated with aqueous phase trapping (or water trapping or blocking as it is often referred to). To understand the concept of aqueous phase trapping, it is essential to differentiate between the concept of initial (often referred to as connate) aqueous phase saturation (S_{wi}) and irreducible aqueous phase saturation (S_{wirr}).

a) Initial aqueous phase saturation is the initial average fractional portion of the pore space which is occupied by water. The value of the initial aqueous phase saturation is controlled by numerous factors, including reservoir geology, depositional history, temperature, wettability, height above free water contact and pore size distribution. The key point to differentiate in this area is that the initial aqueous phase saturation is not necessarily, and often is not, equal to the irreducible aqueous phase saturation and can be either higher or lower than the irreducible saturation. It is in the second case, where the S_{wi} is less than S_{wirr}, where productivity reductions due to phase trapping can occur.

b) Irreducible aqueous saturation represents that saturation which is forced to exist in the reservoir by capillary mechanics. Once again, the value of the S_{wirr} is determined by parameters such as the reservoir morphology, pore size distribution, pore throat size distribution, wettability, surface roughness, etc. We often obtain estimates of S_{wirr} through the use of air-brine or air-mercury capillary pressure tests. Although these values often provide good approximations to S_{wirr}, they may be poor indications of actual S_{wi}.

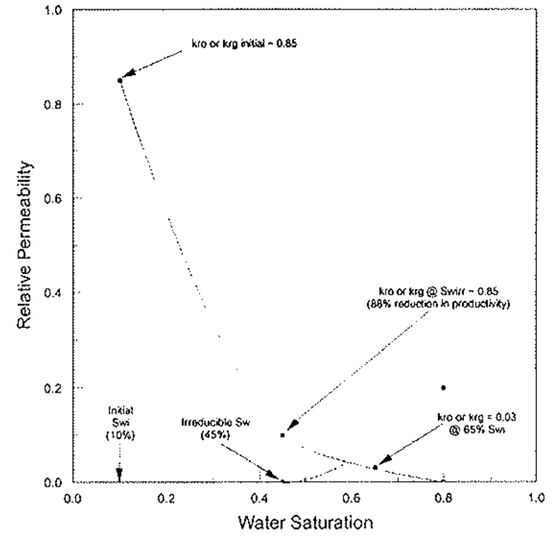


FIGURE 1: Mechanism of aqueous phase trapping.

Mechanism of Aqueous Phase Trapping

Figure 1 provides an illustrative example of a set of relative permeability curves. The diagram is applicable to either an oil or a gas reservoir. Examination of Figure 1 indicates that, if the zone of interest is at some aqueous saturation greater than the irreducible value of 45%, aqueous trapping will not be a severe problem because the reservoir is already initially highly saturated with water and may even be producing free mobile brine. We can see that if this is the case, the initial productivity of the reservoir will already have been substantially reduced due to an unavoidable, pre-existing, high aqueous phase saturation.

TABLE 1: Water carrying capacity of dry natural gas at selected temperatures and pressures(9).

	kg-H_2O/10^3m^3 gas at T & P			
Temperature (°C)	Pressure (kPag)			
	101.3	1380	10340	27570
15.6	14.0	16.3	23.5	46.2
40	51.5	56.3	84.6	125.4
60	139.2	141.6	194.4	282.0
80	328.0	310.8	400.3	578.2
100	539.0	609.0	789.0	1136.7

One factor which characterizes some gas reservoirs and most strongly oil-wet reservoirs is the fact that they exhibit abnormally low initial water saturations. It is not at all unusual for strongly oil-wet carbonate or sandstone formations to exhibit initial water saturations of less than 5%, and these saturations are, in general, fairly independent of the permeability distribution which exists in the reservoir. Gas reservoir aqueous saturations vary with some instances of near zero initial water saturation being observed in numerous Michigan reef gas reservoirs(7), although in most situations a finite but low (e.g., 10-25%) initial aqueous saturation exists.

The phase trap occurs when the formation is invaded by the aqueous phase. Examination of Figure 1 illustrates that the formation basically "springs" back to its true irreducible water saturation once exposed to aqueous fluid. The formation initially absorbs water in a spongelike fashion until the irreducible water saturation is achieved and the aqueous phase achieves a finite relative permeability value and hence becomes mobile and begins to flow in the pore system.

It is obvious from Figure 1 that the severity of the reduction in productivity due to an aqueous phase trap will depend on:

a) The difference between the "initial" S_{wi} and the true "irreducible" S_{wirr}. The larger the difference, the greater the potential permeability reduction (e.g., if S_{wirr} had been 65% instead of 45% in our example in Figure 1, one can see that the Kro or Krg would have been further reduced to only 0.03).

b) The configuration of the gas or oil phase relative permeability curve in the region between S_{wi} and S_{wirr}. Obviously, if this curve is relatively linear (as shown by the dashed line in Figure 1), the damage would be much less than for the presented example of a typical convex set of gas-liquid or water-oil relative permeability curves. Conventional relative permeability measurements are usually conducted above S_{wirr} and thus provide little information on this phenomenon.

c) Saturation hysteresis effects altering the location of S_{wirr}. In some cases, experimental evidence(8) indicates that the actual value of the irreducible liquid saturation can be altered by contact angle hysteresis effects induced by cyclic saturation changes. This phenomenon will be discussed in greater detail in the following sections.

d) Depth of invasion of the aqueous phase into the reservoir.

Origin of Abnormally Low S_{wi}

A major question which always arises in the discussion of water-trapping phenomenon is not so much the existence of the water block, but how the reservoir matrix attained this abnormally low initial water saturation in the first place. Theoretically speaking, given the constraint imposed by Figure 1, if an oil or gas reservoir was initially 100% saturated with brine prior to oil or gas influx, there should be no way that the saturation could have been reduced below S_{wirr} as the aqueous phase has no mobility at saturations below that level.

