AN OVERVIEW OF EXPLORATION GEOPHYSICS — RECENT BREAKTHROUGHS IN GEOPHYSICS AND RECOGNITION OF CHALLENGING NEW PROBLEMS†

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Introduction

Changes in geophysical technology have been rapid and dramatic in recent years; so much so that work done only a year or two ago is referred to as the "old" geophysics. Everyone wants the "new" geophysics. As might be expected, each new method developed gives rise to additional problems, often unforeseen, which limit the use of the method and thus require a new round of improvements. Three topics are chosen to demonstrate this: namely, (1) problems involving velocity-structure, (2) elimination of noises after stacking, and (3) the direct detection of hydrocarbons.

Velocity-Structure

The first example of the velocity-structure problem is from the Michigan basin (Figure 1) and typifies the special case of near-surface "sonic lenses". Highly irregular deposits of glacial till, with abrupt thickness variations of hundreds of feet and velocities varying from 2,000 feet per second to 6,000 feet per second, cause differential time delays and ray path distortions which result in misalignments of the common depth point stack. Until this problem was solved a few years ago, the Michigan Basin was essentially a "no data" area. The disruptions of seismic events caused by the small Silurian pinnacle reefs, a few hundred feet high and roughly 160 acres in areal extent, were often indistinguishable from disruptions caused by stack misalignments under glacial trenches. New correction methods which eliminate misalignments in the stack have led to the current reef detection success ratio of about eight out of ten. This is a special case of the velocity-structure problem since (1) the sonic lenses are known to be at the surface, (2) the wavelengths of the variations are reasonably short relative to shooting distances, (3) there are strong reflections from a shallow Devonian reflector which is structurally simple so that it can be used as a correction plane and (4) the interpretation objective is stratigraphic resolution rather than structural definition so that precise depth determinations at the Silurian level are not required. These methods do not work well in more general situations: i.e., (1) areas where the sonic lenses are not at the surface, such as buried karst topography and submarine gorges, (2) instances where the wavelengths of the variations are long compared to shooting distances, such as permafrost changes near large bodies of water, and (3) provinces where the interpretation objective is accurate structural definition.

Another velocity-structure problem, also a special case, has been encountered in the Gulf Coast province. Here the problem is one of mapping highly contorted beds associated with the mobile salt layer. It is impossible to map the complex structures here without migration, and since the steep dips are misaligned in migration-after-stack

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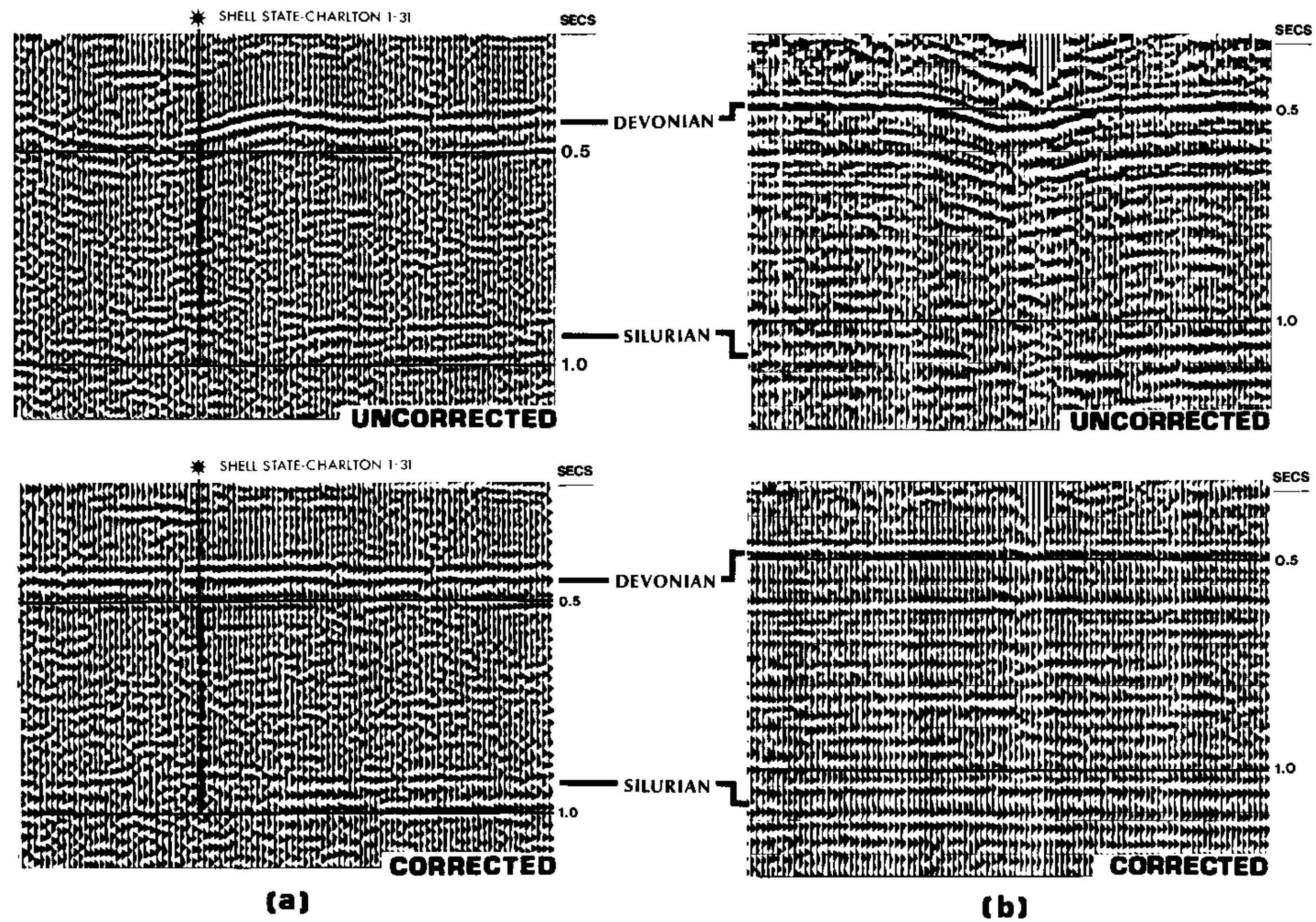


