HYDROCARBON DETECTION

<u>Gardner's rule</u>: relationship between density and velocity

Gardner's rule:

$$\rho = aV^{1/4}, \qquad (5.15)$$

where density ρ is in g/cm^3, $a = 0.31$ when velocity V is in m/s and $a = 0.23$ when V is in ft/s. This equation is often used to obtain density values in synthetic seismogram construction or in inversion.

In the **simplified formula** for the reflection coefficient, density is neglected: this is a generally acceptable approximation.

The presence of gas within a sequence produce a decrease in velocity, but also in density. Both the velocity and the density contribute to decrease the acoustic impedance and also to increase the value of the reflection coefficients.

Generally, high coefficients allow us to recognize the presenceof gas.

HYDROCARBON DETECTION

<u>Willie's Equation</u> :

relation between the velocity of the rock matrix,
the velocity of fluids and the porosity of the rocks.
As stated earlier, porosity is often the most important factor
in determining the velocity of rocks.

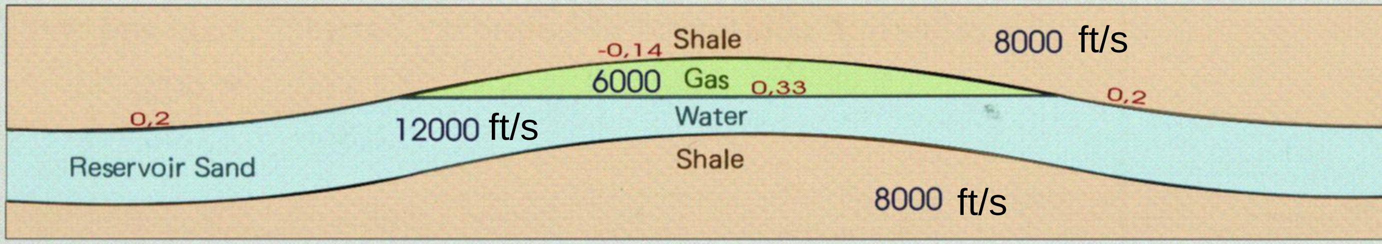
Willie's equation is often used:

$$\Delta t = \phi \, \Delta t_f + (1 - \phi) \, \Delta t_m, \qquad (5.16a)$$

where Δt is the specific transit time (slowness), Δt_f and Δt_m the specific transit times of the pore fluid and rock matrix, respectively. In terms of velocity V, this equation is

$$\frac{1}{V} \equiv \phi \frac{1}{V_f} + (1 - \phi) \frac{1}{V_m} \qquad (5.16b)$$

HYDROCARBON DETECTION



SAND POROSITY θ = 10% = 20%

SAND VELOCITY Vm = 14,000 ft./sec. 4270 m/sec

WATER VELOCITY Vw = 5,000 ft./sec. 1524 m/sec

GAS VELOCITY Vg = 1,000 ft./sec. 305 m/sec

SHALE VELOCITY Vs = 8,000 ft./sec. 2440 m/sec

WYLLIE'S EQUATION : $\frac{1}{Va} = \frac{\theta}{Vf} + \frac{1-\theta}{Vm}$ = 20%

SAND w/WATER Va = 12,000 ft./sec. 3660 m/sec Rcw = $\frac{12{,}000 - 8000}{12{,}000 + 8000} = \frac{4000}{20{,}000} = 0.2$

SAND w/GAS Va = 6,000 ft./sec. 1830 m/sec Rcg = $\frac{6000 - 8000}{6000 + 8000} = \frac{-2000}{14{,}000} = -0.14$

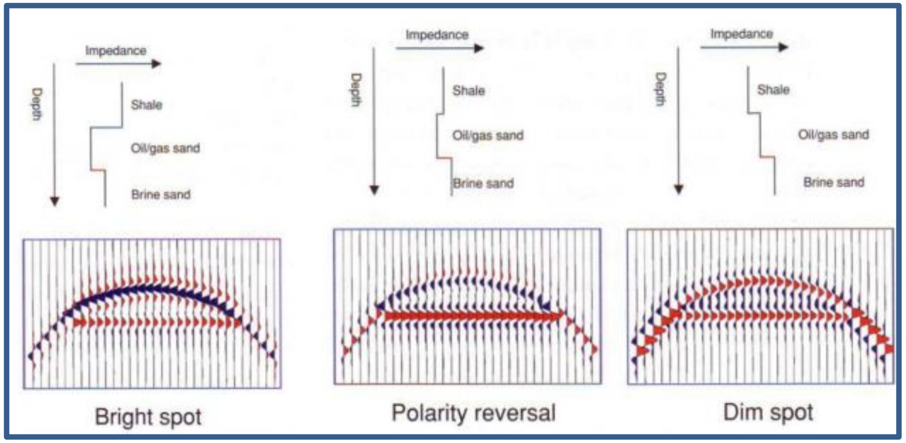
GAS/WATER CONTACT Rc = $\frac{12{,}000 - 6000}{12{,}000 + 6000} = \frac{6000}{18{,}000} = 0.33$

In general we will have:

- an average positive reflection coefficent medio tra argille e sabbie sature in acqua

- un coefficiente negativo , talvolta positivo, tra argille e sabbie sature in gas
    * se accumulo superficiale: alto Rc in valore assoluto
      => BRIGHT SPOT
    * se accumulo in reservoir carbonatico all'interno di argille: ridotto Rc in valore assoluto
      => DIM SPOT

Mocnik, 2012

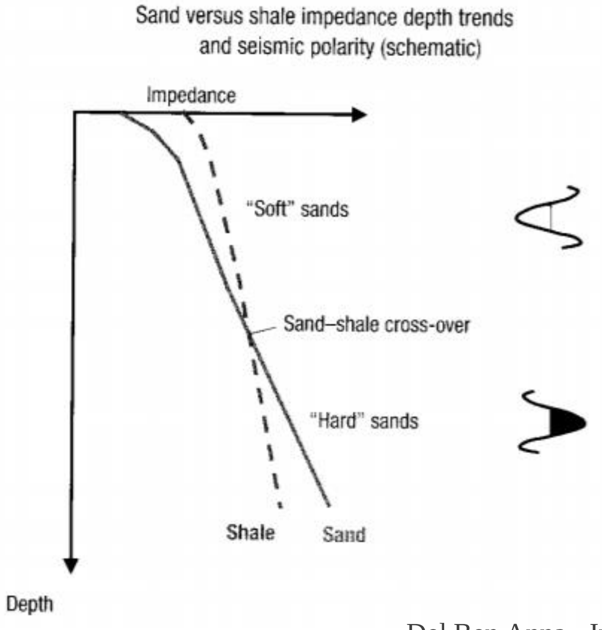


- un buon coefficiente tra sabbie sature in gas e sabbie sature in acqua
  => FLAT SPOT

Bright e dim spots

In a relatively soft sand, the presence of gas and/or light oil will increase the compressibility of the rock dramatically, the velocity will drop accordingly, and the amplitude will decrease to a negative "bright spot." However, if the sand is relatively hard (compared with cap-rock), the sand saturated with brine may induce a "bright-spot" anomaly, while a gas-filled sand may be transparent, causing a so-called dim spot, that is, a very weak reflector. It is very important before starting to interpret seismic data to find out what change in amplitude we expect for different pore fluids, and whether hydrocarbons will cause a relative dimming or brightening compared with brine saturation. Brown (1999) states that "*the most important seismic property of a reservoir is whether it is bright spot regime or dim spot regime.*"

One obvious problem in the identification of dim spots is that they are dim – they are hard to see. This issue can be dealt with by investigating limited-range stack sections. A very weak near-offset reflector may have a corresponding strong far-offset reflector.



… what type of event do we expect, a hard or a soft? A positive pick or a negative trough?

Avseth et al., 2010

Ambiguity

to interpret

a *Bright Spot*

Reflection strength ←

Pitfalls: False "bright spots"

DHI = *Direct Hydrocarbon Indicator*

During seismic exploration of hydrocarbons, "bright spots" are usually the first type of DHI (direct hydrocarbon indicators) one looks for. However, there have been several cases where bright-spot anomalies have been drilled, and turned out not to be hydrocarbons.

Some common "false bright spots" include:

- Volcanic intrusions and volcanic ash layers
- Highly cemented sands, often calcite cement in thin pinch-out zones
- Low-porosity heterolithic sands
- Overpressured sands or shales
- Coal beds
- Top of salt diapirs

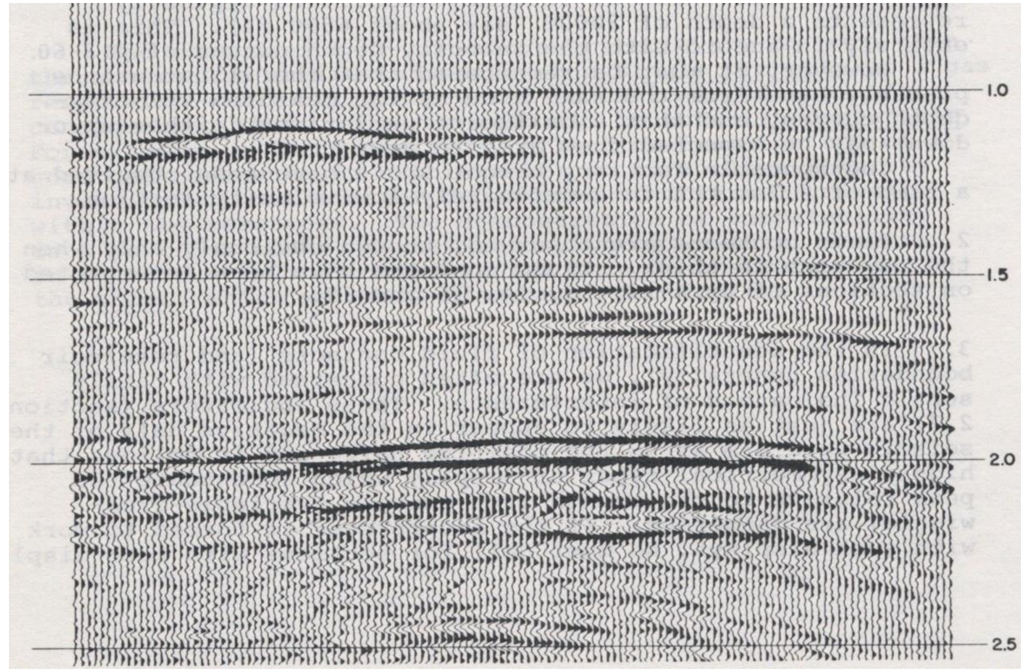
Only the last three on the list above will cause the same polarity as a gas sand. The first three will cause so-called "hard-kick" amplitudes. Therefore, if one knows the polarity of the data one should be able to discriminate hydrocarbon-associated bright spots from the "hard-kick" anomalies. AVO analysis should permit discrimination of hydrocarbons from coal, salt or overpressured sands/shales.

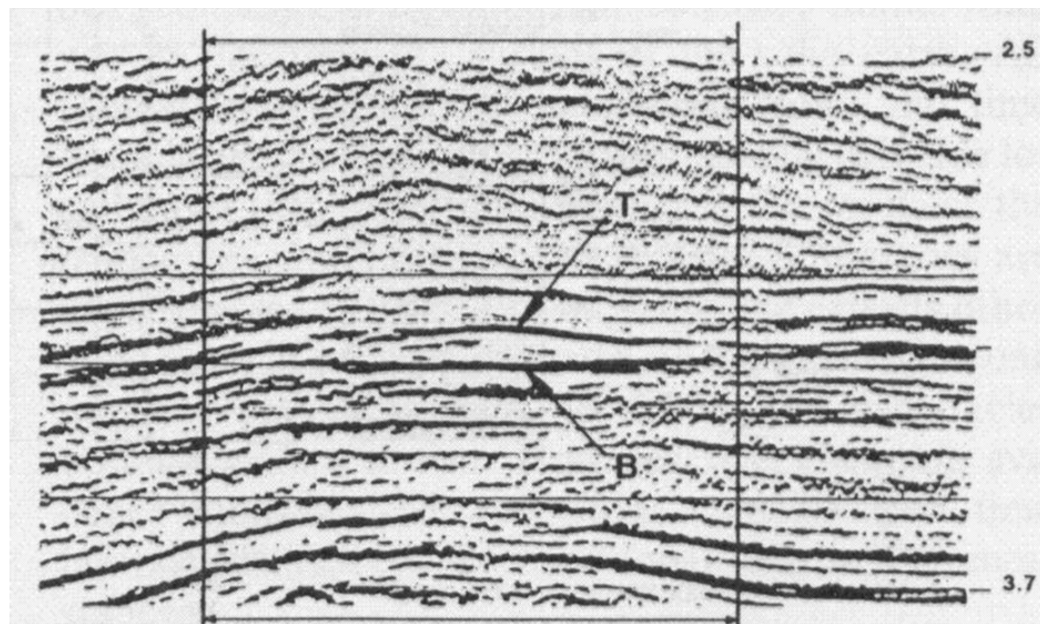
A very common seismic amplitude attribute used among seismic interpreters is reflection intensity, which is root-mean-square amplitudes calculated over a given time window. This attribute does not distinguish between negative and positive amplitudes; therefore geologic interpretation of this attribute should be made with great caution.

Examples of

Bright (T) and

Flat (B) Spots





<u>Gas-liquid contact</u>:

- it must be necessary a positive reflector,

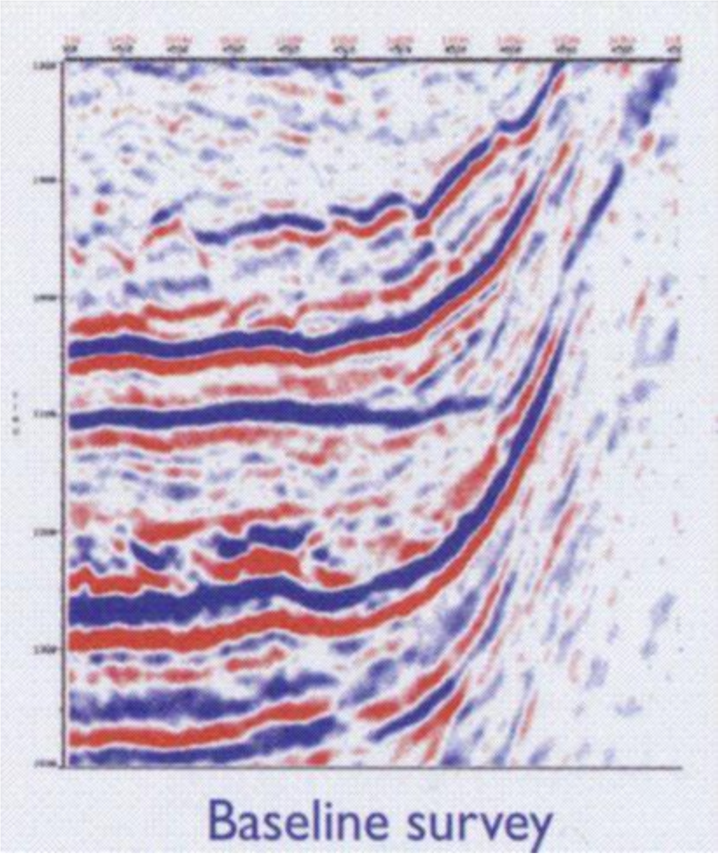
- despite the term *flat-spot,* this contact is not necessarily *flat* and/or horizontal in twt, due to *pull-velocity* effect.

