Chapter Two

Pore Pressure

Oilfield Geomechanics
RTS Geomechanics Services

Topics

- **Pressure-generating mechanisms**
  - Stress and undercompaction
  - Thermal processes and unloading
  - Geological effects
- **Pore pressure prediction methods**
  - Trendline methods
  - Effective stress methods
  - Centroid and buoyancy
- **Data for pore pressure prediction**
  - Seismic
  - Log-data
  - Drilling data
  - Measurements
- **Pore pressure and wellbore stability**
  - Traditional well design
  - 'Pressure' cavings

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Objectives

At the end of this chapter you should be able to

- Explain at least two sources of abnormal pressure
- Describe the limitations of some of the more traditional pore pressure prediction methods
- Recommend the most useful data for pore pressure estimation
- Calculate pore pressure using standard trend line techniques

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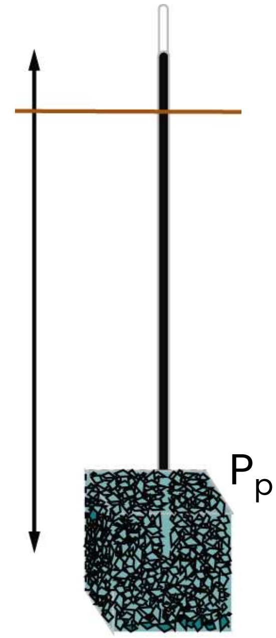
What is Pore Pressure?

- **Equivalent to hydraulic potential measured with respect to Earth's surface**
- **Assumed to be uniform in a small volume of interconnected pores**
- **Directionless**



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Unlike Stress, pore pressure is directionless

Pore pressure at a specific depth represents the average scalar value of that acting within an interconnected pore space. The value of pore pressure is equivalent to a hydraulic potential measured with respect to Earth's surface (actually the free water level).

Hydrostatic pore pressure corresponds to a column of fluid in equilibrium with the Earth's surface (free water level) and implies an open and interconnected pore and fracture network from the depth of interest to the surface.

$$P_p^{hydro} = \int_0^z \rho_w(z) g\,dz \approx \rho_w g z_w$$

In a confined pore volume with sufficiently low permeability (or a dynamic system), pore pressures can exceed or be less than hydrostatic values. Conceptually, the upper bound for pore pressure is the overburden stress. Because of the extremely low tensile strength of rocks pore pressure will always be less than the least principal stress, and may sometimes be limited by leakage along faults.

Hydrostatic ('Normal') Pore Pressure

- **"Hydrostatic pressure" is in communication with the surface free water level**
  - Offshore – sea level
  - Onshore – water table
- **Hydrostatic pressures depend on fluid density**
  - The density of formation water varies with the concentration of dissolved solids, mostly salt
  - Salinity varies as a function of:

    Connate water history
    Temperature
    Diagenesis
    Proximity to salt bodies
    Osmosis

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Hydrostatic pressure, often called 'normal' pressure, is pressure in communication with the free water level. Offshore, this is the sea level. Onshore, the water table.

The hydrostatic pressure also depends on the fluid density which in turn depends on the concentration of dissolved solids. The most important dissolved solid being salt.

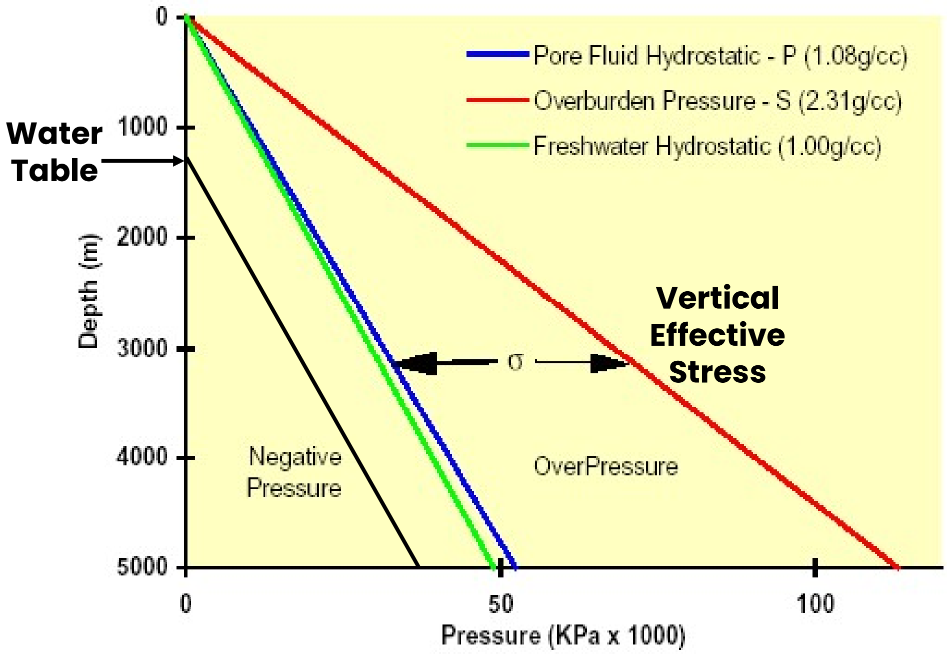
Formation water salinity depends on a number of factors including connate water history, temperature, diagenesis, salt proximity and osmosis.

Connate Water – water trapped in the pores of a rock during the formation of the rock.

Q: What is connate water?

A: Water trapped in the pores of a rock during the formation of the rock.

Absolute Pressure vs. Depth



One way to plot formation pressures is to plot absolute pressures versus depth.

Hydrostatic pressures, pressures in equilibrium with the free water level near the surface, are approximately 10Kpa/1000m or 0.43psi/ft. Hydrostatic pressures may vary depending on the density of the fluid.

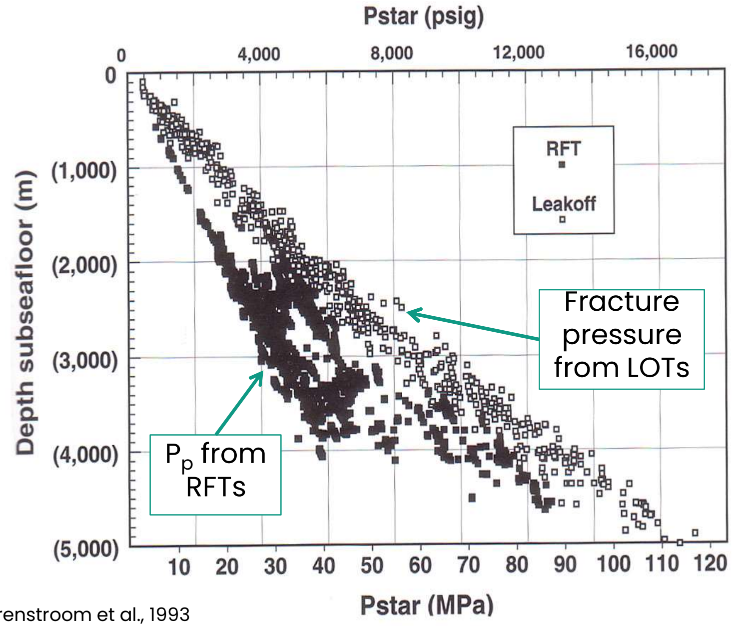
$$P_p^{hydro} = \int_0^z \rho_w(z) g dz \approx \rho_w g z_w$$

Over pressures are any pressure over, and under-pressures (or negative pressures) under, hydrostatic.

Local under- and overpressures, still in hydrostatic equilibrium with the free water level, may develop due to differences between the water table and the reference level (drill floor or ground level). Typically these aquifer effects happen more strongly onshore.

Pressure vs. Depth

North Sea Central Graben Example



Gaarenstroom et al., 1993

- At shallower depths Pp is mostly hydrostatic. Why?
- Deeper in the basin high overpressures are commonly seen. Why?
- At intermediate depths overpressure development is more variable. Why?
- Overpressure appears to be limited by the fracture pressures. Why?

This figure shows absolute pressure (RFT's) and Leak-off (LOT's) measurements from a number of wells in the Central Graben of the North Sea.

Gaarenstroom, L., Tromp, R.A.J., de Jong, M.C., and Brandenburg, A.M., 1993. Overpressures in the Central North Sea: implications for trap integrity and drilling safety. In: Parker, J.R. (ed.), Petroleum Geology of North-West Europe: Proceedings of the 4th Conference; Geol. Soc. Lon, p1305-1313.

Q: In this, and indeed many, petroleum basins it is observed that at shallower depths pore pressures are mostly hydrostatic. Why?

A: Sediments are more permeable and not sealing

Q: Deeper in the basin high overpressures are commonly seen. Why?

A: Two reasons. More pressure is often generated by thermal mechanisms. Also, rocks are tighter and seal better

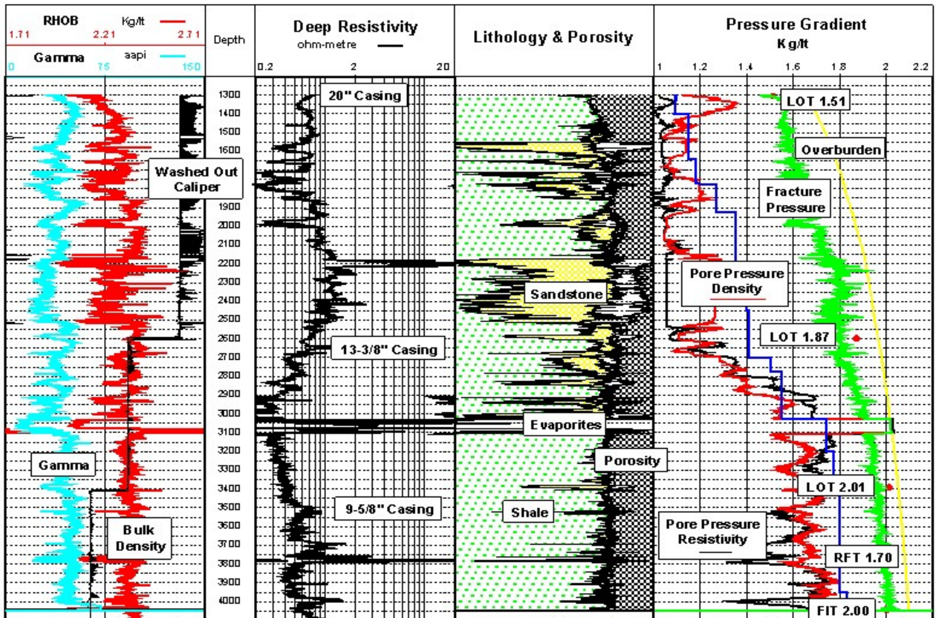
Q: At intermediate depths overpressure development is more variable. Why?

A: In this example from the N.Sea the distribution of permeable sands and seals vary laterally.

Q: Note that the overpressure appears to be limited by the fracture pressure as represented by the LOT's. Why?

A: Pore pressure exceeding the fracture pressure will hydraulically fracture the formation and fluids and pressure leak-off naturally. The fracture pressure therefore puts an upper bound on the pore pressure.

Equivalent Mud Weight Plot



(Temsah Field, Nile Delta, Egypt - Mazzoni,T. et al., 1997)

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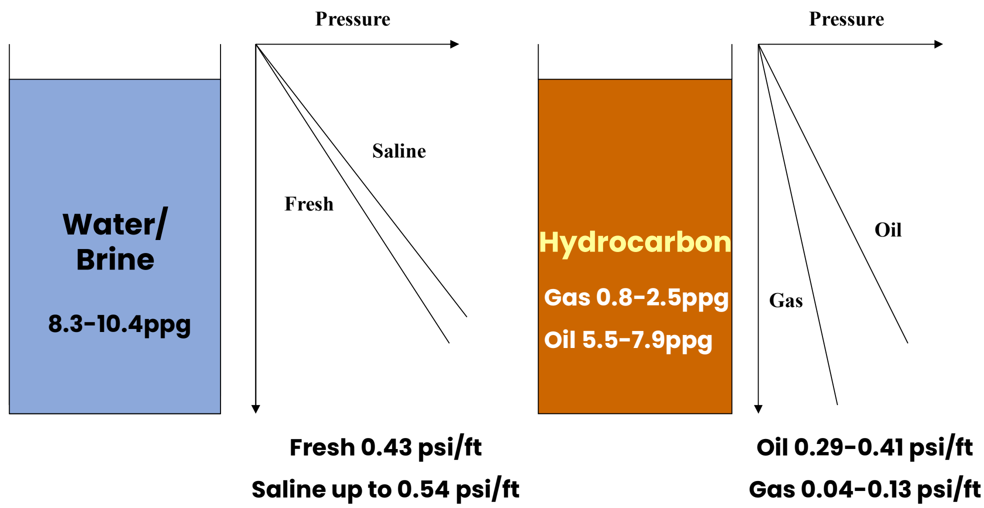
Equivalent mud weight plots are more commonly used to aid well design (casing setting depths) and monitor mud weights compared to pore pressure while drilling. This plot from the Nile Delta, show how the mud weight (blue) is being kept above the pore pressure (red or black) and below the fracture pressure (green).

Mazzoni,T., Wahdan,T.,Bassem,A., and Ward,C.D., 1997. Real-time Pore & Fracture Pressure Prediction with FEWD in the Nile Delta. Paper SPE 37669 presented at the 1997 SPE/IADC conf. In Amsterdam, 4-6 March 1997.

Pressure Gradients



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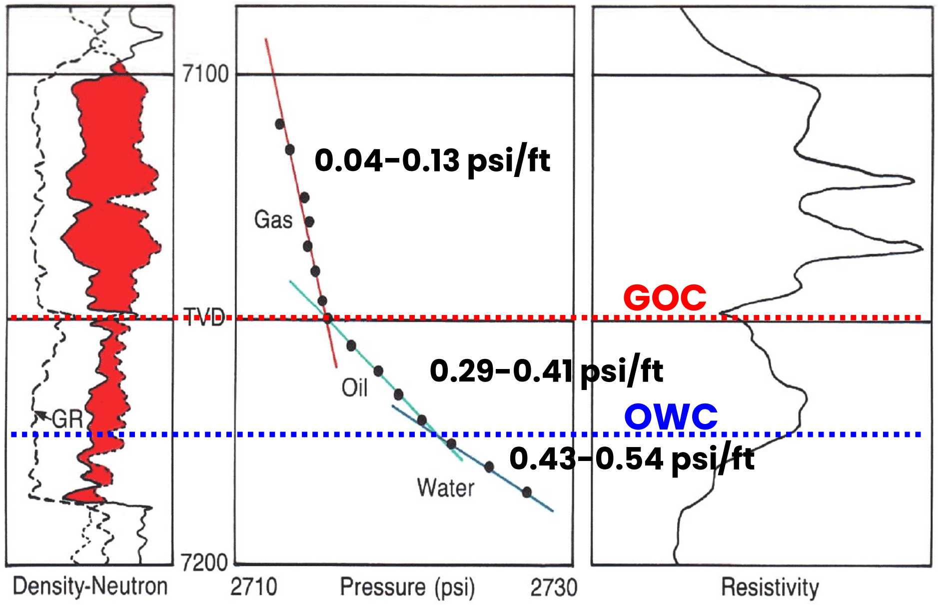
Reservoir engineers are interested in fluid gradients. Water has a fluid gradient of 0.43-0.54psi/ft (1.00sg), however, oil and gas are lighter and have much steeper pressure gradients, particularly gas.

Pressure Gradients for Different Fluid Types



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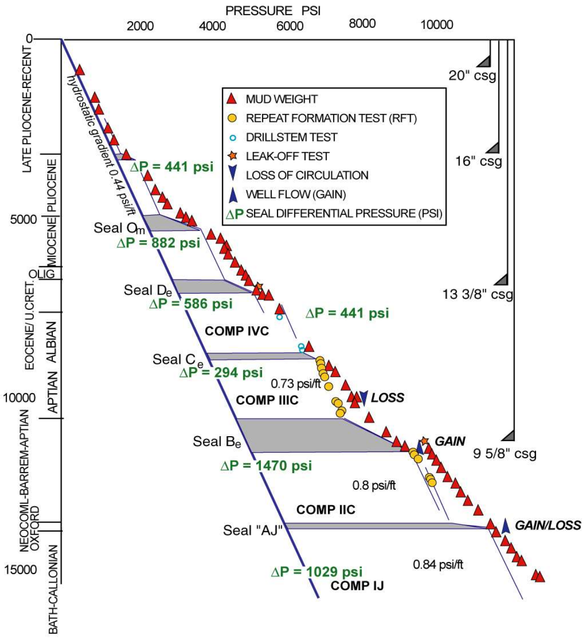
Reservoir engineers use fluid gradients, determined accurate formation pressure measurements, to help determine fluid and hydrocarbon types and contacts with a reservoir.

In this example gas fills the top of the reservoir and has a steep pressure gradient. Between 7150 and 7157ft is an oil layer with a less steep pressure gradient. At the bas of the reservoir is a water layer with a local hydrostatic gradient. Note that for a reservoir engineer a hydrostatic pressure refers to the local reservoir water pressure and not necessarily the hydrostatic pressure in equilibrium with the free water level.

GOC – Gas-Oil contact
OWC – Oil-Water contact

Overpressured Seals and Compartments

Nile Delta, Egypt



Model assumes that pressures are in equilibrium in the seals (shale) and reservoirs (sand). Is this correct?

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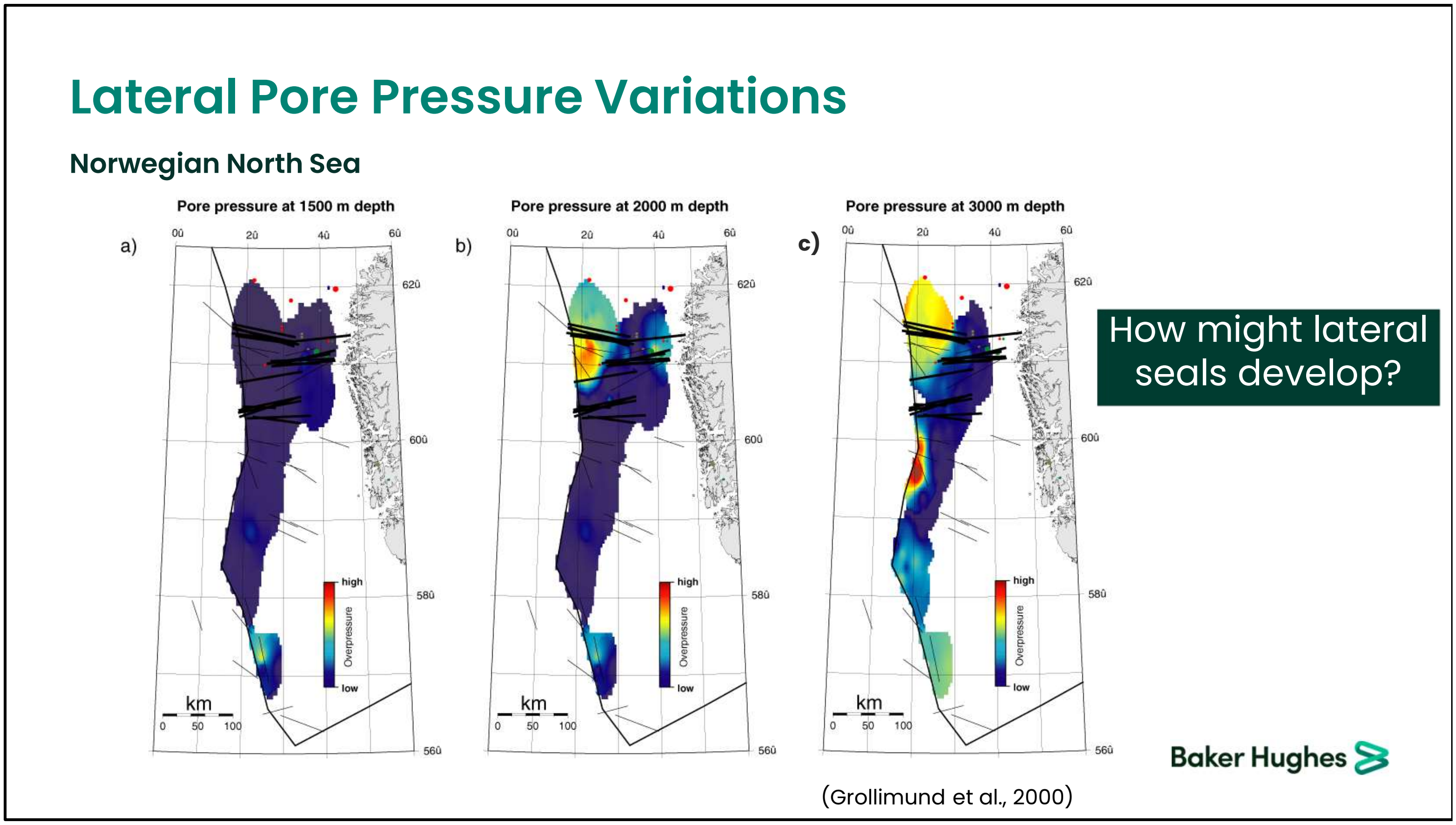
Some think of pore pressures in terms of compartments and seals. Within a compartment pore pressures are in local hydrostatic equilibrium, but between compartments (in the seal) a steeper pressure gradient exists.