Fig. 1. Michigan basin seismic sections showing a valid Silurian reef anomaly (a) and a fictitious Silurian anomaly (b). The top panels show the effects of misalignments due to variations in the near-surface glacial till, and the bottom panels show the data after proper alignment.

procedures, it is necessary to migrate the data before they are stacked. This procedure works quite well if the seismic data are acquired along true dip directions so that there are no cross-line components of dip. Here the problem is straightforward because the velocity overburden is simple: there are no sonic lenses to distort the ray paths and confuse the velocity and the dip determinations. Migration-before-stack is currently the standard migration technique and is valid where these conditions obtain. Furthermore, the method can be extended to situations involving cross-line components if sufficient cross-line information is acquired to uniquely determine all dip components.

The third velocity-structure example (Figure 2) from West Africa represents the general case. Here, the objective is to map beneath a highly deformed Cretaceous salt layer. In addition to the ray path distortions caused by the salt layer, two other layers above it also cause distortion. A Cretaceous carbonate layer immediately above the salt has variable thickness and velocity, and the overlying low-speed Tertiary clastic section has large lateral velocity changes caused by salt solution and collapse. With continuous rms velocity measurements, the pertinent reflections are stacked well enough to be visible, but accurate velocity measurements that will give proper depth conversions are not possible. The ordinary time migration section produced with migration-before-stack techniques does not provide a satisfactory solution since the normal assumption of simple velocity overburden is not valid. Rather, the velocity overburden contains three layers of sonic lenses: the salt, the carbonate, and the clastics. The ray path distortion caused by these layers can be corrected for a good stack, migration, and depth conversion provided an accurate model for each layer can be constructed. This model construction requires the correct measurement of velocity gradients, in the presence of structural dip, for several layers — hence the nomenclature "velocity-structure". All of the pertinent dips are visible on sections processed in this way and the depth conversion looks reasonable. Obviously, improved reflection quality and reasonable looking depth sections do not guarantee a proper migration and depth conversion; there must be better methods to verify the accuracy of the model.

In actual practice the third dimension must be taken into account. The assumption has been that the data were acquired in the dip direction, with no cross-line components.. This assumption must be valid for all three layers of the model. Obviously, it is not possible to satisfy this requirement with one line if the various layers dip in different directions. Three-dimensional analysis and processing is difficult and the acquisition of cross-line information must be sufficient not only to measure cross-line dips and to prevent aliasing, but also to measure velocity gradients in the presence of these dips. This is the general case and simple wide-line recording methods are not likely to provide sufficient density of control to solve the problem uniquely.