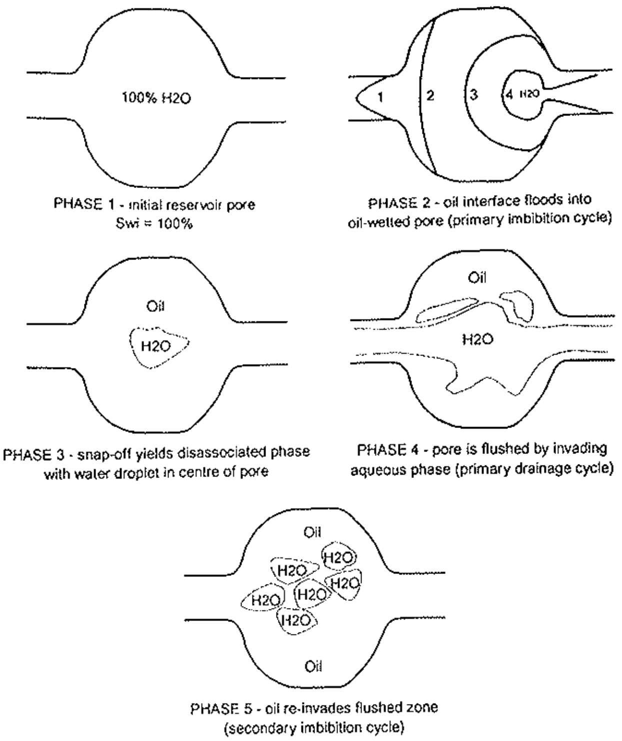
There are several hypotheses as to why this may occur; in fact the phenomenon may be related to a combination of these hypotheses (or possibly to phenomenon not yet defined).

a) Vapourization (gas reservoirs) – Due to the fact that the reservoir is created over geologic time, it is possible that, early in the history of the reservoir, both temperature and pressure were much less when initial gas invasion occurred. Table 1 illustrates the water carrying capacity of natural gas(9). One can see that dry gas at 27,570 kPag and 100°C is capable of vapourizing and holding 1,136.7 kg/10^3m^3 of water vs. only 14.0 kg/10^3m^3 at 101.3 kPag and 15.6°C. Therefore, it can be seen that a desiccation effect could occur. If one goes through the calculations, one finds that gas throughput would have had to be quite large for a significant reduction in S_{wi} to occur due to this mechanism, but over geologic time such a large, regional migration of gas is certainly possible. Localized tectonic activity after deposition, creating high geothermal gradients, may also have been a contributing factor in water vapourization in some instances.

b) Changes in pore geometry (due to overburden compression and diagenesis) – The original depositional environment of the reservoir likely exhibited higher porosity and permeability characteristics during initial migration of hydrocarbons into place. This higher reservoir quality may have resulted in a much lower initial irreducible water saturation. Over geologic time, overburden pressure increased causing compaction and a reduction in porosity and pore size distribution. Reservoir diagenesis processes contribute to the potential formation of high surface area clays and other authigenic materials containing microporosity resulting in an overall reservoir quality reduction and less favourable capillary pressure characteristics. This would result in a much higher S_{wirr} value, but, if no additional water influx occurred, the reservoir water saturation would remain at its original lower value, now at some value less than S_{wirr}.

c) Adsorption – It is known that most clays and many reservoir minerals (e.g., Anhydride) will react with water to form hydrated complexes(7). This physical adsorption process would result in a portion of the effective water being potentially removed from the pore space and hydrated into the clays (if the clays are formed authigenically).

d) Irreducible saturation hysteresis effects – Various authors(10) have documented that the presence of an initial wetting phase saturation tends to enhance the spontaneous imbibition of that fluid (i.e., tends to make it even more strongly wetting). This being the case, one would expect that there



PHASE 1 - initial reservoir pore Swi = 100%

PHASE 2 - oil interface floods into oil-wetted pore (primary imbibition cycle)

PHASE 3 - snap-off yields disassociated phase with water droplet in centre of pore

PHASE 4 - pore is flushed by invading aqueous phase (primary drainage cycle)

PHASE 5 - oil re-invades flushed zone (secondary imbibition cycle)

FIGURE 2: Postulated mechanism for establishment of low S_{wi} and subsequent phase trapping in oil-wet porous media.

TABLE 2: Illustration of Aqueous phase trapping in strongly oil-wet porous media.

Core #	Initial S_w	Koil (mD)	Post-Water Flush S_w	Koil (mD)	% Reduction In Oil Permeability
1	0.0395	156.6	0.2255	5.83	-96.3%
2	0.0259	51.8	0.2057	3.42	-93.4%
3	0.0453	132.3	0.3411	5.83	-95.6%

could be differences in the irreducible saturation obtained if multiple cycles of drainage and imbibition of water were conducted versus only a single primary cycle. This phenomenon for a strongly oil wetted system is illustrated in Figure 2(11). The specific mechanisms presented in Figure 2 are detailed in the following paragraphs.

Initially (Phase 1), the porous media is 100% saturated with the non-wetting phase (water). Phase 2 (steps 1-4) shows various positions of the oil-water interface, as a function of time, as oil invades the pore and wets the rock with a relatively high contact angle (about 160° in this example). This results in a very efficient displacement of water from the pore except for a small discontinuous globule (Phase 3) which is created by snapoff phenomenon. The magnitude of the initial water saturation created by this phenomenon will be influenced by the ratio of pore throat to pore diameter.

Subsequent invasion by an aqueous fluid (Phase 4) results in a preferential channelling of the aqueous phase through the central portion of the pore. As the invaded water contacts the initial water present in the centre of the pore, the potential for the establishment of droplets of encapsulated water, separated by thin films of oil, exists (depending on interfacial tension, oil and water properties and pore geometry).

Subsequent re-invasion of the oil phase (Phase 5) results in the phenomenon of the advancing oil interface now contacting a variety of irregular potential oil-water interfaces instead of the initial uniform displacement (illustrated in Phase 2). This results in the potential for the generation of multiple stable oil-water interfaces and a potential for a larger retained water saturation. The trapped location of these globules of water in the central portion of the pore space will have a greater reducing effect on oil phase permeability than in the initial low S_{wi} state observed at the conclusion of Phase 2.

TABLE 3: Conditions causing potential aqueous trapping phenomenon.

Increasing Severity of Water Trap Potential	Decreasing Severity of Water Trap Potential
1. Strongly oil-wet reservoir with very low (<10%) S_{wi}. Severity appears related to reducing reservoir quality in many cases.	1. Neutral to water-wet oil reservoirs with typical water saturations for the permeability range under consideration (i.e. $S_{wi} \geq S_{wirr}$).
2. Gas reservoir (any permeability) exhibiting unusually low S_{wi} (generally <20%).	2. Gas reservoir (any permeability) with $S_{wi} \geq S_{wirr}$.
3. Low permeability gas reservoirs exhibiting higher S_{wi}'s, but at values still less than S_{wirr}.	3. Low permeability gas reservoir exhibiting high $S_{wi} \geq S_{wirr}$.
4. High rates of uncontrolled aqueous fluid loss to the formation due to poor fluid loss control or extremely overbalanced treatment operations (i.e. overbalanced drilling, fracturing, etc.).	4. Wells with low or zero fluid loss to the formation due to superior fluid loss control (artificial bridging agents, etc.).
5. Multiple cycles of aqueous fluid invasion in a given zone.	5. Eliminating or minimizing cycles of aqueous invasion.

