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Brine Imbibition Damage in the Colville River Field, Alaska

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Abstract

Early exploration well tests in the Colville River Field (also known as Alpine) drilled with water-based mud systems exhibited unexplainably high near-wellbore residual skin damage documented by pressure build-up testing. Typical formation damage mechanisms including clay reactions, mechanical damage, and gas trapping could not explain the damage.

Between March 1998 and July 2001, laboratory testing determined imbibition-induced water trapping to be the primary formation damage mechanism. Insitu water saturation is significantly lower than the residual or connate water saturation, a condition rarely encountered in the field. Lab tests quantified impacts and identified methods to minimize or eliminate formation damage. This paper documents how successful identification of a unique damage mechanism improved drilling results in a low permeability sandstone.

Introduction

Exploration drilling results in Colville River prospects consistently demonstrated higher than expected near wellbore skin damage measured by build-up test analysis. Investigations into more common damage mechanisms such as solids migration and clay swelling could not explain the damage. Early reservoir core studies indicated residual water saturations from relative permeability curves should be higher than observed initial water saturations. Later studies with traced core fluids confirmed initial water saturations were considerably less than natural connate water saturations. Further lab work confirmed the water-blocking tendency by measuring water imbibition and permeability recovery during regain permeability tests. Various drilling fluids were tested, with oil muds consistently delivering higher regained permeability than water-based fluids.

For a number of operational reasons, all wells on the first development pad (CD1) were drilled with brine-based fluids. The second pad (CD2) development team accepted the lab results and after demonstrating the potential benefits of oil-based mud drilling, convinced the Drilling team to develop and test a suitable mud program. Initial test results confirmed the lab results and conclusions when well CD2-47 came in flowing 300% more than predicted, based on equivalent brine-based mud completions in comparable pay. Following this early success, the oil mud program was expanded and has consistently delivered more productive wells in line with expectations from the lab work.

Background. The Colville River Field (also known as the Alpine Field) is located approximately 60 miles due west of the Prudhoe Bay Field on the north slope of Alaska (see Figure 1).

It contains 429 MMSTB of recoverable reserves, with approximately 1 billion barrels of oil-in-place. Production is from the Alpine Oil Pool, a very fine-grained Jurassic age shallow marine sandstone complex with stratigraphically trapped 40° API oil. The reservoir is normally pressured and undersaturated. Initial reservoir pressure is approximately 800 psia above the bubble point, and primary recovery mechanism is solution drive. Tables 1 and 2 (below) present a log and petrophysical overview as well as a summary of key reservoir properties.

The field was discovered in 1994 with drilling of the Bergschrund No. 1. Further delineation confirmed the prospect during subsequent winter seasons, and gravel pad construction began during the 1998 winter season. Field construction for the processing facilities and pipeline infrastructure commenced in the winter of 1999, followed closely by development drilling in May, 1999. The major process modules arrived in March of 2000, and first-oil was delivered in November.

The development strategy utilizes horizontal completions in a direct line drive configuration while maximizing recovery through application of pattern waterflood and miscible-water-alternating-gas (MWAG) injection.

Early Exploration Results. Following the early success of the Bergschrund No. 1 discovery well in 1994, additional wells were drilled during the winters of 1995 and 1996 to further delineate the reservoir and define reservoir properties to predict production performance. Geologic cores were collected from the two earliest cored wells, the Neve 1 and Alpine 1A. Bottomhole fluid samples were collected and analyzed. Due to the brief Arctic winter exploration season, only select wells were production tested. Upon completion of a production test, a pressure build-up test (PBU) was conducted to observe the pressure build-up response of the reservoir. Early well results indicated higher levels of formation damage than routinely observed in North Slope wells. The Table 2 lists the results from early well testing.

Flow Efficiency, F, is calculated from:

$$F = \frac{\bar{P} - P_{wf} - \Delta P_s}{\bar{P} - P_{wf}}$$

Skin as it is used here is Total Skin, including all the geometric, partial penetration, perforation, and other impacts. These early wells were essentially vertical completions drilled with a balanced brine-based LSND (low solids non-dispersed) water-based mud program, perforated over the entire reservoir cross-section. Overbalanced perforating alone could not explain the consistently high mechanical skins. The LSND mud program used had been widely accepted in similar sandstone formations across the North Slope, and contained sufficient potassium chloride to inhibit anticipated clay reactions.

When the project shifted from the Exploration to Production Team, completion engineers focused on this problem. Reservoir permeabilities ranging from 2 to 100 mD, averaging 15 mD, meant managing completion skins through controllable drilling and completion practices was inadequate. Areas for concern included:

1. Higher rates improve wellhead flowing temperatures and reduce wax buildup. Early crude samples confirmed the 40º API crude to be paraffinitic.
2. Higher rates would minimize artificial lift requirements.
3. Formation damage in the pores of low permeability rock is inherently difficult to remove.
4. Formation damage mitigation in openhole horizontal wells is extremely difficult.
5. Formation damage to injection wells limits waterflood injection rates which ultimately dictates production rates.
6. Higher rates were needed to support project economics.
7. Higher rates enhance ultimate recovery.