Elimination of Noises After Stacking

Common depth point stacking is a velocity filter that opened many areas to exploration by discriminating against multiple reflections and other noises. In the example chosen, from the eastern Pacific offshore (Fig. 3), the multiples are so strong that the primary reflections are barely visible on single records and the stacking velocity for primary reflections is not easy to determine. Given the correct velocity, a twenty-four fold stack reveals an anticline but details are obscured by residual multiples not eliminated by the stacking process. Cancellation "beyond the stack" is needed. A method for doing this was applied to the data in this example and details of the anticline become clear, showing evidence of structural growth, unconformities, and a shift in the crest of the anticline at depth.

There are two basic ways to attack multiples "beyond the stack" — (1) use of a velocity filter, or (2) use of a predictive technique. In the first method, use of a velocity filter stronger than the stacking filter may eliminate the multiples, but only if there is sufficient velocity separation in the earth between multiples and

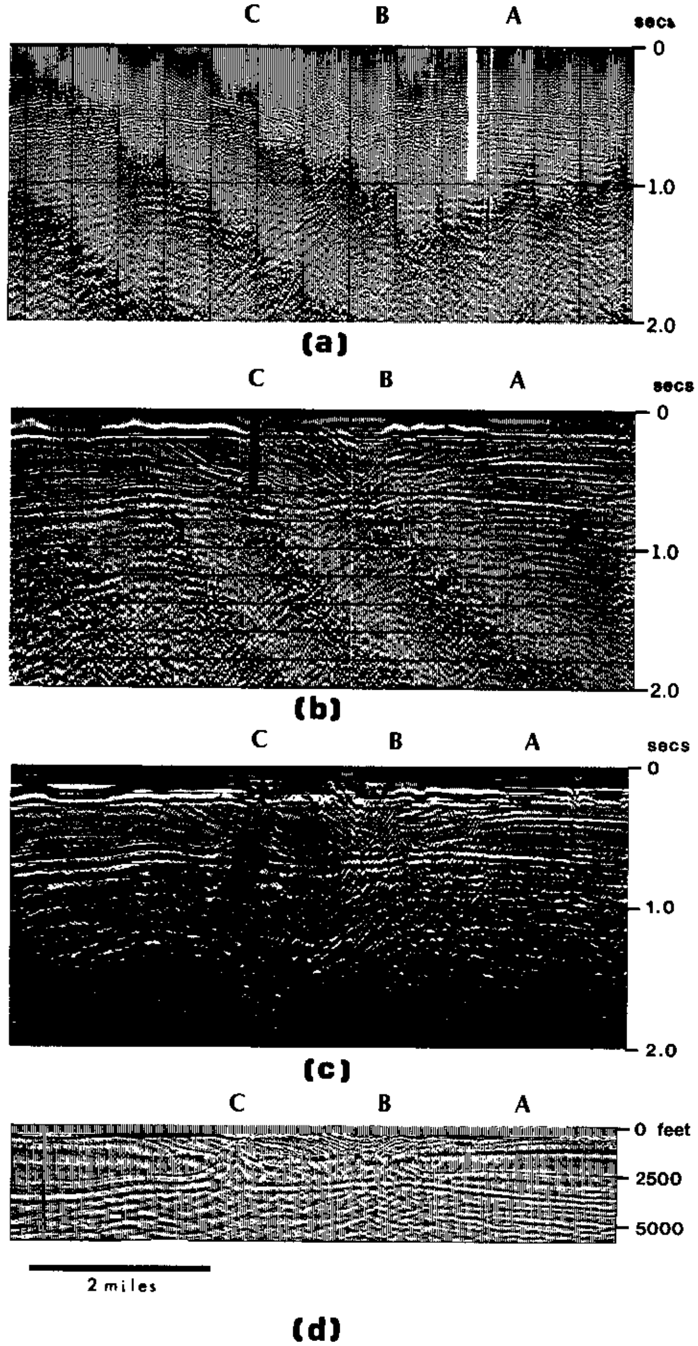


Fig. 2. Example from West Africa illustrating the general velocity-structure problem. (a) Preliminary stack which shows a high at A and indications of a salt dome at C. (b) Refined stack which shows a continuous base salt event between 0.6-0.8 second. (c) Migration-before-stack time section. (d) Migrated depth section showing (1) no deep high at A, (2) indications of a salt dome with overlying collapse at B, (3) a salt dome at C, and (4) a continuous smooth base salt reflection between the depths of 2500 and 4000 feet.

