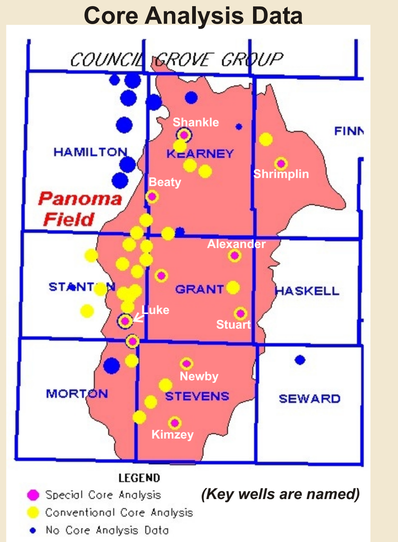
Lithofacies and Associated Petrophysical Properties

Lithofacies Classification

Rock properties data representing analyses from 33 wells (below) that have attempted to sample the complete range in porosity, permeability, geographic distribution, and formational unit for each of the major lithofacies. Lithofacies were described for core using a digital classification system to facilitate data management and because it offered the ability to use non-parametric categorical analysis. Digits generally represent continuous variation of a lithologic property that may be correlated with petrophysical properties. Final petrophysical trends used the eight major lithofacies shown below (selection process is discussed further on).

Core Analysis Data



Digital Rock Classification System

by: Alan Byrnes, Martin Dubois

[illegible]

Litho-facies	Council Grove Lithofacies	Digital Code 1st Digit	Digital Code 2nd Digit
1	NM Silt & Sand	1	2-3
2	NM Shaly Silt	1	0-1
3	Mar Shale & Silt	0.2	all
4	Mdst / Mdst-Wkst	3-8	0-1
5	Wkst / Wkst-Pkst	3-8	2-3
6	Sucrosic (Dol)	3-8	8
7	Pkst / Pkst-Grnst	3-8	4-5
8	Grnst / PhAlg Baff	3-8	6-7

Examples:

12-322-211-9001 Nonmarine clastic, coarse siltstone, well cemented/fractured, [illegible]

52-505-534-9444 Limestone, grainstone, cemented [illegible]

Lithofacies, Porosity, Permeability

Fundamental to construction of the reservoir geomodel is the population of cells with the basic lithofacies and their associated petrophysical properties- porosity, permeability, and fluid saturation. Petrophysical properties vary between the eight major lithofacies classified (see lower left). Mean and maximum porosities increase with increasing lithofacies number for the limestones (mud- to grainstone; histogram below). In situ (stressed) porosities (ϕ) were either measured or were calculated from routine helium porosity ($\phi_{routine}$) values using the developed correlation: $\phi = 1.00\,\phi_{routine} - 0.68$.

Permeability is a function of several variables including primarily pore throat size, porosity, grain size and packing (which controls pore body size and distribution), and bedding architecture. Equations were developed to predict permeability and water saturation using porosity as the independent variable because porosity data are the most economic and abundant, and because porosity is well correlated with the other variables for a given lithofacies.

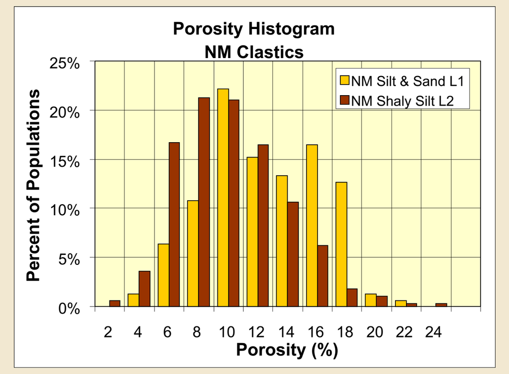
In situ Klinkenberg (high-pressure gas or liquid-equivalent) gas permeability (*k*) exhibits a log-log correlation, or power-law, relationship with porosity though the relationship changes in some facies at porosities below ~6%. Each lithofacies exhibits a relatively unique *k*-ϕ correlation that can be represented using equations of the form:

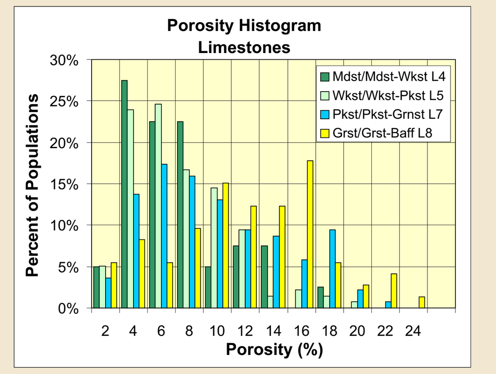
$$\log k = A \log\phi + B \quad \text{or} \quad k = 10^{B}\phi^{A}$$

Lithology Code	Lithology	Permeability Equation A	Permeability Equation B	Permeability Adjusted R^2	Standard Error (log units)	Standard Error* (factor)
1	NM Silt & Sand	7.861	-9.430	0.780	0.769	5.9
2	NM ShlySilt	5.963	-7.895	0.702	0.787	6.1
3	Mar Shale & Silt	8.718	-10.961	0.719	0.847	7.0
4	Mdst/Mdst-Wkst	7.977	-9.680	0.588	0.958	9.1
5	Wkst/Wkst-Pkst	6.260	-7.528	0.774	0.611	4.1
6	Sucrosic (Dol)	7.098	-8.706	0.643	0.673	4.7
7	Pkst/Pkst-Grnst	6.172	-6.816	0.840	0.521	3.3
8	Grnst/PA Baff	8.240	-8.440	0.684	0.600	4.0

At porosities below approximately 6% some facies exhibited higher permeabilities than predicted by the power-law function. For these facies the relationship between permeability and porosity was best represented by an equation of the form: $\log k = A\log\phi + B$.

