OTC OTC-19977-PP

Using Modern Geophysical Technology to Explore for Bypassed Opportunities in the Gulf of Mexico

R.A. Young/eSeis; W.G. Holt, G. Klefstad/ Fairways Offshore Exploration

Copyright 2009, Offshore Technology Conference

This paper was prepared for presentation at the 2009 Offshore Technology Conference held in Houston, Texas, USA, 4–7 May 2009.

This paper was selected for presentation by an OTC program committee following review of information contained in an abstract submitted by the author(s). Contents of the paper have not been reviewed by the Offshore Technology Conference and are subject to correction by the author(s). The material does not necessarily reflect any position of the Offshore Technology Conference, its officers, or members. Electronic reproduction, distribution, or storage of any part of this paper without the written consent of the Offshore Technology Conference is prohibited. Permission to reproduce in print is restricted to an abstract of not more than 300 words; illustrations may not be copied. The abstract must contain conspicuous acknowledgment of OTC copyright.

Abstract

The Gulf of Mexico Shelf is a mature oil and gas province that has been producing hydrocarbons since the early 1950's. Technology advances during the last five decades have led to the identification of new exploration prospects on deep structures, subtle traps, and direct detection of hydrocarbons via seismic amplitude anomalies and AVO (amplitude vs. offset) studies. There are good opportunities remaining in old fields that require another "step change" in technology application.

Seismic inversion is the process of determining the physical characteristics of rocks and fluids which have produced the seismic record. Inversion attempts to remove the effects of the seismic wavelet and therefore is the opposite of forward modeling. Inversion is a dataset that ties all the wells in an area and also honors all the seismic data.

Multi-disciplined asset teams benefit from advanced seismic technologies by using an integrated rock-property based solution to maximize results in exploration, well planning, drilling, production, and reservoir management. The key to success in to understand the rocks with tools to interpret and define lithology, porosity, fluids, pore pressure and reservoir quality; providing seismic data in a geologically meaningful and multi-disciplinary useable format.

Conventionally seismic inversion produces P velocity, S velocity and density. Log analysis, also an inversion process, starts with velocity and density, as well as other measurements, and finishes with lithology, porosity and fluids. The relatively new science of Seismic Petrophysics bridges the gap between these two workflows by starting with seismic data and resulting with 3D seismic volumes of lithology, porosity and fluids. An old field was purchased with intent of applying new technology in the search of bypassed opportunities. This case study will document the results of the work.

Introduction

For decades, the rudimentary process by which geologists determine optimal oil and gas drilling locations for exploration companies has remained intact.

Exploration companies have come to expect that many of the wells they drill will come up empty, despite preliminary research indications to the contrary. But the evolution of seismic petrophysics, combined with new proprietary technologies, provides geologists and engineers with dynamic, 3-dimensional models of the subsurface environment that more accurately reveal the reservoir properties and the likely locations of gas or oil.

The integration of well logs with seismic data is challenging because they are presented in different domains. Well logs are displayed in units of microseconds/ft, gm/cc, gapi, ohm-m, etc., while seismic is displayed in terms of reflectivity. When inversions are carried out to put seismic into a more log-similar domain, acoustic impedance is often chosen. This seems somewhat odd since well logs ultimately are inverted to lithology, porosity and fluids.

Why then take the seismic data to the starting well log domain and not to the final point? All of the measurements have one thing in common: the rocks. So ideally all of the measurements should be placed into the rock domain - that is lithology, porosity and fluids. Then the process can be thought in terms of rock-based integration.

The presented process will first describe how seismic data can be inverted into the lithology, porosity and fluid domains in a similar way that well log analysis is conducted. The results then are integrated with the well log analysis in terms of rocks.

Not only are these new techniques helpful in exploration, but they also are useful in field development and locating bypassed pay. This paper compares a conventional interpretation approach to that of rock-based integration. Following that, a Fairways case study is presented to illustrate the advantage of integrating data at the rock level.

The Old Way

Conventional seismic interpretation is conducted by taking well logs and applying their results to make synthetics. Then horizons are followed on the seismic from well-to-well, but the results hardly provide a complete portrait of the underground rock structure and actual location of natural gas.

Anyone looking at a simple stack may ask: "Where is the gas?" "Where is the sand?" "Where is the shale?"

