Permeability Correlations for Carbonate & Other Rocks

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ABSTRACT

Carbonate rock systems have large variations in both the quantity of pores and in the ability to flow. This makes it difficult to find productive zones without excessive tests in non productive strata. Such variations in pore fabric may be why carbonate systems lack a generally reported permeability equation. Connate water, S_{wc}, and porosity, ϕ, are typical parameters for defining productive potential of a pore fabric. Connate water is residual water held to pore walls by combinations of weak molecular and capillary forces. Unless a zone is shown to contain oil at irreducible water saturation, S_{wc}, then a means of estimating S_{wc} must be used. The Bulk Volume Water parameter, $BVW=\phi S_{wc}$, estimates S_{wc} or minimum mobility ratio by porosity and lithology.

The form: k (md) $=10\phi^{1.5}(1/Swc - 1)^{1.9}$ (if k calc exceeds 200, use 1, not 10) improves description of potentially productive carbonate zones. Figure 1 shows permeability and core porosity and some predicted permeability values. By definition, rocks with S_{wc} of unity cannot be productive. Frequently, permeability estimation equations use the form: $\phi^n/(S_{wc})^m$, which calculate a finite permeability at S_{wc} of 1. This is not physically possible. Such equations are inaccurate at high connate water and low permeability points of Figure 1. This proposed permeability equation is 93% effective at predicting producible zones and 83% efficient in zones with k under 1 md, for this set of core data, Table 3.

A unique rating system for lower productive limits of carbonates, is given in Table 5. Mobility values at or above: BBL/AcFt = $1140BVW^{0.48}$ are prospective deposits. Mobility values falling at or below $568BVW^{0.434}$ are unlikely productive, without secondary porosity. A cut point between productive and non productive carbonates is suggested at: $780BVW^{0.44}$. If lithology cannot be ascertained, mobility values under 140bbl/acft defines over 90% of caprocks, see text for details.

Figures 2 and 3 show S_{wc} correlates to pore diameter as: d(microns) $=0.123/S_{wc}$. The molecular basis is expounded in appendix. This correlation appears valid in either carbonate or sandstone rocks. This inverse relationship makes it problematic to use S_{wc} as a correlating parameter for Vuggy carbonates or coarse grained sands. This is detailed by capillary theory applied to synthetic pore space and a plot of core data, Figure 10 and upper line of Figure 9. The inverse relation of S_{wc} and pore size begs an unjustified accuracy of well logging tools to detail large pores.

For a given lithology, and over a limited porosity range, it is common to express permeability based on porosity alone. Conversely, if porosity is uncertain, S_{wc} can be used as a single correlation parameter for permeability. Craft & Hawkins showed S_{wc} alone could be used to estimate permeability within a given area, Table 2. For a given rock type, S_{wc} alone, adequately correlates permeability, see Figure 9 of core S_{wc} vs. permeability. This is possible because each lithology is considered to have a limited range of BVW and where, permeability correlations are given in terms of porosity, it is possible to substitute BVW/S_{wc} for porosity, given lithology.

Finally, the method was applied to evaluate the upper Ordovician section of western Latvia. This evaluation, proposes to classify the upper Ordovician oolitic limestone section as a leaky carbonate cap rock, which in some places is underlain by a thin (<1 m) sucrosic potentially productive layer, Table 11. This idea is based on S_w calculation, core data, re-calculation of Horner test data for well flow; and lack of liquid hydrocarbon accumulation with occasional gas shows in the immediately adjacent Silurian section, Sil.-r/m, Table 9 and 11.

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Abstract:

Table Summary

Figure Summary

APPENDIX

1.1 Introduction

Choquette and Pray stated, "to illustrate the danger of reasoning –about carbonate pore systems- by analogy, consider a comparison between the pore system of a sucrose dolomite composed of siltstone size rhombic dolomite crystals and that of a slightly cemented quartz siltstone (5 to 50microns). The size shape and sorting of component crystals or particles may be very similar in the two rocks, and superficial analysis would suggest their pore geometries and hence their fluid flow properties might be comparable. But there must be some basic differences in these pore systems. Few quartz siltstones are oil productive, and those which constitute oil reservoirs, have grain sizes near the upper end of the silt size range (60um) However, many petroleum reservoirs produce from dolomites with intercrystal porosity that is no more abundant and superficially is no coarser than that of non productive siltstone. In fact, several dolomite petroleum reservoirs produce from intercrystal porosity in which the crystals are in the smaller silt sizes, some as small as 10um or less. The good reservoir qualities of such microcrystalline dolomites might not be anticipated if one relied solely on knowledge of porosity characteristics of their apparent textural analogs, the siltstones." and,. "Most sedimentary carbonate rocks have very little porosity, but the minority that contain more than a few percent pore space (5% to 15% common in reservoir facies) is collectively of immense economic importance. Porous limestone and dolomite faces contain about ½ the world's known oil reserves." They go on to state: 'core analysis are commonly inadequate for reservoir evaluation; permeability porosity interrelations are greatly varied and commonly independent of particle size and sorting, fracture facies are important components to overall permeability, when present, visual evaluation of porosity & permeability range from easy to virtually impossible, with capillary pressure analysis commonly needed. This last comment by C&P is contrasted to Teodorovich, Aschenbrenner, and Chilingar, and Archie who all proposed visual systems to evaluate porosity and permeability relationships.

Robinson said, "porosity and resulting production from Vuggy limestone (L/S) is so varied, that it is difficult to make meaningful generalizations. However, experience has shown: 1) Vuggy L/S commonly is a prolific initial producing reservoir, 2)porosity development is of limited extent, 3) total porosity is generally not great, unless the producing interval is extremely thick or unless other factors, such as fracturing is involved, 4)Vuggy L/S can be found in almost every limestone province, 5)rocks of this type account for large amounts of production in L/S reservoirs .

With this varied background, the objective of this discussion is to define a system to minimize over looking potential productive zones, while testing the fewest possible non productive zones, using well log data of porosity and resistivity.

1.2. Porosity Fabric Classification

Teodorovich was perhaps first to develop a classification system. It was based on microscope examination of 400 thin sections of Paleozoic carbonate reservoir rocks. He proposed 4 types, a) Canal type pores, b) Compact matrix with or w/o vugs c) poor to few conveying canal pores, and d) granular or sucrosic pore systems. In his system, rocks whose pore space configuration classed as type B with vugs are the better RQR. However, the mathematical model of his pore space model is not effective when compared to parameters developed based on capillary pressure measurements.
Capillary pressure measurements provided the following Carbonate classifications:

A) Archie :

Type I) Compact Crystalline of sharp edges and smooth faces
Type II) Chalky with dull, earthy (argillaceous), or chalky appearance
Type III) Sandy or Sucrosic appearance including Oolitic textures

B) Robinson

Type 1) Partly Dolomitized L/S with pinpoint pore spaces
Type 2) Dolomites with Saccharoidal or Granular pore spaces
Type 3) Vuggy Limestones of Bioclastic, Oolitic, Algal or Fine matrix pores
Type 4) Dense L/S & Dolo, of calcite & anhydrite crystal, w/o visible pores

Table 1, provides a range of values to serve as a preliminary guide for porosity and permeability typing. The table values were extracted from Archie and Robinson to rank relative values of reservoir rock parameters.

Table 1 Basic Parameter Guide

class	Porosity	Air perm.	Resid H_2O	BVW carbs	Max pore	ss grain d	Pd
	Total %	md	$\%S_{WC}$	$\phi * S_{WC}$	Microns	mm	psi
Poor	<5	< 1	>20	>0.05 - 0.09	<2	< $^1/_{16}$	>100
Fair	10	1 - 10	15	0.04 - 0.025	5	¼ - $^1/_8$	100 - 25
Good	15	10 - 100	10	0.025-0.015	16	½ - ¼	10 - 25
Super	>25	>100	<10	<.015	>24	> 3/8	<10

The grain diameter values apply to sandstone systems, while the other values apply to carbonate systems. Displacement pressure Pd, represents average large pore diameter. It is the hydrostatic pressure required by a hydrocarbon fluid to begin filling a rock with oil by displacement of water. At that point a small change in oil capillary pressure results in maximum displacement of water. In some rocks, displacement pressure and entry pressure are nearly equal, but large variations in pore diameter can have large differences in entry and displacement pressure. A rational unit for displacement pressure is "feet of hydrocarbon", as elaborated in the appendix. One rule of thumb is that "Commercial" reservoir rocks have 50% or more of pores greater than 1 micron diameter.

1.3. Comparison of Permeability Equations

This section reviews permeability models and the following section compares results of some equations to core data. Equations for various pore fabric types are presented by Table 2. This table shows three components define real rock permeability: 1)the connectivity of pores, also known as flow path tourtuosity; 2) the quantity of pores and, 3) the pore surface area, or for vug type, effect of bi-modal pore distribution. These three elements were empirically developed by Teodorovich.

The Teodorovich method used visual observation of thin core slices and calculates k using four terms, as k(md) =Λβγδ. Where Λ is related to porosity or canal diameter, and β is a power function of effective porosity, and γ is directly proportional to either the average (d) or maximum pore diameter, (D) and δ is an empirical factor ranging in value from 1 to 4. T'vich forms presented in Table 1 use δ=1. In T'vich view, his type II have the best reservoir quality and a semi empirical factor of δ=2 or more is recommended, if vug systems are well connected. This contrasts some view points that granular dolomite systems are better RQR's. Aschenbrenner points out that permeability for T'vich "type I & II pore systems may be related to effective porosity similar to that established by Trebin for certain sandstones".

Also theoretical models exist for calculation of permeability, 1) BK model and 2) capillary theory model. In these models the critical parameters are amount of pores present and the effective pore size. The BK model was developed for uncemented particles based on considerations of particle surface area to volume.

The BK model uses particle diameter, not pore diameter. However, for any uniform rock, the ratio of pore area exposed on a slice of rock face to the total face area is equal to the actual rock porosity. Geometric considerations show particle diameter and pore diameter to be proportional, pore diameter being about ½ the particle diameter. Wardlaw's examination of dolomite rhombs indicates a ratio of 50% to 125%, any cementation would surely decrease this ratio. So, to some measure, it is possible to group the BK model into a pore diameter based model. The BK model is developed on assumptions about particle arrangements and laminar flow theory, using particle diameter and void volume or porosity, as correlating parameters. The BK model has been validated in uncemented assemblages of particles of regular shapes. Irregular shapes such as long needles, or particles with dual surfaces, such as rings, are not predicted with the BK model. Any correct model must be dimensionally accurate, with units of length squared. If a power series approximation of $p^3/(1-p)^2$ is used, both capillary & BK models predict k of zero at zero porosity and k proportional to d^2 at porosity of unity.

The capillary theory model is based on pore diameter, and not particle diameter. It is derrived by equating Darcy's flow equation to flow in a single capillary and multiplying by porosity to arrive at a total of uniform capillaries. By capillary theory, permeability is effectiveness of pore surface area to conduct flow. Rocks are assemblages of particles which are bound together by some form of cement. When particles are cemented together, then direct flow paths are closed off, and the flow path length increases. Williams notes this effect in cemented particles (real rocks) must be accounted for with a tortuosity factor. Tortuosity factor is related to porosity times F, formation factor. In all but unconsolidated sands, tortuosity factor increases power of porosity term from 1st order to 2nd order for the capillary model. More details are provided in appendix.

Wylie's original equation used Formation factor to correlate permeability. His reasoning to use Formation factor appears based on an analogy of electrical current flow to fluid flow. Changes in F reflect changes in ease or difficulty for fluid to migrate in a rock system. His original equation used a lower porosity power term, (5.36 or less, since most F factors have porosity power terms of 2 or less), than the Schlumberger variant, which has the highest porosity power term. This is contrasted to Timur's 4.4, and Trebin, and Teodorovich 2nd or 3rd order power term. Second or 3rd order power terms in porosity-only equation suggest negligible tortuosity factor, (nearly perfect connection of capillaries).

Insitu measurement of pore fabric diameter is difficult to obtain. Thus, permeability equations were developed using more easily obtainable parameters. A surrogate parameter for pore diameter is connate water, S_{wc}. Figures 2, 3, and, molecular considerations of Appendix all indicate pore diameter to be inversely proportional to S_{wc}. A similar parameter, useful for porosity typing, is Bulk Volume Water, BVW equal to porosity times S_{wc}. In simple terms, BVW is the porosity at which S_{wc} =1.00, and any porosity below that value is an imaginary form, as Sw-c cannot exceed 1. Table 1 presents a range of BVW values commonly accepted for each porosity fabric type. Using S_{wc} to eliminate pore diameter leads to a permeability in terms of either porosity and S_{wc}, or simply porosity alone or simply S_{wc} alone, Wylie-Rose, Wylie, AAPG, Timur, and Schlumberger, Table 2.

C&H empirically correlated permeability using only S_{wc}. They present a chart of permeability and S_{wc}, showing that for a given producing field and for synthetic alumna, k fits the form $\ln k = a*S_{wc} + b$. This is in basic agreement to permeability equations which use porosity and Sw-c as correlation parameters, if the substitution of porosity = BVW/S_{wc} is made, then porosity can be eliminated from these equations. This analysis of core data shows that pore diameter can be related to 1/S_{wc}. Thus capillary theory suggest that k would be proportion to something between 4th and 3rd power of 1/S_{wc}, when porosity is eliminated by BVW/S_{wc} substitution. Craft's permeability change for 5 oil fields plus synthetic alundum, by connate water, S_{wc} showed *2 fold decrease in k was noted for every 7 points of* S_{wc} and in 2 other fields the average was 1.6%. For example, if S_{wc} changed from 7% to 17%, then the permeability would decrease by 50%. In the more sensitive formations, changing Sw-c from 12% to 10% would approximately double k.

Archie presented representative porosity permeability curves for each of his types of carbonates, using porosity as a singular correlating parameter. The value of BVW for each Archie type is I) 0.008 to 0.0125, II) 0.113, and III) 0.038. Thus it is possible to arrange the Archie's carbonate equations in terms of S_{wc}, using BVW to eliminate the porosity term. In simple terms, this gives additional credibility to C&H's method of correlating k to S_{wc}.

Table 2
Permeability Relationship Functions

Equation	. k, md air md unless noted	Pore range	$\%S_{wc}/100$
T'vch type I [8,5,6]	$D*0.10d^{1.55}(\%\phi/100)^{1.93}$	d>10&<2k μm	D-max, d-avg
T'vch all[8,5,6]	$161d(\%\phi/100)^{2.93}$	d>10&<2k μm	D-max, d-avg
B-K particles[22]	$5.6\{d_p, \mu m\}^2\{\phi^3\}/\{1-\phi\}^2$	>30% unconsol.	0.123/d, μm
C&H capillary[3]	$31(\%\phi/100)(d, \text{microns } \mu)^2$	any capillary	0.123/d, μm
C&H fractures[3]	$84(\%frc/100)(w, \text{microns } \mu)^2$	any fracture	N.A.
B-K particles[22]	$10\{\phi^{3.35}\}\{d, \text{particle micron}\}^2$	Unconsold'ted	
Pirson B-K [30]	$\{\phi/(1-\phi)\}^2 (F/1000)(1/S_{wc})^2$	$F=0.62/\phi^{2.15}$	@10% k=15md
Pirson Tortuosity[30]	$\{1/(0.142F\phi)\}^8$	$F=0.62/\phi^{2.15}$	$F\phi=3$;k=920md
Wylie ss, min[17]	$\{72*(F)^{-1.34}/(S_{wc})\}^2$	>10%,	$0.1<S_{wc}<0.60$
AAPG, oil ss[27, 2]	$\{250*(\%\phi/100)^3/(S_{wc})\}^2$	>3%	0.02<Sw<0.70
AAPG, gas ss.[27,]	$\{79*(\%\phi/100)^3/(S_{wc})\}^2$	>3%	0.02<Sw<0.70
Timur, ss.[27, 2]	$\{92.6(\phi)^{2.2}/(S_{wc})\}^2$	150 ss cores	nd
Schlumb 97rev[28]	$:\{100(\phi)^{2.25}/(S_{wc})\}^2$	Oil Indet.grain	BVW/φ
Schlumb 97rev[28]	$\{70(\phi)^2/\{(1-S_{wc})/S_{wc}\}\}^2$	Oil Indet. grain	BVW/φ
C&H empirical[3]	$k_o*\exp(-9S_{wc}) \sim 45k_o/\%S_{wc}^2$	Various ss&crb	S_{wc}
Archie I Carb[4]	$0.0013\exp(0.61\%p)$ or $2.55*(10\phi)^{5.65}$	7% - 20%	(0.0125– 0.008)/φ
Archie II Chalk[4]	$0.048\exp(0.16\%p)$ or $285\phi^{3.22}$	14% - 35%	0.113/φ
Archie III Carb[4]	$0.016\exp(0.61\%p)$ or $9.35*(10\phi)^{5.65}$	5% - 15%	0.038/φ
Chalk, scholle[,32]	$0.02*\exp(0.14*\%\phi)$	5-45%	
Calcar.Chalk, [,32]	$0.007*\exp(0.23*\%\phi)$	20-40%	
Trebin, s.s.[7,8]	$2*\exp(0.316*\%\phi)$ or $(61\phi)^{2.2}$	<12%	<.0014/φ
Trebin, s.s.[7,8]	$4.94*(\%\phi)^2 - 763$ or $(33\phi)^{3.7}$	>12%	0.06
Coats-Damoir[29]	$\{c\phi^{(2w)}/(I'W^4\}^2$ &$c=23+465\rho-188\rho^2$	ρ=> fluid g/cc	BVW/φ
Coats-Damoir[29]	$\{c\phi^{(2w)}/(bvw*W^4\}^2$ by BVW	BVW limit	BVW/φ
Pirson[31]	$\{8.5E8/API-3.5E3/D'\}\phi^2$ BVW^4	MedAPI&D'<6k'	D'=ft depth
This Paper	$10\phi^{1.5}(1/Swc - 1)^{1.9}$	carbonates	0.123/d, μm

A generic equation for sands and shaly sands using S_{wc} has been recommended by the AAPG, Table 2. This AAPG equation is presented as Schlumberger variation of Wylie/Rose k equation. Their equations point to a difference between permeability for oil and gas. Note their difference in values of the constant, 79 for gas and 250 for liquids. This same fact is elicited in the Coats-Damoir equation by the "C" factor, (c = 300 at 1g/cc and 70 for 0.10 g/cc). Most values of laboratory permeability reported are determined using air at 1 to 2 atmospheres pressure. This is contrasted to insitu measurement by pressure decline or buildup curve analysis, which uses natural fluid. The rule presented in the Schlumberger chart is that liquid permeability is 10 times greater than gas, although subsequent revisions, 1997, dropped this chart. Theoretically, permeability is an exclusive property of the solid.

