PS Using 3-D Property Models to Optimize Infill Drilling in an East Texas Tight Gas Play*

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Abstract

The Lower Cretaceous Travis Peak Formation is a tight gas sandstone reservoir that occurs in Carthage field at depths between 6,000 ft and 10,000 ft. The Travis Peak Formation in Carthage field (study area) largely consists of fluvial continental to coastal siliciclastic facies. It is a micro Darcy reservoir with low porosities (3 - 18%); the product of multiple regimes of diagenesis. Since discovery in 1968, it's been through periods of intense development; corresponding to drilling densities of 640, 320, 160 and now about 80 acres (some operators are even drilling at denser well spacing). The development paradigm has mainly been: drill wells (vertical), do hydraulic fracturing across multiple intervals then hookup for production; but not all wells have been a commercial success.

This study area (a part of Carthage field) contains about 250 wells (all have log data). The area lacks 3D seismic coverage so well log and performance-based data were used to model the 3D distribution of rock properties using geostatistical methods. Sequential Indicator Simulation and Sequential Gaussian Simulation methods were used in building 3D property models (porosity and pay) which were then used to predict fairway continuity (a basis for quasi 'sweet spot' delineation). The modeling of pay (a composite variable) was designed to discount the impact of the pervasive and 'difficult to predict' diagenesis observed in Travis Peak Formation Sands. Comparisons of pseudo (pre drill) to actual (post drill) porosity and pay logs along with interval 'predicted pay' thicknesses (gross and trended) were all used to validate 'best fits' from a number of equiprobable realizations.

The results show that this method can be used to predict pay connectivity especially in facies that are relatively extensive (laterally) or connected (laterally or stacked) and is useful as an additional tool in planning future Travis Peak infill development.

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The results show that this method can be used to predict pay connectivity especially in facies that are relatively extensive (laterally) or connected (laterally or stacked) and is useful as an additional tool in planning future Travis Peak infill development.

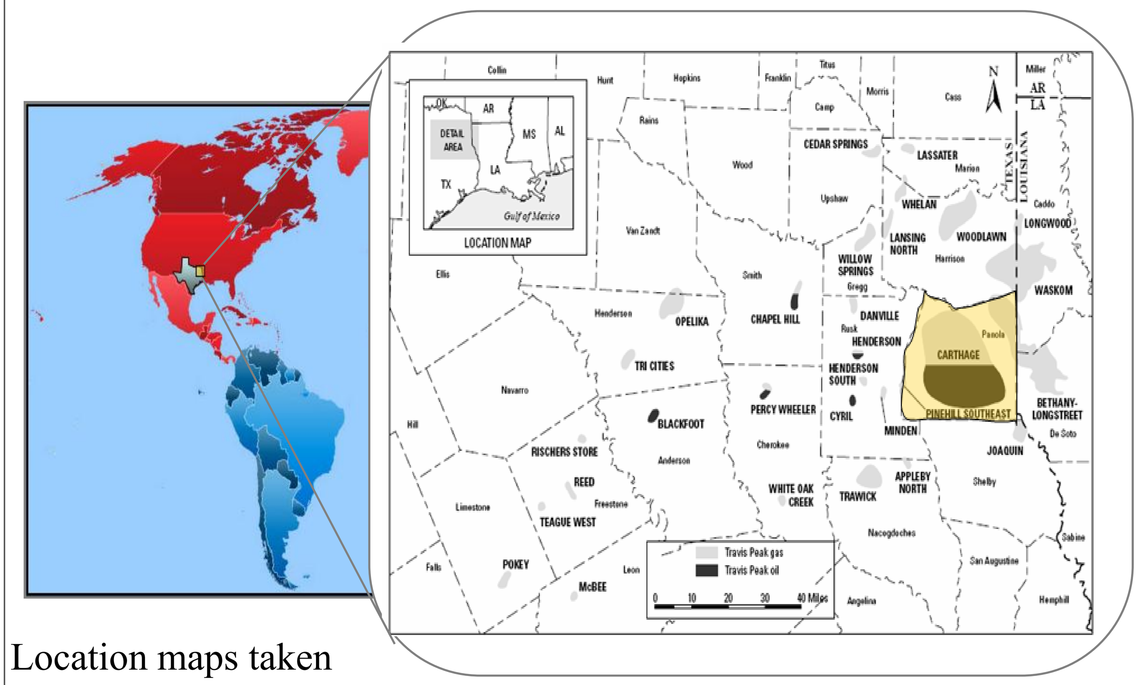
Key Issues

Pay extent prediction and delineation.
Optimizing the value from routine data.
Developing alternative but effective reservoir modeling methodologies for Tight Gas Sands.

Introduction

This study outlines multiple approaches to building geocellular models in the Travis Peak Formation tight gas play. It outlines both Indicators-based and object-based methodologies which utilize the large volume of available conventional wireline data complemented by 'understanding gained from previous core studies' and existing production data.
Rock property models have been used to predict infill well characteristics, and Crossplots have been used to identify the high energy trends which are a guide to delineating the main trend of channel belts (wireline data has been used to infer channel belt trends; a key input into object modeling). All these have contributed to pay extent prediction which is key to deciding on the potential of infill targets.

Location and Geological Setting



Location maps taken from http://www.map-menu.com and Bartberger et al., 2003).

Fig.1 Location of Travis Peak Formation

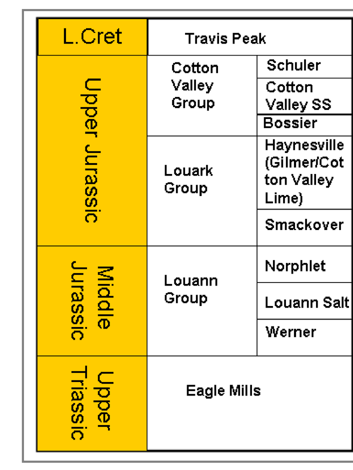


Fig.2 Partial Stratigraphic column of East Texas Basin Showing the position of Travis Peak Formation.

