Seismic Basics in 5 Pages

Seismic velocities are given by:

$$V_P = \sqrt{\frac{\lambda + 2\mu}{\rho}} \; ; \; V_S = \sqrt{\frac{\mu}{\rho}} \; ; \; \frac{V_S}{V_P} = \sqrt{\frac{0.5 - \sigma}{1 - \sigma}} \; .$$

where V_p, V_S = velocity of P-, S-waves,
λ, μ = lamé elastic constants,
ρ = density,
σ = Poisson's ratio

The empirical time-average equation relating P-wave velocity to porosity is:

$$\Delta t = \phi \, \Delta t_f + (1 - \phi) \, \Delta t_m, \quad \text{or} \quad \frac{1}{V} = \frac{\phi}{V_f} + \frac{1 - \phi}{V_m} \, ,$$

where ϕ = porosity,
Δt = slowness of interval transit time,
Δt_f = slowness of interstitial fluid,
Δt_m = slowness of rock matrix,
V = velocity of interval transit time,
V_f = velocity of interstitial fluid,
V_m = velocity of rock matrix.

Reservoir velocity and density depend on: lithology
porosity
interstitial fluid (hydrocarbons)
and other factors.

Without additional information (as from wells), these effects cannot be separated

E.g., if we believe a bed has no major changes in lithology or interstitial fluids, amplitude changes may result from porosity-thickness.

An increase in amplitude is usually good: sandier,
thicker,
more porous, or
hydrocarbons.

REFLECTIONS; TUNING

A reflection from a reservoir involves at least 2 reflections, from reservoir top and base, plus possibly reflections from fluid contacts (gas-oil or gas-water) and interlayers within the reservoir.

A reflection for a zero-phase embedded wavelet for a thin reservoir (< $\lambda/4$ thick), is a trough-peak or peak-trough, depending on whether the reservoir's impedance is lower or higher than the surrounding rock's.(for seg standard polarity).

The nature of interpretation changes at a reservoir thickness of $\lambda/4$:

For thick beds (thickness > $\lambda/4$), we determine the gross thickness by the time interval between reflections from top and base of the bed.

For thin beds (thickness < $\lambda/4$), we determine the net thickness by measuring reflection amplitude.

Gross thickness is the distance between top and base of bed

Net thickness is the thickness of one lithology within the bed (e.g., net sand excluding shales)

Equation dividing thick- and thin-bed cases is

$$\frac{\lambda}{4} = \frac{\textit{RESERVOIR VELOCITY}}{\textit{4 DOMINANT FREQUENCY}}$$

For 6000 ft/s velocity and 60 Hz frequency, $\lambda/4 = 25$ ft.
For 8000 ft/s velocity and 40 Hz frequency, $\lambda/4 = 50$ ft.
For 10,000 ft/s velocity and 25 Hz frequency, $\lambda/4 = 100$ ft.

Many reservoirs are in thin-bed class.

In vicinity of $\lambda/4$, constructive interference of reflections from top and base of bed produces tuning (amplitude increase).

Amplitude measurements must be corrected for tuning.

The velocity and density contrasts at a shale-sand boundary may be either negative or positive, and hence hydrocarbon Indicators such as bright spots, polarity reversals, and AVO anomalies may change character.

Reflection amplitude changes may indicate:
- Tuning (which often parallels structure)
- Changes in lithology or stratigraphy (often associated with patterns)
  - reservoir thickness (change often gradual, may have associated patterns)
  - porosity
  - fluid content (often abrupt change)
  - other factors
- Acquisition/processing errors;

Attributing the changes to one factor implies that other factors are constant

Amplitude is often interpreted as porosity-thickness.

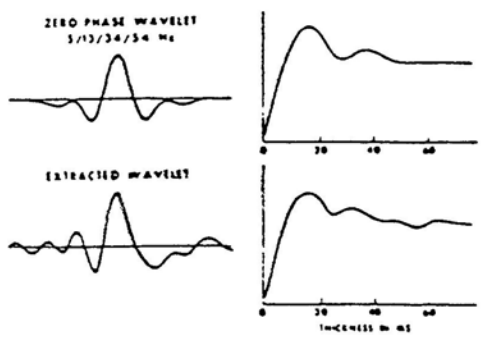
TUNING

ASSUME { ZERO-PHASE WAVELET; RESERVOIR TOP MARKED BY PEAK; RESERVOIR BASE MARKED BY TROUGH } OR VICE-VERSA

REFLECTIONS REINFORCE AT λ/4 THICKNESS (TUNING)

ABOVE TUNING, TIME DIFFERENCE GIVES GROSS THICKNESS

BELOW TUNING, AMPLITUDE GIVES NET THICKNESS.



g. 11. Various wavelets and their corresponding deterministic tuning curves.

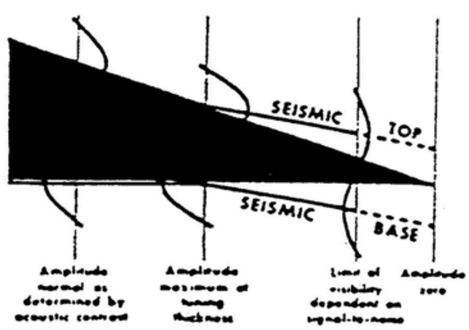


Fig. 9. Tuning phenomena in amplitude and time which occur between reflections from the top and base of a reservoir as the reservoir thins. (The reflectivity at the top and base of the reservoir are assumed to be equal in magnitude and opposite in polarity.)

Fig. 10. Wavelets of four different phases showing the relative relationships between the amplitude maximum and the time of the reflecting interface.

INVERSION (one-dimensional):

$$Z(t) = Z_0\, e^{k\int A(t)\,dt}$$

$$V(t) = V_0\, e^{k'\int A(t)\,dt}$$

where $Z(t)$, $V(t)$ = impedance, velocity with time,
Z_0, V_0 = impedance, velocity at top,
$A(t)$ = amplitude with time,
k, k' = constants.

Reservoir description based on seismic data often depends on amplitude measurements
Reflection amplitudes depend on contrast: the change of properties between surrounding rock and that of the reservoir,
and on bed thickness (and other factors)

When an amplitude change is observed, we imply no change in the surrounding rock.

Qualitative inversion requires
- Good data quality
- Local wells to control values (to calibrate)
- Slowly changing geoilogy so calibration applies

Often benefit from inversion is that it simply gives a different view of data
and a different view may suggest ideas not otherwise considered

The same benefits apply to other trace attributes
Envelope amplitude, instantaneous phase, instantaneous frequency, apparent polarity, etc.
And attributes can be called up very easily at a workstation

HYDROCARBON INDICATORS:

The cause of most indicators is the lowering of P-wave velocity
as hydrocarbons replace water in the pore space.

Amplitude effects: Bright spot and, sometimes, Amplitude shadow
Dim spot
Polarity reversal
Which of these depends on velocity contrast with adjacent rocks

If there are more reflections involved than from reservoir top and base,
Phasing (change of amplitude but not necessarily polarity reversal)

Flat spot from fluid-fluid intewrfaces

Frequency shadow- usually low frequencies just below reservoir

Gas chimney effects due to gas leaking into overlying formations

P-wave anomaly but no S-wave anomaly

AVO anomaly- like amplitude effects, can show up in different ways

Trapping mechanism

AMPLITUDE VARIATION WITH OFFSET (AVO)

Increase of amplitude with offset is often interpreted as indicating gas;
But other conditions can also cause increase of amplitude with offset,
Gas does not always cause an increase, and the gas found may not be commercial.
AVO is very sensitive to acquisition and processing.
AVO modeling gives confidence, but often critical S -wave velocities are unknown.

Reflectivity (reflection coefficient) at perpendicular incidence is $R_0 = \dfrac{\rho_2 V_2 - \rho_1 V_1}{\rho_2 V_2 + \rho_1 V_1}$

Shuey equation for reflectivity at an angle θ is:

$$R = \left(\frac{\Delta V_p}{2V_p} + \frac{\Delta\rho}{2\rho}\right) + (A_0 + C\,\Delta\sigma)\sin^2\theta + B\,(\tan^2\theta + \sin^2\theta)$$

Hilterman equation for reflectivity at an angle is:

$$R = R_0\cos^2\theta + 2.25\sin^2\theta.$$

Hydrocarbon porefluid generally lowers V_p with only a small effect on V_s
Hence, at top of reservoir, $\Delta\sigma$ is usually negative.
If the normal reflectivity R_0 is also negative, then amplitude increases with offset.

But if R_0 is positive (high-impedance sand), amplitude first decreases with offset, the polarity may change and then increase with further offset.

The opposite occurs at base of reservoir and often interferes with reflection from top.

At fluid contact R_0 is always positive.

Note that water and oil (as well as gas)may cause negative $\Delta\sigma$,and so can other factors.

GEOSTATISTICS deals with relations among
- well-log measurements,
- seismic velocity,
- seismic amplitude,
- density,
- lithology,
- bed thickness,
- porosity,
- interstitial fluid (hydrocarbons), and
- possibly other factors.

With so many parameters (which we do not know), we generally use a statistical approach.
We assume that the property we're seeking is given by a linear relation among the measurements available to us, and that the relation changes slowly because of factors we cannot measure.
We make values exact at control points.

And this is the end of Seismic Basics in 5 pages

WHAT DO WE SEE ON A SEISMIC SECTION AND WHY ?

Answer: we see seismic reflections as function of time or depth. The reason is the reflection of the seismic waves from the layer boundaries and faults. (Comment: plus in reality we can see a lot of different noises.)

What is the <u>acoustic impedance</u> ?
The product of density and velocity in a given layer.

What is a <u>seismic reflection</u> ?
The energy or wave from a seismic source which has been reflected (returned) from an acoustic-impedance contrast (= reflector) or series of contrasts within the earth. The impedance contrast is:

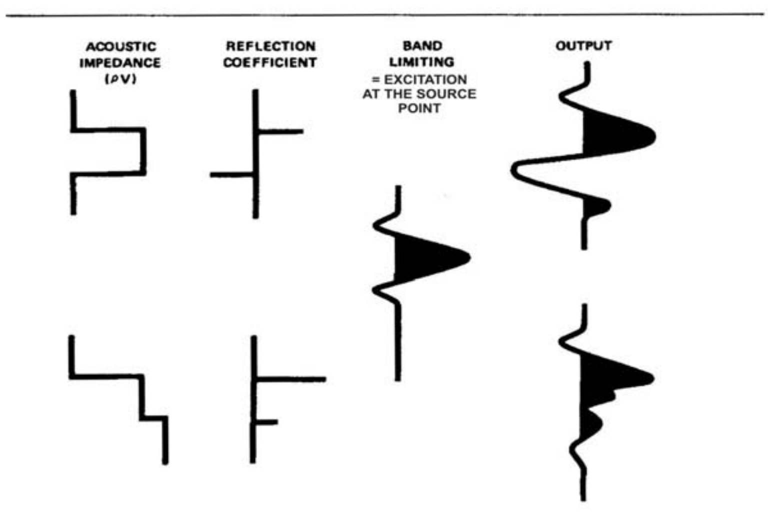
$$R = \frac{\rho_2 v_2 - \rho_1 v_1}{\rho_2 v_2 + \rho_1 v_1}$$

where:
ρ_i is the density in the i-th layer
v_i is the velocity in the i-th layer
R is the <u>reflection coefficient</u> at the layer boundary. Or in other words: <u>acoustic impedance contrast</u>. You can calculate it easily, if you know the velocity and density in the layers (for example from well-logs or cores).

- comment 1.: The equation is valid for normal incidence on the interface for P-wave. In the more general case of a plane-wave incident at an angle, both reflected P- and S-waves will be generated. (-> Zoeppritz's equation) [2].