AAPG also provides a more detailed method using resistivity ratio, fluid density, and porosity, Coats & Damoir. The C&D method improves on the problem of very low and zero Sw-c. For at near zero Sw-c values, k would go to infinity. In practice, most reservoir have S_{wc} between 10% and 20% in zones with initial production, C&H, pg30. The C&D method uses $W^2=[3.75-\phi]+(2.2+\log I')^2$ & the term I' =Rw/Rt-c, Rt-c being taken where $Sw=S_{wc}$, which by basic Sw equation, $\{(S_{wc})^2=R_wF/R_t\}$ gives: $I'=(\phi S_{wc})^2=(BVW)^{2.}$, when $F=1/\phi^2$. However, for this data set of core properties, Table 3, col.12 and Fig.4, C&D method does not appear reliable for carbonate facies. Pirson's equation; related to API gravity, and C&D, (neither were widely accepted), are correlations which define permeability by fluid properties. The C&D and Pirson equation, in original format, have terms for free water. These two formats are likely more related to relative permeability, than absolute permeability. Absolute permeability is a property of media alone. However, relative permeability is related to both free fluid fractions and viscosity ratio.

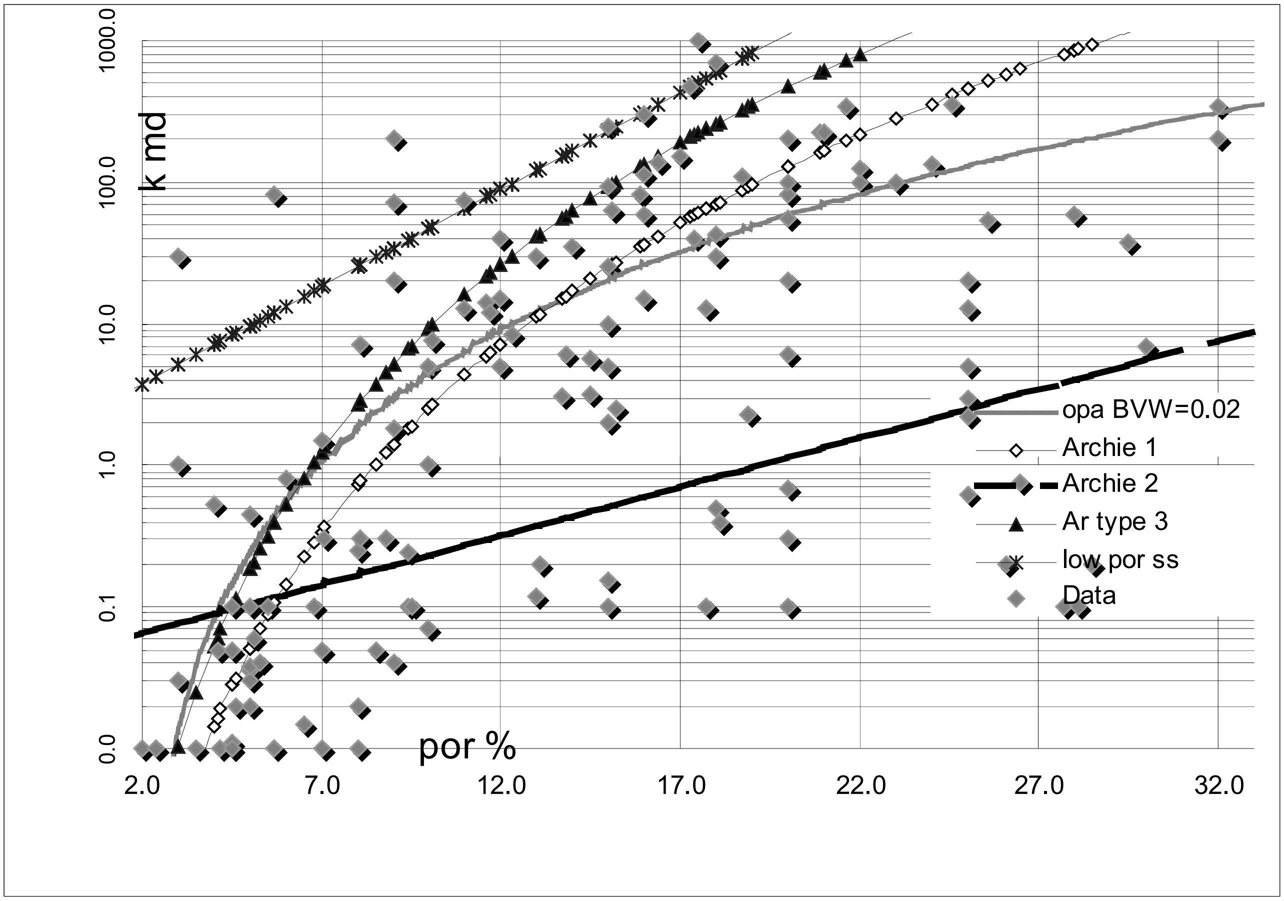
1.4. Comparison of Permeability Porosity Equations

Graph 1 is a plot of over 100 permeability values and associated porosity from ref. 1, 3, 4, 12-16 along with some of the porosity permeability relationships of Table 1. Only exceptional cores have permeability of the magnitude predicted by the Trebin low porosity sandstone equation.

Graph 1 plots Trebin low porosity equation, the three Archie types, plus this Equation at BVW =0.02. Only for Trebin low porosity types (upper straight line) will substantial permeability develop at low porosity, but S_{wc} for this type was shown to be low, indicating large pore size. The data points were for typical reservoir quality rocks but some cap rocks have been included to show the effect of ultra low pore diameter and/or porosity. The AAPG equation cannot accurately represent chalky (Archie type 3) k values without the use of S_{wc} values in excess of one.

Most curves above conform to a simple power of 2 rule, for Archie-II&I each 1.2 Δ%P doubles k, for A-III each 4.4% Δ%P doubles k and for T low porosity type sands, each 2.2Δ%P doubles k, i.e. going from 5 to 7.2% porosity would double k, if the rock conformed to that form. If using only S_{wc}, then at 5% Sw-c, each decrease of 1.5% S_{wc} doubles k, at 10%Sw-c, k doubles for each 3% points change in S_{wc}, at 20% S_{wc}, k double for every 6% ΔS_{wc} and 30% is 9% to double, 40% is 12% ΔS_{wc} to double, given constant porosity. Provided that Craft's fields conform to these rules, then the initial S_{wc} would be in the range of 20 to 30% for the 2-7% rule to work.

Graph 1
Comparison of Core Data Permeability to Porosity Predictive Methods



Connate water acts to reduce the pore diameter and reduces the volume of effective pores. If all water, in a core, is held as connate water, the effective porosity would be zero. The AAPG method to identify whether or not a rock is at irreducible water saturation level is by plotting Sw against porosity. It is known, (Wylie, Asquith) that rocks at S_{wc} will plot along a hyperbolic curve. Likewise, if the rock porosity and type are known it is also possible to identify connate water level. Free water is produced when water fraction exceeds S_{wc}.

1.5. Comparison of Multi Parameter Permeability Equations

Some comparisons of core data permeability to the various dual parameter equations were made, using the data below. Column 1 is the source reference; 2, displacement pressure; 3, calculated average pore diameter; 5, maximum pore diameter micron, based on Pd; 6, reported porosity; 7, reported permeability; and columns 8 to 13, calculated permeability.

Table 3 Comparison of Core Data Analysis

1	2	3	4	5	6	7	8	9	10	11	12	13
ref	pd	sw	avg d	max D	por	md						
	ft oil		um	um	v/v	k	k(T1)	k(T2)	k(A)	k(AA2)	k(KD)	k™
s7	2.3	0.62	0.27	29.6	0.151	63.0	18.7	10.6	0.2	0.2	0.02	5.5
R12	218.0	0.59	0.23	0.3	0.040	0.2	0.0	0.0	0.0	0.0	0.00	0.0
s9	190.0	0.55	0.23	0.4	0.177	0.2	0.4	0.1	0.5	0.5	0.07	14.0
s4	13.0	0.40	0.37	5.2	0.081	0.4	0.5	0.8	0.5	0.0	0.01	0.9
S11b	85.0	0.38	0.30	0.8	0.045	0.1	0.0	0.0	0.2	0.0	0.00	0.1
s5	68.0	0.30	0.35	1.0	0.117	12.0	0.3	0.3	2.0	0.1	0.10	7.6
r8	125.3	0.27	0.32	0.5	0.024	0.1	0.0	0.0	0.3	0.0	0.00	0.0
r6	0.4	0.25	0.54	166.7	0.057	82.0	6.1	18.0	1.1	0.0	0.00	0.5
r2	32.7	0.23	0.43	2.1	0.088	0.3	0.3	0.4	2.6	0.0	0.04	3.7
S10	97.0	0.17	0.35	0.7	0.123	8.5	0.2	0.2	8.8	0.6	0.64	29.6
s8	0.5	0.15	0.77	136.2	0.090	1.8	18.9	50.5	7.3	0.1	0.12	9.6
r7	0.4	0.14	0.86	166.7	0.138	6.1	81.0	157.1	16.8	1.9	2.11	75.1
r3	8.2	0.12	0.85	8.3	0.137	3.1	4.0	7.6	22.3	2.4	2.76	95.5
r5	2.5	0.10	1.14	27.8	0.187	109.3	32.9	62.5	52.6	22.2	28.32	540.8
S11a	10.0	0.08	1.24	6.8	0.189	2.3	8.3	17.0	85.1	36.9	52.08	885.6
R11	6.0	0.08	1.05	11.4	0.177	12.8	11.5	21.2	77.1	24.9	34.49	663.5
s6	6.0	0.05	1.98	11.4	0.256	53.0	33.7	80.9	34.8	583.7	1066.43	8615.5
r9	1.9	0.02	3.82	35.7	0.164	138.0	28.8	208.1	108.1	252.2	214.44	7589.6
r4	9.5	0.02	2.67	7.1	0.336	52.3	47.1	116.2	316.9	18648.4	53521.67	178155.3
R10	7.6	0.01	3.76	8.9	0.116	14.3	2.6	26.2	244.6	126.3	15.18	6615.8
P							0.86	0.86	0.93	0.64	0.64	0.93
NT							1.00	1.00	0.83	1.00	1.00	0.67
OvP							2.7	6.1	6.9	33.1	89.4	381.7

The data is of capillary pressure evaluations of cores selected by Stout, s, and Robinson, r, to represent what they considered a large variation of the possible pore fabric types encountered in various moderate to highly agitated depositional environments. Omitted are quiet water and oolicastic fracture faces. This data is analyzed using permeability equations of T'vich, (k(T1 & T2), Wylie Sandstone, (k(AA2)), Coats/Damoir, (k(KD)), Timur Sandstone, (k™) and this paper's proposed equation, k(A). The accuracy is ranked by 1) ability to accurately predict producible (P) zones, 2) detection of Non-Testing zones, k<1md and 3) amount of Over Prediction in producible zones. Of the 20 data points, six are no test zones, k<1 md, and 14 are producible zones.
Both the AAPG equation and the C-D equation over predict non-testing zones, meaning these methods overlook possible producible deposits, while the Timur equation over predicts producible zones, meaning excessive expenses in testing non-producible zones.

The T'vich method does a good job of predicting non testing zones with a 100% accuracy, but is only 87% accurate in predicting testable zones. Tvich method II has a modified constant to improve prediction accuracy with this data set, $50d*D*p^{1.93}$, here D is the micron equivalent diameter of the displacement pressure, effectively, a measure of the average large pore size, and d is the average pore size by $1/d = \Sigma(f/d)i$. However, these parameters are available only from core studies.

This proposed method, uses Sw-c modified to calculate effective pore diameter, as given in Table 1. This proposed method is 93% accurate at predicting producible zones while it minimizes over-testing to only 17%. Possibly, a good well site geologic analysis could reduce this percentage even more by applying T'vich's method to well cuttings. The T'vich methods have the least amount of over prediction for permeability in producing zones, but his prediction parameters are only available from core studies. This equation, on the other hand, uses commonly available log data and is orders of magnitude more accurate at predicting permeability than other dual parameter equations. The Archie equations were not presented here, since using only porosity will over test non producing zones. This idea is easily visualized in Graph 1, by the points of high porosity but low permeability.

Prediction of production economics by the better methods may be off by a factor of 3 to 7, and by the less accurate methods, useless. Asquith's recommendation is to make production estimates using ratio predictions from nearby wells. Clearly, ratio predictions should use a method which can properly trend productivity changes.

1.6. Significance of Connate Water, S_{wc}

For a given porosity type, larger diameter pores yield lower connate water and higher permeability, Graphs 2 and 3. For porosity-only methods, Sw-c level is implied via porosity typing. Results for Archie's types are as follows:

Table 4

Pore Fabric Type: Porosity, S_{wc} and BVW Range

T'vich	Archie	Type and porosity range	%S_{wc} - AAPG	BVW
	Compact	Archie I 5%<p<20%	25%	3.8%
	Chalky	Archie II 14%- 35%	**>200% n/a**	11.3%
IV	Sucrose	Archie III 4% - 25%	11%	1.3-0.8%
I & II		SS or T'ch I&II, P <12%	~1% -~5%	<0.3%
I & II		SS or T'ch I&II, P >12%	~6%	na

Archie type II is a high porosity chalk with pores under 0.05 mm. High porosity and low permeability types rocks are indicated by S_{wc} levels in the range exceeding 30-40% and corresponding high entry pressures. In Archie's words, "most pores are small grading to very small and connate water levels would be expected to be high".

Compact rocks of modest permeability, on the other hand represent rocks with a scarcity of pores and to develop permeability, these rocks must have larger pore diameter to compensate for the lack of number in pores. Another type not considered by Archie seems to be vug type porosity. Figure 9, upper curve illustrates the effect of well aligned vugs. In this type, the permeability is hardly effected by changes in S_{wc}. T'vich considered these as better type reservoir rocks. Insertion of vugs has little effect on S_{wc} but a modest capillary or fracture can greatly improve permeability, w/o respect to average porosity or average pore diameter. This effect is shown by calculations on a synthetic pore space, see appendix.

Asquith, for Williston basin carbonates, used $S_{wc} = (F/A)^{0.5}$, and typically, this reduces to $S_{wc} = BVW/p$. A BVW value of 0.02 was commonly used by Asquith as exploration criteria.

Lithology and BVW typing to obtain S_{wc} values expressed as BBL/AcFt may be a far more useful, as indicated in Table 5. These parameters can be used to express both static and dynamic aspects of a deposit by plotting mobile HC as bbl/acft against BVW, as in and Figure 11 A and B. At any BVW value, the change in mobile HC directly relates to permeability, see appendix . For example, the maximum capacity of a deposit is at S_{wc} of zero, and maximum porosity of say 33%. When expressed in units of BBL/AcFt, at Bo=1, is 2500 bbl/Ac-Ft. Ultimate recovery seldom exceeds 80%, so the maximum movable HC saturation is about 2000 BBL/AcFt. Figure 11A maps 1980 US carbonate oil production statistics in these terms, with an insert of calculated permeability. Point A shows that 80% of all production is obtained at BVW less than 0.06 and under 900 bbl/acft mobile HC. Point B shows the median production limit is mobile HC under 550, point C shows the lower ¼ of all production is from a mobile HC of less than 250 bbl/acft.

Table 5a Movable HC and Lithology

	Min bvw	max bvw	min bbl/AcFt	mx bbl/AcFt
vug carb	0.005	0.015	76	123
vug & IX carb	0.015	0.025	123	154
.Intr gran crb.	0.025	0.04	154	189
Chalk carb	0.05	0.1	189	283
$780BVW^{0.44}$	<=crb	BVW ss=>	or 28ln BVW +220	
coarse ss	0.02	0.025	110	117
medium ss	0.025	0.035	117	126
fine ss	0.035	0.05	126	136
v.fine ss	0.05	0.07	136	146
siltstone	0.07	0.09	146	153

Point D indicates less than 11% of production is from calculated mobile HC under 150. These trends indicate that increased mobile HC indicates both increased possibility of productive deposit and increased deposit value.

Table 5a indicates the lower limit of a normal carbonate ranges between 125 and 190 bbl/AcFt. Deposits falling below these limits, unless vug (large pore size) or secondary (unseen large) pore types present, are unlikely recoverable, due to slow moving fluid phase and a lack of capital return. Chalk, siltstone and shales types have upper mobility limits set only by fineness of average particle size. Vug and secondary porosity types have lower production limits fixed only by the upper average pore size. Production history for limestone indicate 90% of all production is between BVW of 0.11 and 0.005, for dolomites 0.11 and 0.002. Average production is at BVW of 0.031 for dolomites and 0.038 for limestones.

Table 5b Summary BBL/AcFt

	avg	min	max
ss avg	125	110	140
silt avg	145	135	155
vug crb	90	76	125
.ool/sucr a	150	125	190
chlk avg	240	190	290

The sandstone values of Table 5 were constructed with extrapolation to zero permeability, as described in appendix. This is a classification for cap rock. Indicating caprock HC index of 110 BBl/AcFt for sandstone and 80 to 130 for carbonate systems, exceptions are silts and chalks. The minimum level for carbonate rocks was adjusted based on production trends, as shown in Graph A. In graph A, the upper 2 points, about 550 and 450 are the eighty percentile and fifty percentile points for production. These points clearly indicate, higher mobile HC, increases productivity chances. But the lower points between 150 and 250 also represent significant production levels, as much as 27% for dolomite reservoirs. However, core data plot, Graph B, shows a significant permeability break around the 0.1md trend line. For purposes of estimating minimum producable values, use the 0.2 md line, $780BVW^{0.44}$. Dolomitic formations are exceptionional, and when H/C is found sheltered there-in, the lower 5% of production is at 50bbl/acft. Which indicates only a 1/20 chance dolomites less than this level will be productive. But dolomites have substaintial production at mobility values otherwise indicating limestone caprock. USA statistics of siluran and older rocks, indicate dolomites have double the productive occurence to that of limstones as oil reserviors and 60% of all dolomite reservoirs are in siluran and older dolomites.

Application of mobile HC concepts can be illustrated by J.L. Stouts' data for the well Skelly-Larson#1 of McKenzie county in North Dakota USA. The caprock was cored and tested as was the reservoir rock. The following table summarizes the data and calculated results:

	Por	Sw	k lab	k clc	BVW	BBL/AcFt	type	depth
Caprock	0.045	0.39	0.1md	0.2md	0.018	153	L/S	9216 ft
Reservior	0.189	0.12	2.3md	36md	0.023	670	Dolomite	9233 ft

Stout describes the reservoir rock as "cryptocrystalline dolomite", and cap rock as, "a water wet clastic limestone that could sustain up to 66 feet of oil column below and possible leakage rate of between 5% and 10%, were there not a favorable hydrodynamic gradient present", and "such a leak is common in carbonate reservoirs".

Analysis:

Assume M-N lithology information is available and finds a normal limestone carbonate of 4.5% and dolomite of 18.9% porosity. Assume a BVW of 0.02, to calculate mobile HC value of $7760\{\phi^{0.8}(\mathrm{BVW})^{0.2} - \mathrm{BVW}\}$ =142 and 780. For 0.02 BVW, the minimum productivity value is $780\mathrm{BVW}^{0.44}$ or 140, while the certain production level is $1150\mathrm{BVW}^{0.48}$, or 175. Thus, porosity tools indicate the upper unit is border line to non-productive, while the lower unit is certianly productive (780 vs minimum mobility of 175), provided oil is present. If drilling cuttings indicate oil in both sections, then perforations would only be indicated for the lower, high porosity section.