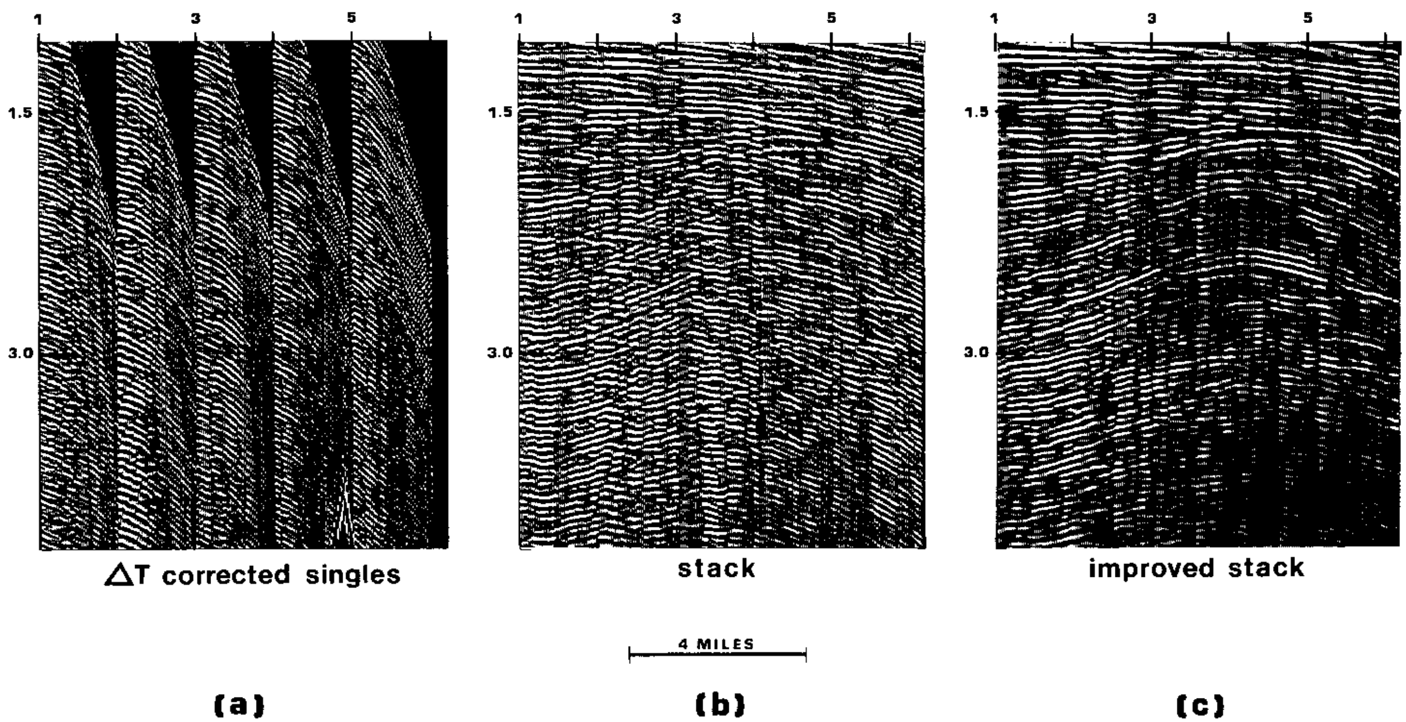


Fig. 3. Example from eastern Pacific offshore multiple reflection problem area (a) showing some multiple attenuation obtained with stacking (b) and additional rejection obtained with processing "beyond the stack" (c).

primaries. Even with a sufficient velocity separation, however, dips of the multiple generators may in some cases cause the multiples to coincide with the primaries and hence any velocity filter would be insufficient. The second method involves predicting the positions of multiples and subtracting them. This requires a detailed model of the multiple generators which must be obtained from the reflection record by accounting for all of the reverberations, simple multiples, and peg-leg multiples generated by the reflecting interfaces. Or, it requires a predictive model derived from the periodicity of multiply reflected events through autocorrelation. In either method of modeling, the periodicity and amplitude of the multiples change with time and distance respectively. Moreover, the water-bottom reverberations of multiples and of primaries have distinctly different phase characteristics. Therefore, since the required models are complex and are dynamic in space and time, these techniques must be used with great discretion.