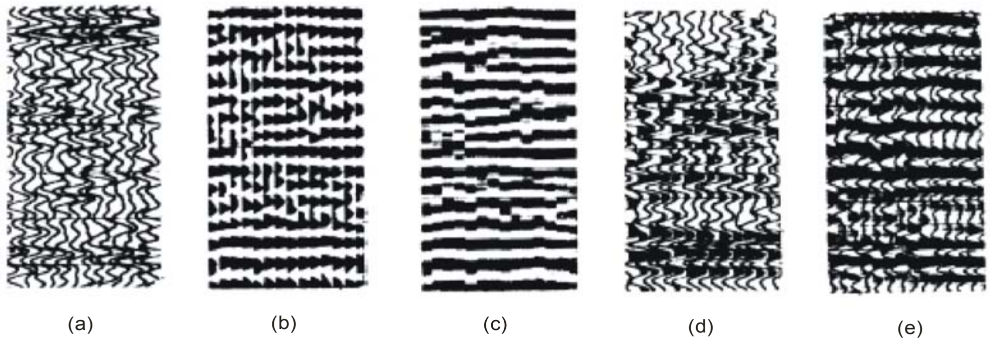
- comment 2.: the relationship is obtained by solving boundary condition equations which express the continuity of displacement and stress at the boundary [2].

<u>Seismic reflector</u>: A contrast in acoustic impedance, which gives rise to a seismic reflection.

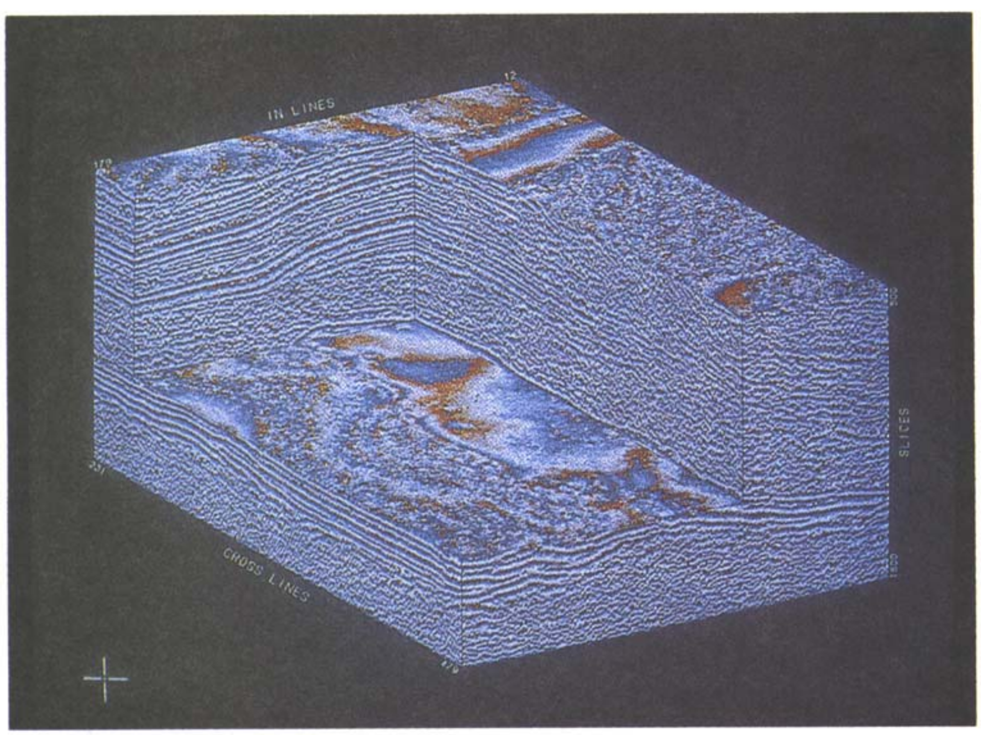


Earth response model

DISPLAY MODES IN SEISMIC

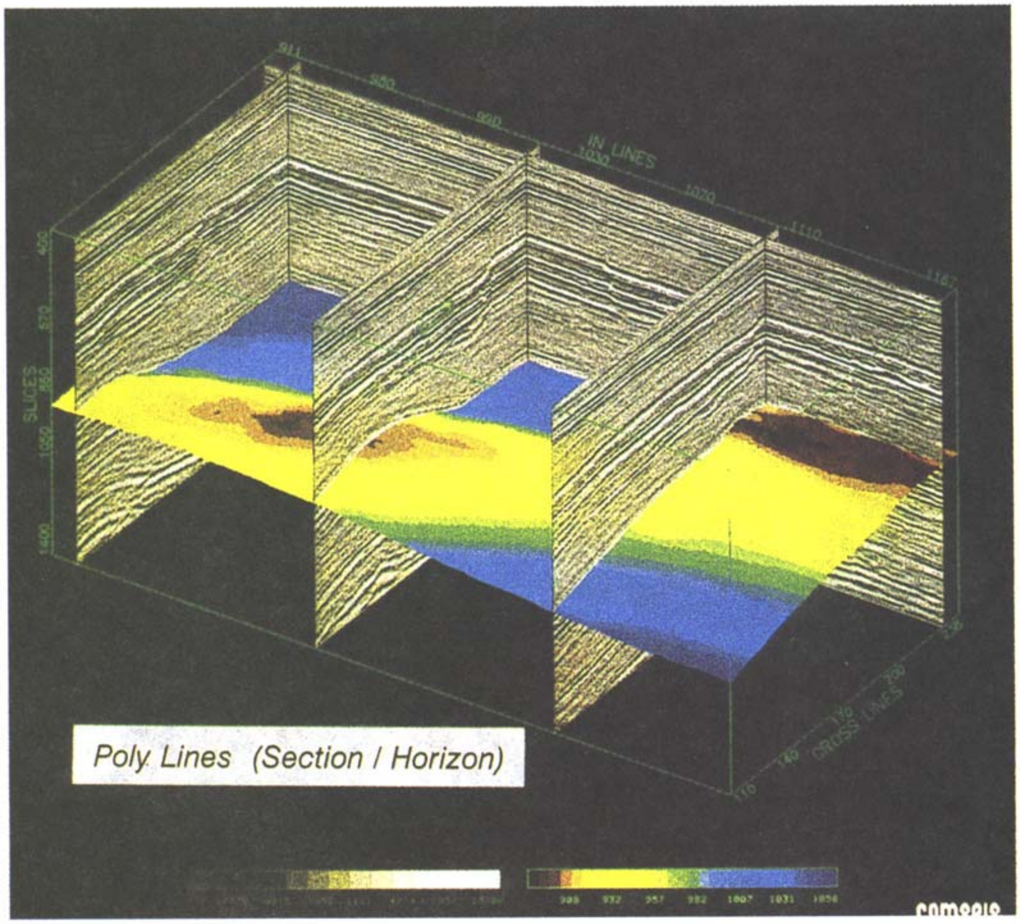


Back/white display modes. (**a**) Wiggle (or squiggle) trace. (**b**) Variable area. (**c**) Variable density. (**d**) Wiggle trace superimposed on variable.



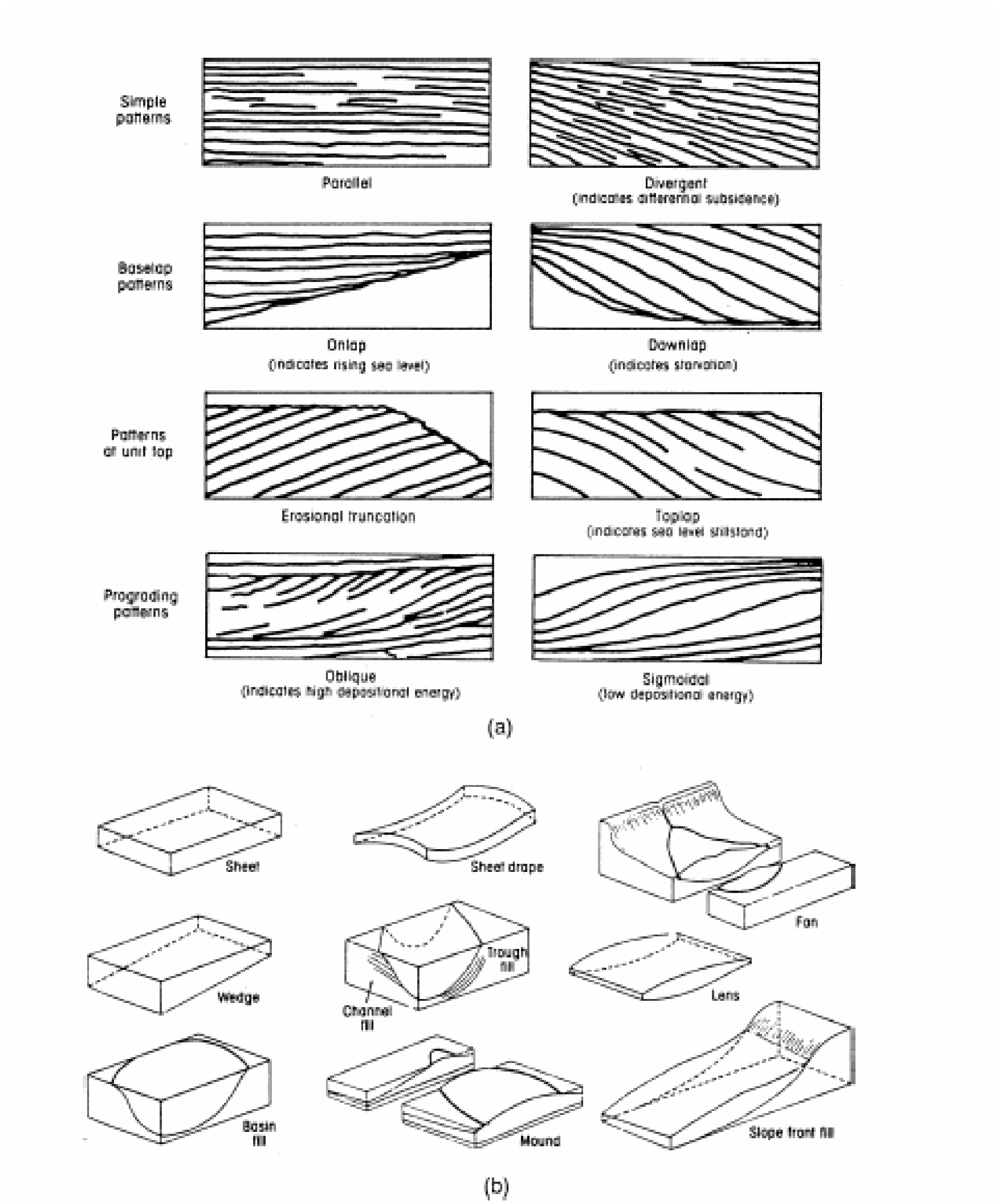
(h)

Color display mode. 3D data from different lines or different time slices may be composited together to form a variety of displays as this **chair display**. (Courtesy Prakla-Seismoc AG.)