Alternativly, if only an electrical survey were available and found 670 mobile HC in the upper section and 153 in lower section, using resistivity data. Provided the drilling cuttings indicated both sections as normal oil stained carbonates, one would recommend that same perforation pattern as with the porosity survey.

A third alternative would be if both porosity and electrical survey were available, and gave the Sw and porosity values of the above table. The upper unit would show a minimum mobility value of 133 and a certain productive value of 165. This indicates only a small likelyhood of the upper unit being productive, whilst the lower unit far exceeds the 168 certain productive value. Again indicating lower perforation only.

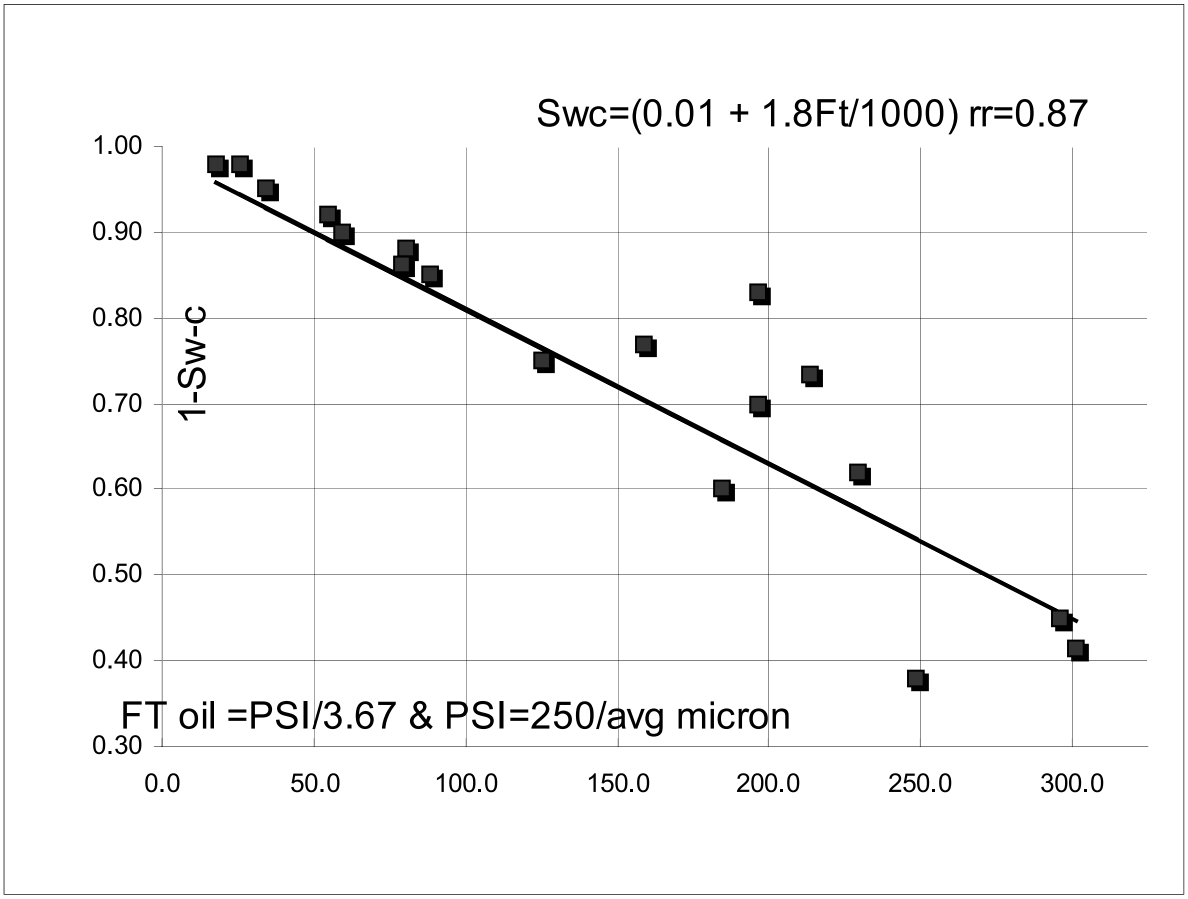
A reasonable question is: what indications clue the 4.5% porosity unit is a cap rock? Firstly, since the lower unit holds oil, the upper unit could not have high permeability, thereby eliminating vug and/or secondary permeability, plus being limestone eliminates the cap rock as a low BVW dolomite.

Contained in the appendix is an analysis of Latvia deposits. The analysis concludes some Latvian deposits resemble the above situation. In that, an upper tight, low permeability, limestone overlays a layer of higher porosity, and possibly productive carbonate. The analysis can be found in the discussion of Table 11.

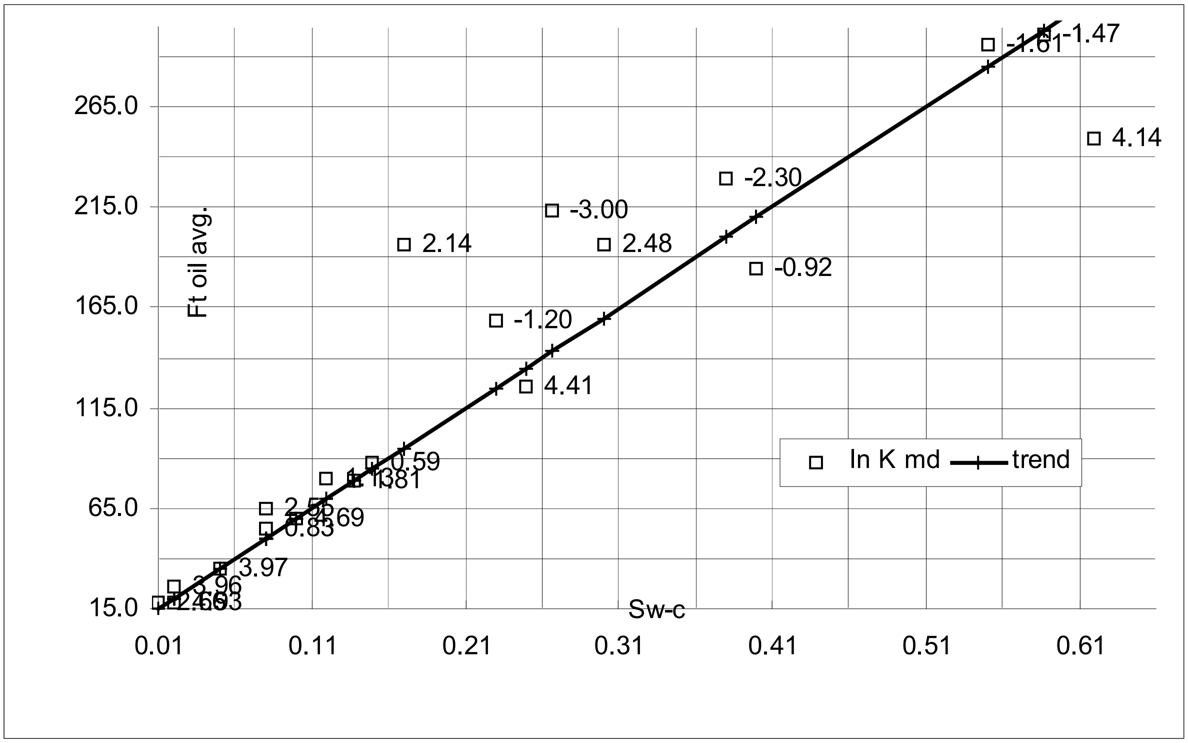
1.7 Summary

- The generic permeability equation for carbonates: k (md) $=10\phi^{1.5}(1/Sw\text{-}c - 1)^{1.9}$ (if k calc exceeds 200, use 1, not 10) should reduce over testing non productive zones and minimize missing productive zones.
- Pore diameter is inversely related to Sw-c for either sandstones or carbonates. It was found that effective pore diameter in microns is 0.123(1/Sw-c – 1)
- It was confirmed, Figure 9, Sw-c may be used as permeability parameter by BVW relationship if porosity is uncertain, provided vug porosity does not contribute to permeability.
- Expression of a formation's effectiveness in terms of movable barrels per acre-foot is recommended, for the expression at once details both the ability to flow and the ability for capital recovery, given BVW, thickness, and depth. An upper limit of caprock is expected at $780BVW^{0.44}$ "movable" bbl-ac-ft. The evaluation equation $1150BVW^{0.48}$, can be used as a productive rock guide, with mobility values at or above these most likely suitable for production.

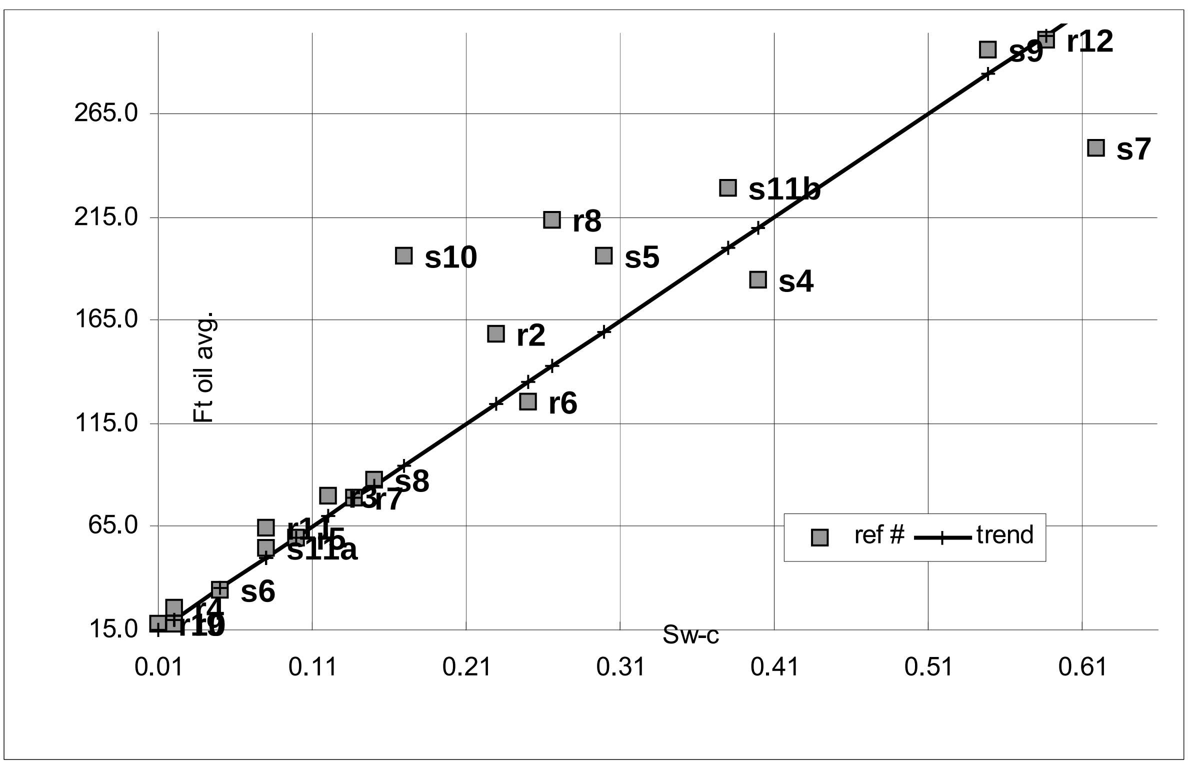
Graph2 Core Data Correlation: Feet of Oil (65.7/µvs.vs Connate Water,



Graph 3a Core Data: Avg. Pore Size (65.7/µ) vs. Connate Water, w/k=md



Graph 3b Core Data: Avg. Pore Size (65.7/µ) vs. Connate Water, w/ref#



R8, BVW => RQR, actual K=.05md   S7, non commercial, %Pe<50%@60'oil high water cut expected, S5&S10, non-RQR due to hi Pd

Figure 4 Comparison of ln[(Core Permeability)/Prediction)] by: Coats;, Archie/Wylie SS, T'vich, Capillary Theory