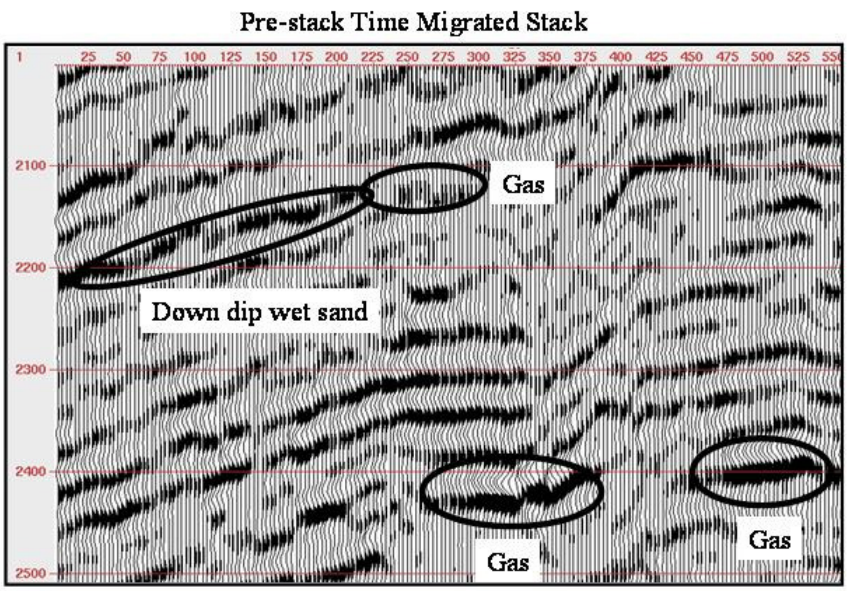

Figure 1

Gas is trapped in three different places in this section. *(Figure 1)* Two are bright spots (AVO Class 3 Gas Anomalies) and one is a dim spot (AVO Class 1 Gas Anomaly). Bright spots and dim spots occur because the stacking process emphasizes Class 3 anomalies, which have flat to increasing amplitude with offset distance, and suppresses Class 1 anomalies, that dim with offset.

Gas sometimes makes the stack bright, sometimes dim, and sometimes does not do anything at all. That is because seismic stacks respond to lithology, porosities, and fluids. As an analog, well logs also respond to these same factors.

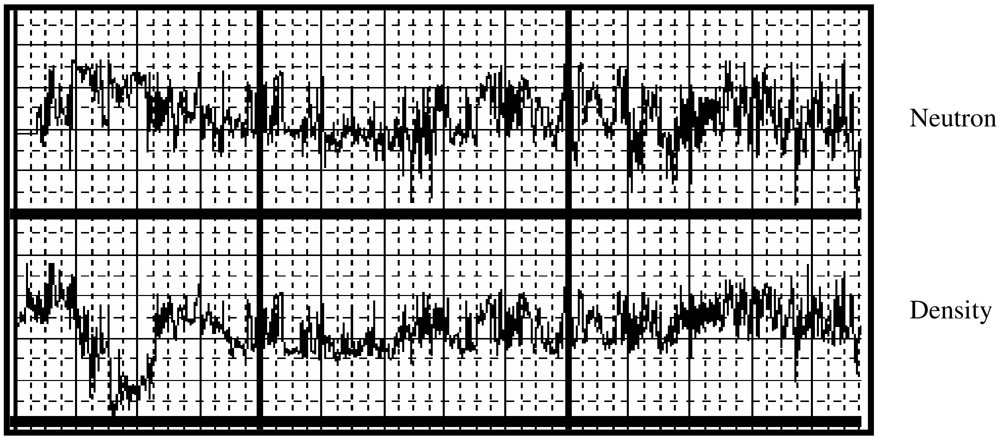

Figure 2

Reviewed separately, a neutron log or a density log would not accurately identify sands, shales or gas zones. (*Figure2*) By overlapping the density log and the neutron logs in compatible scales on the same track, pieces of information come together to fill in the puzzle. When the two log curves cross over, gas is indicated. When the two log curves are separate, shale is likely present. When the two log curves are on top of each other, sand can be found. And the porosity is the average of the two – what is known as crossplot porosity.

A crossplot can also be developed by putting the neutron points on the x-axis and the density points on the y-axis, resulting in a blob of data. The meaning of the blob is revealed by referencing a chart book. The result is shale, sand, gas and porosity.