Pore pressure, mud weight and related parameters in the Mango-1 well in northern Egypt. Note that the pore pressure measurements in Compartment II_C & III_C confirm that pore pressure increases with a hydrostatic gradient within this compartment even though the absolute value of pore pressure is well above hydrostatic values. Pore pressure values in other compartments are interpreted to increase with hydrostatic values, in some cases at values estimated based on mud weights (for example, below Seal AJ and in the Tertiary section at shallow depth).

Q: The model shown assumes that adjacent seal (shale) and

compartment (sand) pressures are in equilibrium. Is this correct?
A: Probably not. As we will see later centroid and buoyancy effects can lead to higher pressures at the top of the reservoir compared to the surrounding shales.

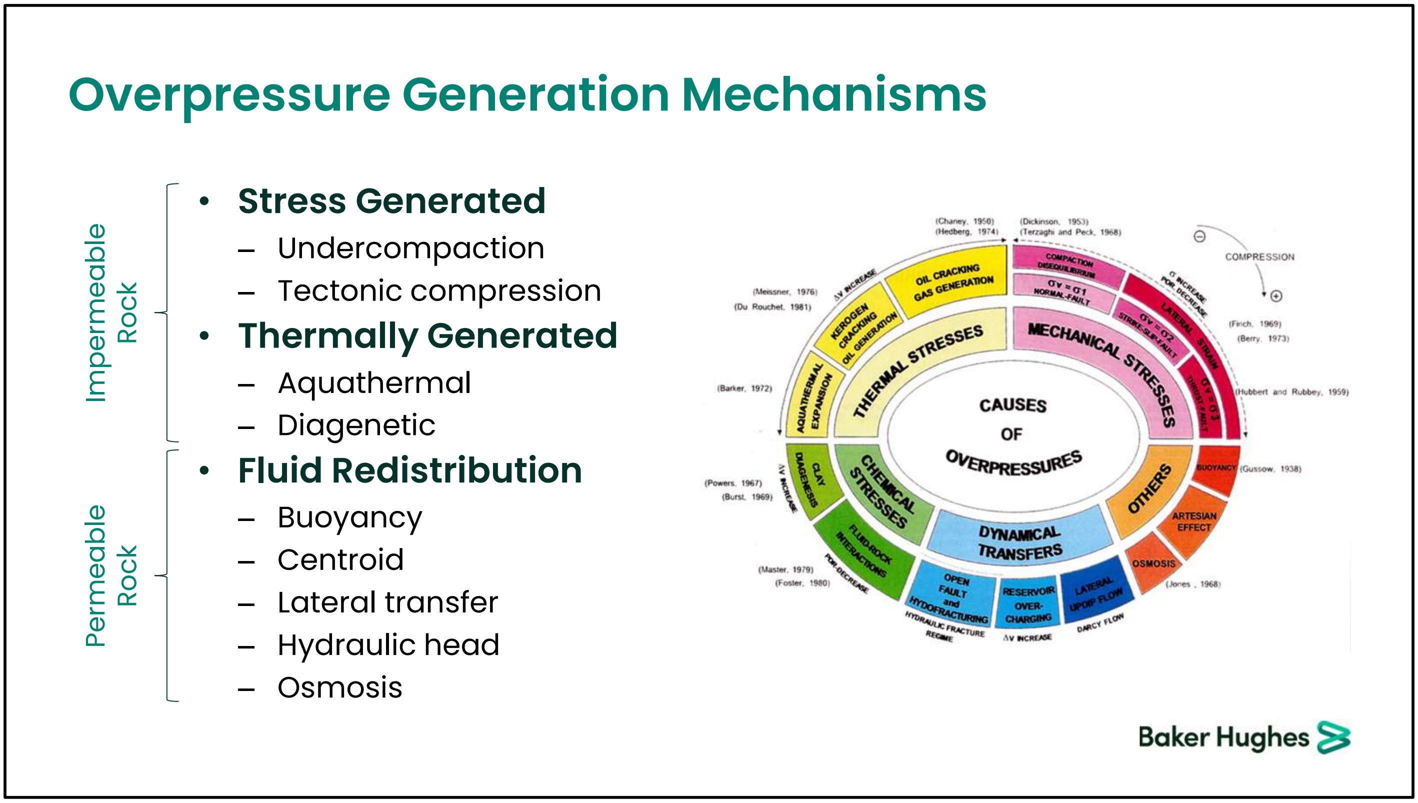


Seals and compartments may occur laterally too.

Spatial variations of pore pressure at various depths in the Norwegian sector of the northern North Sea. Note that at 1500m depth, near hydrostatic values of pore pressure are observed almost everywhere. At greater depths, regions of elevated pore pressure are observed to develop in several areas. “Hard” overpressure (i.e., values near lithostatic) are observed in only a few restricted areas (after Grollimund et al., 2000).

Q: How could lateral seals develop as opposed to vertical seal?
A: Through permeability barriers. These could be seidmentary changes but are often, as in this case in the N.Sea, due to faults.

Pore Pressure Generating Mechanisms



Overpressure always wants to go back to equilibrium. So how is overpressure generated? Over the years more than a dozen mechanisms have been put forward and are summarized in this figure. Here lies one of the biggest problems in pore pressure prediction – which mechanisms apply where.

To simplify things we can group them into three main categories which will also help us recognize the different mechanisms and ultimately find ways to predict pore pressure.

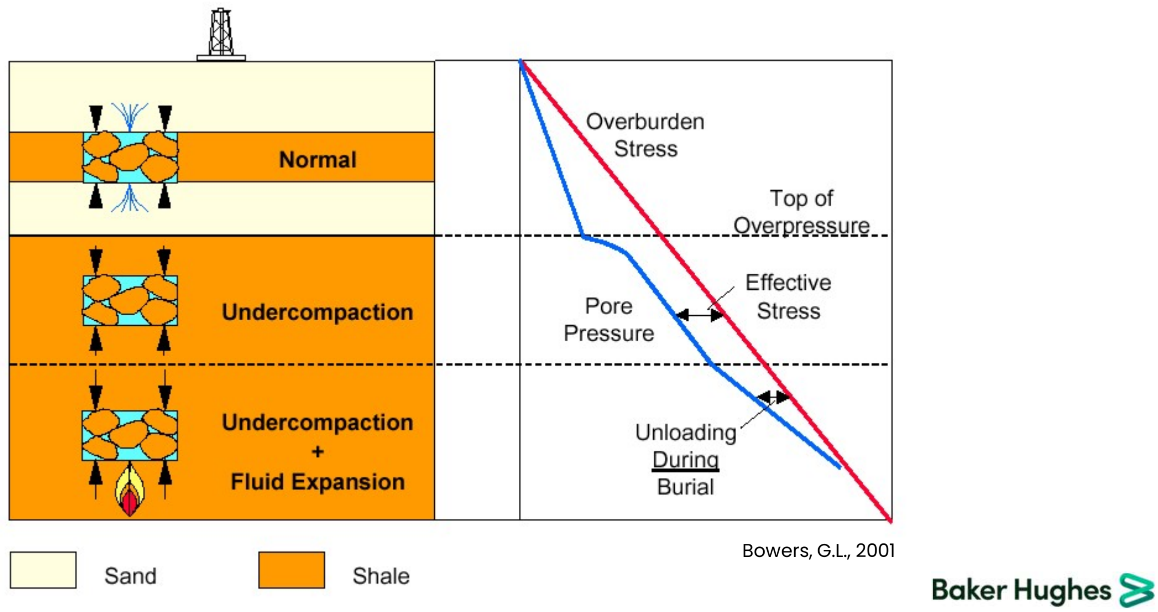
Burial or tectonic stress is a major overpressure-generating mechanism, particularly in rapidly subsiding basins and active tectonic areas.

Thermal and diagenetic changes can also generate overpressure *in-situ* when thermal and chemical conditions allow.

Once generated, overpressure wants to equilibrate back to hydrostatic. In this way fluid redistribution in permeable zones can locally alter the overpressures.

(Figure: Grauls. D, edited Overpressure in petroleum Exploration; Proc. Workshop, Pau, April 1998)

Multiple Overpressure Generation Mechanisms



Not only are there a number of different possible over- or underpressuring mechanisms possible. It is also possible, indeed common, to have more than one mechanism in the same basin or well.

This example shows hydrostatic pressure in the sand dominated upper section, then an interval where overpressure has developed from undercompaction, and deeper down even higher overpressure generated by thermal mechanisms. On top of this, fluids can be redistributed within permeable systems.

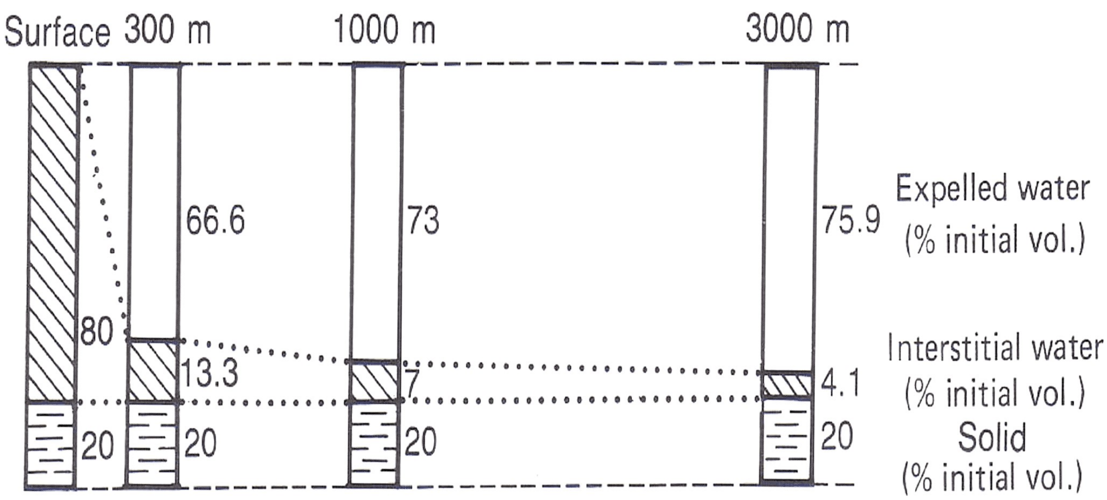
It is not uncommon to find two, three or more possible overpressure-generating mechanisms occurring in the same well.

Bowers, G.L., 2001. Determining an Appropriate Pore-Pressure Estimation Strategy. OTC13042, paper presented at the 2001

Offshore Technology Conference held in Houston, Tx, 30 Apr – 3 May 2001.

Compaction

Expulsion of Water in Response to Stress



Mouchet, J.P. and Mitchell, A., 1989

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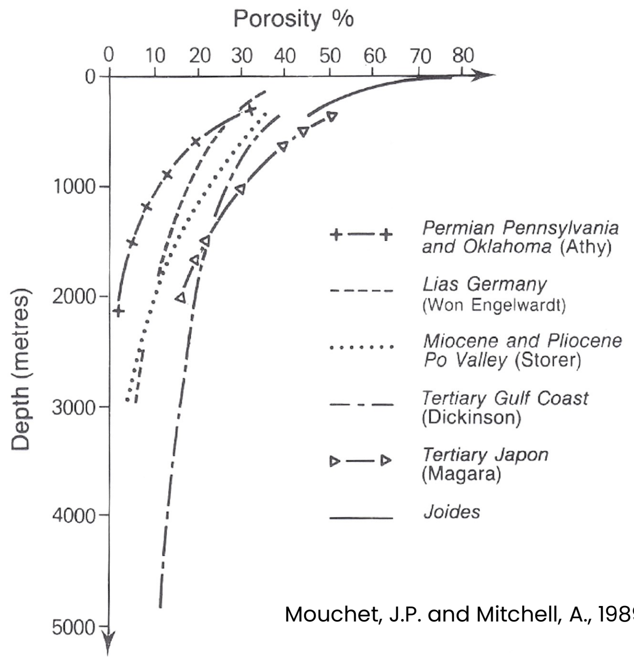
Compaction is the expulsion of water in a porous media in response to mean stress. This is usually predominantly due to burial stress but could be tectonic. During compaction it is assumed that pore pressures remain hydrostatic.

Initially, when deposited on the seabed, sediments are highly porous. Shales and carbonates may have 70-80% porosity (water), sands typically less (35-40%). Porosity loss due to compaction is rapid at first but takes much higher stresses to reduce porosity at higher stresses or depths.

Mouchet, J.P. and Mitchell, A., 1989. Abnormal pressure while drilling. Elf Aquitaine Manuals Techniques, No 2.

Typical Compaction Curves in Shale

If these are all shale, why are the curves different?



Mouchet, J.P. and Mitchell, A., 1989

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Shale compaction curves plotted against depth show the rapid porosity loss at shallow depths, with porosity loss becoming retarded with depth. The different curves represent shale compaction curves from a number of different basins.

Similar curves could be represented by seismic, log or drilling data, which are proxy's for shale porosity. When plotted on a log scale and a log linear 'normal compaction trend' (NCT) is established from this trend. Deviation from this trend are the basis for most pore pressure calculation methods.

Mouchet, J.P. and Mitchell, A., 1989. Abnormal pressure while drilling. Elf Aquitaine Manuals Techniques, No 2.

Q: So why are the curves so different?
A: Many possible reasons. Different shale types; Different overburden – offshore less than onshore; Different stress

history – The Oklahoma example has been uplifted; Different pore pressure – this figure assumes all the examples are normally pressure whereas some could be overpressured or even underpressured.

Undercompaction

- **Undercompaction occurs when sediment dewatering is inhibited during burial. This happens if either**
  - New sediments are deposited before fluid has had chance to drain, i.e. rapid burial
  - Seals and barriers to fluid flow form
- **During undercompaction pore fluids are trapped, porosity is retained, and further compaction is slowed or prevented**
- **As burial continues pore fluids support part of the weight of the overlying sediments and the fluid becomes overpressured**

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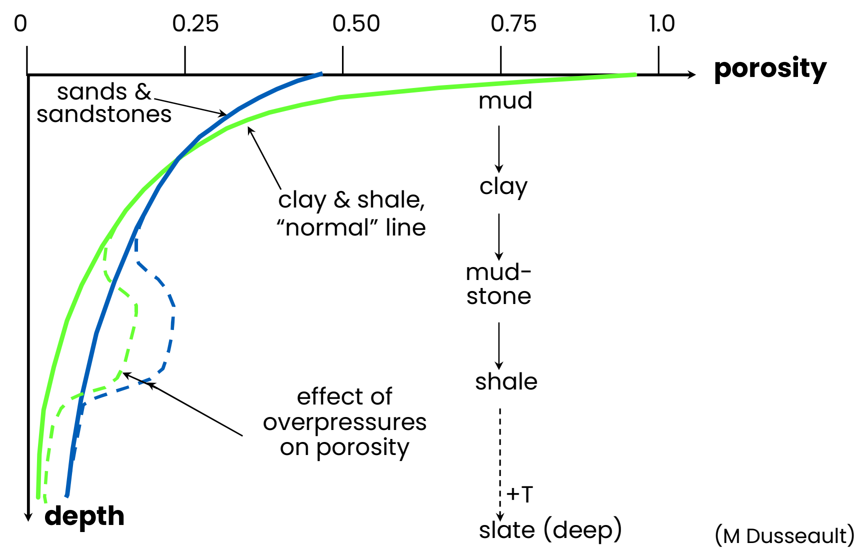
Undercompaction, sometimes called disequilibrium compaction, occurs when burial stress is added to the rock and dewatering is inhibited. This can happen due to the rapid deposition not giving enough time for the fluids to drain, or due to the formation of seals and barriers to fluid flow.

As burial continues the pore fluids start to support part of the weight of overlying sediments, instead of the grain-to-grain contacts, and the fluid becomes overpressured. Also, as a result of undercompaction porosity is retained and the rock appears to be less compacted than one would expect at a given depth, hence the term undercompaction for this overpressure-generating mechanism.

Porosity and Depth



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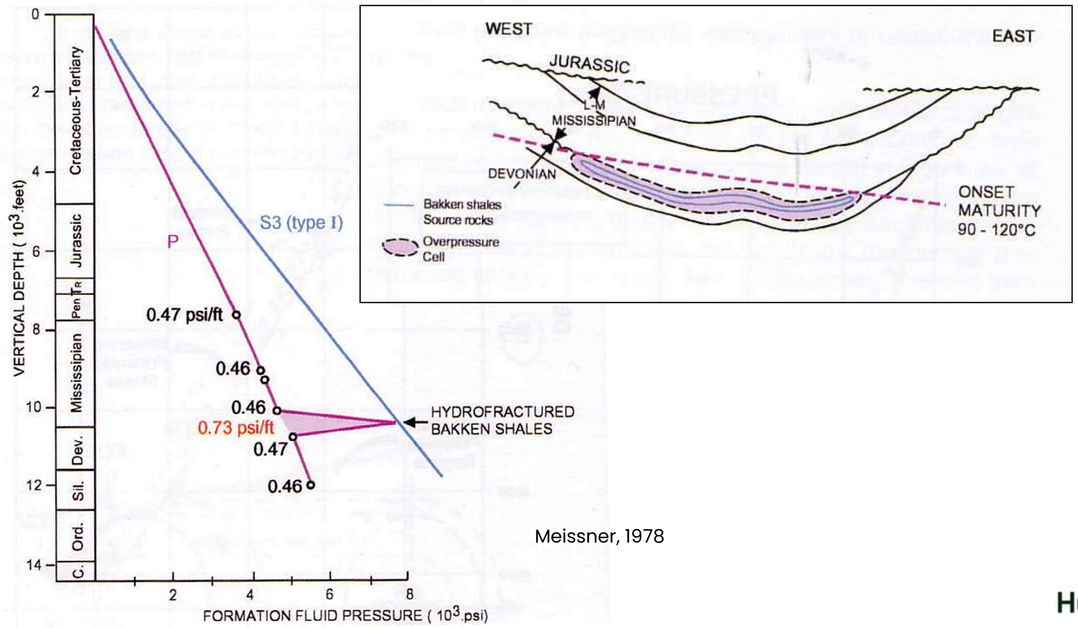
As rocks are buried and fluids are expelled in response to burial stress rocks compact (solid lines). If fluids are retained, either due to rapid burial or the formation of a seal, then porosities are preserved (dashed lines). The fluids start to take up part of the weight of the overburden and overpressure develops.