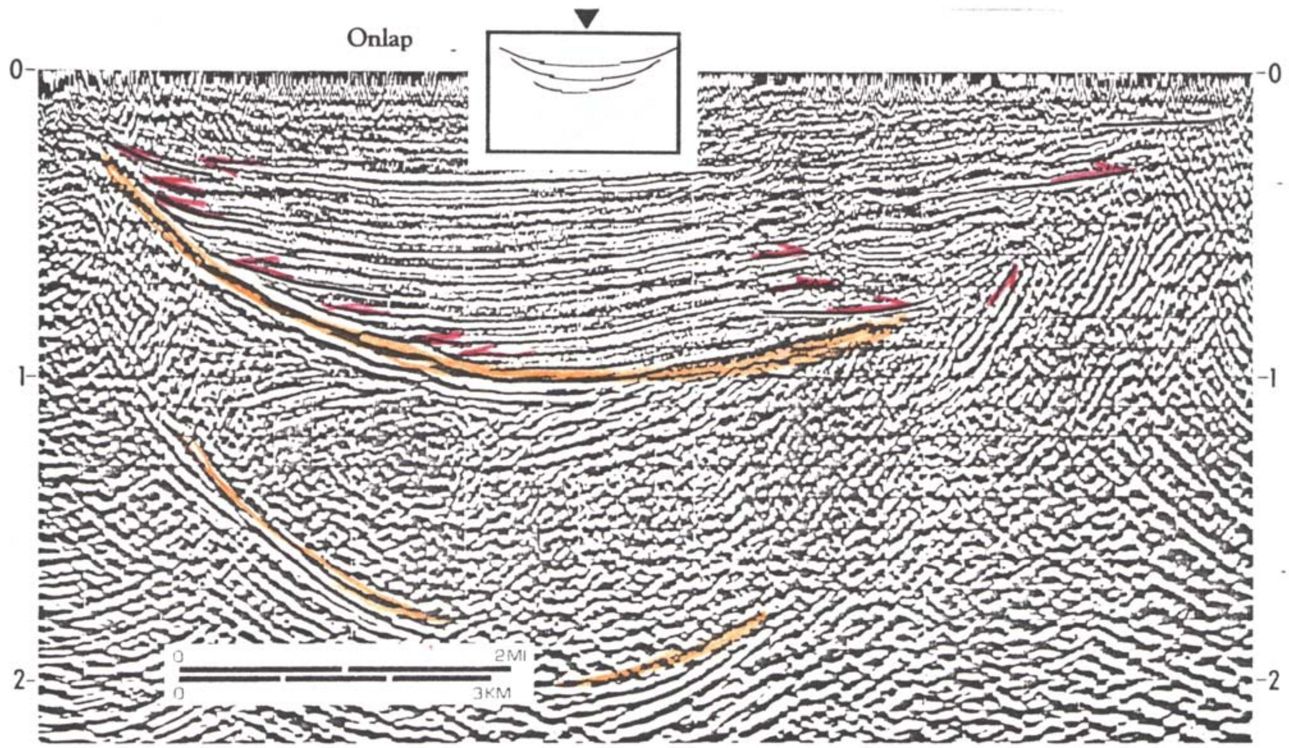
Color display mode. 3D fence diagram. Here several lines and a tracked horizon are combined. (Courtesy Prakla-Seismoc AG.)

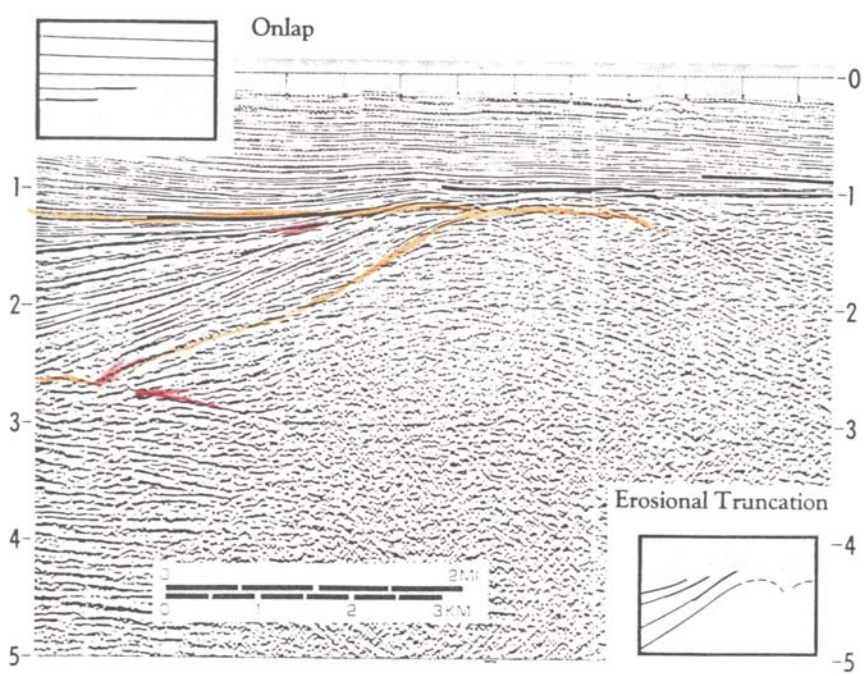
REFLECTION PATTERNS AND CONFIGURATIONS



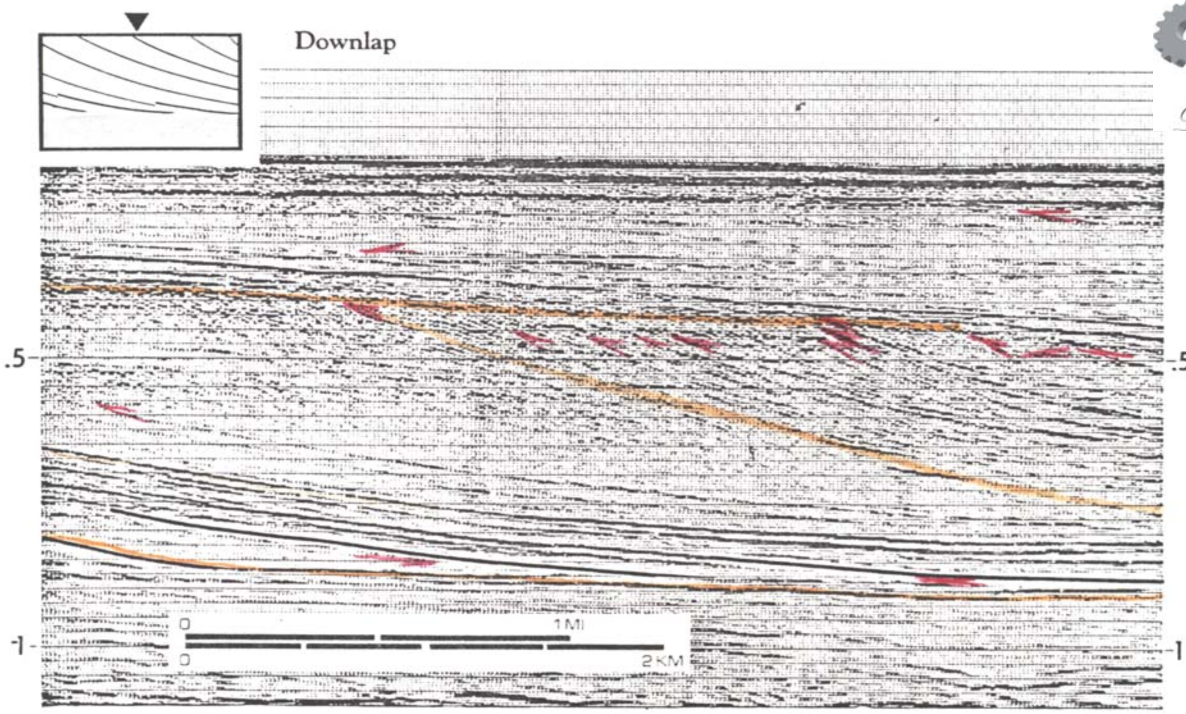
Reflection configurations. (a) Reflection patterns on seismic sections. (b) Three-dimensional shapes of seismic facies units. (After Sangree and Widmier, 1979.)

EXAMPLES OF REFLECTION PATTERNS (AND CONFIGURATIONS)

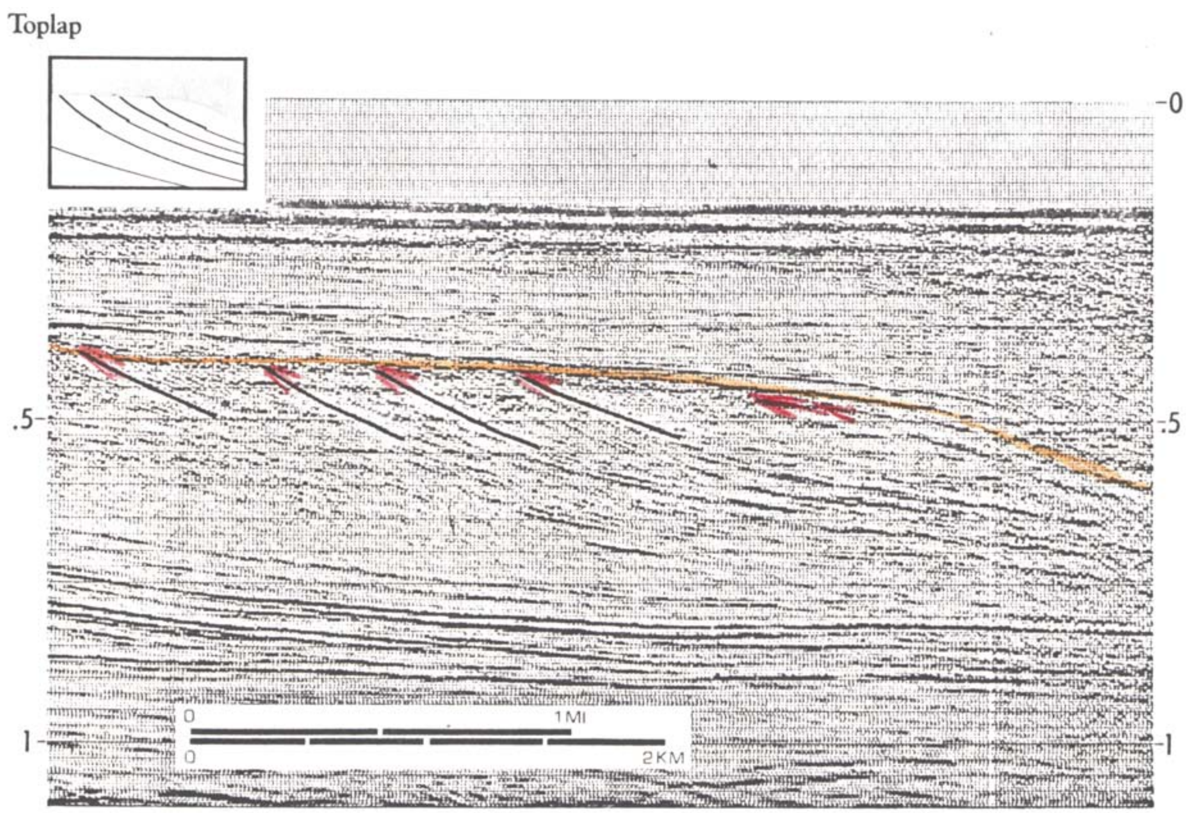




Examples of onlaps.
Onlap: aggradation against a previously formed sloping surface (e.g. on a sequence boundary on a seismic document. Indicates rising sea-level (the definition of the erosional truncation is on page 12).