Direct Hydrocarbon Detection

For the past few years, geophysicists have been routinely predicting hydrocarbons from "bright-spot" amplitude analyses. The amplitudes of seismic reflections are governed by differences in the acoustic impedances (velocity X density) of the rock layers at reflecting interfaces. Since the acoustic impedance of a loosely cemented rock filled with hydrocarbons is different from that for a similar water-filled rock, it follows that the presence of hydrocarbons may be detected by amplitude changes under certain conditions.

In the first example, from the Gulf Coast province, there are several bright-spot anomalies (Figure 4a) near the 5,000-foot depth on the right side of the profile at well location No. 1. Borehole logs in the No. 1 well confirmed five hydrocarbon pays as indicated by the seismic data, and a substantial field was discovered. On the left side of Figure 4a there is an equally good bright spot at the same depth, tested by wells 3 and 4. The only anomaly on the borehole logs in these wells is cycle skipping on the sonic logs at the level of the bright spot. There is a sand at this level which correlates with one of the pay sands in well No. 1, just across the syncline. It was suspected that the bright spot and cycle skipping are caused by low saturation gas in this sand unit. A theoretical paper presented by Domenico (1974) demonstrated that a small percentage of free gas in a reservoir, too small to affect the resistivity measurements on borehole logs, should give a strong velocity change and hence a bright-spot amplitude anomaly. A second example of the same problem in the Gulf Coast is shown in Figure 4b. The deep bright spots below 2.0 seconds are confirmed in wells 1 and 3 as good gas pays. The two shallow bright spots near 1.0 second are confirmed in both wells by resistivity logs as wet sands, but with pronounced cycle skipping on the sonic logs. Fluid entry tests were made in these sands with a recovery of 9.7 cu. ft./bbl. of methane. Inasmuch as this quantity is close to the maximum amount of gas that can be dissolved in the formation water it cannot be used as positive evidence of free gas in the reservoir. Sidewall cores from these sands were analyzed in the laboratory and the results are presented in Figure 4c. A small fraction of porosity occupied by a gas, air in this case, has a large effect on the velocity in the core. It is thought that the mild disagreement between the theoretical curve and the measured curve is caused by inhomogeneity of gas distribution in the sample which is more noticeable at 75 kHz than it would be at seismic frequencies. All the evidence leads to the tentative conclusion that low saturation gas does occur in reservoirs at depths of interest and although the quantity is too small to see on the resistivity log, unfortunately it can be seen all too easily on the seismic data.

In another instance, at a Gulf Coast salt dome prospect, two tests were drilled into a fair "bright spot" target. It was found that the amplitude anomalies were caused by two thin, broken gas sands, with good saturation, separated by a thin hard streak of silty shale. The gas in these poor quality sands was non-commercial. It requires high resolution seismic data and a good geological prognosis of the reservoir quality