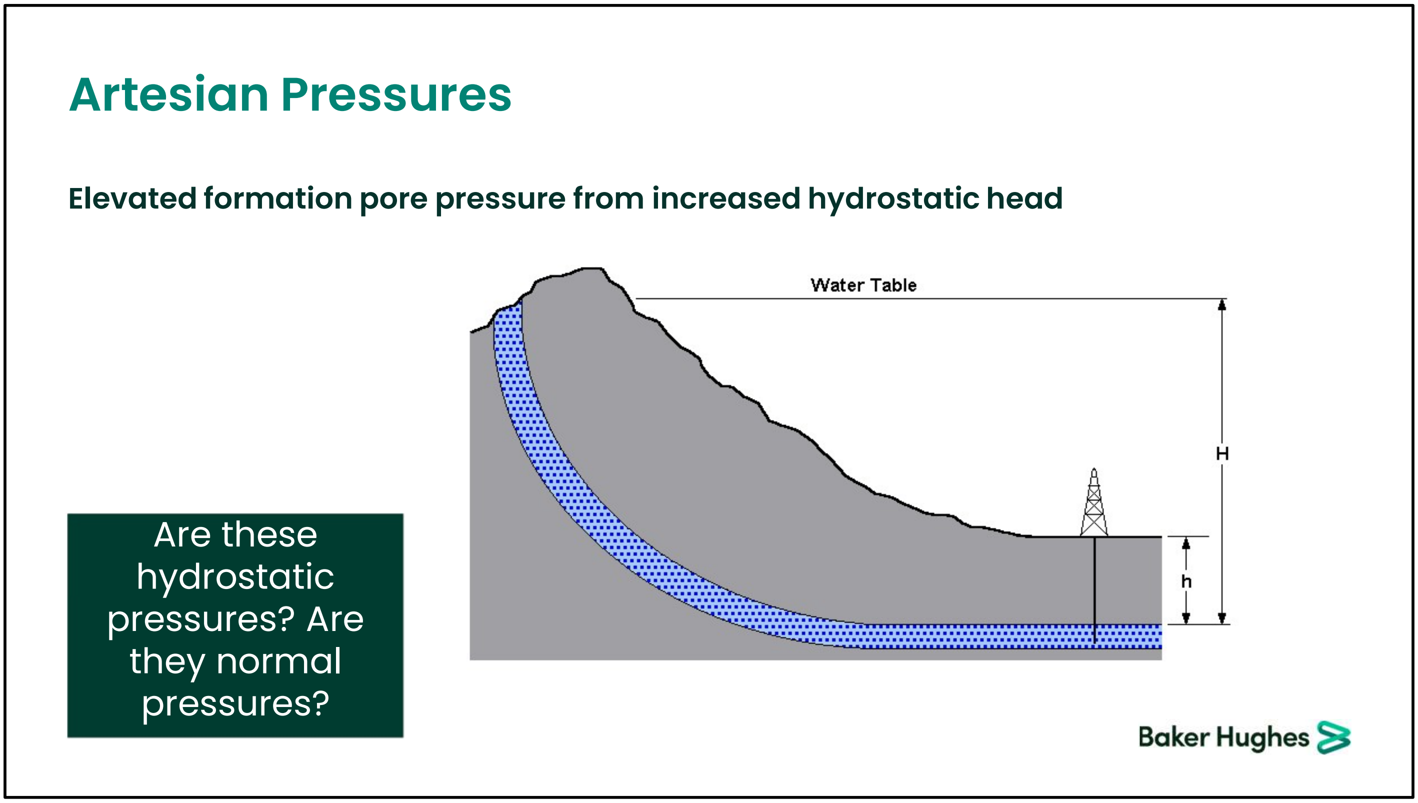
Bakken Shale, USA



Meissner, 1978

Relation of fluid pressures to oil generation in Antelope Filed, Williston Basin, North Dakota (Meissner 1978). In; Hunt 1979

Q: What could be generating the overpressure in the Bakken Shales?
A: It is hard to envision anything but hydrocarbon generation could do this. The Bakken is a source actively generating hydrocarbons in the center of the basin. Where it is currently generating hydrocarbons it is overpressured but only in the shale and not the bounding reservoirs.

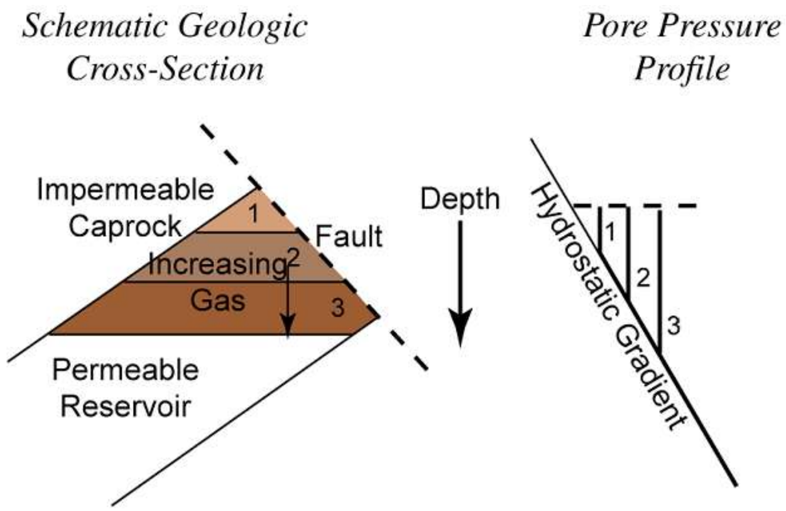


Artesian pressure are elevated pressures, relative to the land surface (rig floor), from an increase in hydrostatic head. This usually occurs onshore where the water table is elevated relative to the rig floor, typically in areas with a lot of topographic relief.

Q: Are these hydrostatic (‘normal’) pressures?
A: Depends on the reference. Yes, compared to the water table. No, for the driller.

Hydrocarbon Buoyancy Effects

Hydrocarbon Columns Create Local Overpressure



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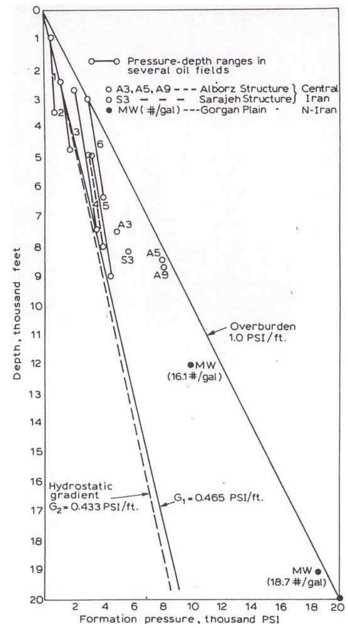
Because hydrocarbons, particularly gas, are less dense than water they are buoyant and tend to float to the top of a permeable reservoir with gas settling above oil, and oil above water. The steeper pressure gradient of the hydrocarbons results in local overpressure in the reservoir the magnitude depending on hydrocarbon fluid density and column height.

In some cases, especially overpressured reservoirs with thick gas columns the pressure at the top of the reservoir may be sufficient to breach the seal and thereby limit the volume of hydrocarbons in the reservoir. For an exploration prospect, particularly an over pressured gas prospect with a lot of structural relief in the reservoir, it may be prudent to drill the structure first in a downdip location to reduce the drilling risk and more quickly evaluate the reservoir potential.

Hydrocarbon Buoyancy - Iran

Large gas columns combined with very large structures leads to severe overpressures at the top of the reservoirs



Fertl, W.H., 1976

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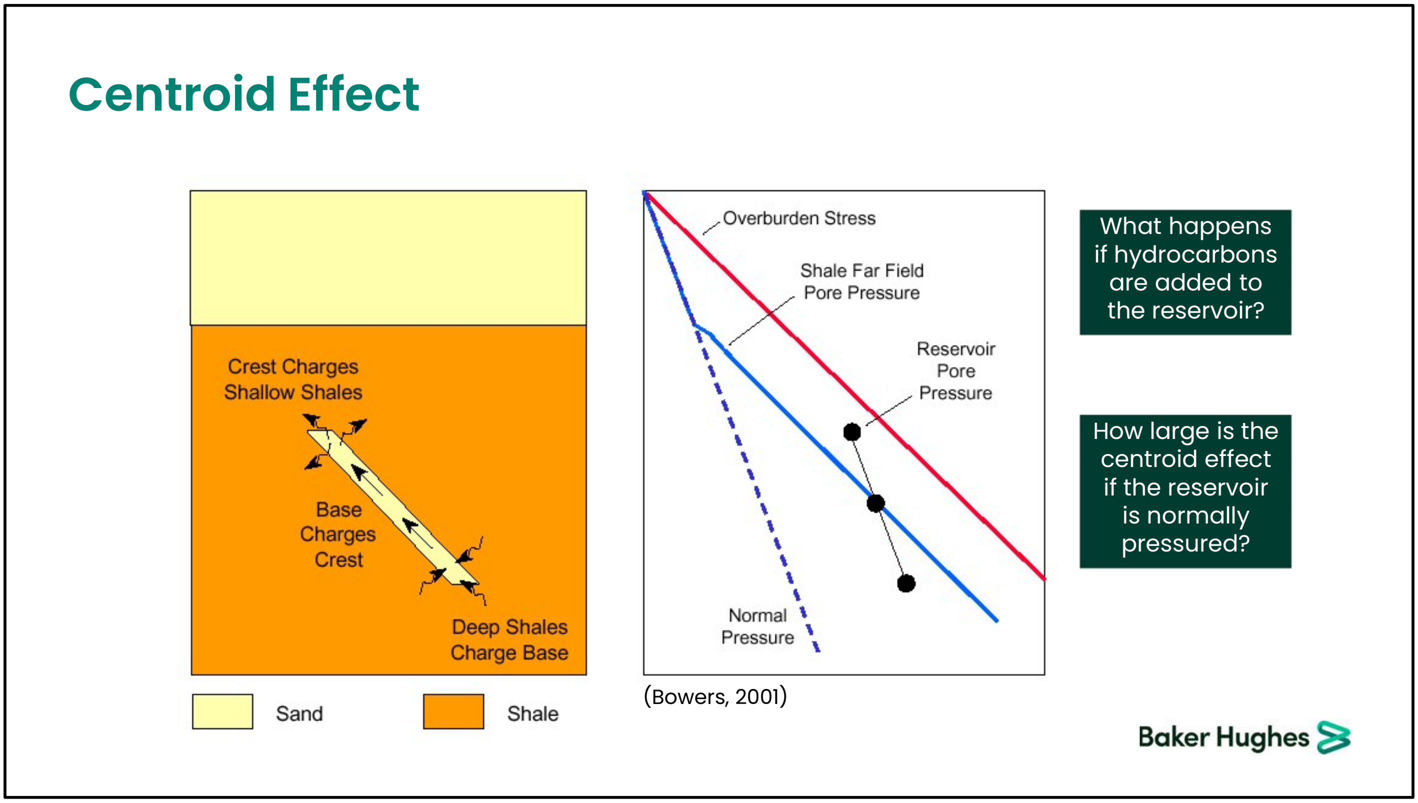
Hydrocarbon buoyancy effects can be profound. In this example from Iran, large gas columns combined with very large structures have combined to give severe overpressures at the top of the reservoirs, even though they have a normally pressured aquifer.

Unfortunately reservoirs like this are not so common nowadays.

Fertl, W.H., 1976. Abnormal Formation Pressures

Q: If reservoir and shale pressure can be so different, what does this say about the methods we typically use for pore pressure prediction?
A: All standard methods calculate pressure from logs in shales and it is assumed the reservoir has the same pressure as the bounding shale. However, reservoir pressures can be a lot different from the shales – in this

case due to gas buoyancy.



The “centroid” effect is an up-dip transfer of reservoir pressure within a permeable reservoir, trapped within a non-permeable formation (shale). Within a permeable layer formation pressures are in equilibrium along a local hydrostatic gradient parallel to the ‘normal’ pressure. If this layer is embedded within an impermeable shale holding a pressure gradient then the pressure in the reservoir will only be in equilibrium at the mid point, the ‘centroid’. Updip from the centroid, reservoir pressures will be higher than shale pressure, and downdip the shale pressures higher than the reservoir pressures.

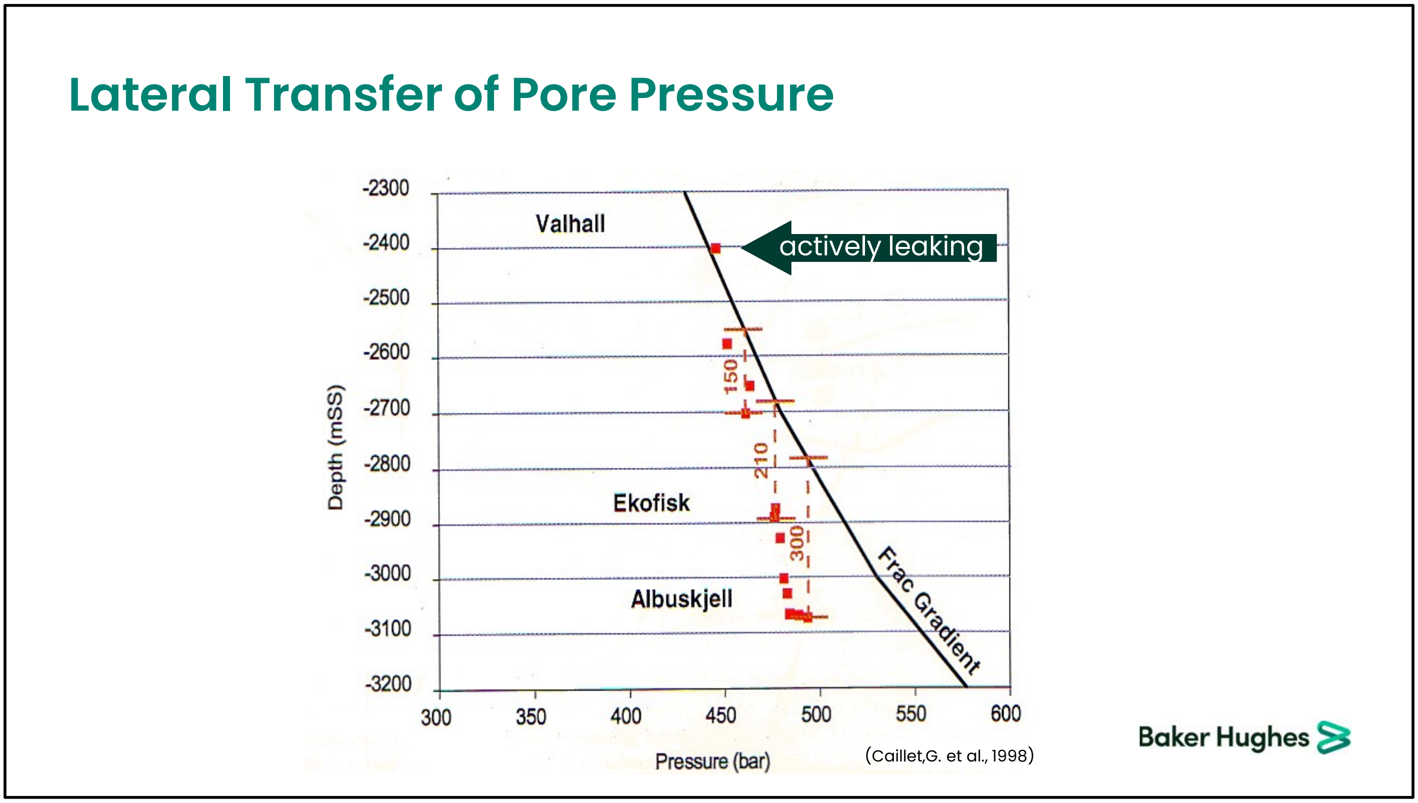
The magnitude of this effect depends on the background pore pressure and the structural relief. Like the buoyancy pressures, drilling the top of structures poses the most risk.

Bowers, G.L., 2001. Determining an Appropriate Pore-Pressure Estimation Strategy. OTC13042, paper presented at the 2001

Offshore Technology Conference held in Houston, Tx, 30 Apr – 3 May 2001.

Q: What happens if hydrocarbons are added to the reservoir?
A: Pressure will increase further at the top of the reservoir due to an additional buoyancy effect. This may be partially offset by a deepening of the centroid point.

Q: How large is the centroid effect if the reservoir is normally pressured?
A: If the reservoir pressure ans shales are hydrostatic then there is no centroid effect. There will still be a buoyancy effect.



Lateral transfer is really like a big centroid, except that pressure is transferred across compartments, typically fault bounded. In this example a number of fields in the greater Ekofisk area, Norwegian North Sea are clearly in pressure communication even though they are separate structures. The shallowest field, Valhall, has a pore pressure close to the fracture pressure and is actively leaking hydrocarbons from the top of the structure (there is a large gas cloud). That pressure and the leakage appears to be controlling the reservoir pressure in all the other fields in this area.

Left – Plot of pore pressures calculated at the top of structures vs. depth in the chalk of the Greater Ekofisk area.
Caillet,G. et al., 1998. Overpressures in Petroleum Exploration, Pau.

Right – Plot of the ratio of Pp/Sv vs. depth in the chalk of the

Greater Ekofisk area.

Caillet,G. et al., 1997. Petroleum Geoscience, 3, 33-42.

Pore Pressure Prediction Methods

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Trend-line Methods

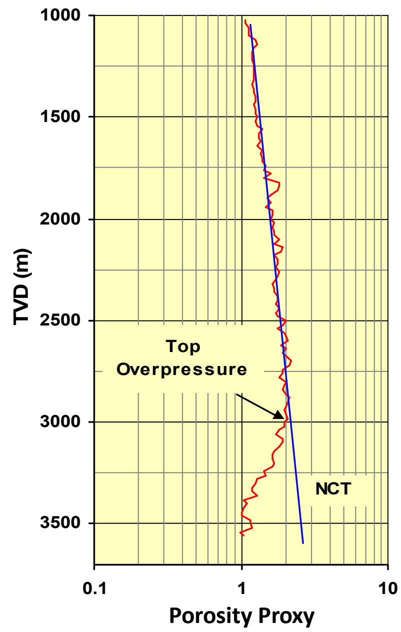
- **Require the establishment of a normal trend-line**
  - Normally pressured compaction curve (NCT)
- **Applies only to 'clean' shales**
- **Many different methods**
  - Early popular methods include Ratio, Equivalent Depth, & Eaton
  - Many other methods, many proprietary
- **Applicable to many types of data**
  - d-exponent, sonic, velocity, resistivity, density, etc.
- **Regional overlays can be constructed and applied to new wells and even new regions**

Baker Hughes

Normal Compaction Trend

- Normally compacted (normally pressured) down to 3000m
- Normal compaction trend (NCT) fit in blue
- A deviation from the trend in the same rock type indicates overpressure
- Can be applied to any formation porosity information

What pitfalls might you expect plotting the NCT?



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To calculate pore pressure using trendline methods a linear normal compaction trend (NCT) is fitted to formation porosity information (or directly to data proxying for porosity such as Dc-Exponent, sonic, resistivity, etc) on a log scale in the normally pressured (hydrostatic) interval.

Usually this is only done in shale formations and other lithologies are filtered out beforehand using gamma information. Sometimes ‘clean’ shale points are handpicked, sometimes the shale points are smoothed, sometimes the final calculated pore pressure is smoothed or handpicked from the results.

Pore pressure is recognized by a deviation from the NCT, and at a given depth can be calculated from relationships between the value of the data and the value of the NCT projected to that depth. Many different calculation methods using this basic approach have been developed and can be applied to the trend-line method.

Q: What pitfalls might you expect plotting the NCT?
A: Small changes in fitting the NCT can have a large effect on the pore pressure results. The user has a lot of flexibility fitting the trend.