Standard error of prediction ranges from a factor of 3.3 to 9.1. At ϕ > 6% permeability in grainstone/ bafflestones can be 30X greater than mudstones and >100X greater than marine siltstones of similar porosity. Differences in permeabilities between nonmarine silt/ sandstones and shaly siltstones range from 3.3X at 12% porosity to 7X at 18%. Regression analysis required careful data filtering such as to removed data from fractured samples. Full-diameter cores frequently exhibit permeabilities as great as 50X plug permeabilities due to stress relief fracturing.



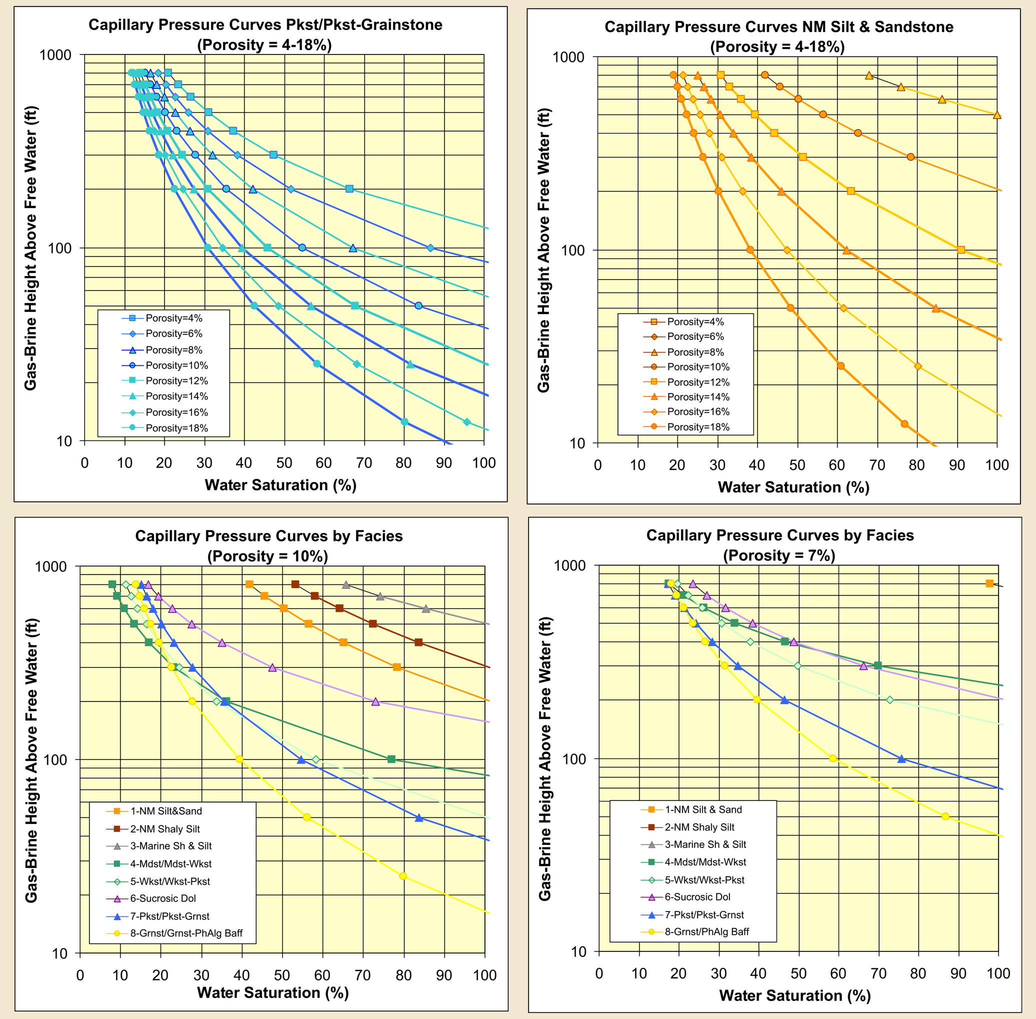


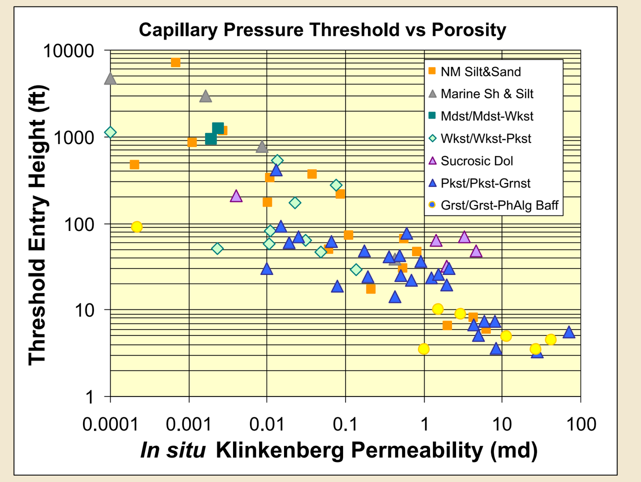
Capillary Pressure and Water Saturation

Capillary pressures and corresponding water saturations (Sw) vary between facies, and with porosity/permeability and gas column height. Threshold entry pressures and corresponding heights above free water level are well correlated with permeability. (See figure below). This is consistent with the relationship between pore throat size and permeability. The figure shows that for rocks with in situ Klinkenberg gas permeability below approximately 0.003 md, threshold entry heights are greater than the gas column heights available in the Council Grove and therefore the samples have Sw=100%. Synthetic capillary pressure curves were constructed from capillary curves from 91 cores representing the range in facies and permeability shown in the figure below.

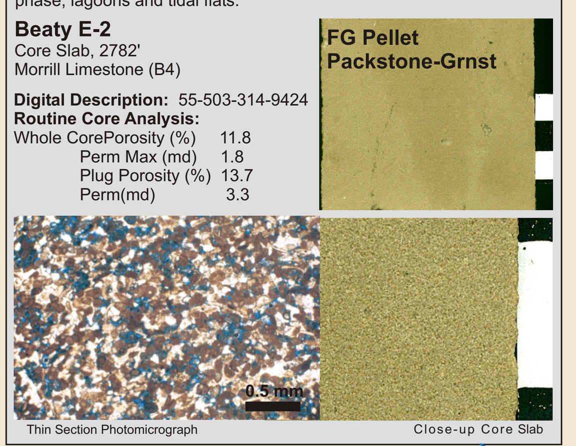
Capillary pressures in each facies can be represented to be a function of porosity. The figures to the left for the NM sand/ siltstones and the Pkst/Pkst-Grnst facies illustrate that with decreasing porosity and permeability, threshold entry heights and heights necessary to decrease Sw increase. Differences in Sw between porosities increase with decreasing height above free water level. High porosity NM Sandstones exhibit lower entry pressures than similar porosity carbonates but have higher "irreducible" water saturations and threshold heights increase greater with decreasing porosity. Note that NM Silt/ Sandstone with ϕ < 6% do not appear on the figure because of high entry heights.

Differences in Sw between facies increase with decreasing porosity and decreasing height above free water level (figures below). For example, at 7% porosity (which represents >50% of all Mdst/Wkst) at 200 ft above free water, Mudstones are 100% water saturated while [illegible]

