Do the Seismic Velocities Depend from Time-Temperature Index?*

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Abstract

The objective of our study is to test whether seismic velocities of rock depend on time and temperature index (TTI). This study is motivated by the observations that overpressure and reservoir qualities depend on temperature and time in many sedimentary basins. TTI, an important thermal maturity indicator, is directly linked with oil and gas generation and combines the effects of temperature and time. However, there is no existing model (theoretical, empirical, and numerical) to predict TTI from observed seismic velocities. Our study identifies an empirical-numerical relation between TTI and seismic velocities. In order to obtain this relation, we perform petroleum system modeling at a well location. The well is located in deep-water petroleum system at Rio Muni Basin, West Africa. The essential petroleum system elements and TOC are identified based on petrophysical and rock-physics analysis. The TTIs obtained from finite-element modeling of petroleum system are then compared with velocities measured at the same well location. We find that both Vp and Vs increase exponentially with TTI. The results can be applied to predict TTI, and thereby thermal maturity, from observed seismic velocities.
Do the Seismic Velocities Depend on Time-Temperature Index?

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Ken Peters, U.S. Geological Survey
Notes by Presenter

We tested whether seismic velocities of rock depend on time and temperature index (TTI).
Some of you might know that time-temperature index is an important indicator of thermal maturity. The co-authors are Tapan and Gary from SRB, and Ken Peters from USGS.
Objective

We provide an empirical-numerical relation between time-temperature index (TTI) and seismic velocities.

– TTI is obtained numerically from petroleum system modeling at a well location in deep-water petroleum system, Rio Muni basin, West Africa
Notes by Presenter

We find an empirical-numerical relation between time-temperature index, abbreviated as TTI and seismic velocities. TTI is obtained numerically from petroleum system modeling at a well-location in deep-water petroleum system. TTI's obtained from numerical modeling are then compared with velocities measured at the same well location. We have found that seismic velocities, both Vp and Vs, increase exponentially with increase in TTI. Let me now give you a formal definition of TTI
Definition of Time Temperature Index (TTI)

\[ TTI = \sum_{n_{\text{min}}}^{n_{\text{max}}} r^n \Delta t^n \]

where,

- \( \Delta t^n \) is the time (in Ma) that the rock spent in the \( n \)-th temperature interval of 10\(^o\) C
- \( n_{\text{min}} \) and \( n_{\text{max}} \) are the minimum and maximum values of the index \( n \)
- \( r=2 \)

(Lopatin, 1971; Waples, 1980)
Notes by Presenter

ΔΠ depends on both time and temp; delta-t refers to the time (in Ma) the rock spent in a temperature interval of 100 C. There are temp. intervals of 100 C from zero to 150 C. nmin and nmax are the minimum and maximum values of the index n and, r=2 You may think, why this ΔΠ is important?
Time and Temperature affect reservoir quality

- Reservoir qualities depend on both time and temperature in many sedimentary basins.
  - **Overpressure** typically starts at \( \sim 60\,^\circ C \) and reaches near-lithostatic fracture pressures at \( \sim 120\,^\circ C \)
  - **Quartz cement volume** increases with temperature > 60\(^\circ\) C
  - **Illitization** leads to dramatic reduction of permeability beyond \( \sim 120\,^\circ C \)
  - **Carbonate hard-grounds** represent time-dependent processes
  - **Biodegradation of oil** occurs in reservoirs with temperatures below 80\(^\circ\) C
Time and temperature affect reservoir quality and TTI combines both these time and temp effects. Here I show you some specific examples that depend on specific temperature and time. For example, in different sedimentary basins, overpressure occurs at different depths. But, usually they start as similar temp, about ~60o C and reach near-lithostatic fracture pressures at ~120o C. Quartz cementation, smectite to illite transformation, carbonate hardgrounds and biodegradation of oil represent temp and time dependent processes. Although there are reported exceptions of this ideal temperature window, identification of this thermal window may be useful to predict reservoir quality in frontier basins. In addition to temperature window, TTI can be a useful parameter that combines both temperature and time effects of rock.
TTI is an indicator of thermal maturity

<table>
<thead>
<tr>
<th>Event</th>
<th>TTI values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Onset of oil generation</td>
<td>15</td>
</tr>
<tr>
<td>Peak oil generation</td>
<td>75</td>
</tr>
<tr>
<td>End oil generation / Onset of wet gas generation</td>
<td>160</td>
</tr>
<tr>
<td>End wet gas generation / Onset of dry gas generation</td>
<td>1500</td>
</tr>
<tr>
<td>End dry gas</td>
<td>65000 (Allen and Allen, 1980)</td>
</tr>
</tbody>
</table>
Notes by Presenter

Also, $\text{T}_1\text{TI}$, is a quantitative indicator of thermal maturity of organic matter. It is directly linked with oil and gas generation. For example, oil generation starts at $\text{T}_1\text{TI}$ value 15.