General Reservoir Description. The Alpine reservoir is characterized by a series of mature, well sorted, shallow marine sandstone deposits at approximately 7,000' TVDSS on Alaska's North Slope[1]. A type log is presented as Figure 2. The primary target is the Alpine "C" Sand, which is composed of two facies. The Stillstand facies is a very fine grained quartzose sandstone containing <5% glauconite with generally 3-8% matrix clay, average porosity of 19.3%, average permeability of 12 md and thickness ranging from 25 to 101 feet. Approximately 65% of the recoverable reserves reside in the Stillstand. The second dominant facies is the Transgressive, which is a very fine to fine grained sandstone with slightly coarser grain size but lower clay content averaging 1-5%, 5-20% glauconite, average permeability of approximately 30md, 20% porosity, and thickness ranging from 5-25 feet. Both facies have pore throats ranging from 1-5 microns, and median pore throats of 1 micron. Both were well sorted and bioturbated. The Transgressive sands represent the higher quality reservoir sands. The lower "A" Sand is of marginal quality, often considered non-pay, and characterized by lower clay content, permeability averaging 10 mD, average porosity 17.5%, and thickness ranging from 1 to 30 feet. Very few recoverable reserves are attributed to the "A" Sand due to the poor overall quality and scattered locations where it has been identified.

Average water saturation in the zones of interest is approximately 19%. This was initially estimated through log calculations and later confirmed through lab analysis of a preserved core drilled with deuterium ("heavy water") traced coring fluids. Reservoir wettability is mixed with a tendency towards 'oil wet' in the higher permeability Transgressive facies, and mixed with a tendency towards 'water wet' in the lower permeability Stillstand facies. Both conclusions were based on capillary pressure testing.

Laboratory relative permeability curves (Figures 3 and 4) indicate fairly suppressed initial water phase relative permeability's with water mobility being virtually zero at saturations less than approximately 40-50%. Endpoint permeability to water increases at water saturations above approximately 60% and very low residual oil saturations are obtained under waterflood indicating excellent sweep efficiency. This is consistent with a mixed wettability system.

Initial free gas saturation is zero with no active water drive or pre-existing gas cap support. Due to the absence of significant external pressure support, pressure maintenance of the Alpine reservoir is essential to prevent rapid declines in reservoir pressure.

Alpine crude is somewhat paraffinic, with a cloud point of approximately 89ºF and 2.8% paraffin content. Pour point temperature is approximately 30ºF. The solution gas is very rich, containing +31% C_2^+ which could present issues with hydrate formation in the future.

Formation Damage Mechanisms. The development team initially studied the Alpine sandstone composition looking for sensitive or reactive components. The formation is simple quartz-rich sandstone containing relatively minor amounts of clay minerals. In general, Stillstand sections contain a higher clay content ranging from 3-8%, with 30-50% of the clays being potentially reactive mixed layer illite-smectite. The higher permeability Transgressive sections generally contain 1-5% clays, with again almost 50% reactive mixed layer illite-smectite. Clays in general are well disbursed in both facies, but more so in the Transgressive. Neither contain significant quantities of clays, and the clays are too dispersed to impact the structural integrity of the matrix.

Lab studies conducted both at the company research center and outside labs concluded that a completion fluid brine of >4% potassium chloride would be reasonably inhibited, and no significant permeability reductions were observed resulting from clay reactions and swelling in lab studies. Corollary studies concluded that seawater proposed for the waterflood is similarly non-reactive. However, fresh water triggers clay reactions, which result in permeability reductions in areas of filtrate invasion. Additionally, the use of caustic or other high pH (10+) fluids results in the deflocculation of clays, particularly kaolinite, which exists in limited concentrations in the pore system. Migration of mobilized fines results in pore throat plugging. Fines generally tend to migrate in the wetting phase, which for the tight microporous clays in a mixed wetting system, tends to be water. Expectations are that oil-based drilling and completion fluids would minimize problems related to either clay floculation or mobilization. In summary, lab analysis indicated application of appropriately inhibited brines minimizes filtrate leak-off impacts on sensitive clays.

Mechanical damage refers to the invasion of extraneous solid material from drilling, completion, or kill fluids into the near wellbore region of the formation. The most common damage source for Alpine drilling operations would occur with overbalanced drilling operations, cement slurries, and filtrates in the final well completion. Typical solids associated with LSND drilling muds include natural formation solids and microfines generated by the milling action of PDC bits, and mud additives such as barite, bentonite, calcium carbonate bridging agents, or LCM materials. However, considering the relatively homogenous nature of the Alpine sandstones, relatively low permeability, small pore throat and grain sizes, and low overbalance pressures utilized during drilling, deep formation damage is not expected. The formation acts as a filter element capturing solids on the surface of the formation face. Solids invasion doesn't penetrate deeper than 1/8" – 1/4" into the formation. Normal perforating charges should penetrate well beyond any expected radius of invasion. Since the exploration wells were cased, cemented, and perforated completions, it is unlikely that the high apparent skin factors observed on these wells can be attributed to near wellbore formation damage.