- **It is generally *flat* only in the**
- **depth migrated profiles.**

- **Sometimes the *flat-spot* is not horizontal even in the depth migrated profiles, generall due to the presence of faults or due to lateral change of the permeability.**

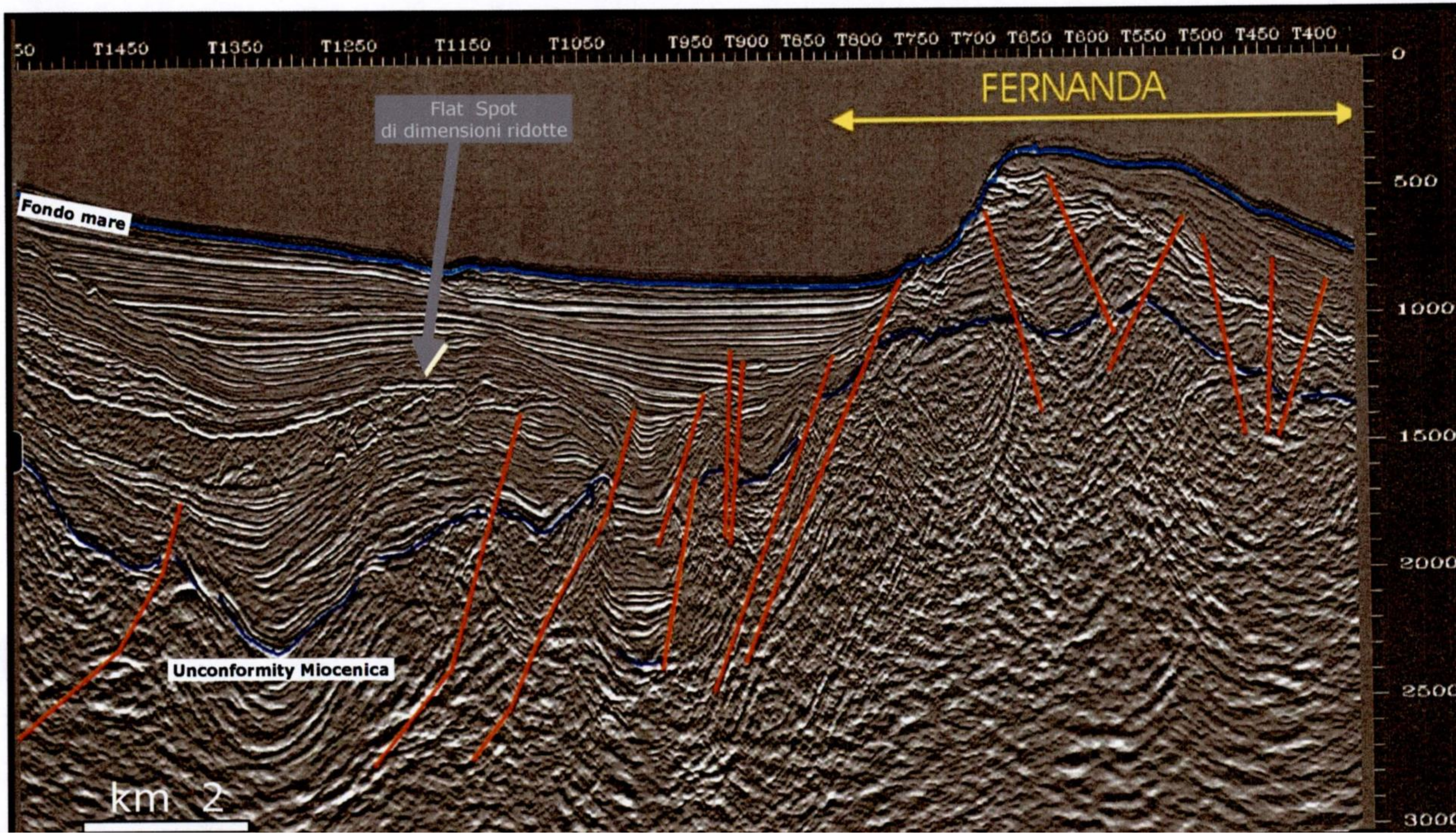
For wboreholes siting and *reservoir* evaluation, each anomaly must be defined very precisely.

Note: this reflector can often cross the reflectors of sedimentary sequences!



Permesso F.R28.AG - Lead FERNANDA

3D Crotone – In Line 5680



Example of a *Flat Spot* related to a reservoir: Calabrian Arc

Pitfalls: False "flat spots"

One of the best DHIs to look for is a flat spot, the contact between gas and water, gas and oil, or oil and water. However, there are other causes that can give rise to flat spots:

- Ocean bottom multiples
- Flat stratigraphy. The bases of sand lobes especially tend to be flat.
- Opal-A to opal-CT diagenetic boundary
- Paleo-contacts, either related to diagenesis or residual hydrocarbon saturation
- Volcanic sills

Rigorous flat-spot analysis should include detailed rock physics analysis, and forward seismic modeling, as well as AVO analysis of real data (see Section 4.3.8).

Ambiguity to interpret a *Flat Spot*

DHI = ***Direct Hydrocarbon Indicator***

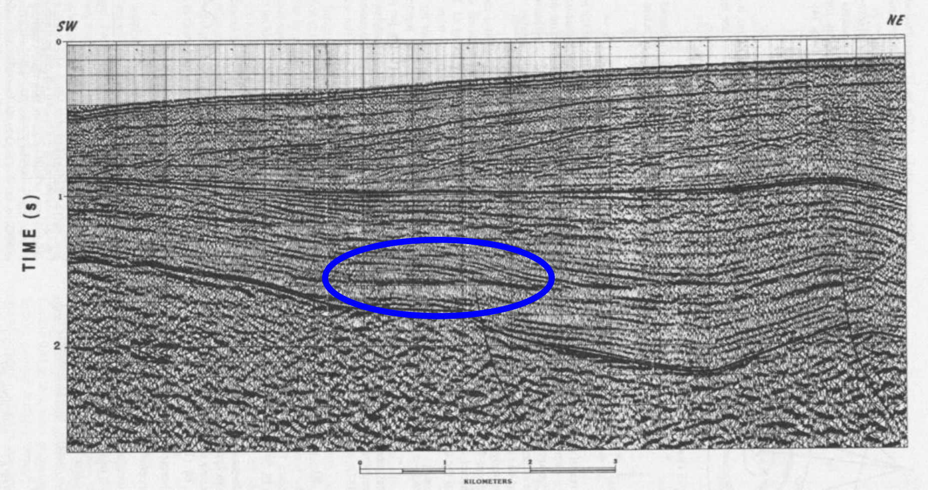


Fig. 6.11 Seismic section showing a horizontal reflector (at ~ 1.57 s) attributed to pressure-controlled diagenetic change from opal-CT porcellanites above to quartz chert below. A change from opal-λ to opal-CT at 1.20 s may also produce reflections. (From Hubbard, Pape, and Roberts, 1985: 85; reprinted with permission.)

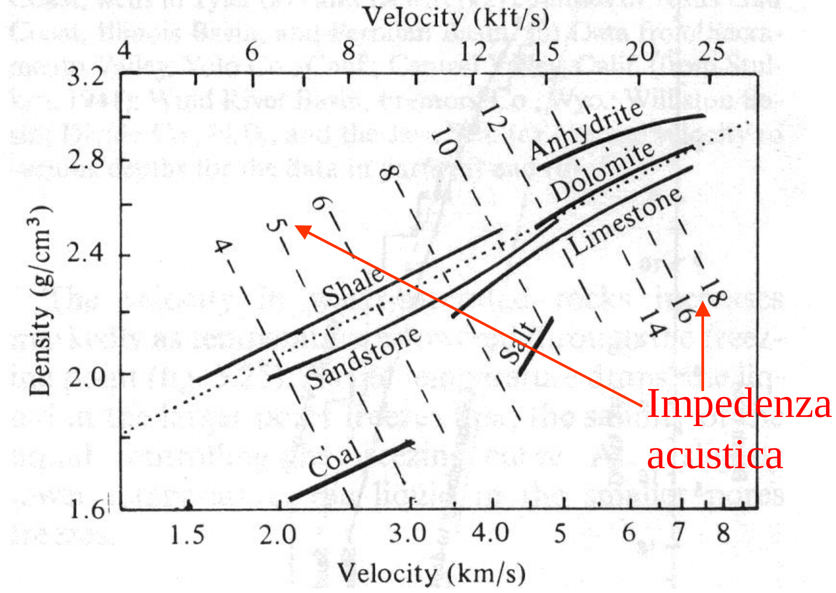
reflector ascribed to the diagenetic variation from CT opal to quartz, due to pressure →

HYDROCARBON DETECTION (HDI)

Although we often spoke of direct recognition, in reality HDI is the identification of the acoustic contrast associated with the presence of free gas.

Therefore, the seismic evidence of a gas accumulation depends on:

- **overlying material,**
- **porosity,**
- **depth,**
- **water saturation,**
- **reservoir configuration.**

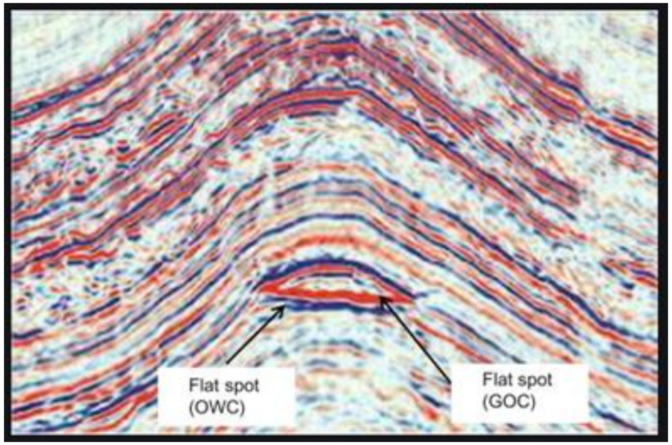


Anstey (1977) lists the criteria for the direct identification of a reservoir. All these criteria must be analyzed for a correct interpretation.

1) <u>Gas-liquid contact (*flat-spot*)</u>

It represents the reflection related to the variation in the fluid phase: above, the porosity is occupied by water and free gas, below, the porosity of the same lithology is occupied only by water.
Being a surface due to the distribution of fluids as a function of their density, it will depend on the pressure and will therefore be, in general, a horizontal surface.

da Anstey (1977)



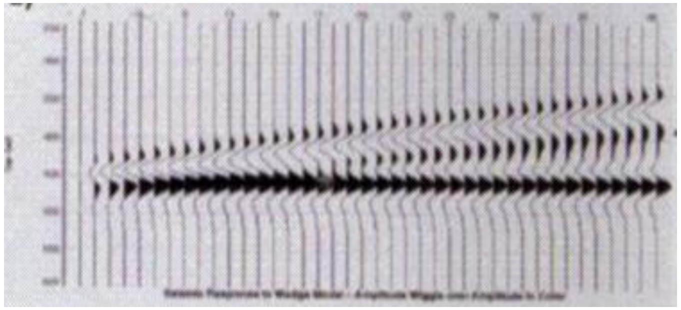
2) Anomalous Reflection Coefficients

Generally our attention is attracted by amplitude anomalies, but we must remember also the effects due to:

- amplitude gain in the initial *processing phases*

- the effects due to the frequencies (low frequencies events seem to be more wide)

- the *tuning effects, that are a* positive interferences →



Although such ambiguous situations are possible, the main amplitude anomalies are often associated with gas accumulations:
BRIGHT SPOT ***or*** ***DIM SPOT***
(which do not necessarily mean sand or limestone with gas).

by Anstey (1977)

Tuning: the constructive interference between the two converging reflectors should not be interpreted as *Bright Spot*

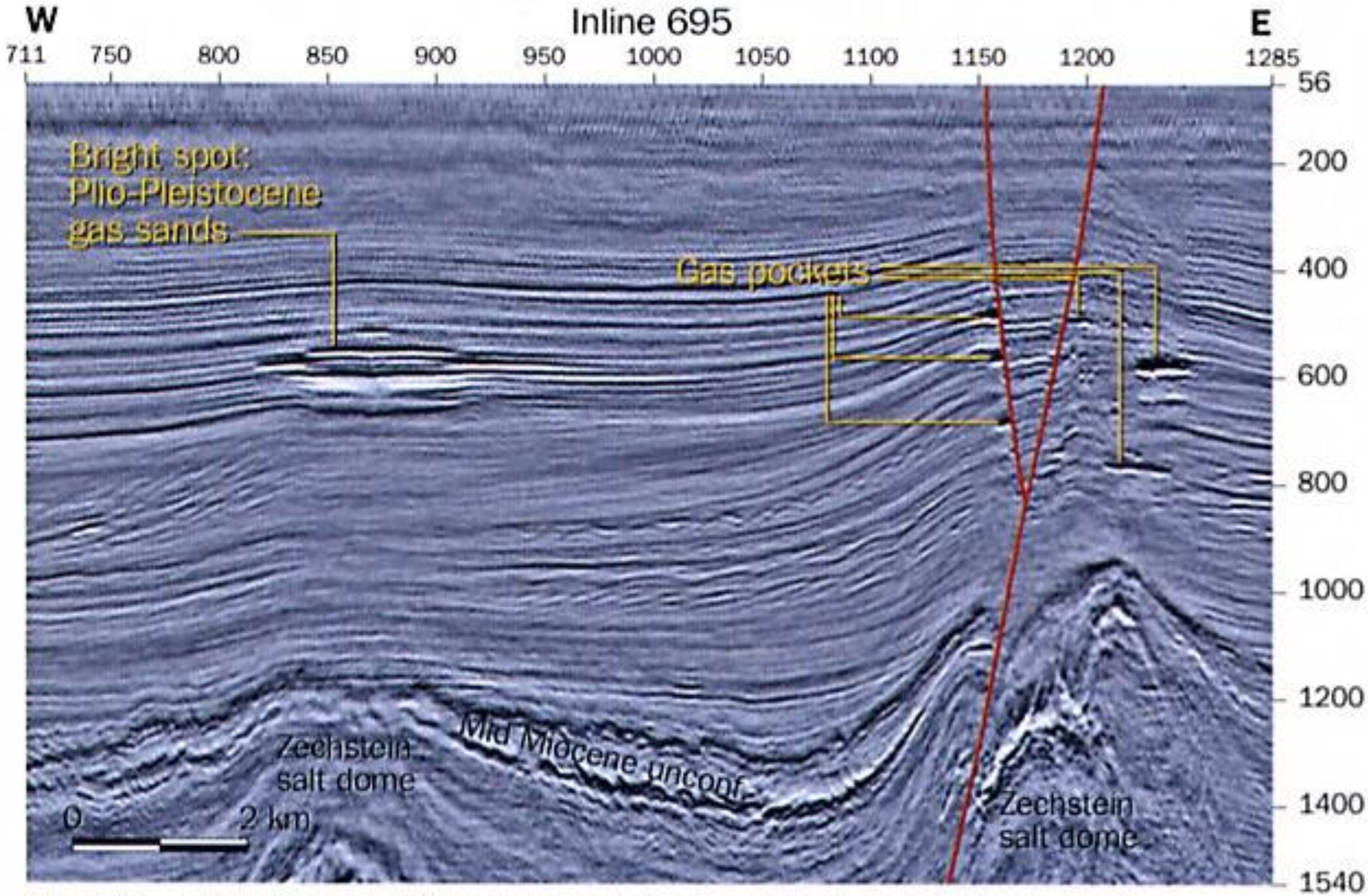


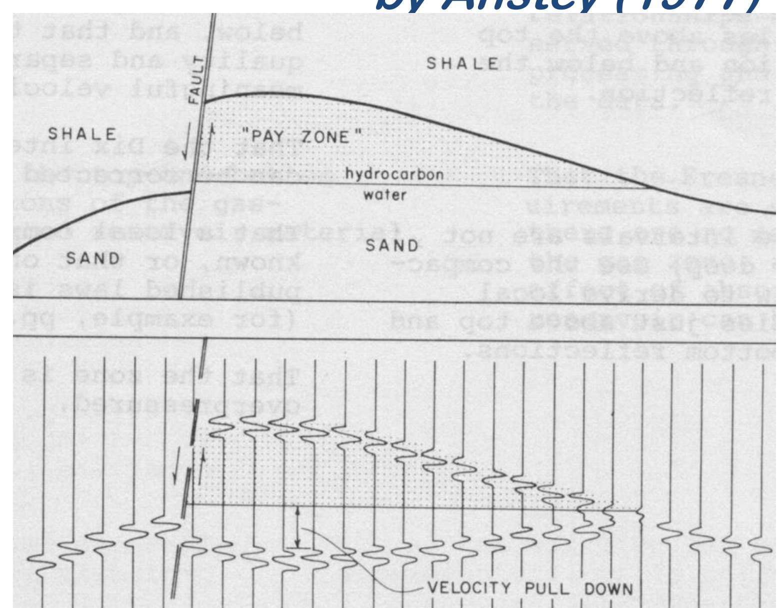
Figure 8. A fault system that appears to be leaking. Bright spots indicate small gas pockets along the faults wherever the faults intersect with highly porous layers

3) Anomalous Low Velocities

The presence of gas in large quantities always gives a significant decrease in velocity (non-bi-univocal rule); this decrease can be highlighted directly by:

- low interval velocity between the *top* and the *bottom* of the gas saturated layer, if they are sufficiently separated

by Anstey (1977)



- decreased of the *stacking* velocity (rms velocità)

- *pull-down* at the base of the *reservoir* and below it

4) Polarity Inversion

This is corroborative evidence, non necessary, to establish the presence of gas:

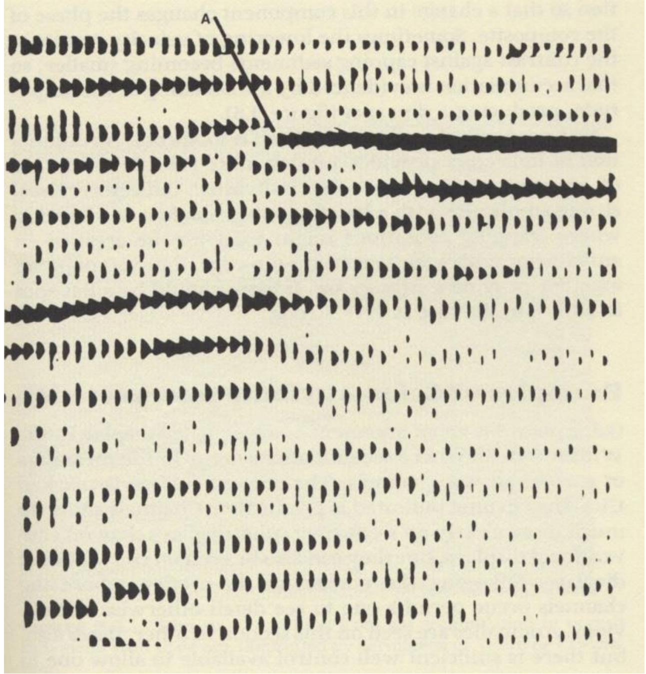
-if and only if there is a positive reflection coefficient between two lithologies, of which the deeper one is water saturated

and,

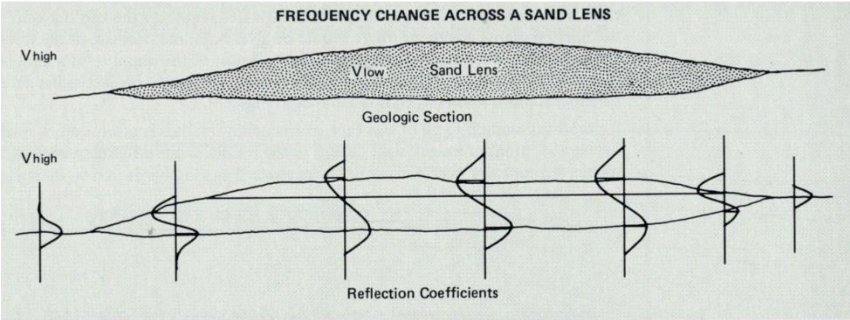
- if and only if the local replacing of water in the pores with gas gives a negative reflection coefficient,

➔ polarity inversion will occur.

da Anstey (1977)



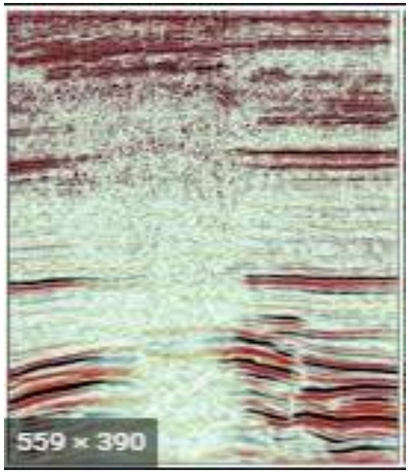
However, this effect is often difficult to recognize due to interference, and can sometimes be confused with the presence of small faults.

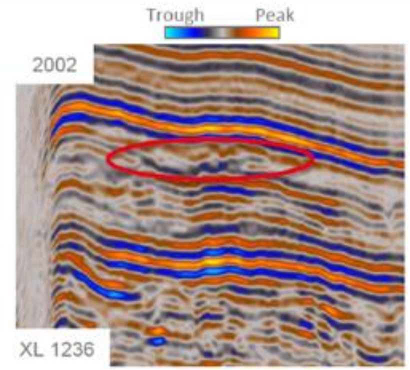


5) Shadows

Incorrect processing phases can lead to reduction of the amplitudes above and below a *bright spot.*

Furthermore, the *bright spot* itself can produce multiples.





Shadow

Multiple produced by a reservoir

6) Diffractions

Diffraction can be produced when:

-high contrasts of acoustic impedences, common condition when there is presence of a *bright spot*;

-sufficient thicknesses of the reservoir and abrupt lateral variation of velocities (as in presence of faults),

while there are generally no diffractions in the presence of lenticular sandy reservoirs.

da Anstey (1977)

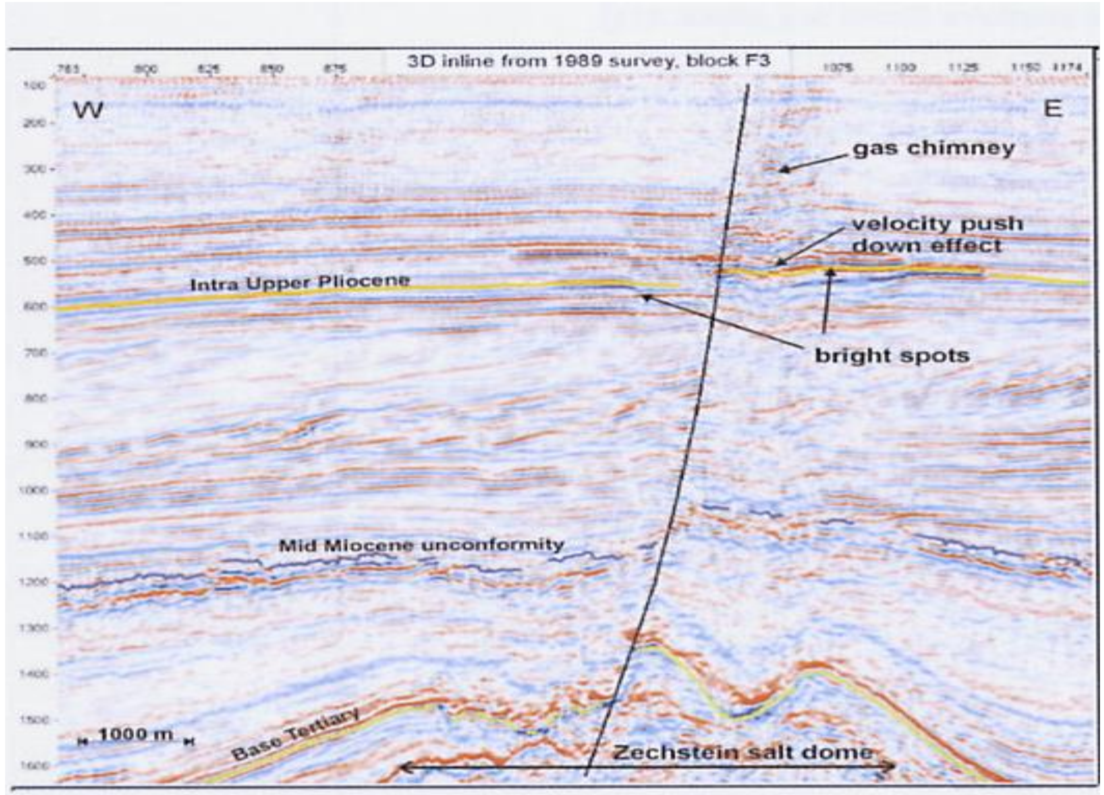
7) *Inter-relation* between previous criteria

The single criteria defined above are simple manifestations of single properties.

The criteria must be mutually compatible:
for example, a large positive amplitude reflection at the top of a reservoir is not compatible with a decrease in interval velocities …

da Anstey (1977)

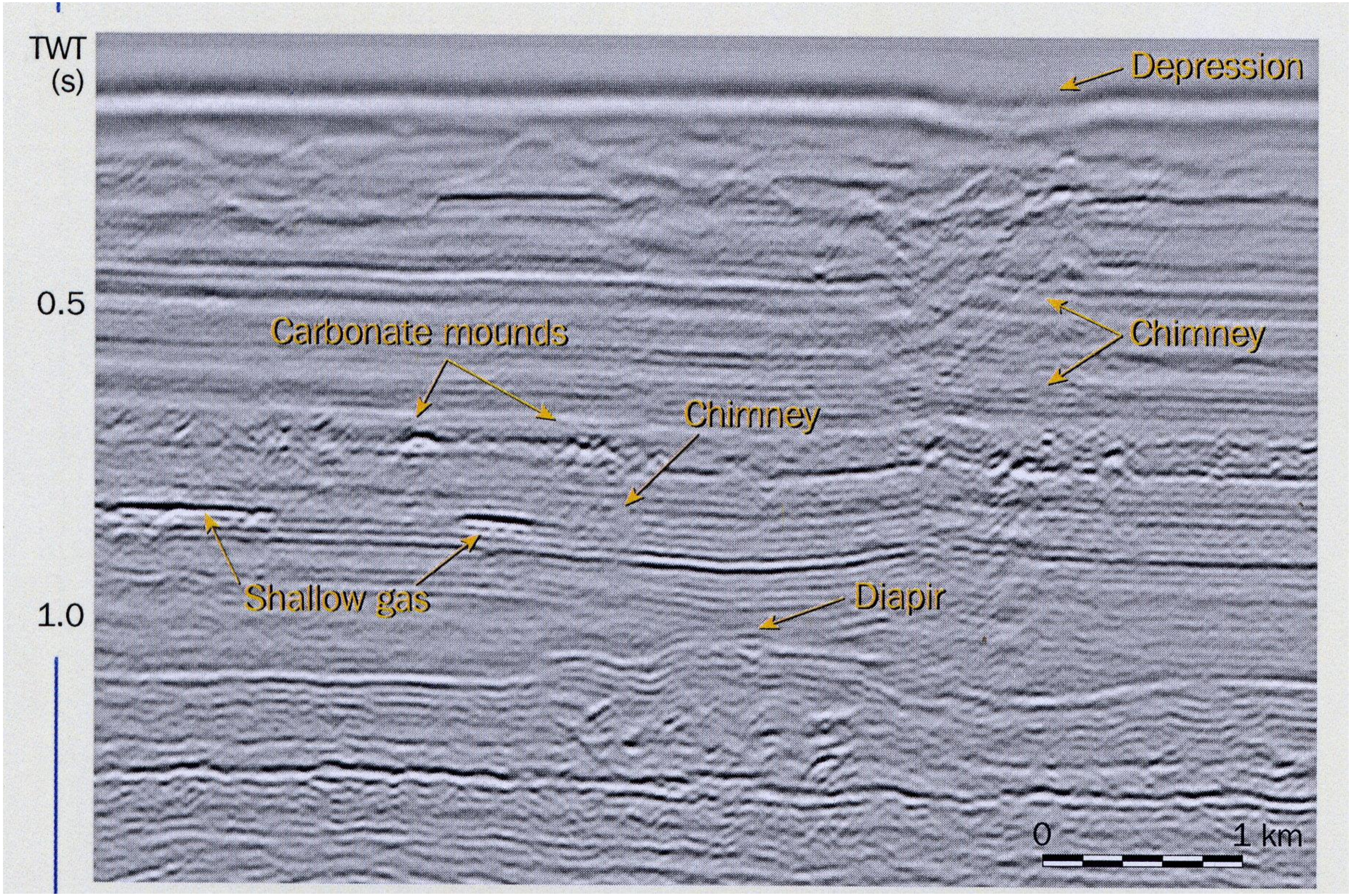
Seismic effects related to the diffuse presence of gas : “*gas chimney*”



Subsoil area with a low gas concentration generally widespread toward the top. This gas generally starts from a hydrocarbon accumulation covered with a rock which is not perfectl impermeable to gas or from a system of (micro-) fractures that allow the migration of gas toward the surface (*gas leakage*).

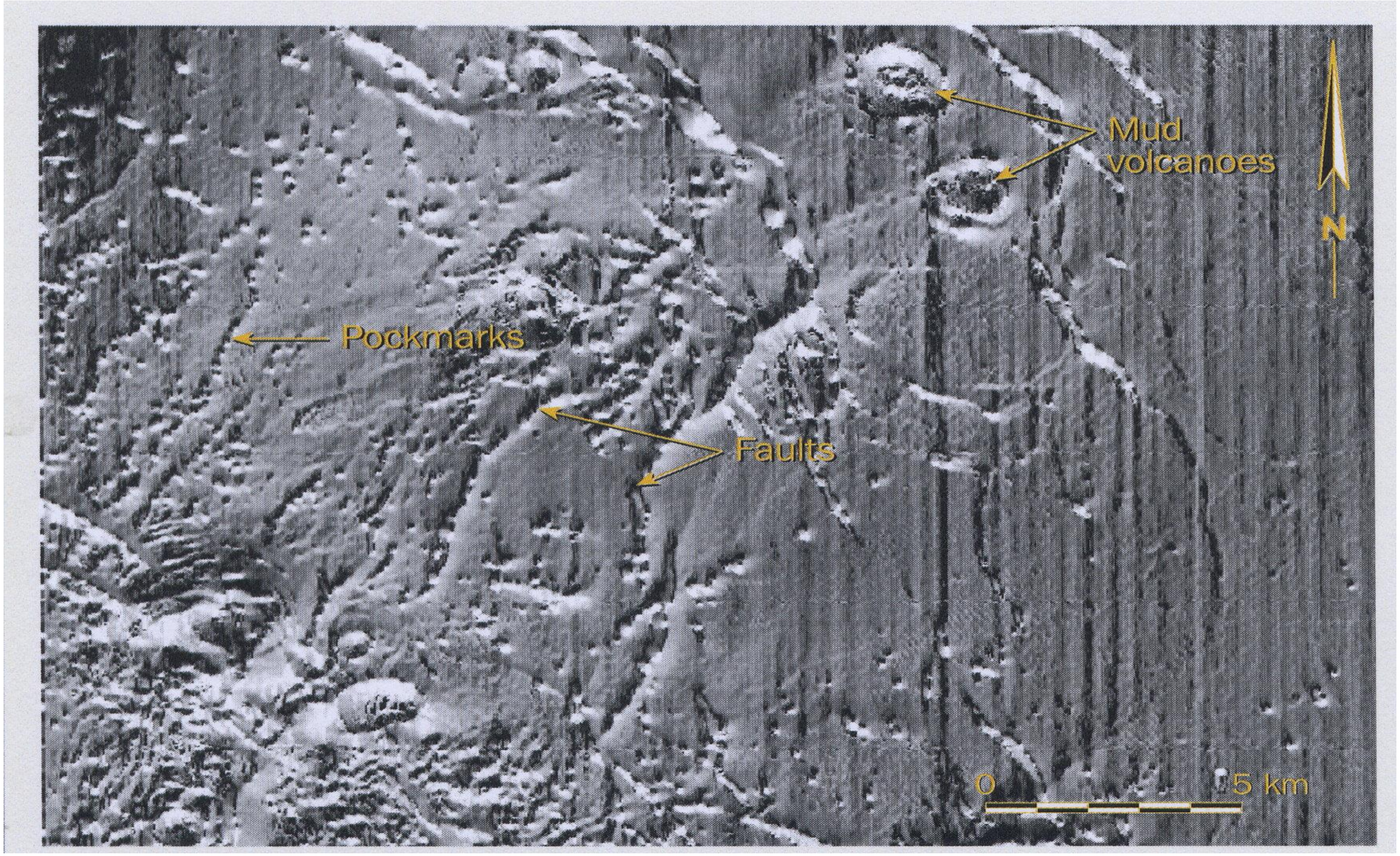
It usuall shows a region of extremel deteriorated seismic quality, often associated with low velocity and topull-downs of the reflectors beneath the chimney itself.