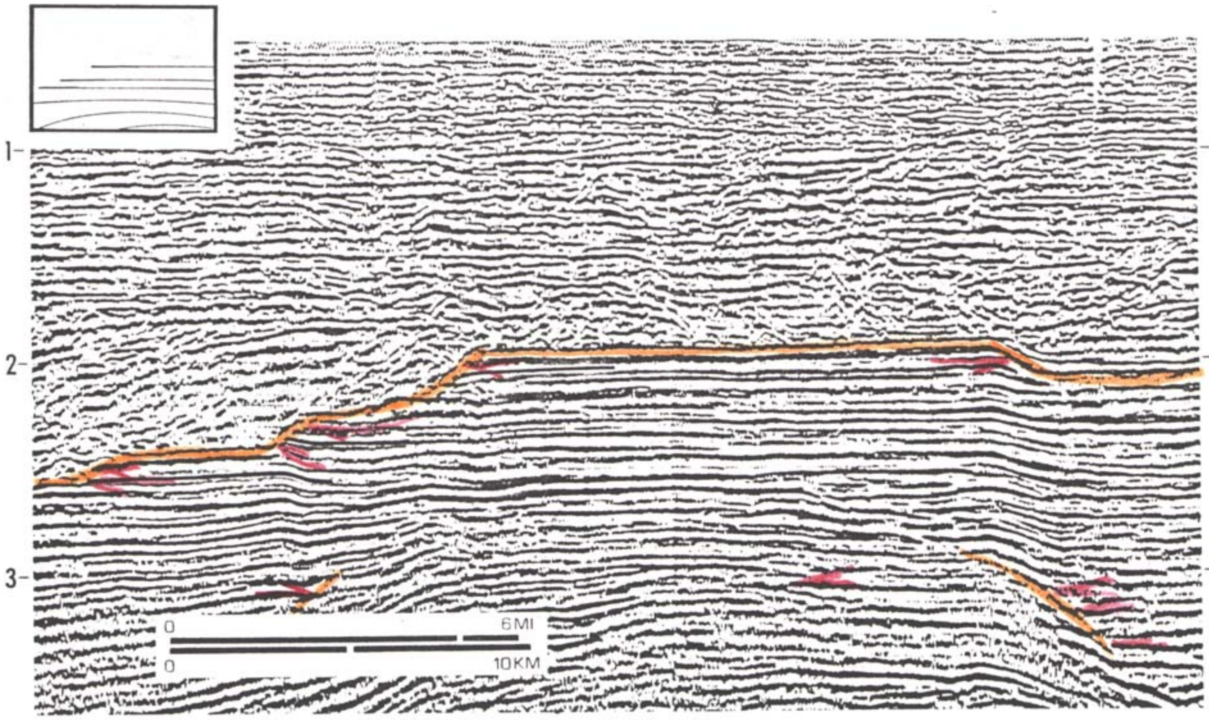


Example of downlaps. Downlap: Progradation on a previously formed basal surface. Indicates starvation.

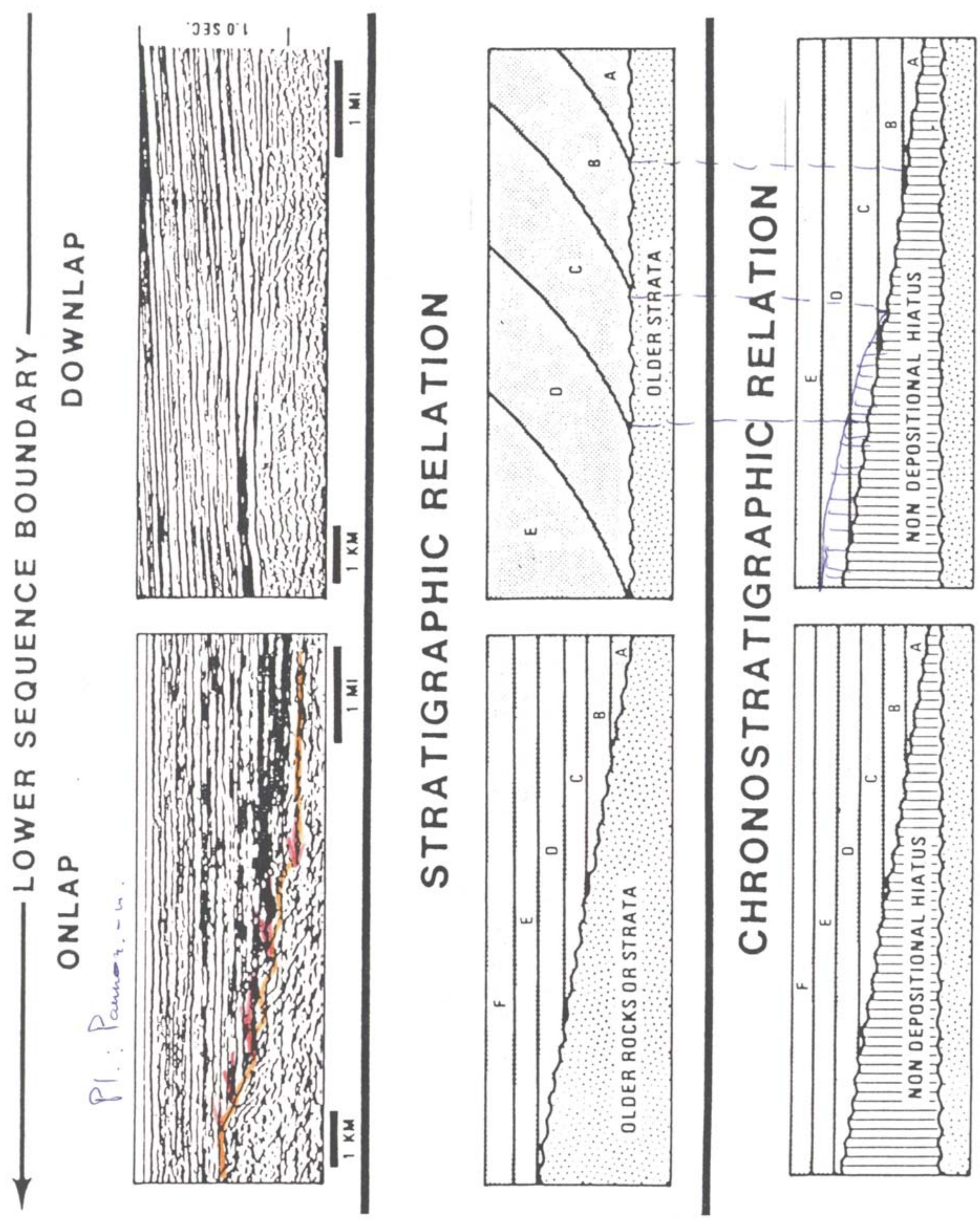


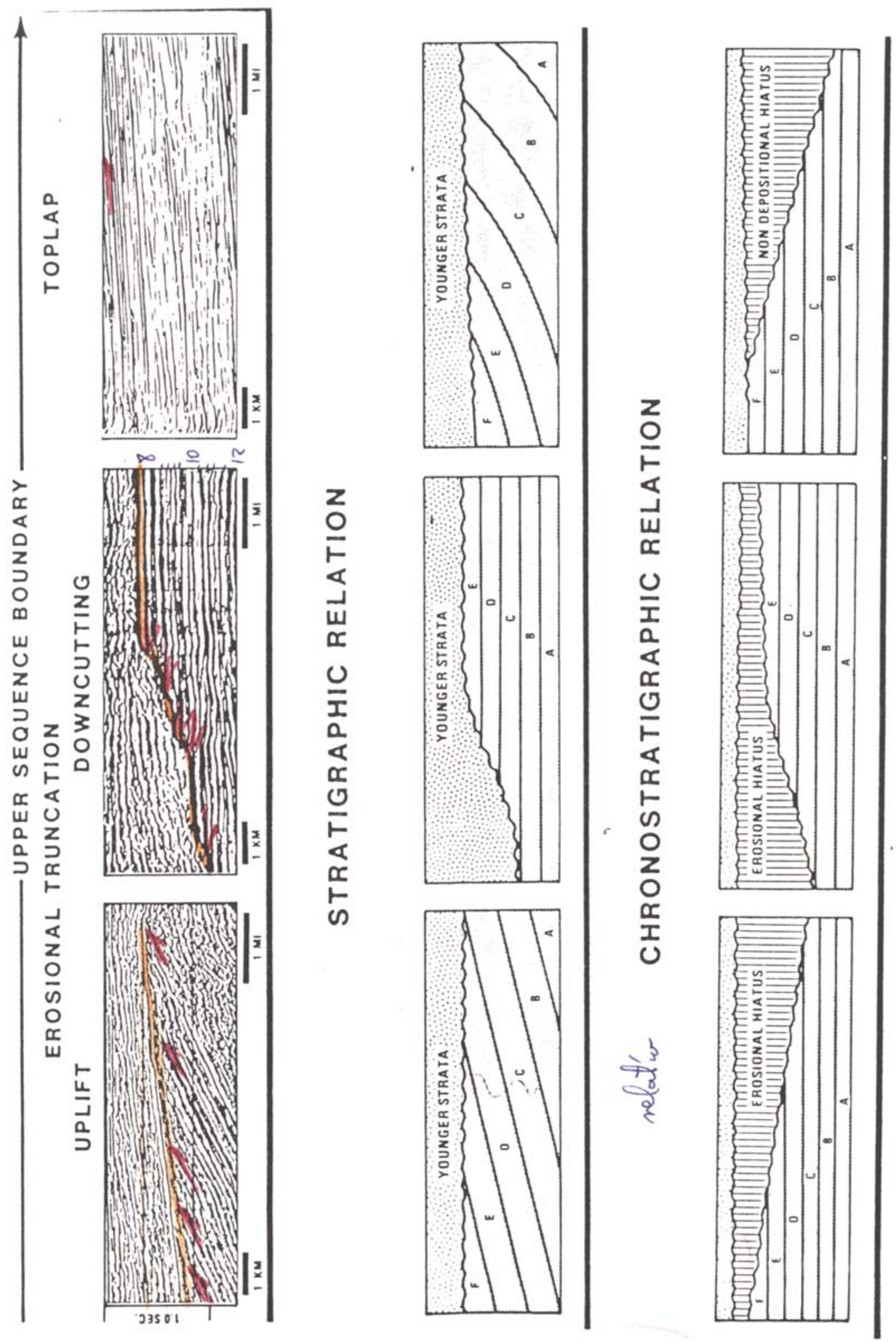
Example of toplaps. Toplap: Progradation bounded by an upper limiting surface. Indicates sea level stillstand.