Imbibition Concerns. Analysis of Alpine reservoir petrophysical data indicates very low apparent insitu water saturations relative to the permeability range. Core tests from four different wells indicate average water saturations are significantly below 30% at effective air permeability's of 1md. Even at higher reservoir permeability ranges, such as 10-50md, water saturations remain below 20%. These initial saturations are considered sub-irreducible for the permeability ranges common in the Alpine sands. For example, a conventional capillary pressure test desaturated at the average column height of the Alpine reservoir would tend to indicate a much higher irreducible water saturation. Water-oil relative permeability tests based on Alpine core indicate the irreducible water saturations from normal capillary desaturation should be in the 40-50% range. The establishment of low initial water saturation may be due to a very significant height above free water contact or possibly the mixed oil-wet nature of the Alpine matrix. Therefore, the Alpine sands exhibit a potential hydrophilic tendency to spontaneously imbibe, or under forced displacement conditions, retain potentially significant water saturations.

Water mobility is virtually zero below saturations of 40-50%. Although this creates favorable waterflood performance it's also indicative of potential phase trapping problems with water-based drilling fluids. Therefore if water-based drilling or completion fluid were displaced into the formation, capillary forces would dominate making it virtually impossible to reduce near wellbore saturations below 40-50%. As seen in the oil-water imbibition relative permeability curves above, the resulting increase in near wellbore water saturation could easily reduce the effective permeability to oil by 80-90%. This damage mechanism appears to be consistent with the apparent high skin factors observed in the early exploration wells. Early examination of induction log results identified numerous examples of noticeable separation between the shallow and deep induction profiles, indicating invasion and retention of fluids in the near wellbore region[3-8].

Additionally, water-based polymers present in drilling or completion fluids may result in physical adsorption of polymer on the rock face. There may be a propensity for Alpine oil to emulsify with certain water-based completion fluids.

Downhole precipitation of paraffin's or asphaltenes, or mechanical glazing of the formation face due to rotating or sliding the drilling string may be damaging the Alpine formation. However, in comparison to the potential damage from imbibition, it appears unlikely these would be major damage mechanisms.

Laboratory Test Results. Figure 5 provides an illustration of the coreflood apparatus that was used to conduct the Alpine reservoir coreflood studies. This apparatus was configured to allow dynamic drilling mud studies, where whole mud containing natural and artificial solids can be circulated at a desired overbalance pressure with fluid leakoff monitored, and the effect of drilling fluid invasion on oil permeability at various drawdown pressures. The equipment is also configured to allow underbalanced circulation of water-based fluids at varying underbalance pressure levels while constantly measuring the permeability to oil as water contacts the 'wellbore' face of the sample to observe capillary pressure induced water-based fluid countercurrent imbibition effects.

Table 3 summarizes the results from three countercurrent imbibition and water-based phase trap tests conducted on preserved core material obtained from well CD1-01. Sample 1-1B represents high quality Stillstand, sample 2-1B represents lower quality Stillstand and sample 3-1B represents low quality Transgressive sand facies. Examination of the data indicates that permeability to oil rapidly dropped due to countercurrent imbibition effects as water was exposed to the production face, even when an applied delta P gradient of 100 psi to oil was present flowing in the opposite direction. This indicates that the subnormal water saturation condition, coupled with the mixed wettability of the Alpine matrix, creates the potential for a strong capillary imbibition gradient which can create significant transient permeability reductions. Table 4 provides transient imbibition data for one core sample (1-1B). This data has been plotted and appears as Figure 6 and illustrates the rapid and severe reductions in oil phase permeability created by even moderately underbalanced water contact in the various Alpine facies.

Table 3 indicates that, as the level of underbalance pressure is reduced, the force counteracting the water phase imbibition also is reduced and the amount of water imbibed increases further reducing the permeability to oil. In two of the samples, at the lower underbalance pressures, sufficient water was countercurrently imbibed to exceed the water-oil capillary pressure threshold for the system creating a 100% reduction in oil phase permeability. Table 3 also indicates the application of moderate drawdown pressures using pure oil (with free water contact eliminated from the core face) was capable of regaining a portion (50-60% in general) of the lost permeability. Some residual damage was present due to permanent entrapment of imbibed water in the core matrix by capillary pressure effects. To simulate a worst case situation with overbalanced water-based mud filtrate invasion, several pore volumes of water-based mud filtrate were then dynamically displaced through the three core samples simulating a filtrate flushed region adjacent to the wellbore. This was followed by another series of return permeability measurements to oil (Table 3) to note the effect of total water-based filtrate flushing of the core matrix. It can be seen that the damage caused by water-based phase trapping was severe, with only 10-30% of the original oil phase permeability regained even after application of drawdown pressures as high as 500 psi. The increased damage is due to more thorough and deeper invasion of the core plug sample by direct water-based fluid flush in comparison to the limited invasion occurring over a relatively short time period in the countercurrent imbibition tests. Results indicate that even in an underbalanced condition, after extended periods of exposure to water, countercurrent induced damage could become very severe in the near wellbore region and may approach in magnitude those observed with direct fluid flushing which occurs during normal overbalanced drilling operations. The initial, 100 psi imbibition level, post imbibition regain perm and post overbalanced flush perms for the three samples are comparatively illustrated in Figure 7.