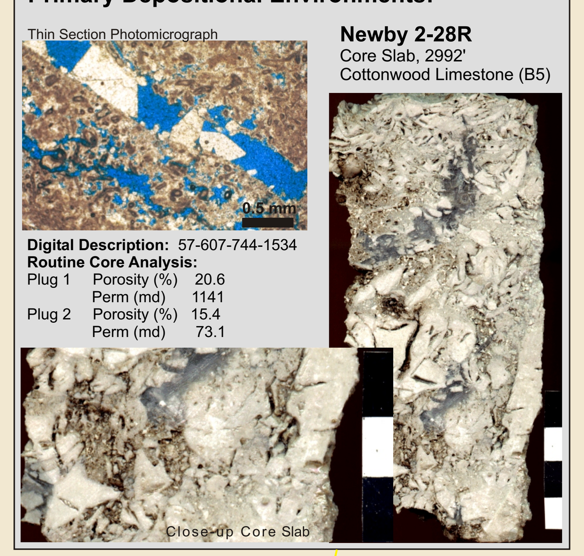




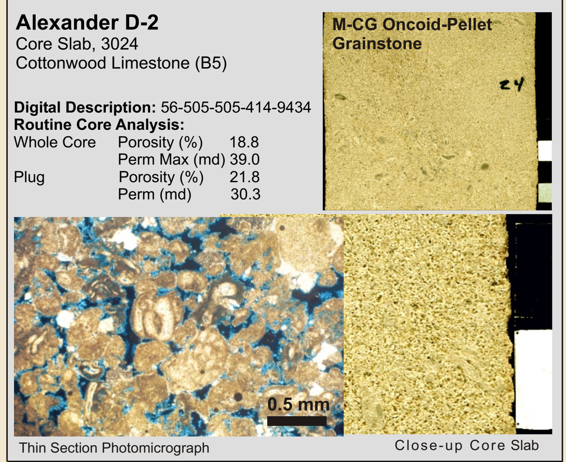
L-7 Packstone and Packstone-Grainstone



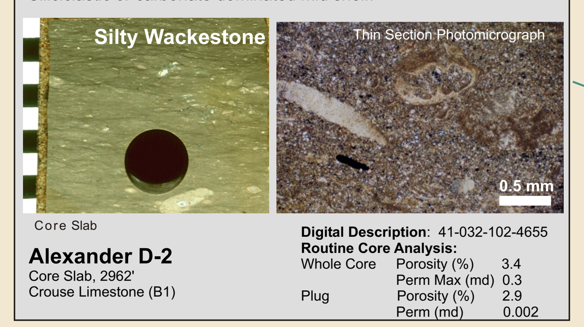
L-8 Phyloid Algal Bafflestone

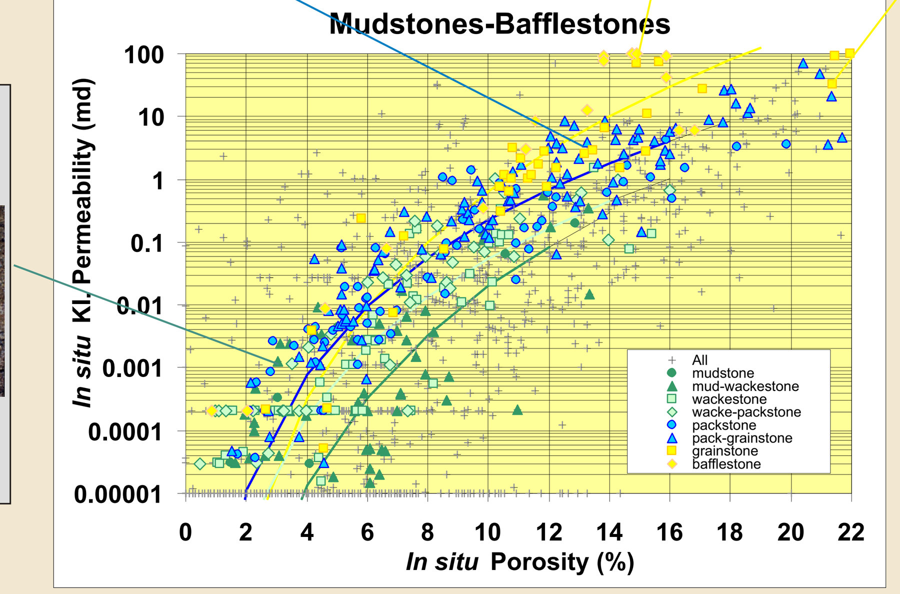


L-8 Grainstones

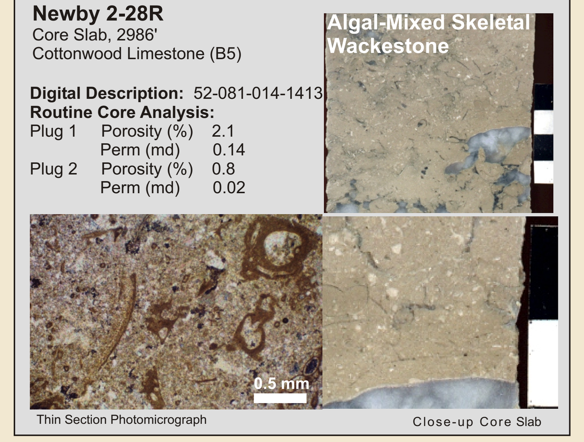


L-4 Mudstones and Mdst- Wackestones

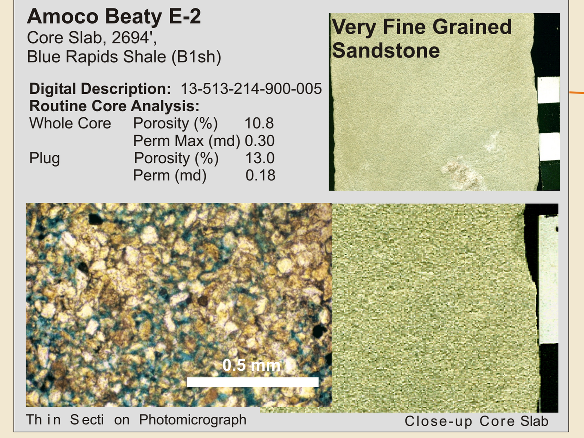


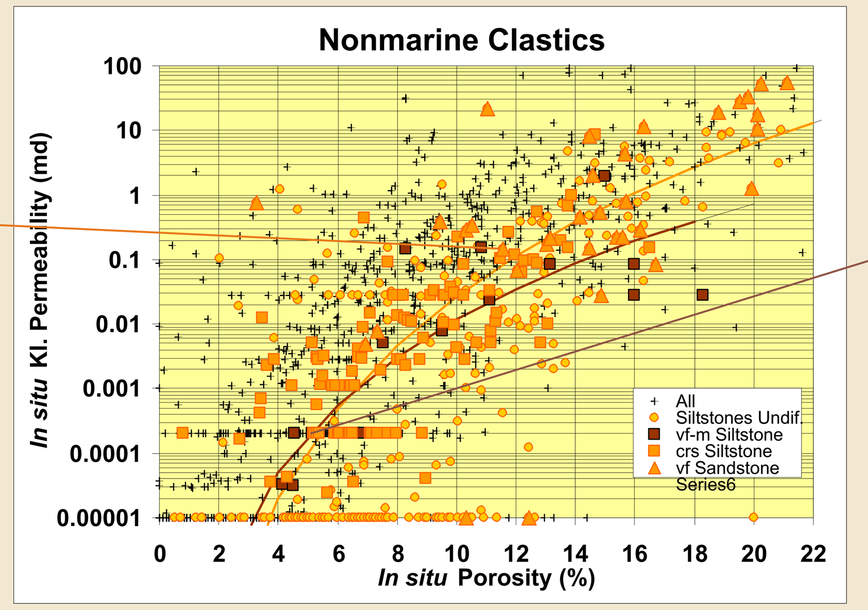


L-5 Wackestones and Wkst-Packstones

