Methodology for Combining Old Log Suites with Modern Modeling Technology, Louden Oil Field CO_2 Injection Pilot, Illinois Basin

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ABSTRACT

In mature fields where porosity logs are lacking, it is difficult to obtain analogs of parameters necessary for reservoir modeling and simulation that must precede any test of EOR and sequestration using CO_2. Louden is such a field, having been discovered in 1937 and developed in the 1930s and 1940s. Though the wells form a tight grid (10-acre spacing), not all were logged, and few have logs more modern than an SP-Resistivity suite. For 138 wells in the model area, 62 logs and 17 cores were available.

The first test of CO_2 EOR sequestration is a huff-n-puff technique applied to a Mississippian Cypress Sandstone reservoir. Cypress reservoirs in this area are typically small, coalescing lenticular "pods" less than 160 acres in area and ten to twenty feet thick. According to geological mapping, the Owens #1 well lies near the margin of one such pod.

To generate a reservoir model it was necessary to convert SP – the log curve most nearly independent of hydrocarbon content – to a sand/shale curve through normalization. The normalized data were transformed using Gaussian Anamorphosis and modeled using two geostatistical methods, Plurigaussian and Turning Bands, which served as the reservoir model for input to simulation.

The normalized SP curves were cross-plotted against the seventeen core analyses to obtain regression curves relating SP to permeability and permeability to porosity. Estimated values at cored wells were overwritten by analytical values during modeling. The permeability and porosity models were submitted to reservoir simulation along with the reservoir model after upscaling.

INTRODUCTION

Two important steps in the design of any oil field operation from basic field development to enhanced oil recovery are creation of a digital reservoir model reflecting its geology and simulation of the behavior of subsurface fluids. Successful creation of the reservoir model, a critical input to reservoir simulation, requires estimation of the porosity and permeability throughout the reservoir body. In modern fields, the data on which this estimation are based is derived from wireline logs and measurements made on subsurface cores.

In the process of preparing a simulation for the Midwest Geological Sequestration Consortium's (MGSC) first test of CO_2 for enhanced oil recovery (EOR), data availability proved problematic. The giant Louden Field of Illinois (figure 1) was discovered in 1937 and developed in the 1930s and 1940s, well before wireline porosity tools became available. While core data are available, data from cores in development wells often emphasize the "best" portions of producing formations. This tendency proved true in the area of the Carter Oil C. Owens #1 well chosen for the MGSC's first test (figure 2). While the Cypress Sandstone section in the Owens #1 appears from log signatures to comprise thin (6-10 feet) sandstones separated by shale and shaley sandstone, most nearby cores were taken in a thick, massive sandstone body near the base of the Cypress, informally termed the "Heckert facies."

Figure 1: Index map showing location of Louden Field, Illinois. Red star is approximate location of Owens #1 well.

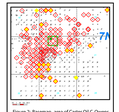


Figure 2: Basemap, area of Carter Oil C. Owens #1, 19-7N-3E Fayette Co., Illinois. Owens lease is marked by a green box; the C. Owens #1 is the well marked by a green dot. Red diamonds indicate wells for which digitized logs are available, filled yellow diamonds mark the location of wells for which core data are available for the Cypress Sandstone.

Early attempts to create reservoir models near the target well using core-derived porosity and permeability data resulted in an overly optimistic model dominated by the numerous nearby cores taken in Heckert sandstones, a facies absent in the Owens #1 and adjacent wells (see figures 3, 4). Conceptual, log-based models (figure 5) of "Owens-facies" sandstone bodies suggest that the reservoir consists of stacks of thin (less than ten feet), discontinuous sandstones characterized by lenticular shape and a size of less than 180 acres. What core data are available suggest that permeability and porosity are reduced by increased clay content along both lateral and vertical margins of thinner sandstone bodies. As the conceptual geological model locates the Owens well near the margin of such a lens, the overly optimistic porosity and permeability predicted by the first reservoir model made it unsuitable for reservoir simulation.

The ideal reservoir model would be based on data that are both representative of the target zone and widely distributed throughout the study area. Given the scarcity of porosity data in the Owens facies as opposed to the wide availability of electric logs, albeit primitive, the use of log data as an estimator of rock properties seemed the best choice.