Table 5 illustrates the results of a series of whole drilling fluid leakoff tests conducted on better quality Stillstand formation core from well CD1-01. Table 5 includes both the classic water-based drilling mud originally used in the field as well as the new oil-based system which, since base oil is miscible and compatible with the Alpine formation crude oil, exhibits no phase trap potential. The difference in regain permeability character due to the reduction in phase trap potential and easier filter cake lift-off is dramatically apparent in this data and has been reflected in associated field performance of the Alpine completions since this work was conducted. The permeability data summarized in Table 5 have been plotted and appear as Figure 8.

Field Results. After completion of each producing well, the extent of near-wellbore damage was assessed by modeling inflow performance and wellbore hydraulics from stabilized well tests. A total skin value was determined from model matches of actual performance to quantify the level of damage in the well.

The openhole segments of development wells at CD1 were drilled and completed utilizing a drill-in mud consisting of a clarified zanthan biopolymer system in a KCl base brine. Total skin values for the wells drilled with brine muds ranged from 5 to 40, with an average of 23. Consistent with lab results, a high level of damage was observed in the wells and attributed to water retention in the near-wellbore region. Differences in rock quality appear to explain the spectrum of damage in the wells. Wells with lower skin values are generally observed in high permeability rock as shown by a sample of 10 CD1 wells drilled with brine-based mud in Figure 9. In this scenario, invaded water is more readily flushed from the near-wellbore region in the higher permeability rock due to lower capillary pressure based retention effects, thus mitigating the water block damage. In very early well tests, limited free water production is observed as new wells clean up, which further confirms the expulsion of filtrate fluids.

In contrast, wells completed in lower permeability rock display consistently higher skin values as shown in Figure 9. Reduced deliverability results in substantially longer cleanup periods. A review of well test history shows slight water production for 5-8 months as invaded water is slowly recovered from the near-wellbore region in some wells. As observed in lab studies, low permeability wells with higher relative microporosity exhibit higher capillary attraction for brine, and retain it under higher drawdown pressures. Unfortunately, the associated deliverability further reduces the formations ability to recover from brine invasion.

Six producers were drilled and completed at CD2 with brine-based polymer drill-in fluids. Damage levels in these wells were comparable to the damage levels observed at CD1. This was of particular concern since CD2 wells are generally lower permeability. Inflow performance modeling quantified the production increases expected, based on lab results with oil-based drill-in fluids. As shown in Figure 10, two inflow performance curves are described at bottomhole conditions. Assuming the well is produced at a manifold pressure of 225 psig, an AOF of 1,972 BOPD is achieved with a skin of 23, the average total skin for water-based wells drilled to date. An oil mud drilled well with a skin of 8, or 66% less damage than an average brine mud drilled well, was also modeled and shown in Figure 10. With this reduction, an AOF of 3,293 BOPD is attained, an increase of 67%. For that reason the development team introduced oil-based drilling fluids in the CD2 program. To date, 10 producing wells have been drilled and completed with oil mud at CD2. Current well performance demonstrates an overall total skin reduction in oil-mud (OBM) wells relative to the water-based mud (WBM) wells of 3.5:1.

To further illustrate the benefit of OBM, two wells were highlighted from CD2. Wells A, B, and C were completed with WBM while Well D was completed with OBM. Comparing Wells C and D geologically, both wells were completed in comparable Stillstand facies sections with approximately the same thickness (150 ft) and horizontal length (3,505 ft vs. 3,704 ft). From core taken in the offset exploration well, Neve #1, the average reservoir permeability in this area is approximately 6.5 mD. As shown in Table 6, Well D returned twice the productivity and tested oil deliverability. Appropriately Well D's skin is approximately one-third of Well C, further validating lab results via tested field results.

Unlike wells completed with brine-based drill-in fluids in low permeability intervals, water production has not been observed in Well D or other oil mud drilled wells.

Conclusions

The use of oil-based drilling fluids in the Alpine formation of the Colville River Field has successfully mitigated the water-based imbibition damage identified in the laboratory. This unique formation damage mechanism stemming from drilling in rock with water saturations below normal connate levels is not commonly observed in the field. The following conclusions can be noted:

1. Careful analysis of early core and reservoir properties can lead to the successful identification of damage mechanisms.
2. Sub-critical water saturations (in-situ saturation below connate levels) have been observed in Alaska North Slope sandstones.
3. Careful selection of drill-in fluids leads to improved completion performance.
4. Waterflood breakthrough can be expected to reduce wellbore relative permeability as near wellbore formation water saturation increases.

Remedial treatments which successfully remove near wellbore bound water can be expected to improve performance of early wells drilled with brine-based muds.

Acknowledgments

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The interpretations and conclusions presented in this paper are those of the authors and do not necessarily reflect the opinions of ConocoPhillips Alaska, Inc. or its copartners in joint ventures.

