Challenges in Pore Pressure Prediction for Unconventional Petroleum Systems*

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Abstract

Formation pore pressure prediction is essential for executing a safe drilling program. For unconventional resources, pore pressure has also a significant impact on our ability to artificially fracture shale formations and to achieve successful completion. In addition, over pressure increases the production drive of liquid hydrocarbons, and favors higher production rates. Our reservoir engineering models suggest that an increase of pore pressure gradient by 0.04 psi/ft will lead to increase in production rate by 150%, and ultimate recoverable volumes by 73%. Thus accurate pore pressure prediction can enable us a much better resource play economic forecasting, especially in the current low commodity price environment.

There are commonly three ways to predict formation pore pressure, seismic methods (inversion of interval velocity derived from stacking velocities), petrophysical calculation (the integration of resistivity, sonic and density data to measure porosity and to associate it with vertical effective stress), and basin modeling (finite element simulation from physical/chemical equations that relate to all possible mechanisms of pore pressure generation). However pore pressure prediction in shale systems is hampered by the lack of "true" pressure values inside shale formations. Due to extremely low permeability in the resource play shales, direct pore pressure measurements with wireline tools for conventional reservoirs do not work. Pressure data in unconventional plays are generally inferred from mud weights and drilling events, instantaneous shut-in pressure (ISIP) during the pad stage, electric Submersible Pump (ESP) pressure gradient estimates or diagnostic fracture injection test interpretations (DFIT). If good quality data are available, these can be used to calibrate pore pressure prediction.

Pore pressure encountered in onshore shale systems can range from significant over pressure, which in many basins is due to uplift and erosion of overburden rocks, to under pressure where subsurface strata are hydraulically connected via outcropping to high altitude surfaces. Generation of subsurface abnormal pressure can be one or a combination of several mechanisms: shale rock under-compaction (disequilibrium compaction), lateral compression, aqua thermal expansion, mineral transformation, hydrocarbon generation, cementation, centroid effect, hydrocarbon buoyancy, etc. Pore pressure prediction from the basin modeling approach depends on good understanding of physical principles of each process, and our ability to decide which of these processes play a more dominant role than the others.

This presentation will describe our experience when using different modeling tools to reconstruct formation pore pressure. Many times default shale compaction curves, while being very effective in over pressure generation for offshore Tertiary basins, are inadequate to cause large magnitude over pressure in unconventional shales, because these curves are probably representing much higher permeability than those observed in these shales. The contributions from hydrocarbon generation and aquathermal effects are often needed, and significant, for additional over pressure generation. Chemical compaction via quartz/carbonate cementation provides an alternative or addition to simulate pore pressure transition. This presentation will also discuss the impact of complex burial/uplift history to overburden and pore pressure evolution in shale systems.

The fact that some high abnormal pressures have existed for tens to hundreds of million years after original shale deposition and after hydrocarbon generation has baffled geologists as to how these over pressure systems were formed and persisted in geologic history. These observations and the way we understand them will also have implications on the interpretation of inter-connectivity of subsurface pore systems, and on the hydrocarbon charge and migration in and out of unconventional shales.

Reference Cited

Swarbrick, R.E., M.J. Osborne, and G.S. Yardley, 2002, Comparison of overpressure magnitude resulting from the main generating mechanisms, *in* A.R. Huffman and G.L. Bowers, eds., Pressure regimes in sedimentary basins and their prediction: American Association of Petroleum Geologists, Memoir 76, p. 1-12.

CHALLENGES IN PORE PRESSURE PREDICTION FOR UNCONVENTIONAL PETROLEUM SYSTEMS

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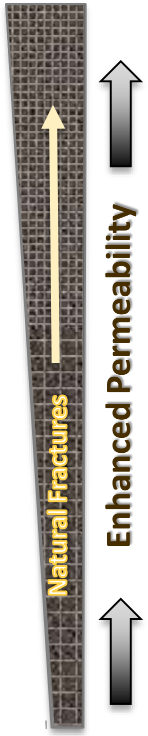
TALK OUTLINE