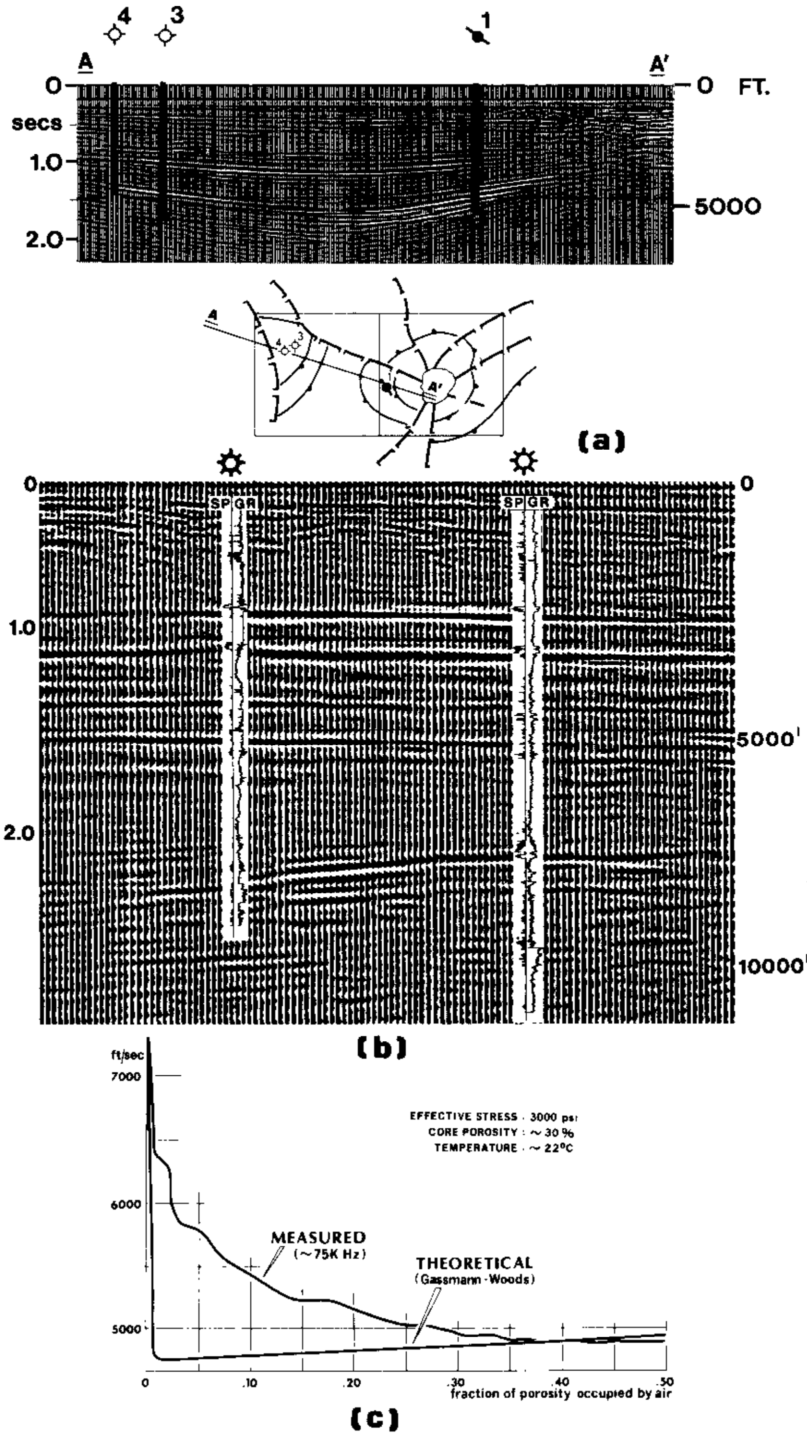
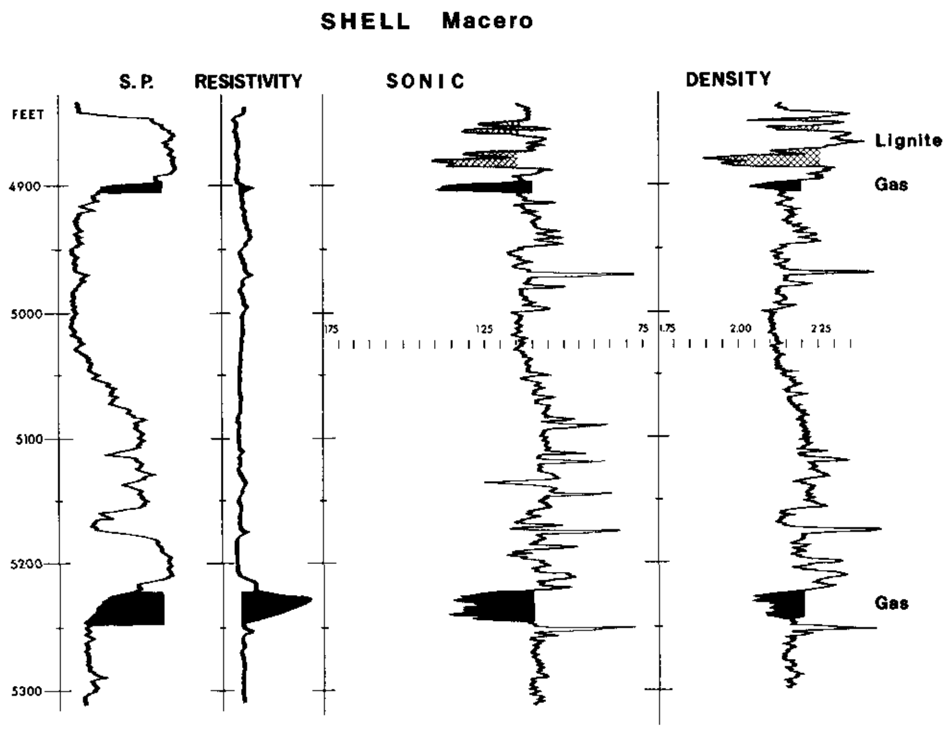
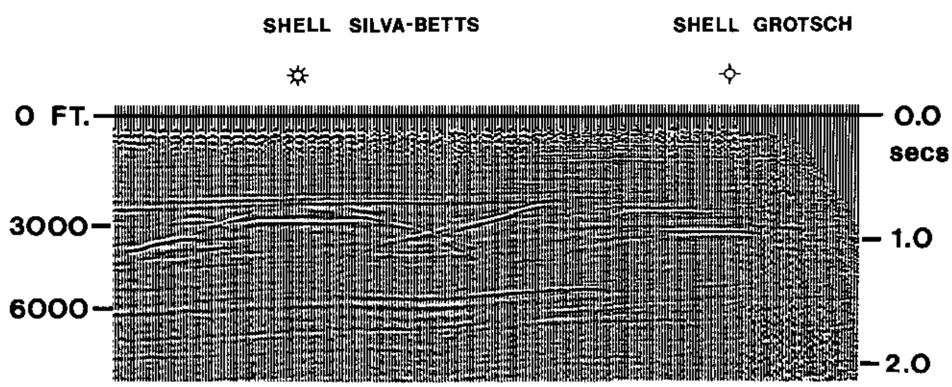