Ratio Method

- **The difference between observed values and the normal trend-line extrapolated to the same depth is proportional to the increase in pressure**

For sonic logs = $$\Delta T_{log} = \Delta T_n \frac{P}{P_{hyd}}$$

For density logs = $$\rho b_{log} = \rho b_n \frac{P_{hyd}}{P}$$

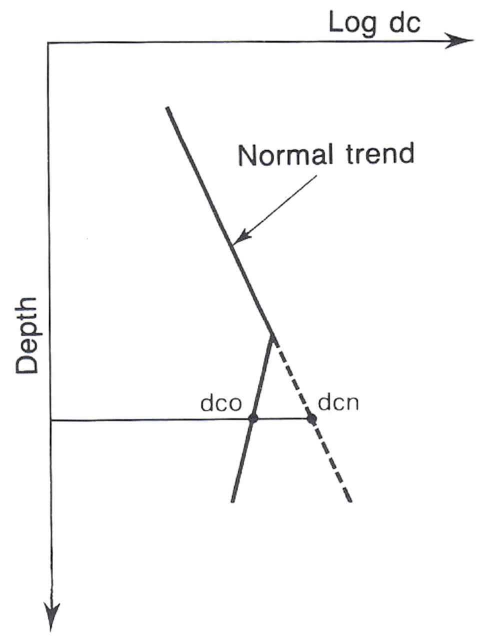
For resistivity logs = $$R_{log} = R_n \frac{P_{hyd}}{P}$$

ΔT_n = the value of the normal trend-line at a given depth
P = the pressure value to be calculated
P_{hyd} = normal hydrostatic pore pressure
ΔT_{log} = log-value value for each curve corresponding to the required pressure value

The ratio is the earliest and the most simple method. It simply takes a ratio of the log value at a given depth and normalizes it to the normal hydrostatic pressure. Any absolute or gradient pressure value can be used as long as it is consistent.

Ratio Method

- **Very simple calculation**
- **Does not take into effect overburden stress differences**



Mouchet, J.P. and Mitchell, A., 1989

Baker Hughes

The main limitation with the ratio method is that is does not account for overburden changes. It may works reasonable well in areas with a consistent overburden profile say harder rocks onshore. However, in areas with large overburden changes such as deepwater it is wholly inappropriate and may even calculate overpressures greater than the overburden.

Mouchet, J.P. and Mitchell, A., 1989. Abnormal pressure while drilling. Elf Aquitaine Manuels Techniques, No 2.

Equivalent Depth Method

- **Every point in and undercompacted shale or clay (A) is associated with a normally compacted point (B)**
- **The compaction (porosity) at point A and B is identical, but the overburden stress has increased, so:**

$$d_{eql}A = GG_A - \frac{ZB}{ZA}(GG_B - d_{eql}B)$$

$d_{eql}A$ = equilibrium density at A
$d_{eql}B$ = equilibrium density at B
ZB = equivalent depth
ZA = depth of undercompacted clay
GG_A= overburden gradient at A
GG_B= overburden gradient at B

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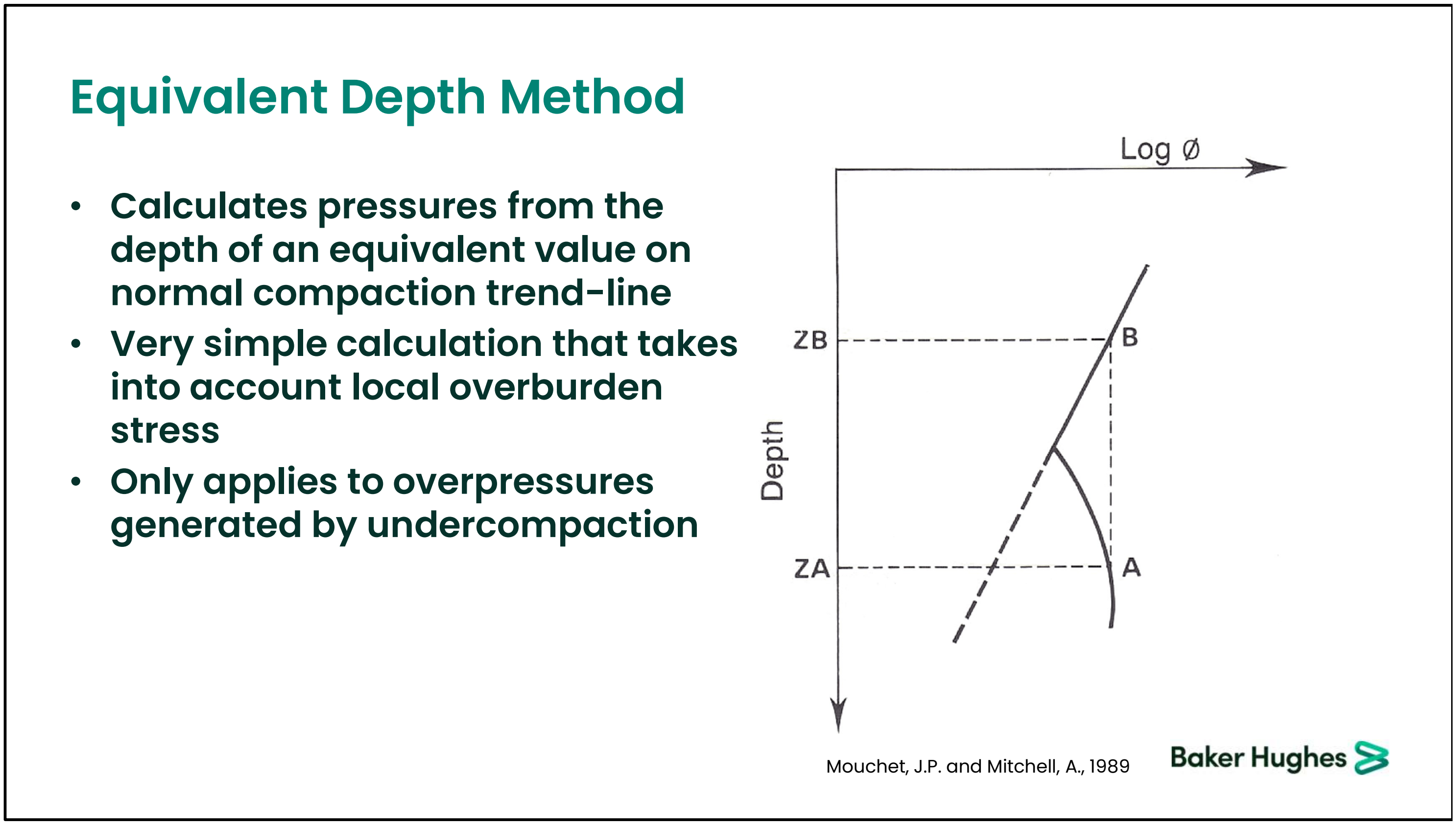
The equivalent depth method was the first trend-line method to account for variable overburden and can be applied to any porosity or log data proxying for porosity (sonic, resistivity, density, etc).

Essentially, this is the effective stress law re-written for a depth-based trend-line approach and should therefore be correct for calculating overpressures generated by undercompaction.



The equivalent depth method basically assumes that for every undercompacted overpressured shale (A) has an equivalent compacted point on the NCT (B). Since the effective stress is known at depth ZB (overburden – normal pore pressure) then for undercompaction the effective stress should be the same at point ZA. Since effective stress is constant the overpressure is simply due to the additional overburden at depth ZA.

Note this method has no fudge factors and can only predict pore pressures generated by undercompaction in shales.

Mouchet, J.P. and Mitchell, A., 1989. Abnormal pressure while drilling. Elf Aquitaine Manuels Techniques, No 2.

Eaton Method

Calculates a pore pressure based on the relationship between the observed parameter/normal trend-line ratio and the overburden gradient

- **for resistivity**

$$P = S - (S - P_{hyd})\left(\frac{Rsh_{log}}{Rsh_{n}}\right)^{1.2}$$

- **for sonic**

$$P = S - (S - P_{hyd})\left(\frac{\Delta T_{n}}{\Delta T_{log}}\right)^{3.0}$$

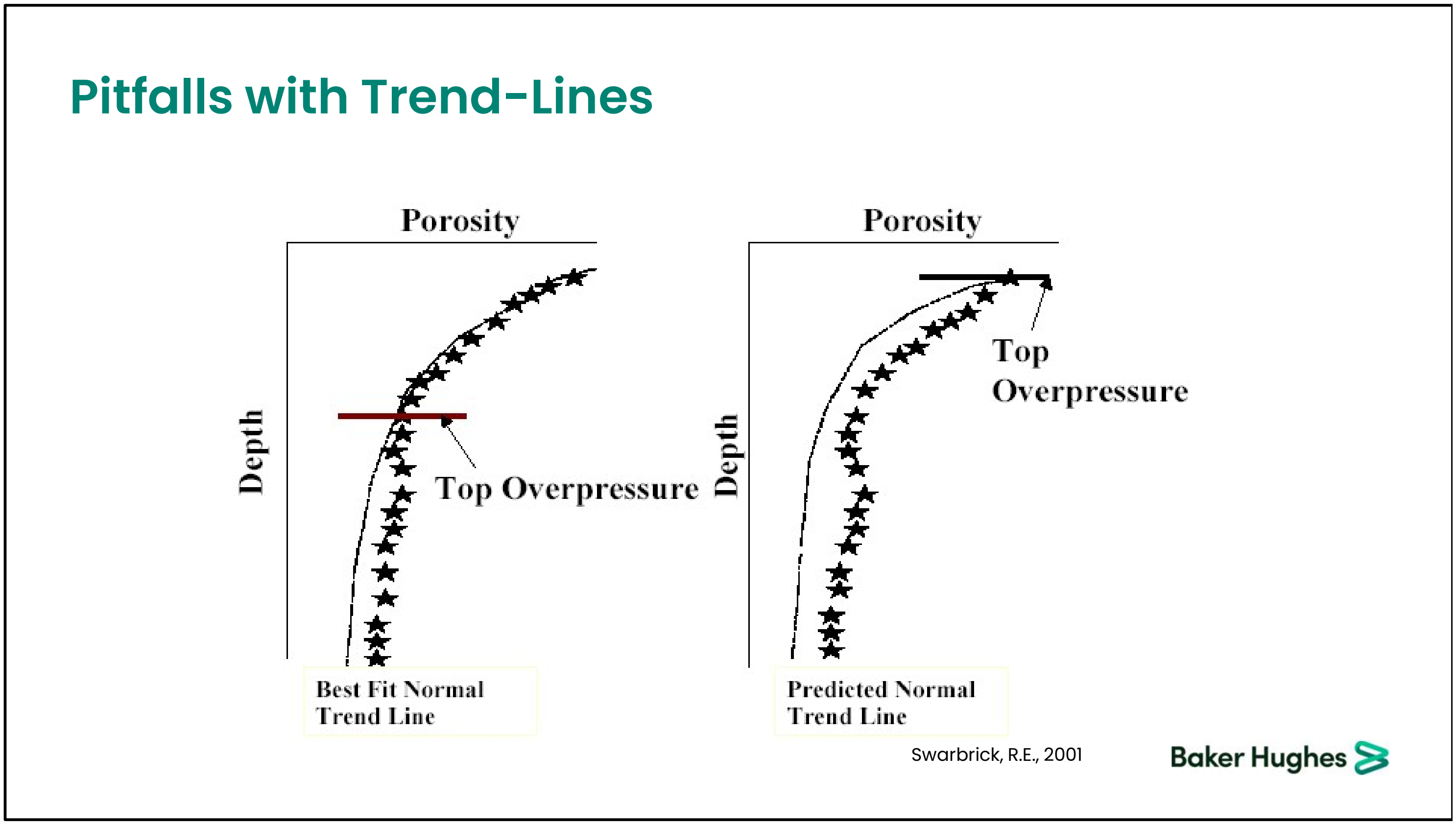
Eaton exponent

P = formation pressure
S = overburden
Rsh = resistivity of shale
DT = sonic transit times
log = observed values of the log at the given depth
n = value of normal at the given depth
hyd = normal hydrostatic pressure

Baker Hughes

Eaton was the first to introduce a fudge factor, the Eaton exponent. This enables the user to affect not only the trend line, but if that does not match the expected results he has the opportunity to alter the exponent too. Most trend-line pore pressure methods after this are variations with their own locally calibrated fudge factors. Eaton is generally sufficient it really isn’t necessary to use other methods.

Eaton established exponents for the GOM shelf as 1.2 for resistivity and 3.0 for sonic. These values may need altering for other basins and generally need adjusting down to account for overpressure mechanisms other than undercompaction.



So what's wrong with trend-lines? One problem is that they require a normally pressured interval to establish the trend and this may not always be present. In deepwater, in particular, overpressure may begin very shallow and before there is any data to establish a trend.

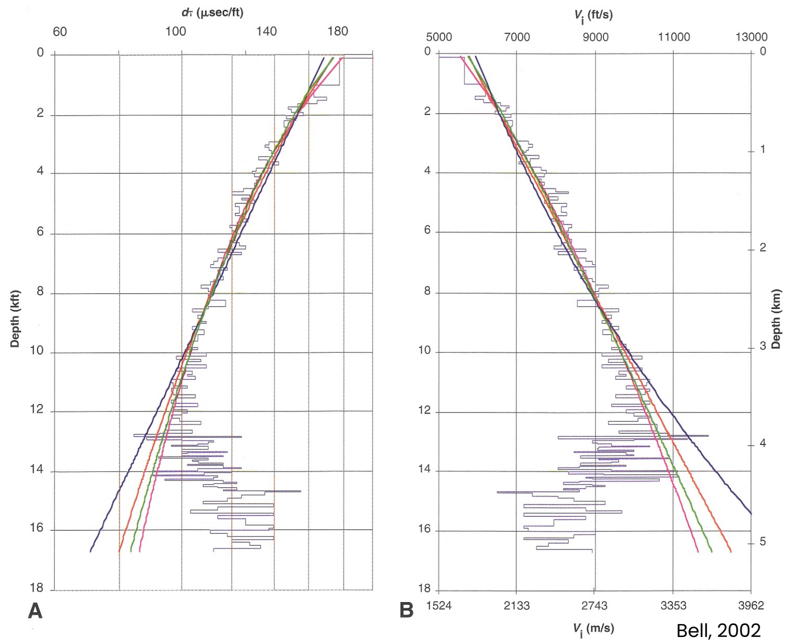
Overall, it is their very flexibility that makes them so popular. They allow the user to easily get the answer they want, matching RFT's, kicks, hole problems, gas, mud weights or any other indicator they care to choose. This also creates a risk, particularly in real-time, where the operator can easily adjust the trend or the exponent to get the answer he or the customer is expecting.

Swarbrick, R.E., 2001. OTC 13045

Q: What else is wrong with a trend-line approach?

A: Sometime a lack of data to fit the normal pressure trend. The main problem is the user has a lot of flexibility fitting the NCT and the results can be very sensitive

What’s Wrong with Trend-Lines?



Baker Hughes

Comparison of exponential trend lines: (A) transit time with a log scale; (B) velocity with a linear scale. Coefficients for blue line determined from best statistical fit to time-depth data from 3000 to 12,000ft (914-3658m). Coefficients for other lines determined by different operators. Lack of consistency shows difficulty in consistently picking a trend-line.

Bell, 2002. Velocity estimation for pore-pressure prediction. In: Pressure regimes in Sedimentary Basins. AAPG Mem 76.

Thermally Generated Pressures

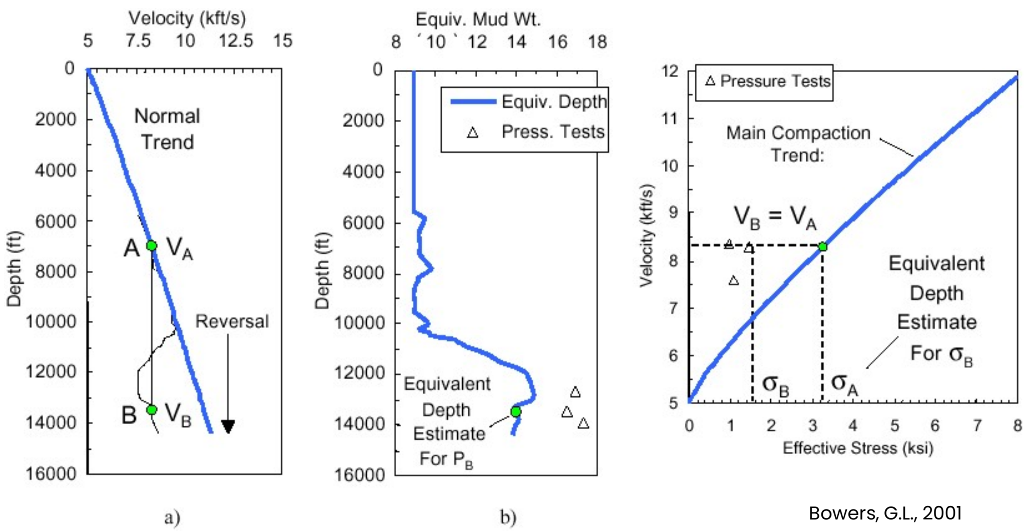
- **High pressures often associated with low porosities are typical**
- **Caused by thermally generated fluid expansion that unloads the rock**
- **The traditional undercompaction (effective stress) – porosity relationships breakdown**
- **We need to use effective stress – unloading relationship**

Baker Hughes

One reason that overpressure calculated by standard trend-line and effective stress methods underestimate overpressure could be because thermal generating mechanisms are playing a role.

Remember, in areas with thermally generated pressures we often have high overpressures associated with low porosities. Pressure has been generated *in situ* under stress due to diagenetic phase changes in the rock (e.g. hydrocarbon generation, smectite diagenesis) and this gradually unloads the rock. As a result the traditional undercompaction relationships do not apply and we need new effective stress relationships to account for these mechanisms.

Thermally Generated Overpressures



Bowers, G.L., 2001

Why do you think undercompaction was left relatively unchallenged for so long?

Baker Hughes

For a long time undercompaction was though to be the dominant overpressure generating mechanism It was not until the early 90’s that people began to question this and advocate that other mechanisms were important in many places

Bowers here presents a case where the equivalent depth method fails (underestimate overpressures) due to velocity reversal data diverging from the compaction trend for shallower formations. Since the equivalent depth method only calculates overpressure due to undercompaction and has no fudge factor he argued that the overpressure here must come from another source.

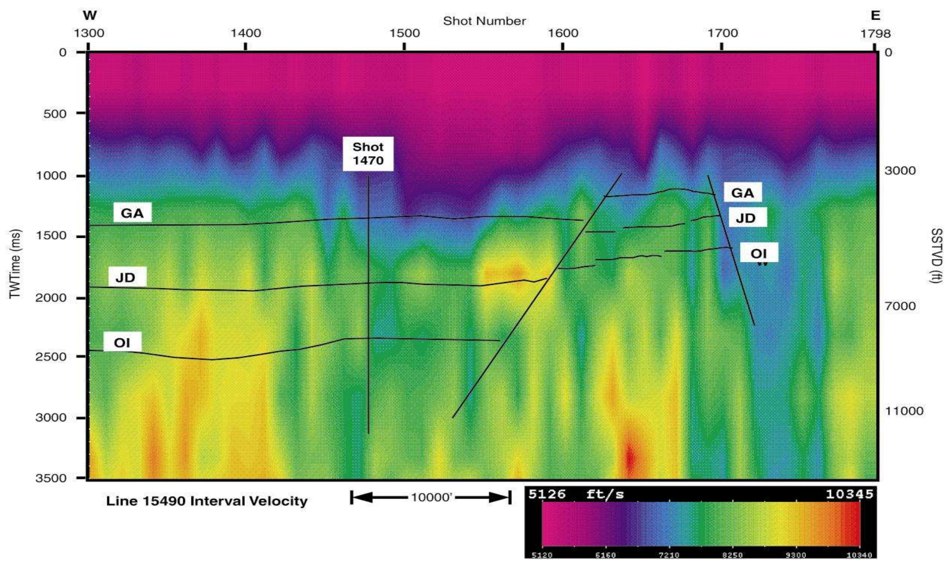
Bowers, G.L., 2001. Determining an Appropriate Pore-Pressure Estimation Strategy. OTC13042, paper presented at the 2001 Offshore Technology Conference held in Houston, Tx, 30 Apr – 3 May 2001.

Q: Why do you think that undercompaction was left relatively unchallenged for so long?
A: Basically empirical methods (like Eaton) were developed that accounted for these for these other mechanisms in many cases. They still assumed it was undercompaction however.