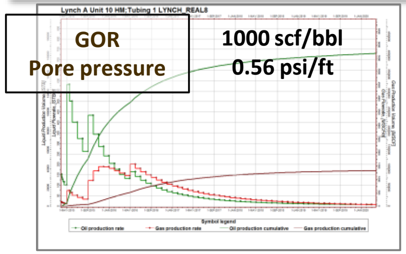
- The importance of pore pressure on unconventional play development
  - Overpressure relationship with production rate and EUR
  - Overpressure impacts mechanical fracturing
- Overpressure generation mechanisms
- Methods of pore pressure prediction
- Pore pressure measurements in UCR
- Permeability measurements
- Case studies:
  - offshore Tertiary basin
  - onshore Mesozoic basin
  - onshore Paleozoic basin
- Pressure dissipation time scale in older basins
- Conclusions and implications

IMPACT OF FORMATION PRESSURE TO HZ PERFORMANCE

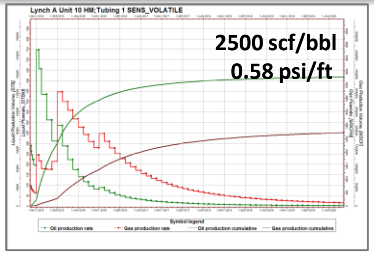
- UCR: “reservoir” which requires significant stimulation to provide economic production rates
- Fine-grained rock acting as both hydrocarbon source and reservoir
- A simple sector numerical model to simulate production history of a horizontal well
- To test sensitivity of its performance to parameters of fluid quality, pressure, and reservoir quality

Increasing maturity and pressure

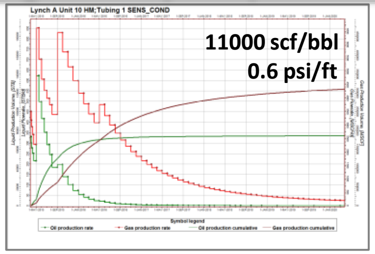




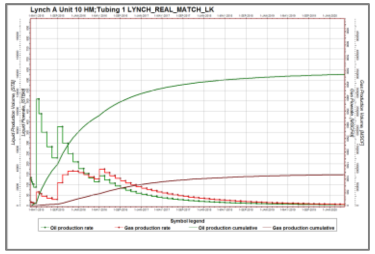
Black Oil (Base Case)
- IP: 680 BOED (86%Oil)
- Cum@360days: 161 MBOE (66%Oil)
- Cum@5yr: 320 MBOE (51%Oil)
- Cum@20yr: 390 MBOE (57% Oil)



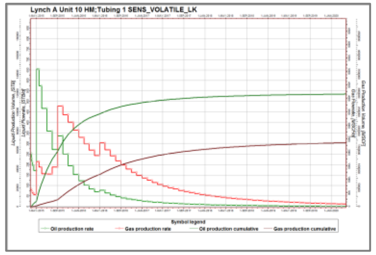
Volatile Oil
- IP: 1,065 BOED (70%Oil)
- Cum@360days: 261 MBOE (42%Oil)
- Cum@5yr: 462 MBOE (30%Oil)
- Cum@20yr: 499 MBOE (28% Oil)



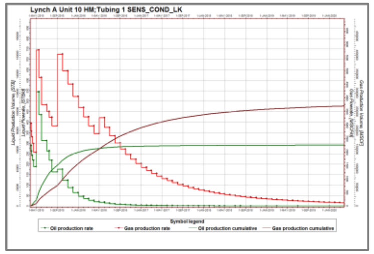
Retrograde condensate
- IP: 1,700 BOED (36%Oil)
- Cum@360days: 343 MBOE (20%Oil)
- Cum@5yr: 591 MBOE (13%Oil)
- Cum@20yr: 674 MBOE (11% Oil)