By taking a simple petrophysical workflow, it is possible to crossplot a neutron log and a density log to calculate lithology, porosities, and fluids. *(Figure 3)*

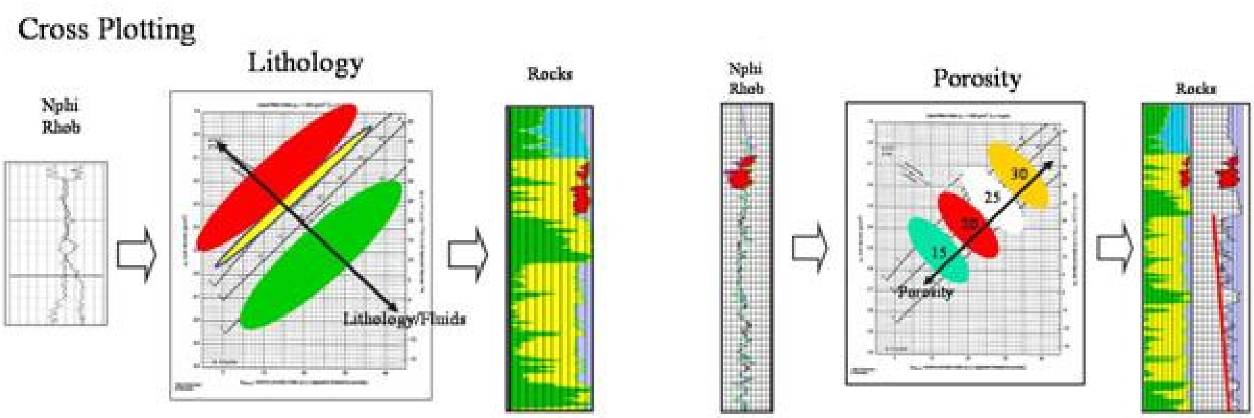

Figure 3

In geophysics, putting a near offset stack and a far offset stack next to each other might give a hint of how one is changing relative to the other, but you cannot get a complete picture with just two logs, much less with two seismic sections.

The New Way

An advanced seismic analysis technique combines well log analysis concepts with pre-stack seismic data to determine volume based lithology, porosity, and fluids. By extracting lithologic measurements from the seismic data before stacking or averaging, the result is a more accurate rock-based description of the subsurface.

In petrophysical analysis, the neutron and density combination allows for the separation of lithology and fluids from porosity. This works because neutron and density are independent from each other and both respond to lithology, porosities, and fluids.

A similar technique can be applied to the seismic data; however, two independent seismic sections will be needed instead of one. That problem can be solved by using AVO (amplitude variation with offset), a technology that has existed since the mid 1980's.

The acquisition of seismic data results in the sampling of each surface point at many different angles. The variation of amplitude with offset can thus be analyzed, resulting in zero offset (P) and AVO gradient (G) sections, two independent seismic measurements. *(Figure 4)* Conventionally, all the gathers are added up or averaged to create the full offset stack resulting in just one measurement, which would be similar to adding the neutron log to the density log.

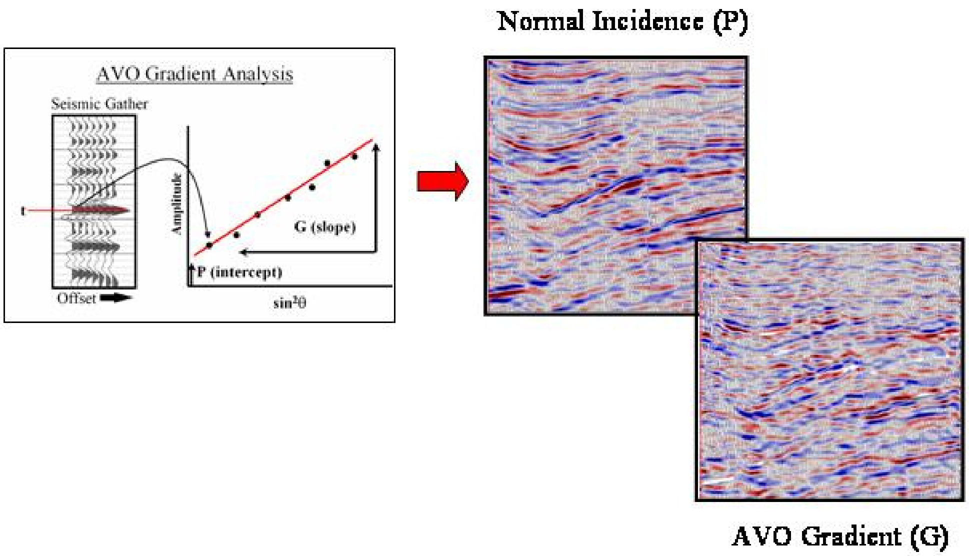

Figure 4

These two sections provide the equivalent of two well logs in the logging world. A crossplot is created by putting P on the X-axis and G on the Y-axis and plotting all the points. The resulting crossplot blob is equivalent to that created by the neutron and density logs so a chart book is needed to understand the blob in terms of lithology, porosities, and fluids.