Laboratory Verification of Aqueous Phase Trapping in Strongly Oil-wet Porous Media

Table 2 summarizes the results of three reservoir condition coreflow tests conducted on preserved state strongly oil-wet sandstone core samples. The cores utilized in these tests had never been previously contacted with water, being exclusively drilled and cored with hydrocarbon based fluids. Examination of the initial water saturations of the three preserved samples indicated very low initial values ranging from 2.5 to 4.5%, consistent with the strongly oil-wet nature of the rock. Initial permeability of the samples to oil at the initial S_{wi} varied from 51.8 to 156.6 mD. Each sample was then flushed with a non-damaging equilibrium formation brine, and then reflushed to irreducible water saturation at field realistic drawdown pressure gradients of 4,000 kPa per metre. Examination of the data indicates that the irreducible saturation increased from less than 5% in all cores to the range of 20% to 34%. This resulted in a 93%-96% reduction in effective oil permeability, clearly illustrating the reducing effect of the establishment of an aqueous block on oil phase permeability.

Reservoir Processes Which Can Cause a Water Trap and Reservoir Types Susceptible to Damage

The potential for aqueous phase trapping occurs anytime an aqueous fluid invades an abnormally low initial water saturation reservoir. These fluids could include:

a) Water based drilling fluid filtrates
b) Cement filtrates
c) Water based completion fluids
d) Water based workover fluids
e) Water based kill fluids
f) Water based stimulation fluids

Table 3 provides a comparative summary of conditions which tend to increase or decrease the potential severity for aqueous trapping in selected situations. These guidelines are based upon general experience and should not be taken as indicative of all potential reservoir scenarios.

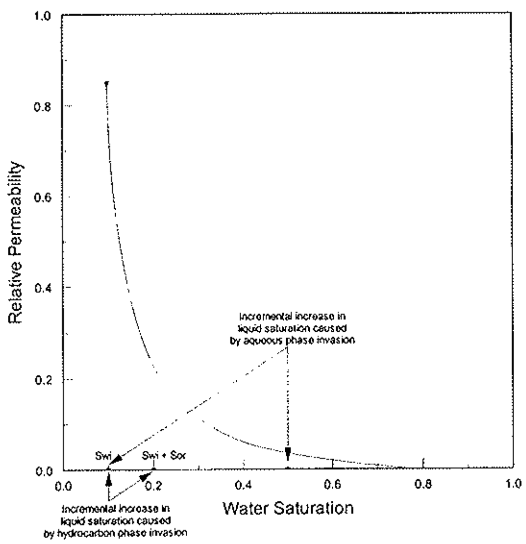


FIGURE 3: Use of hydrocarbon-based fluid to reduce aqueous trapping effects in a gas reservoir.

Minimizing Potential for Aqueous Trapping in the Field

If productivity reductions due to aqueous phase trapping are identified as a potential problem source for a given reservoir, the following options should be considered:

a) Avoid the use of water based drilling, completion or stimulation fluids in the reservoir, if economically and technically feasible. It is obvious that use of a hydrocarbon fluid which will be miscible with the reservoir crude oil is an advantage in an oil system as this eliminates the potential for any type of an aqueous trap. This, of course, assumes that the introduced fluid itself does not cause any deleterious incompatibility effects (e.g., asphaltene precipitation, sludges).

Hydrocarbon fluids may also have particular application in gas reservoirs where water trapping occurs. It is obvious that, if we introduce a hydrocarbon based fluid into a reservoir initially containing only gas and water, we will establish a trapped hydrocarbon saturation. Since the vast majority of dry gas reservoirs exhibit it strongly water-wet behaviour (unless there is some immobile initial liquid hydrocarbon saturation present in the pore space which could cause an oil-wetted state), the entrained hydrocarbon saturation will be encapsulated in the central portion of the pore and will often be much less in its total magnitude than the additional liquid saturation which may have been entrapped had an aqueous fluid been introduced into the system. This phenomenon is further detailed in Figures 3 and 4 and two field case histories follow illustrating this type of reservoir behaviour.

The use of a hydrocarbon fluid in a gas reservoir situation could be contraindicated in situations where:

i) Permeability is very low causing a greater capillary retention of hydrocarbons.
ii) An initial and potentially wetting immobile or mobile liquid hydrocarbon saturation is present.
iii) The reservoir contains potential minerals which may be naturally oil-wet (i.e., pyrobitumen, graphite, talc, coal, sulphur, sulfides, etc.).

If a potential for oil-wetting in a gas reservoir is apparent, the reservoir may retain an undesirably high oil saturation, increasing the relative apparent damage (comparable or worse than that induced by the use of water-based fluids).

If aqueous fluids must be utilized due to economic or technical considerations, minimizing the depth of the flushed zone is crucial in minimizing damage. This would include consideration of low fluid loss systems, artificial bridging agents, balanced or underbalanced drilling operations, use of air drilling or gaseous based frac fluids, etc.

Methodologies for Removing Existing Aqueous Traps

Various methodologies have been attempted by different operators to attempt to stimulate reservoirs damaged by aqueous phase trapping phenomenon. A major problem in most cases is ensuring that the injected treatment fluids come into contact with the affected zone. This may require several cyclic type treatments of gradually increasing radius in certain situations. Common stimulation treatments include:

a) Injection of CO_2 gas (dissolves in trapped water, increases available blowdown energy to produce water, can lower gas-liquid interfacial tension).
b) Injection of a mutual solvent (usually methanol), sometimes