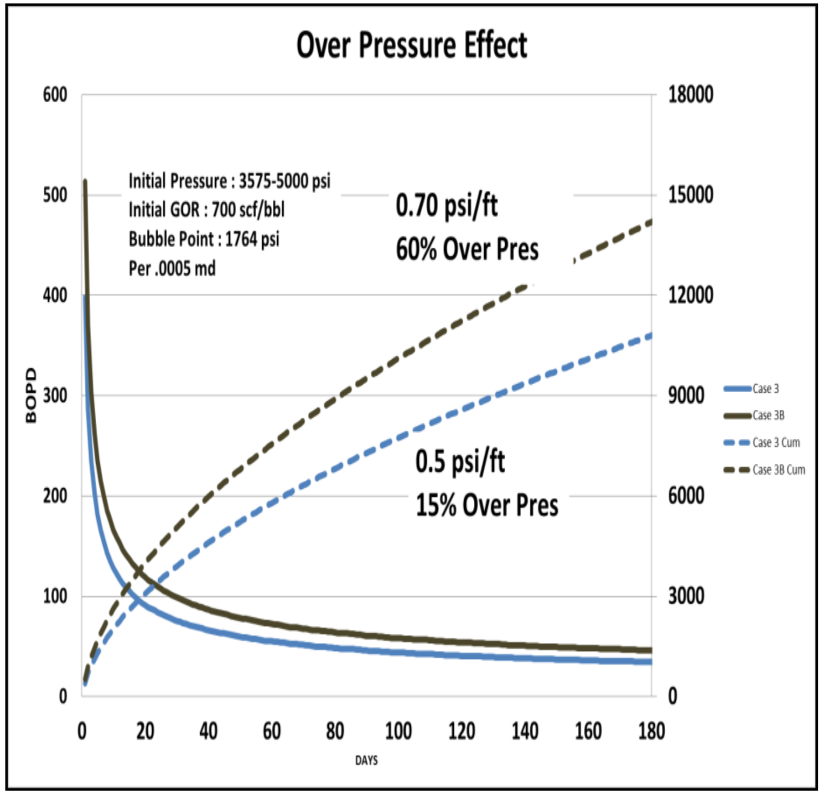
Black Oil (fewer nat. fractures)
- IP: 594 BOED (86%Oil)
- Cum@360days: 140 MBOE (66%Oil)
- Cum@5yr: 277 MBOE (50%Oil)
- Cum@20yr: 309 MBOE (54% Oil)



Volatile Oil (fewer nat. fractures)
- IP: 819 BOED (70%Oil)
- Cum@360days: 228 MBOE (42%Oil)
- Cum@5yr: 400MBOE (30%Oil)
- Cum@20yr: 415 MBOE (29% Oil)



Retrograde condensate (fewer nat. fractures)
- IP: 1,510 BOED (36%Oil)
- Cum@360days: 299 MBOE (20%Oil)
- Cum@5yr: 507 MBOE (13%Oil)
- Cum@20yr: 533 MBOE (12% Oil)