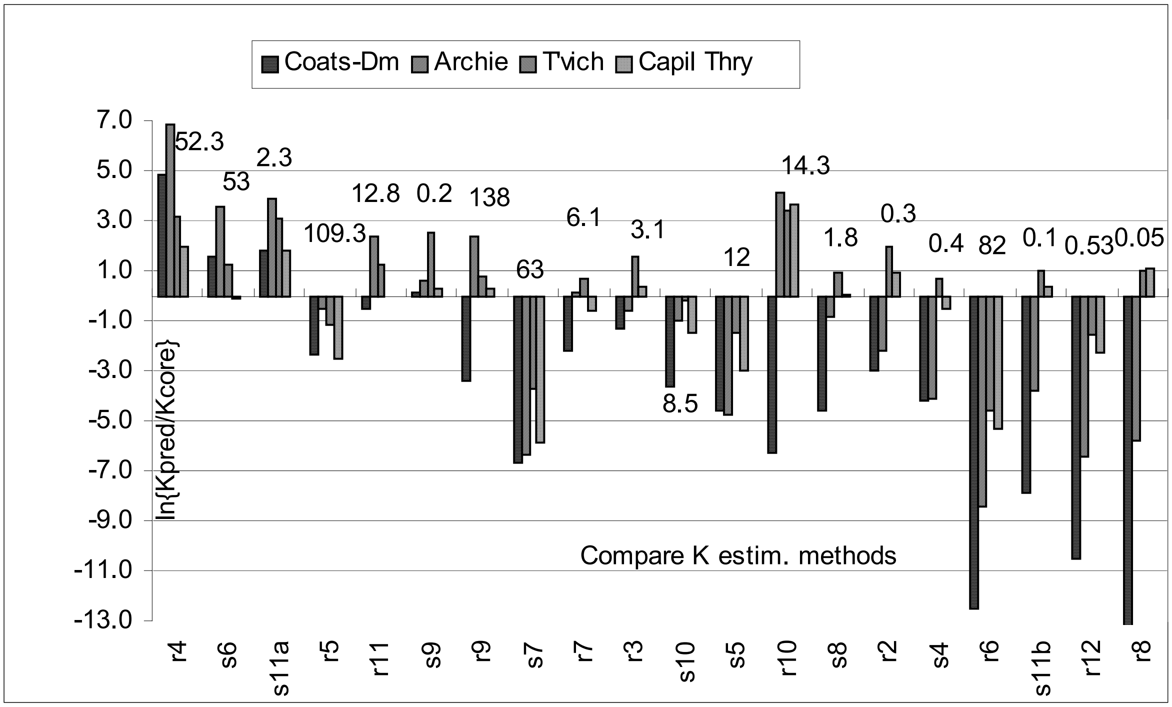


Figure 5 Compare Core Permeability, to by Capillary Theory & Coats/Damoir

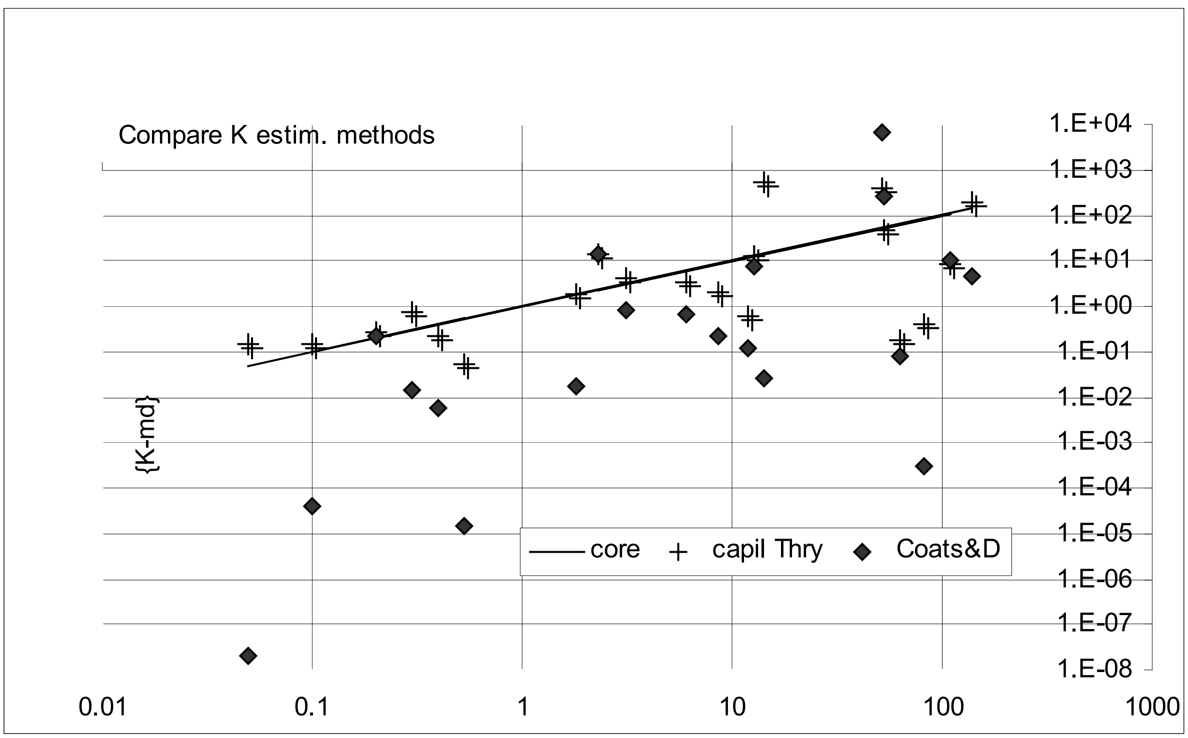


Figure 6 Classification of Core Data by Porosity vs. S_{wc} using BVW iso's

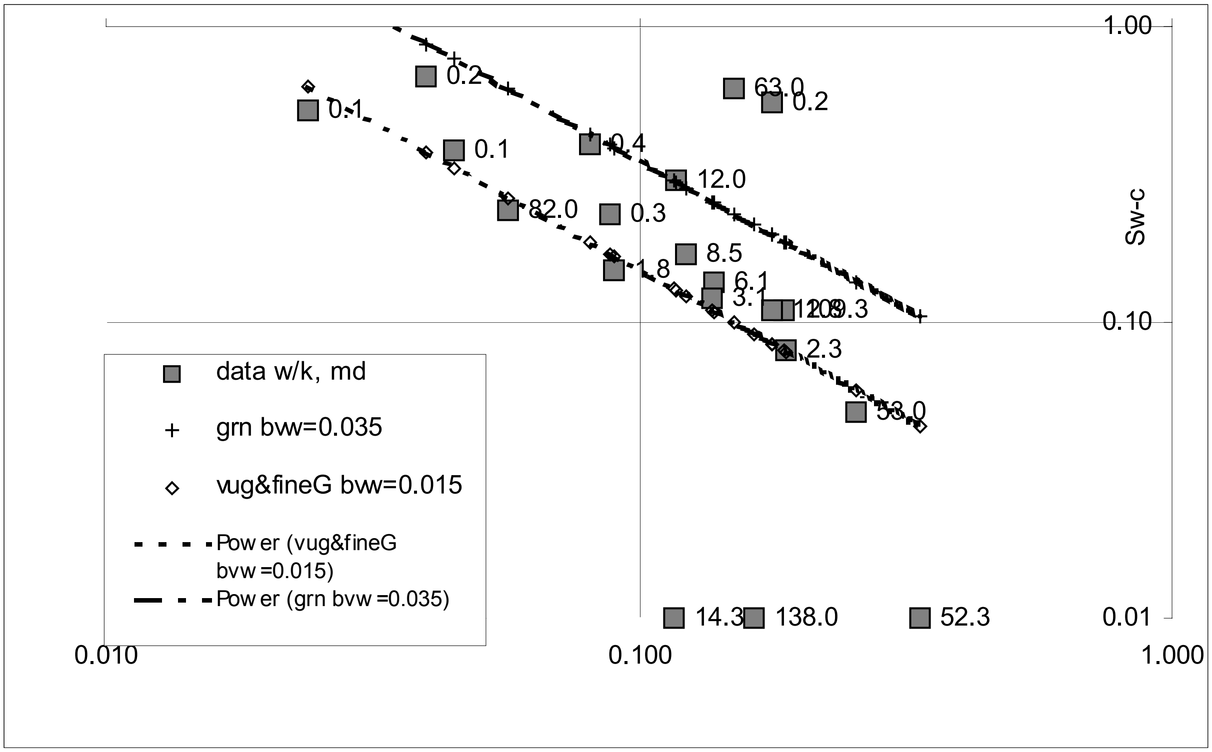


Figure 7 Classification of Core Data by BVW plot using Archie Criteria

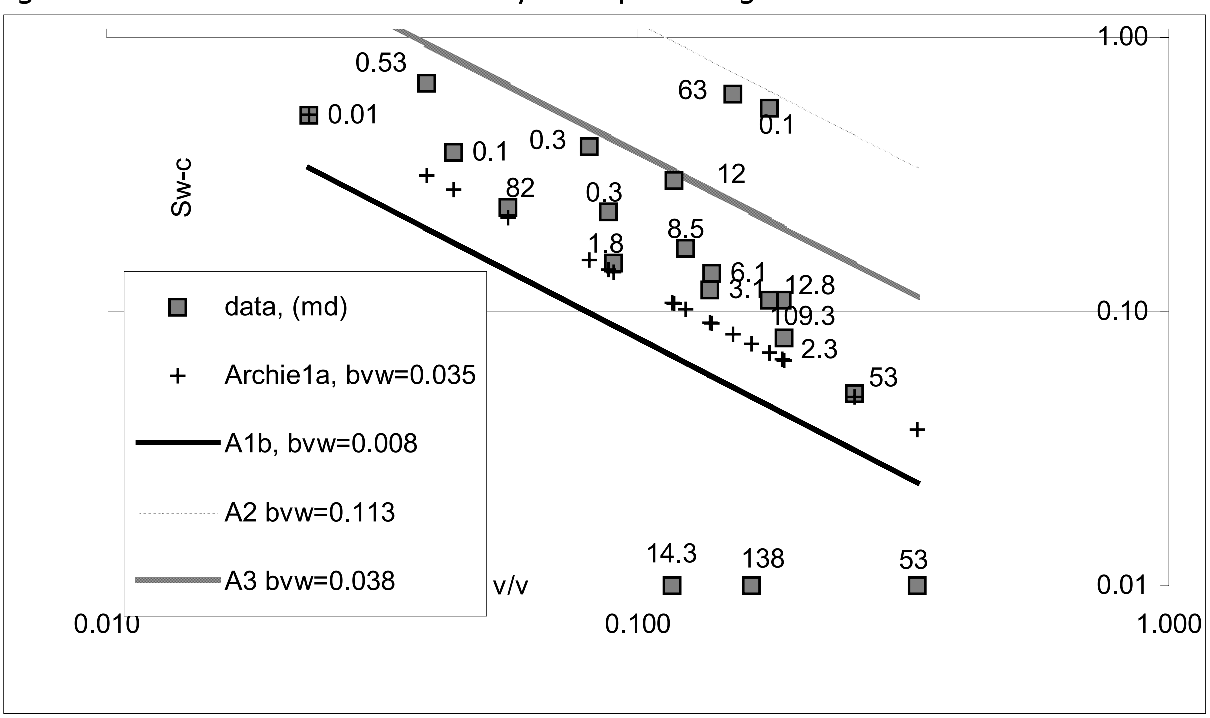


Figure 8 Comparison of Core k & porosity Data to Archie Classification Method

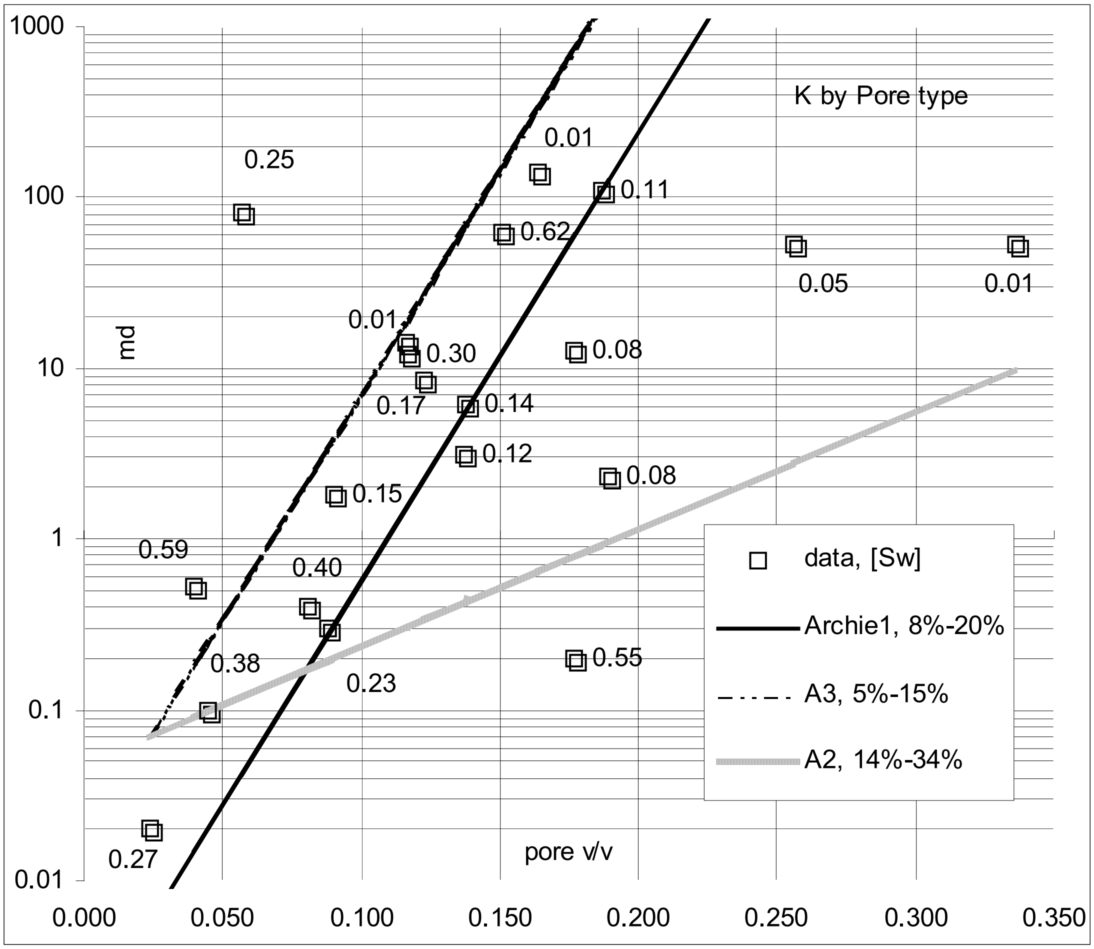


Figure 9 Classification of Core Data by k vs. S_{wc} Plot

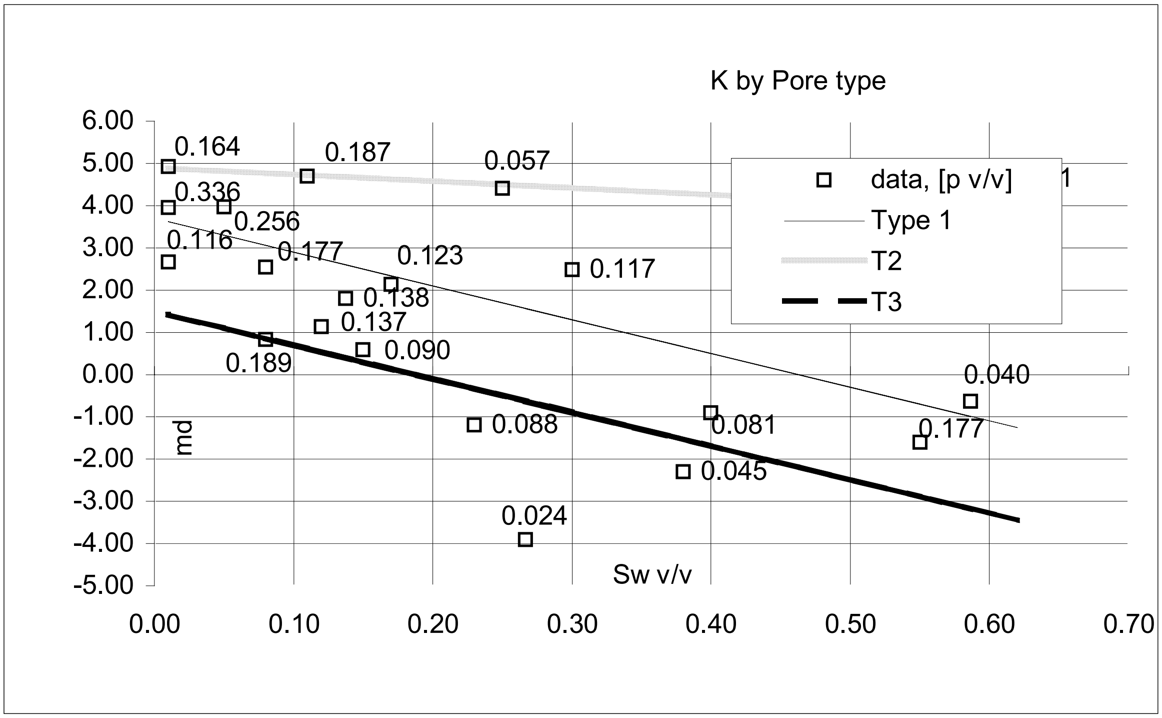
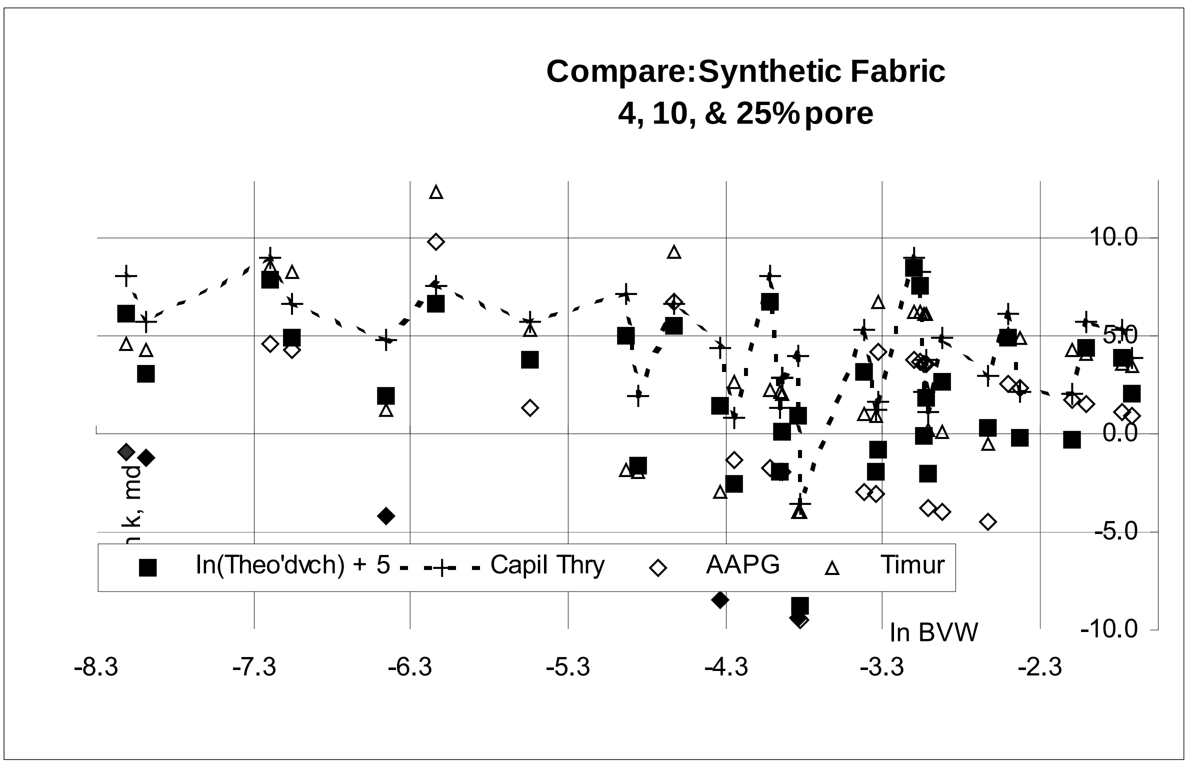
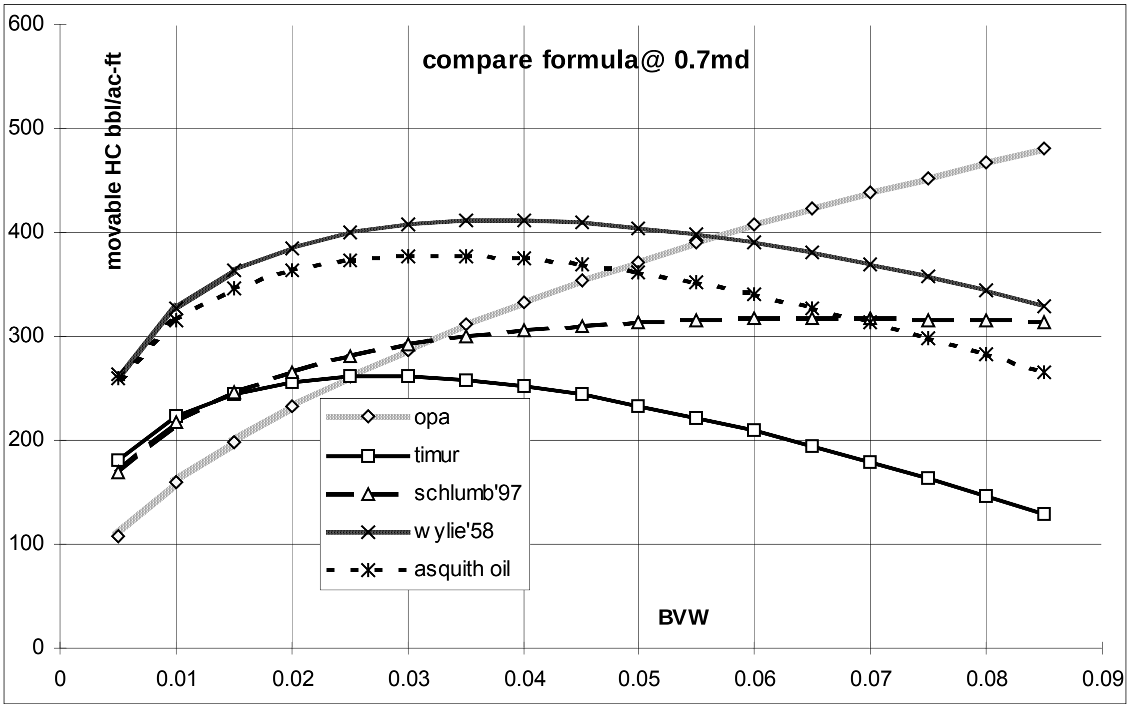


Figure 10: Comparison of k Predictive Methods on Synthetic Pore Space to Show Effect of Vug Porosity



.F.11a, k Equations with $1/S_w^n$ are inaccurate but using $(1/Sw-1)^n$ gives a unique solution