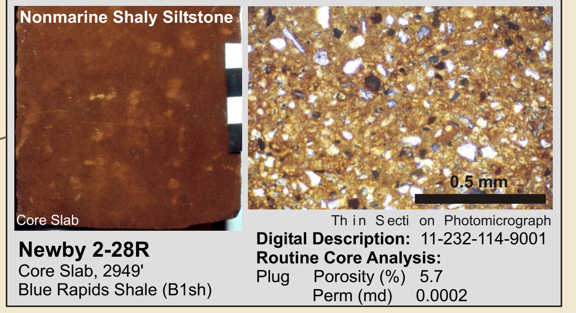


L-1 Nonmarine Siltstone and Sandstone

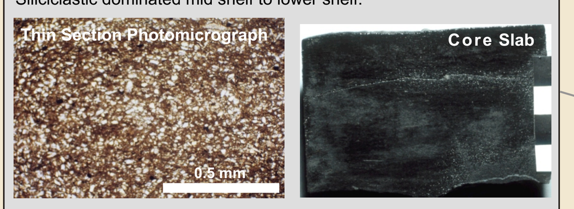


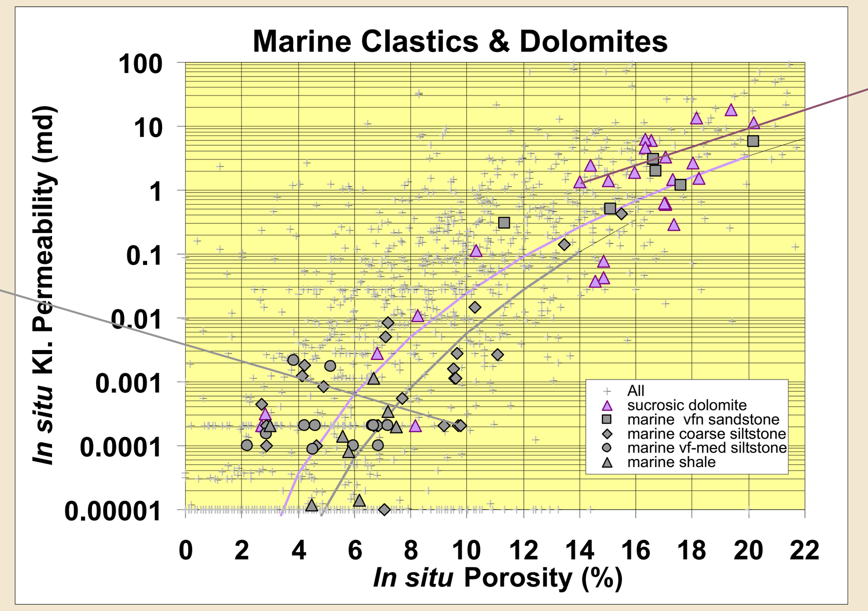


L-2 Nonmarine Shaly Siltstone

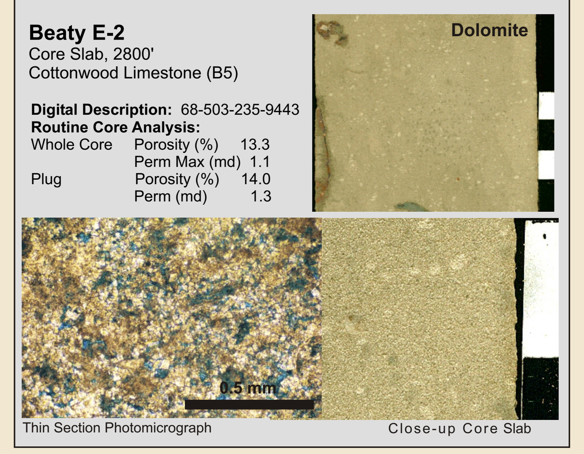


L-3 Marine Siltstone and Shale





L-6 Dolomite



Lithofacies Prediction: Tools, Methods, Results

Steps to Predict Lithofacies In Non-cored Wells

Determine predictor variables, lithofacies categories, and optimal predictor tool in an iterative, logic-based, trial and error process.

Optimize neural network parameters through cross-validation and logic-based, trial and error.

Select two neural network models, one for wells with PE curve and one for wells without PE curve.

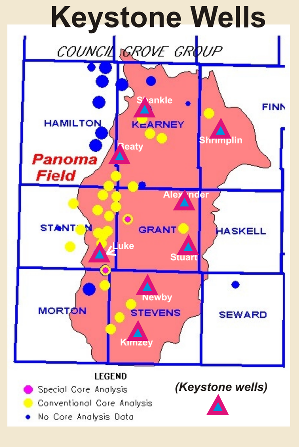
Develop code to automate process of generating the Marine-Non Marine curves and neural network predictions.