To create this chart book, a lot of modeling was required. Conventional seismic modeling is conducted by using the well logs to make synthetics then changing the well logs to sand the synthetics change. However, that does not help because the relationship between well logs and synthetics is not what is of interest. Rather, what is desired is the relationship between rocks and synthetics/seismic.

Log analysis is about the relationship between logs and rocks. Seismic models relate logs to seismic. Therefore, the math already exists to relate rocks to synthetics/seismic. Studying how rocks influence seismic reveals what seismic is telling us about rocks.

In modeling, lithology derived from the well logs is used to create the synthetic seismic gathers. As the lithology changes, the modeled seismic gathers also change. This allows for the creation of thousands of modeled responses of different rocks. From these responses, gathers are created, then P and G sections are created, then finally all rock responses are plotted into P/G crossplot space. *(Figure 5)*

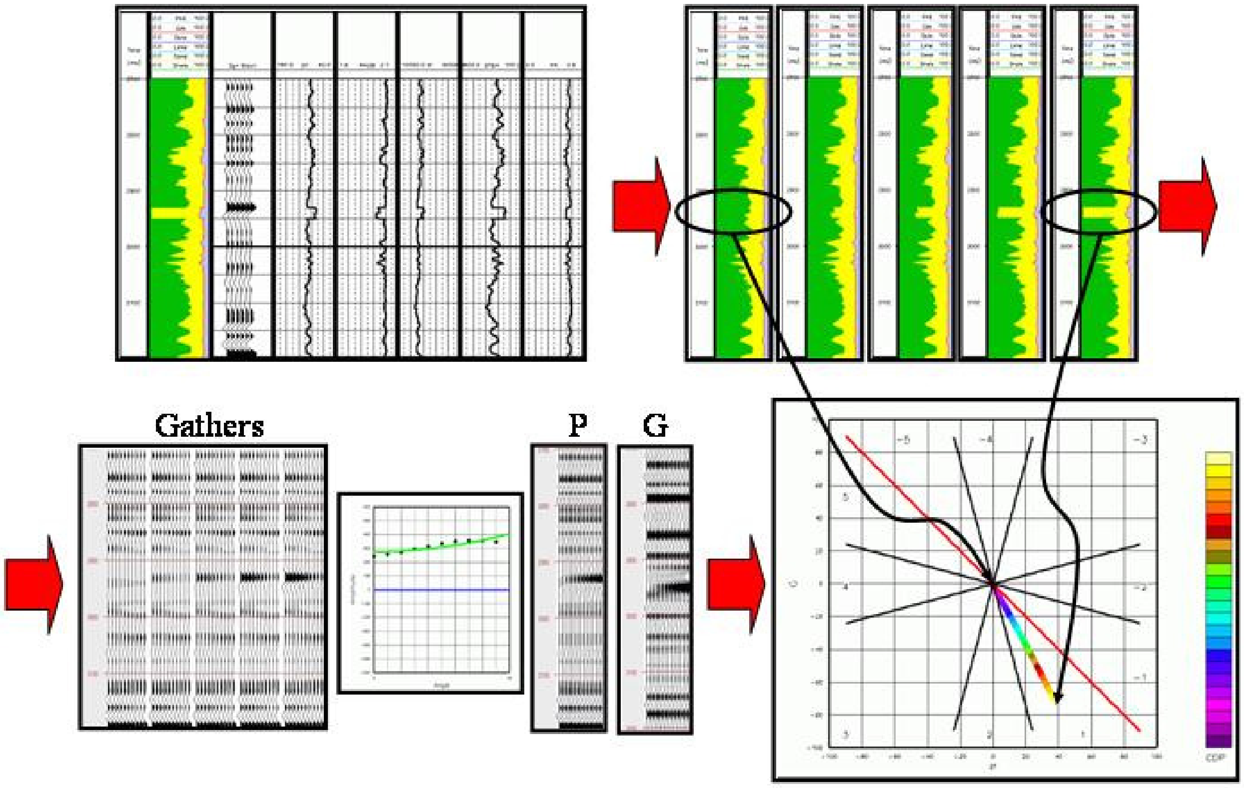

Figure 5

The location that a given shale/sand interface point will plot depends on the properties of the sand and shale. After studying many models it becomes evident that, as the sand becomes cleaner, the point plots further from the origin. Add gas to the sand, and the distance increases in generally a southwesterly direction. Change the porosity, and the direction changes. In other words, porosity acts in an orthogonal way to lithology and fluids. This is similar to what happens with a neutron/density log crossplot.