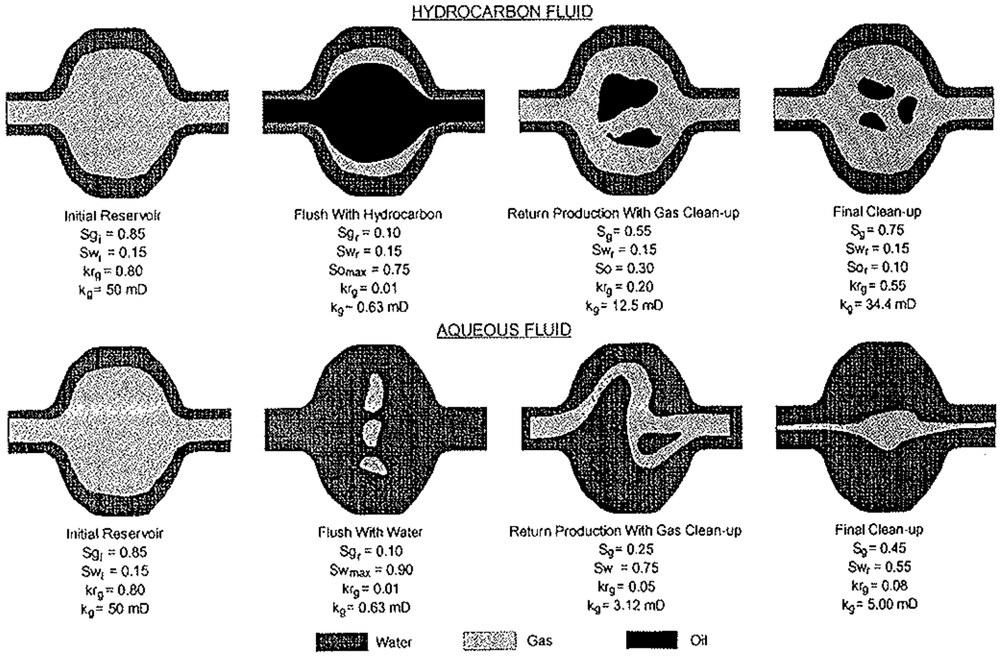


FIGURE 4: Pore scale mechanism of hydrocarbon vs. aqueous invasion in a gas reservoir.

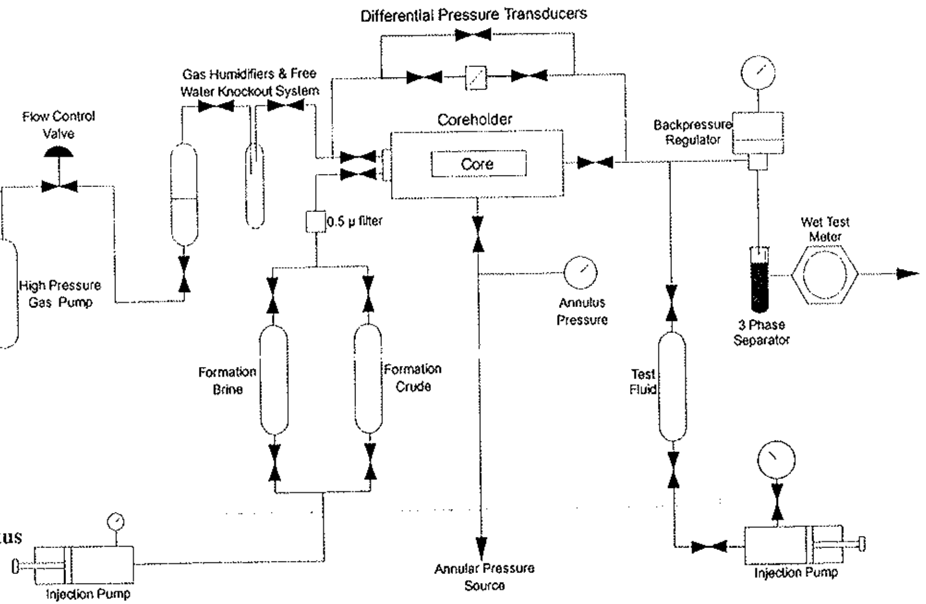


FIGURE 5: Experiment laboratory apparatus used to evaluate aqueous trapping.

in conjunction with CO_2. This type of treatment has experienced the most success in field experimentation with gas reservoirs. Heavier alcohols are often used for oil reservoir applications (i.e., isopropanol, butanol).

c) Evaporation of the water in the trapped zone by extended duration dry (desiccated) gas injection.

d) Hydraulic fracturing beyond the trapped zone (providing a suitable fracture fluid which does not aggravate existing damage problems can be formulated).

Laboratory Techniques to Evaluate the Potential for Water Trapping Phenomenon

Recent developments in laboratory special core analytical techniques have made it possible to ascertain formation sensitivity to aqueous trapping and to evaluate and optimize potential fluid systems for use in the field. Ideally, laboratory tests should duplicate reservoir conditions of temperature, pressure and overburden pressure as closely as possible. Aqueous trapping tests can follow a number of different types of procedures, but the most common is as follows:

a) Obtain samples of representative reservoir core material. Full diameter samples may be required if the formation is particularly heterogeneous. Preserved state core samples (at the correct S_{wi}) or restored state core samples at correct initial oil and water saturations must be utilized for oil reservoirs and core material at the correct initial S_{wi} (or S_{wi} and S_{oi} if liquid hydrocarbons are present) must be utilized for gas reservoirs. Specialized handling and restoration techniques must be utilized to obtain the correct initial sub-irreducible saturations which are important in quantifying aqueous trapping effects.

b) Aqueous phase saturation is gradually introduced by precisely metering and dispersing fluid throughout the sample. Permeability measurements to humidified equilibrium gas or oil are measured at specified saturation levels to note how increasing water saturation reduces relative permeability.

c) Once the irreducible water saturation is exceeded, mobile water begins to be produced from the core. This allows us to ascertain the difference between the initial permeability at S_{wi} vs. the apparent permeability which will result at S_{wirr} if the reservoir is contacted by an aqueous phase.

Using this type of methodology, a figure similar to Figure 1 can be generated for any particular system. This will provide an indication of the severity of the effects which may potentially be expected due to an aqueous phase trap and the value of the true S_{wirr} in comparison to the initial S_{wi}. Good initial S_{wi} data are crucial and are best obtained from analysis of oil based core or log data where a combination of deep/shallow induction logs indicate that near wellbore flushing effects have not affected the values of the log measured water saturations. Data from water based cores and wells which have experienced extensive and deep fluid invasion or data from conventional relative permeability or capillary pressure tests may yield artificially high estimates of S_{wi} in some cases and should be utilized with caution.

Once an aqueous phase trap is established, additional laboratory tests can be conducted to simulate various types of stimulation treatments (i.e., mutual solvent and CO_2 flood) which may be attempted on a damaged zone to ascertain the effectiveness of these techniques prior to the expense and risk of their implementation in the field.

Figure 5 provides a schematic of the typical lab apparatus utilized for these types of experimental studies.