Generate predicted lithofacies and probability curves and output LAS format files through batch processing of input LAS files.

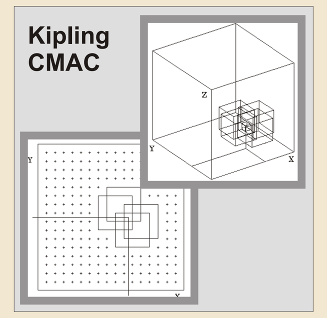
Automation

Significant custom programming by Bohling has made possible the generation of the Marine-Nonmarine predictor variable LAS curve through a Visual Basic routine in MS Access that allowed the mining of the KGS Oracle data base, automated cross-validation exercises via R-language scripts, and batch prediction of lithofacies from a large LAS file data base by extending Kipling.xla with Visual Basic Code that applied the neural network and output an LAS lithofacies curve files for each well in the data set.

Keystone Wells

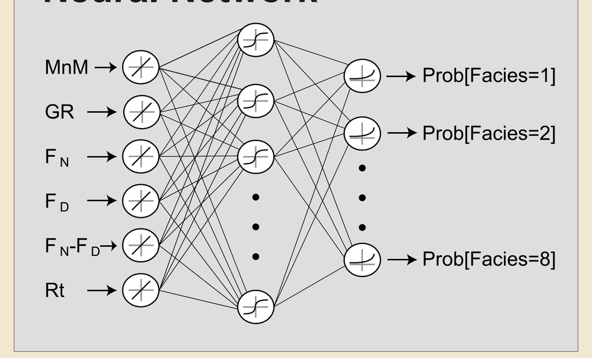


Kipling CMAC



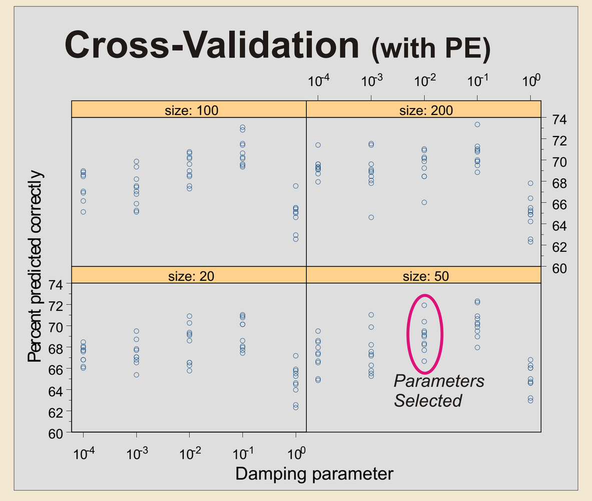
Kipling/CMAC tesselation of predictor variable (well log) space in two and three dimensions. This non-parametric classification technique was considered but not used in favor of the neural net.

Neural Network



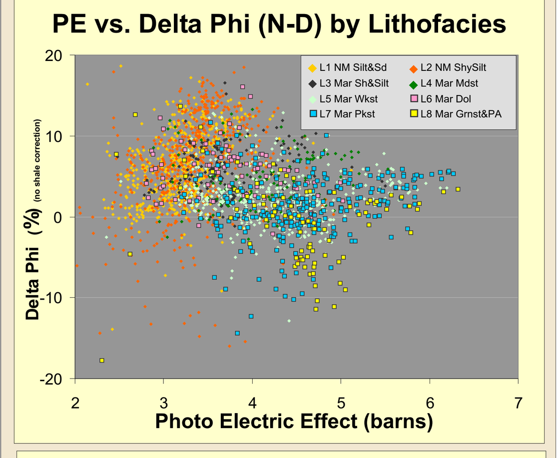
Predicted lithofacies probabilities from logs and marine/non-marine indicator (MnM). PE curve, not shown, was used when available. A standard single hidden-layer neural network was used (Duda et al., 2001) and we focused our model calibration efforts on the selection of an appropriate number of hidden-layer nodes, which governs the richness of the model, and an appropriate damping parameter, which constrains the magnitude of the network weights to help prevent overtraining.

Cross-Validation (with PE)

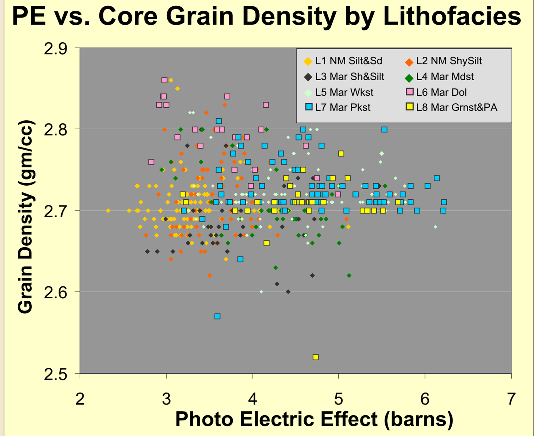


Results for model with GR, Nphi, Dphi, Nphi-Dphi, Rt, PE, and Marine-nonMarine indicator as predictor variables. Ten data points are shown for each combination of network size (number of hidden-layer nodes) and damping parameter, each point representing a different random split of the keystone data into training (2/3) and prediction (1/3) subsets. Parameters selected for PE model were 50 hidden-layer nodes and 0.01 damping parameter. 100 and 0.01 were selected for the no PE model.