Another interesting case to look at in crossplot space is that of laminated sands. The far offsets of the seismic data see these laminations very differently from blocky sand because these laminated sands are very layered therefore less rigid and more shearable than blocky sands.

An important consideration in crossplot space is that of thickness. The distance from the origin will behave just like the classic tuning curve, relating amplitude to thickness. Thickness and tuning do not influence the direction, only the distance from the origin.

After studying thousands of different models and hundreds of different data sets, it is easy to figure out what is important in crossplot space:

1. ***Elliptical distance from the origin***

The crossplot is elliptical by nature, and its elliptical distance from the origin is a function of lithology, fluids, and thickness. *(Figure 6)*

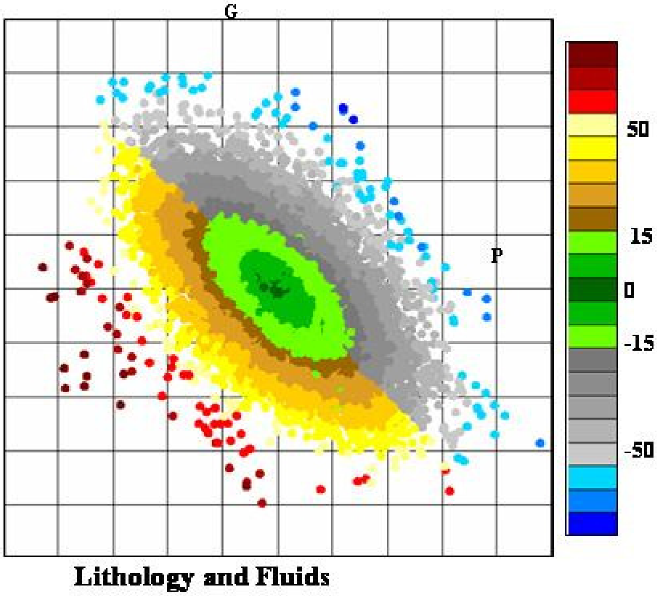

Figure 6

2. Direction

Direction is a function of porosity and whether the sand is blocky or laminated. Together these help infer the depositional facies. Direction is called AVO type and is divided into 10 different types form 5 to -5 as shown. *(Figure 7)*

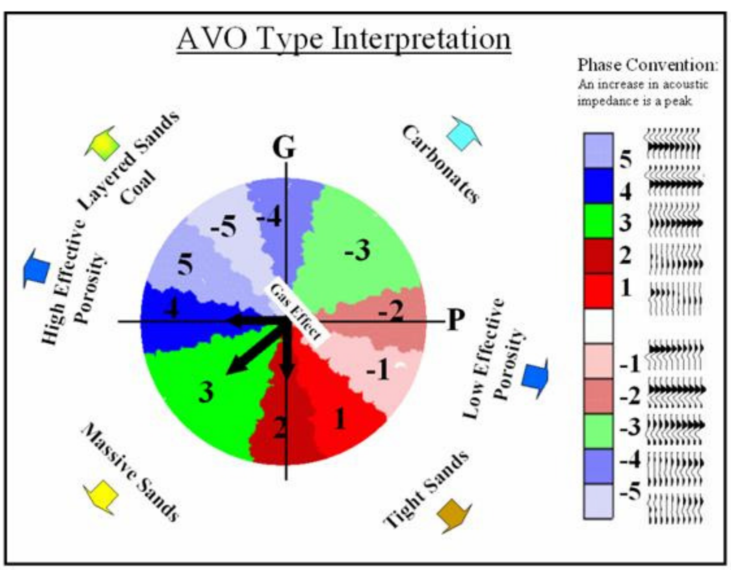

Figure 7

The lithology fluid section (elliptical distance) gives insight into the rock's lithology contrast, fluid contrast, and thickness. The AVO-type section (direction) provides insight into the rocks porosity and depositional facies. From this information it is easy to pinpoint the best well position.

A Real World Case Study

The usefulness of employing rock-based integration is illustrated by this Fairways case study. Fairways was looking for a tool to help it identify bypassed pay and better understand stratigraphic variability in an old field located offshore in the Gulf of Mexico. The field was very structurally simple, with a lot of stacked pay and much stratigraphic variability. The main zone of interest was oil sands located above 9,000 feet.