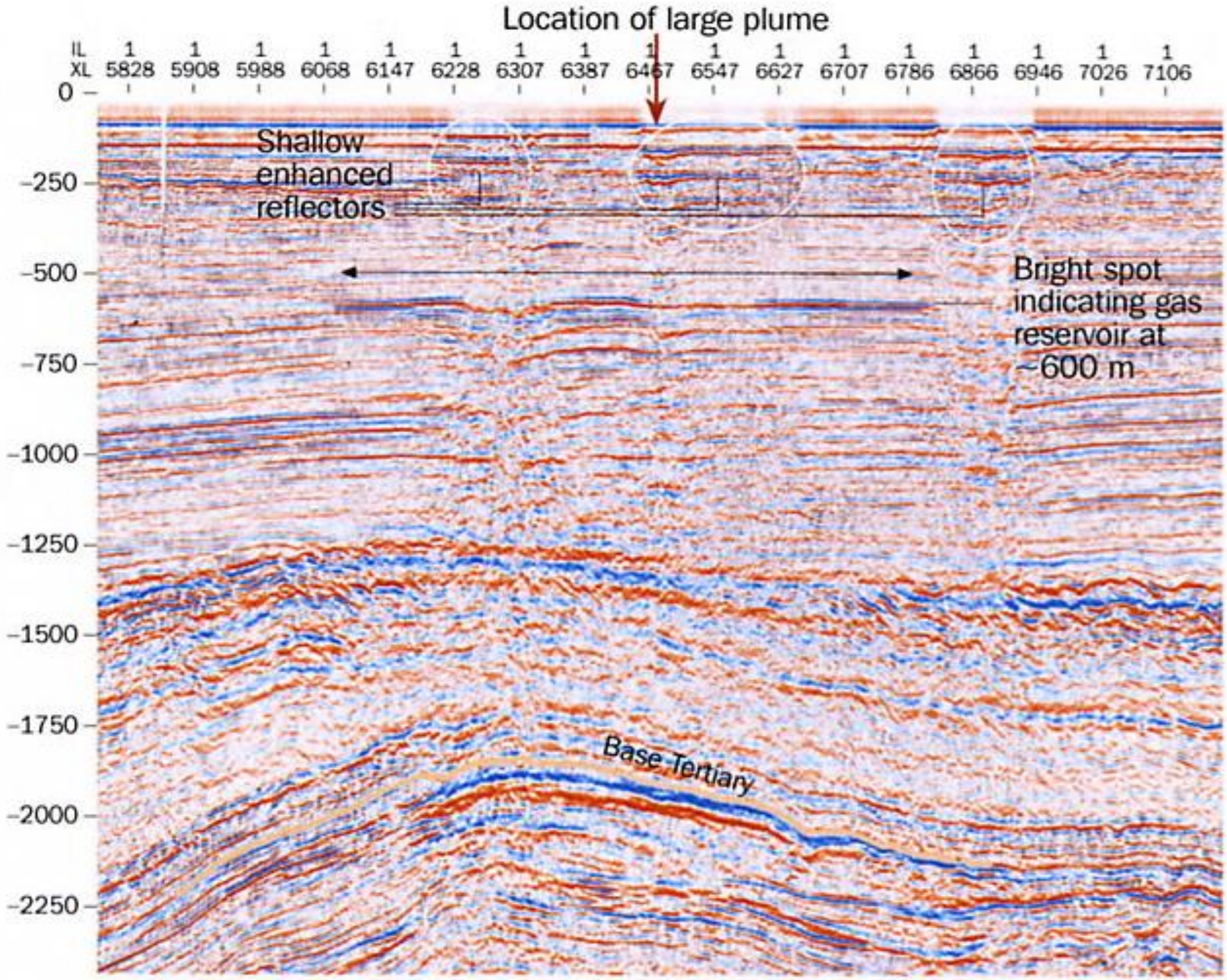
Gas-leakage phenomena can produce typical surface structures (pockmarks, mud volcanoes, etc).



TWT
(s)
0.5
1.0
Depression
Chimney
Carbonate mounds
Chimney
Shallow gas
Diapir
0
1 km

The effects of the gas leakage on the surface are generally visible through the use of higher resolution geophysics (Side-Scan Sonar, Multibeam, Chirp) that the common reflection seismic: in fact, these are structures connected to the liquefaction of melted sediments (pockmarks and mud-volcanoes) and micro-fractures of the order of a few tens or a few hundred meters: the largest of them can obviously also be seen along the reflection seismic profiles.




Location of large plume
IL 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
XL 5828 5908 5988 6068 6147 6228 6307 6387 6467 6547 6627 6707 6786 6866 6946 7026 7106
0
-250
-500
-750
-1000
-1250
-1500
-1750
-2000
-2250
Shallow enhanced reflectors
Bright spot indicating gas reservoir at ~600 m
Base Tertiary

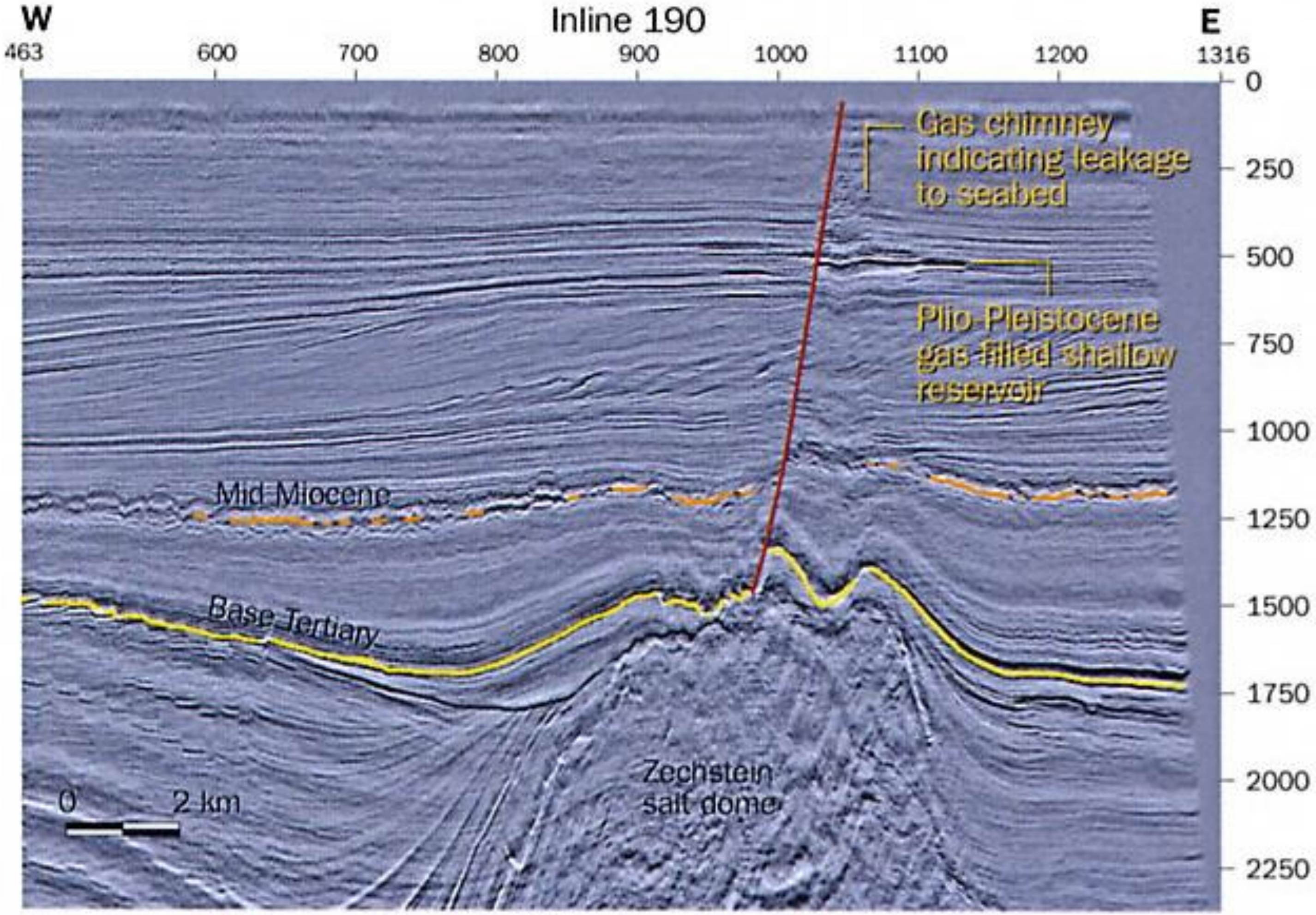
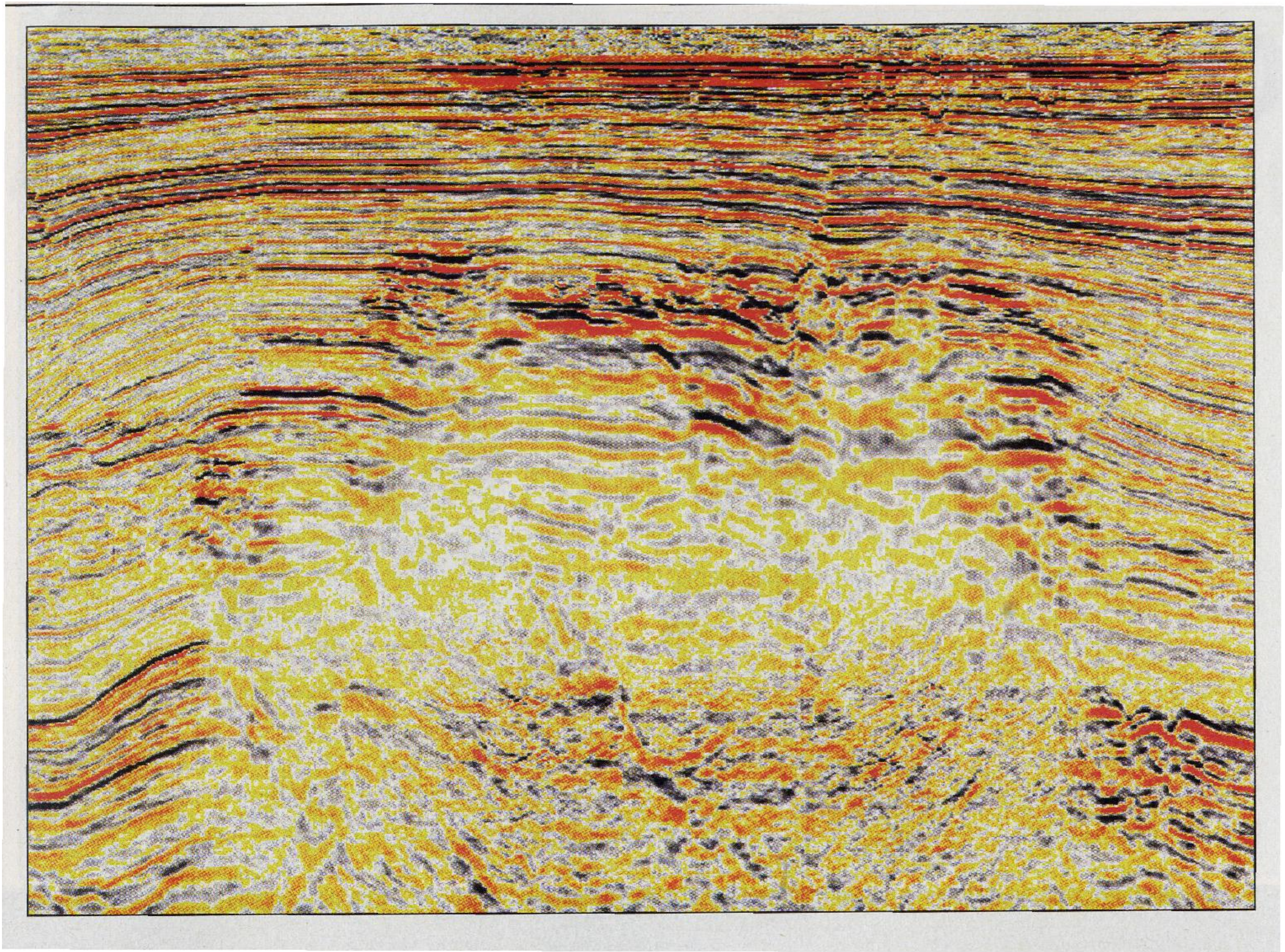


Figure 7. A shallow gas chimney visible on 3D seismic data as a seismic anomaly with higher amplitudes and lower reflector continuity in comparison to the surrounding sediments. The chimney is an expression of methane leakage from underlying Plio-Pleistocene gas sands

Example of seismic effect due to the presence of diffused gas within sediments



Example of seismic effect due to the presence of diffused gas within sediments: *bright spots* e *gas chimney*

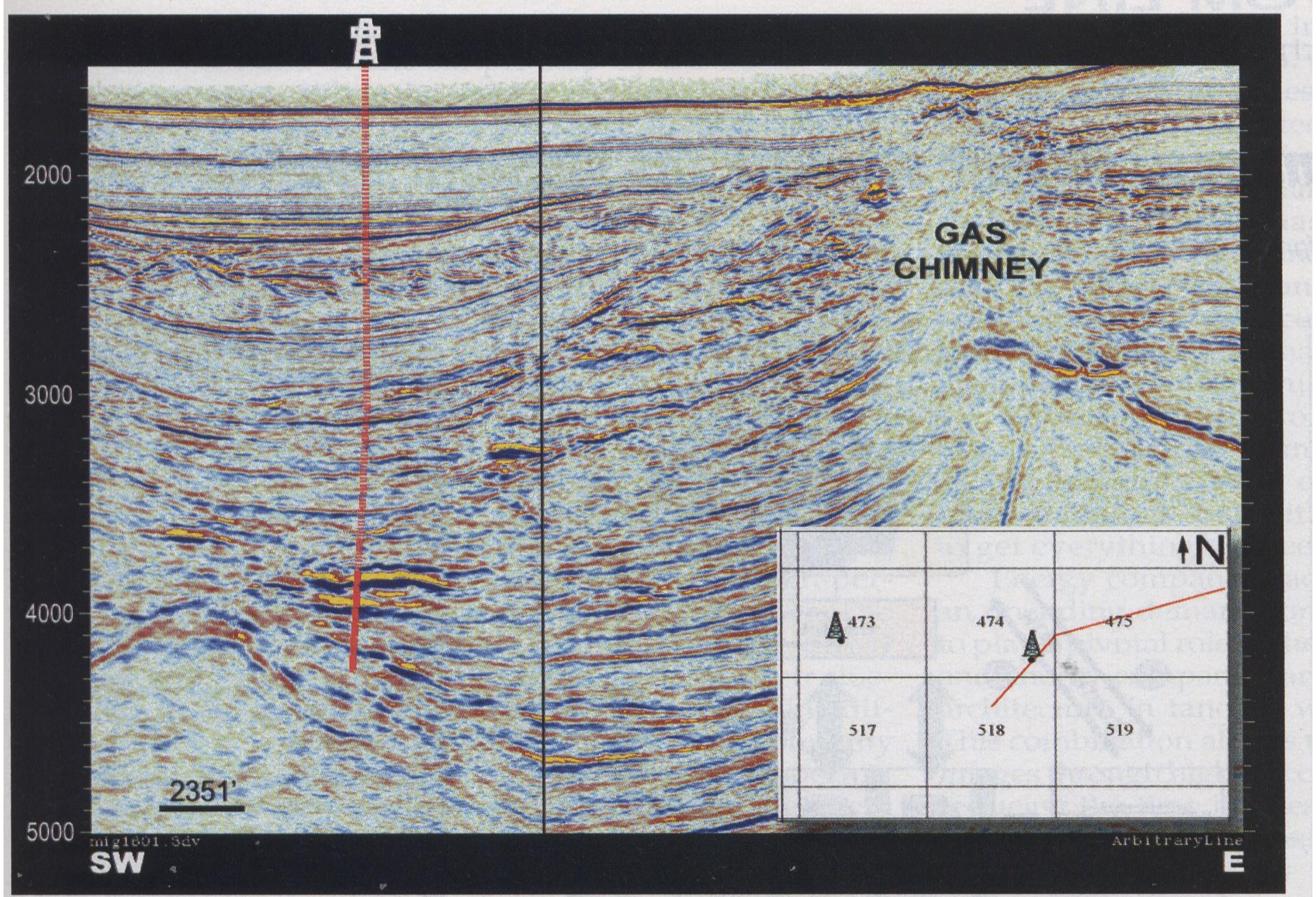
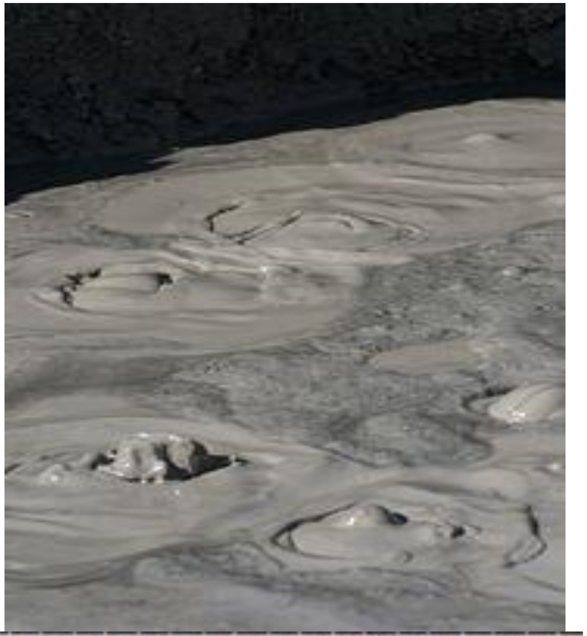
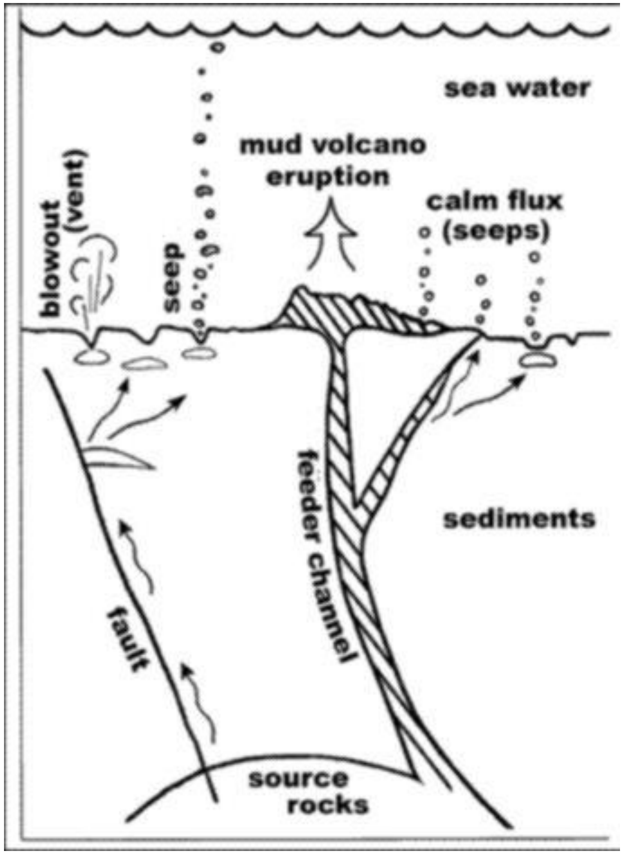
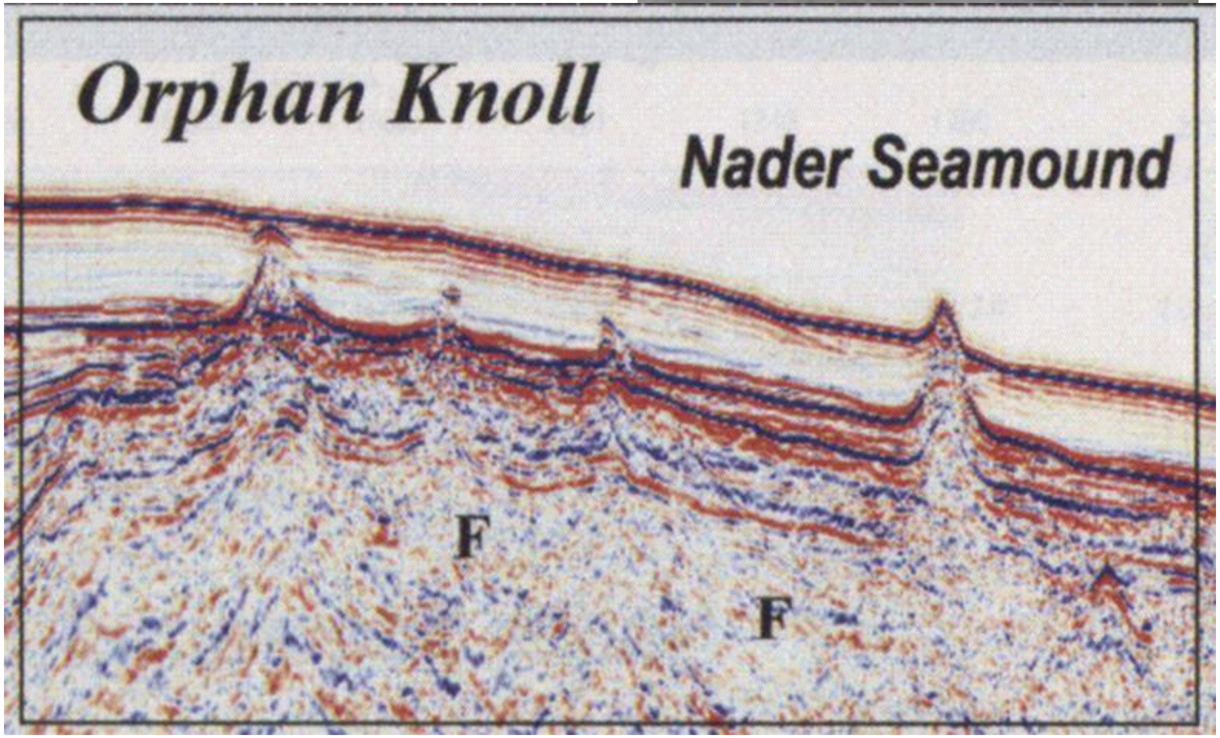