.F.11.b; Given BVW, increases in K, corresponds to increased mobile HC Factor

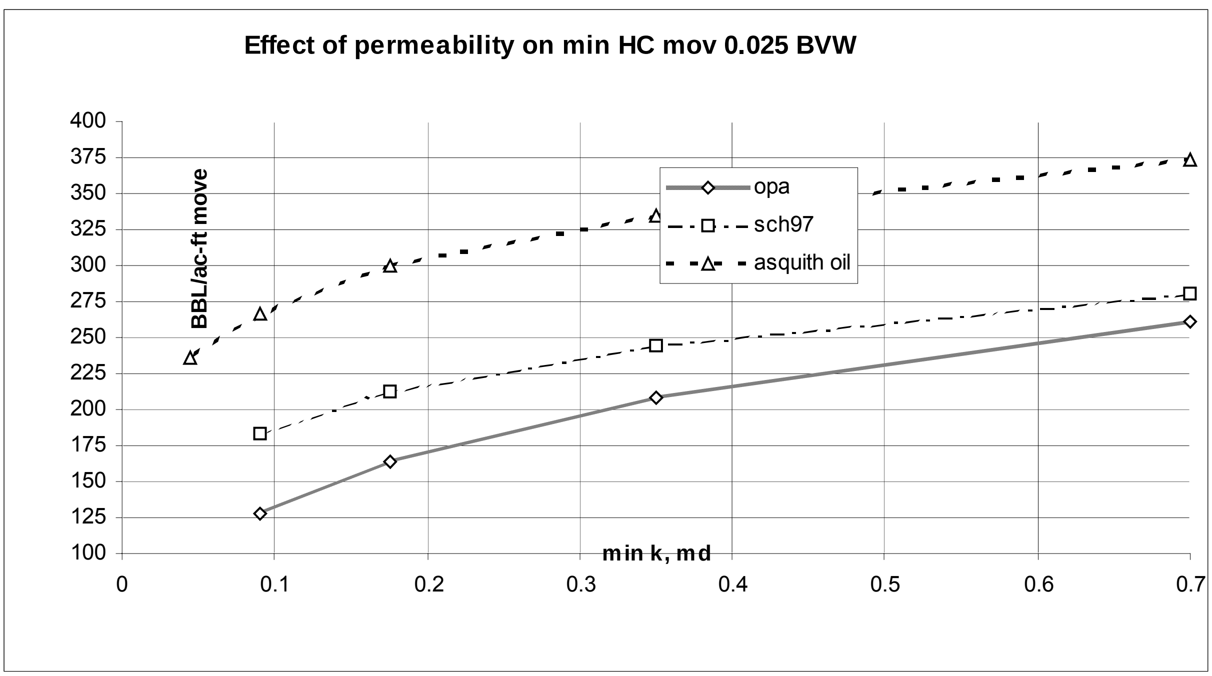


Figure 12a USA Production Data Plotted as Mobile HC vs BVW

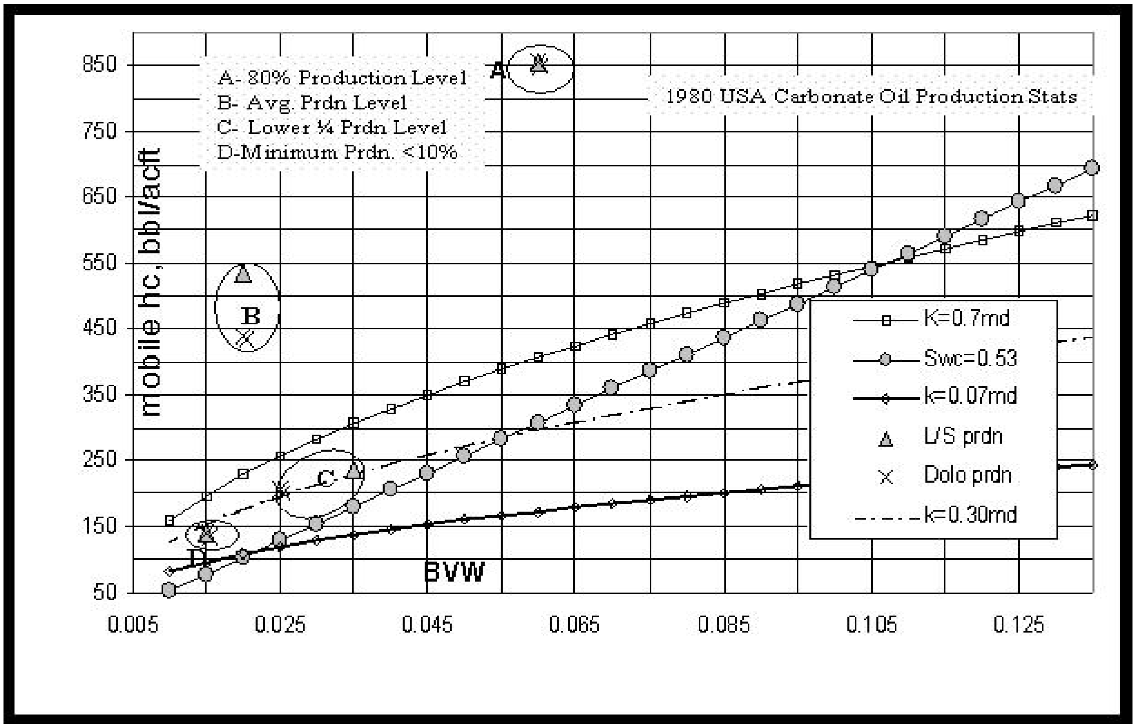
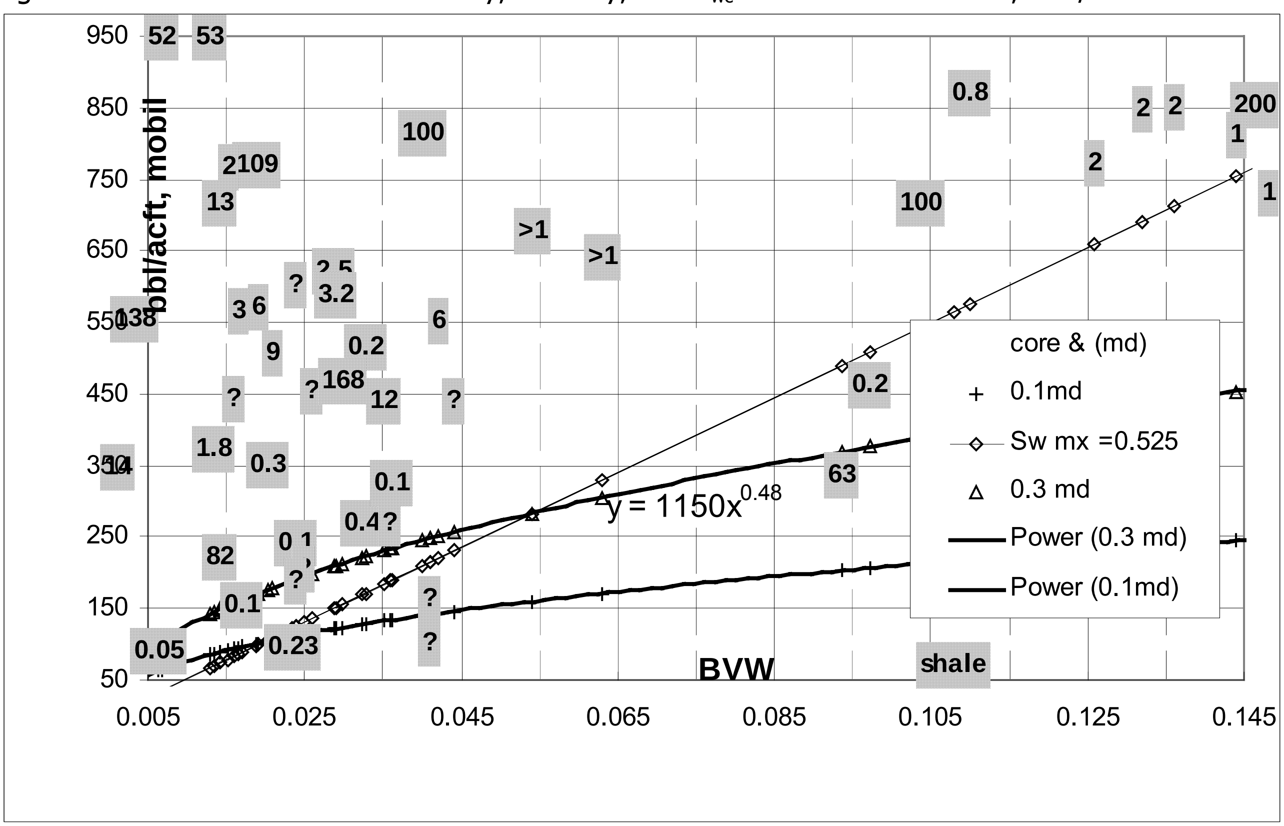


Figure 12b Core Values of Permeability, Porosity, and S_{wc} Plotted as Mobile HC, BBL/acft vs. BVW



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. s/s method compare	Tim.nu/Tim.old	Tim./Nu oil	Tim/old-oil	Wyle/Tim
Ratio	0.95	1.53	5.31	0.33

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APPENDIX 1: Considerations on Pore Size, Water Saturation, and Permeability

A1.1) Molecular Calculations: S_{wc} and Pore Diameter Considerations

Graphs 2 and 3 show a nearly perfect correlation of S_{wc} and inverse average pore diameter. This correlation is valid for sandstone or carbonate cores. The regression equation can be re-arranged with the listed factors to:

$S_{wc} = 0.01 + 0.123/\mu$, & $dS_{wc}/d\mu = -.123\mu^{-2}$ where μ is pore diameter in microns

At S_{wc} of 1, the pore diameter extrapolates to about 0.123 microns, by definition of S_{wc}, this is the point at which the pore is completely filled with water, held by molecular forces. The effective pore diameter for flow is total diameter less coating:

$\mu_e = 0.123/S_{wc} - 0.123 = 0.123(1/S_{wc}-1)$

From the above, clearly, equations for permeability using only $1/S_{wc}$ as surrogate for pore diameter cannot be effective at predicting permeability for rocks at high S_{wc}. This is because at high S_{wc}, effective pore diameter is not close to total pore diameter, where-as for low S_{wc}, effective pore diameter and total pore diameter are nearly equal.

If a pore of diameter, d, is coated with a uniform layer of water of thickness, t, the volume of water inside per unit of length is: $Vw = \pi*d*t$. The pore volume is $Vt = \pi*d*d/4$. The fraction of water, S_{wc}, is just the ratio, $Vw/Vt = 4t/d$. It is expected that S_{wc} be proportional to 1/d and the change or derivative proportional to d^{-2}. This was the overwhelming correlation of these 2 sets of data, as shown in Graphs 2 and 3 of this data set.

The thickness of one spherical molecule high layer at NTP is the molecular diameter or 2 times the molecular radius. For water at NTP, the molecular radius estimates as:

$R = \{(3/4\pi)(1mol/6.02E23\ molecules)(22.4liter/mol)(1000cc/liter)\}^{(1/3)}$ cm or

$R = \{0.24*3.72E-20\}^{(1/3)}$ cm = 2E-7 cm or times 1E4 for microns =2E-3 and D=2r = 4E-3, which is one molecular thickness unit, t at one molecule thick layer.

Since Sw=4t/d, then 4t, is the numerator or 4 times 4E-3 equals 1.6E-2 microns,

Sw = 0.016/d and if multi-layer adsorption and surface irregularities increase height by a factor of 10, then: Sw = 0.16/d, where d is pore diameter, expressed in microns.

The empirical factor is 0.123/d. The molecular thickness and surface irregularities introduce a factor of about 80 molecules thick for liquid density.

Given the close agreement of the basic form of Sw-c by both molecular methods and by regression analysis, consideration of the implications are as follows:

- Large pore diameters imply low S_{wc} and vice-versa
- Conversely, small pore diameters imply high S_{wc}
- S_{wc} is not an effective correlation parameter for large diameter pores
- The high level of multi layer adsorption implied, indicate that surface adhesion reducing agents can be effective at increasing effective pore diameter and thus production in reserves sheltered by "tight" or formations of low permeability. If

such agents are effective, production by such means would be accompanied by liberated-water of such actions.

As pore diameter increases, correlation of permeability by S_{wc} cannot be accurate due to instrument errors. For example going from pores of 50 to 100 micron diameter implies S_{wc} changes from 0.25% to 0.12% but if estimates of S_{wc} are accurate (+/-) ½%, such changes could not be detected, nor accurately measured. Figure 9 has a good illustration of this point. It shows two types which have a large permeability dependence on S_{wc}, however there is a 3rd type which has large k values but very weak dependence of k on S_{wc}. These are classed as vug type permeability, since even at 5% porosity, permeability of 70 md is present. Additional discussion on vug permeability is given in the section on Synthetic Pore Fabric. Also since T'vich equations for vug types uses largest pore times average pore, then permeability equations for vug systems would take form of D(1/Swc-1), and not to the square of S_{wc}.

Wylie showed that porosity, ϕ, times F is a ratio of L_e/L, or $L_e \sim L*F\phi$. L_e being a measure of how much lateral movement must be made in the flow path to find a pathway around solid particles and move in a direction normal to the rock face, L. The changes in F reflect changes in the ease or difficulty of a fluid to migrate in a rock system, tortuosity. Smaller permeability represents more resistance to flow, (dp=q/kA) so as Le increases, k must decease, meaning k is inversely proportional to Le. Wylie's original permeability equation in Table 2 shows k is inversely proportional to F. Since F is generally of the form a/ϕ^2, then the increases in power term of porosity above 1, indicates increasing tortuosity of a pore fabric. For example, AAPG sandstone k equation has an order of 6 on the power term for porosity, indicating k is very sensitive to porosity changes, as compared to lower power term or less sensitive slope for k with carbonates. This mathematical fact agrees with the introduction note by Choquette and Pray.

Combining the effective pore diameter S_{wc} equation, with Wylie's tortuosity factor for an arbitary L/S of $F=1/\phi^2$ and the capillary flow equation (Table 2) gives a theoretical equation (Ref 24) of permeability:

$$k= (L/Le)31\phi\mu^2 =(1/F\phi)31\phi\mu^2 = 31\ \phi^2\ \mu^2 = 31\ \phi^2\ (.123(1/S_{wc}-1))^2 =0.5(\phi(1/S_{wc}-1))^2$$

For unconsolidated sand or oolitic L/S, (Pirson pg24, Table 3.1) $F=1/\phi^{1.3}$ then

$$k= 31\ \phi^{1.3}\ (.123(1/S_{wc}-1))^2 =0.5\phi^{1.3}(1/S_{wc}-1)^2$$

Estimation of S_{wc}, with arbitrary carbonate BVW = 0.03; 20% por, and S_{wc} equals 0.15 giving k of 0.6md. For the second instance with 0.005 BVW, 38% por, then S_{wc}=0.013, k=860md.

This formulation suggest a porosity power term to range between 1.3 and 2 when using Swc as surrogate for pore diameter, this papers' k equation correlated with a power term of 1.5, and trending of Ref. 27/28 was to lower porosity power term from 6 to 4. If BVW is used to eliminate S_{wc} and or pore diameter, the porosity power term would increase to between 3.3 and 4. The power terms of Archie type 2 and Trebin s/s and Coats-Damoir, and the formulation by this work, Table 2, have power terms well within this range.

With the above and T'vich's vug or bimodal pores formulation gives: $k=3.8D\phi^2(1/S_{wc}-1)$. Which for 4% pore, 0.005 BVW and 100 micron vugs gives k of 5.5md.

A1.2)<u>Useful Conversion Factors</u>

Permeability has basic units of area, or length times length, with 1013 millidarcy per 1 square micron. Expressed rationally, $k(\rho/\mu)_f$ has velocity units of L/t and for constant pressure drop; Q=kiA, where i is hydraulic gradient. For water, k is listed below for some materials:

Material	clay	silt	VFS	FS/S	20%clay/30%silt/50%sand
particle, mm	0.0025	0.03	0.075	nd	0.01
k gpd/sf	<0.01	5	30	150	1 (55md) (1040bpd/acre)

By using the kinematic viscosity of water, md units are: 100md= 1.82 gallon/dy/sq.ft., 1md=6900BBL/yr/acre, 1md= 1ft/yr. Wylie, p172, proposed to measure permeability in situ using a decline rate for "sloshing" effect $^{\Delta}f = Wk(\rho/\mu)_f /\rho_b$. Where ρ_b is bulk density (related to porosity, fluid density, and matrix density) and $^{\Delta}f$ is "shear decrement", related to declines in harmonic frequency of the composite. The impractical problem of separating "jostling" effects of the solid rock from "sloshing" prevented wide scale use of this method. Instead, drill stem tests and NMR logs are more commonly used to estimate insitu formation permeability. For converting surface tension, 1 psi is about 69,000 dyne/cm/cm. Some useful scale conversion factors are:

scale	exponential	hyperbolic	linear	logarithmic
Form	$Y=aX^n$	$XY = c$	$Y=aX+b$	$\ln Y = aX+b$
change	$\Delta y/y=n\Delta x/x$	$\Delta y/y=-\Delta x/x$	$\Delta y=a\Delta x$	$\Delta y/y=a\Delta x$

The first form is a general case for the next 2 forms with n=1 and –1, respectively, the 4th form, logarithmic, is also known as a half-life form, i.e. a linear change in x, gives a percent change in y, most often expressed as amount of x change for a y to decline by ½ the initial value.

A1.3)<u>Capillary Pressure Measurement</u>

The mercury capillary pressure is defined by equating capillary force to static head inside a very small diameter tube as:

$\pi r^2(psi) = 2 \pi r \gamma \cos\theta \Rightarrow r = (2 \gamma \cos\theta)/psi$ and $d=2r = (4 \gamma \cos\theta)/psi$

The results of Stout's work was regressed to arrive at an approximate value of 250 for the term $(4 \gamma \cos\theta)$. For Mercury inside a glass tube, a value of 175 is sometimes used. The term 3.67Ft of oil/psi of Hg, indicates an oil specific gravity of 0.9, Hg gravity of 13.6, surface tension of 484 dyne/cm and oil tension of 25, with the factors of 144sq-in/sq.ft. & 62.4pcf, at constant d and wetting angle. Wardlaw for large pores in dolomites of Rainbow Lake area, Alberta acted used a sheet model and value of d= 107/psi.

The Sw factor is derrived by regression of Stout and Robinson capillary pressure data:

$S_{wc} = 0.01 + 1.8$ Ft/1000 rr = 0.87; d, micron = 250/psi and Ft = psi/3.67. Ft is feet oil column equivalent of Mercury capillary pressure, psi. At S_{wc} =1, then Ft of capillary pressure is 0.99*1000/1.8 or 550 and psi = 3.67*550 = 2,020 and pore diameter in microns is 250/2020 = 0.123 microns. The equation for S_{wc} can be simplified by saying that at infinite pore diameter S_{wc} is zero, instead of 0.01, in which case one has S_{wc} = 0.123/d, microns. For large pores, effective porosity and true porosity are identical. At decreased pore diameter, effective porosity is porosity times the term $(1/S_{wc} - 1)$. This gives zero effective porosity at S_{wc} of 1.

A1.4)Effect of Vugs on Sw-c & k by Synthetic Pore Space Evaluation

A synthetic pore space was created and evaluated for permeability relationships. The pore ranges were 10 decrements of about ½ the larger value. Each pore decrement was assigned a percentile value, except the minimum value fraction was always > or = 0 and defined by ($1-\Sigma_{(max-1)}fi$). The averaging functions for pore diameter and some results are given below. Other properties calculate as follows:

BVW =$p*\Sigma(fi*Swi)$, $Swi=0.123/di$, & for calculation of: $d(T'vch)=(\Sigma(Ki)/(30*p))^{1/2}$, $Ki=30*fi*(di)^2$, $Kt=30p*\Sigma Ki$.

The significance of the various averaging functions is illustrated below in table:

Table 6 Compare diameter averaging methods

Pore arrange=>	= %	Low ¼ =%	Hi ¼ =%	mid =%	90/10Hi	90/10Lo
$d_{avg}=\Sigma(fi*di)$	77	1.0	186	14	450	50
$d_{(Sw)}=1/\Sigma(fi/di)$	**1.3**	0.5	72	5	**2.5**	**0.28**
$d_{(Ki)}=\sqrt{\Sigma(f*d^2)}i$	166	1.2	263	18	475	150
	u-m	u-m	u-m	u-m	u-m	u-m

The problem with the Blake-Kozney or Sw averaging method is that any inclusion of small fractions will over-bias the calculated average towards the smaller fractal. If one uses Sw averaging in cases where vugs are well aligned, then a severe under estimation of fluid conductivity will happen. The table shows a variation in calculation of average pore size to be about 100's between 3 dimensionally consistent methods.

It is significant that lateral relationships of a uniform pore fabric will typically not exist in natural rocks. This is relevant because: 1) Well logging tools can only survey short distances from the well bore, 2)likewise core studies have an even more restricted lateral survey than well logging tools. This rule is clear by the substantial differences in permeability calculations for uniform lateral variations and the permeability factors coming from Teodorovich Equation for canal type pores. The below table illustrates this point:

Table 7 Compare k predictive methods on synthetic pore space

	d range	avg mic	d(Sw)	d(Ki)	std dev	pore vol	BVW	K-TV	K-Sw	K-sum(Ki)
.max	500	150	150	167	47.4	24	0.115	493.0	108000	107823
.min	0.25	0.25	0.25	0.127	0.065	4	3.3E-05	6.44E-07	0.075	0.02
.Avg.	77.1	14.22	7.16	26	3.72	13.5	0.032	19.8	24	68.82
	micron, u	u	u	u	Avg u	%	v/v	millidarcy	md	md
	1	2	3	4	5	6	7	..8..de by sumK..9		10

Teodorovich valuations, col 8, of the extreme K's is two orders of magnitude less than what is calculated by the sum K method, col. 10. This concept was presented in 1936 by Howard & David, with the concept of continuous and non-continuous porosity, pp15/16. They point out, "continuous porosity is almost always restricted to immature limestone, which are rarely, if ever, oil reservoirs or to limestone with secondary porosity, which are frequently oil reservoirs…mature limestone that have not been made porous by solution, have a discontinuous type of porosity.. 'studies of asphalt bearing limestone from non – indigenous sources confirmed by segregated pockets, the concept of discontinuous porosity by lack of continuity in the asphalt pockets'… chalks coquinas, and many oolitic limestone have high porosity and may have continuous porosity to some extent… theses limestone may be considered immature and represent early stages of induration.. limestone with heterogeneous carbonate materials are most apt to form the most continuous type of secondary porosity by solution processes." Landes cites several examples where porosity from dolomitization or by re-crystallization is of a local nature and "confined to the some meters or feet adjacent to seams, bedding planes, joint cracks, fault planes, minor fractures, and fissures which supply ground water circulation and most often underground waters are ascending rather than descending, in some cases the dolomitized zone lies some few feet below a thick shale cover which is theorized to have dammed ascending waters, so that they spread out and moved laterally in the upper part of the limestone." More recently, the effect by bands of "Super K" zones have been studied in the Gawar field, both for the initial productive nature and for 'damming-off' to improve oil recovery and minimize water production.