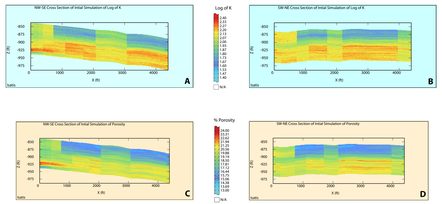


Figure 3: Results of initial reservoir modeling in the area surrounding the C. Owens lease, in which rock property distribution is based entirely on available core analysis data (as depicted in Figure 2). Panels **A** and **C** are dip cross-sections from northwest (left) to southeast (right) passing through the location of the target well, Owens #1, at the center of the sections. Panels **B** and **D** are strike sections running southwest (left) to northeast (right), likewise with the Owens #1 well at the center.

The upper panels (**A**, **B**) represent a geostatistical estimate of the distribution of horizontal permeability, displayed as the $\log_{10}$ of the permeability measured in the core samples. The lower panels (**C**, **D**) represent the estimated distribution of porosity expressed as a percent of rock volume.

Note in all four illustrations a preponderance of warm colors (yellow to red), especially in the lower half of the models. This display indicates that both permeability and porosity are estimated to be relatively high. The models estimate that the target sandstone interval in the Owens #1 has porosities in the range of 20-22% and horizontal permeability of 100 millidarcys or greater. Experience in the Illinois Basin suggests, however, that while the predicted porosity is within a reasonable range, the predicted permeability is likely to be high by 30 to 50%. Such optimistic results would adversely affect the results of the next step in modeling, the reservoir simulation.

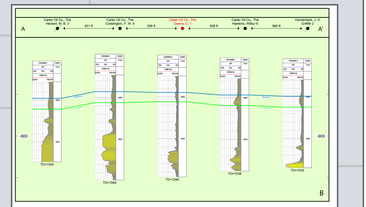
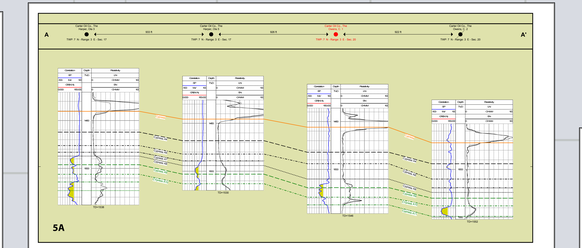


Figure 4: Log cross-sections (raw SP curve only) along the same trends as the reservoir model sections displayed in figure 3. Owens #1 well, at center of both sections, is marked by a red label.

A) Southwest (left) to northeast (right) structural cross-section along strike; **B)** northwest (left) to southeast (right) structural cross-section along dip direction. The blue line is the top of Barlow lime, green is top of the Cypress Sandstone. The colored fill depicts approximate sand content where gray coloration is relatively shaly and yellow is relatively sandy. Note the thicker, relatively clean Cypress Sandstone section in the wells to the west and south (Heckert facies) and the thinner, more shaly Cypress section (Owens facies) in the Owens #1 well and wells to the north and east.



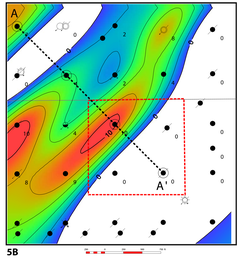


Figure 5: Conceptual geological model based on log responses.

A) Northwest-southeast cross section **A-A'** through the C. Owens lease, including the Owens #1 well (labeled in red), which was selected for the first CO_2 EOR test. Left-hand track is raw Spontaneous Potential (SP) curve, shaded where SP curve indicates a lithology composed of greater than 50% sandstone. Right-hand track shows shallow (solid) and deep (dashed) resistivity curves. An informal Cypress Sandstone internal stratigraphy has been picked from logs as shown.

B) Map of the area around the C. Owens lease, which is marked by the dashed red square. The position of cross section A-A' (see **figure 5A**) is indicated by the dashed black line; the Owens #1 well is located in the northwest corner of the lease. Contours represent the net sandstone isopach for the A9 interval (see cross section); contour interval equals 2 feet. Note the pronounced linear trends displayed by the contours, which reflect and support the conceptual model of a series of discrete, elongate shallow marine or tidal sandstones with a dominant northeast grain.