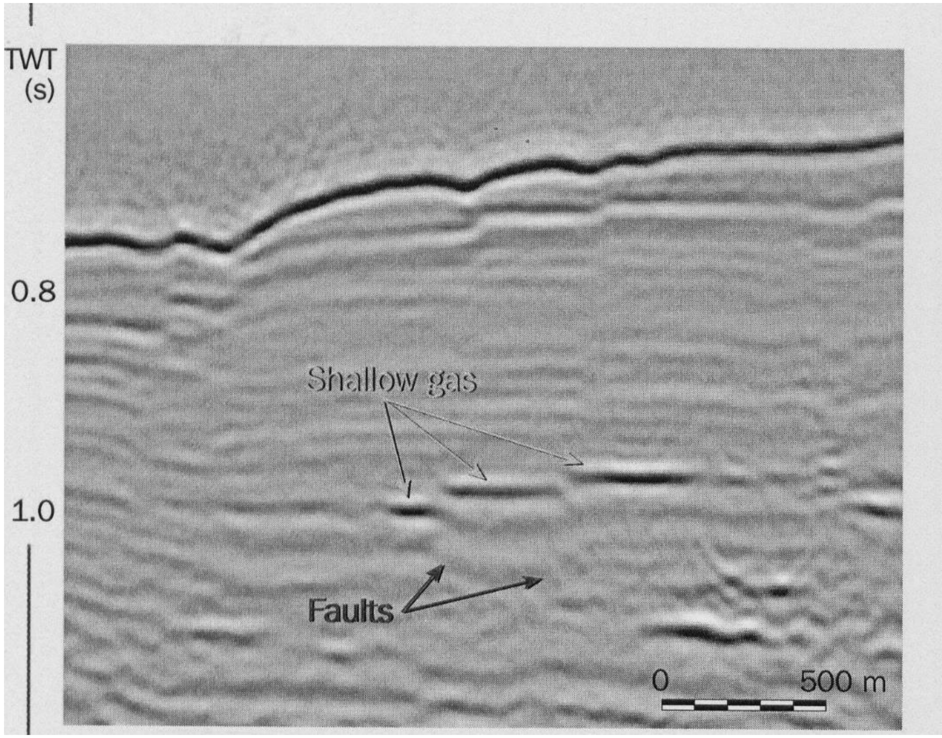
Figure 14. Seismic profile showing gas chimney located 4 miles northeast of the Lisa Anne Prospect.

Shallow evidence of fluids seeps in the sea bottom : *mud volcanos*



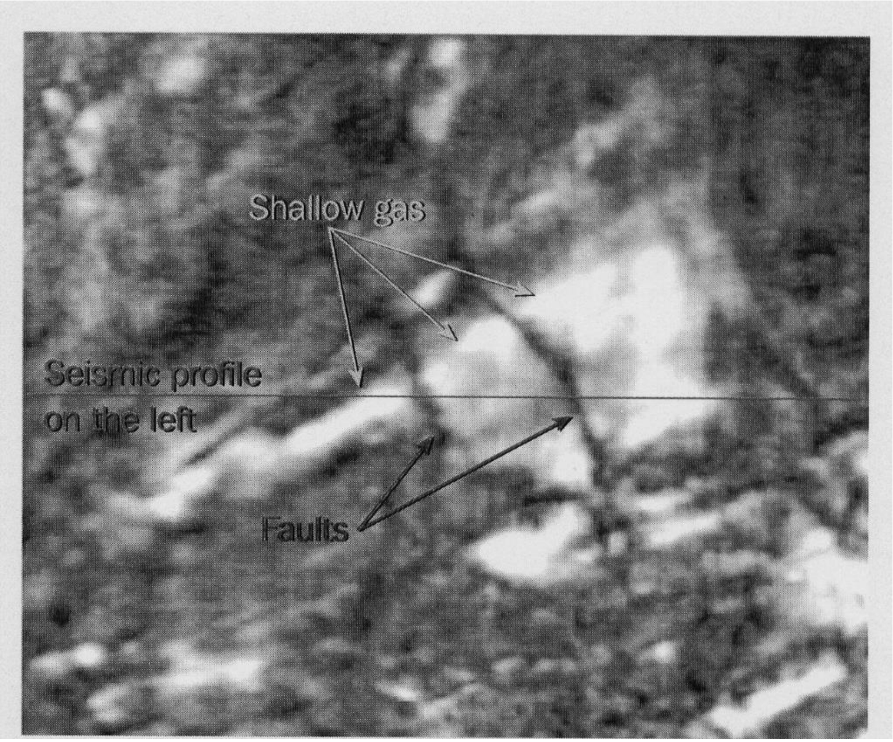




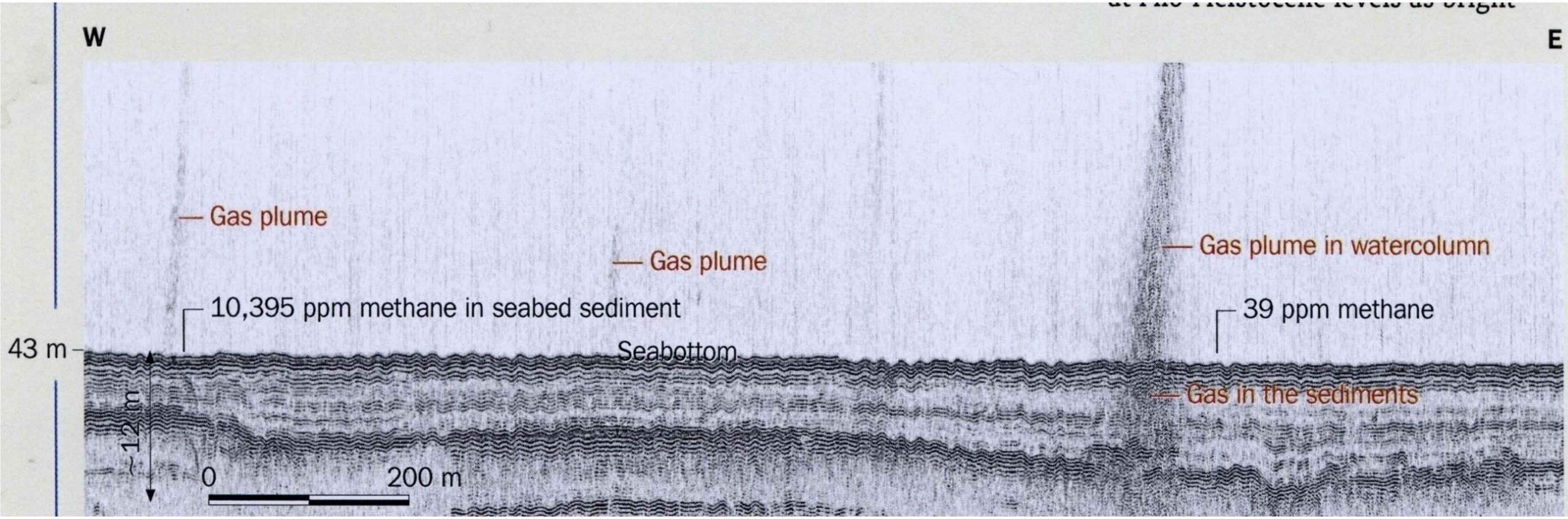


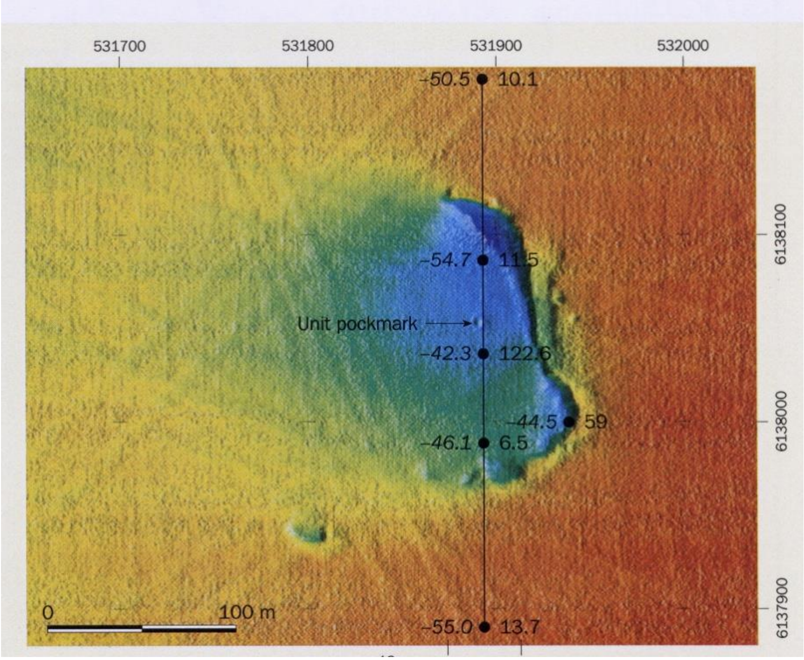
profile

slice



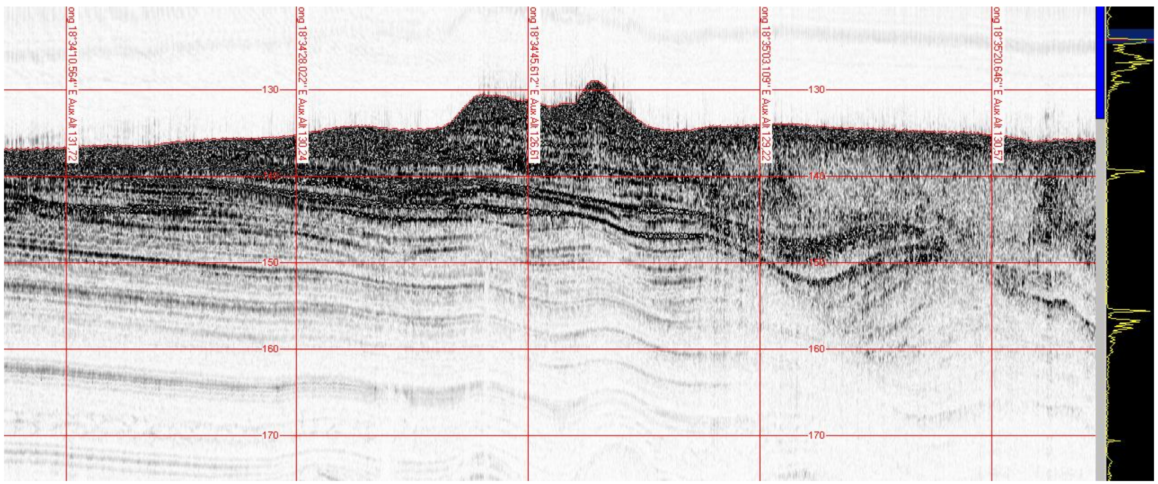
In the profile we can recognize gas pockets that origin "*gas-seeps*" on the sea bottom through a normal fault system, also evident on the *slice*.

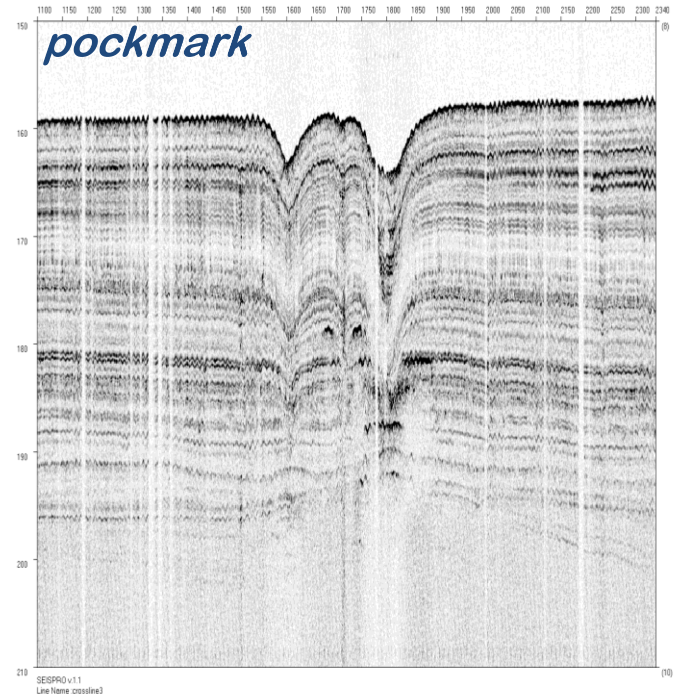


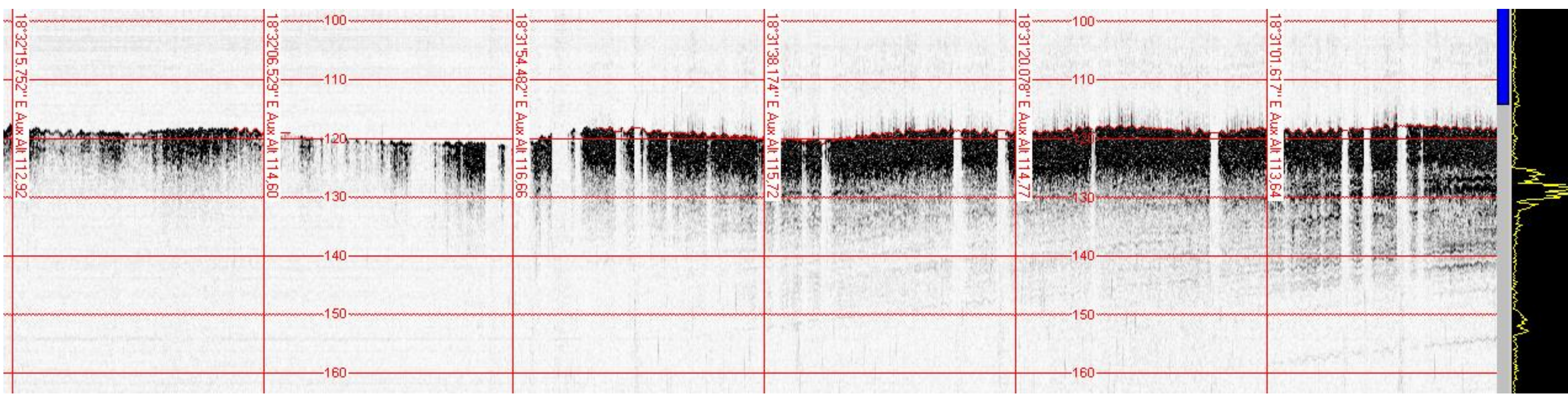


In this example the presence of gas within sediments leads to an important gas seep in the water layer (*gas plume*), well evident also in the seismic profile.