However, the existing rock physics models (theoretical, empirical, and numerical) do not relate seismic velocities and time-temperature index ($\text{T}_1\text{TI}$).
1D petroleum system modeling approach

1. Well log interpretation: Identify chronostratigraphic units, lithology and petroleum system elements
2. Define source rock parameters
2. Specify boundary conditions for finite element simulations

We have used Petromod, a basin modeling software.
Notes by Presenter

In order to numerically obtain TTI and know the thermal maturity, we perform 1D petroleum system modeling and use this workflow. First we identify the chronostratigraphic units from the well logs and specify their present-day thickness, lithology and define the petroleum system elements; such as, which unit is source rock, reservoir, seal, and overburden rock. Next we define source rock parameters, specify boundary conditions, and perform Finite element simulations.
Well log interpretation

5 different lithofacies

- Shale
- Shaly-sand
- Sandy-shale
- Sandstone
- Cemented calcite

Decompacted thickness:

\[(1 - \phi_N)T_N = (1 - \phi_0)T_0\]

Conductive heat-flow:

\[Q \propto \lambda\]
These are the well logs from a single well. We are showing the time, measured depth, vshale, and the cross-over between gamma ray and porosity from density logs. Based on the cross-overs and different cross-plots, we identify seven different lithofacies. 6 are depositional, and 1 is diagenetic: calcite-cemented facies. Now, each facies is characterized by different depositional porosity, which affects the decompacted thickness. Also, each facies has different thermal conductivity that affects the conductive heat flow.
Fining-upward Patterns for Turbidite Channelized Sequence

Well log data from West Africa
The well logs in channelized turbidite typically give rise to fining-upward pattern. Here I am showing you various logs.

In this region, the uncemented sandstones are typically underlain by carbonate cemented sandstones, which show blocky pattern on the well logs.

These uncemented sandstones are genetically composed of different facies. In the next few few slides, I am going to show you the vertical facies succession within uncemented sandstones and how they affect porosity and impedance.
Facies Interpretation using Rock Physics Modeling

The velocity drops by additions of shale lamina in pore network.
Notes by Presenter

This is the entire vertical facies succession in channelized, turbidite sequence. Please note the large change in Porosity and small change in P-Impedance. This could be due to the effect of increase in shaliness as well as deteriorating sorting from high-porosity to low-porosity end-member.
Well log interpretation

Petroleum system elements

- Overburden
- Seal Rock
- Reservoir (Turbidite shaly sands)
- Source Rock
Notes by Presenter

Next, we define the petroleum system elements in this West-Africa well. The source rock is Albian-Aptian age; reservoir is composed of turbiditic shaly sands. This is the seal rock and overburden.

Next, we identify the total organic carbon in this source rock.
TOC from resistivity and sonic logs

\[ \Delta \log R = \log_{10} \left( \frac{R}{R_{ns}} \right) + k \left( S - S_{ns} \right) \]

where,
\( \Delta \log R \) is curve separation
\( R \) is measured formation resistivity (ohmm)
\( R_{ns} \) is resistivity of non-source shales (ohmm)
\( S \) is sonic log reading (usec/ft)
\( S_{ns} \) is sonic log reading in non-source shales (usec/ft)
\( K \) is a scale factor = -0.02

\[ TOC = (\Delta \log R)10^{(2.297 - 1.688 LOM)} \]

where,
\( LOM \) is level of organic maturity

Passey et al., 1990
Notes by Presenter

Total organic carbon or TOC can be measured geochemically. But, in absence of geochemical data, we can compute TOC using geophysical well logs.

First, we compute delta-logR from resistivity and sonic logs using reference reading at non-source shale interval. Next, we use this delta-logR to compute TOC in the source rock.
TOC in organic-rich shale interval

Computed TOC in source rock ~ 3
Notes by Presenter

Using this equation, we compute TOC in source rock to be 3. There is another source rock parameter, hydrogen index, and we obtain that from analog basin.
Boundary conditions in modeling

1. **Paleo-water depth**: from seismic data
2. **Heat flow**: decreases from 90 to 75 mW/m² over a geologic period from 120 Ma to present
3. **Sea-water interface temperature**

Based on Wygrala, 1989

![Temperature map](temperature_map.png)
Next we define the boundary conditions. Paleo-water depth. We consider the heat flow value changing from 90 to 75 over a geologic period from 120 Ma to present. This heat flow value is consistent with a typical rift basin, like the one in West Africa.