Data for Pore Pressure Prediction

Baker Hughes

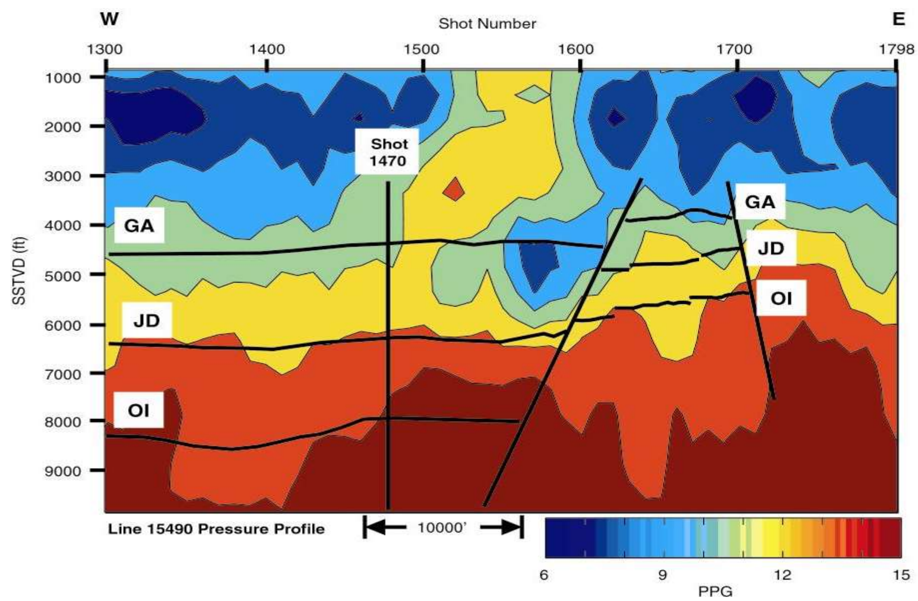
2D/3D Pore Pressure Prediction from Velocity



Baker Hughes

A 2D slice from a 3D velocity cube. Immediately you can see that velocity increases with depth due to compaction. However, this is not even and towards the east appears to be influenced by the structure.

2D/3D Pore Pressure Prediction from Velocity



Baker Hughes

The pore pressure calculated through the same slice. You can see the general pore pressure increase with depth and what looks like a pressure jump across the fault.

Pore Pressure Prediction – Basin Modelling

Advantages:

- Basin modeling adds stratigraphy & structure and thereby helps in evaluation of vertical & lateral pressure seal properties
- Constrain porosity and pressure regimes surrounding hydrocarbon accumulations and helps in evaluating risks of structural effects on reservoir pressures
- Allows the user to corroborate & calibrate all relevant information and perform an area-wide pore pressure analysis, independent of typical trend line approaches

Drawbacks:

- Being a calibration modeling approach - it relies heavily on input data – Garbage IN / OUT
- Availability of actual well data is an important requirement to avoid 'over-dependency' on model assumptions
- Being a specialized job, needs expertise & experience

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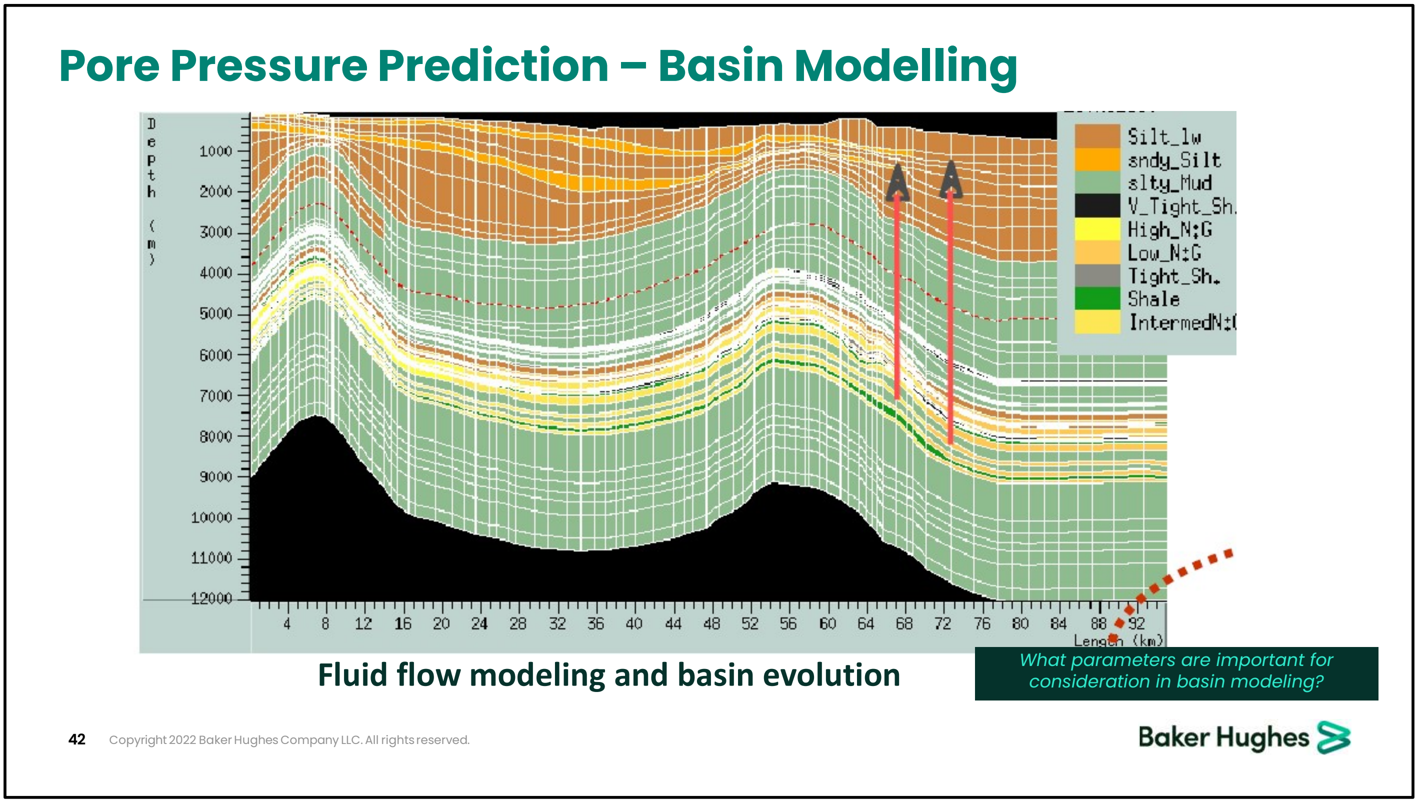
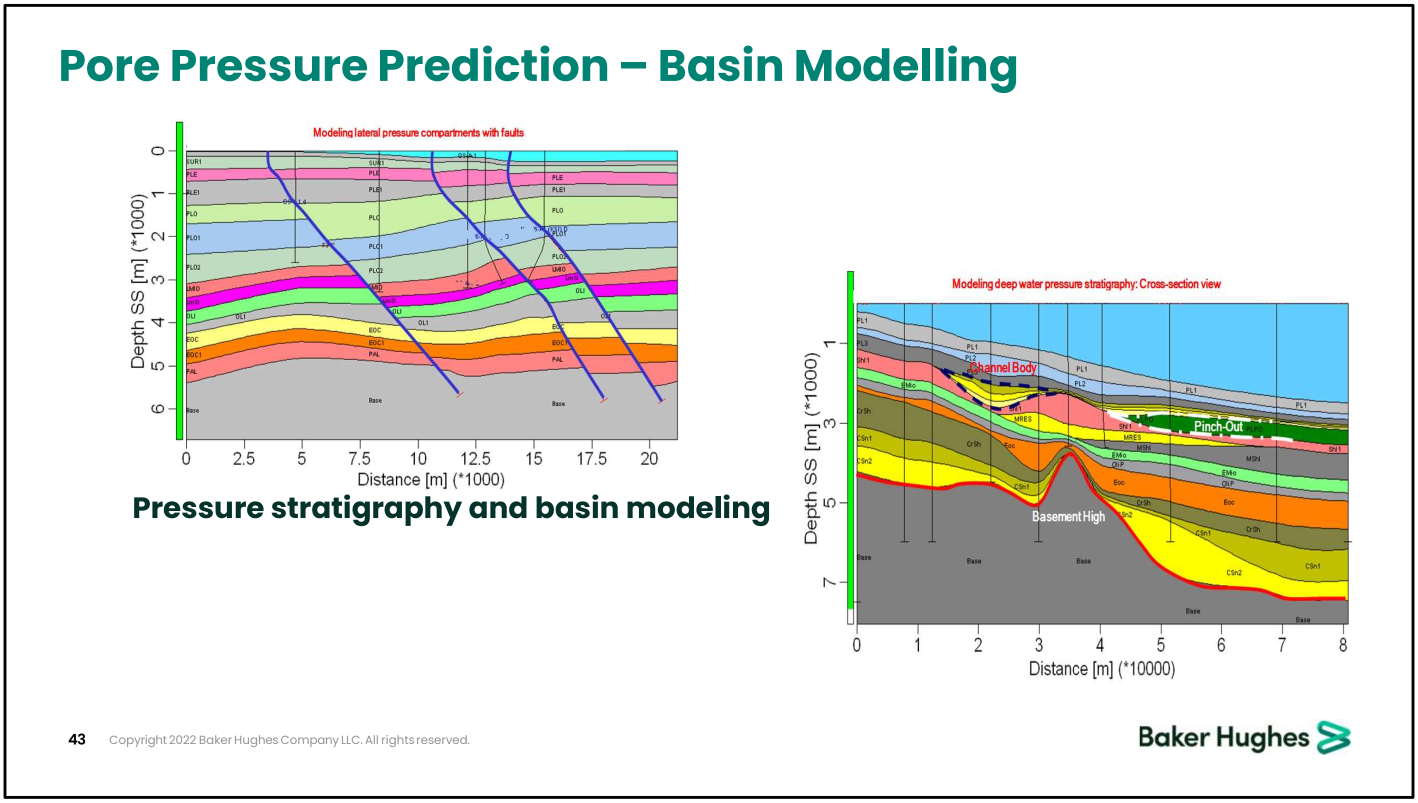
Baker Hughes

Basin modeling can be an excellent tool to understand pressure distribution.
Results however, strongly depend on the geological models (definition of litho-facies, shaliness, sand distribution, etc.) Modeling approach is not feasible in absence of at least a relatively proximal calibration point. The principal calibration is with respect to porosity as pressures are often calculated from equations based on effective stress and porosity.
Usually a dual approach – combining seismic based and basin modeling approach – help to reduce geological uncertainties inherent in pore pressure estimation. In some areas, velocities may not be valid for pore pressure estimation and basin modeling is the only alternative.



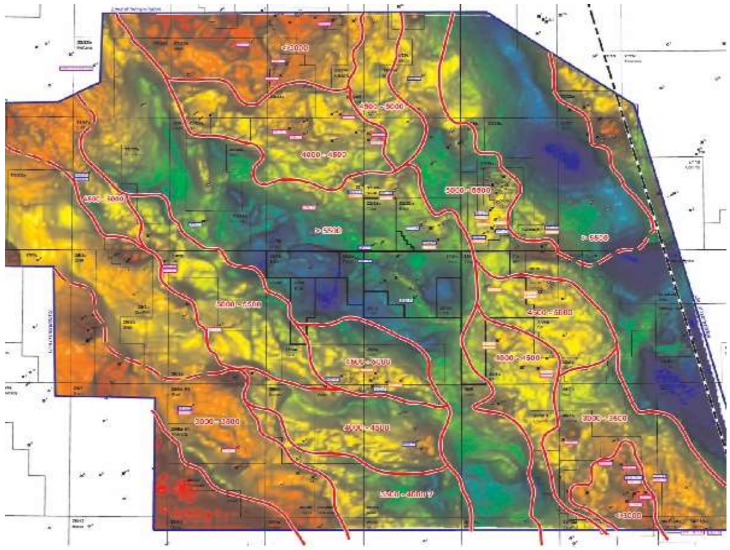
Geologic interpretations are used in basin modeling. The lithology descriptions and distributions are critical in governing how fluid flows through the basin as it develops. Modeling different geologic scenarios helps establish error bounds on pressure predictions.

Q: What parameters are important for consideration in basin modeling?
A: Lithology along with sediment diagenesis, sedimentation rate and its relationship with porosity-permeability evolution with burial, plays an important role in determining possibilities of pressure generation as well as preservation through geologic time. Also sensitive to temperature.



Basin modeling brings geological aspects into pressure estimation workflow. It helps in better understanding of the relationships that exist between basin evolution and pressure generation. One can model various geologic and structural features and it’s impact on the pressure regime including understanding of pressure variations with respect to stratigraphy / stratigraphic units (pressure stratigraphy).

Pore Pressure Prediction – Basin Modelling

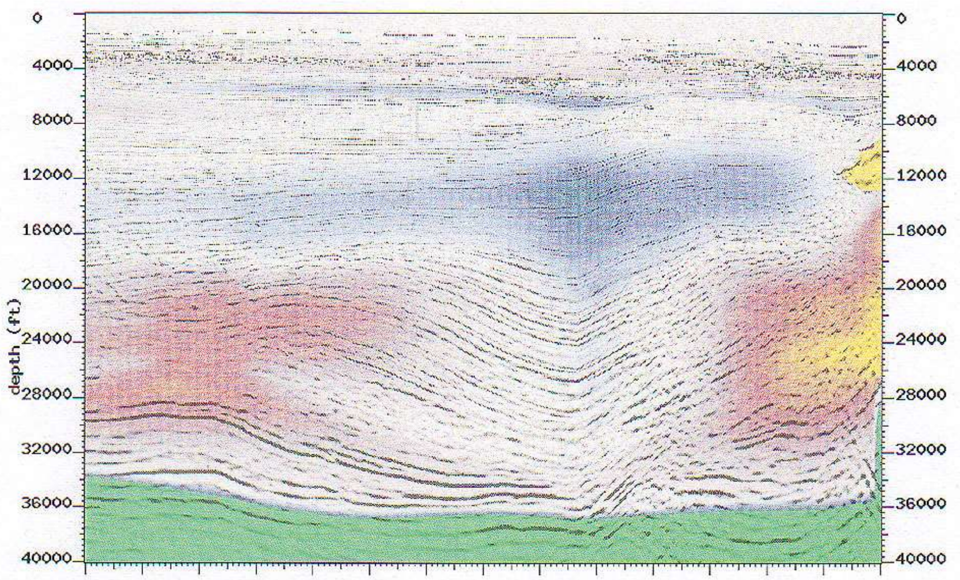


Pressure cells and dynamic modeling approach at basin scale

44 Baker Hughes

In many areas, due to geologic challenges or places where seismic velocities are unusable, basin modeling provides the only alternative to pore pressure modeling on a regional / basinal scale and provides invaluable information for understanding fluid dynamics, prospect and play conceptualization.

Pore Pressure Prediction – Basin Modelling



Comparison of basin modeling output with seismic velocities

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Baker Hughes

A difference plot of modeled and seismic derived pressure gradient. Red and yellow regions represent areas where basin modeling indicates the pressures are higher than velocity based estimates. Blue and green regions are areas where the basin model underpredicts pressure with respect to the velocity based estimation. These results can be used to focus subsequent model calibrations, revise sand distributions and lithologic descriptions, and detailed velocity reprocessing efforts.

Albertin, M.L. et al, 2003. OTC 15295.

Pore Pressure Prediction – Seismic Velocities

Advantages:

- Most widely available form of data with extensive basin/block-wise coverage
- Velocities are strongly affected by compaction, which in turn is also affected by changes in pore pressure and hence can be used for pore pressure predictions in undrilled locations

Drawbacks:

- In general, the vertical resolution of velocities is very large and hence not suitable for estimation of small variations in pressure regimes (stacking velocities are usually meant for providing a stacked seismic section useful for identification & interpretation of structural framework and stratigraphic features)
- In addition to compaction, velocities are also affected by many other rock properties which are not independent of each other viz. density, porosity, pore fluid type, fluid saturation, lithology and clay content. It also gets affected by subsurface structural features

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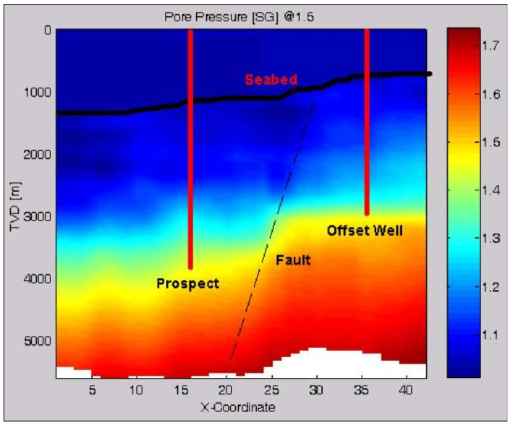
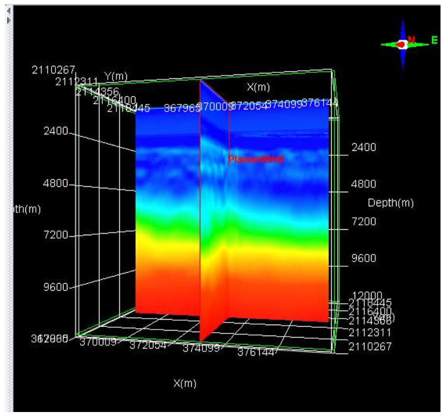
Baker Hughes

Seismic velocities, being the most widely available data, provides an important source for pore pressure modeling. Seismic velocities have been historically used for this purpose however, the effort to improve the quality of input data (in the form of different types of velocities with different stages of reprocessing) have picked-up in recent times. Though, 'routine' processing have nowadays been able to provide high quality velocity data, high-end processing is still an expensive proposition.

Quality of velocity data also inversely related to depth and more often than not, becomes unreliable in deeper zones.