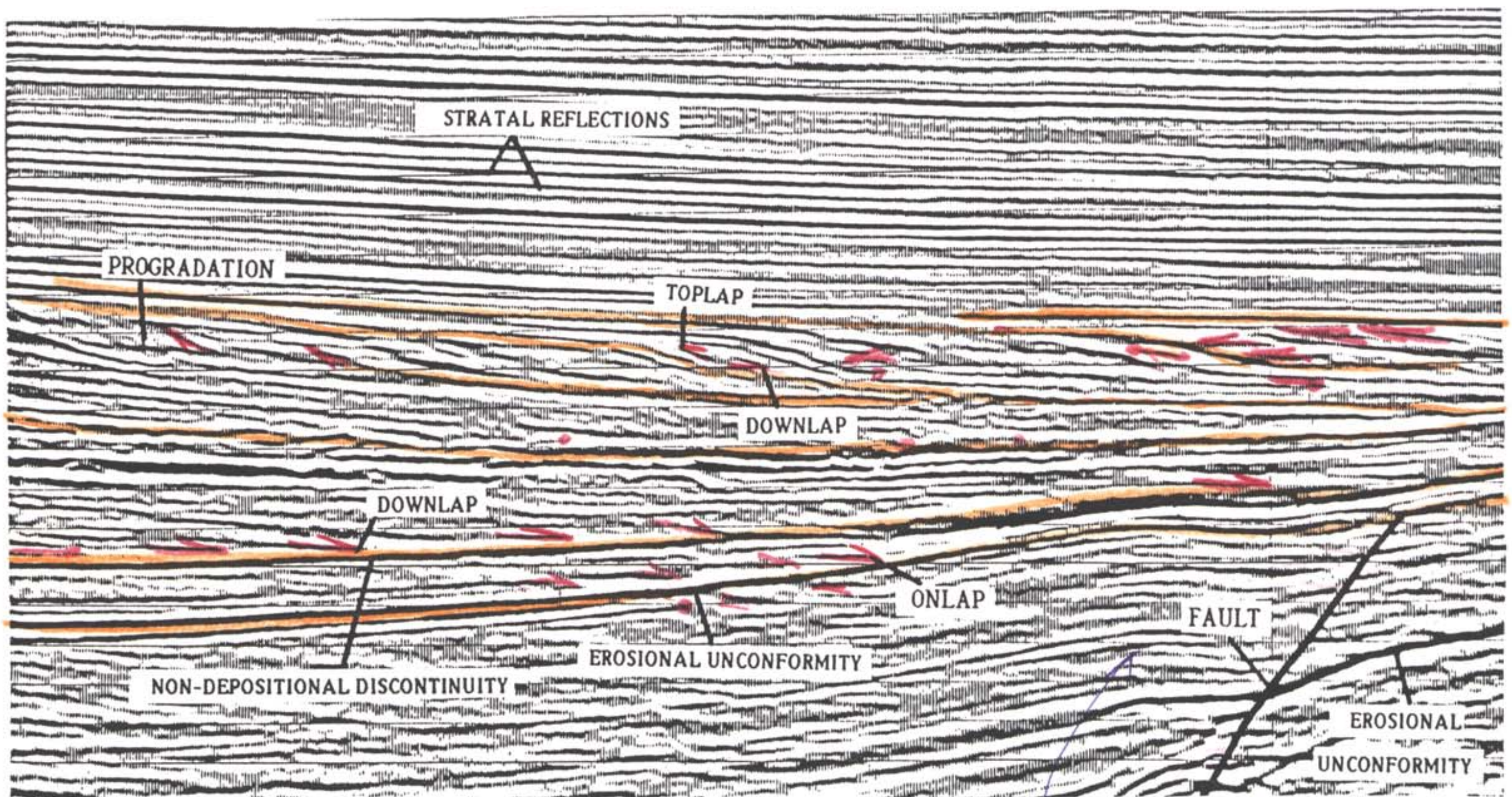
Down Cutting Erosional Truncation



Example of erosional truncations: Termination of strata or seismic reflections interpreted as strata along an unconformity surface due to post-depositional erosional effects.

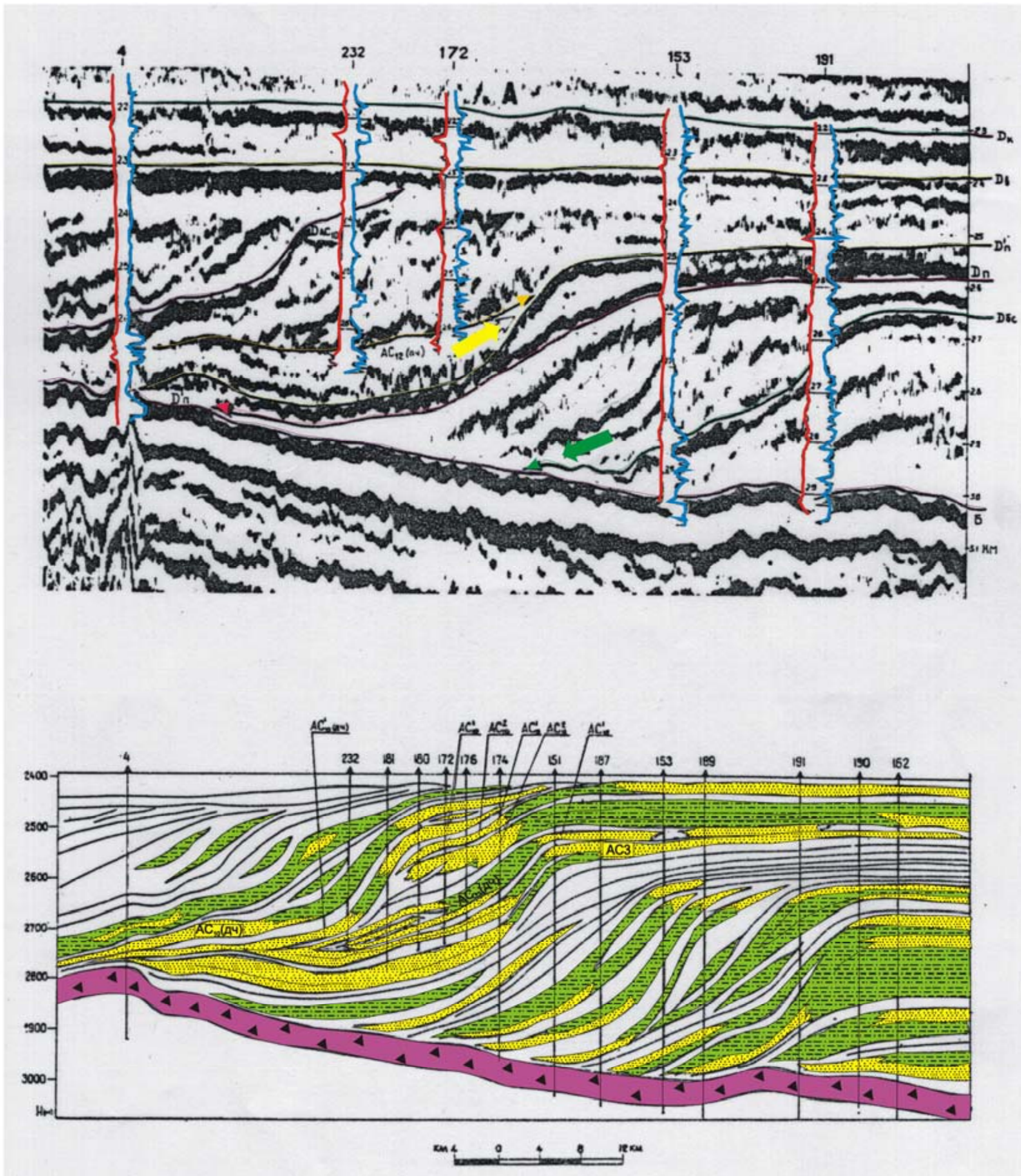

LOWER SEQUENCE BOUNDARY
ONLAP
DOWNLAP
1 KM
1 MI
1.0 SEC.
STRATIGRAPHIC RELATION
OLDER ROCKS OR STRATA
OLDER STRATA
A B C D E F
CHRONOSTRATIGRAPHIC RELATION
NON DEPOSITIONAL HIATUS


UPPER SEQUENCE BOUNDARY
EROSIONAL TRUNCATION
UPLIFT
DOWNCUTTING
TOPLAP
1.0 SEC.
1 KM
1 MI
STRATIGRAPHIC RELATION
YOUNGER STRATA
CHRONOSTRATIGRAPHIC RELATION
EROSIONAL HIATUS
NON DEPOSITIONAL HIATUS



roll over?
inverz vető?

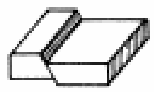
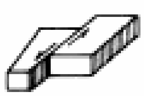
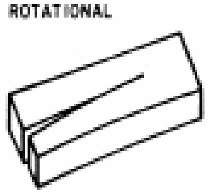
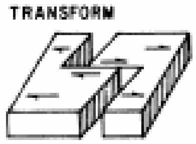
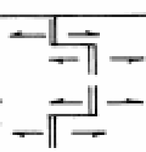
Example of interpretation of different reflection patterns on seismic sections.



Example of seismic stratigraphic analysis: Tipical model of seismo-stratigraphic sequences of clinoform-like structures in West-Siberia.

FAULTS

Fault: a displacement of rocks along a shear surface. The surface along which displacement occurs is called the fault plane often a curved surface and not ''plane'' in the geometric sense [2].

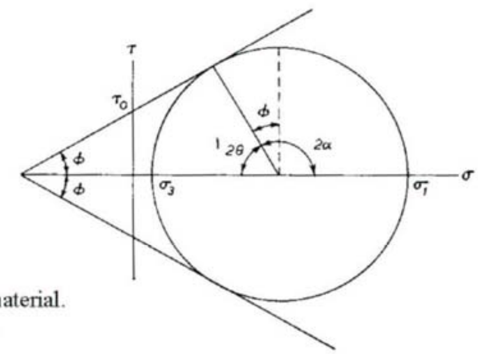
FAULT TYPE	RELATED TERMS	STRESS DIRECTION MINIMUM	STRESS DIRECTION MAXIMUM	CHARACTERISTICS
NORMAL 	TENSION FAULT GRAVITY FAULT SLIP FAULT LISTRIC FAULT (CURVED FAULT PLANE)	HORIZONTAL (Tension)	VERTICAL (Gravity)	Dip usually 75° to 40°
REVERSE 	THRUST FAULT LOW ANGLE (dip < 45°) HIGH ANGLE (dip > 45°)	VERTICAL	HORIZONTAL (Compression)	Fault plane may disappear along bedding
STRIKE - SLIP 	TRANSCURRENT FAULT TEAR FAULT WRENCH FAULT RIGHT LATERAL (Dextral) LEFT LATERAL (Sinistral)	HORIZONTAL	HORIZONTAL	Fault trace often 30° to maximum stress
ROTATIONAL 	SCISSORS FAULT HINGE FAULT			Throw varies along fault strike; may vary from normal throw to reverse.
TRANSFORM 	DEXTRAL SINISTRAL 	HORIZONTAL		Associated with separation or collision of plates New material fills rifts between separating plates or one plate rides up on another if plates collide.

Fault types [2]

CRITERIA FOR FRACTURING AND FAULTING

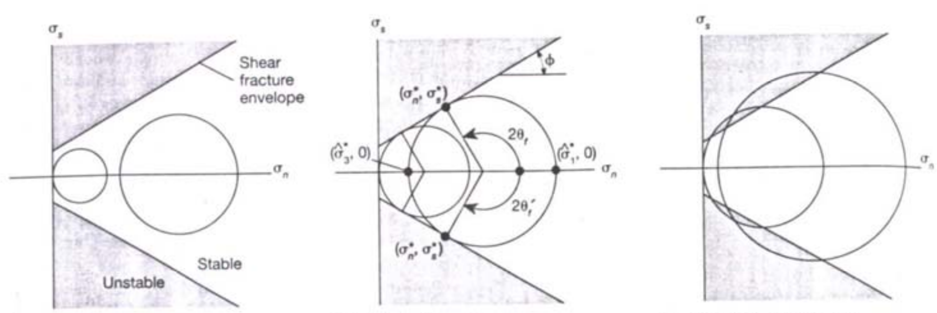
STRESS CONDITIONS FOR SHEAR-FRACTURING IN COHESIVE MATERIALS

Faults occur at an angle $= 45 + \dfrac{\phi}{2}$ to the axis of least stress.



Where normal stress is σ_n, and shear stress is τ.
$\Phi = \tau / \sigma$ is approximately a constant for a given material.
The straight lines are the 'shear fracture envelopes'.

The different stress regimes depend on the position of the circle and the shear fracture envelopes:



A. Stable states of stress **B.** Critical states of stress **C.** Unstable states of stress

Addendum:
The derivation of the Mohr–circle is the next:

Geologists and engineers calculate normal and shear stresses from the orientation and magnitude of two of the three principal stresses using the Mohr diagram. This diagram graphically illustrates in two dimensions the complex mathematical relationships between the components that make up a traction.