PE vs. Delta Phi (N-D) by Lithofacies



PE vs. Core Grain Density by Lithofacies



Log Response and Lithofacies

The eight lithofacies can be discriminated effectively by four wireline log properties. Although the log distributions of the separate lithofacies show overlaps in their ranges, their collective use within multivariate statistical analysis results in good predictions of lithofacies identity as decisions rooted in probability.

Gamma-ray log contrasts the generally low radioactivity within the carbonates to higher levels emitted from clay minerals and silt fractions.

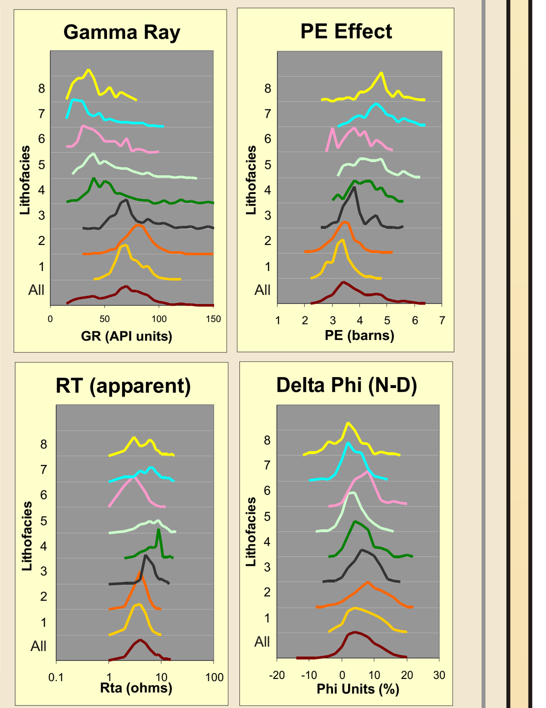
Photoelectric effect is a direct function of the lithofacies aggregate atomic number and can be related to mineral content.

Resistivity log is sensitive to both pore volume and pore fluid content in the carbonates as well as conductivity caused by clay mineral cation-exchange properties in the shaly lithofacies.

Delta Phi transform (neutron minus density porosity) is highly correlated with the grain density of the lithofacies and is

PE	Rock
5.1	Limestone
5.1	Anhydrite
1.8-6.3	Shale (~3.4 is common)
3.1	Dolomite
1.8 - 2.7	Sandstone (Qtz = 1.81)

Density	Rock
[illegible]	Limestone
[illegible]	Dolomite
2.65	Sandstone
2.98	Anhydrtite
Variable	Shale



L1	NM Silt & Sd
L2	NM Shaly Silt
L3	Mar Silt & Sh
L4	Mar Mdst
L5	Mar Wkst
L6	Mar Dol
L7	Mar Pkst
L8	Mar Grnst & PA

Prediction Results

measured by comparing predicted vs. training set.

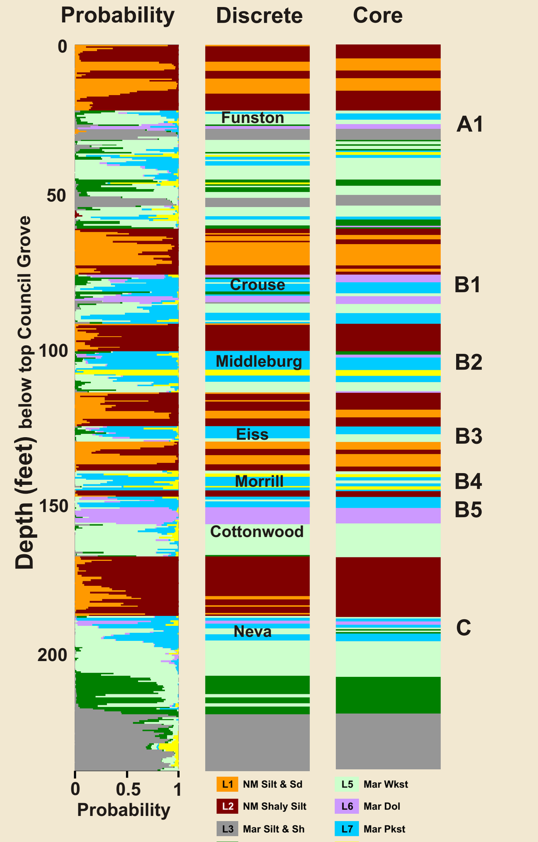
Correct Lithofacies Predictions
Impact of error lessened if lithofacies predicted is closely related.

Reservoir Thickness by Lithofacies
Impact of error lessened if the total count for a given lithofacies is close to actual.

Reservoir Volume by Lithofacies
Impact of error lessened if the total volume for a given lithofacies is close to actual.

Porosity Distribution by Lithofacies
Permeability is not a linear relationship with porosity, thus the porosity distribution is critical.