Fig. 4. Gulf Coast province examples (a and b) showing seismic amplitude anomalies associated with both commercial and non-commercial hydrocarbon accumulations. (c) Plot of theoretical and measured velocities as a function of gas saturation.



(a)



(b)

Fig. 5. California examples. (a) Velocity and density data for lignite and gas layers. (b) Seismic section showing "bright spots" associated with both commercial and non-commercial gas accumulations.

in order to predict the commerciality of pays associated with these kinds of amplitude anomalies. In another prospect in the Gulf Coast onshore a good bright spot was seen in the Oligocene section. Well data show that this amplitude anomaly, which has a good fit with structural contours is related to a thin lime build-up (non-hydrocarbon bearing) that apparently developed on a low relief topographic high. Since this paleo high coincides with present-day structure, the structural configuration of the bright spot is the same as would be expected with a hydrocarbon accumulation. However, if the reflection polarity can be determined, this kind of amplitude anomaly can be ruled out as being a hydrocarbon indicator.

In a California onshore example, dealing with Upper Cretaceous sands, targets indicated by two bright spots were drilled. Logs from this well are shown in Figure 5a. The upper bright spot at 4850 feet was slightly better on the seismic data than the lower bright spot at 5220 feet. The upper one was caused by lignite; the few feet of gas at 4900 feet is too thin to give an amplitude anomaly. The lower bright spot was caused by a good gas pay. It is clear that the sonic and density responses of lignite are very close to those of gas sands. As a consequence, in this area of stratigraphic traps the significance of bright spots is often difficult to determine. Another example from California (Figure 5b) shows two wells drilled into bright spot targets in the Upper Cretaceous. The well on the right, at a seismic time of 1.0 second, encountered a wet sand with low resistivity but a good low-velocity sonic anomaly. It is estimated that the free gas saturation in this reservoir is about 10%. Moreover, the logs in this case seem to indicate a water level below the low gas saturation. A good gas pay was encountered in the well on the left at a depth of 3,000 feet where a prominent bright spot occurs. In many respects these two bright spots look alike, but one leads to a commercial gas discovery and the other a dry hole.

These examples were chosen to illustrate that interpretations of amplitude anomalies are not always straightforward. There are ambiguities and great care must be exercised in interpretation because not all bright spots indicate hydrocarbons and conversely not all hydrocarbon accumulations give rise to bright spots.

Conclusion

All of the examples discussed in this paper deal with the interpretation of bona-fide seismic signals and do not deal with other classes of problems, such as spurious seismic events and processing artifacts. The point is, there are still ambiguities in the interpretation of the best data. Even if we describe the earth in precise layers of velocity and density contrasts, with known attenuation properties and correct structural attitudes, the geological interpretation may be ambiguous in some instances. But these ambiguities will be fewer as we recognize and solve each new complexity and use good geological reasoning in our interpretations, thus making the "new" geophysics of today the "old" geophysics of tomorrow.

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Reference

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