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Table 1. Alpine Reservoir Average Parameters

Recovery, MBO	429
OOIP, MMBO	1,000
Area, acres	40,000
Depth, fee Subsea	7,000
Average Net Pay, feet	50
Average Porosity, %	19
Average Oil Saturation, %	80
Average Permeability, md	15
Oil Gravity, API°	40
Initial Reservoir Pressure, psi	3215
Bubble Point Pressure, psi	2454

Table 2. Alpine Initial Well Test Damage Analysis (Drilled Using Water-Based Mud

Well I.D.	Permeability mD	Total Skin	Flow Efficiency %
1	56.4	10.6	40.3%
2	4.5	16.9	30.9%
3	6.6	28.9	17.0%

Table 3 – Water Spontaneous Imbibition/Phase Trap Test Results for Various Alpine Reservoir Rock Facies (Using Solids Free Water-based Mud Filtrate)

Rock Type	Sample No.	Baseline Oil Perm ΔP	Oil Perm During Imbibition			Post Imbibition Perm @ Drawdown	Drawdown	Post-OB Pulse Perm @ Drawdown	Drawdown
		100 psi	100 psi	30 psi	5 psi				
		(mD)	(mD)	(mD)	(mD)	(mD)	(psi)	(mD)	(psi)
1	1-1B	1.831	0.211	0.000	0.000	0.766	500	0.278	500
2	2-1B	1.887	0.673	0.000	0.000	0.908	100	0.621	100
3	3-1B	1.601	0.692	0.415	0.395	1.186	100	0.178	500

Table 4: Illustration of Pressure/Time Dependant Countercurrent Imbibition Effects for a Typical Alpine Core Sample

Core No.		1-1B	Rock Type					1
Depth (ft)		7118-7119	Porosity (%)					21
Imbibition Phase								
100 psi			30 psi			5 psi		
Cuml Time	Oil Flow Rate	Oil Perm	Cuml Time	Oil Flow Rate	Oil Perm	Cuml Time	Oil Flow Rate	Oil Perm
(min)	(cc/min)	(mD)	(min)	(cc/min)	(mD)	(min)	(cc/min)	(mD)
26	19	1.784	10	0.20	0.063	10	0.00	0.000
87	8.85	0.831	30	0.00	0.000	30	0.00	0.000
135	3.75	0.352	60	0.00	0.000	60	0.00	0.000
246	2.7	0.254	90	0.00	0.000	90	0.00	0.000
288	2.40	0.225	120	0.00	0.000	120	0.00	0.000
382	2.30	0.216	180	0.00	0.000	180	0.00	0.000
552	2.25	0.211	240	0.00	0.000	240	0.00	0.000
644	2.25	0.211	300	0.00	0.000	300	0.00	0.000

Table 5: Comparative Whole Water and Oil-based Drilling Fluid Performance in Alpine Stillstand Facies Sandstones

Sample I.D.	Depth Ft	Mud Type	Initial Oil Perm (mD)		Fluid Leakoff During Mud Exposure cc	Post Mud Oil Perm (mD)		% Reduction in Oil Perm
			5 psi DD	100 psi DD		5 psi DD	100 psi DD	100 psi DD
2B-4	7112.8	H20 Base	6.69	4.57	1.4	0	0.45	-88.7
2B-3	7112.7	H2O Base	3.76	3.73	1.9	0	0.8	-78.6
2B-1	7112.5	Oil Base	5.69	5.05	0	3.08	5.04	-0.6
2B-2	7112.6	Oil Base	1.65	1.81	0	1.6	1.8	-3.5

Note: Exposure period consists of mud at 500 psi overbalance and 14-day shut-in under mud.

Table 6: Alpine Well Flow Properties: OBM vs WBM

Well	Mud	Qo (BOPD)	FTP (psig)	Perm (mD)	PI (STB/D/PSI)	Skin
A	WBM	4,950	292	24.5	4.9	13
B	WBM	3,006	215	17.7	1.5	33
C	WBM	1,694	234	6.6	1.0	22
D	OBM	3,256	293	6.4	1.9	8