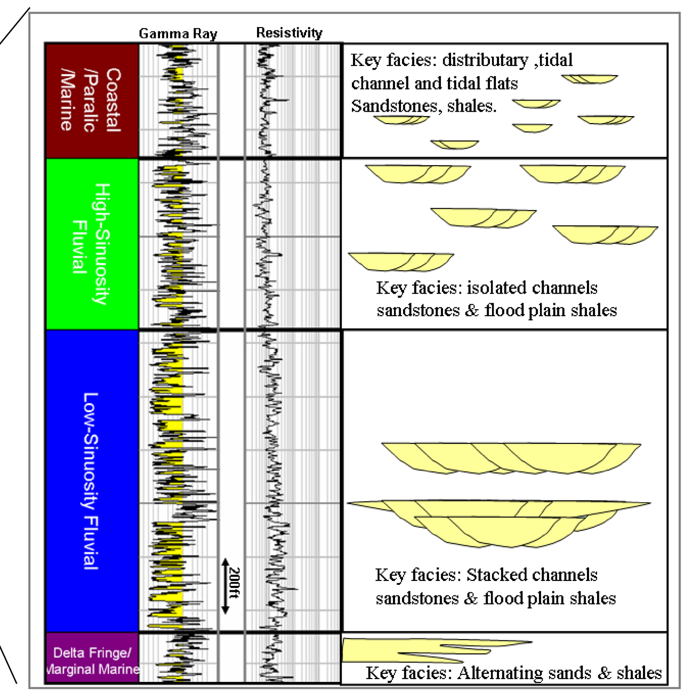


Fig.3 Composite log panel from Carthage well showing gamma-ray and resistivity character of Travis Peak Formation in East Texas Basin Travis Peak is informally divided into three main intervals on the basis of sand and shale content (after Davies et al.,1991):
1.A basal deltaic sequence
2.A middle fluvial sequence (divisible into a lower interval of 'stacked braided channel and splay sandstones' and an upper interval of meandering channel sandstones).
3.A Cap of coastal plain facies.

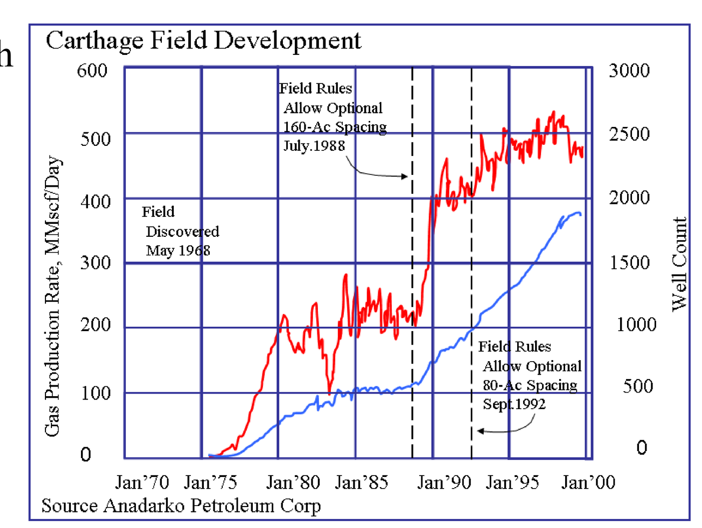
The Travis Peak (Hosston) Formation (fig.2 and fig.3) was deposited in the Lower Cretaceous as a basinward-thickening wedge of terrigenous clastic sedimentary rocks underlying the northern gulf of Mexico coastal plain from eastern Texas across southern Mississippi, southern Alabama, and the Florida panhandle (Bartberger et al.,2003). The thickness of the Travis Peak Formation. Within the study area, the Formation is about 2000-2300ft thick.

The assumptions made during modeling include:

1. The near well bore area will undergo hydraulic fracturing (if chosen as a completeable interval), an established practice done to stimulate the well in this tight gas sand play. This enhances connectivity across complex sand geometries in the near wellbore area..
2. Splays are deposited adjacent to channels in a migratory channel belt.

Commonly used property prediction methods rely on simple 2D "lateral interpolation" of layer/interval averages of reservoir properties and this can produce misleading results because it assumes simple layering and discounts directional anisotropy (consequently leaving out trends).
This paper describes techniques that utilize 3D simulation algorithms to predict inter-well rock property distribution, also results are extracted form the cells of models which provides more realistic interval maps.

Fig4. Growth Sprout with reducing well density in Carthage (Williams, 2004).