Field Case Studies

Case #1 – Paddy Formation

a) Reservoir Description – The Paddy "A" gas reservoir, Figure 6, in the Deep Basin area of west central Alberta, has a history of extensive formation damage among the most prolific wells in the zone. While undoubtedly many factors contribute to this problem, only recently has the importance of aqueous entrainment to formation damage in the Paddy been identified.

Discovered at a depth of 1,700 m in the late 1970's, the pool has been on production since 1980 and has produced in excess of 4,200 x $10^6 m^3$ of gas to date. Characteristic of the Deep Basin, the zone was initially under pressured at an original reservoir pressure of 12,500 kPag. The formation reaches thicknesses of 25 m with an average porosity of 15%, water saturation ranges from 10 - 25%, and in situ permeabilities have values up to 800 mD. Production is sweet gas with an average methane content of 85%. A typical log profile of a well in the zone is presented in Figure 7.

In its geologic setting, the Paddy formation comprises a number of stacked, tidal and fluvial channel-fill deposits within an estuarine bay complex. The Paddy "A" pool consists of a thick accumulation of clean, uniform, well sorted medium-to-coarse-grained sands deposited under a characteristic high energy environment. The sands consist of over 90% quartz with associated cherts, calcite and minor amounts of diverse clays.

b) Previous Field Experience – During 1980, Canadian Hunter drilled four wells in the main pool with a fresh water gel chem system. Drill stem tests across two of the wells (10-6-72-11 W6

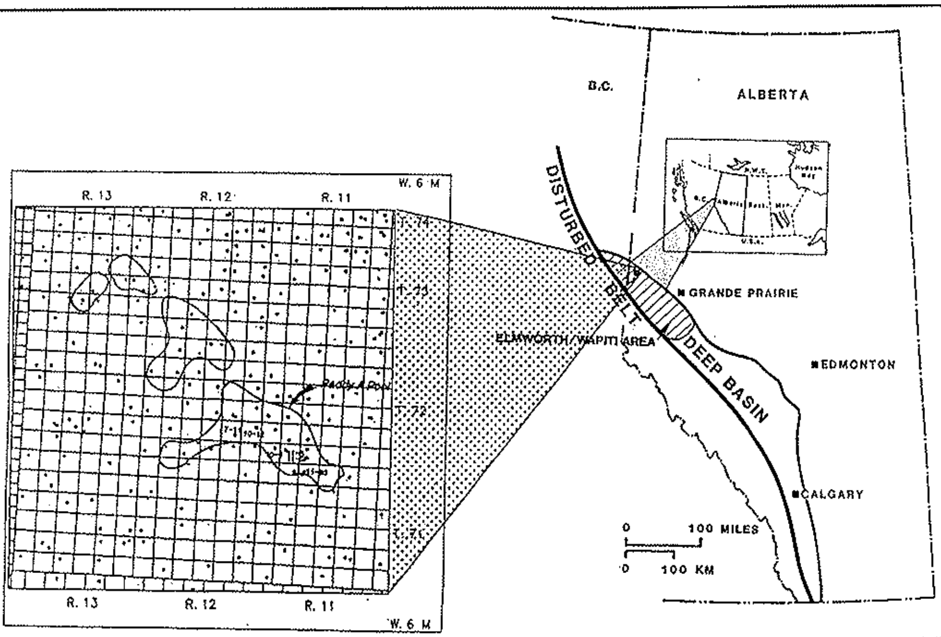


FIGURE 6: Paddy "A" gas pool outline.

and 10-12-72-12 W6) indicated little significant damage to the zone while a third well (11-5-72-11 W6) showed substantial damage with a calculated skin value of +28. Notably, the 11-5 well demonstrated considerable cleanup and had not achieved a stabilized rate over the two hour main flow. The fourth well (7-11-72-12 W6) encountered a mechanical problem during the drill stem test and could not be analysed. However, significant damage would not have been expected as the well DST'd a stable 155 x 10^3 m^3/d at an 800 kPag drawdown with no fluid recovery.

Subsequently on completion, the four wells were hydraulically fractured with 23 tonne treatments using a gelled KCl water system. Post frac production testing revealed consistently high induced formation damage across the fractures, with calculated apparent skin factors ranging as high as +51 in the 7-11 well. Multiple rate testing across the 7-11 and 10-12 wells revealed that only a minor portion of the skin effect was due to turbulence. For the 7-11 well, in particular, the calculated skin was effectively the true skin.

The wells were subsequently placed on production and further workover attempts were limited to reperforating with marginal success. By the fall of 1985, a redrill of the 11-5 location was approved and the twin 11-5 well was air drilled to the base of the zone. Upon production testing, the redrill had again been damaged through the Paddy, calculating an apparent +30 skin from buildup analysis. By contrast to the previous wells, however, the skin effect was determined to be dominated by turbulent flow with a true skin of +4. The damage induced by air drilling consequently appeared to be related to an effect of fines plugging within the formation as contrasted to the previous fluid entrainment phenomenon.

The following year in early 1986, a sixth well (11-33-71-11 W6) drilling an uphole target was extended to the Paddy off the southeastern flank of the established pool. The well encountered a prolific sand in a new lobe 800 kPag below the original pool pressure but still 5,200 kPag above the average pool pressure to the northwest. Again drilled with an aqueous gel chem system, a DST upon penetration demonstrated a moderate skin effect of +6.5 which may likely have been dominated by turbulence at the test flow rate of 350 x 10^3 m^3/d. In an attempt to minimize further invasive damage, casing was run to depth but cemented above the Paddy leaving the zone open hole behind pipe. The casing was subsequently perforated underbalanced through tubing and tested at a rate of 460 x 10^3 m^3/d with a true skin of -3.3. This experience with the 11-33 well dramatically demonstrated the sensitivity of the Paddy to aqueous fluid invasion.

c) Laboratory Design Program – Recognizing the broader significance of fluid entrainment problem (in particular with respect to the water blocking effect in the deeper Cadomin formation within the Deep Basin), a program of laboratory studies was initiated in 1990 to further research this phenomenon and develop appropriate solutions. A pure hydrocarbon based drilling fluid was developed with the dual objectives of minimizing overbalance to limit fluid invasion while drilling and eliminating water from the system.