Figure 1: Alpine Area Field Locations

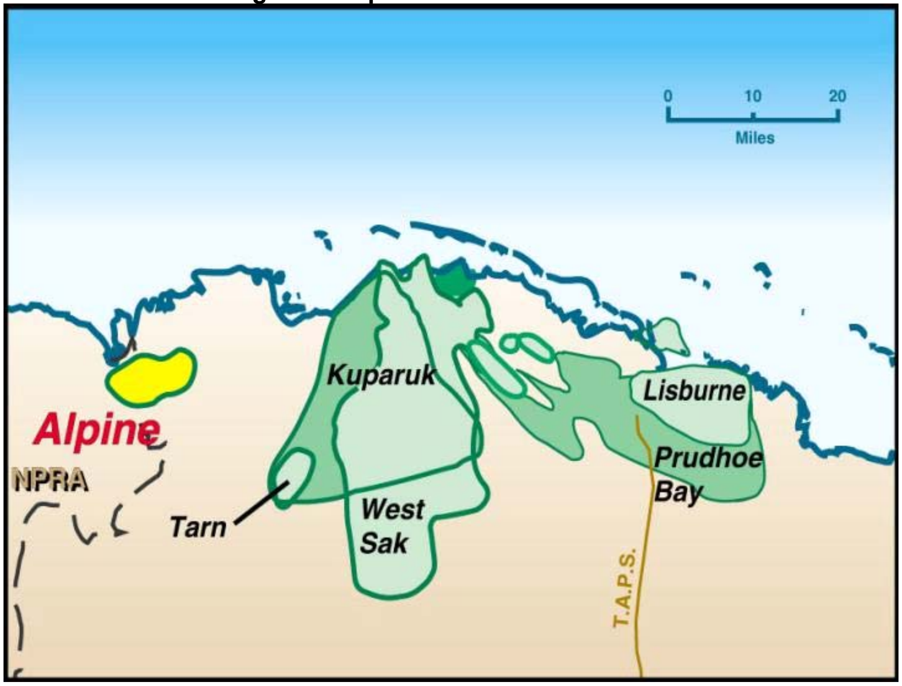
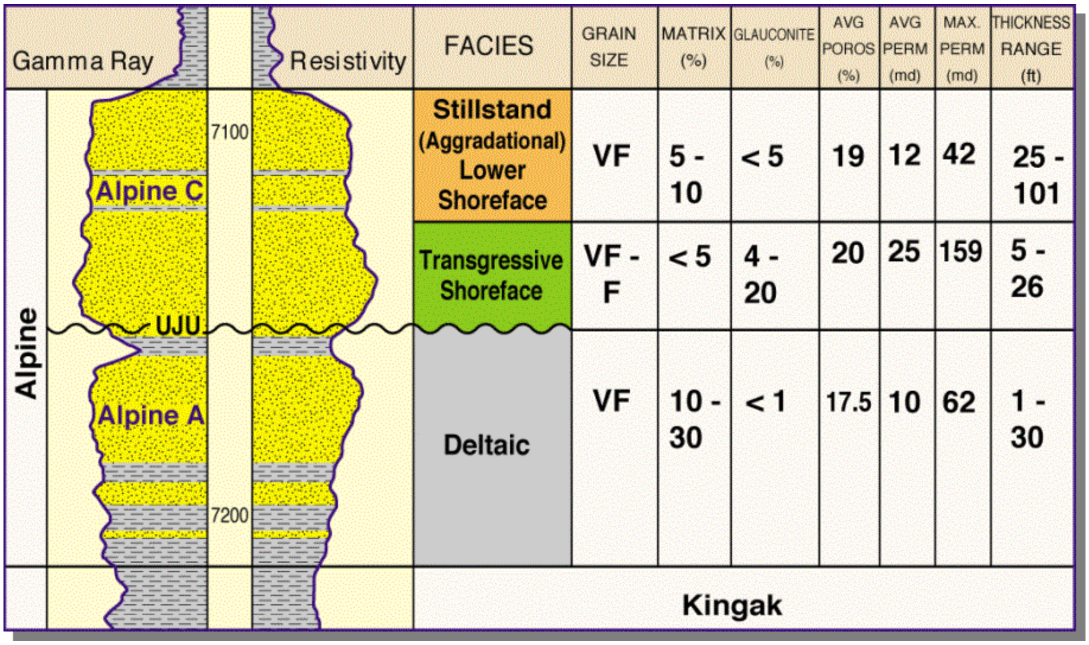


Figure 2: Alpine Type Log



FACIES	GRAIN SIZE	MATRIX (%)	GLAUCONITE (%)	AVG POROS (%)	AVG PERM (md)	MAX. PERM (md)	THICKNESS RANGE (ft)
Stillstand (Aggradational) Lower Shoreface	VF	5 - 10	< 5	19	12	42	25 - 101
Transgressive Shoreface	VF - F	< 5	4 - 20	20	25	159	5 - 26
Deltaic	VF	10 - 30	< 1	17.5	10	62	1 - 30
Kingak							

Figure 3: Alpine Stillstand Formation Oil-Water Relative Permeability Curves

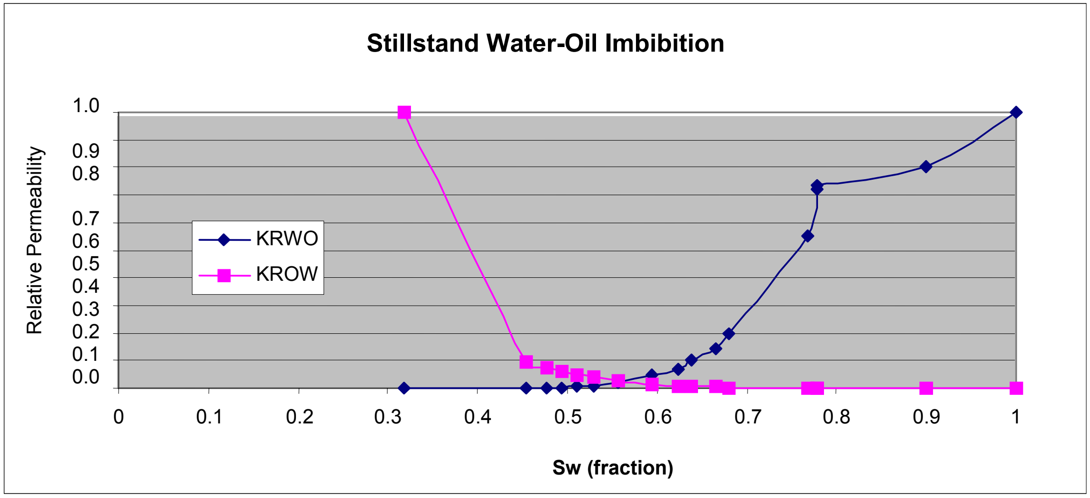


Figure 4: Alpine Stillstand Formation Transgressive Water-Oil Relative Permeability Curves