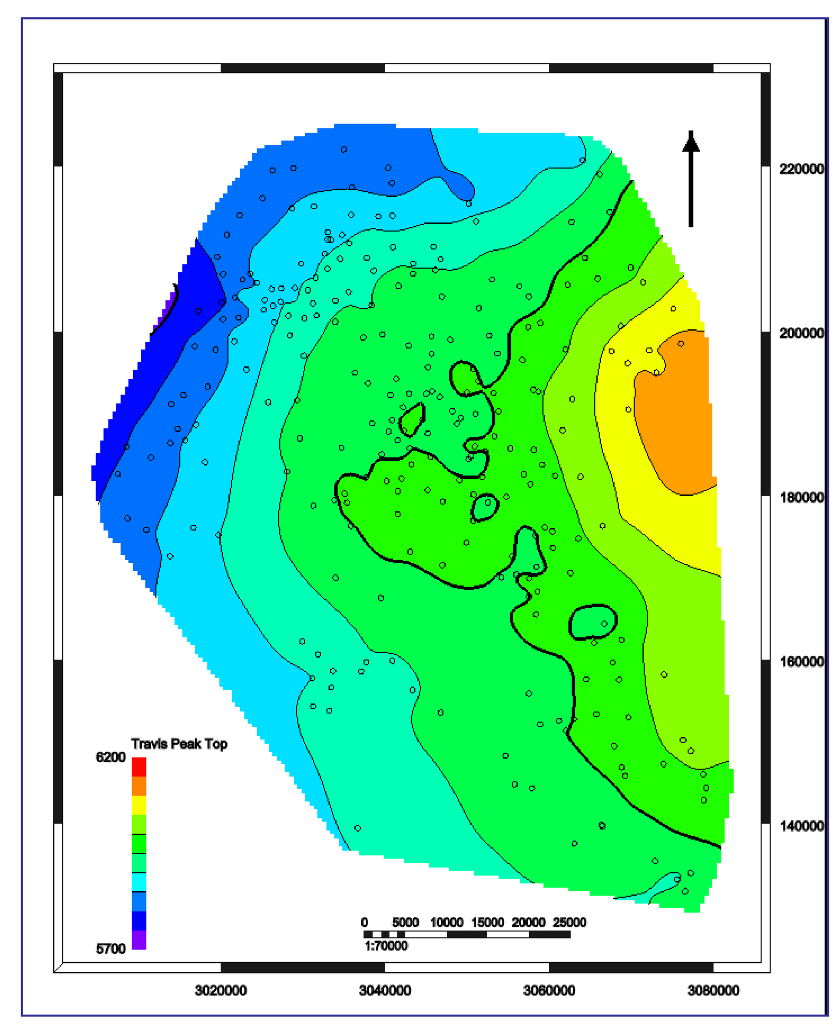


Fig.5 Top Structure Map of Travis Peak Formation in the study area. Observe the gently dip away from the Sabine uplift.

Data

Well logs from about 250 wells were used. Core interpretations form studies and reports were also used (Davies et al., 1991).
Petrophysical data was also interpreted using techniques similar to Howell and Hunt (1986). Estimates for lateral extent of fluvial facies were based on empirical equations from Bridge and MacKay (1993). These were used to define the search area of the modeling algorithms.

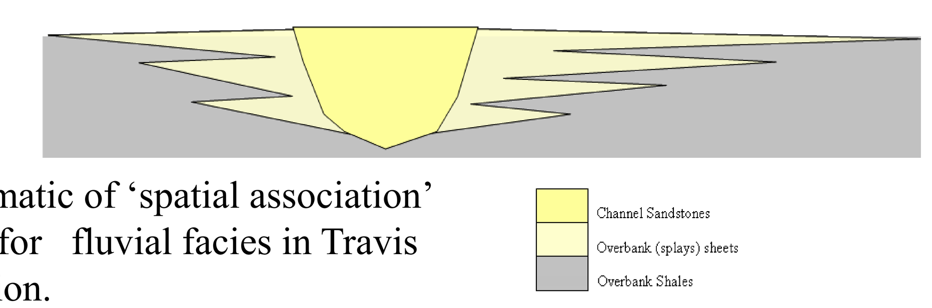
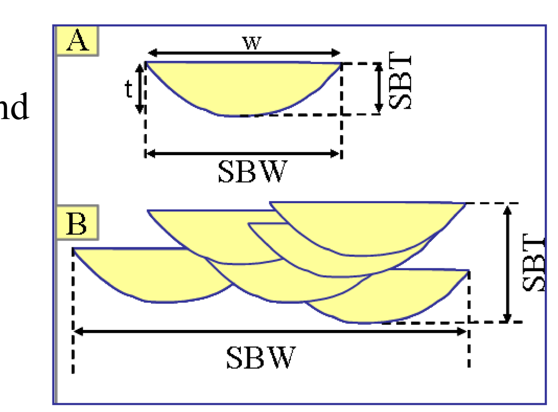


Fig.6a Schematic of 'spatial association' assumptions for fluvial facies in Travis Peak Formation.

Fig.6b Channel belt and sand body geometry definitions (after Gouw, 2007). A) In unconnected channel belts, sand-body width (SBW) equals channel-belt width (w) and sand body thickness equals channel belt thickness (t). B) When two or more channel belts are connected, SBW is defined as the maximum horizontal distance between the edges of the sand body. SBPT is the maximum vertical distance within the sand body.