Shallow Evidence of *gas-seeps* *in the sea bottom of the Otranto Channel*



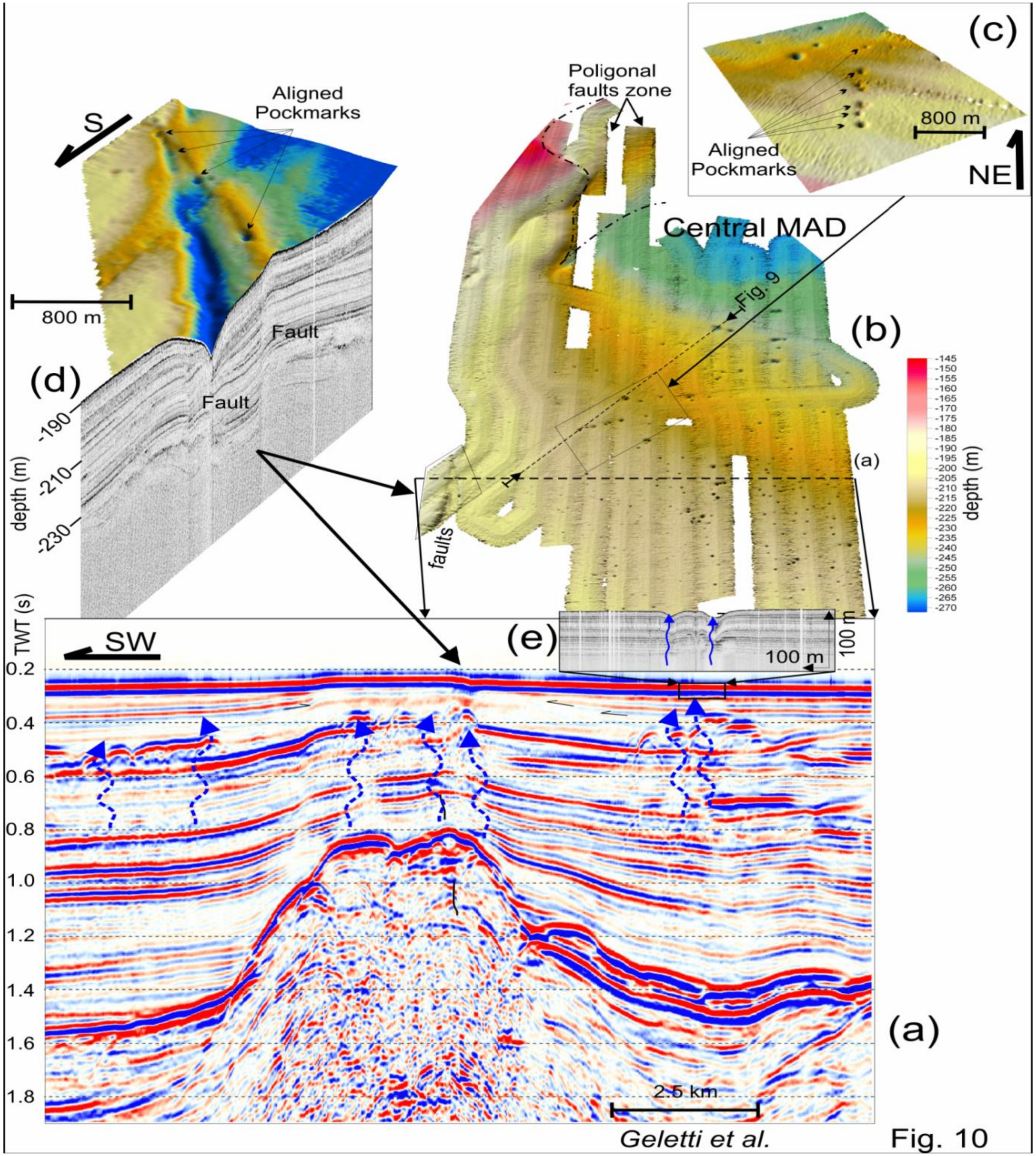


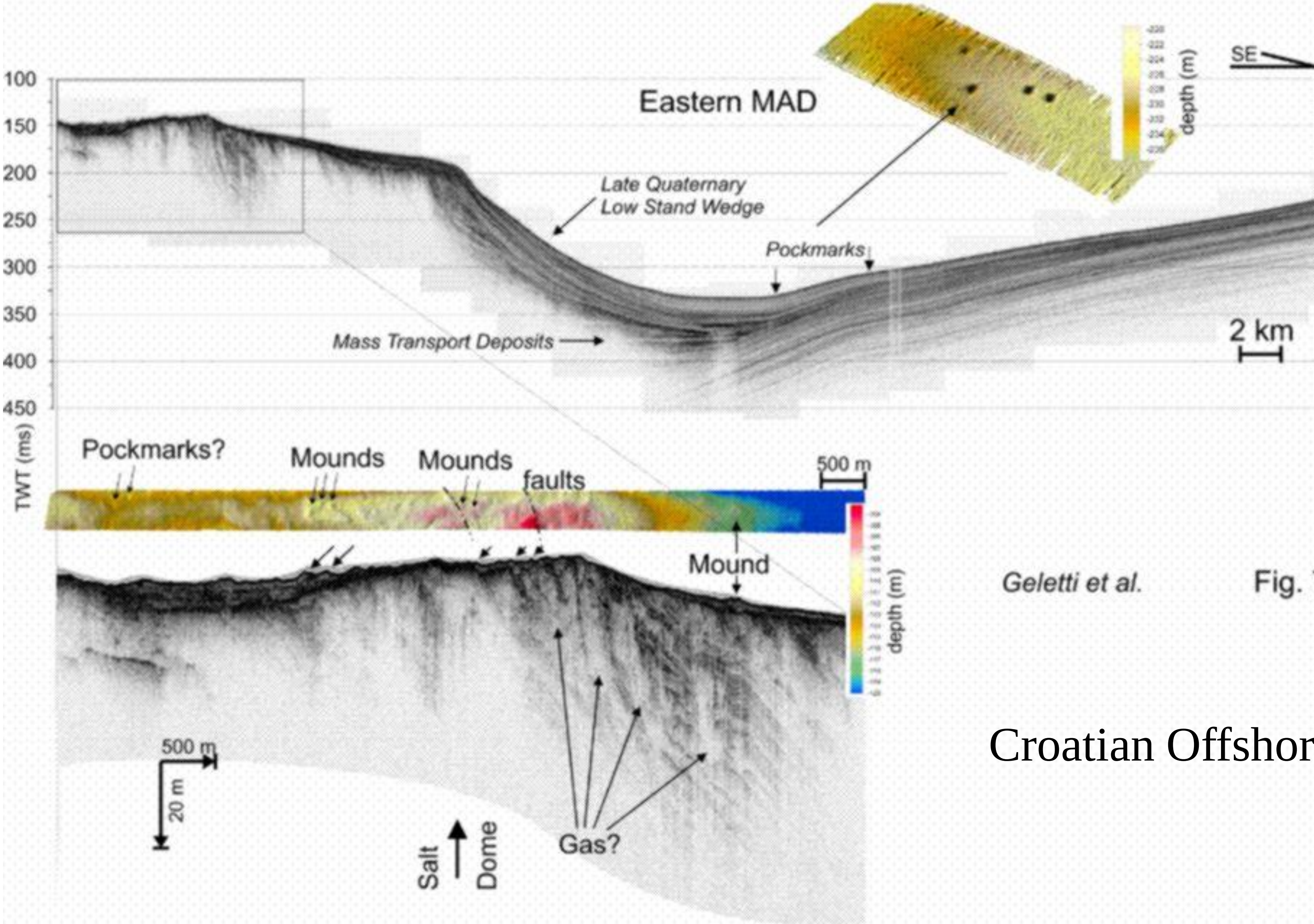


Evidence of *gas-seeps* in the Central Adriatico Sea.

The buried salt diapirs produced structures where accumulations of gas developed, even with fracture systems that allow the tertiary migration of fluids toward the sea bottom.

Multibeam data often highlight groups of *pockmarks*, generally aligned along the fractures.





Geletti et al. Fig. 7

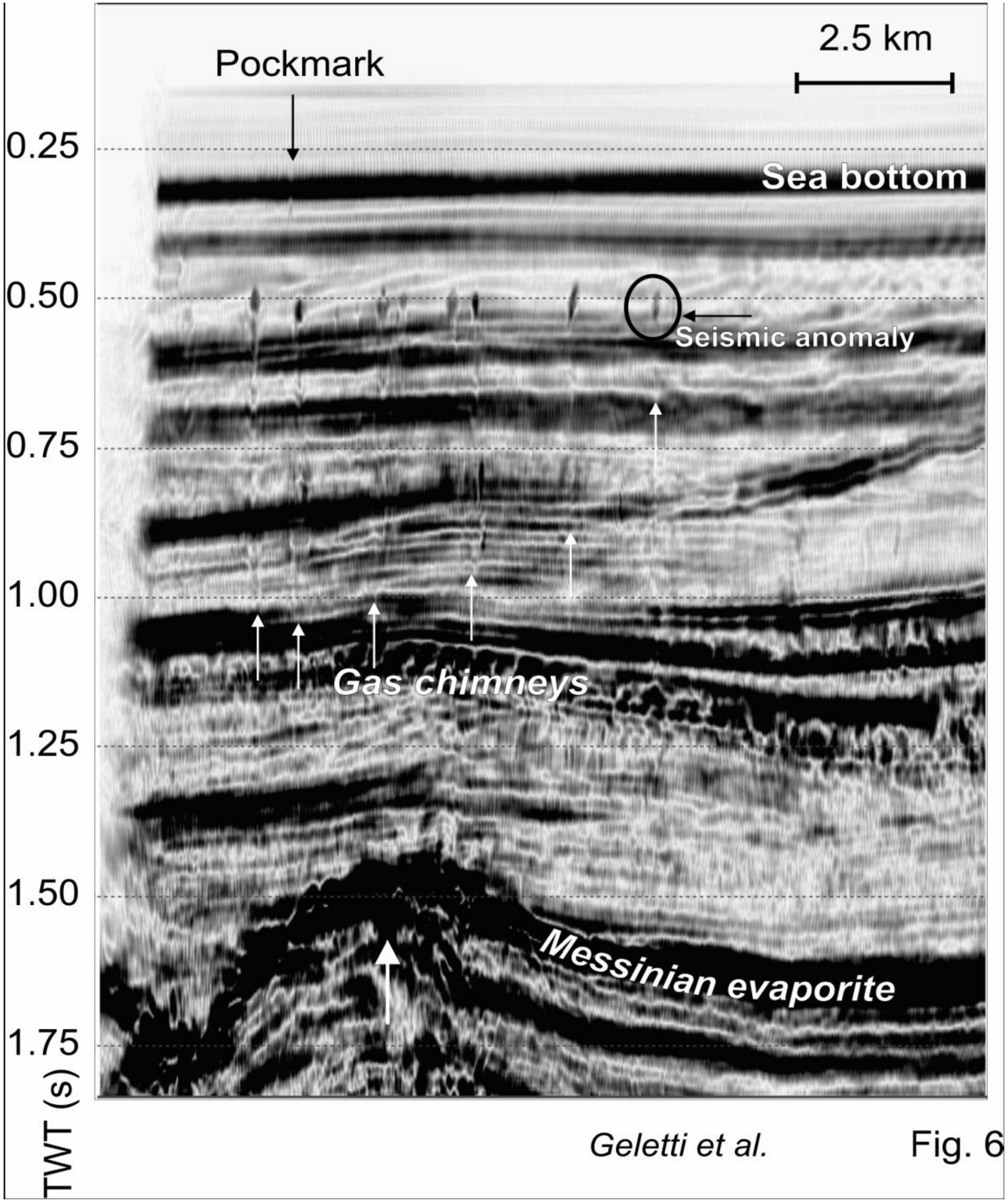
Croatian Offshore

Seismic Attributies: a useful tool to define the presence of gas in sediments

In the example:

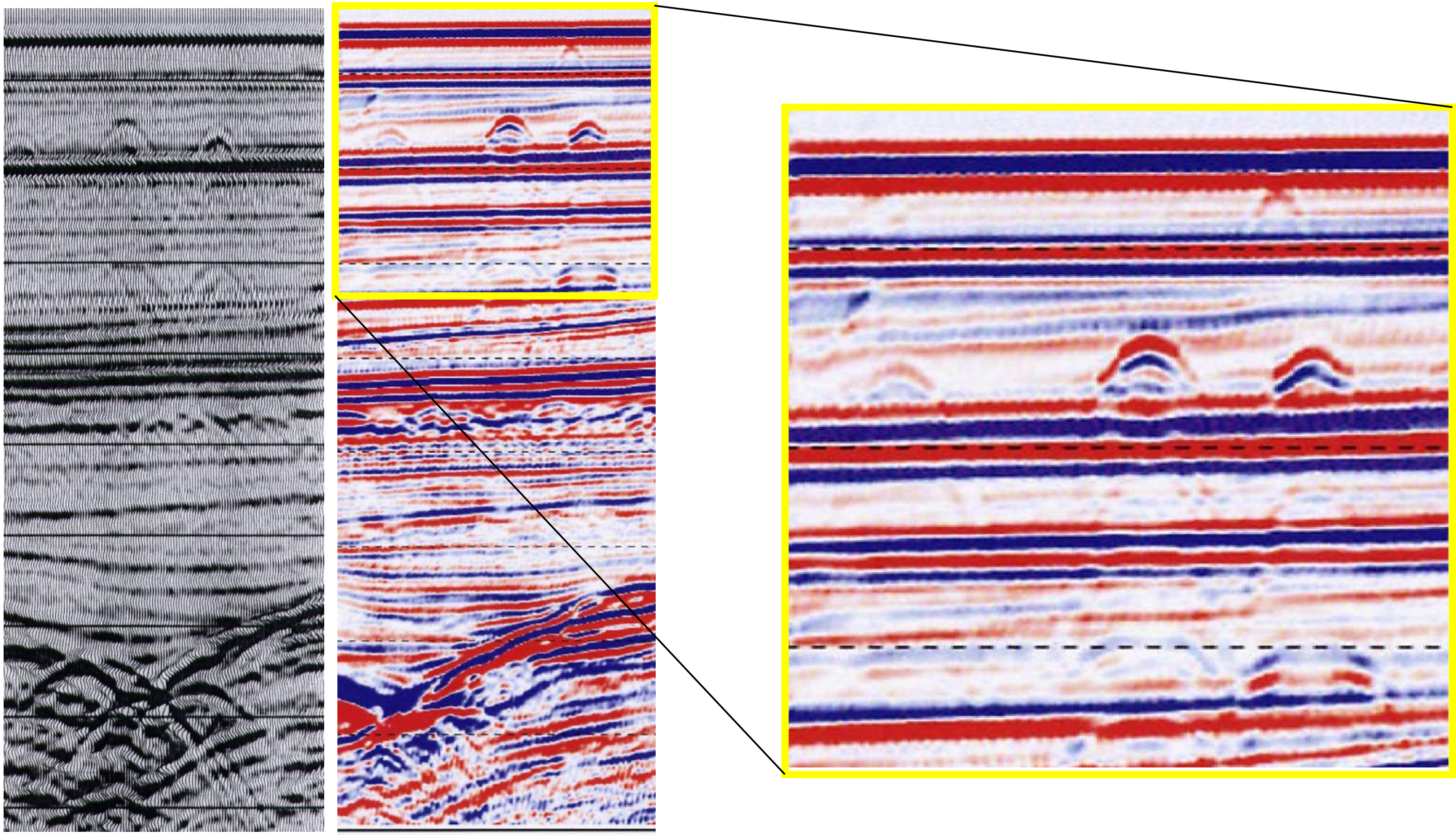
Reflection strength

Evidence of gas pockets and vertical fluid paths



Geletti et al. Fig. 6

Seismic profile in in the Central Adriatic Sea



section detail

stack migrated

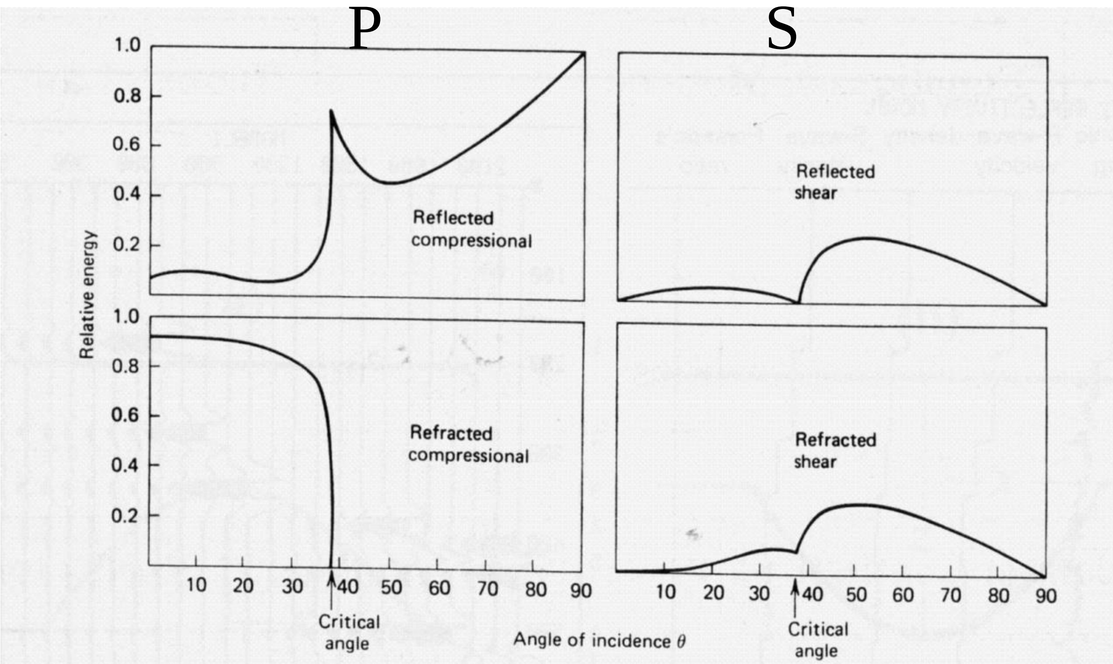
<u>4C seismic</u>
or
<u>*Multicomponent seismology*</u>

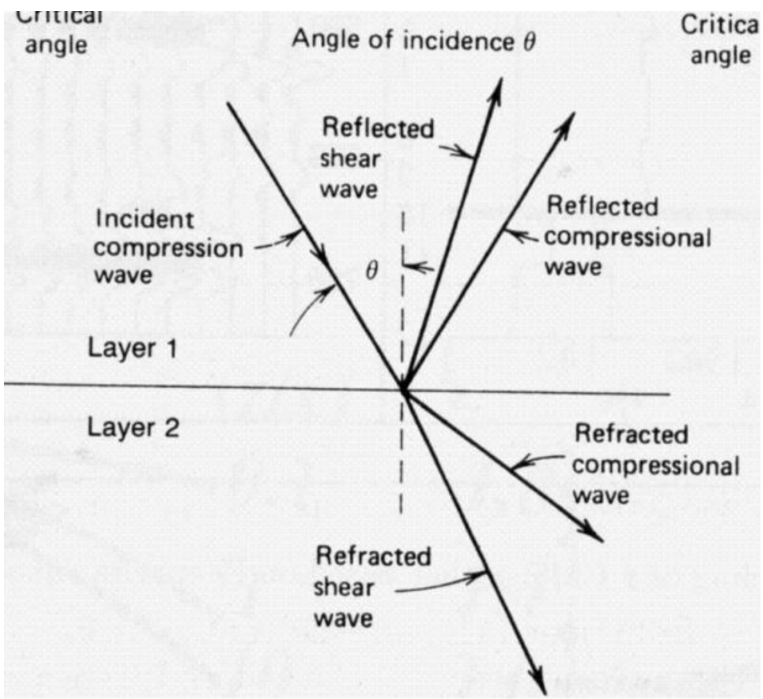
- multicomponent acquisition technique
(P and "converted S" waves are recorded)

- born in the early 90s in the North Sea
- was presented for the first tinme at an EAGE meeting in the year '94

- was marketed in 1996

- is based on 4 components (4C) using 3 geophones and 1 idrophone





For P wave incidence angle > 0° (non-normal incidence), awe will have:

→ transmitted P wave,

→ reflected P wave (PP)

→ converted S wave (S), in turn divided into transmitted and reflected (PS).

Zoeppritz Equations:

provide the value of reflected and transmitted amplitudes of P and S as a function of:

- incident angle,
- reflection angles of P and S,
- transmission angles of P and S,
- velocities of P and S waves,
- densities.

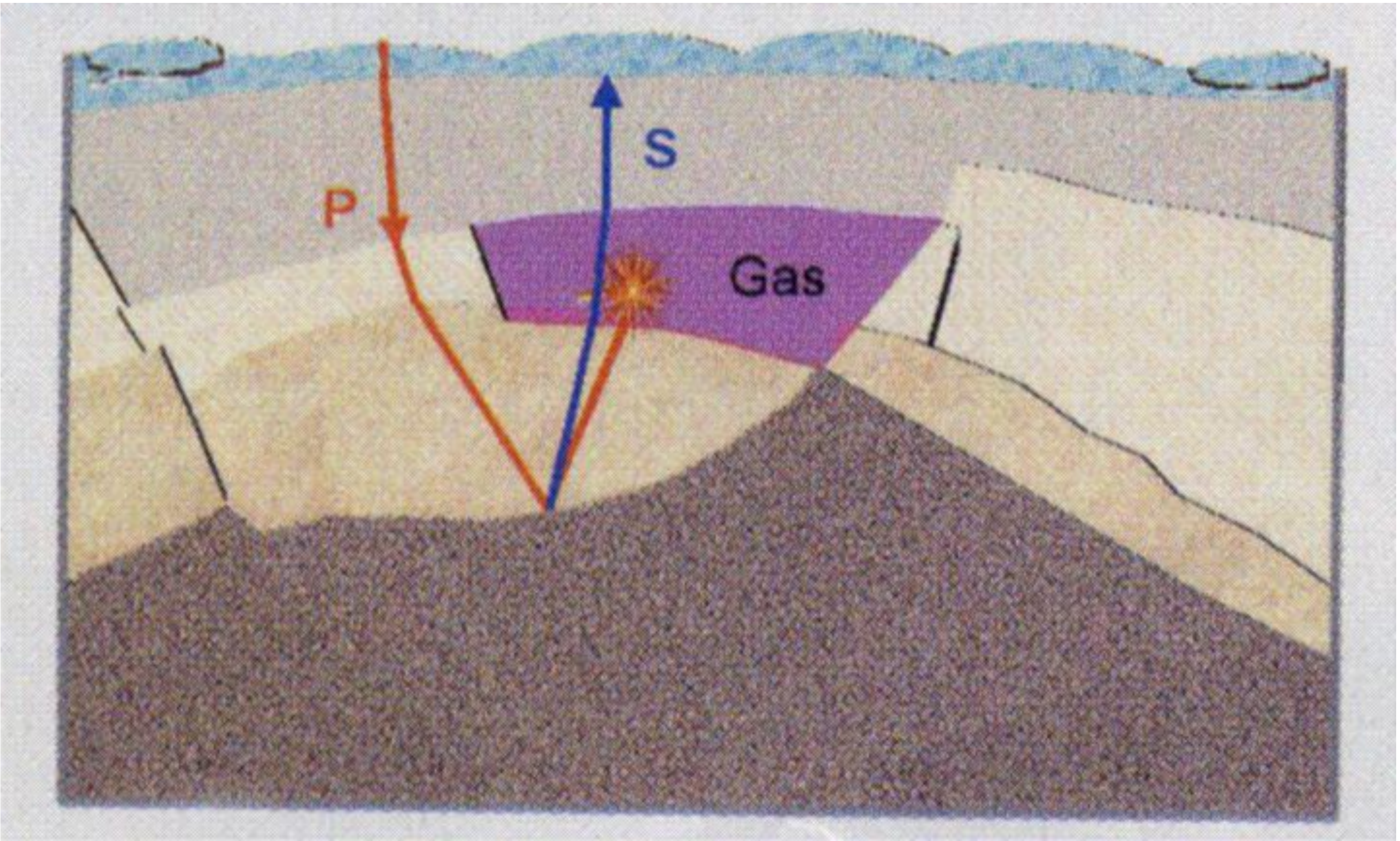


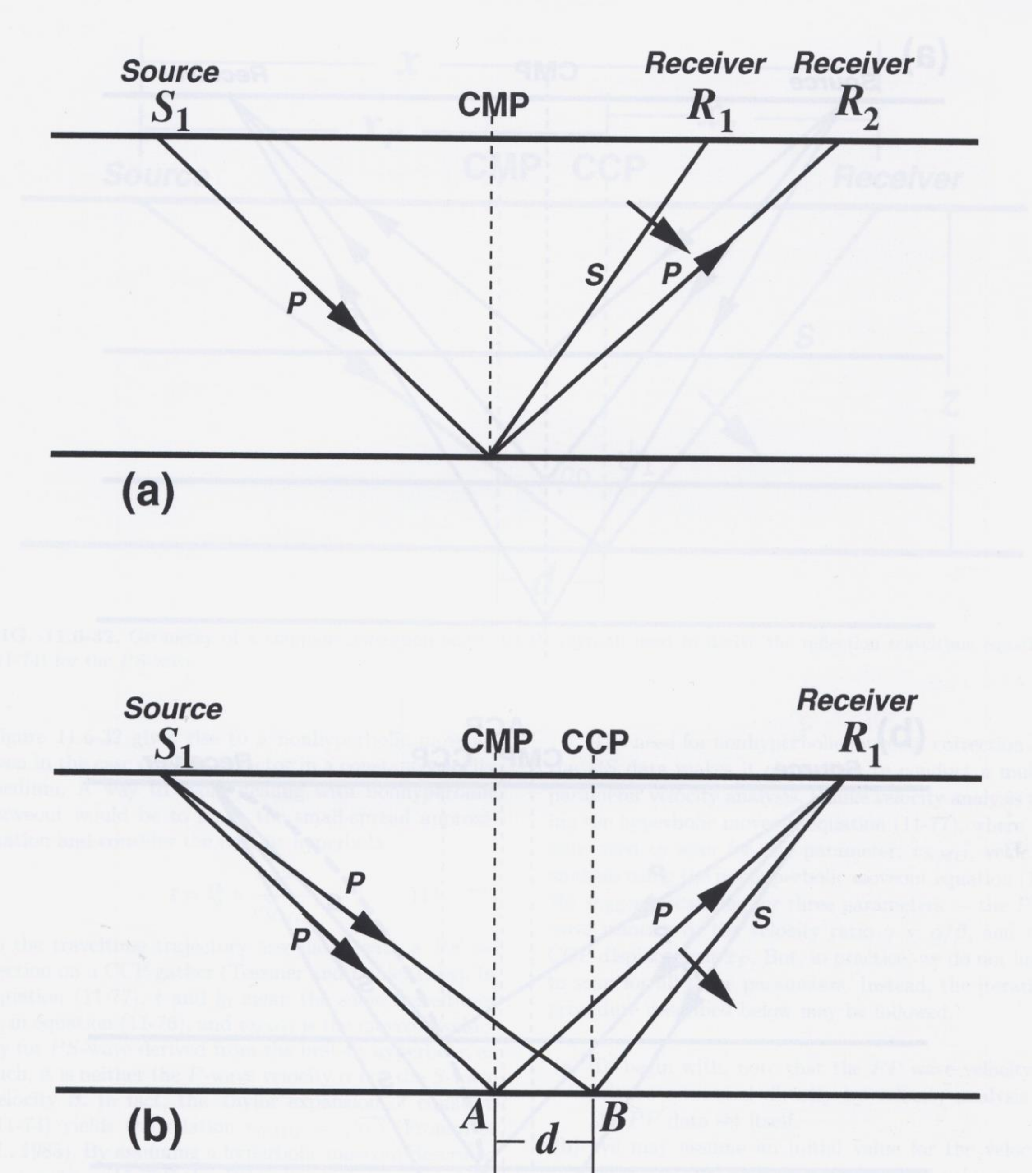
Diagram of an incident wave P (*downgoing):*
it origintes the riflected waves PP and PS,
both "*upgoing*", which cross the gas layer:
while the PP waves are mostly dispersed, the PS waves cross undisturbed through the rocky matrix.

Seismic 4C

While for the reflected P wave the reflection angle is equal to the incidence angle, for the converted PS wave the reflection angle is smaller; Therefore the registration points or, alternatively, the investigated reflecting points, will be different.

While for the PP section we will talk of *Common Mid Point* (CMP), for the PS section we will talk of Common *Conversion Point* (CCP).

Note: the *raypath* of the converted S is not symmetric



Sismica 4C

Ratio of P–wave velocity to S–wave velocity

$$\frac{\beta}{\alpha} = \sqrt{\frac{1-2\sigma}{2(1-\sigma)}}$$

Table 1. Comparison of *S*-waves and *P*-waves

- Most of the oil industry's seismic work is done with *P*-waves, using single or dual sensor technology.
- *P*-waves travel faster than *S*-waves, from roughly twice as fast at depth to as much as 8-10 times as fast (occasionally even more) very near the seafloor.
- *S*-waves can be created by conversion of *P*-waves at rock property boundaries, so conventional marine air-gun arrays can be, and are, used to create *S*-waves.
- *S*-waves cannot exist in fluids, but *P*-waves can and commonly do.
- To first order, *S*-waves are not affected by the pore fluids in rocks, but *P*-waves are.
- Taken together, these two types of energy can provide much more information about a reservoir than can be provided by either alone.
- To record *S*-waves in the marine environment, special recording equipment that contacts the seafloor is required.