The effect of vugs on permeability is illustrated in Figure 10. For almost identical BVW, Fig. 10 shows order of magnitude changes in permeability. These changes happen by introduction of small percent of large diameter pores. This small % of large diameter pores will have a negligible effect on BVW. However, because pore conductivity is proportional to square of diameter, this small % of large diameter, perfectly connected capillaries will be very effective conductors. A linear sum of conductive paths where vug alignment is good is the more accurate method for estimating permeability for well aligned vugs. This is the basis of T'vich canal type method, which uses the product of max D and average d, such a method is applicable to core samples. Where-as tool methods using Swc, bias towards lower size, as illustrated in the first table of this section.

In summary, permeability equations represent these complex relationships in natural rocks by factors developed in regional and local context to present information on the pore fabric relationship to average porosity and pore diameter.

Appendix 2 Movable Hydrocarbon, H/C, Factor, Porosity and BVW

Mobile H/C factor has a validity equal to the commonly accepted ratio method[2,28], for both methods apply the same assumption. The mobile H/C factor conveys more useful information than Sw by the ratio method. A basic understanding of lithology and H/C physical properties is needed for the area of investigation. Mobility ratio is similar to effective, $\phi(1-S_{wc})$, porosity term. Using movable hydrocarbon, H/C, factor, expressed as BBL/AcFt is not a new concept. Doll of Schlumberger used such a factor in the 1950's in various publications[31], as did Dresser[30]. Although used to identify producable zones, Wylie[17], considered the factor unreliable and recommended testing all potential zones. This discussion seeks to show that Mobile H/C factor is nothing less than a mapping of various minimum rules into a rational factor of H/C in place, which in-turn indicates productive potential.

In this Appendix, residual H/C saturation (RHCS) is indirectly calculated via water saturation, $S_{w\text{-}xo}$, for RHCS=$(1-S_{w\text{-}xo})$. The concept of residual HC saturation in rocks is an established fact. Residual H/C saturation is indifferent to either gas or oils, as confirmed by core studies. Relative permeability equations express existance of zero oil/water flow or gas/water flow at a finite RHC saturation. Recovery equations also indicate that residual H/C saturation exists, although other factors contribute to recovery efficiency. Given existance of residual H/C, there is a minimum H/C saturation level below which H/C production does not exist, even though rock contain H/C.

Only the 1/5 power rule, used here-in, has held regular acceptance[28,17], since introduction in the 1950's. No other methods, Tixler[41] √Sw, Hilche[42] or constant ROS, nor Naar-Henderson[40] (1+Sw)/2, have found regular acceptance for determination of ROS. For this reason the 1/5 power rule was adapted for this development, with results compared to empirical results.

A.2.1) CALCULATION of BBL/AcFt Mobile FROM LOGGING PARAMETERS

The following is a description of how mobile HC parameter is calculated using basic well logging parameters of R_{xo}, R_t, R_{mf}, and R_w. The movable HC method is as follows:

$S_{w\text{-}xo}/\sqrt{F} = \sqrt{(R_{mf}/R_{xo})}$ & $S_{w\text{-}t}/\sqrt{F} = \sqrt{(R_w/R_t)}$

And $1/\sqrt{F} = 1/\sqrt{[a(\phi)^{-2}]} = \phi/\sqrt{a'}$ so, $\phi S_{w\text{-}xo} = \sqrt{a}\sqrt{(R_{mf}/R_{xo})}$ & $\phi S_{w\text{-}t} = \sqrt{a}\sqrt{(R_w/R_t)}$

Next, it is possible to use rational coordinates of BBL/Ac-Ft by multiplying both sides by the term 7760 and H/C in flushed zone BBL/Ac-ft= $7760\phi(1-S_{xo})$ and initial HC in unflushed zone = $7760\phi(1-S_{wt})$, and the difference yields movable H/C:
Max. recoverable HC = 'Initial' less 'Flushed' =
$7760(\phi S_{w\_xo} - \phi S_{w\_t}) = \phi(S_{w\_xo} - S_{w\_t})7760 = 7760[\sqrt{a}\sqrt{(R_{mf}/R_{xo})} - \sqrt{a}\sqrt{(R_w/R_t)}]$

Max. recoverable HC =	$[\sqrt{a}]*[\sqrt{(R_{mf}/R_{xo})} - \sqrt{(R_w/R_t)}]7760$	Calculate by e-logs

Generally, F is calculated using n=2 and a=1 for most carbonate applications. However in some instances other values of F are more appropriate. Archie correlated the F factors (a/ϕ^n) for his carbonate types and the results are given below.

Table 8 Carbonate Formation Factor Values

Generic	Archie I	Archie II	Archie IIIa
.n 2	2.2	2	2
.a 1	1.25	1	0.9

In order to keep the simplicity of n=2 it is possible, in a limited porosity range, to represent carbonate F factors using a': a' is a psuedo factor when using n =2.

The variances in root of 'a' are as follows:

Table 9 Root factors for n=2 Archie Formation Factors

	Type I cap roc ϕ<7% Compact Crystal	Type 1 ϕ>7% Compact Crystal	Type 2 chalky	Type 3 oolitic or sucrose
√ a'	1.50	..1.39	1.00	0.95

A.2.2) Doll's Derivation, the Ratio Method and Calculation from PSP Log Parameter

The following is valid in zones where shale is not significant and it gives rise to the ratio method

$R_{xo}(S^2_{xo})/R_{mf} = F^*$ & $(S^2)R_t/R_w = F$ & $F^*=F$, then: $R_{mf}/R_w = R_{xo}(S^2_{xo})/(S^2)R_t$ & $SP/-K=\log(R_{mf}/R_w)$

$SP/-K = \log(R_{xo}(S^2_{xo})/(S^2)R_t) =[\log(R_{xo}/R_t) + 2\log(S_{xo}/S)] = \log(R_{mf}/R_w)$

{Aside: the above eqn. Gives rise to the SP plot method by using $S_{xo}=S^{0.2}$ & $S_{xo}/S=S^{-0.8}$
Aside: plot $x=(-SP/K)$ vs. $y= [\log(R_{xo}/R_t) – 1.6\log(Sw)]$ to be applied only in shale free sections}
It is possible to show that the ratio method is just a logarithmic expression of the movable HC method, less the conversion factor of 7760bbl/AcFt by suitable re-arrangement of SP terms:
$\log(R_{mf}/R_w) = [\log(R_{xo}/R_t) + 2\log(S_{xo}/S)]$

$[\log(S_{xo}) - \log(S)] = \log(R_{mf}/ R_{xo})^{½} - \log(R_w /R_t)^{½}$

The above derivation shows the ratio method to be an arrangement of movable HC terms into a logarithmic expression of the same basic terms. In such a view, expression of movable HC in BBl/AcFt seems to be a more rational unit of expression. When expressed as movable HC, information is given about both HC mobility and recovery potential.

Doll's original method used the ratio technique with the, 'root a' is set equal to 1.00. The Ratio method, is the most basic technique and when shale free, Sw is:

$Sw = [(R_{xo}/R_t)/(R_{mf}/R_w)]^{0.625}$

Doll's chart accounted for shale presence using $S_{wxo} = S_w^{0.2}$ and BBL/AcFt is:

$$\phi(S_{w\_xo} – S_w)7760 = \phi[S_w^{0.2} – S_w]7760 = S_w\phi[S_w^{-0.8} – 1]7760 = \sqrt{(R_w/R_t)}[S_w^{-0.8} – 1]7760$$

Doll then solved Sw with Schlumberger Research PSP shale equation, which corresponds to calculation of Sw by the ratio method using an exponent of (1-Vsh)0.625. If shale volume is 1, then Sw is always unity, and if shale free, Sw calculates as conventional ratio-Sw. Doll's chart used the ratio of PSP divided by SSP as (1-Vsh). PSP is the actual SP corrected for bed thickness and resistivity, SSP is the ASP in a thick, clean bed or use the ratio Rmf/Rw and K(T). Alternatively, Vsh could be calculated by gamma tool or other applicable methods.

Finally, Doll's mobility chart[31] applied a recovery efficiency to the mobile HC factor. These values need to be divided by Bo, if reference is made to stock tank barrels[31]. His recovery efficiency was dependant only on the production mechanism and oil gravity, API. For water drive, Doll's recovery efficiency is approximately $0.038(API)^{0.84}$. If production is by pressure depletion, an approximation to Doll's recovery is obtained by subtracting the following value, bbl/acft from the water drive value, $2.5(bbl/acft)^{0.45}(API)^{0.38}$. If after subtraction, the value is negative, then recovery is zero. This corresponds to a minimum mobile HC factor of about 110bbl/acft, at 30API.

B) Baselines for Minimum Mobility Values: Section 1: Empirical Values

B.1.1) Dresser Method

In the early 1950's when Doll expounded his method, it was common to discuss recovery in terms of BBL/AcFt, akin to recovery in terms of porosity.

Table 10, Ultimate recovery factors for various reservoir conditions.

Dresser Recv. Factors	H20 Drive	Depletion &/or Gas Drive
High visc=low recv.	bbl/AcFt/(%por)	bbl/AcFt/(%por)
Min	5 Lo k & low API	3 Frac L/S, hi consol SS
Max	35 Hi md & API	15 IntGranular L/S, unconsl SS
Average	20 Avg md & API	10

Using the water drive average factor of 20, and 5% minimum porosity and 50% efficiency one comes to 20*5/0.50 or 200BBL/AcFt of mobile oil. It would then be expected, that on average, lesser values are unlikely to be perspective. Using a factor of 5, and 5% minimum porosity and 15% recovery efficiency gives, 5*5/0.15 or 167 BBL/AcFt of mobile oil.

B.1.2)Mobile HC as a Mapping Parameter

The Movable HC ratio can be mapped as an expression of maximum S_{wc}, minimum porosity, or minimum permeability, i.e. $(BBl/AcFt)_{mo} = 7760[\phi(S_{wxo}) - \phi(S_{wo})]$,

B.2.1) Max Swc

$= 7760\phi(S_o)[(1/S_o)(S_o)^{0.2} - 1]$, & using $(S_{xo}) = (S_{wo})^{0.2}$ with $\phi(S_{wc}) = (BVW)$, then

$(BBl/AcFt)_{mo} = 7760(BVW)[(S_{mx})^{-0.8} - 1]$

The problem with exclusively using a maximum Sw rule, is that it leads to excessive testing in low porosity formations and inadequate testing of high BVW formations. For example, at Swc of 0.53 and 0.1BVW, the Sch97 equation calculates 5md and minimum mobility is 514 bbl/acft.

Maximum recommended Sw by AAPG using ratio method are; 0.64 in SS & 0.53 Carbs. By this maximum rule and 6% minimum porosity, the respective mobility ratios are: 129 and 163, at BVW's of 0.038 and 0.032. These BVW's evaluate as medium grain size. At BVW below these values, the porosity is less than 6%. At BVW greater than the above and at constant Swc, calculated minimum permeability values exceed accepted minimums.

B.1.3) Minimum Porosity

$\phi(S_o^{0.2} - S_o)7760 = 7760\{\phi^{0.8}(S_o\phi)^{0.2} - S_o\phi\} = 7760\{\phi^{0.8}(BVW)^{0.2} - BVW\}$

at Minimum Porosity of 6%: $(BBl/AcFt)_{mo} = 7760\{0.11(BVW)^{0.2} - BVW\}$

The min porosity function causes mobile HC factor to increase with decreasing BVW, up to a maximum close to zero BVW, opposite to constant Sw function, above, which increases with BVW. The min porosity rule excludes possibly productive formations when applied to vuggy types, ie at 0.005BVW, min mobility is 206 and Sch97 k calculates at 2md. A minimum permeability plot has a wider range of BVW. A minimum permeability rule reduces over and under testing possibly introduced by min porosity or max Swc boundries rules.

B.1.4) Minimum Permeability

Mapping by minimum permeability is most easily shown by using the older power term type formula, i.e. Timur, for permeability. First, substitution of $S_{wc}=BVW/\phi$ in Timor's equation gives: $K_{min} = \{92.6(\phi)^{2.2}/(S_{w\text{-}c})\}^2 \Rightarrow \phi_{min} = \{\sqrt{K_{min}} * BVW/92.6\}^{0.313}$ next using these terms in the movable HC formula: $7760[\{\sqrt{K_{min}}/92.6\}^{0.25}(BVW)^{0.45} - BVW]$.

Permeability equations using only $\{1/(S_{w\text{-}c})\}^2$ follow an inverted parabolic form, Figure 11A. The origin is close to 0,0, and increase to a maximum at some BVW value, afterward approaches zero with increasing BVW. The Timur equation has a maximum BBL/Acft at $BVW = 0.03K^{0.23}_{min}$ and decreases to zero at $BVW=0.13K^{0.23}_{min}$. Permeability equations which do not use the term $(1/S_{wc}-1)$ cannot accurately depict effect of high S_{wc} values and incorrectly bow back towards lower movable HC ratios after reaching a maximum. Acknowledging these short comings, the Timur equation at k_{min} of 0.21md yields limits of between 131 and 198 bbl/acft with BVW range of 0.024 to 0.055.

Use of more accurate permeability equations with the form (1/Sw-1), require numerical solution of an implicit minimum porosity term. Figure 11A shows the Schlumberger '97 sandstone revision and this papers' carbonate equation correctly increase movable HC ratio as BVW increases. As previously described in this discussion, increased BVW is due to smaller pore size which translates to increased retention of immobile fluids in rock pores.

Solution for minimum porosity with this papers equation is possible by numerical methods. Approximations for porosity with this paper's equation are:

$\sqrt{[0.60*BVW\sqrt{(K_{min}/10)}+(BVW/1.9)^2]} + BVW/2.3 = \phi$

$(K_{min}/10)^{0.67} = \phi$ (if $S_{wc}=BVW/\phi$ is close to 0.5)

$(\sqrt{BVW})(K_{min}/10)^{0.30} = \phi$ (if $1/S_{wc}=\phi/BVW>>1$)

If the first approximation is substituted into $7760\{\phi^{0.8}(BVW)^{0.2} - BVW\}$, it gives a mobile HC at BVW=0.024 and K_{min}=0.21md, of about 175bbl/acft, and 260 at 0.055 BVW.

Source	Kmin	BBL/AcFt	rr
Sch'97	0.0md	20.6ln(BVW, v/v) + 221	0.94
Sch'97	0.7md	51ln(BVW, v/v) + 458	0.93
This	0.0md	34ln(BVW, v/v) + 220	0.99
This	0.7md	$1778(BVW)^{0.524}$	0.999

Figure 11B shows each BVW value has an extrapolated zero permeability value of mobile HC. Results are provided in the Table at right.

In summary, Figure 11B & equations show that BBL/AcFt movable, is nothing less than a mapping of BVW into a more rational term, mobile HC. Stated otherwise, given a minimum acceptable permeability, greater than or equal to zero, each value of BVW corresponds to a minimum mobility value.

This concept is illustrated in this table, using the range of accepted values for BVW and an average equation for zero permeability, as above.

Table 11

Mobile H/C values at extrapolated k=0.0md

	Min bvw	max bvw	min bbl/AcFt	mx bbl/AcFt
vug carb	0.005	0.015	72	102
vug & IX carb	0.015	0.025	102	117
Intr gran crb.	0.025	0.04	117	130
Chalk carb	0.05	0.1	136	156
	BVW	BVW	28ln BVW +220	
coarse ss	0.02	0.025	110	117
medium ss	0.025	0.035	117	126
fine ss	0.035	0.05	126	136
v.fine ss	0.05	0.07	136	146
siltstone	0.07	0.09	146	153

Table 11 indicates a minimum mobile HC range between 150 bbl/acft for fine grains, and 110 for coarse or intergrainular porosity types.

B2) Min. HC Mobility from Data:

B.2.1) Plot of Core Values as Mobile HC vs BVW

A plot of core values reporting porosity, permeability and connate water in terms of mobile HC vs BVW is given in Figure 12b. The graph indicates at each BVW level, higher mobility ratio correspond with higher permeability values. Plotted also are three tie lines. Two of the tie lines are of minimum permeability by this paper's equation at 0.3 and 0.1 md. A third tie line is that of S_{wc} =0.5. This tie line of 0.5 S_{wc}, shows when testing rocks of BVW< 0.055 will likely result in over-testing, or uneconomical production.

If on the other hand, testing based on the criteria of 0.3md line will likely prove economical, provided stimulation costs are not excessive. The 0.3md line was regressed to the form: BBL/Acft(min) = $1140BVW^{0.48}$. This calculates a minimum mobility ratio of 190 at bvw=0.024 and 283 at BVW of 0.055. Mobility values at or above the 0.3 md line are most certianly productive. While the 0.1md line regressed to: $y = 568BVW^{0.434}$ Mobility values falling close to or below this tie line are unlikely productive, without presence of a secondary porosity.

B.2.2) Production Practices

The previous sections indicate minimum mobility ratio is defined by exploration criteria, but how does production practice compare with these values? Schmoker, Krystinik, Halley[35] reviewed production characteristics of some three thousand, 3000, carbonates reservoirs in the USA as reported through 1980. They show that production from Limestone, L/S, is substaintly different from that of Dolomite. There is an important difference in production from low porosity units, with dolomite production at about ½ the porosity of low end limestones.

They reported results in terms of histograms for various parameters. Table 12A shows that less than 5% of producing L/S reservoirs had porosity under 5.3%, but at 2.7% porosity units for dolomites. While 95% of all production was from reservoirs of under 20.5% porosity units, 19% for dolomites.

At the upper limit of connate water saturation, SKH reported fewer than 4% of L/S reservoirs produced with connate water levels over 52.5%, and under 3% of dolomites produced from connate water over 52.5%. The median Swc was 30%, with a normal distribution of 78% L/S and 74% of dolomites at Swc between 17.5% and 42.5%.