Methodology

Pay Modeling

Hcpv Model

Trend Influenced modeling

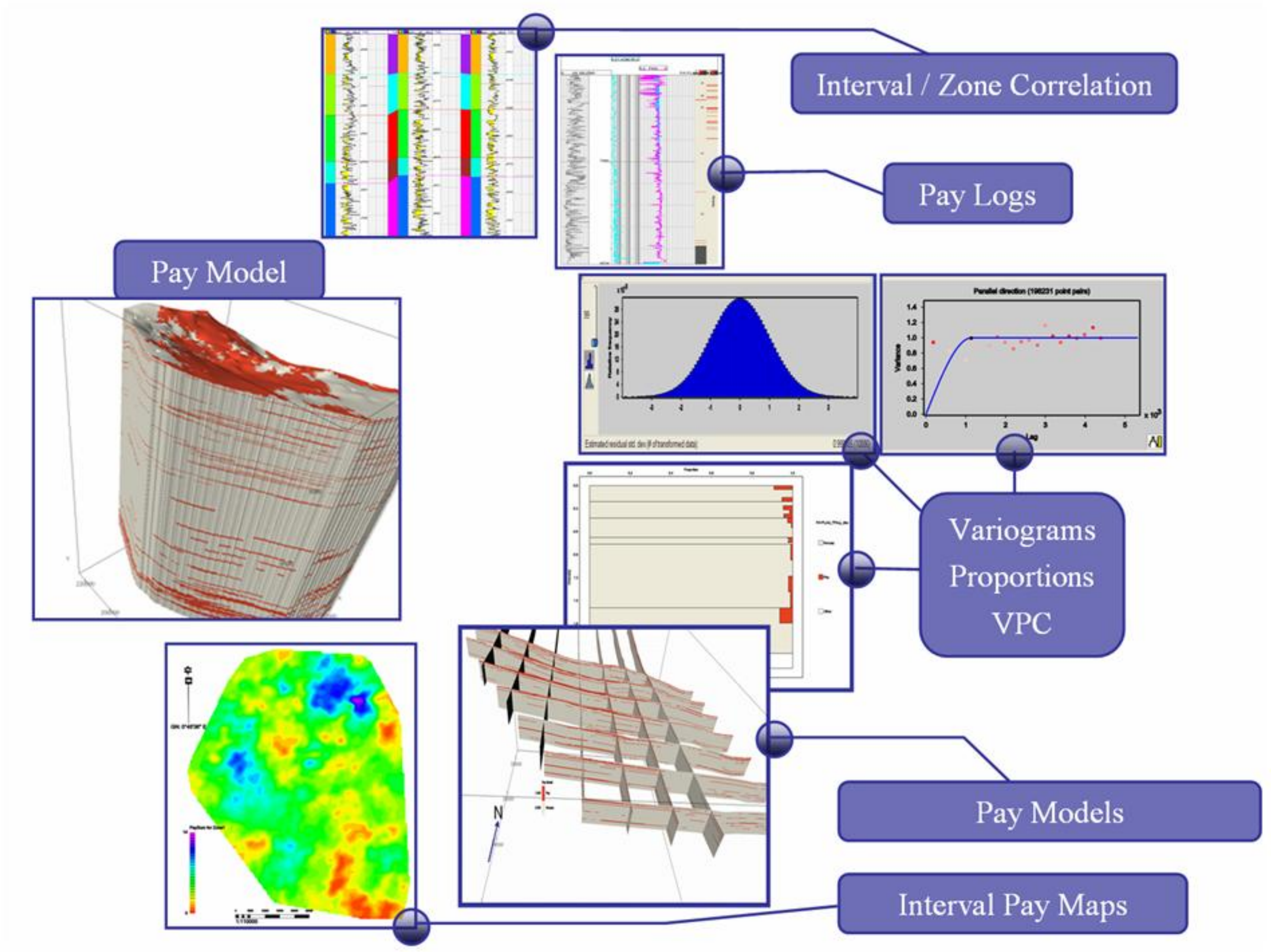


Fig.7 The workflow used to build a Pay model for Travis Peak, some results and possible application.

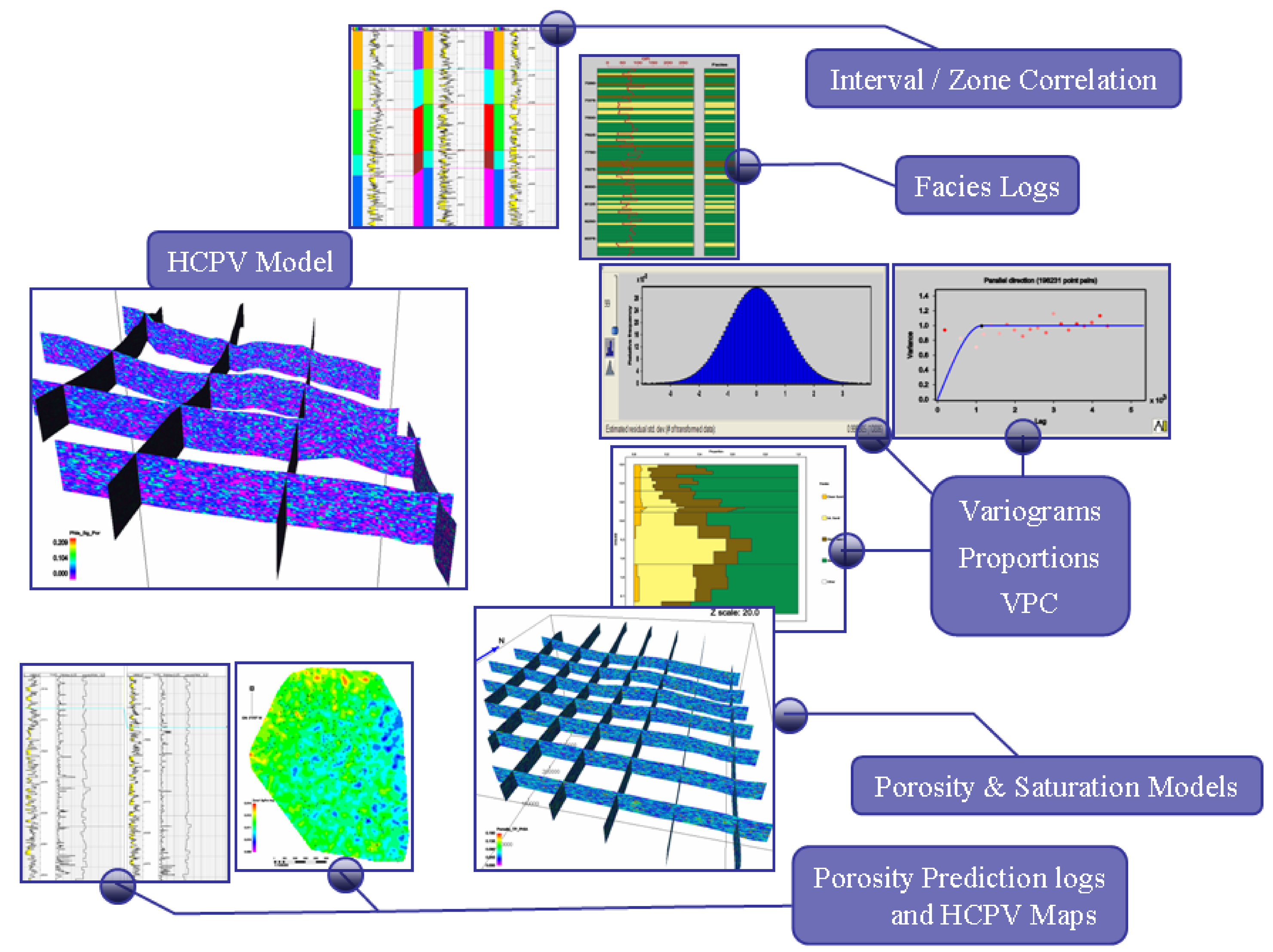


Fig.8 The workflow used to build a Hydrocarbon Pore Volume model for Travis Peak , some results and possible application