The fundamental stress equations for normal stress (σ_n)

$$\sigma_n - \left(\frac{\sigma_1 + \sigma_3}{2}\right) = \left(\frac{\sigma_1 - \sigma_3}{2}\right)\cos 2\theta$$

and for shear stress (τ)

$$\tau = \left(\frac{\sigma_1 - \sigma_3}{2}\right)\sin 2\theta$$

Squaring both sides of Equations and reveals

$$\left[\sigma_n - \left(\frac{\sigma_1 + \sigma_3}{2}\right)\right]^2 = \left(\frac{\sigma_1 - \sigma_3}{2}\right)^2 \cos^2 2\theta$$

and

$$\tau^2 = \left(\frac{\sigma_1 - \sigma_3}{2}\right)^2 \sin^2 2\theta$$

Combining the last two equations yields

$$\left[\sigma_n - \left(\frac{\sigma_1 + \sigma_3}{2}\right)\right]^2 + \tau^2 = \left(\frac{\sigma_1 - \sigma_3}{2}\right)^2 \cos^2 2\theta + \left(\frac{\sigma_1 - \sigma_3}{2}\right)^2 \sin^2 2\theta$$

Simplifying

$$\left[\sigma_n - \left(\frac{\sigma_1 + \sigma_3}{2}\right)\right]^2 + \tau^2 = \left(\frac{\sigma_1 - \sigma_3}{2}\right)^2 \left(\cos^2 2\theta + \sin^2 2\theta\right)$$

Now recall the trigonometric relationship $\left(\cos^2 2\theta + \sin^2 2\theta\right) = 1$. Substituting this relationship into the right hand side

of equation results in

$$\left[\sigma_n - \left(\frac{\sigma_1 + \sigma_3}{2}\right)\right]^2 + \tau^2 = \left(\frac{\sigma_1 - \sigma_3}{2}\right)^2$$

Recall from your college algebra class that the equation of a circle drawn in an *x-y* coordinate system is

$$(x-h)^2 + (y-k)^2 = r^2$$

Details

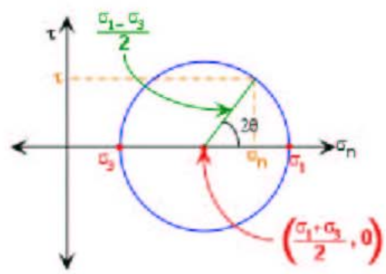
where r is the radius of the circle and (h, k) are the coordinates of the center of the circle. Comparing Equations and reveal that the fundamental stress equations define a circle in σ_n- τ space centered on the point

$$\left(\frac{\sigma_1 + \sigma_3}{2}, 0\right)$$

with a radius of

$$\frac{\sigma_1 - \sigma_3}{2}$$

The figure illustrates a circle constructed from Equation . The circle represents the locus of all possible normal and shear stresses for a given state of stress acting on planes whose normals make an angle of θ degrees to σ_1.



The Mohr circle constructed from Equation with a radius defined by Equation and a center with the

coordinates in Equation.

Structural geologists refer to Figure 18 as a "Mohr circle" after the German engineer Otto Mohr (1835-1918) who first introduced them over a century ago. Note further that the average stress is simply

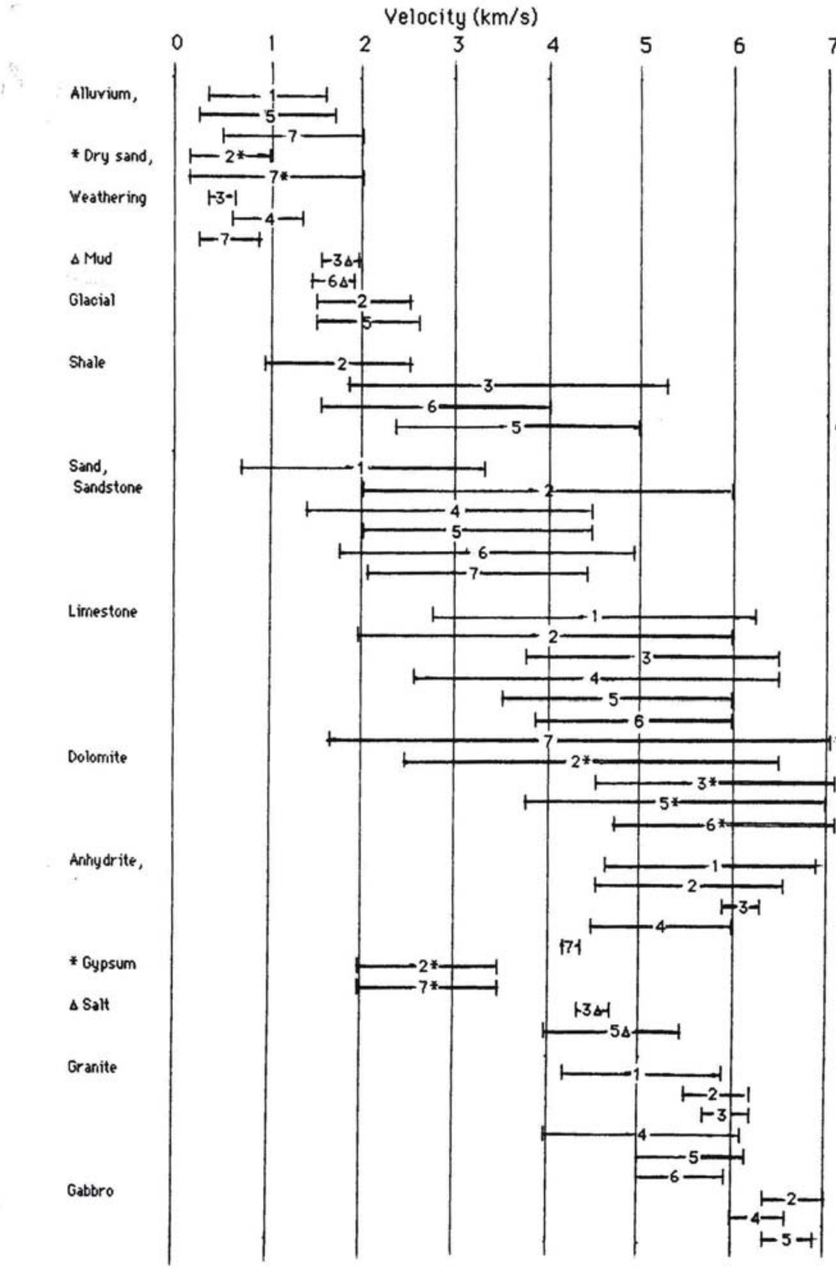
$$average\ stress = \frac{\sigma_1 + \sigma_3}{2}$$

or, in three dimensions

$$average\ stress = \frac{\sigma_1 + \sigma_2 + \sigma_3}{3}$$

In a Mohr diagram, average stress is the center of the Mohr circle. Differential stress is the difference between maximum and minimum principal stresses. In a two dimensional Mohr diagram differential stress is the diameter of the Mohr circle.

P WAVE VELOCITIES



Generally carbo-
nate rocks have
higher velocity
than sand and
shales.

P-wave velocities for various lithologies. Data from (1) Grant and West (1965); (2) Kearey and Brooks (1984); (3) Lindseth (1979); (4) Mares (1984); (5) Sharma (1976); (6) Sheriff and Geldart (1983); and (7) Waters (1987).

Details

Instantaneous velocity: the speed at any given moment of a wavefront in the direction of the energy propagation (perpendicular to the wavefront). This term is occasionally used for velocity determined from *seismic acoustic impedance logs* (q.v).

Apparent velocity: the apparent speed of a given phase in a particular direction, usually the geophone spread direction at the angle θ to the wave direction:

$$V_a = V/\sin\theta.$$

Average velocity $\bar{V}$: the ratio of distance along a certain path to the time to traverse the path:

$$\bar{V} = \int_0^t V(t)\,dt / \int_0^t dt.$$

Has meaning only with respect to a particular paths, although a vertical path is often implied. If the section is made up of parallel horizontal layers of velocity V_i and thickness z_i with the traveltime across each layer $t_i = z_i/V_i$, then the average velocity $\bar{V}$ is

$$\bar{V} = \Sigma_i V_i t_i / \Sigma_i t_i = \Sigma_i z_i / \Sigma_i (z_i/V_i).$$

Root-mean-square (rms) velocity V_{rms}: also refers to a specific raypath; assuming horizontal layers,

$$V_{rms} = [\Sigma_i V_i^2 t_i / \Sigma_i t_i]^{1/2}.$$

The rms velocities are typically a few percent larger than corresponding average velocities.

NMO velocity V_{NMO}: the velocity for the *normal-moveout correction* (q.v.) in the limit as the source-receiver distance becomes very small. For isotropic horizontal layers,

$$V_{NMO} \approx V_{rms}.$$

Stacking velocity V_S: the velocity value determined by *velocity analysis* (q.v.) that is used for common-midpoint stacking. In the limit as offset approaches zero, it approaches the NMO velocity. The difference between stacking velocity and NMO velocity is sometimes called the spread-length bias (Hubral and Krey, 1980, 72).

Interval velocity V_i: the average velocity over some interval of travelpath. Often approximated by Dix velocity. Also used for the average velocity calculated from sonic logs and that calculated from well surveys for the intervals between measurements;

Dix velocity (Dix, 1955): approximate interval velocity for vertical travel between horizontal reflectors,

$$V_i = \left[\frac{V_n^2 t_n - V_{n-1}^2 t_{n-1}}{t_n - t_{n-1}}\right]^{1/2},$$

where V_n is the rms velocity and t_n is the zero-offset arrival time of the nth reflection. This equation yields fictitious values if both reflectors are not horizontal if there are lateral velocity variations between or above them, or if the interval is large.

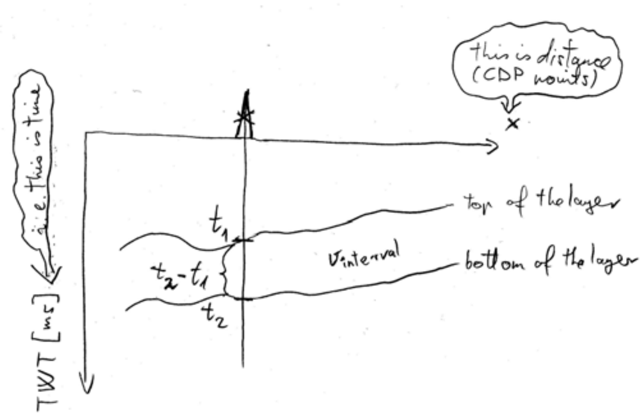
Usually "velocity" means the apparent speed of a phase (**phase velocity**, q.v.), but sometimes the speed of the center of a packet of wave energy (**group velocity**, q.v.).

Seismic velocity terminology.

Important

On a seismic section you can compute the thickness of a given layer, if you know the interval velocity ($v_{interval}$) for example from the acoustic (=velocity) log, and the TWT (=Two Way Traveltime) from the top to the bottom of the layer:

$$\text{Layer thickness} = \frac{(t_2 - t_1) * v_{interval}}{2}$$



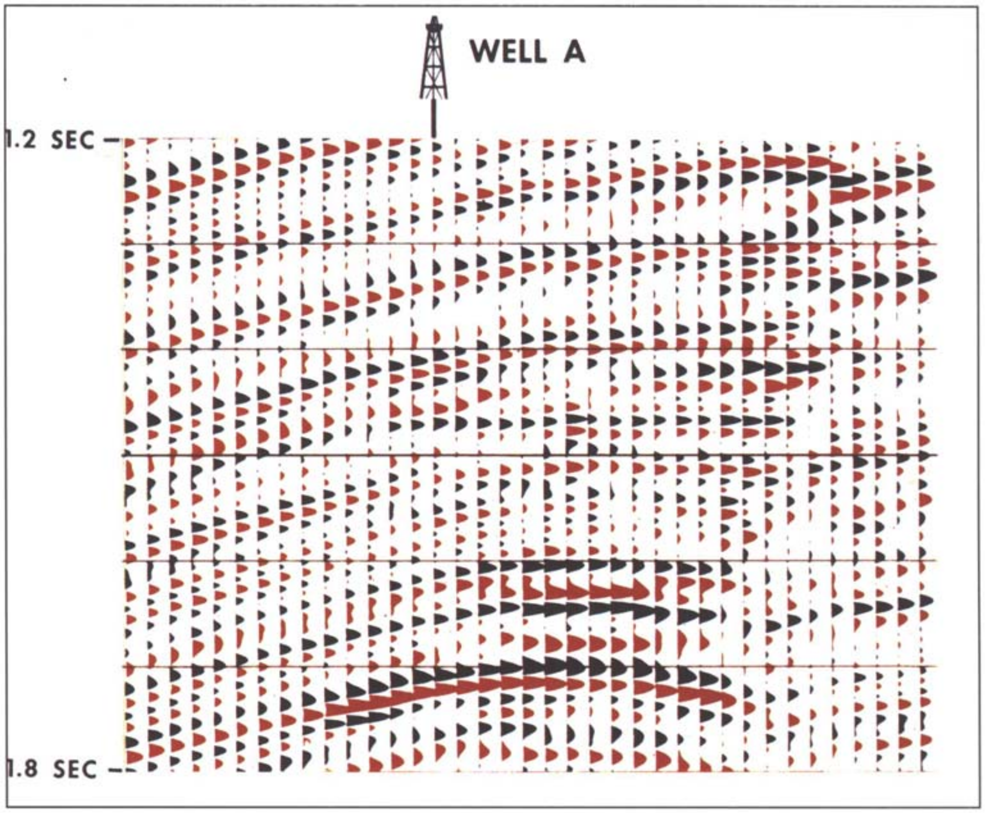
DIRECT HYDROCARBON INDICATORS

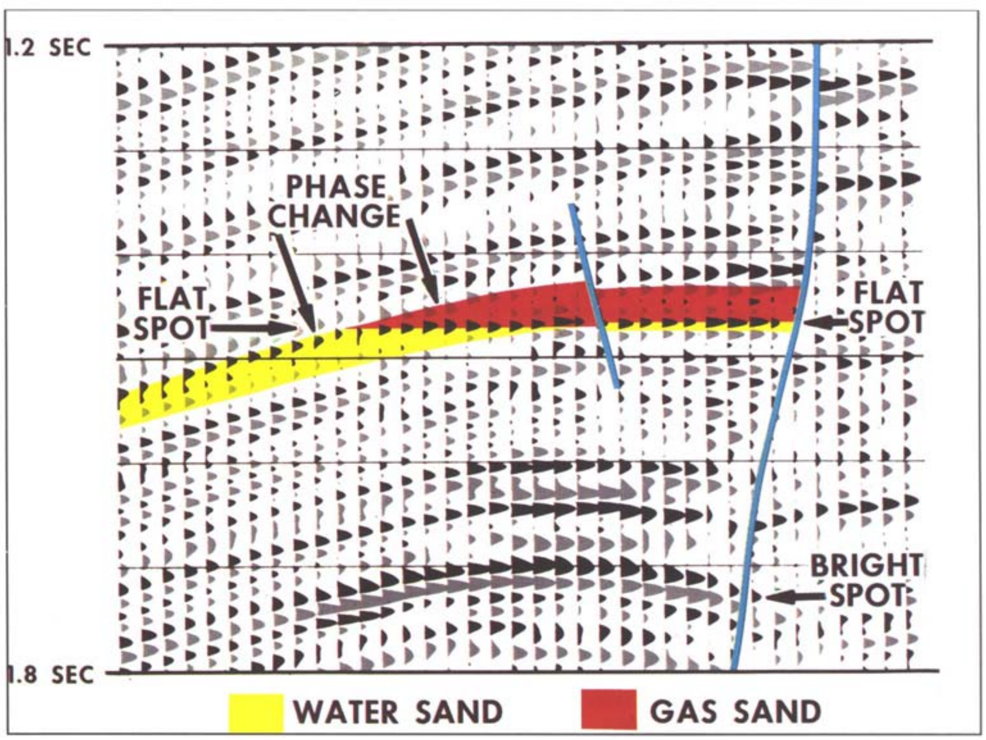
Hydrocarbon indicator (HCI or DHI): A measurement that suggests the presence of a hydrocarbon accumulation. See table below. The most important are outlined with red. The indicators can also be caused by things other than hydrocarbons.
They are also called DHI for ‘‘direct HCI’’ or direct detection, although there is nothing direct about them [2].

Indicators include amplitude increase (**bright spot**) or decrease (**dim spot**), polarity reversal, a waveshape change (**phasing**), a change in the frequency content (especially a local lowering of frequency), a horizontal event reflected from a gas-water, gas-oil, or oil-water contact (**flat spot**), a decrease in amplitude below the accumulation (**shadow zone**), lower velocity than laterally equivalent sediments producing an apparent sag in lower reflections because of increased time in transiting the accumulation (**velocity sag**), an increase in amplitude with offset (see *AVO*). See Sheriff (1980, chapter 9), Sheriff and Geldart, v. 2 (1983, p. 141–143),

Structural crest or against a fault?	**trapping location**
Local increase in amplitude?	**bright spot**
Local decrease in amplitude?	**dim spot**
Discordant flat reflector?	**flat spot**
Local waveshape change?	**polarity reversal** or local **phasing**
Reservoir limits consistent?	(if reservoir base and top separately visible)
Polarities consistent?	(if zero-phase data)
Low-frequencies underneath?	**low-frequency shadow**
Time sag underneath?	**velocity sag , gas sag**
Lower amplitudes underneath (and sometimes above)	**amplitude shadow**
Increase usually in amplitude with offset?	**AVO anomaly**
P-wave but no S-wave anomaly?	**S-wave support**
Data deterioration above (and perhaps minor bright spots)	**gas chimney**

Comment:. All indicators can have causes other than hydrocarbons; a case for hydrocarbon accumulation is stronger where several indicators agree.

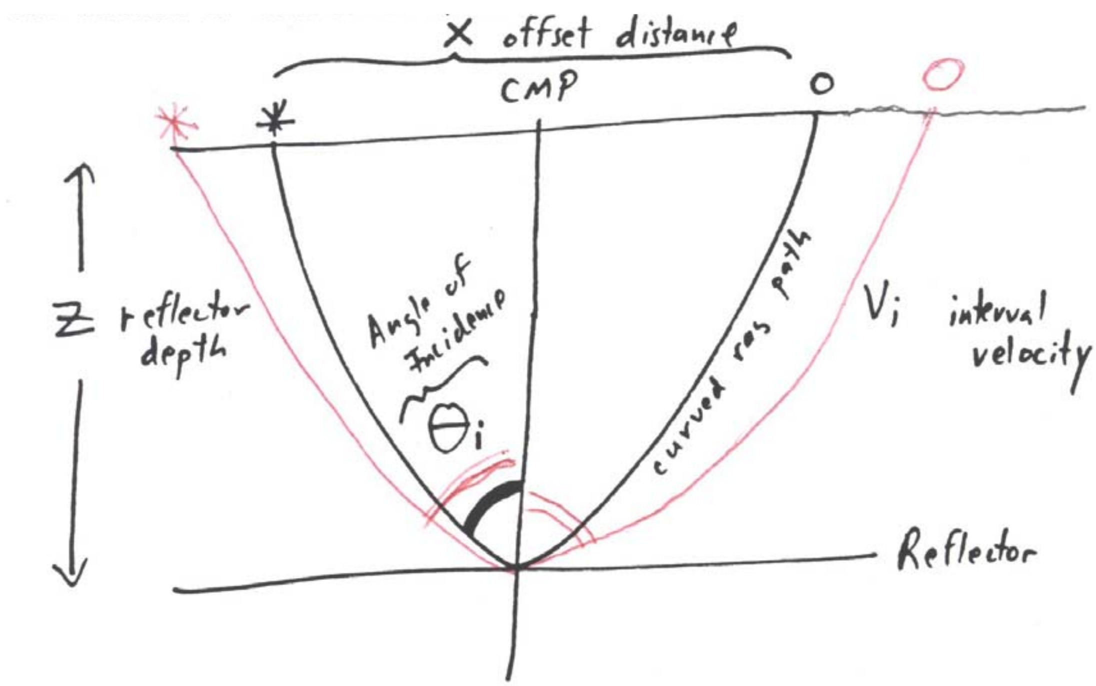

WELL A
1.2 SEC
1.8 SEC


1.2 SEC
PHASE CHANGE
FLAT SPOT
FLAT SPOT
BRIGHT SPOT
1.8 SEC
WATER SAND
GAS SAND

AVO: Amplitude Variation with Offset

The variation in the amplitude of a seismic reflection with angle of incidence or source-geophone distance. Depends on changes in velocity, density, and Poisson's ratio (i.e. the ratio between the longitudinal and transversal wave in the medium). See mathematical details in the 'Seismic Basics in 5 Pages' on page 5 !

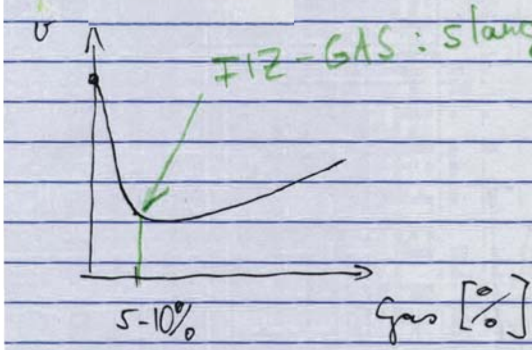
AVO often used as a hydrocarbon gas indicator because gas generally decreases Poisson's ratio and often increases amplitude with incident angle/offset. Other conditions can produce similar effects.



Seismic ray paths with different angle of incidence or source-geophone distance.

THE MAIN PROBLEM OF AVO

FIZ-GAS : slang: carbonated water



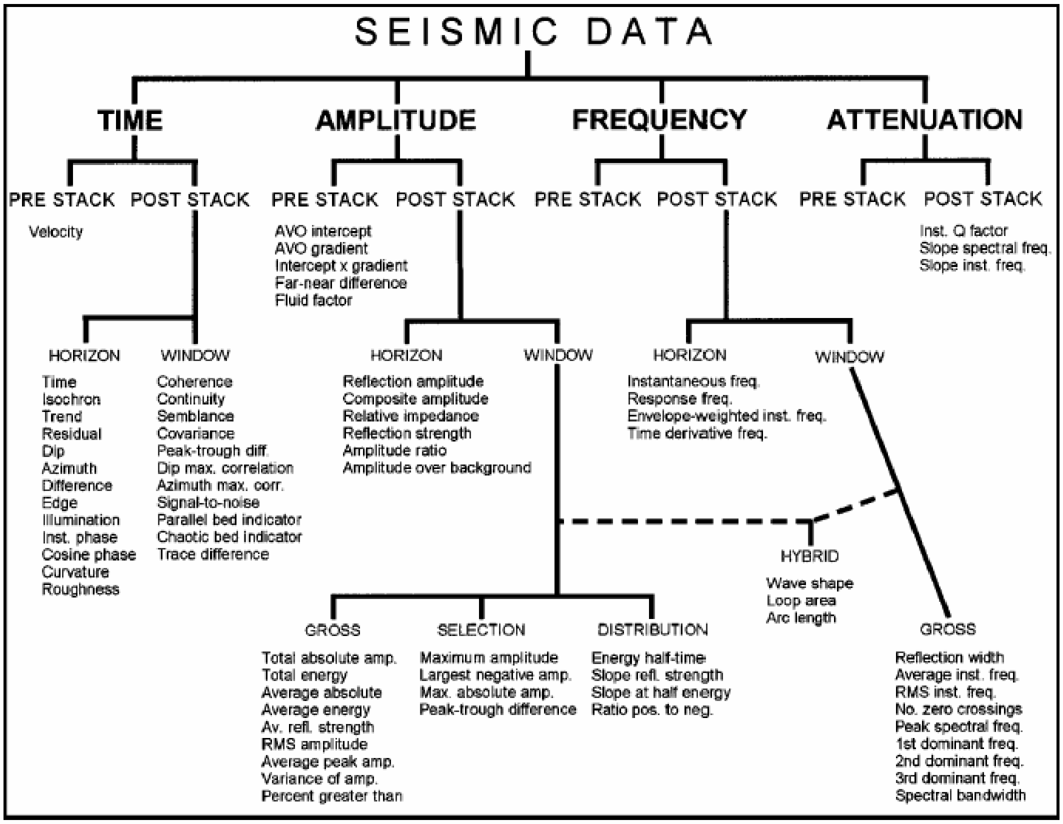
The v changes most at very small quantity of gas.
⇒ This . led to very many dry holes!