GEOLOGICAL MODEL

Compartmentalization is a prevalent characteristic of Cypress Sandstone reservoirs in the Illinois Basin. Correlating and mapping reservoir compartments is an important aspect of reservoir characterization for two reasons. Compartment geometry combination with other stratigraphic characteristics including bedding and biologic sedimentary features can be employed to interpret environments of depositional. Determination of reservoir compartment geometry, particularly within a depositional model framework, is especially important for defining flow units, the knowledge of which is useful to project flow direction within a reservoir and therefore ascertain the most effective and efficient design to drain hydrocarbons from a reservoir.

Cypress Sandstone electric log character, mostly the SP trace, and core data from the Owens and nearby leases shows cyclical or stacked beds of clean sandstone typically from two to ten feet thick, separated by shaly sandstone to shale beds of similar to thinner bed thickness. Using an interval of approximately ten feet as the maximum thickness of an individual sandstone cycle and carefully correlating the sandstone in that cycle at a particular stratigraphic position relative to a marker bed, *i.e.* overlying Barlow Limestone, simultaneously using interval cycles adjacent to the particular bed being correlated for guidance, individual compartments can be correlated, mapped and geometry determined. In the Owens area, sandstone geometry within an interval shows lenticular reservoir compartments on the order of ¼ mile wide to ½ mile in length, typically less than eighty acres in size and trending northeast-southwest.

A depositional model can be established by comparing compartment geometry and stratigraphic features with similar characteristics found in the modern environment. Distinguishing bedding characteristics of the lenticular compartments include ripple laminated sandstones that display ubiquitous thin, wavy shale/mud laminations and commonly show reversed or herringbone bed sets. Biologic indicators are absent in the sandstones with only minor burrow traces found in the shaly sandstone or shaly beds. The combination of lenticular sandstone compartment geometry, shaly ripple laminated, herringbone beds and sparse biota indicators are characteristic of modern settings in high tidal range, turbid water, embayed coasts. Linear tidal sand ridges similar to the Owens area sandstones are commonly found in high tidal range areas of the world. Examples of modern settings are the northern coast of Australia and the coast of the Yellow Sea, to the south of Korea.

South and southwest of the Owens lease the equivalent stratigraphic interval to the Cypress tidal ridge facies changes to a thick, blocky, cleaner sandstone facies, more uniform in character. Core from this facie shows rare shale laminations and subparallel to tabular cross bedded sandstone. This facies is characteristic of bay head delta mouth bars and shoals that develop where flow velocity is abruptly reduced as river water enters into the standing water of an embayment along the coast of the ocean. The delta front forward of the channel mouth is the site of deposition of the coarser bead load material. The embayed tidal deltas along the northern coast of Australia are modern analogs of this depositional setting.

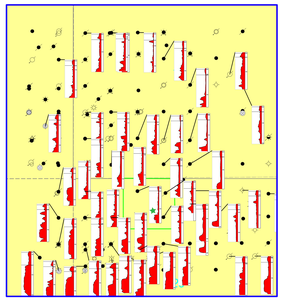


Figure 6: Map of study area depicting raw Self-Potential (SP) logs of the Owens #1 (marked by green star) and nearby wells. The C. Owens lease lies within the green square. The top of each log image is default centered on its respective wellsite but where images have been moved the images are visually connected to the well spot with tie lines.

All log segments begin at the Barlow lime (top horizontal line) and extend through the Cypress Sandstone section into the underlying Paint Creek Formation, or to TD. Note the thick, blocky, well-developed sandstone near the bottom of the log trace in many wells lying to the west and south of the Owens lease; this is the facies termed "Heckert type" sandstone. Compare this section to the thinner and more ragged log signature seen at the same stratigraphic level in the Owens #1 well (green star) and most wells lying north and south of the Owens lease.

METHODOLOGY

Sixty-five wells in the model area, including all wells in and adjacent to the C. Owens lease and all available wells with cored intervals in the Cypress Sandstone were scanned and digitized (figure 6). Of these sixty-five wells, none had a porosity log although four had gamma ray logs. The logs of cored wells were inspected to differentiate those cores taken in the Owens facies from those which represented sandstone of the Heckert facies, and the latter were excluded from the study.