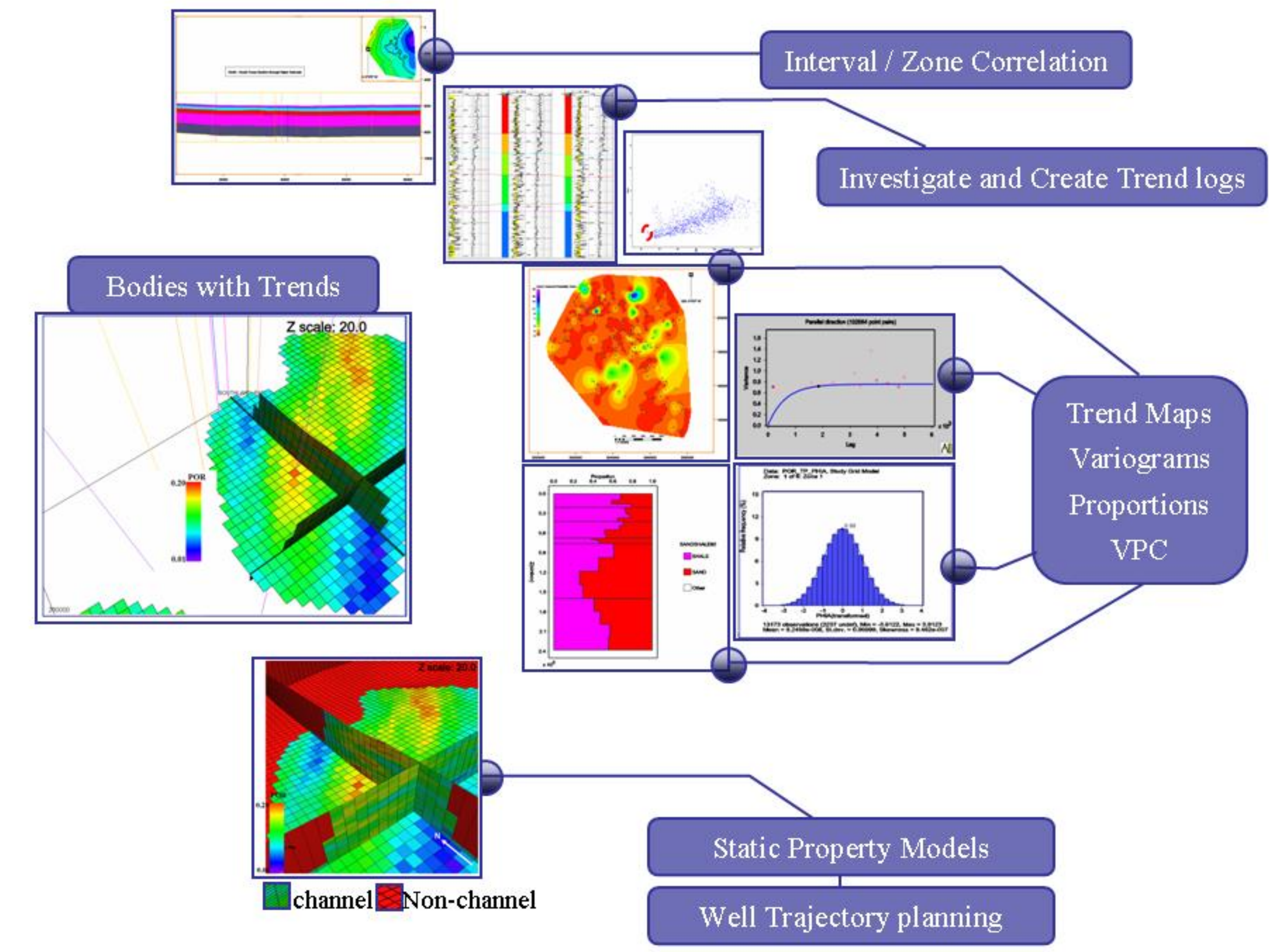


Fig.9 The workflow used to build a trend influenced channel model in Travis Peak some results and possible application.

Concepts

Pay Model

The Pay logs were modeled using Sequential Indicators Simulation Assumptions:

1. That the facies in a fluvial system are at least partly juxtaposed (see Fig.6A on facies idealized spatial association).
2. Channel belts are migratory.
3. The near well bore area will be stimulated by hydraulic fracturing (if chosen as a completeable interval (an established practice done to stimulate wells in this tight gas sand play). This can enhances connectivity across complex sand geometries for hundreds of feet from the well bore.

Methodology: Pay logs were created using a combination of Saturation, Porosity , Resistivity and GR logs. The Pay logs were then converted to discrete logs and modeled using Sequential Indicator Simulation; which assigns facies into grid cells on the basis of an estimated conditional probability. Variogram ranges were used to define '3D simulation' search neighborhoods such that they are no larger than the mean estimated channel belt widths in each interval/zone of the model (Bridge and MacKay, 1993). The sequential indicator simulation algorithm was constrained to over 250 wells during the Pay modeling process (fig.7).

Hcpv Model

Porosity and Saturation logs were the key inputs into building this model. The basic assumptions used in modeling generating the Pay model also hold here.

The Porosity model (an intermediate step output) and its realizations were generated using the Sequential Gaussian Simulation algorithm. Pseudo-porosity logs were extracted from this model at control well locations for model validation (fig.8 and fig.13).

Methodology: By using log estimated proportions, variograms, vertical proportion curves and facies models (pixel-based Indicators facies models were built based on GR cutoffs and used in conditioning porosity as there exists a relationship between facies and rock properties such as porosity (Davies et al., 1993). The porosity and saturation and HCPV models were conditioned to over 250 wells that exist in the study area (fig.8).