Pore Pressure Prediction – Seismic Velocities

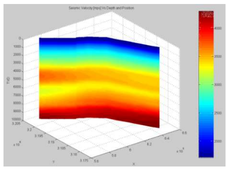




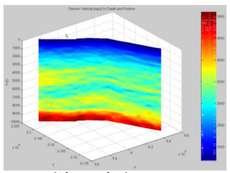
- Velocities can provide shale pore pressure on the basis of relationship established between seismic velocities and porosity
- Seismic data, especially 3D, provides a general assessment of the larger area and, when calibrated with existing offset wells, provides reliable data for pressure estimation

Since every velocity anomaly is not caused by variations in pore pressure, it is always important to have a geological knowledge of the area and also to understand sensitivity of sonic velocity, electrical resistivity and density to pore pressure changes

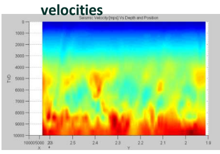
Pore Pressure Prediction – Seismic Velocities



Migration velocities



High resolution velocities



Tomographic velocities

- Quality of seismic data is inversely related to the depth of the objective
- Errors in seismic data exist depending on the geology, acquisition parameters and processing sequences
- Usually for pore pressure prediction, the use of PSTM or PSDM gathers provides the two major data sources from which velocities are extracted and it's important to know the processing steps
- A velocity field with dense sampling pattern (both spatially and temporally) is preferred for pressure analysis work – if possible, with velocity analysis at every CDP or bin

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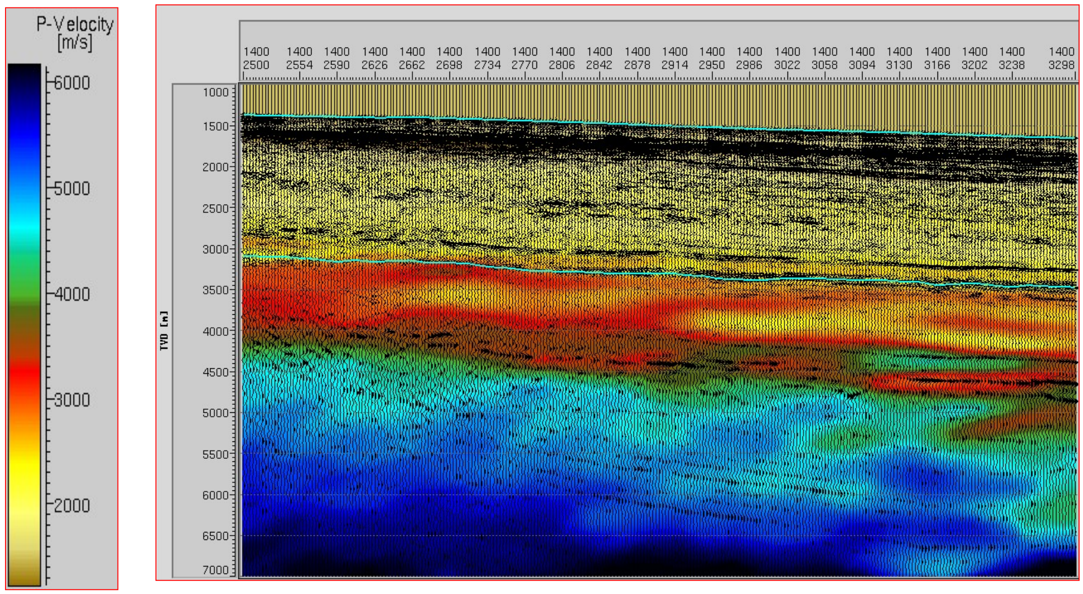
Baker Hughes

It is always advisable to make a comparison of velocities derived from seismic to measured sonic values from drilled wells to gain a better understanding of the relative sensitivity of the seismic velocity field to pore pressure and lithologic changes

Dense velocity picking near major faults and other structural elements may be helpful. Moreover, a velocity smoothing may also be required to avoid non-desired spikes and high frequency effects on the data

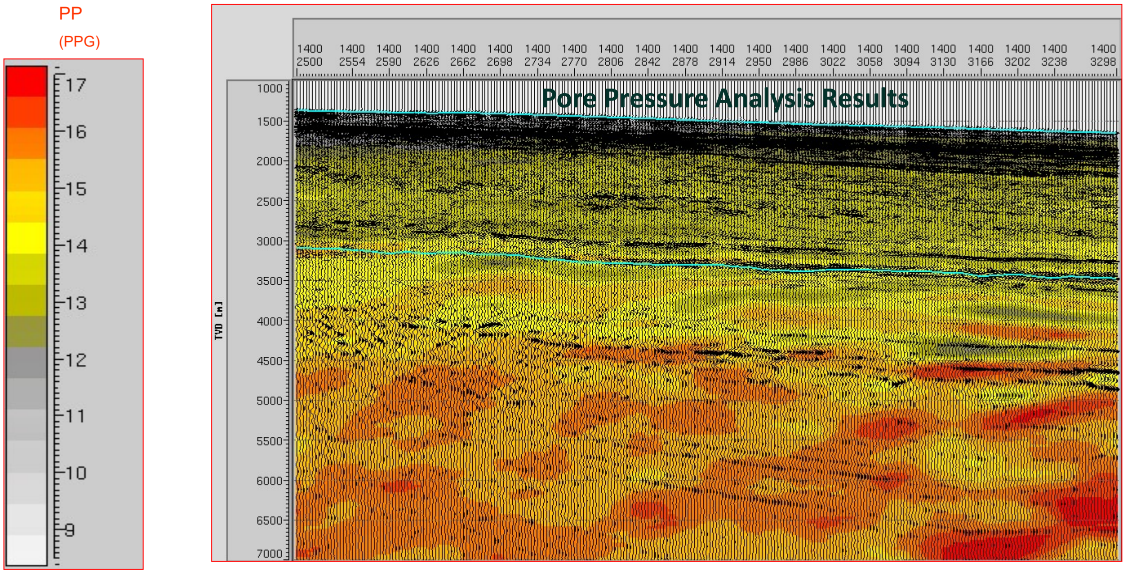
Pore Pressure Prediction – Seismic Velocities



Baker Hughes

High resolution velocity model indicates presence of low velocity pockets. In this deepwater setting, in addition to under-compaction, presence of free gas is a possibility below the BSR

Pore Pressure Prediction – Seismic Velocities



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Baker Hughes

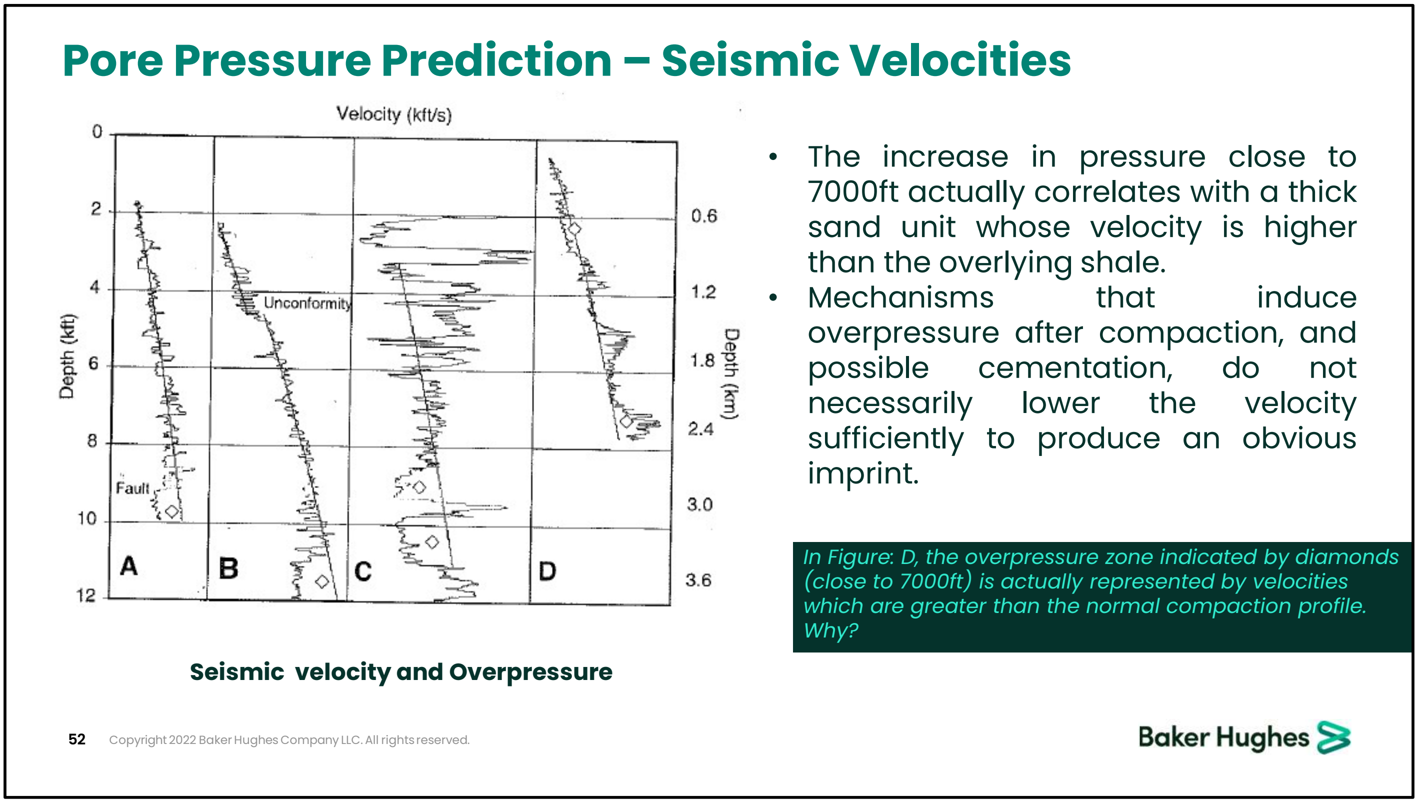
Low velocity sequences, translate to high pore pressure zones. High pressure in the permeable zones could result from possible gas accumulation and may require detail geobody mapping for determining pressure differential between shale and sands.

Pore Pressure Prediction – Seismic Velocities

Types of borehole seismic velocity data:

- Sonic
- Check Shots (VSP)
  - ✓ Average Velocity
  - ✓ Interval Velocity (ITT)
- Seismic While Drilling

Baker Hughes



Seismic velocity vs. depth for four wells (A to D). Approximate normal compaction trends shown as smooth lines. Overpressure zones indicated by diamonds.

A: A typical velocity profile in a young clastic basin. The velocity increases uniformly with depth according to a smooth empirical compaction trend. Close to 9000ft, there is an abrupt decrease in velocity away from the trend line where the well bore intersects a fault (major pressure transition can occur across fault). The region of low velocity below the fault corresponds to a region of high pressure.
B: A similar velocity decrease around 11000 ft again correlating with overpressure. Also there is a positive break in the trendline at a major unconformity near 5000ft. Sediments below the unconformity have experienced tectonic uplift and therefore exhibit a higher velocity for a given depth than expected from the compaction trend calibrated with sediments above the unconformity.
C: The velocity profile is complicated by variations in lithology. The velocity decrease near 6000ft reflects a change from carbonates to clastic, rather than a change in pressure. The second velocity break near 9000ft does result from

excess pore pressure.

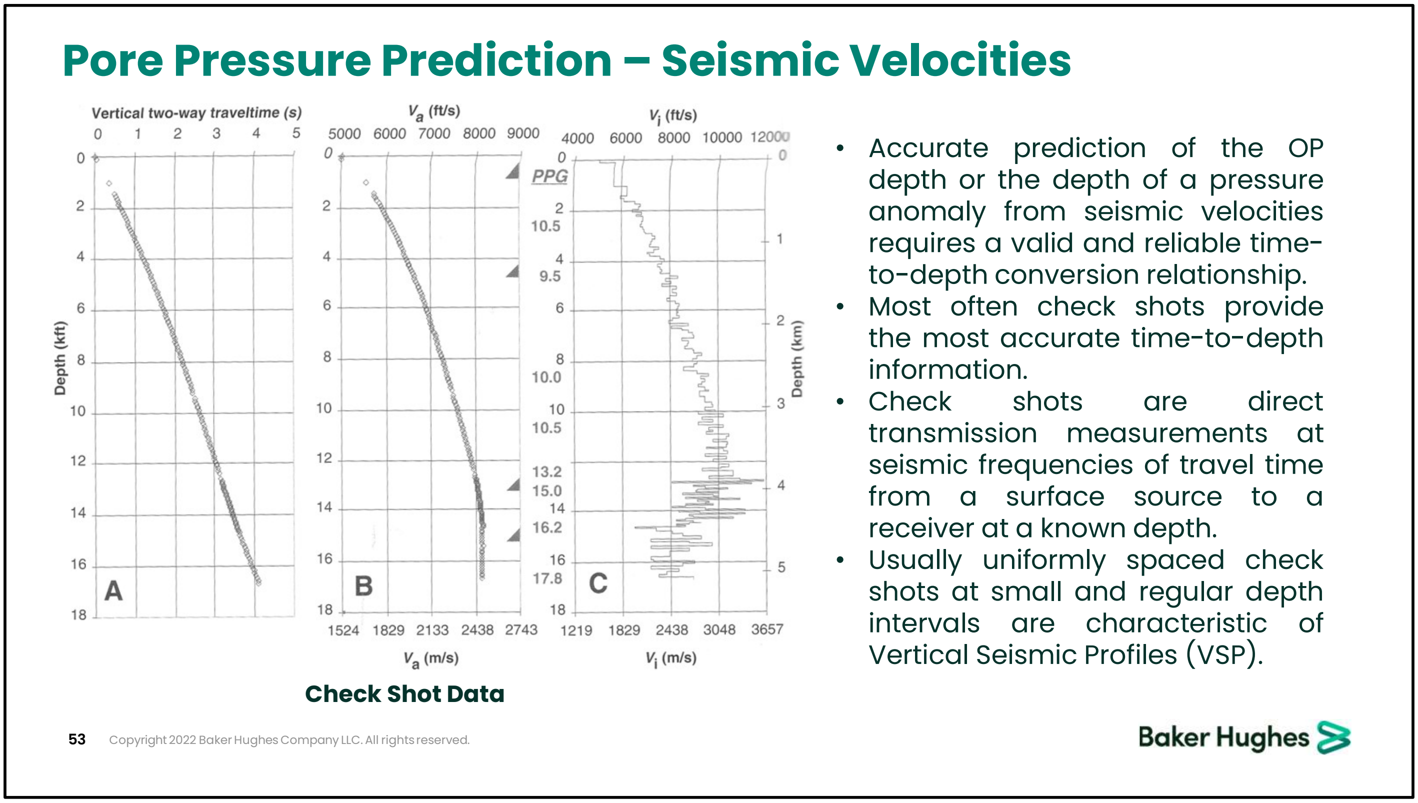
D: Not all velocity changes due to overpressure are as abrupt and even a modest deviation from the normal velocity trend can represent a change in pressure from 9 to 11ppg as seen close to 2000ft.

Q: In Figure: D, the overpressure zone indicated by diamonds is actually represented by velocities which are greater than the normal compaction profile. Why?

A: The increase in pressure close to 7000ft actually correlates with a thick sand unit whose velocity is higher than the overlying shale.

Mechanisms that induce overpressure after compaction, and possible cementation, do not necessarily lower the velocity sufficiently to produce an obvious imprint.

Bell, 2002. Velocity estimation for pore-pressure prediction. In: Pressure regimes in Sedimentary Basins. AAPG Mem 76.



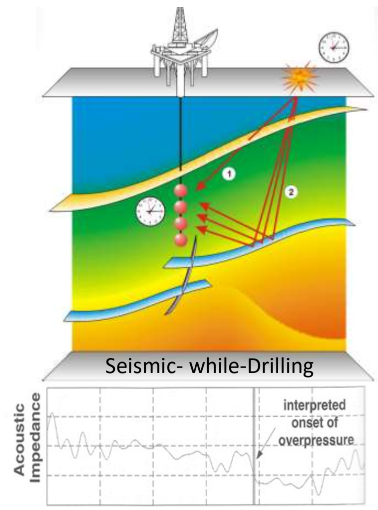
Accurate prediction of the OP depth or the depth of a pressure anomaly from seismic velocities requires a valid and reliable time-to-depth conversion relationship. Most often check shots provide the most accurate time-to-depth information. Check shots are direct transmission measurements at seismic frequencies of traveltime from a surface source to a receiver at a known depth. Usually uniformly spaced check shots at small and regular depth intervals are characteristic of Vertical Seismic Profiles (VSP). Processed VSPs also provide a seismic trace that can be tied with surface seismic data in the form of waveform changes in time and thereby to formation boundaries in depth.

(A) Time-depth relationship, (B) Average velocity – depth, and (C) Interval velocity-depth relationships from check shots (VSP) in a GOM well.

Bell, 2002. Velocity estimation for pore-pressure prediction. In: Pressure regimes in Sedimentary Basins. AAPG Mem 76.

Pore Pressure Prediction – Seismic Velocities

- Synchronize clocks on surface – receiver & source (The LWD tool is synchronized prior to running in hole and once again when the tool returns to surface (to measure the relative time-drift while downhole).
- The seismic source is same as wireline VSP: high pressure airgun array.
- Seismic data are acquired during connections (no circulation and quiet environment). Usually 10 shots are fired (each with a 15-sec shot cycle time) and thus require 2.5min per connection to acquire one checkshot level.
- The individual waveforms are stacked together downhole, and a small windowed part (around 500ms long cenetred around the first arrival) is selected to be sent to surface (by mudpulse telemetry when drilling and pumping resume).
- Once at surface, the break time of the first arrival on the waveform is picked and processed, and the predrill surface seismic velocity is updated to produce revised depth predictions.



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Baker Hughes

In addition to providing RT check-shot data, seismic-while-drilling also has the benefit that it can be deployed from vertical to highly deviated wells. Hydrophone and geophone sensors in the seismic-while-drilling tool are part of the drillstring. Depending on how good a coupling exist between the sensors and the formation (depending on hole angle, hole size, etc.), hydrophones or geophones are utilized for measurements. Principal benefits of seismic-while-drilling:

• Control drilling parameters while anticipating high risk zones, viz.

– Pressurized zones

– Base of salt rubble zones

– Depleted zones

• Better casing depth selection and thereby increase the probability of hitting the target

Pore Pressure Prediction – Seismic Velocities

- In addition to providing RT check-shot data, seismic-while-drilling also has the benefit that it can be deployed from vertical to highly deviated wells.

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Control drilling parameters while anticipating high risk zones, viz.

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– Base of salt rubble zones
- Carbonates
– Depleted zones

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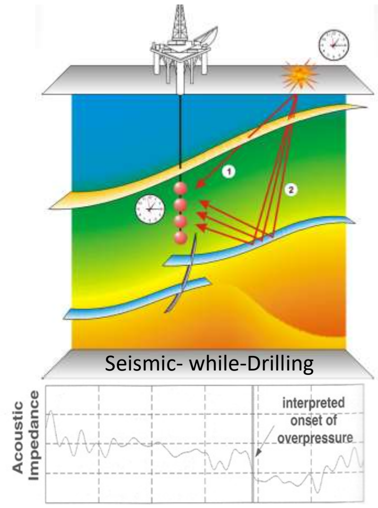

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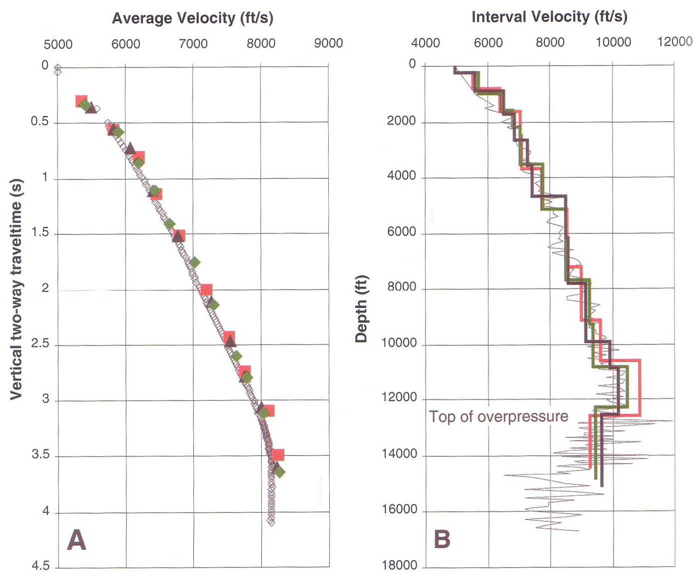
Pore Pressure Prediction – Seismic Velocities



Check Shot and Seismic stacking velocity comparison

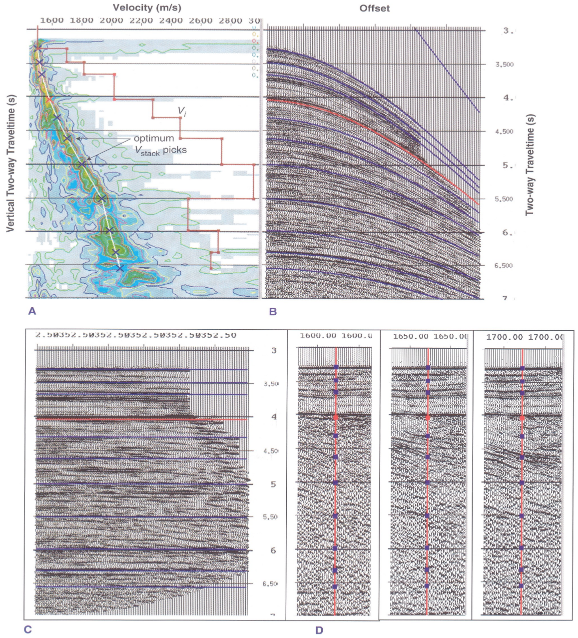
Comparison of well velocities (Check shots) with Seismic velocities (extracted at three locations closest to the well). Seismic stacking velocities from three locations near the well converted to Va and Vi. A: Average velocity vs. two-way traveltime: The average velocity trends are similar though the seismic velocities tend to be slightly faster than the checkshot values.

B: Interval velocity vs. depth: The interval velocities correctly locate the first OP top in depth (around 12500ft). The difference in velocity between the three curves provides an estimate of the uncertainty in the technique. However, the second pressure break (around 14500ft) has not been resolved by velocities. Seismic processors commonly err on the high side where there is uncertainty in the stacking velocity trend, as there is a danger of stacking multiples in poor data zones. In this case (not shown below 15000ft), the deeper picks were simply extrapolated such that the resulting interval velocities increases rather than decrease.