Sea-water interface temperature also changes with time. After specifying the boundary conditions, we perform finite element simulations.

To calculate boundary conditions, Neumann and Dirichlet are both used. Dirichlet is used to define the upper boundary and Neumann is used to calculate the basal and the side boundaries.

For the thermal calculations, heat flow is used for the basal boundary conditions; temperature is used for the upper boundary. To explain it more geologically: the heat flow is the thermal input at the base of the model; temperature is the thermal output at the top of the model (expressed as SedimentWaterInterfaceTemperature).
Simulation results: 1D Burial history with TTI overlay

![Graph showing burial history with TTI overlay](image)

- **Age (Ma)**
- **Burial depth (meter)**

**Source rock**
Notes by Presenter

This is the burial diagram with the overlay of TTI
Simulation results: Source rock maturation

<table>
<thead>
<tr>
<th>Oil</th>
<th>Gas</th>
<th>Overmature</th>
</tr>
</thead>
<tbody>
<tr>
<td>Immature</td>
<td>Liquid</td>
<td>Overmature</td>
</tr>
</tbody>
</table>

Source rock

Age (Ma)

Burial depth (meter)
Exponential relationship between $V_p$ and TTI

$$f(x) = a \exp(bx) + c \exp(dx)$$

Goodness of fit: $R^2 = 0.7$

$a = 2.548 \ (2.138, 2.958)$
$b = 0.0004934 \ (-0.000434, 0.001421)$
$c = -0.7916 \ (-1.222, -0.3611)$
$d = -0.05831 \ (-0.1291, 0.0125)$
Exponential relationship between $V_s$ and TTI

$$f(x) = a \exp(bx) + c \exp(dx)$$

Goodness of fit: $R^2 = 0.7$

- $a = 1.053 \ (0.744, 1.361)$
- $b = 0.0009603 \ (-0.0006577, 0.002578)$
- $c = -0.4972 \ (-0.815, -0.1793)$
- $d = -0.04791 \ (-0.1154, 0.0196)$
Notes by Presenter

R-square= coefficient of determination = SSr/ SSt = 1 - SSe/ SSt
SSt= total sum of squares
SSr= regression sum of squares
SSe = sum of squared errors
Rock physics model for Mechanical Compaction

Hertz-Mindlin Model

\[ K_{eff} = \left[ \frac{C^2 (1 - \phi)^2 G^2}{18 \pi^2 (1 - \nu)^2} P \right]^{1/3} \]

\[ G_{eff} = \frac{5 - 4\nu}{5(2 - \nu)} \left[ \frac{3C^2 (1 - \phi)^2 G^2}{2 \pi^2 (1 - \nu)^2} P \right]^{1/3} \]

P = Pressure

\( K_{eff} \) = Effective Bulk Modulus; \( G_{eff} \) = Effective Bulk Modulus

C = Co-ordination number; G = Shear modulus

\( \Phi \) = Porosity; \( \nu \) = Poisson’s Ratio
Effects of mechanical compaction

![Graph showing the relationship between velocity (Vp) and depth. The graph includes a trend line and observed data points.](image)
Velocity decreases with Temperature

Experiments by Wang and Nur, 1990
Notes by Presenter

VP measured in n-Alkanes versus temperature. The Numbers represent the carbon numbers.
Velocity decreases with Temperature

Velocity decreases significantly (~15%) for rocks saturated with heavy oil.

Wang and Nur, 1990
Notes by Presenter

Vp (a) and Vs (b) versus temperature in a heavy oil sand. Both Vp and Vs decrease by about 15% as temperature increases from 22°C to 177°C. Vp drops further between 120°C and 177°C at low pore pressures (50 and 100 psi) as water inside the rock transforms to steam [the top two curves in (a)], adding another 10%, or so, Vp decrease. In contrast, Vs increases by about 5% as result of steam.
Effects of Temperature

Decrease in Velocity due to Temperature
Conclusion

1. Vp and Vs increase with TTI and a general exponential equation fits the data reasonably well.

2. Rock physics modeling can help us to understand the control of pressure and temperature on rock.
Notes by Presenter

Application:
Our modeling results can be applied to predict TTI and thereby thermal maturity from observed velocities.
References


Thank You.