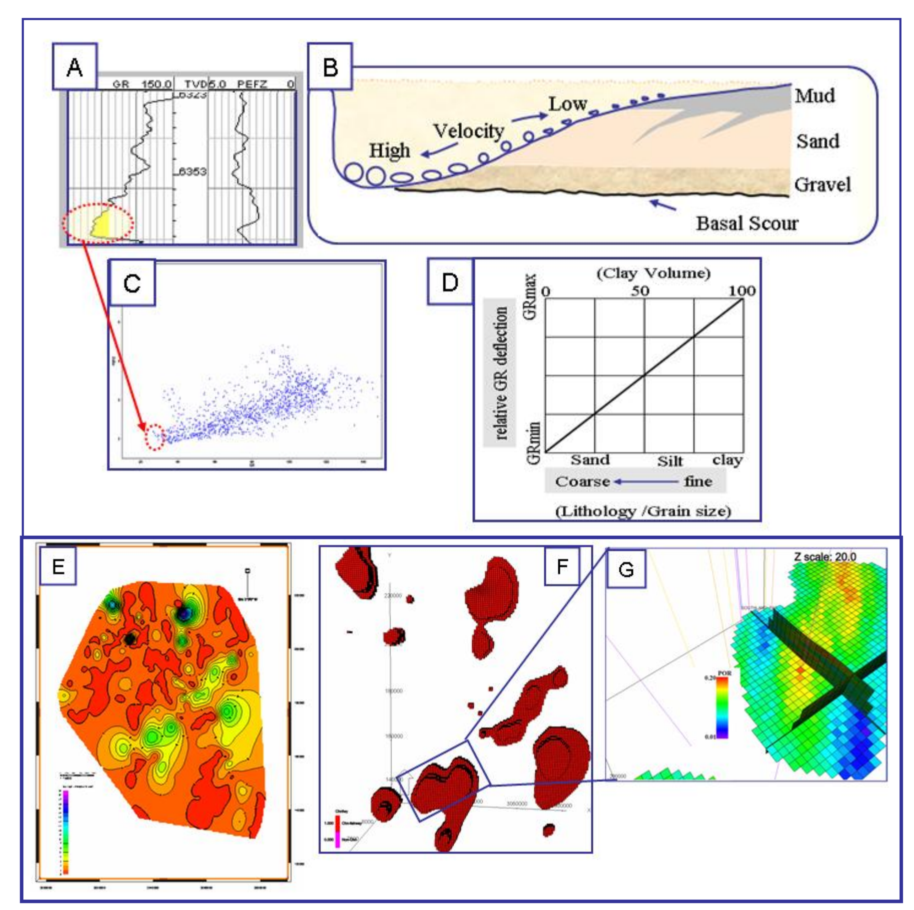


Fig.10 The methodology used to build a create a high energy sand probability trend which is interpreted as a channel probability trend in a fluvial system.

Trend Influenced object model

Well Logs were investigated for channel probability/clean sand trends, then wells within the trends were used for conditioning. The Sequential Gaussian Simulation algorithm was used to model the distribution of porosity in this model, it was used to investigate and preserve intrabody trends (fig.9).

The methodology used to define channel probability trends within zones/intervals in the model is outlined below and in figure 10:

A. GR log profile of meandering channel in Travis Peak. During flow, the coarsest grains are found at the base of the channel, it typically is the zone of highest energy. The fining upwards profile typifies the progressive reduction in velocity.

B. A cross section schematic of flow in a meandering channel illustrating the typical energy level in the system. The base of the channel typically has the cleanest and heaviest grains (modified from Slatt, 2002).

C. A crossplot of GR v PEF was used to determine the cleaner parts of the fluvial system that also holds the largest grains. This will have the highest probability of being channel sand. The GR is a sand quality indicator while the PEF can detect some of the cements in Travis Peak (Rider, 2002).

D. A schematic showing an empirical relationship between GR and grain size (it is usually not linear) modified from Rider, 2002.

E. Map of result from C above.

F. A 3D trend (filtered on high probability discontinuous pods) created from sub thickness of lower bar (from E above) that has been transformed with empirical equations into channel belt width and used as sand body (including point bars) trends (see Fig. 6b).

G. 3 way slice through a deterministic 3D porosity model showing axial and margin porosity trends in a channel body sand.