Velocity picking in many cases therefore needs to be specifically done for pore pressure prediction and needs to be QC'd by someone who is familiar with the concepts of pressure prediction.

Bell, 2002. Velocity estimation for pore-pressure prediction. In: Pressure regimes in Sedimentary Basins. AAPG Mem 76.

Pore Pressure Prediction – Seismic Velocities



Determination of stacking velocity from seismic

Baker Hughes

Commonly used seismic velocity analysis displays from a good-quality, deep-water location and determination of optimum stacking velocity from seismic data.

A: Semblance panel with stacking-velocity picks and resulting interval velocities; contours plot semblance as a function of stacking velocity (amplitude) and vertical two-way traveltime. The slope break in the stacking velocity trend probably indicates OP. However, it is to be noted that: Minor changes in stacking velocity within the contours of high semblance have little influence on the final stack, but can cause large changes in the interval velocity domain, particularly if the picks are close to each other.

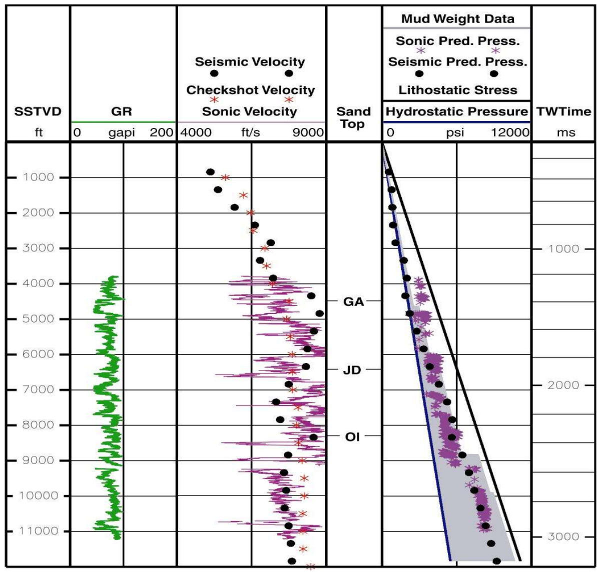
B: CMP gather showing hyperbolic moveout with offset

C: CMP gather after normal moveout (NMO) correction using stacking-velocity picks. Events should be flat after the moveout correction. All the traces after NMO are summed to form a single trace for that CMP location. The semblance is high where events are correctly flattened and low where they are not.

D: The result of stacking several CMPs with constant velocity around the analysis location. Constant stacking velocity stacks at 1600 (left), 1650 (middle), and 1700 (right) m/s. Moveout curves properly fit by those stacking velocities appear flat. Continuity of events at a given time is another indication that the correct stacking velocity has been obtained. In poor data areas (which unfortunately are usually associated with OP), distinct events may not be seen in CMP gathers. In those cases, constant velocity stacks are an important QC tool.

Bell, 2002. Velocity estimation for pore-pressure prediction. In: Pressure regimes in Sedimentary Basins. AAPG Mem 76.

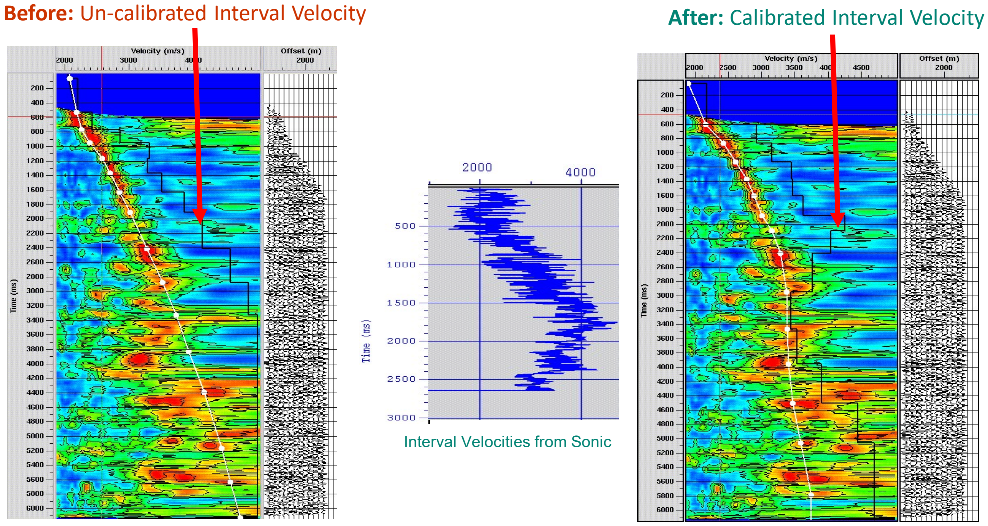
Pore Pressure Prediction – Seismic Velocities



Comparison of seismic velocities, check shot data and sonic log

Baker Hughes

Pore Pressure Prediction – Seismic Velocities



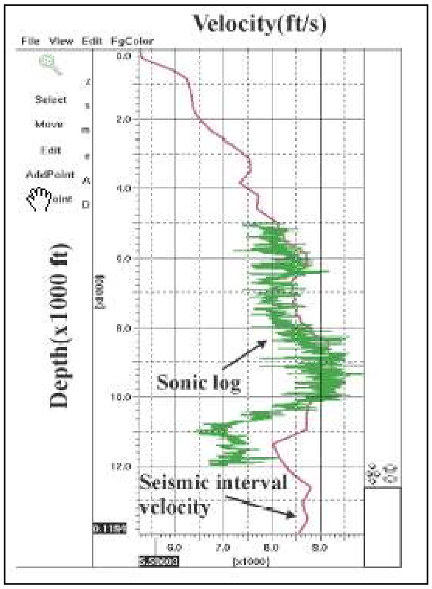
Velocity calibration with recorded sonic data

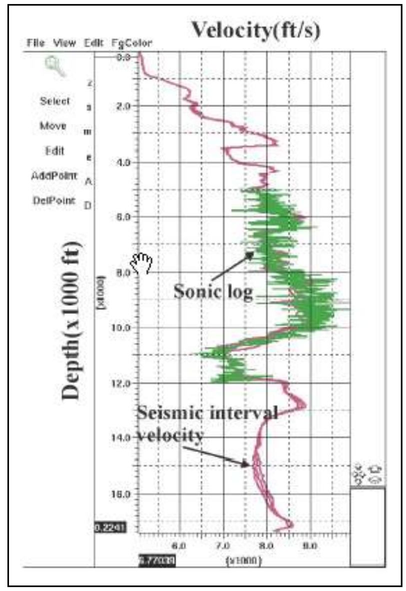
Baker Hughes

Processing of seismic data to improve its quality, depends on the presence or absence of coherent reflectivity. If the seismic section exhibits strong bedding indications, possibilities of reliable and good quality velocity data exists.

Velocities reprocessed by TraceSeis compared well to the checkshot and LWD sonic data from along the Aspen#3 well path.

Pore Pressure Prediction – Seismic Velocities

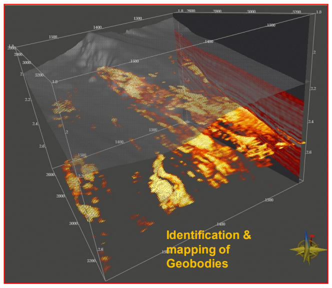


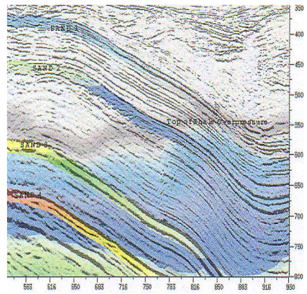


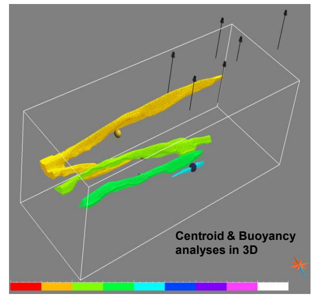
Baker Hughes

Left – Seismic interval velocities and sonic log from the Gulf Coast
Right – Final seismic interval velocities and sonic log from the Gulf Coast
Lee & Xu, The Leading Edge , January 2000.

Pore Pressure Prediction – Seismic Velocities







- Requires identification of possible sand bodies (or reservoir zones) and creation of suitable 'regions' within the 3D cube of isolated or multiple permeable zones.
- Possible centroid depth is then defined by taking into consideration similar understanding from 1D modeling and combined with information from the geological model (downdip/lateral connectivity from amplitude interpretation, possible connectivity through faults, spatial distribution and connectivity of mapped geobodies, etc.) and possible pore pressure within the permeable units are then estimated.
- A similar approach can also be utilized for understanding possible buoyancy effects in the reservoir bodies using different hydrocarbon gradients.

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Baker Hughes

Creation and application of centroid / buoyancy modeling in 3D requires high quality seismic velocities that allows geobody interpretation and mapping.

Pore Pressure Prediction – Petrophysical Data

Advantages:

- Unlike velocities, data acquisition techniques are more robust and have dense vertical resolution. This helps in predicting even minor changes in pressure regimes.
- Most of the data are available on realtime basis. Predrill pore pressure model can thus be updated simultaneously while drilling.

Drawbacks:

- Spatial distribution of data is restricted with respect to available wells. Only 1D analysis of well logs may not show the 'big picture'.
- Difficulties arises in pore pressure interpretation with respect to complex geological set ups. For example, areas with intense faulting.
- Technical limitations of the tools viz. salinity & temperature, lithological effects, unsuitability in HPHT conditions, etc.

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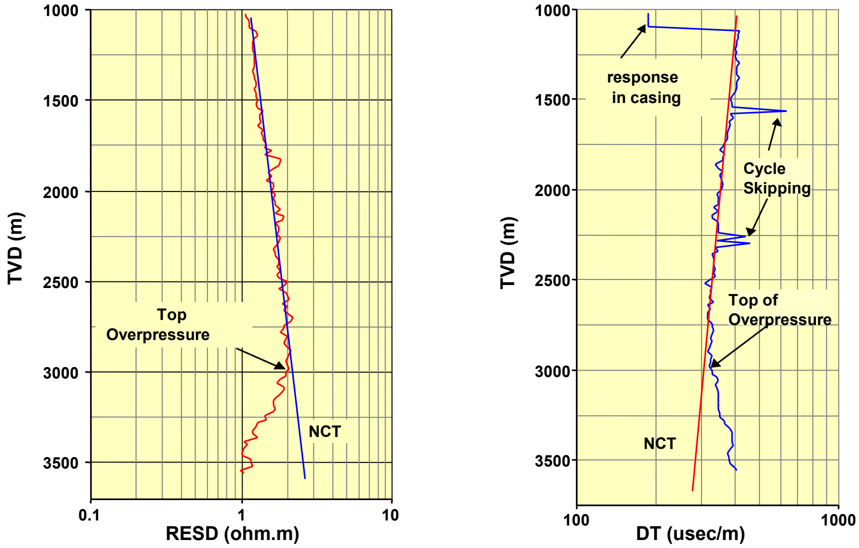
Pore Pressure Prediction – Petrophysical Data



Resistivity and Acoustic data

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Pore Pressure Prediction – Petrophysical Data

- Bulk Density

$$f = (r\ \text{matrix} - r\ \text{bulk}) / (r\ \text{matrix} - r\ \text{fluid})$$

- Deep Resistivity

$$f = ((Cw + (Vs\ \text{´}\ BQv\ \text{shale}))/Co)^{-1/m}$$

- Sonic Travel Time

$$f = (Dt\ \text{matrix} - Dt\ \text{bulk})/(Dt\ \text{matrix} - Dt\ \text{fluid})$$

Note: Unlike petrophysicist, we are most interested in shale porosity for pore pressure prediction

Pore Pressure Prediction – Petrophysical Data

Potential pitfalls using Density data:

- Shale matrix density (ρ matrix)
  - Variable clay mineralogy
  - Clay mineral dehydration and transformation
  - Organic fraction
- Fluid density (ρ fluid)
  - Salinity
  - Hydrocarbon saturation
- Hole condition
  - *Hole enlargement*
  - *Shale reaction*

$$\phi = (\rho \text{ matrix} - \rho \text{ bulk}) / (\rho \text{ matrix} - \rho \text{ fluid})$$

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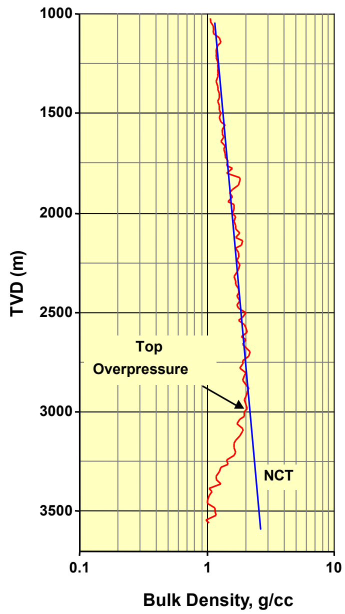
Caliper & Density corrections: If density corrections are more than 0.05gm/cc; density data is probably not usable.

Pore Pressure Prediction – Petrophysical Data



Limitations

- Effected by Borehole Condition
- LWD commonly only run in the reservoir section
- Not very sensitive to unloading

Benefits

- Overburden calculation
- QC for resistivity and sonic

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Pore Pressure Prediction – Petrophysical Data

Potential pitfalls using Resistivity data:

- Formation water conductivity (Cw)
  - DST samples, Archie in clean sandstones and limestones, Back calculate from known pressures in offset
- Shale surface charge effect (BQv shale)
  - Shale surface area (CEC or DCM) measurements
  - Smectite abundance
- Hydrocarbon saturation
  - Typically, in organic-rich shales and reservoirs
- Proximity to salt bodies
  - Often difficult to predict
- Fracture abundance and orientation
- Anisotropy

$$\phi = [(Cw + (Vs \times BQv\ shale)]/C_0)^{-1/m}$$

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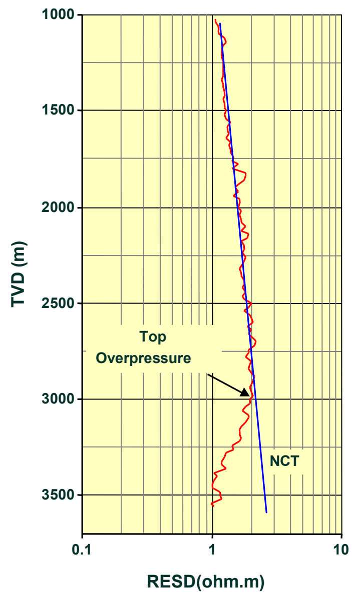
Pore Pressure Prediction – Petrophysical Data



Limitations

- Affected by changing salinity
- Affected by variations in clay types
- Increasing temperature causes a decrease in resistivity for a given salinity

Benefits

- Relatively Unaffected by Hole Condition
- Commonly Run

Pore pressure from Resistivity

Pore Pressure Prediction – Petrophysical Data

Potential pitfalls using Acoustic data:

- Matrix travel time (Dt matrix)
  - May vary in shales depending on:
    - Clay mineralogy, Rock fabric anisotropy, Fracture abundance and orientation, Organic and Hydrocarbon Fraction
- Fluid travel time (Dt fluid)
  - May vary depending on:
    - Water salinity and temperature, Hydrocarbon saturation, Fluid pressure
- *Borehole effects*
  - *Shale reaction*
  - *Cycle skipping*

$$\phi = (\Delta t\ \text{matrix} - \Delta t\ \text{bulk})/(\Delta t\ \text{matrix} - \Delta t\ \text{fluid})$$

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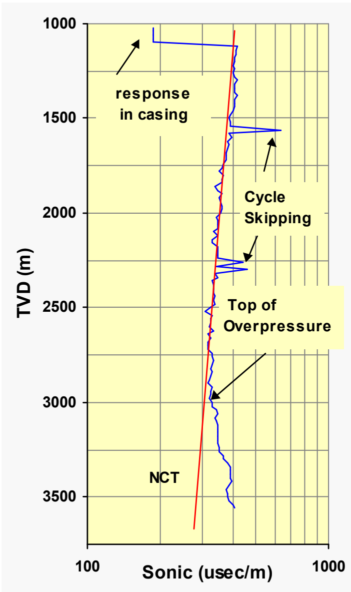
Pore Pressure Prediction – Petrophysical Data



Limitations

- Cycle skipping of sonic return caused by weak signals
- Borehole effects

Benefits

- Correlation with seismic
- Unaffected by salinity

Pore pressure from Sonic

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Pore Pressure Prediction – Petrophysical Data

Prediction Accuracy

Difficult to assess because much of the uncertainty is with the data quality and pressure generating mechanisms

Blind Tests

- Nearby wells, some with known pressures some withheld

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Pore Pressure Prediction – Petrophysical Data

Some common lithological effects to look out for while interpreting petrophysical data for pressure prediction

Mica	:	Affects GR
Coal	:	Affects Resistivity & Sonic
Carbonaceous Material	:	Affects Density
Volcanics	:	Affects Neutron measurements and Imaging tools May look like clay May look like sand
Pyrite	:	Affects Resistivity Affects Density measurements
Siderite	:	Affects Density measurements
Carbonate cemented sandst.	:	Affects Density
Thin-bed Effects	:	Affects GR (Sandstone-shale sequence may appear as homogenous siltstones)

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Pore Pressure Prediction – Drilling Data

Dc Exponent

- A model developed to assess the drillability (ROP) of a formation while compensating for changes in:
  - ROP (ft/hr)
  - Rotary speed (rev/sec)
  - Weight on bit (lbs)
  - Bit diameter (ft)
  - Mud weight (ppg)

- Changes in the Dc Exponent reflect changes in compaction with undercompacted (overpressured) formations drilling faster
  - Other drillability models include Sigma log, MLNDR, etc.