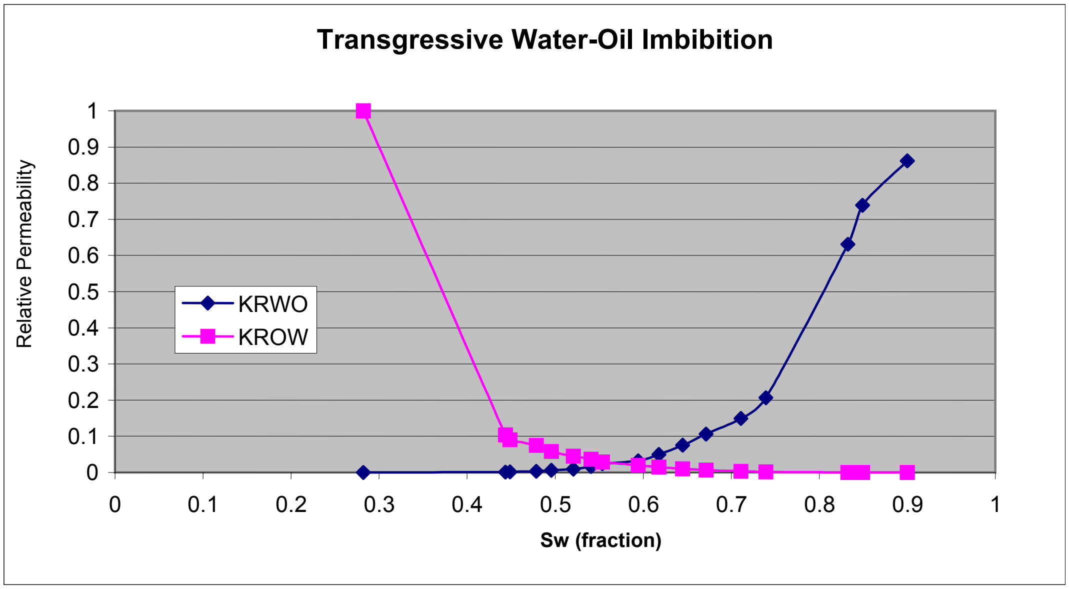


Figure 5 – Alpine Whole Mud Leakoff and Countercurrent Imbibition Apparatus

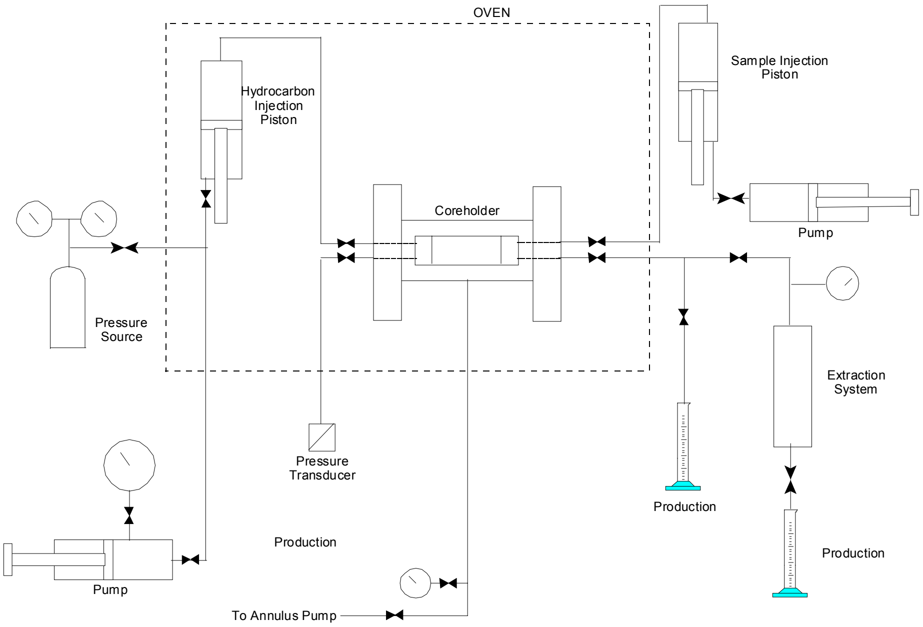


Figure 6 – Sample 1-1B Illustration of Water Countercurrent Imbibition Effects on Permeability to Oil at 100 psi Drawdown Level

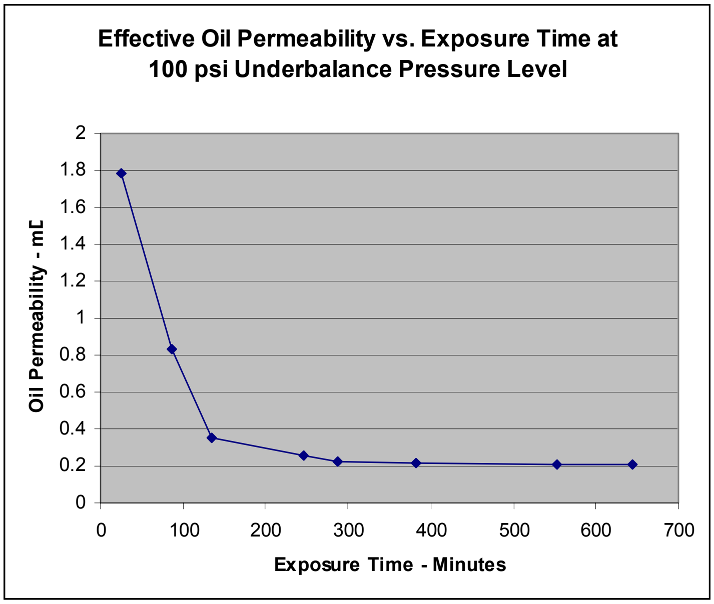


Figure 7 – Comparison of Alpine Water-Based Countercurrent Imbibition and Phase Trap Test Results