In the case study, this AVO technology was run on the 3D dataset to obtain lithology, porosities, fluids, and AVO types. Log analysis was run on approximately 70 wells in the project. Good petrophysical analysis goes beyond doing net pay counts. Well logs are subject to error, as any dataset is, and therefore these errors must be corrected. Things such as borehole washout, fluid invasion and swelling shales account for a large portion of errors that must be corrected. In a field study such as this, the logging data issues become even more difficult. Different suites of logs are run in each of the wells, making some sort of normalization process necessary. Most of these wells were deviated and had only Resistivity and SP curves. There were a few straight holes that had sonic logs available, and these few wells were the first to be run through log analysis and tied into the seismic and lithology. Once a suitable tie was made for these wells, one was chosen to be used for the time/depth relationship on the wells that did not have sonics. Since the log analysis performed came up with a rock model, sonics were created from the rock model in the wells that did not have them. The time/depth function mentioned earlier was used as a starting point for the synthetic tie. Small adjustments were made to the wells in order to get the best ties.

After all 70 wells were tied into the lithology/fluid volume, the volume was checked against the wells for accuracy. All of the wells matched the lithology/fluid volume so this and the other output volumes were delivered to Fairways for loading into their interpretation system to begin their search for bypassed pay. *(Figure 8)*

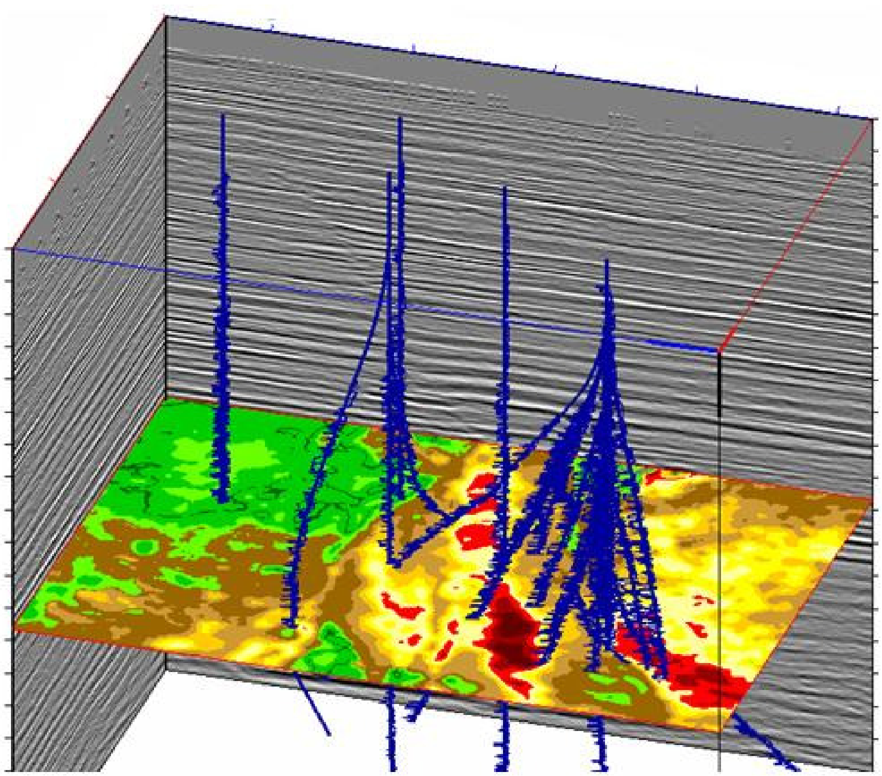

Figure 8

A total of approximately 500,000 barrels of bypassed reserves were located by using this technology. Unfortunately, the location of the bypassed pay was scattered and would take too many wells and too much cost to develop. In future projects it will be helpful to see the results of this type of work before deciding to buy fields or in deciding how much to pay for them. Another method that builds on the technology here is still in development, but has shown promise in lending even more insight into the development of these older fields.

Summary

These technologies allow companies to more easily and accurately find and develop reserves with tools that are useful throughout the lifecycle of a project. The marrying of petrophysics with geophysics results in a science we term seismic petrophysics. The goal is to understand the petrophysical information that seismic data brings to the table. This starts with a good understanding of the rocks. Having seismic data in terms of lithology, porosities, and fluids, not velocities and densities, this information can be used by all members of the asset team and provide exploration companies with a more strategic and precise model for finding hidden oil and gas reservoirs.