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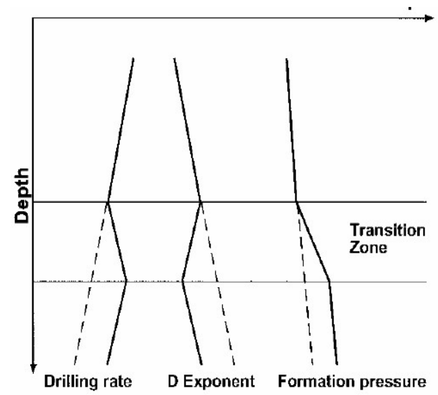
Pore Pressure Prediction – Drilling Data

D Exponent

$$R/N = a(W/D)^d$$

- R = Drilling Rate, ft/min
- N = Rotary Speed, rpm
- W = Weight on bit, lbs
- D = Bit diameter, inches
- a = Lithological constant
- d = Compaction exponent (dimensionless)



Response in drilling rate (and D Exponent) to changes in formation pressure

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Pore Pressure Prediction – Drilling Data

Corrected d-Exponent (dc)

dc = d x d1/d2

dc = Corrected d-exponent
d = d-Exponent
d1 = Formation fluid density for the hydrostatic gradient in the region (1.00 to 1.08)
d2 = Mud Weight (d_{eqv})

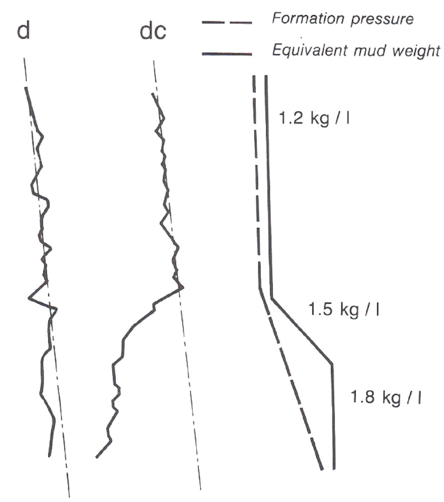

Fig. 59. — Comparison of "d" and "dc"

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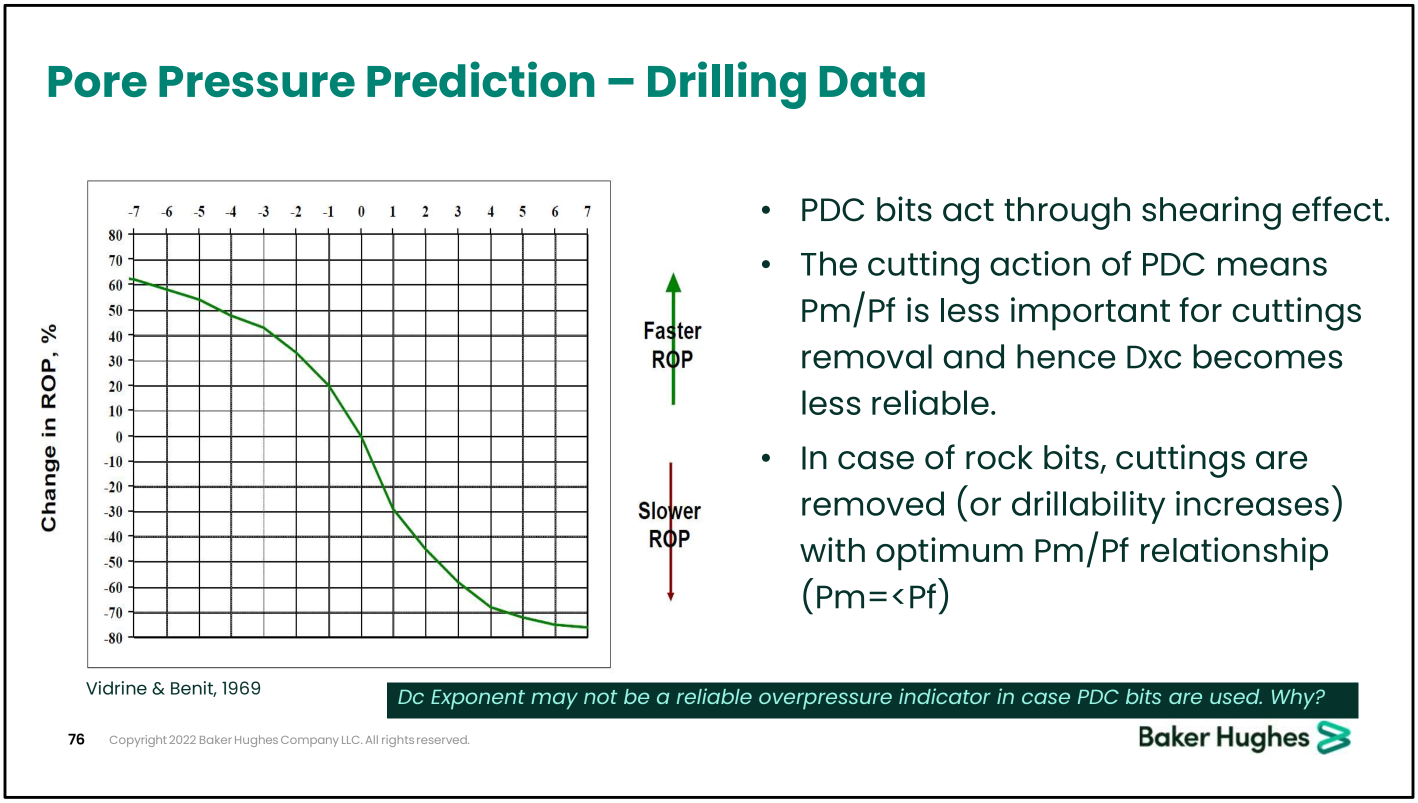
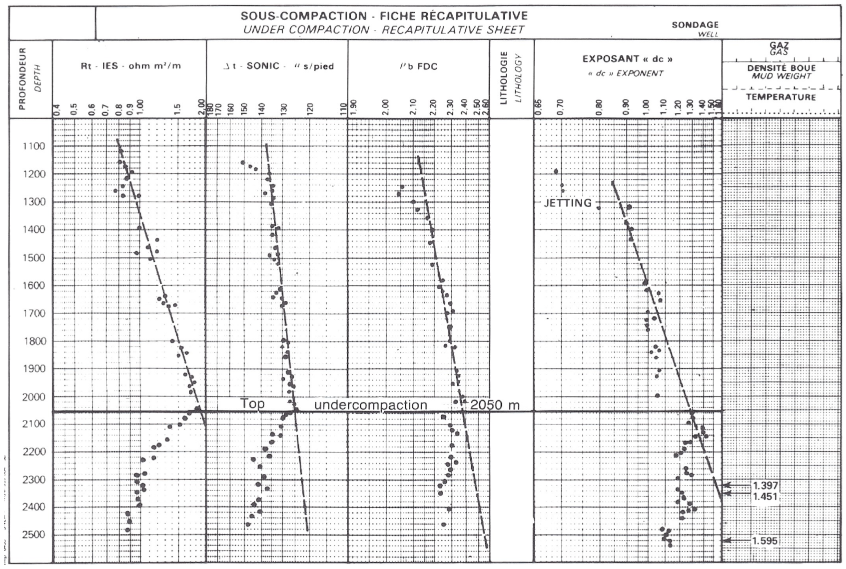


Diff. Press = Pmud-Pp, psi x 100

Q: Dc Exponent may not be a reliable overpressure indicator in case PDC bits are used. Why?

A: PDC bits act through shearing effect. The cutting action of PDC means Pm/Pf is less important for cuttings removal and hence Dxc becomes less reliable. In case of rock bits, cuttings are removed (or drillability increases) with optimum Pm/Pf relationship (Pm=<Pf)

Pore Pressure Prediction – Drilling Data



Corrected d-Exponent (dc) and comparison with other Logs

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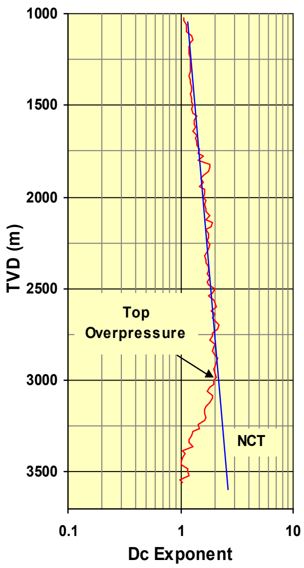
Typical comparative log produced after the well. In: Mouchet & Mitchell

Pore Pressure Prediction – Drilling Data



Limitations

- Developed for vertical well rotary drilling with rock bits
- Sensitive to differential pressure (MW-Pore Pressure)
- Does not measure rock properties directly (i.e., formation porosity)

Benefits

- Cheap

Pore pressure from Dc Exponent

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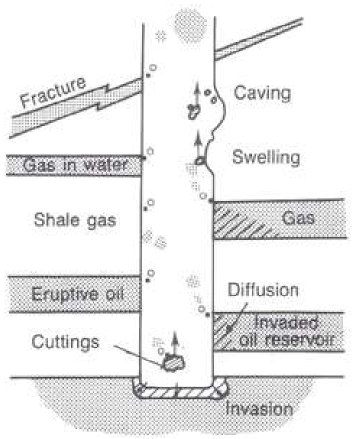
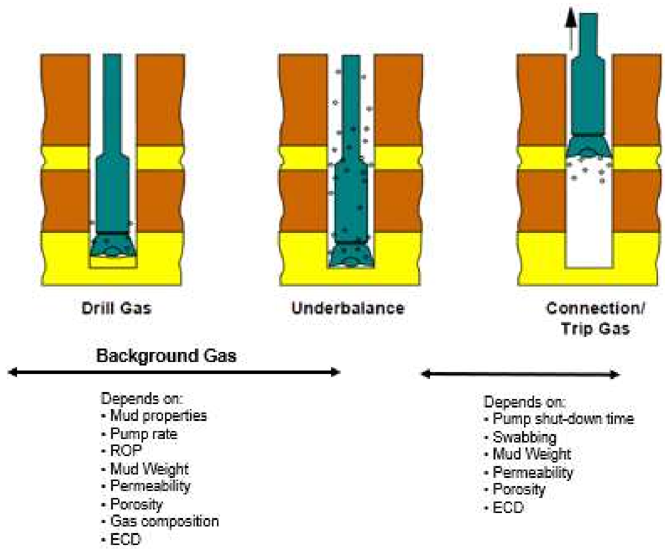
Typical comparative log produced after the well. In: Mouchet & Mitchell

Pore Pressure Prediction – Drilling Data



The Various Sources of Gas Shows



The Various Sources of Gas Shows

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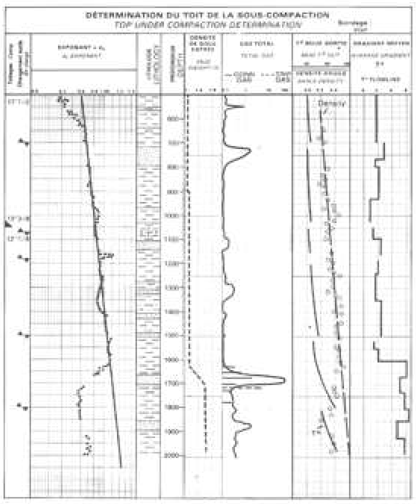
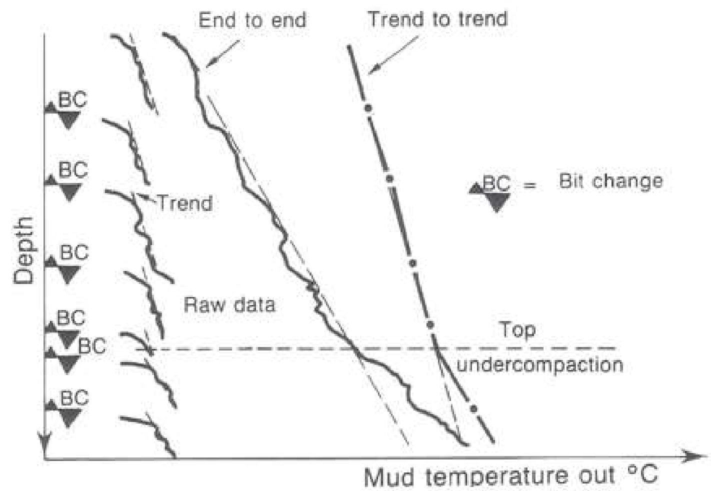
Pore Pressure Prediction – Drilling Data

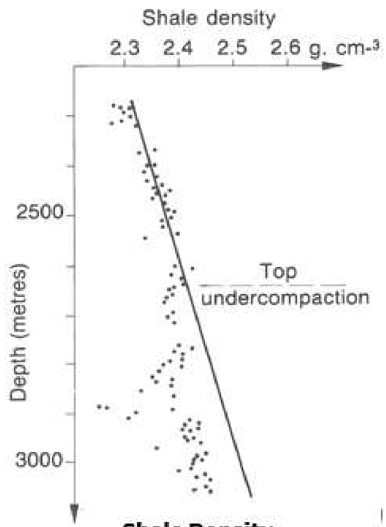


Connection Gas

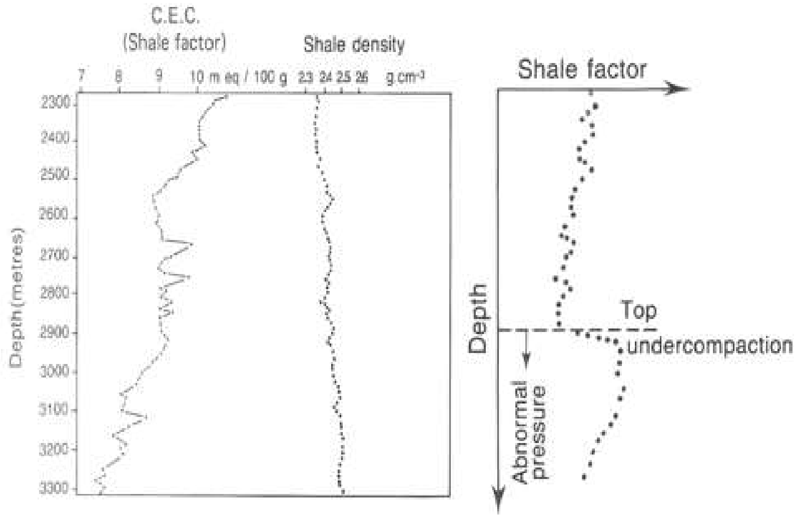


Mud Temperature

Pore Pressure Prediction – Drilling Data



Shale Density



Shale Factor

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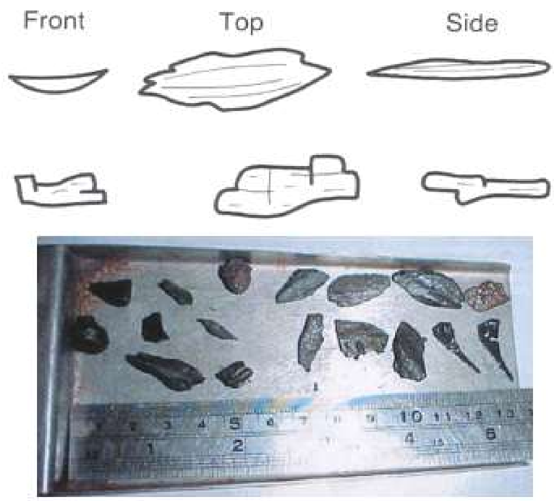
Pore Pressure Prediction – Drilling Data



'Pressure' Cavings

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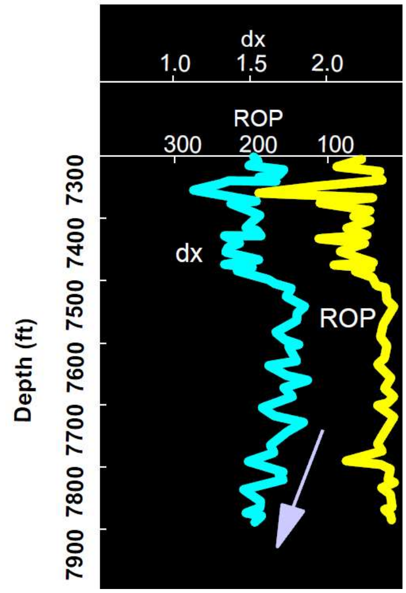
Pore Pressure Prediction – Drilling Data

- **Increase in:**
  - Gas
  - Rate of Penetration
  - ‘Splintery’ Pressure Cavings
  - Volume of shale cuttings
  - Flowline Temperature
  - Chlorides
- **Decrease in:**
  - Shale resistivity and sonic (LWD)
  - d-Exponent
  - Shale density (Cuttings / LWD)

No Single Indicator is Accurate and Foolproof

Key is to Integrate different Observations & Measurements



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Pore Pressure Prediction – Key Points

- Surface seismic data is very valuable, particularly in exploration acreages where offset well information is lacking.
- Quality of seismic velocities has a direct impact on the inherent uncertainties associated with the predrill models.
- Offset well calibration is valuable – confidence increases if sonic, resistivity and density is available.
- Real-time monitoring is important to reduce uncertainties and update the predrill model.
- Real-time monitoring is best with sonic (sometimes resistivity)
- Basin modeling outputs become unreliable in the absence of calibration data. However, in many instances, it may be the only applicable approach.
- More care should be taken with drilling information – it does not measure formation properties directly

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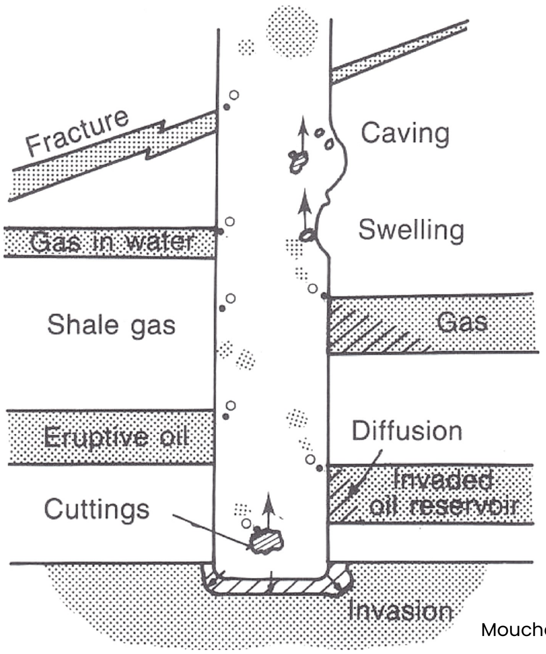
The Various Sources of Gas Shows



- Gas from fractures
- Drilling gas
- Cuttings gas
- Cavings gas
- Background gas
- Recirculated gas
- Connection gas
- Trip gas
- Flow or kick

Which types of gas tell you the pore pressure?

Hughes

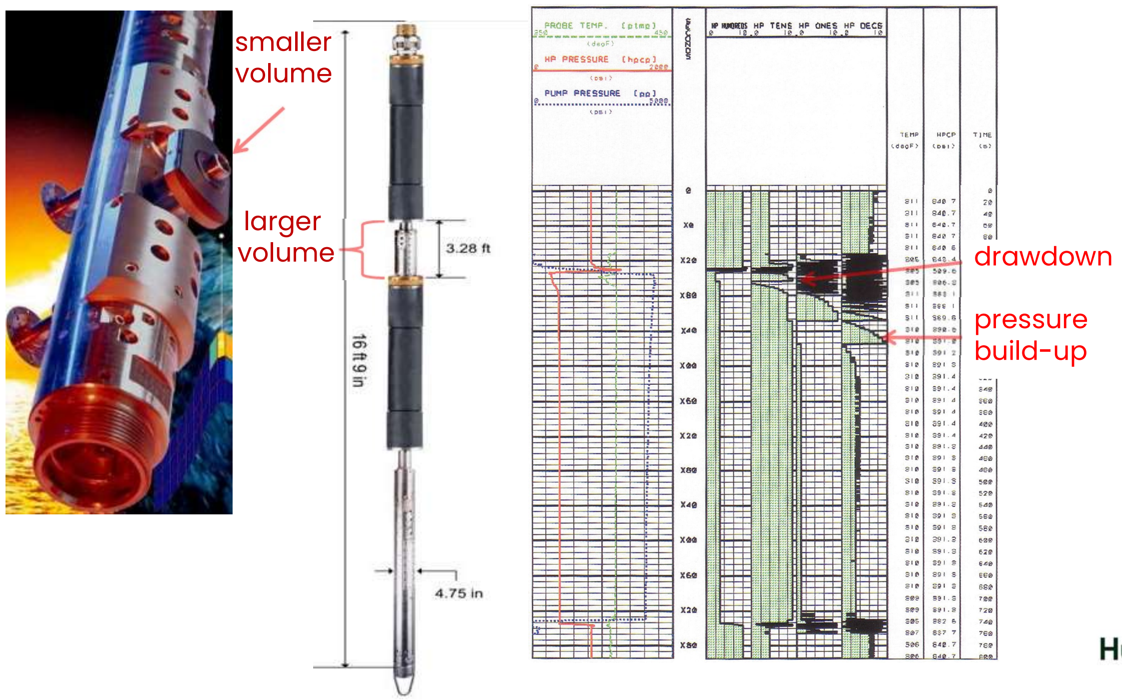
Mouchet, J.P. and Mitchell, A., 1989

Gas is one of the main indicators for pore pressure during drilling. There can many different types of gas in the drilling mud such as drilling, cuttings, cavings, background, recirculated, connection, trip and or course flows and kicks. Some of these can give a qualitative indication of overpressure some a more quantitative indication. Sometime gas indications can be confusing.

Mouchet, J.P. and Mitchell, A., 1989. Abnormal pressure while drilling. Elf Aquitaine Manuels Techniques, No 2

Q: Which types of gas tell you the pore pressure?
A: Quantitatively, a flow/kick and connection/trip gas. Increasing gas is not an indicator although often used. In many cases connection/trip gases are misidentified

Wireline Formation Testers



The best way to measure downhole pressures is with a formation testing tool. There are two types, one (left picture) pushes a pad and seal against the formation and then pushes a snorkel into the rock. Pressure is then drawndown and then the build up observed (right hand figure). The stabilized buildup represents the formation pressure. The other type of tool on the right has two packers which straddle the zone of interest, a larger volume is drawdown and the pressure build up observed.

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