Hard Rocks

	Shale:	Sand:
Vp	= 14 139 ft/s	= 14 960 ft/s
Vs	= 8 373 ft/s	= 9 756 ft/s
Rhob	= 2.5464 g/cc	= 2.4066 g/cc
Vp/Vs	= 1.689	= 1.533
PR	= 0.23	= 0.13
Zp	= 36 003	= 36 003
Zs	= 21 321	= 23 479

Δ(Vp/Vs) = -0.156
Δσ = –0.1
RCss = 0.048

Consolidated Rocks

	Shale:	Sand:
Vp	= 9 016 ft/s	= 10 000 ft/s
Vs	= 4 331 ft/s	= 5 774 ft/s
Rhob	= 2.3454 g/cc	= 2.1146 g/cc
Vp/Vs	= 2.082	= 1.732
PR	= 0.35	= 0.25
Zp	= 21 146	= 21 146
Zs	= 10 158	= 12 210

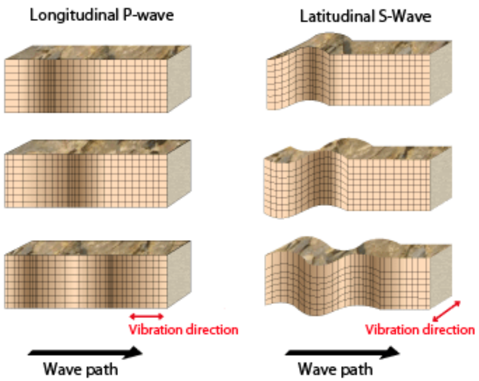
Δ(Vp/Vs) = -0.350
Δσ = –0.1
RCss = 0.092

Unconsolidated Rocks

	Shale:	Sand:
Vp	= 6 750 ft/s	= 7 000 ft/s
Vs	= 1 606 ft/s	= 3 180 ft/s
Rhob	= 2.1593 g/cc	= 2.0821 g/cc
Vp/Vs	= 4.203	= 2.201
PR	= 0.47	= 0.37
Zp	= 14 575	= 14 575
Zs	= 3 468	= 6 621

Δ(Vp/Vs) = -2.002
Δσ = –0.1
RCss = 0.313

Seismic 4C



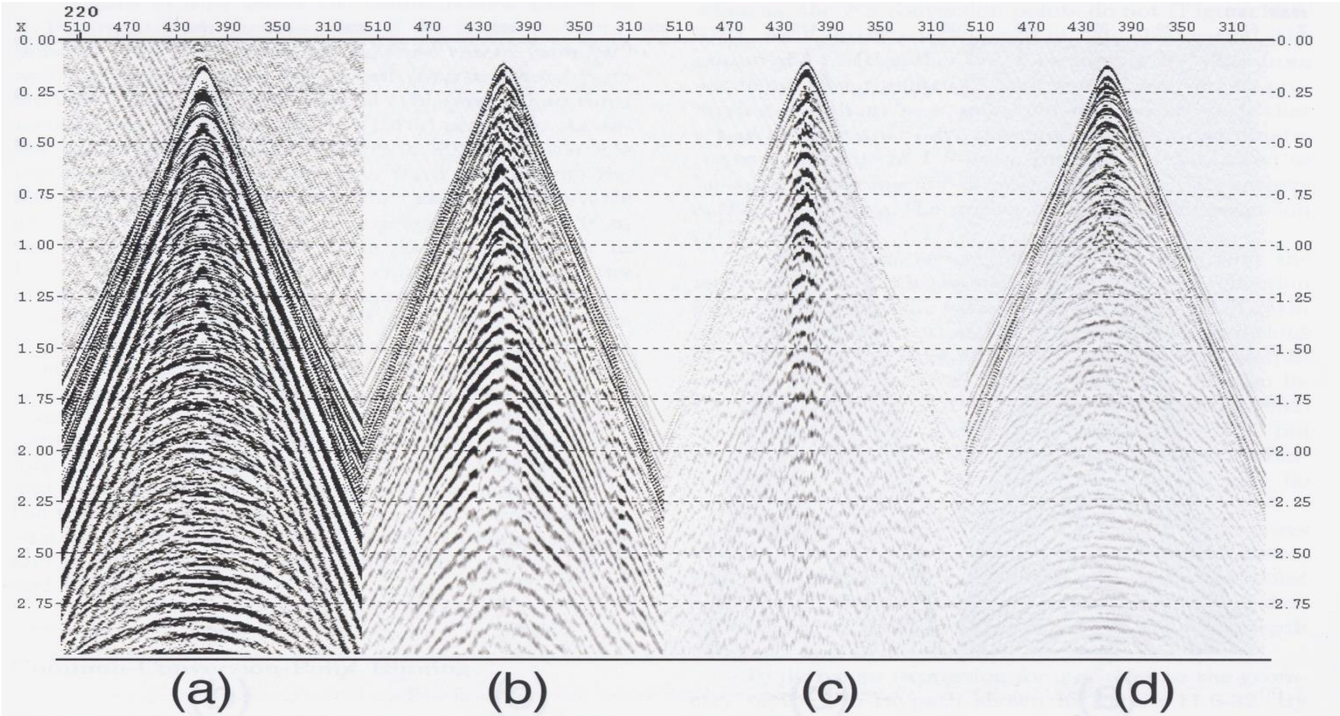


FIG. 11.6-10. A close-up portion of the composite common-shot gather shown in Figure 11.6-6 and the spectra of the individual components, (a) the hydrophone, (b) inline, (c) crossline, and (d) vertical geophone components.

-4C Seismic used at sea (cheaper and easier to apply)
-S waves are not transmitted in fluids

} → The recording tools must be placed on the seabed (implies the need to make static corrections).

These instruments will be:

- two geophones to measure the horizontal components (perpendicular to each other and to the direction of the wave, considered vertical) (b & c) } **PS**
- (d) a geophone to measure the vertical component
- (a) un hydrophone to measure the pressure variation } **PP**

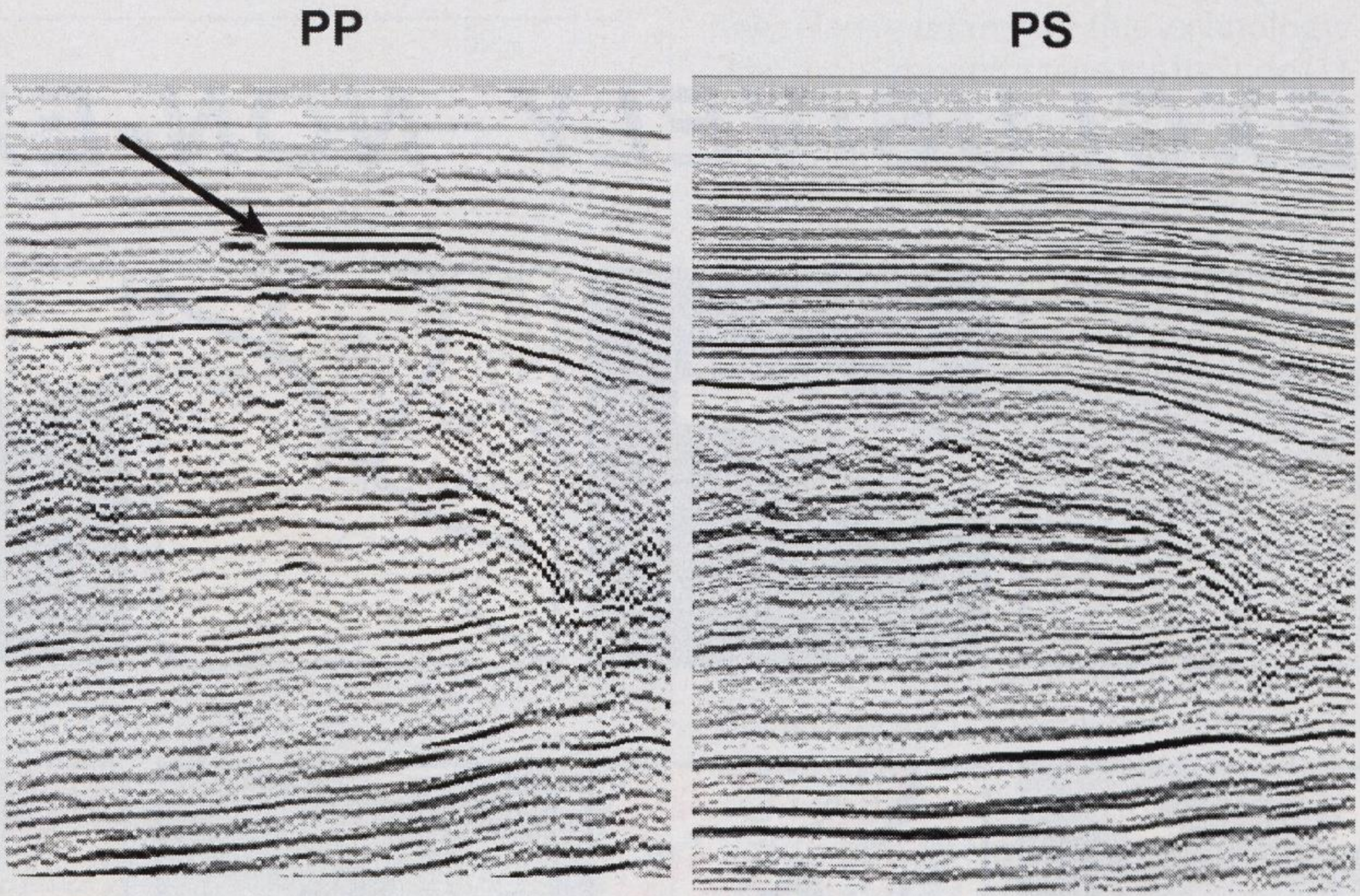
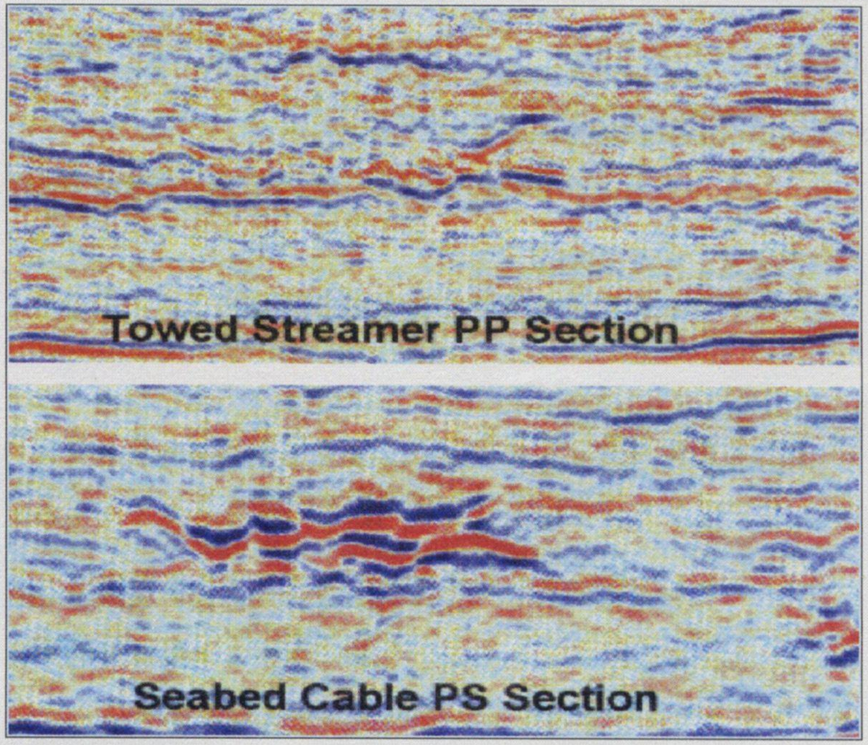


Figure 9. These Far East data show the difference in response between the *PP* section on the left and the *PS* section on the right. The bright spot indicated by the arrow shallow on the *PP* section is a gas accumulation that obscures the data beneath it. The gas accumulation has no amplitude anomaly, as expected, on the *PS* section. The two sections taken together suggest a gas accumulation, and the *PS* section provides a clearer picture of the underlying structure and stratigraphy.

The two sections, PP and PS, are <u>not alternative but complementary</u>, both of them are useful (necessary) to an optimal evaluation of the *reservoir*.

The 4C seismic offers several possibilities of applications, as:

(a) Imaging beneath gas plumes,
(b) Imaging beneath salt domes,
(c) Imaging beneath basalts,
(d) Delineating reservoir boundaries with a higher S-wave impedance contrast than P-wave impedance contrast,
(e) Differentiating sand from shale,
(f) Detection of fluid phase change from oil-bearing to water-bearing sands,
(g) Detection of vertical fracture orientation,
(h) Mapping hydrocarbon saturation, and
(i) Mapping oil-water contact.



– Image from MacLeod et al, EAGE Meeting Abstracts, 1999.

Figure 2 – Low P-wave contrast sands. The normal P-wave section top shows almost no reflections from the Alba Field reservoir. The converted wave section bottom shows clear high amplitude reflections from the same sands.

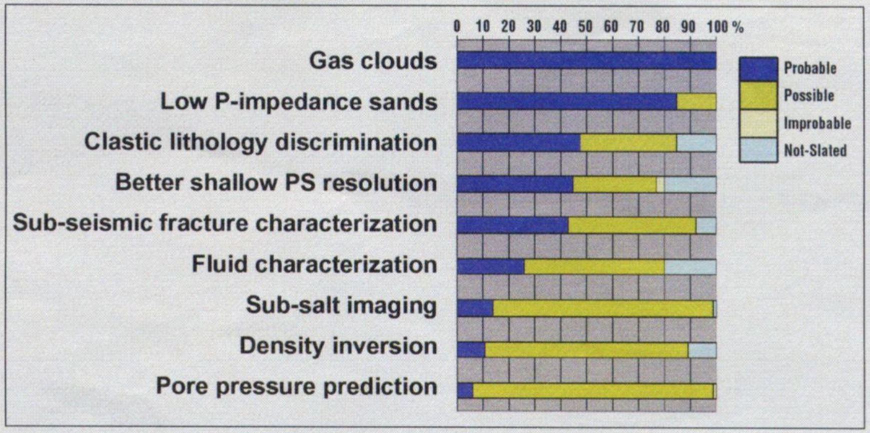
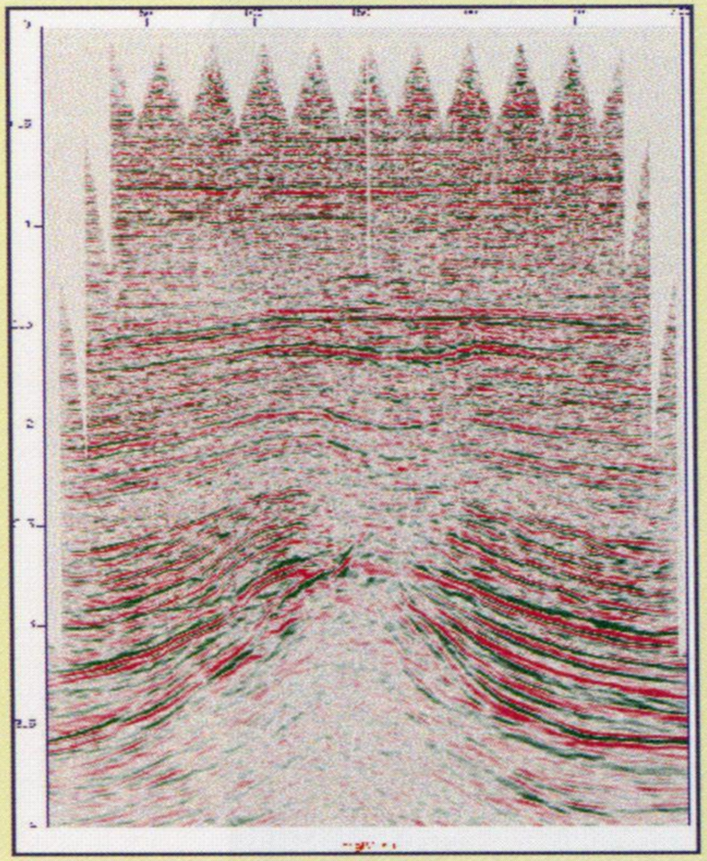
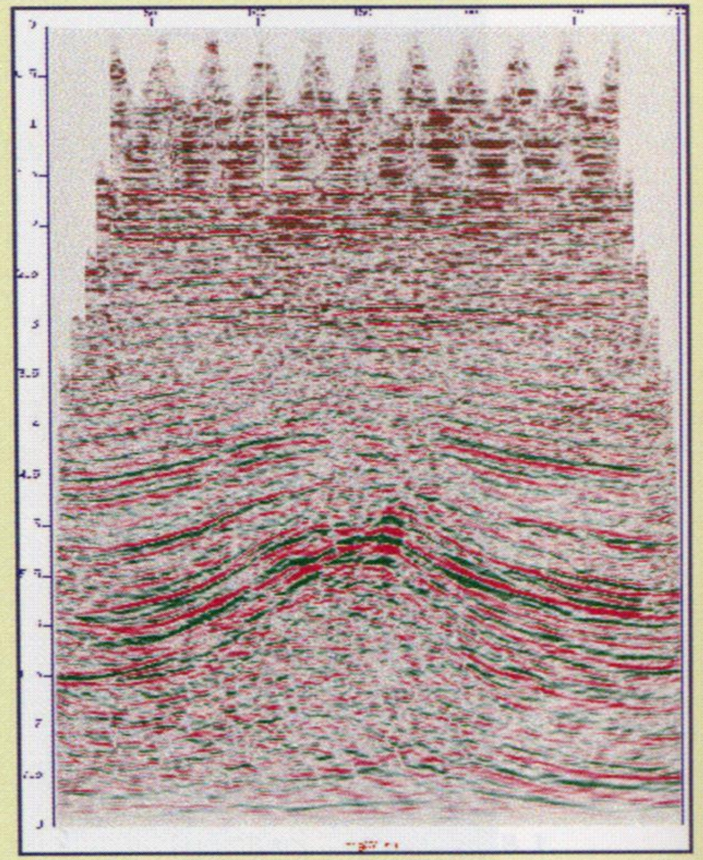


Table 1 – Maturity of Multicomponent Applications. A group of experts at the 2000 SEG Summer Workshop indicated the likelihood of technical success of a multicomponent survey designed for each of several applications. The most mature applications are gas clouds and low P-impedance sands.



PP migrated section



PS migrated section

Seal not perfectly efficient.

The PS waves will furnish a good description of the *target*,
The PP will be considered for the wells planning**.**

Sonic logs
for PP and PS waves
in well in a production field.

Velocity of the S waves:
clear contrast at the top
and at the base of the
reservoir,
no significant contrast
at the oil/water contact.

Velocity of the P waves:
different gradients
at the *top* of the *reservoir*,
but not clear contrast
(*dim spot*);
contrast very evident
at the OWC.