Results

Pay Modeling

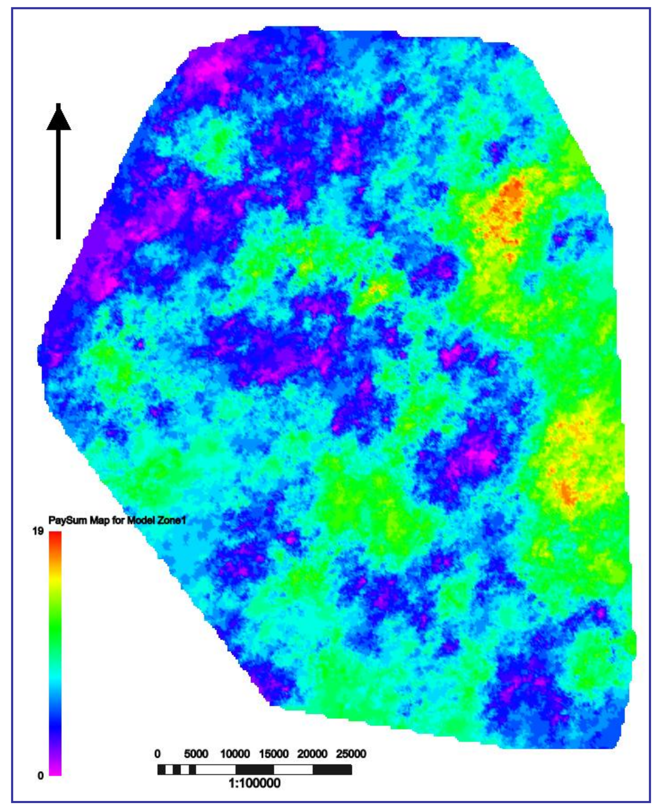
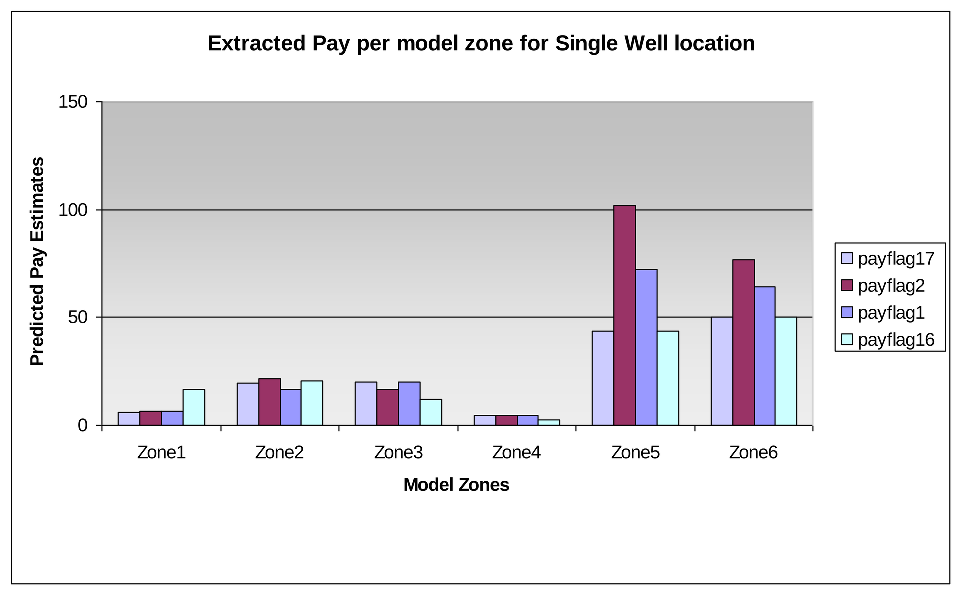


Fig.11 A map of the sum of pay extracted from one zone in the 3D model. Each grid cell in this map is the sum of all pay values in the corresponding cell pillars (i.e. column of cells) within that zone (also see Fig.15). The hot colors are the sweet spots. This shows pay distribution and estimated pay extent for an interval in the model.

Fig.12 By using 3 alternate fits of variograms in all three directions (Parallel, normal and vertical) to define a distribution (low base high), sensitivities were run on the model. Variogram ranges were no larger than estimated channel belt widths in this interval/zone of the model and were based on the empirical equations of Bridge and MacKay, 1993. The range of Predicted pay for a single well position (Well Payflag1) is shown here. This method was used in validating the model and also in estimating the range of possible reward from proposed wells (the table shows estimated reward uncertainty in „zone totals" for a single location). Zone totals from sensitivity runs shown here are in feet.



Hcpv Model

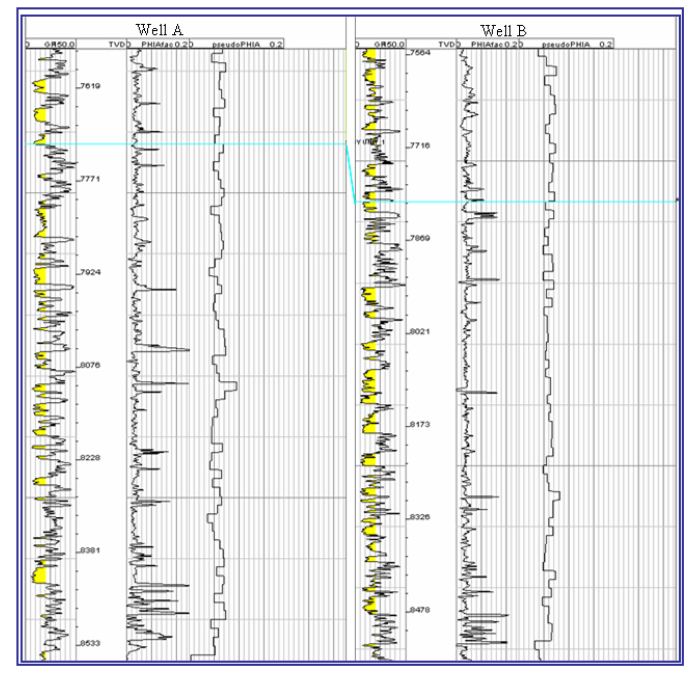


Fig.13 Pseudo porosity logs were extracted at two control well locations (existing wells not included in model) and compared to the actual well logs. The results improve with increasing well density. This is expected in continuous rock property models built with sequential Gaussian simulation that are conditioned to wells.

By identifying and using the key rock property uncertainties in sensitivity runs, a large range of logs were extracted and used in prediction planning including comparing proposed locations and completions planning.