What would be the indicator of fiz-gas? Nobody knows.

SEISMIC ATTRIBUTES

SINGLE ATTRIBUTES:

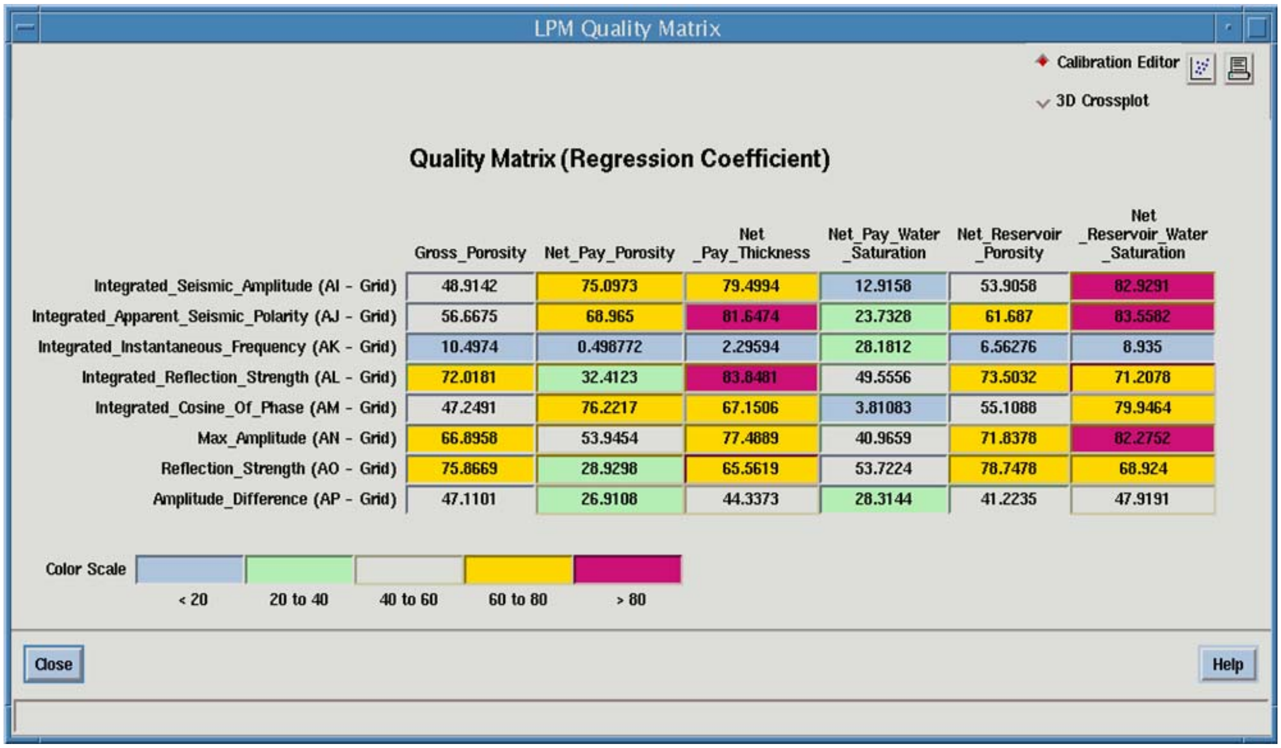
Seismic attributes: any measurement based on seismic data. Any measurement derived from seismic data, usually based on measurements of time, amplitude, frequency, and/or attenuation. Generally, timebased measurements relate to structure, amplitudebased ones to stratigraphy and reservoircharacterization, and frequency-based ones /while often not clearly understood/ to stratigraphy and reservoir characterization. Attenuation measurements are usually very uncertain. Measurements are usually based on stacked or migrated data, but prestacked data are used in determining *stacking velocity* /q.v./, AVO /*amplitude variation with offset*, q.v./, and other attributes. Because there are many ways to arrange data, attributes constitute an open set, and because they are based on so few types of measurements, attributes are generally not independent. Attributes are useful to the extent that they correlate with some physical property of interest. The primary usefulness of attributes is that they sometimes help one to see features, relationships, and patterns that otherwise might not be noticed. Seismic measurements usually involve appreciable uncertainty and do not relate directly to any single geologic property. With so many geologic variables, correlation with a particular property in one situation is apt to not hold in another situation. Attributes generally respond to a variety of geologic situations and a geologic change may mean a change in the correlation. The problem is determining the limits to an observed correlation, especially when we do not understand the underlying physics—How wide ranging is a correlation valid? During a Direct Detection Symposium in 1973, Miller Quarles presented numerous processing schemes to enhance hydrocarbon signatures; **in response to a question about the ''scientific basis of all these attributes,'' he responded, ''We don't know yet, but remember, (we) invented them.'' Unfortunately we still do not understand how to relate most seismic attributes to geologic causes and situations.** Among the ways we calculate attributes are smoothing and averaging over windows of various sizes, finding residuals, peak values, measuring the distribution within a window /mean, median, kurtosis, percent greater/smaller than a threshold, sums, residuals, scatter, etc./, continuity, edges, smoothness, linearity or curvature, gradients or other derivatives, absolute values, polarity changes /zero-crossings/, peak-trough differences, etc. Relations may be measured over windows /spectra, correlation, semblance, covariance/, etc. Attributes can be measured along a single trace or throughout a volume or in other ways. The first attributes identified as such were the 1D complex-trace attributes of envelope amplitude, instantaneous phase, instantaneous frequency, and apparent polarity /see *complex-trace analysis*/ and acoustic impedance /or velocity/ determined by *inversion* /q.v./. Attributes may be measured along a defined /picked/ surface /horizon attributes/ such as *amplitude extraction, dip magnitude, dip azimuth, artificial illumination*, and *coherence*/q.v./. *Hydrocarbon indicators* /q.v./ are attributes. Attributes can be combined to make new attributes. Transformations of attributes are sometimes given physical-property names /porosity, fluid saturation, lithology, stratigraphic or structural discontinuity, etc./, usually based on local crossplots or local correlations with borehole-log or other measurements; they may be reasonable approximations locally but they are apt to give erroneous values under different circumstances. [2]



Seismic **attributes**. ‘‘Windows’’ can be constant time intervals, constant intervals hung from one horizon, or intervals between horizons.

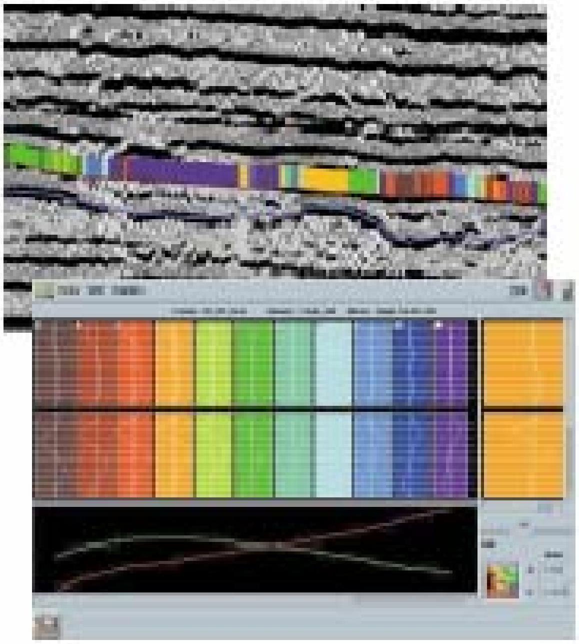
COMBINED MULTIATTRIBUTE ANALYSIS BASED ON GEOSTATISTICS

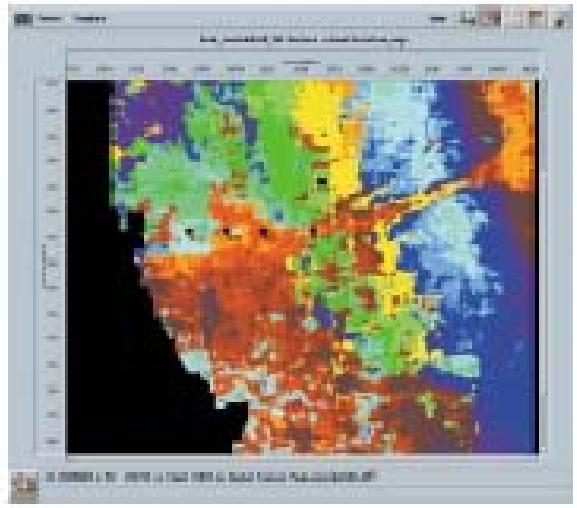
The method combines geostatistics and multi-attribute transforms integrating the seismic data with the well log. The computed output of the process can be petrophysical or any other reservoir parameter map (‘property grid’) with statistically estimated uncertainty grid.

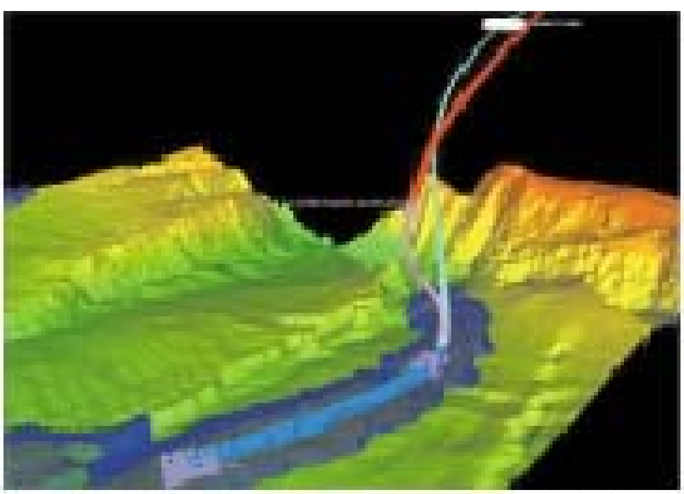


	Gross_Porosity	Net_Pay_Porosity	Net _Pay_Thickness	Net_Pay_Water _Saturation	Net_Reservoir _Porosity	Net _Reservoir_Water _Saturation
Integrated_Seismic_Amplitude (AI - Grid)	48.9142	75.0973	79.4994	12.9158	53.9058	82.9291
Integrated_Apparent_Seismic_Polarity (AJ - Grid)	56.6675	68.965	81.6474	23.7328	61.687	83.5582
Integrated_Instantaneous_Frequency (AK - Grid)	10.4974	0.498772	2.29594	28.1812	6.56276	8.935
Integrated_Reflection_Strength (AL - Grid)	72.0181	32.4123	83.8481	49.5556	73.5032	71.2078
Integrated_Cosine_Of_Phase (AM - Grid)	47.2491	76.2217	67.1506	3.81083	55.1088	79.9464
Max_Amplitude (AN - Grid)	66.8958	53.9454	77.4889	40.9659	71.8378	82.2752
Reflection_Strength (AO - Grid)	75.8669	28.9298	65.5619	53.7224	78.7478	68.924
Amplitude_Difference (AP - Grid)	47.1101	26.9108	44.3373	28.3144	41.2235	47.9191

Example to multiattribute statistical analysis: the red cells show higher than 80 % correlation between the reservoir parameters and the seismic attributes! It means, that we can estimate the reservoir parameters away from the borehole.







These figures represent the 2D-3D visualization of a fluvial channel based on multiattribute analysis of the well-log and seismics.