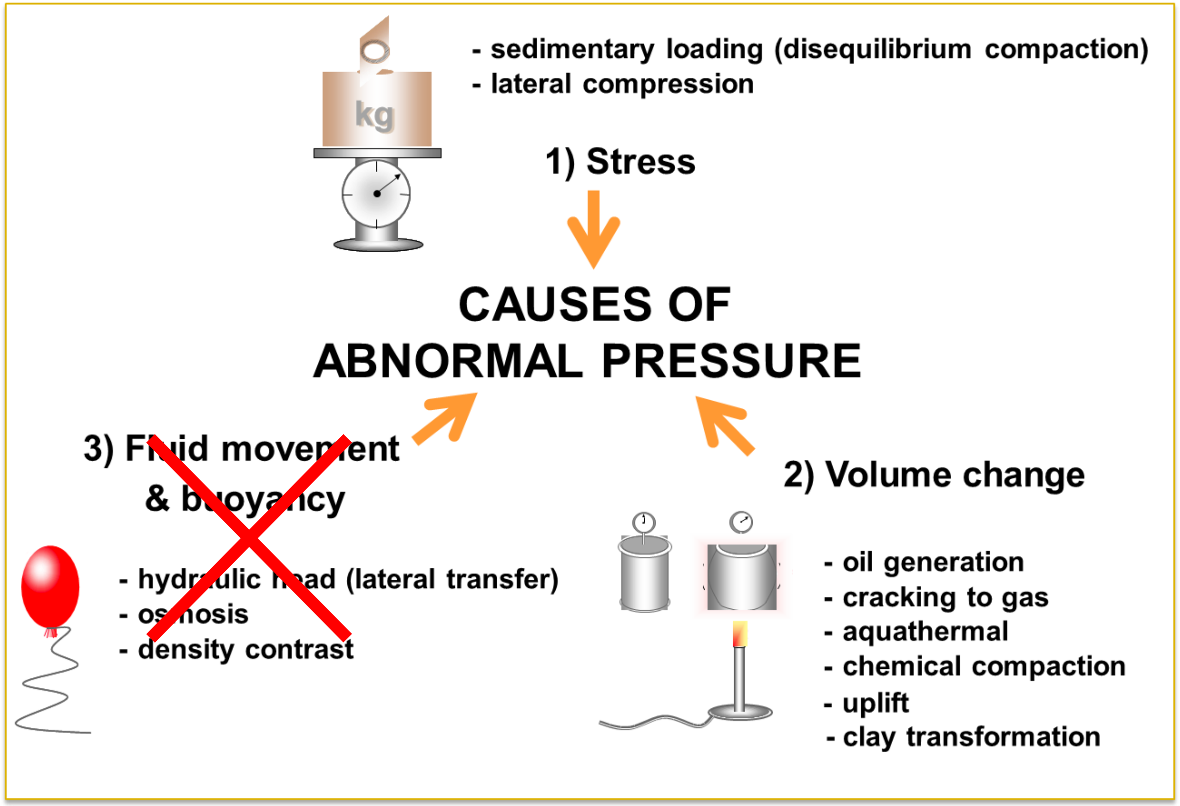


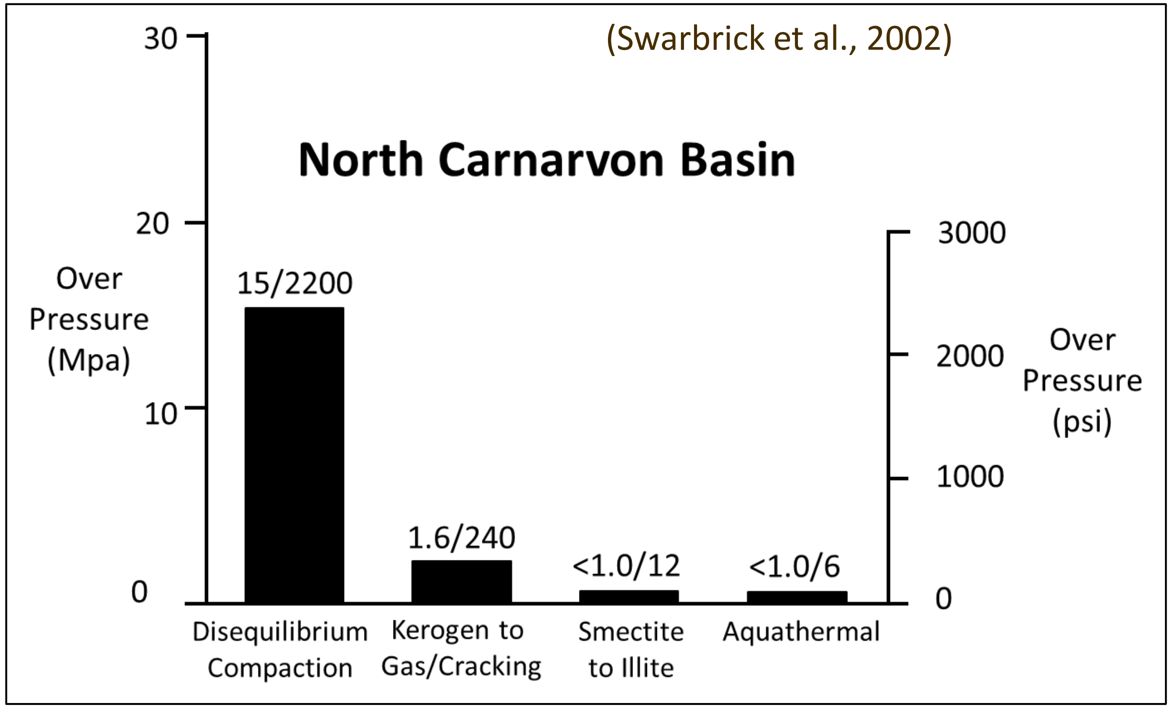
OVERPRESSURE- EFFECT IN FRACKING

- Fracture Geometry & initiation
  - Primarily controlled by in-situ stresses
  - Must overcome the 'minimum' stress to generate a fracture
  - $\sigma_h = P_{cl} = (\upsilon/(1-\upsilon)) * (OB - P_R) + P_R + T_{tectonics}$

    h - horizontal stress; cl - closure pressure; ʋ - poisson's ratio; OB – overburden; R – reservoir
  - Given a Poisson's ratio of 0.33, ~50% of the overpressure will translate into increasing minimum stress value

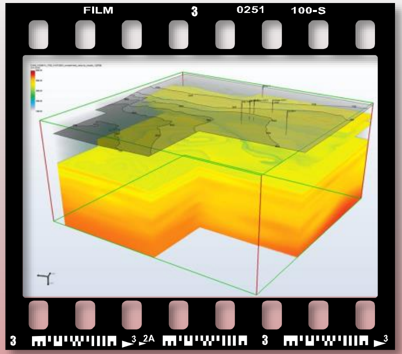
MECHANISMS OF ABNORMAL PRESSURE GENERATION





"Magnitude of overpressure from fluid expansion mechanisms is controlled by the rate of volume change which might be slow for the burial rates and temperature gradients found in most basins."