Trend Influenced Modeling

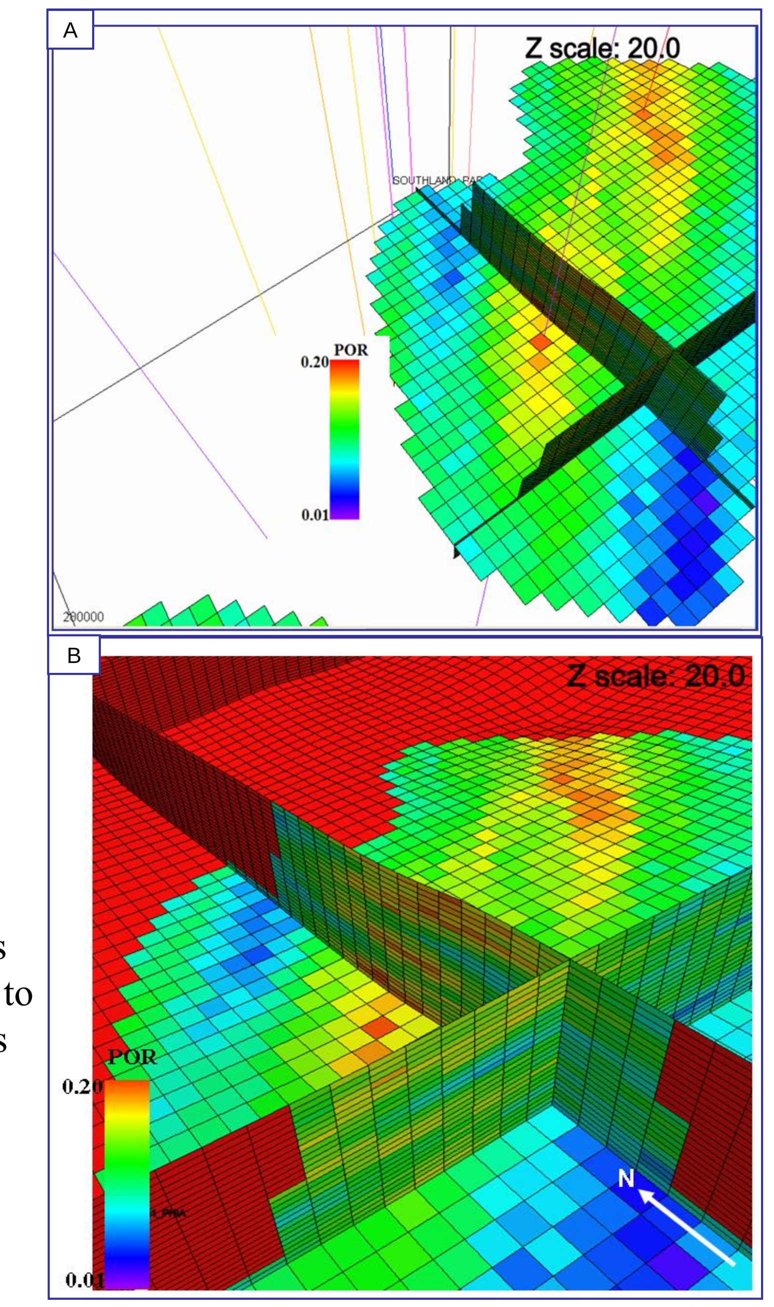


Fig.14a&b. Deterministic channel modeling was based on channel probability/clean sand trends (Fig.10) and empirical equations. This model was constrained to wells (A). The ability to condition to wells helped establish the axial and margin trends (B). This model provided additional information for well placement.

Discussion

The methods and results presented above have some implications in the reservoir characterization of Tight gas sands.

Firstly it can be seen that with some wells being drilled only 933ft apart in some parts of Travis Peak (Chandler, 2007), the possibility of drilling more than one well through the same channel sand in the upper part of Travis Peak (isolated channel sands encased in shales) is higher than it has ever been. Based on channel belt width empirical equations (Bridge and Mackay,1993; Bridge and Tye, 2000), a maximum bankfull flow depth of about 10ft can translate to a channel belt width of about 1420ft . In a high energy system with encased sand bodies, this means a single sand body can be this extensive and be modeled using many conventional techniques.

Furthermore, data from wireline logs, core and empirical equations (derived from core and analogues) were used in building „well constrained" 3D stochastic and deterministic models for rock property prediction.

Maps (i.e. zone averages, zone sums, iso-property) extracted from 3D geocellular property models preserve the heterogeneity in the reservoir while maps generated from simple well-based 2D lateral interpolation algorithms are unable to reflect that same level of geologic detail (Fig.15).

Finally through the placement of pseudo wells in planned infill locations, pseudo properties can be extracted from 3D geocellular models and used in ranking proposed well locations and for completions planning.

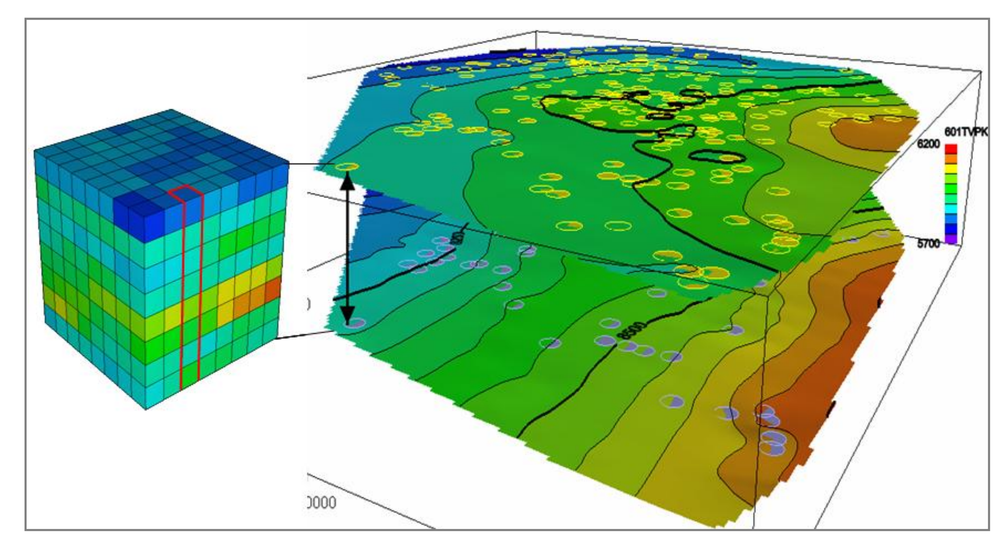


Fig.15 Surfaces (mean, sum, iso e.t.c.) calculated from 3D „property models" are based on the values of simulated cells rather than simple interpolation of well derived values (2D interpolation) and they preserve the heterogeneity of the reservoir.

Conclusion

Creative use of conventional data and 3D modeling tools can provide data useful for optimizing infill development plans;

- It is possible to predict pay distribution in a field with a high density of wells.
- 3D geomodeling techniques can be used to investigate the possible location, amount and spatial distribution of pay when field performance and rules permit the drilling of multiple wells within a channel belt width.
- HCPV and Pay models can be used as predictive tool in Tight Gas field wells and completions planning.

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