I: Normalize SP curves:

1. Visually pick the highest and lowest observed values within approximately 150 feet of the Barlow lime. This reduces the effects of shale baseline drift. The cleanest sandstones in the interval were generally in the Tar Springs Sandstone (~100 feet above the Barlow), and the shaliest intervals were usually in the Frailey Shale immediately above the Barlow.
2. Normalize the curve between 0 (pure shale) and -100 (clean sand) using the formula

$$SP_{nor} = (SP_{raw-low} - SP_{raw})/(100/(SP_{raw} - SP_{raw-l})).$$

This normalization technique produces a curve that is a rough estimate of the percent of sand in the logged interval (figure 4). The set of sixty-five normalized SP curves were ported to Isatis for creation of a preliminary geostatistical model estimating the distribution of lithologies within the reservoir interval. This lithologic estimate was built using a plurigaussian technique (figure 8).

II: Choose transformation formulae

1. Depth-shift cores to minimize driller/log depth difference errors.
2. Crossplot multiple permutations of permeability (both raw and $\log_{10}$), porosity, and SP_{nor}. This step used a data window containing only the data points in which SP_{nor} was greater than 50% sand, and used a reduced major axis fit for regression. Multiple regression equations were applied to each crossplot.
3. Visually and mathematically evaluate regression curve fits to determine optimum regression curves (see figure 7).

Evaluation of the "goodness of fit" found that the relationship between permeability and normalized SP in the dataset was marginally stronger than the relationship between porosity and normalized SP.

III. Apply transformations

1. Convert the SPnorm curves to calculated permeability curves using the formula in figure 7a, substituting observed permeability values for calculated values where core analyses are available
2. Convert calculated permeability curves to calculated porosity curves using formula in figure 7b, substituting observed porosity values for calculated values where core analyses are available

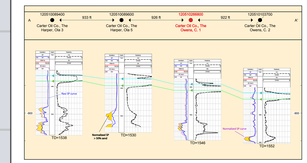


Figure 7A: Cross section showing same wells as figure 5A, comparing the raw and normalized SP curves. Yellow highlights indicate intervals where normalized SP exceeds 50% sand. Note the subtle effect of normalization on the SP through the target section of the Owens #1 when compared to the effects of normalization on the Ola Harper #3 (lefthand-most well).

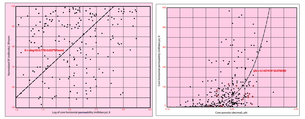


Figure 7b: Crossplot relationships used to transform normalized SP to permeability and permeability to porosity. See text for discussion of methodology and formulae.

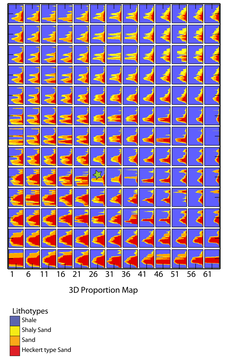


Figure 8: Vertical proportion curves produced by plurigaussian simulation of normalized SP data within Isatis® software. Each curve represents the relative proportions of facies vs. depth. Facies lithotypes are arbitrarily assigned to representative ranges of normalized SP. These curves were created using the facies data at each point in a three-dimensional grid calculated using the normalized SP data and an inverse squared distance algorithm. Each square represents the proportions at one-foot intervals over a rectangular area approximately 470 feet on a side. By comparison, standard well spacing in this area is 10 acres, or 660 feet between adjacent wells. The approximate position of the Owens #1 is marked by the green star in square 21N-26E.

Note the domination of the southern and western portions of the map by curves with large proportions of the clean, porous, and permeable Heckert-type lithofacies, shown in red, which are not present in or near the Owens #1. Analysis of wireline logs supports the relative scarcity of clean sands. near the Owens #1, which was not borne out by early modeling attempts.

3D RESERVOIR MODELING

Final modeling of internal reservoir stratigraphy followed a two-step process beginning with creation of a numerical model using a plurigaussian technique, followed by a turning bands simulation.