Table 12A & B After, Schmoker, Krystinik, Halley

A) USA Production Statistics of Porosity & Water Saturation

	%pore Low'r 5%	%pore Low'r 10%	%pore median	%pore up'r 10%	%pore up'r 5%	%Sw Low'r 10%	%Sw median	%Sw up'r 10%	%Sw up'r 5%
LS	5.3	7.0	12.9	15.2	20.5	17.5	30.0	43.0	50.0
Dolo	2.7	3.9	10.1	16.6	19.0	17.5	32.0	45.0	49.5
LS*	**153**bbl/acft				*844bbl/acft*	*0.53*	0.49	0.41	**0.37**
Dolo*	**78**bbl/acft				*781bbl/acft*	*0.53*	0.48	0.40	**0.37**

B) USA Production Stats, Extrapolated Values from Permeability

k	%por	%por	%SWc	%SWc	LS	Dol	% LS	%dolo	L/S	dolo	L/S	dolo
md	LS	dolo	LS	dolo	bl/AcFt	bl/AcFt	Prdn	Prdn	BVW	BVW	K, md	K, md
<5.0	7.5	6.0	44.9	38.0	**236**	**207**	27.0	45.0	0.034	0.023	0.31	0.38
<150.0	19.7	19.4	11.0	7.2	**813**	**777**	80.0	89.0	0.022	0.014	51.56	124.92
=0.21	4.0	4.0	37.0	37.0	**139**	**139**	3.0	9.0	0.015	0.015	0.21	0.22
Unkn	2.0	2.0			**55**	**55**	1.0	6.0	0.010	0.011	0.03	0.02
Avg	12.9	10.1	17	17	**535**	**439**	50%	50%	0.020	0.017	12.19	6.92
N	2166	866	982	499			1352	510			Clc'd	Clc'd
A	B	C	D	E	F	G	H	I	J	K	L	M

Less than 2% of dolomite, and 1% of L/S production under 7.5% Swc. If it is assumed for dolomites, the lower 5% of production were from the upper 5% of Swc, (50%Sw), the movable HC comes to 78bbl/acft and likewise at 153 for L/S. The bottom right hand rows compare the variation of the function ($S^{0.2}$ - S). The variation of this function between upper 5% and lower 10%, which includes 85% of all samples has a variance of only 30%, while over the same range, porosity varies by between 300% and 430%. This indicates porosity is a more influential parameter than water saturation.

Looking at the data by moveable oil saturation, BBL/AcFt shows an average H/C saturation level between 535 and 439 bbl/acft. Also, 80% of all limestone, L/S, reservoirs and 85% of all dolomites produced from rocks with a mobile oil content under 813 bbl/AcFt. A high percentage of L/S (27%) and dolomite (45%) reservoirs produced with modest porosity levels, HC saturation values, 240 and 210 bbl/acFt. The movable HC saturation value was calculated by taking the water saturation in the flushed zone as water saturation raised to the 0.20 power. Of interest to the authors were the significant amounts of production below 6% porosity.

An estimation was made for well productivity from porosity under 6%. SKH data showed a median depth of L/S reserves to be 3,630 feet and 4,050 feet for dolomites, with an average thickness of 22 feet and 18 feet respective. A medium gravity oil of 32API, dead oil viscosity of 16 centipoise, 0.43 psi/foot pressure gradient, draw down of 1/3 available pressure gradient was used for this calculation. The formula used for calculations are detailed in another section. The cost of a stimulated well was put at $200k and a 1.5 year payout time required at $40/bbl oil selling price. For either L/S or dolomite, a well stimulation factor of five was used, assuming zero skin factor. This means economically required production rate was divided by five, to calculate required well permeability. A permeability of 0.21 was calculated in either case, L/S or dolomite. This corresponded to an initial well production of 1.83 bpd. Such low production figures would preclude completion without stimulation. Acid stimulation in carbonates is typically effective and can improve J by a factor of six, or more, pg 51 ref 24. Using the permeability equation of this paper and 5% porosity, Swc calculated at 42% and movable HC at 160bbl/acft. This gives an indication of the lower limit of normal carbonate production, in the absence of secondary porosity or vug type porosity.

Production enhancement from secondary porosity, or fractures was cited by SKH as cause for the high production levels from lower quality rocks. Proof of this idea, can be seen in production levels from porosity levels under 6%. SKH cite 6 porosity units (195bbl/acft mobile) as commonly chosen for a lower economic unit in mapping net feet of porosity reserves. They state: "it is doubtful that carbonate reservoirs with matrix porosity of less than 6% … could be viable unless fractured… under similar conditions dolomite has greater ultimate strength and is less ductile than limestone… dolomite is more likely than L/S to yield by fracturing than by intergranular flow … fractures in dolomite are more effective than fractures in limestone... because the greater mechanical strength of dolomites act to keep fractures propped open." For example on the very lower end of the production scale, dolomites are 6 times more likely to produce than is L/S.

Why are deposits with porosity under 4% producible? . In the case of Limestones, only 1% of all L/S completions were in such low porosity rocks. This could be explained by operators making bad economic decisions. Allowing a two percent rate of bad decisions, still leaves 4% of dolomite completions in what would appear to be low productivity formations. The SKH explanation of dolomite reservoirs having secondary porosity factors appears to be sound reason for these high completion levels, in what would otherwise be an abandonment. In theory, there is no lower porosity limit on production from large vugs or large secondary fractures. Practically speaking, SKH data indicate:

- o Less than 1% of L/S reserves would be overlooked by neglecting L/S formations with 70bbl/acft mobile oil or less.
- o Less than 4% reserves gain is likely in L/S formations if values under 95 bbl/acft movable are produced. Addition of these reserves will prove to be more expensive, due to the nature of sand prop acid frac work.
- o On the other hand, were the same criteria applied to dolomite deposits, one would overlook 15% of available reserves.
- o prospecting in dolomitic rocks of low quality is likely to be 3 to 6 times more productive than prospecting in similar low quality L/S rocks
- o a viable exploration criteria in L/S appears to be 145bbl/acft movable but there is no lower criteria, with secondary porosity. The below table puts this value into perspective. For the normal range of L/S bulk volume water, the extrapolated zero permeability ranges between about 85 and 105 bbl/acft, mobile.

BVW	0.01	0.02	0.03	0.04	0.09
zero k bbl/acft mobile.	63	87	101	111	138

In ideal conditions, Mobile HC values may exceed 1250bbl/ac-ft, in practice, 85% of carbonate production in USA is from rocks of less than 850bbl/acft and 90% of USA production is from rocks exceeding 150bbl/acft. Mobile HC expressed as BBL/Acft is a handy way to express various min/max rules, provided deposit lithology is understood. The closer values are to litho-minimums, the less the chances of economic HC extraction. Low mobility values also indicate low permeability and reduced chance of economical production.

The minimum mobile HC ratio, expressed as BBL/AcFt is a rational expression of various screening criteria boundary rules and is equal in validity to the ratio method. In instances where a porosity log is unavailable, it may be the only available screening criteria.

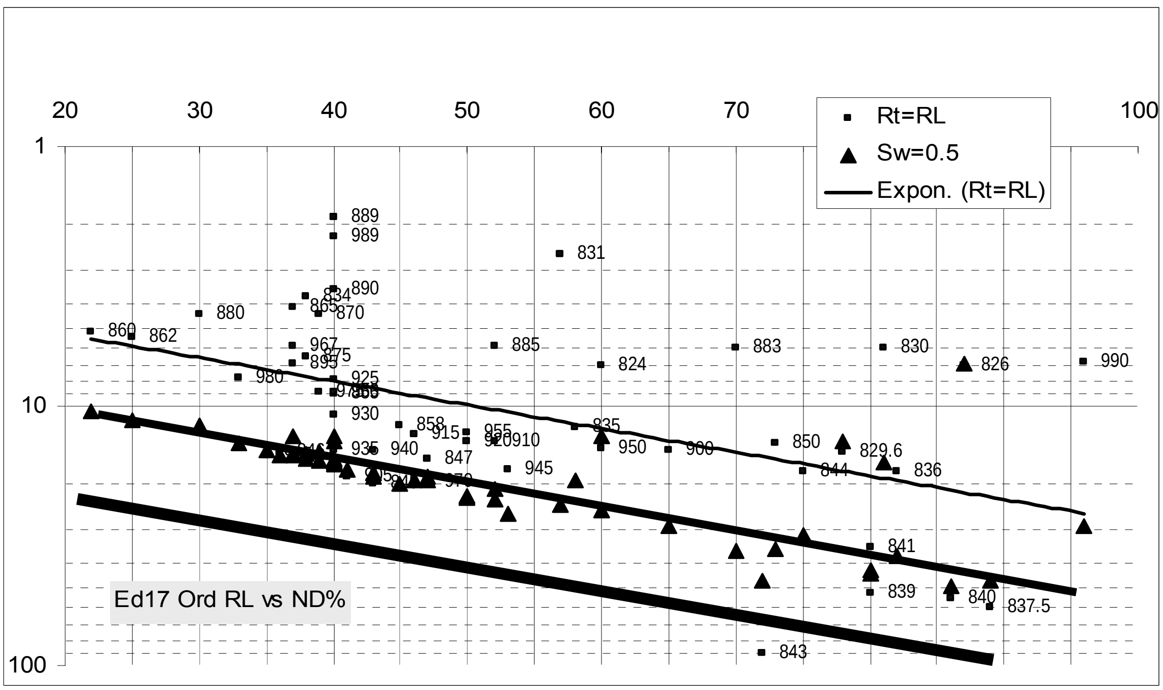
Basis	Criteria	Eqn	BVW	min	BVW	min	type
Doll	30^{o}API	a	n/a	117	n/a	110	ss?
Dresser	5%p min prod'n	b	n/a	170	n/a	200	ss
Max Sw min p	Sw0.52, 0.64 p=6%	c	0.031	165	0.038	127	.cb/ss
Min k	0.3md	f	0.020	174	0.055	283	carb
Archie	0.3md	d	Avg	167	.04		carb
Stout	0.1md leaky cap R	d	0.018	151			carb
SKH US pdn	5%Porosity 0.21md	d	0.021	160			LS/dolo
SKH US pdn	Lower 5% of Prdn.	d	0.005	80			Dolo
Min Crb pdn	$780BVW^{0.44}$	h	0.02	139	.055	220	crb

a)$2033/API^{0.84}$ b)[34 or 40]%p c) $7760(BVW)[(S_{mx})^{-0.8} -1]$ d) $7760\{\phi^{0.8}(BVW)^{0.2} - BVW\}$
e)zero k= 28ln BVW +220 f)0.3md= $1140BVW^{0.48}$ g) $7760(\phi)[(S_w)^{0.2} - S_w]$ h) min crb$780BVW^{0.44}$

From the above summary table, the following conclusions seem valid:

- Vug or /2nd porosity, may have mobile HC of 90 or less. Statistical occurrence is only 6% of dolomite reserves and insignificant from L/S.
- 10% of US production is from mobile HC under 160 with Dolomites being the main source of low porosity procuction.
- If chalks or silts are present, production mobile HC criteria is upwards of 180
- Minimum HC mobility may be calculated by $780BVW^{0.44}$
- Given lithology, values less than these minimums are likely to be cap rocks
- 80% of US production is from 850 BBL/acft & average mobility of US production is 400 bbl/acft
- Increased mobility equals increased chances of a productive formation, especially within a given rock type, constant BVW

Example: Latvian Well Edole 17



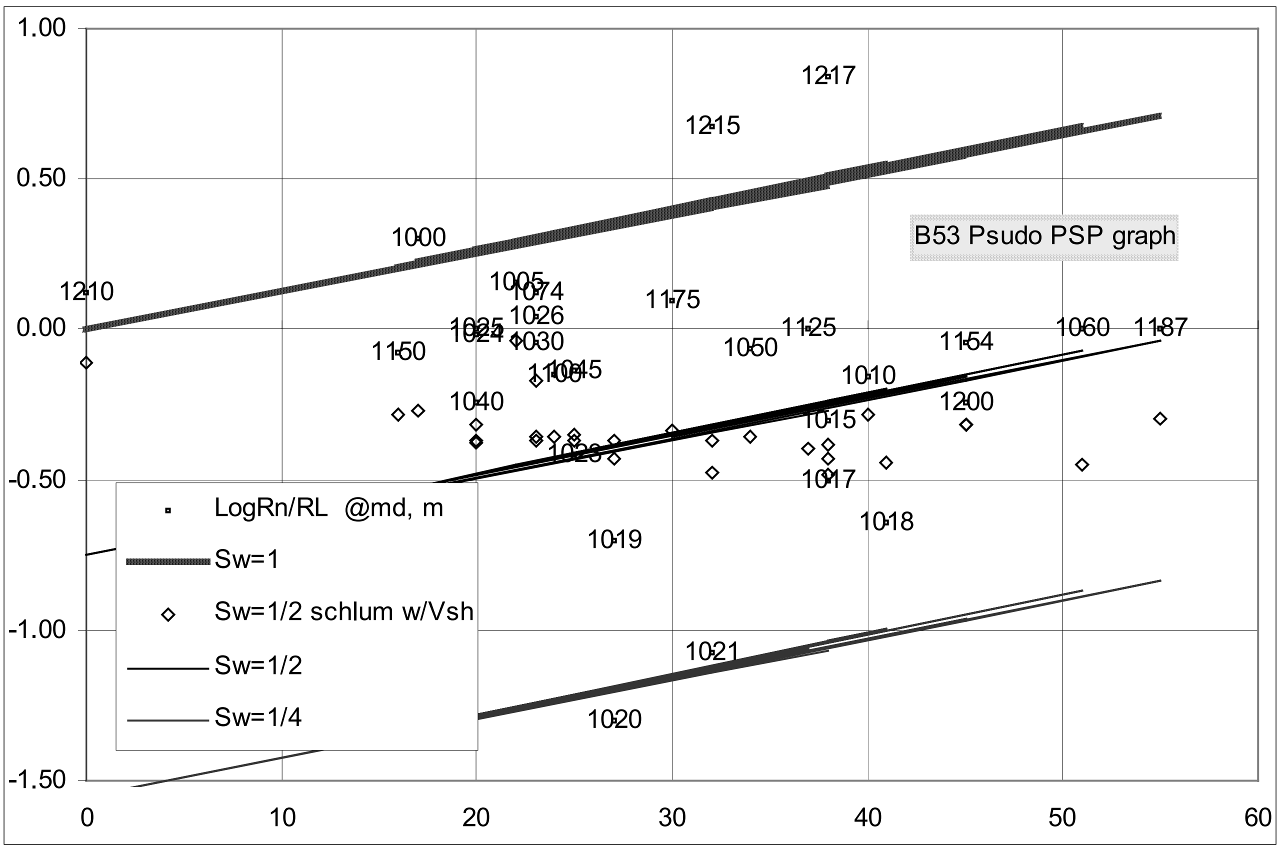
Three points one the above plot are selected, in order of lower Sw, at 843, 839, and 841 meters. Two methods are available for calculation of mobility ratio, when using Pickett Plots: 1) $(R_w/R_t)^{½}$ 2) use psudo resistivity of R_{ts1} at Sw equal 1. This value is directly read from Pickett plot at constant porosity, vertical from the point where Sw is read, in which instance BVW is $S_w(R_w/R_{ts1})^{½}$.

The results of mobility and BVW were averaged due to wide variance in

Rt at d	Rt/Rw	Sw	Rx/Rmf	d, m	M	BVW	por	min M
100	833	0.19	56	843	768	0.035	0.19	178
52	433	0.35	81	839	491	0.048	0.14	205
35	292	0.50	96	841	337	0.059	0.12	224
Rt(S=1)	Rw	Sw	Φ	F			alt. 1	
16.5	0.12	0.19	0.085	138	350	0.016	0.094	126
19	0.12	0.35	0.079	158	284	0.028	0.069	161
19	0.12	0.50	0.079	158	229	0.040	0.059	189

calculated porosity. The respective results show ratios of Mobility to that of minimum producable mobility of 3.6, 2.1, and 1.4. These ratio, imply that best performance will be obtained at a depth of 843, with 841 meters being the least perspective.

Well B53 log suite data did not use a porosity or density tool, only GR, SP & 3 e-logs. In the O1 section at 1016 and 1022m, the SP log increases, at const GR, a certain indication of oil. The first section test for oil flow, but this section section was never tested. Lets see what prognosis can be developed for that section. The ratio method gives the value of $R_{mf}/R_{xo} = (R_t/R_w)/S^{(8/5)}$. From which



APPENDIX 3

Application Notes Upper Ordovician Section, Western Latvia

Application of this method is given for some wells which have been previously logged and tested. In this application, porosity is missing or difficult to calibrate to Neutron Deflection units. Thus, this analysis used resistivity values to construct a comparison table. Mud filtrate resistivity values are not available, and considerable effort was made to estimate water resistivity. Values from the Normal sonde are used to approximate Rxo, and Long Survey Sonde resistivity is used for Rt. The average ratio of Rxo/Rt for a 20 meter section is used to estimate Rmf/Rw and Rw of 0.13 o-m at 20C is used to calculate Rmf.

The API recovery factor and conventional recovery are calculated as follows:

BBL/AcFt= (%Rec/100)7760ϕ(1-Sw)/Bo, the term Bo is unrelated to reservoir properties and is taken as 1.00 in calculating movable HC, but can be estimated, when needed, by: $1.05+5GOR/10^4$ or alternatively, 1.05+5(depth, ft)/100,000. The differences between oil in place recovery and movable HC are: 1) movable HC does not use (1-Sw), but $[S_{wc}^{0.2} - S_{wc}]$ & although the two factors are often close, they are never-the-less not equal, 2) statistical recovery factor results from a variety of environmental factors beyond what is experienced in a bore hole, 3) Sw and S_{wc} may not always be equal but if Sw is much greater than S_{wc}, then actual oil flow will be reduced by water flow and movable ratio is still likely to be a good indicator of actual oil flow. The API recovery is estimated by:

%Rec. gas drive: $41.8\{\phi(1\text{-}Sw)/Bo_{bp}\}^{0.161}(k/\mu_{bp}1000)^{0.098}(Sw)^{0.372}(P_{bp}/P_{abd})^{0.174}$

%Rec. H_20 drive: $54.9\{\phi(1\text{-}Sw)/Boi\}^{0.042}(k\mu_{wi}/\mu_o1000)^{0.077}(Sw)^{-0.19}(P_{abd}/P_{init})^{0.22}$

%Rec C&H H_20 drive sands: $0.114+0.272\log k+0.256Sw-0.136\log\mu_o-1.538\phi-0.00035h$

%Rec C&H: $100(1-(0.292-0.044\ln k)-\exp\{0.034(\ln\mu_o)^2+0.093\ln\mu_o-1.11\})$

Both Sw and porosity are in fractions, not percent, Pressures: bp=bubble point, abd= abandon, and init= initial, h is formation producing interval in feet, k is in millidarcy, viscosity, μ, is in centipoise, wi= water initial, o=oil

The dead oil viscosity, μ_d, cp at T, F, $\log(\log(\mu_o+1))= 3.0324-0.02023API-1.163\log(T,F)$

The saturated oil viscosity, u_o, cp at T, ~ (μ_d at T)*exp{-3.3(GOR, scf/bbl)/1000} or by

[Bo(μ_d at T)]/{1+4(Bo-1)(μ_d at T)}, and Mehan list the bubble point pressure by

ln(Pb,psia)=(1/B)ln[GOR/(A*SGg*exp(C*API/T,R))], with A=0.0362,B=1.094,C=25.72 and if API >30, then A=0.0178,B=1.187,C=23.93, with gas SG taken at 114.7psia. The API gravity = 141.5/sg – 131.5, sg = g/cc. Water viscosity, μ_{wi} , is: cp=exp(3106/(460+F) –5.918) and add 5% for each 40,000ppm of salinity i.e. for 100F and 100,000 ppm, water viscosity is 0.8cp.