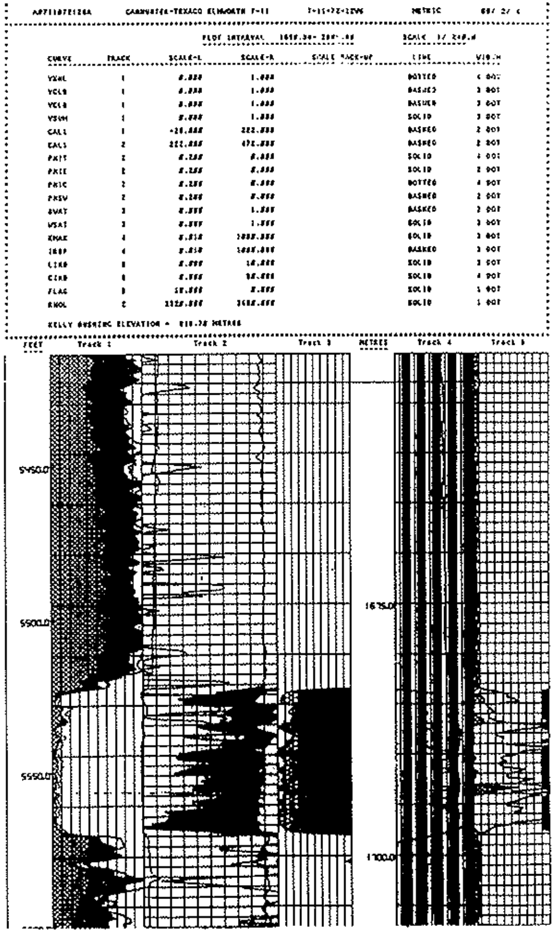


FIGURE 7: Composite log analysis for 7-11-72-12W6M.

Coreflood studies were subsequently extended to the Paddy

TABLE 4: Paddy coreflood permeability summary.

Test Phase	S_w	S_o	S_g	Measured Permeability	
				$(\mu m)^2 \times 10^{-3}$	(mD)
Initial Bench Air Permeability ($S_w = 0.0$)	0.000	0.000	1.000	103.0	104.0
Initial Brine Permeability ($S_w = 1.000$)	1.000	0.000	0.000	45.0	45.6
Gasflood Terminal Permeability (at initial S_{wr})	0.447	0.000	0.553	13.3	13.5
Internal Pore Depressurization (to reduce S_{wr})	0.431	0.000	0.569	-	-
Gas Permeability (at new S_{wr})	0.431	0.000	0.569	17.6	17.8
Fracture Oil Displacement	0.431	0.521	0.048	-	-
Gasflood Terminal Permeability	0.431	0.085	0.484	15.3	15.5
Note: all gas/fluid permeabilities reported were conducted at full reservoir conditions of 9950 kPa and 55°C.					

formation in which core samples, restored to conditions of original reservoir pressure and temperature, were flooded with formation brine and reverse flooded with humidified nitrogen gas to measure entrainment effects. Following this, a light condensate was used in place of brine repeating the cycle to evaluate the effects of potential hydrocarbon invasion in the zone.

The results of an example run are tabulated in Table 4. Initial bench permeability of the core sample to air was 104 mD. At restored reservoir conditions, single phase permeability of the core sample to brine measured 45.6 mD (which equates to the single phase gas permeability at reservoir conditions). Upon reverse gasflood to equilibrium, the relative permeability of the sample to gas is reduced to 13.5 mD with an accompanying residual water saturation of 44.7%.

In a further attempt to reduce the entrained water saturation, the core was subsequently pressure pulsed (rapidly depressurized to 0 kPag and then repressurized). The endpoint water saturation showed only a marginal reduction to 43.1% and a slight permeability increase to 17.8 mD.

Originally, from DST and log analysis of the cored well, formation water saturation was evaluated to average 10% while near wellbore in situ permeability calculated to 39 mD. Consequently, the effect of induced water invasion would appear to create in the order of a four and one half fold increase in connate water saturation held by the core with a corresponding two-thirds reduction in relative gas permeability. The substantial magnitude of this effect is, similarly, in proportion to the reduced flow efficiency observed in the original four post-fractured wells.

At the higher residual water saturations established in the core sample above, further flooding with the light hydrocarbon resulted in a reverse gasflood condensate saturation of 8.5% with a corresponding 13% permeability reduction to 15.5 mD. This relatively benign effect of the hydrocarbon phase on the return permeability was consistent with earlier results in developing the previously mentioned non-aqueous drilling system.

d) Field Application – In ensuing development within the Paddy formation, this oil based drilling fluid was utilized. Each well was drilled to the base of the zone with the oil based mud and terminated as an open hole completion removing any contact to the formation with water. The first three wells drilled in the program encountered reservoir with formation permeabilities of 46, 169 and 167 mD and respective flow capacities of 410, 680 and 1100 mD-m. Corresponding skin values of +4.5, -1.1 and +8.9 at flowrates of 340 x 10^3, 350 x 10^3 and 420 x 10^3 m^3/d respectively were again likely dominated by turbulence.

Within the same time period, a fourth well in the area was drilled through the formation with a flocculated water, gel chem system to a deeper target. From an initial DST, the reservoir displayed a permeability of 40 mD, 350 mD-m flow capacity and an apparent skin of +12.2. The zone was subsequently cased, perforated under a water column, flow tested and it was determined that a remedial cement squeeze would be required to isolate an adjacent water bearing zone.

The pay interval was then completed using an innovative penetrator tool drilling eight radial laterals with the hydrocarbon system. Both post cleanup flow rates, prior to and after the penetrator workover, were identical. However, from further post completion flow testing, comparable reservoir parameters of 53 mD and 420 mD-m for the formation were again masked by invasive damage calculating in excess of a +50 skin value.

The above field experience with the Paddy formation has contrasted several examples where aqueous invasion of the zone has been a dominant factor in the final productivity analysis. Where an aqueous drilling system has been used, initial DST results have shown a range from essentially none to smaller amounts of invasive damage. This might be attributed to the filter cake building properties of the mud system designed to minimize fluid loss.