Plurigaussian

In the plurigaussian framework, data values were assigned to four lithotypes that were used to model the proportions of the facies within a three-dimensional space. Normalized SP values for all wells were assigned a lithofacies as follows:

Lithotype Facies		Normalized SP Range
Shale	:	0 to -30
Shaly sandstone	:	-31 to -50
Sandstone	:	-51 to -80
Heckert-type Sandstone	:	-81 to -100

Trends in facies distribution were examined by creating a vertical proportion matrix for the study area (figure 8). As the curves show, there are significant high-sand facies in the southwest corner of the area and lower-sand facies in northeast. A graphical lithotype rule, which describes the transitions from one facies to another, and Gaussian random functions (variograms) were generated from this matrix.This agrees with conceptual model of thick wedges of high-permeability sandstones in the southwest and interbedded sandstones and shales in the northeast corner. The next step was to create to define the lithotype rule and the Gaussian random functions (variograms). The lithotype rule is a graphic representation meant to describe the transitions from one facies to another. Only the first Gaussian function was necessary because of the nature of the transitions between facies. The function was modeled using a spherical structure with a sill of 1.2 and a range of 200 ft along the Y axis direction, 80 feet along the X axis, and twelve feet along the Z axis with a rotation of N40E in the horizontal plane. Fifty Plurigaussian simulations were created using the defined variograms and lithotype rule. The resulting simulations were used to guide subsequent simulation of the distribution of permeability and porosity with a turning bands method.

Turning Bands

In both initial and final turning bands simulations of porosity and permeability distribution, variograms were created after application of a gaussian anamorphosis transformation to the data. The final variogram model was based on an exponential structure with a range of 300 feet in X, 1200 feet in the Y, and twenty feet in the Z directions; and with an overall horizontal rotation of N40E. This model had a nugget of 0.1 and a sill of 0.6. After performing successful cross validation, fifty simulations were created using 1000 turning bands on a stratigraphic grid. The grid consisted of seventy-six nodes in the X direction and eighty-one nodes in the Y direction with mesh spacing of forty feet, and 100 nodes in the Z direction with a mesh spacing of one foot.

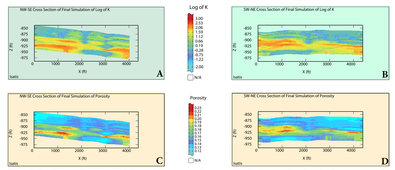


Figure 9: Results of final reservoir modeling in the Owens area. Rock property distribution is based on the plurigaussian model of sandstone/shale relationships (figure 8) generated from normalized SP curves. Panels **A** and **C** are dip cross-sections from northwest (left) to southeast (right) passing through the location of the target well, Owens #1, at the center of the sections. Panels **B** and **D** are strike sections running southwest (left) to northeast (right), likewise with the Owens #1 well at the center.

The upper panels (**A**, **B**) represent a geostatistical estimate of the distribution of horizontal permeability, displayed as the $\log_{10}$ of permeability. The lower panels (**C**, **D**) represent the estimated distribution of porosity expressed as a decimal value.

In comparison to the core analysis-based models of permeability and porosity (figure 3), this set of models more closely fits the conceptual model of discrete lenses of reservoir-quality sandstone encased in shale and poor-quality sandstone. Here, the high permeability and porosity seen in the Heckert facies is areally restricted to the south and west portions of the modeled area. The models predict reasonable porosity of ~18% and permeability of 40-60 md in the Cypress Sandstone section penetrated by the Owens #1. Compare these numbers to the 20-22% and >100 md predicted by the initial model. In addition, the model predicts that sandstones penetrated in the Owens #1 well are unlikely to be in the same flow units as wells that also penetrate cleaner sandstones, which more accurately predicts the size and shape of the wells drainage area.

CONCLUSIONS

1) In the absence of modern log suites and especially where gamma ray logs are lacking, the use of normalized SP can aid in construction of a geologically reasonable model of the distribution of sandstone and shale. The normalization step reduces variation from well to well that result from fluid chemistry and other borehole conditions, creating a calculated curve that is more representative of lithology than is a raw SP.

2) Crossplotting of rock properties (*e.g.* permeability and porosity) obtained from core analyses vs. normalized SP can be used to develop a transform relationship or relationships with which to populate a digital 3D reservoir model. Care must be exercised to ensure that the cores used to construct a transform relationship are segregated on the basis of facies before statistical analysis is undertaken.

3) The results of this methodology allow for better overall control of the reservoir model that is ultimately input to reservoir simulation. In the case of the Owens #1 CO_2 test well, use of the method yielded a model that more faithfully represents both the conceptual geological model of the immediate area and regional norms for the modeled rock properties.

ACKNOWLEDGMENTS

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