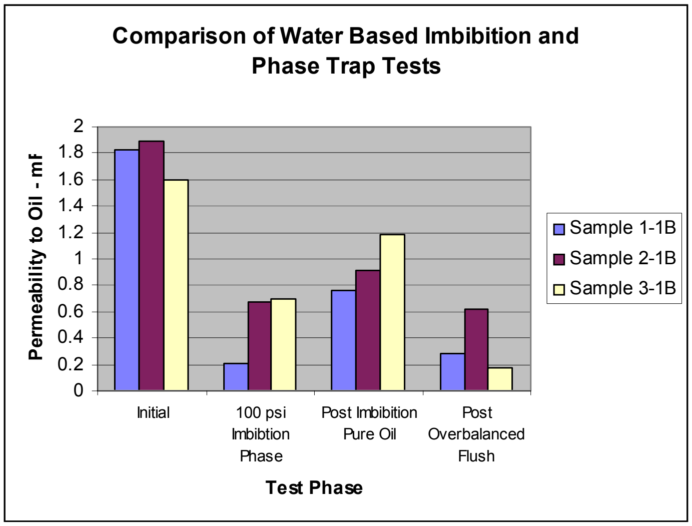


Figure 8 – Comparison of Alpine Stillstand Whole Water and Oil-Based Drilling Fluid Leakoff and Regain Permeability Tests

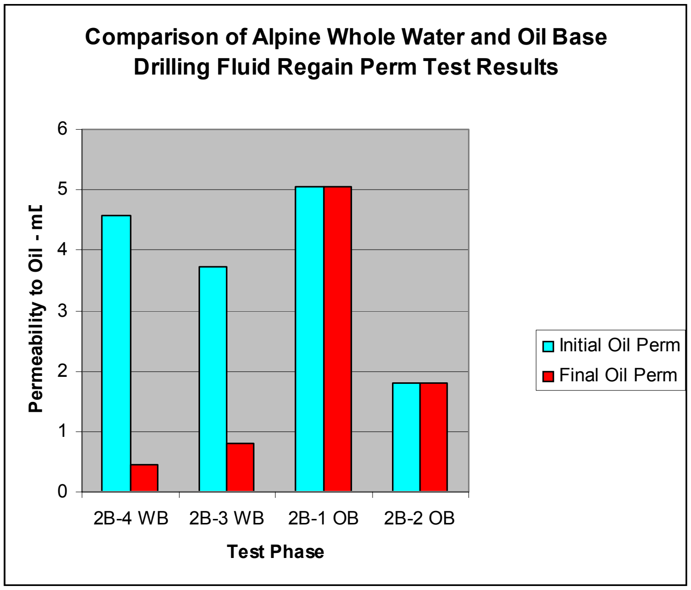


Figure 9: Alpine Water-Based Drilled Wells

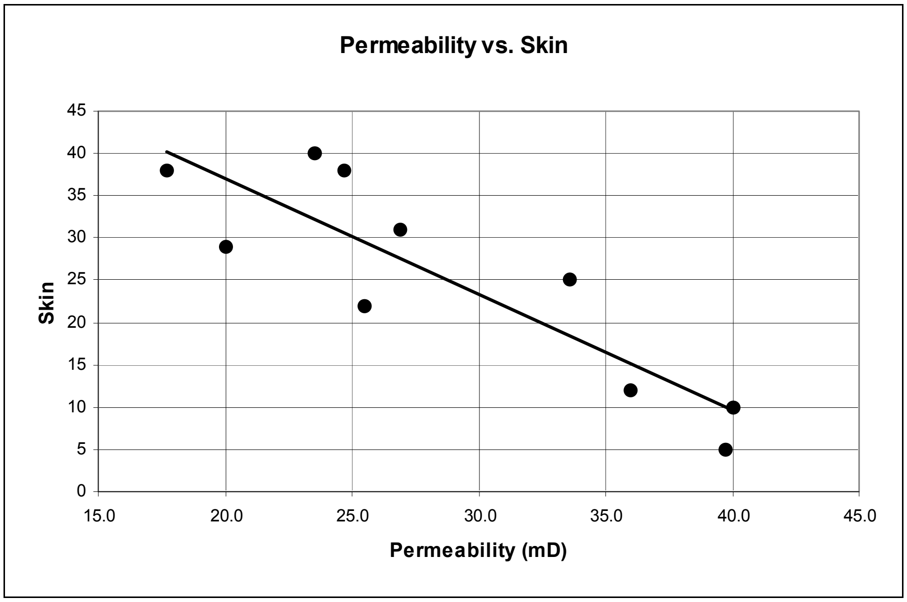


Figure 10 – Inflow Performance Relationships of OBM vs WBM