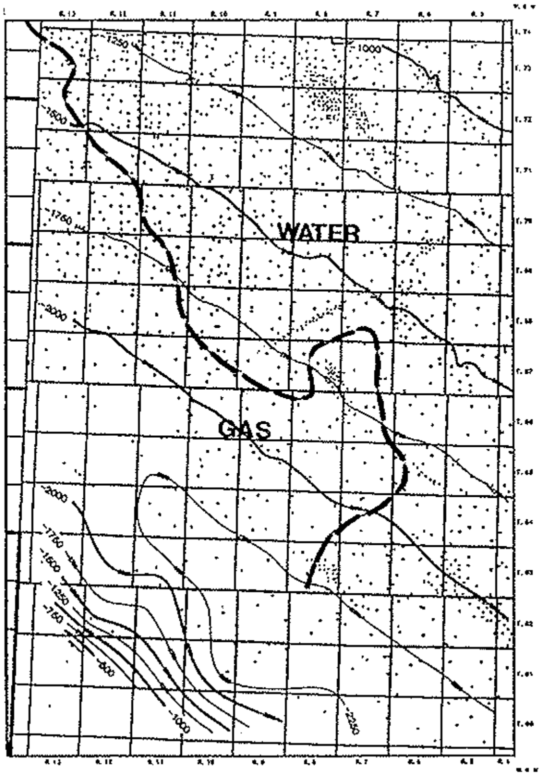


FIGURE 8: Cadomin regional water/gas contact.

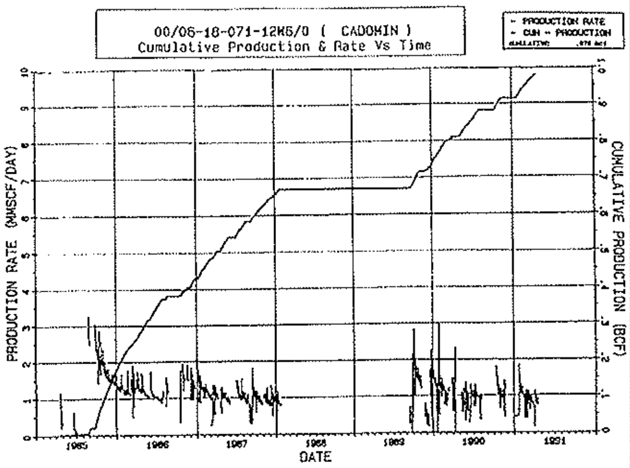


FIGURE 9: Production profile for a vertical cadomin well.

Alternately, where an exposed aqueous system has been otherwise employed (i.e., highly invasive hydraulic fracturing treatments), it would appear the damaging effects are pronounced.

Case #2 - Cadomin Formation

a) Reservoir Description – The Cadomin formation in the Deep Basin area of west central Alberta is unusual in that up dip, regionally pressured, water overlies down dip, under pressured gas (Figure 8). The zone is a regionally extensive, highly heterogeneous, sandy conglomerate deposited from multiple alluvial fans originating from the mountains to the west and later reworked by a crosscutting braided stream sourcing additional material from the southeast. In contrast to the Paddy formation discussed previously, the Cadomin presents a case study for a markedly lower permeability reservoir displaying similar, pronounced aqueous entrainment effects.

Currently, in excess of 100 x 10^9 m^3 of gas in place have been delineated by vertical penetrations demonstrating matrix permeabilities in the micro to 10 millidarcy range overlain with a natural fracture system. The zone is comparatively thin, averaging 6 m in thickness, with a corresponding 5-6% porosity, 20% water saturation and 20,000 kPag reservoir pressure at an average depth of 2,450 m.

The gas accumulation is believed to have been generated during a period of deep burial from southeastern coals that may have released in excess of 8 x 10^{12} m^3 of gas. Over time, this volume subsequently migrated hundreds of kilometers to northwestern outcrops displacing water updip to the water/gas transition and concurrently desiccating the formation below an equilibrium connate water saturation. With following uplift, erosion and cooling, the zone is presently both undersaturated and underpressured. In addition, a variation of decreasing pressure at datum is demonstrated ranging from the southern area of source coals to the northwestern outcrop indicating the system remains in a dynamic state of gas migration(12).

b) Previous Field Experience – Experience with a number of vertical wells brought onstream in the early 1980's typified the production characteristics for the zone as illustrated by the daily production history for an example well of Figure 9. In general, production rapidly declines from an initial rate ranging from 30 - 180 x 10^3 m^3/d to within 20 - 35% of this initial rate within several months.

While pressure readings within the first few months of shut-in indicate single well reserves between 15 - 70 x 10^6 m^3 from material balance evaluation, pressure buildup data across several years can often be extrapolated to original reservoir pressure supporting the extensive, lower permeability deposit as mapped. The drainage volume accessed on the shorter time scale, however, often averaged significantly less than the mean 110 x $10^6 m^3$ volume mapped across a single section spacing unit indicating tighter vertical well control would be required to adequately drain the formation.

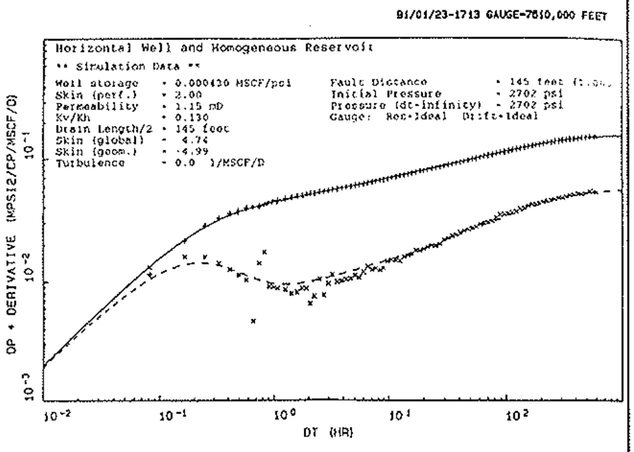


FIGURE 10: Cadomin horizontal well pressure build-up analysis.

Confirming earlier petrographic and geological studies, the wide variability in rate and pressure buildup response among the vertical wells in the zone suggested an extremely heterogeneous reservoir environment across a scale as small as several tens of metres. Rationalizing the production profile observed, a vertical penetration in the zone might rapidly drain a localized pod of higher permeability reservoir with the surrounding tighter matrix controlling the longer term inflow (dual porosity response) complicated by variations in reservoir geometry. What would be required to more effectively drain the formation would be some form of a highly conductive, deeply penetrating completion.

Traditionally, the majority of completions across the Cadomin were limited to multistage, balled acid treatments often taken to near the 42 MPa breakdown pressure of the formation. From experience, this stimulation generally achieved comparable results to propped hydraulic fractures which suffered from a number of anomalous problems. Of the numerous hydraulic fracture designs attempted, roughly half prematurely reached casing strength pressure limitations in the range of 65 MPa while almost all showed very poor conductivity irrespective of the proppant volumes placed. The greater majority of these fractures were run with an aqueous frac fluid, most often a gelled water/methanol system.