Porosity may be estimated as follows:

$\phi = [\sqrt{a}]*[\sqrt{(R_{mf}/R_{xo})} - \sqrt{(R_w/R_t)}\ ]/[S_w^{0.2} - S_w]$,

The above method is valid only for S_w <1. In zones void of HC accumulation use: $F=a/\phi^n = R_{mf}/R_{xo} = R_w/R_t$, with R_{xo} being more accurate in holes of good caliber.

Aside: For this cap rock, shale content is zero or very low, but some sections may not be and, the degree of shale effect can be rapidly estimated by closeness of the ratio: $(F_{s\text{-}xo}/F_s)^{0.63}$ to 1.00. If this ratio is off by more than 8%, then corrections to the above may be necessary by using apparent aqueous resistivity: $R_{mf\text{-}a} = F_{sxo}R_{mf}$ and by $R_{wa}=F_sR_w$ for calculation of Sw and porosity and max recoverable HC, BL/AcFt by:

$[7760/B_o]*[\sqrt{(R_{mf}/R_{xo} +(CR_{mf}V_s/\phi R_s)^2)}-\sqrt{(R_w/R_t +(CR_wV_s/\phi R_s)^2)} +C(R_w - R_{mf})\phi(V/R)_s]$

The above was arrived at using Simandoux equation for water saturation and noting that $5c^2$ is often close to unity, which retains a close resemblance to the original Doll form, with exception of three new terms. Where C is Simandoux shale constant, 0.45 carbonates, 0.4 for s/s and F sub shale is

$F_s = 5C^2/\{1+2C(FR_w/SW)(V/R)_s\}$ & $Fs\text{-}xo= 5C^2/\{1+2C(FR_{mf}/SW_{xo})(V/R)_s\}$

A3.2) Calculation of well production using Skin Factor

Parts of the statistical database of American carbonate production can only be explained in terms of well stimulation. That database shows the degree to which marginal carbonate formations are susceptible to stimulation by hydraulic fracturing and acidization. This brief discussion is given to show the basis of artificial well stimulation. In the first instance, the production of an ideal well with a pressure boundary is calculated by:

.q (bpd) = (dp, psi)(k, md)(h, ft)/[141B(u, cp){ln(re/rw)-c+s}]

The term, ln(re/rw)-c typically ranges between 6 and 8, Ref.36p5 & Ref 3p284/5. The skin factor is S. Skin factor is a term used to describe either the degree of well bore damage or alternatively the degree of well stimulation. In the case of neither well bore damage nor stimulation S=0. If well bore damage exists, S is a positive number with no upper limit. When a well is stimulated, S will be a negative number, the absolute value being always less than ln(re/rw)-c. "Rarely does a well have S less than –7 or –8, and such skin factors arise only for wells with highly conductive, deeply penetrating fractures", Lee p5. Others state that if S is more negative than –6, the test data is usually suspect. From which it is concluded, that the value of ln(re/rw)-c, is seldom more than 6 in practical applications.

A common term used to describe well flow is the J factor, which gives rise to well efficiency:

J=q/dp = kh/{141.0*u*B*[ln(re/rw)-c]} & Je = kh/{141u*B*[ln(re/rw)-c+s]} & Ew=Je/Jw.

Finally, if ln(re/rw)-c is taken to have a maximum value of 6, then well efficiency is :

Ew = Je/Jw =1/(1+S/6)

Stimulation practices can typically improve J by a factor of six, or more, pg 51. ref 24. This corresponds to an S of (–5) in the above equation.

The above equations are general in scope, but for purposes here, it describes single phase flow. An oil well will stay in single phase flow, if the face pressure of the well bore exceeds bubble point pressure. Single phase flow can be sustained, provided gas saturation values are less than critical level, typically between 5% and 10% free gas. Carbonate sections can be over pressured when adequate sealing exists, and formation consolidation prevailed after oil migration or generation. This constrains well dp to a value close to the difference of the external pressure and the bubble point pressure or the water coning differential pressure. In many instances, this maximum pressure differential is something between 20% and 40% of the normal pressure gradient. If no better information is available, the pressure gradient can be taken as either, 0.43 psi per foot of depth or (mud wt, ppg*0.052=psi/ft). For example, a well producing from 4000ft has a net pressure of 1720 psi, and maximum draw is 688psid.

If oil viscosity and volume factor are unknown, they may be estimated as above, given bottom hole temperature and oil gravity. For example, the 1980 database average limestone well was at a depth of 3630 feet, in a 22foot thick section of 12md, with a likely bottom hole temperature of 140F and 30API oil. Such conditions would indicate a B of 1.23.

Analysis of Latvian Deposits

C&H method estimate an oil deposit of 2 cp in a 10 foot section of sand having 1000md, Sw of 0.25, and 0.2 porosity to have a 75% chance to be 64.2% recoverable plus or minus 10%. C&H's simple method estimates about the same recovery using only viscosity and permeability. The C&H simple method predicts that oil deposits with viscosity exceeding 90cp are not recoverable by primary methods. Which implies costly secondary processes are required to obtain any appreciable recovery. The C&H simple method is somewhat contradicted by the Latvian Cambium deposit, where a 30 day pump test produced with 75% oil and 25% brine cut of 100,000 ppm salinity. However, relative permeability calculations indicate such a high viscosity oil will be rapidly overtaken by water production, leaving behind a deposit needing expensive viscosity reducing methods to further extraction, even with excellent sand permeability.

The concept of relative permeability provides an important cross check to recovery estimates. This method is quickly applied to oil-water systems, such as the Adza deposit of Latvia. For example, at an insitu oil viscosity of 100cp and a brine viscosity of 0.9cp, and economic recovery ending at water to oil ratio of 8 to 1, the water saturation calculates as:

.$k_o/k_w=(q\mu)_o/(q\mu)_w$ = (1*100)/(8*0.9) = 13.9 & for k_o/k_w = 1220*exp(-13Sw) => 13.9=1220*exp(-13Sw) to give Sw of 0.34. This implies a possible recovery of about 31% for 5% initial Sw, obtained by pumping out and re-injecting 8 volumes of brine for each oil, the same calculation for 1/1 ratio gives a recovery of 14%. Other environmental factors could reduce recovery, such as water coning, permeability streaks, oil-water interface, etc.

Below are some reported sample values for oils recovered from various wells in Latvia.

REPORTED SAMPLE VALUES

Well	Fm'tn	por%	md	sg/20C	cp/20C	API/20C
J-E6	upper	17.4	40.5	0.836	6.3	37.8
B2	upper	nd	nd	0.87	20	31.1
B6	upper			0.854	23.7	34.2
B53	upper	9.4	0.24	0.876	8.5	30.0
D36	upper?			0.855	18.6	34.0
D15	upper?			0.853	16.5	34.6
K15	lower	15.9	82.7	0.887	10.7	28-29.5*
KA6	lower	16.0	14.9			
K11	lower	5.3	0.04			
V19	lower	9.4	0.01			
K2	cambr.	15-22	>500	0.8912	128/200*	27.3/23.5*

REPORTED DEAD OIL ANALYSIS

Well	Fm'tn	vabp C	sg/20C	cp/20C	API/20C	UOP K
K2	C2/3	342	0.8912	128	27.3	11.58
K15	O1	337	0.8866	10.7	28.1	11.61
Ed17	O3	332.4	0.858est	nd	33.4est	11.97

*USA analyzed sample, increased s.g. & md. typically represents sample aging prior to analysis. All samples on dead oil. The GOR of Latvian Ordovician oils is not expected to exceed 250 scf/BBL, based on observation and reports for Lithuania Ordovician oil. Cambium oil is expected to be even less. Lithuania has only one Cambium age deposit of water washed crude oil, all others have more conventional viscosity and GOR values. The oil sample from Adza Cambium deposit is particularly interesting due to the high viscosity. The reported values exceeded other oils (and typical estimation methods) by a factor of 10 or more, but the high value was confirmed by supervised measurement. It is proposed to classify this deposit is a water washed deposit. This means that water most likely passed under the deposit and removed the lighter components. Recovery of the deposit is however problematic due to the low gas factor, low formation temperature (22C) and resulting high viscosity.

Kuldiga Area Wells Core Analysis Published Results
Porosity % for Cambrian & Ordovician Rocks, 1, oldest or lower rocks

well#	Cm2	O1	O2	O3
6	23-26	-	7-8	4-6
11	-	5	6-8	4-5
12	14-21	1.89	4-5	4-10
13	-	-	6-11	-
14	-	-	8-10	4-6
15	11.8-12.2	15.9	4-9	3-6
16	16.5-19	6.5	7-10	2-13
17	18	-	6-8	5
18	15-24	-	5-9	3-5
19	16-21	9.4	3-7	4.7-7.4

Kuldiga Area Wells Core Analysis Published Results
Gas Permeability, md,, 1= oldest or lower rocks

well#	Cm2	O1	O2	O3
6	353	-	-	-
11	-	0.031-0.036	0.004-0.01	0.004-0.02
12	1200	0.0027	0.0093-0.022	0.005-0.022
13	-	-	0.005-0.088	-
14	-	-	0.002-0.08	0.01-0.8
15	33-50	81.6-82.7	0.003-0.03	0.008-0.02
16	14-47	-	0.003-0.04	0.006-0.0154
17	16-70	-	0.09-0.25	0.03
18	93-133	-	0.003-0.015	0.005-0.03
19	114-1460	0.014-0.1	0.003-0.15	0.005-0.03

Analysis by movable oil ratio in this instance compares the maximum resistivity deflections for the long and normal sonde in the upper Ordovician section. In some cases the bed thickness was insufficient for the long sonde to develop a maximum value. Porosity in this case is determined from the normal sonde, assuming a residual HC saturation of 15%, i.e. adding 15% to the calculated porosity. The results are given in Table 11 and shows an average porosity of 5.5% for the 45 or so well logs examined by this method. The maximum porosity is 7.8% and the minimum is about 3 %. Calculated permeability ranges from 1.5 to less than 0.1md, with an average of 0.44 md.

Table 10a Latvia Core Analysis

Well	por%	md	*Sw-c*	*BVW*	*pore d, um*
JE6	17.4	40.5	*0.107*	*0.019*	*1.14*
B53	9.4	0.24	*0.524*	*0.049*	*0.23*
B1	7.1	0.3	*0.440*	*0.031*	*0.28*
K16	5.7	0.01	*0.798*	*0.045*	*0.15*
K15	5.7	0.01	*0.798*	*0.045*	*0.15*
K12	5.1	0.06	*0.585*	*0.030*	*0.21*
Ed64	4.6	0.02	*0.698*	*0.032*	*0.18*
D38	4.2	0.01	*0.756*	*0.032*	*0.16*
K15	15.9	82.7	*0.072*	*0.011*	*1.72*
KA6	16	14.9	*0.160*	*0.026*	*0.77*
K11	5.3	0.04	*0.643*	*0.034*	*0.19*
V19	9.4	0.01	*0.854*	*0.080*	*0.14*
report	report	report	*calc'd*	*calc'd*	*calc'd*

b) Horner Analysis Revision

Well J-E6

Horner	Analysis	Compare
	Danish	*OPA*/core
t, m	*10.00*	*0.62*
por %	*11.00*	17.40
k, md	*2.50*	40.50

Tab.10c)Compare.porosity

calcϕ	coreϕ	well@m.d
0.047v/v	0.062v/v	B2@996.5
0.061	0.094	B53@?
0.056	0.057	K16@?
0.046	0.057	K15@?
0.040	0.053	K11@?

Table 10a gives reported core values of porosity and permeability for these wells. The onshore porosity values exceeding 10% are for the lower siltstone section, not covered by this calculation. The values of Sw-c are calculated by this papers permeability function, BVW by calculated Sw-c and reported porosity and d by the formula 0.123/Sw-c. The permeability values tend to support the results from the well log analysis.

An exception was for offshore well JE6 and the values used by Danish geologist to analyze Horner data presented a large discrepancy between core values and Horner values. This analysis input core values to back-calculate thickness of producing interval. It is not surprising that the calculated thickness corresponds to approximate reported thickness of core sucrosic sections for the better onshore wells.

Table 11 Cap Rock Latvia Wells using Max R's, Upper Ordovician

				cap	rock	cap	rock	cap	rock	cap	rock
well	Rw/Rmf	Rmf	Rw	Rt	Rxo	bbl/ac-ft	Sw	p v/v	k,md	t	md-m
Ap1	0.65	0.20	0.13	72.00	62.00	111.22	0.70	0.061	0.52	6.5	838.5
Ap2	0.82	0.16	0.13	102.00	85.00	58.10	0.79	0.045	0.13	8.5	841.5
B2	0.83	0.12	0.10	60.00	57.00	39.25	0.86	0.047	0.16	7.0	996.5
B20	1.40	0.07	0.10	22.00	33.00	-162.15	1.59	0.042	0.09	4.0	1010.0
B24	0.82	0.12	0.10	50.00	40.00	81.52	0.77	0.058	0.42	6.0	930.5
B53	1.08	0.12	0.13	190.00	45.00	198.93	0.43	0.061	0.54	6.0	1014.0
B6				oil	trace					7.0	987.0
C265	0.24	0.54	0.13	20.00	90.00	-23.62	1.05	0.077	1.39	11.0	887.0
D13	1.15	0.11	0.13	100.00	35.00	160.38	0.57	0.064	0.62	8.0	986.5
D14	1.14	0.11	0.13	110.00	50.00	103.36	0.66	0.052	0.25	7.0	917.0
D15	1.27	0.10	0.13	120.00	50.00	95.32	0.67	0.049	0.19	6.0	927.5
D35	1.14	0.11	0.13	50.00	25.00	127.76	0.70	0.072	1.08	5.0	967.0
D36	1.17	0.11	0.13	105.00	38.00	147.16	0.58	0.060	0.49	8.5	922.0
D37	1.07	0.12	0.13	27.00	43.00	-126.25	1.40	0.050	0.20	3.0	984.0
D39	1.00	0.13	0.13	27.00	60.00	-177.25	1.65	0.042	0.09	5.0	944.0
Ed17	1.27	0.10	0.13	90.00	48.00	64.02	0.78	0.049	0.18	10.0	834.5
Ed60	1.25	0.10	0.13	60.00	60.00	-38.13	1.15	0.040	0.07	8.0	820.5
Ed64	1.05	0.12	0.13	75.00	75.00	-7.79	1.03	0.040	0.07	9.5	856.0
Jm30	0.73	0.14	0.10	18.00	30.00	-54.00	1.13	0.066	0.73	2.0	1241.0
K1	1.13	0.12	0.13	72.00	52.00	36.07	0.88	0.048	0.18	7.0	837.5
K11	1.85	0.07	0.13	50.00	40.00	-70.82	1.28	0.040	0.06	6.5	940.0
k13	0.27	0.48	0.13	82.00	150.00	128.67	0.65	0.062	0.54	7.5	844.0
K15	1.39	0.09	0.13	70.00	45.00	19.50	0.93	0.046	0.14	8.5	835.0
K16	0.92	0.14	0.13	80.00	50.00	100.25	0.71	0.057	0.38	7.5	892.5
K2	1.00	0.13	0.13	90.00	45.00	122.16	0.65	0.059	0.43	6.0	818.0
K3	1.09	0.12	0.13	71.00	33.00	134.27	0.65	0.065	0.70	6.5	828.0
K4	1.05	0.12	0.13	60.00	38.00	81.18	0.78	0.060	0.48	7.0	842.5
K5	1.25	0.10	0.13	52.00	37.00	23.41	0.93	0.054	0.29	8.5	837.5
Ka6	0.82	0.16	0.13	72.00	55.00	87.35	0.75	0.057	0.38	7.5	826.5
Kd6	1.20	0.11	0.13	90.00	45.00	85.82	0.73	0.052	0.26	8.0	826.0
Pt-l	1.23	0.11	0.13	52.00	27.00	97.36	0.76	0.066	0.74	8.0	1004.5
Pt-m	0.83	0.16	0.13	70.00	53.00	87.72	0.75	0.058	0.40	4.5	929.0
Pt-r	1.00	0.13	0.13	53.00	30.00	126.50	0.70	0.071	0.98	4.3	969.0
Sn90	0.35	0.37	0.13	21.00	72.00	-53.20	1.12	0.070	0.95	3.0	987.5
V45	0.17	0.76	0.13	170.00	750.00	33.20	0.84	0.033	0.02	12.0	825.0
V46	0.44	0.29	0.13	160.00	350.00	3.14	0.98	0.029	0.01	8.0	982.0
V50	0.16	0.82	0.13	200.00	350.00	178.53	0.45	0.057	0.38	6.0	827.0
Vc19	1.16	0.11	0.13	34.00	34.00	-35.06	1.10	0.056	0.36	3.0	886.0
Avg							0.84	0.055			0.417
Max							1.00	0.078			1.449
Min							0.43	0.029			0.008

One caveat in this analysis is the type of resistivity tools. They appear to have been a dual electrode survey sonde, possibly 16" normal and longer Laterolog The value for Rt was a digitized log reading of SL and for Rxo was digitized log reading of SN. In wells with thickness under 6 meters, neither sonde developed a flat profile, possibly indicating data to be of less than quantative value, although the digitized values were reported to be accurate for beds as shallow as $^1/_3$ to ½ meter.

In *conclusion, this analysis* leans towards interpreting the upper Ordovician section as a leaky cap rock of marginal porosity. Were this upper Ordovician oolitic lime to have permeability there is no trapping mechanism except a hot shale bed some 10 meters above this section and the intermediate section would also calculate or show oil, this however is not the case. The poor flow test results of Table 12 also supports concluding this oolitic section to be a leaky cap rock. In some cases this cap rock may be underlain by a thin sucrosic section similar to the better core samples recovered for time to time. However, examination of logs, verbal reports and the revised Horner test results, Table 10b, all indicate this lower section is not more than 1 m thick, if and when present.

Table 12 Latvia Well Test Results

well	Comments
B2	oil trace upper, oil flow lower 994 to 1004.8
B2	core:996.5,p=6.21%, 999.5,p=6.61%
B20	oil trace, water flow 1011 to 1020
B24	no flow upper, 0.13 m3/dy lower 1030 to 1041
B53	oil flow 1015 to 1019
B6	oil trace, water flow 993-996
D13	no flow 988to 998m
D14	water flow 926.5 to 910
D15	oil flow 0.2 m3/dy 930 to 936
D36	oil flow 0.15 m3/dy 923 to 930
Ed17	oil flow 838.4 to 842
Ed60	no flow 838.8 to 841.3
K11	water flow 942.5 to 946.8, gas&oil show 926 to 940
K13	no flows 845 to 855
K15	leaking well oil flow 0.8m3/dy 910 to 975
K16	gas show 880-890
K4	no flows 842 to 853
K5	leaking well, oil flow w/ water 835 to 855
Ka6	oil/water flow 0.4m3/dy 827.4 to 843