Keystone Well Example
3-34R Stuart



Predicted Lithofacies Scorecard (Counts)

Core Lithofacies (Actual); rows: Predicted Lithofacies

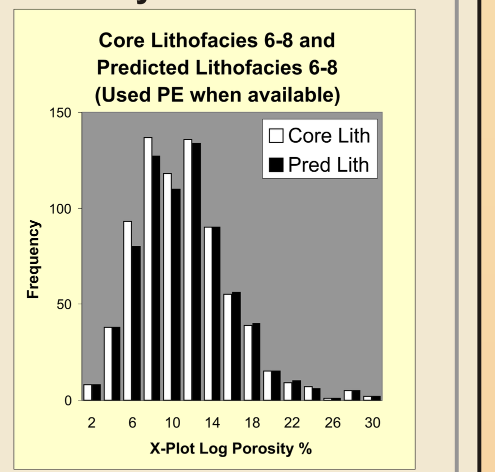
Facies	1	2	3	4	5	6	7	8	Total	Pred Within 1 Facies
1	783	172							955	100%
2	135	738							873	100%
3			235	11	19	2	11	2	280	88%
4			14	152	58	6	19	2	251	89%
5		1	21	42	464	11	57	5	601	86%
6			3	6	12	113	12	1	147	93%
7			13	16	73	10	336	14	462	78%
8			4	2	17	10	24	90	147	84%
Total	918	911	290	229	643	152	459	114	3716	
Pred/Actual	96%	104%	104%	91%	107%	103%	99%	78%		

Correct

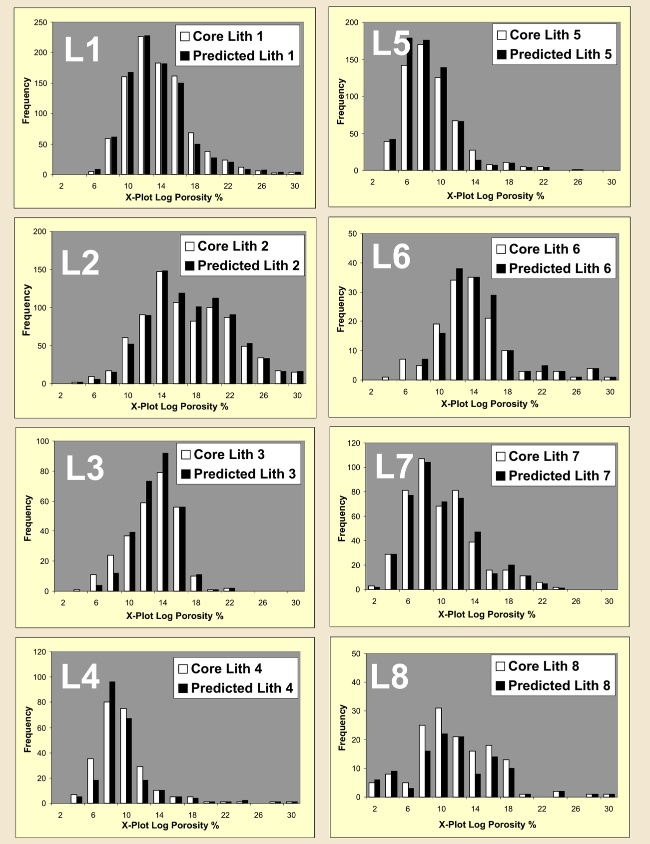
95.9% of actual predicted for L6,7,8

Combined Neural Net Models

Porosity Distribution Pay Lithofacies



Porosity Distribution Predicted Versus Core Lithofacies



Porosity distribution for predicted lithofacies compares favorably with that of the core lithofacies in the eight well training set. Porosity histograms for predicted lithofacies are compared against core lithofacies for the training set of 8 "Keystone Wells." Predictions were made using two neural net models, one using the PE curve (five wells) and the other not using the PE curve (three wells) as predictor variables.

Training Set Prediction Statistics

		Core	Predicted	Pred/Core
Lith 1	Mean Phi	12.8	12.5	0.97
	h*phi	61.0	57.0	0.94
	Feet	475	457	0.96
Lith 2	Mean Phi	16.2	16.4	1.02
	h*phi	66.1	70.1	1.06
	Feet	408.5	427	1.05
Lith 3	Mean Phi	11.8	12.2	1.04
	h*phi	16.5	17.7	1.07
	Feet	140	145	1.04
Lith 4	Mean Phi	8.6	8.6	1.00
	h*phi	10.8	9.9	0.92
	Feet	125.5	114.5	0.91
Lith 5	Mean Phi	7.9	7.6	0.96
	h*phi	23.7	24.4	1.03
	Feet	300	321	1.07
Lith 6	Mean Phi	13.0	13.6	1.05
	h*phi	9.6	10.3	1.08
	Feet	73.5	76	1.03
Lith 7	Mean Phi	9.0	9.1	1.01
	h*phi	20.7	20.8	1.00
	Feet	229.5	228	0.99
Lith 8	Mean Phi	10.6	10.5	0.99
	h*phi	7.8	6.0	0.76
	Feet	73.5	57	0.78
Lith 6-7-8	Mean Phi	10.1	10.3	1.01
	h*phi	38.1	37.0	0.97
	Feet	376.5	361	0.96
All	Mean Phi	11.8		
	h*phi	216.1		
	Feet	1825.5		

Mean Phi = X-Plot Log Porosity %