Given the history of associated problems and limitations with hydraulic fracturing in the Cadomin, in 1989 Canadian Hunter experimented with the drilling of a 285 m horizontal well in the zone. In addition to the advantage of providing extended access to the reservoir, horizontally drilling through the formation added the dual advantages of providing control over the orientation of the well (perpendicular to the direction of induced and potential natural fractures governed by the regional stress environment) and obtaining direct data on the properties of the penetrated formation.

The well was drilled with an aqueous mud system utilizing calcium carbonate as a bridging agent to offset the 5,500 kPag overbalance of the static mud column, and completed open hole with an uncemented liner over the horizontal zone. The well encountered 210 m of horizontal pay interval from log analysis. The presence of natural fractures perpendicular to the well trajectory was also confirmed from the interpretation of both a formation microscanner log and production testing.

Subsequent to rig release, the well was acidized and flowed to cleanup at an initial rate of 110 x $10^3 m^3/d$, comparable to the performance of an immediately offsetting vertical well within the spacing unit and consequently considerably below expectations. In ensuing operations on the well to identify the basis of this apparent anomaly, it became evident that significant fluid losses to the formation were experienced, particularly in kill operations using KCl water prior to reconfiguring downhole tubulars. The reservoir displayed a marked tendency to imbibe water resulting

TABLE 5: Cadomin coreflood permeability summary.

Displacement Phase	Saturation			Permeability		Relative Permeability
	S_o	S_w	S_g	$(\mu m)^2 \times 10^{-3}$	(mD)	
Air @ 20°C, 1,380 kPag	0.000	0.000	1.000	3.8	3.9	-
Air @ 82°C, 27,580 kPag	0.000	0.000	1.000	0.16	0.16	-
Brine	0.000	1.000	0.000	0.175	0.177	1.000
Reverse Gas	0.000	0.520	0.480	0.054	0.055	0.310
Raw Escaid-90 @ 2,760 kPa	0.721	0.210	0.069	-	-	-
Raw Escaid-90 @ 4,140 kPa	0.753	0.180	0.067	-	-	-
Raw Escaid-90 @ 5,520 kPa	0.774	0.160	0.066	-	-	-
Raw Escaid-90 @ 6,890 kPa	0.784	0.150	0.066	-	-	-
Reverse Gas	0.090	0.150	0.760	0.142	0.144	0.814

in a significant reduction in the permeability to gas.

c) Laboratory Design Program – In order to further investigate this behaviour, a program of laboratory coreflood studies was undertaken at reservoir conditions in an attempt to simulate the downhole processes. The coreflood testing immediately revealed a significant water entrainment behaviour in the Cadomin. From leakoff tests conducted on full diameter core mounted to measure vertical permeability across the zone (Table 5), bench Kv to air was 3.9 mD (Kv measured was approximately 0.5 Kh_{max}). At restored reservoir conditions, the in situ single phase core permeability to either air or formation brine decreased to 0.17 mD. However, upon reverse gas flooding the brine saturated core, entrained water saturations in excess of 50% were observed after stabilized flow periods, reducing the core permeability by two-thirds to 0.055 mD. By contrast, this residual water saturation is a 2.5 fold multiple of the formation water saturation established from logs. The magnitude of this effect on the relative permeability to gas across a 0.3 m core sample provided a profound insight into the potential aqueous phase trap problem observed in the horizontal well.

In order to mitigate this entrainment effect, further lab studies were conducted to evaluate the invasive characteristics of several non-aqueous fluids. Table 5 presents the results of pursuant leakoff testing on the above core sample with a commercially refined C_{10}-C_{11} component mixture. It was observed that at increasing pressure differentials through the core, entrained water was remobilized reducing the residual water saturation in the core to in situ levels while introducing up to a 9% residual hydrocarbon saturation. Of consequence, however, the return permeability of gas in the core increased to 0.144 md, within 80% of the original single phase gas permeability. This behaviour indicated the potential for the development of a drilling fluid based on a nonpolar medium which would provide relatively benign invasive properties. In addition, the use of a water free, hydrocarbon based fluid in well operations would provide an essentially near balanced hydrostatic liquid column which would act to further minimize invasion into the formation.

d) Field Application – Upon the design and lab testing of an appropriate drilling system for this application, Canadian Hunter drilled a followup 600 m horizontal well in the Cadomin in 1991. Despite encountering an overall comparatively poorer reservoir, this well penetrated an equivalent length of thinner net pay interval to the first well and was rig released as an unlined open hole. Upon production testing, the well immediately flowed at similar rates to the first horizontal with no further stimulation efforts. Pressure buildup analysis of this well later indicated only a nominal skin damage of +2 (Figure 10) which could be expected from ancillary effects such as damage from drilling fines invasion as one example. Irrespectively, it would appear that the severe permeability reductions associated with aqueous entrainment observed in the laboratory were not evidently manifest in this second well.

The Cadomin case study has served to significantly impact the approach to field operations within Canadian Hunter from two major aspects. Primarily, attention has now been focussed on the relative importance of the aqueous entrainment effect to productivity restrictions. Secondly, the broader applicability of hydrocarbon fluid systems has become recognized in the design of various well programs, with particular emphasis on the unique characteristics of horizontal wells.

Conclusions

The laboratory and field results indicate that:

1. Aqueous phase trapping has the potential for severe productivity reductions in both oil and gas reservoirs. The magnitude of the reduction appears to be a function of:
   a) The difference between initial and true irreducible water saturation.
   b) Wettability of the porous media (oil-wet porous media generally exhibit much lower initial water saturations).
   c) Cyclic hysteresis effects caused by multiple invasion and drainage cycles of an aqueous phase.
   d) Depth of the invaded zone.
2. Case studies indicate that the use of hydrocarbon based fluids may be advantageous in certain situations where the potential for a water trap exists. However, hydrocarbon fluids may also be significantly damaging to reservoirs in situations where:
   a) Incompatibility between the invading hydrocarbon phase and formation crude oil or brine exists.
   b) Very low permeability zones are present (<0.01 mD) causing high capillary retention of either oil or water.
   c) Presence of an initial and potentially wetting liquid hydrocarbon phase (in a gas reservoir).
   d) Presence of naturally oil-wetted minerals (in a gas reservoir).
3. Properly conducted laboratory studies can provide insight into the severity of potential aqueous trapping problems and allow design and evaluation of effective drilling, completion and

stimulation fluid systems to maximize production rates and minimize costs associated with expensive and often unsuccessful stimulation treatments.

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