METHODS OF PORE PRESSURE PREDICTION



GEOPHYSICAL BASIS

Velocity or frequency analysis.

Vertical resolution dependent on seismic interval velocity picking.

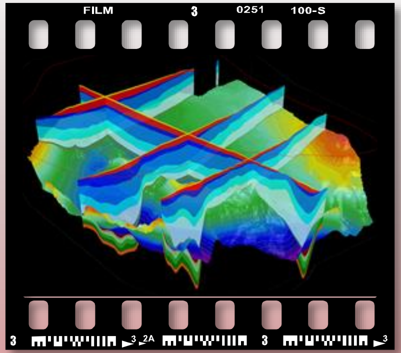
Predicts pore pressure in shale.

“Centroid” assumptions for predicting sand pressures.

Influenced by sand presence, mudstone composition, gas, organics…

Benefits from calibration.

Seismic



GEOLOGICAL BASIS

Honors geology and “plumbing”.

Captures geologic uncertainty.

Multiple models – quantifies abundance of sand presence.

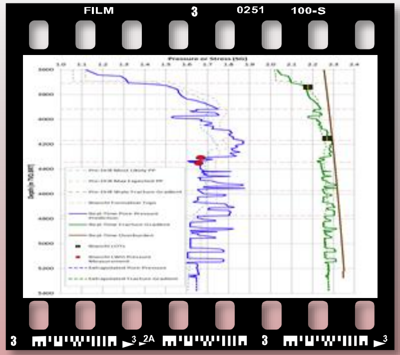
Allows for mudstone composition.

Can predict where seismic is poor – e.g. sub-salt.

Predicts hydrocarbon type.

Needs well control, cuttings analysis, etc. ideally.

Basin Modeling



OFFSET EXPERIENCE BASIS

Honors offset experience.

Based on routine logs (sonic, resistivty, density).

Accurate for the well in question; limited by extrapolation to new well locations.

Predicts pore pressure in shale.

Influenced by sand presence, mudstone composition, gas, organics…

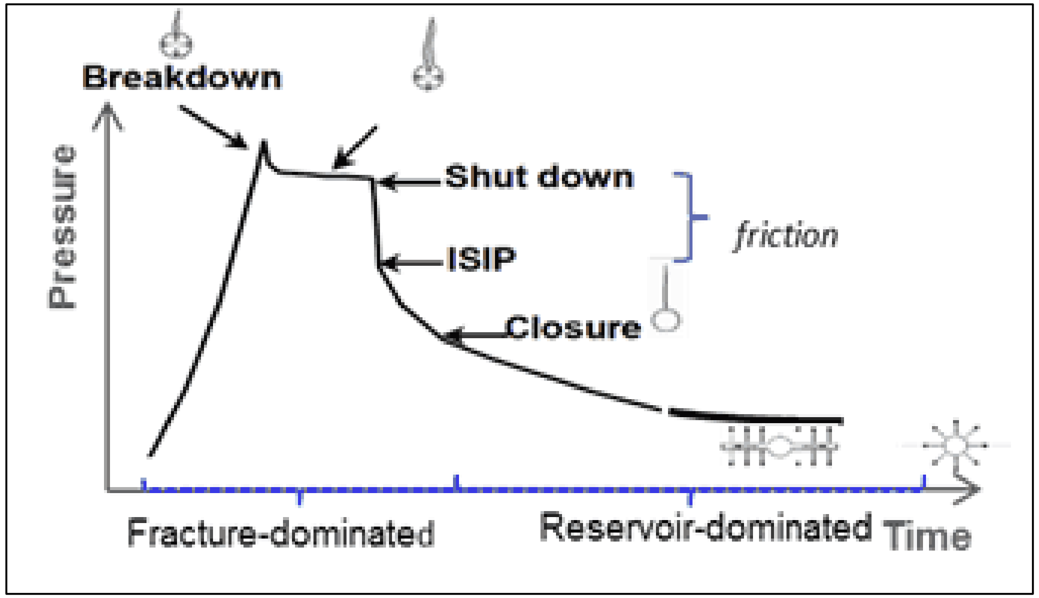
Offset well data

Petrophysical challenges for UCR :

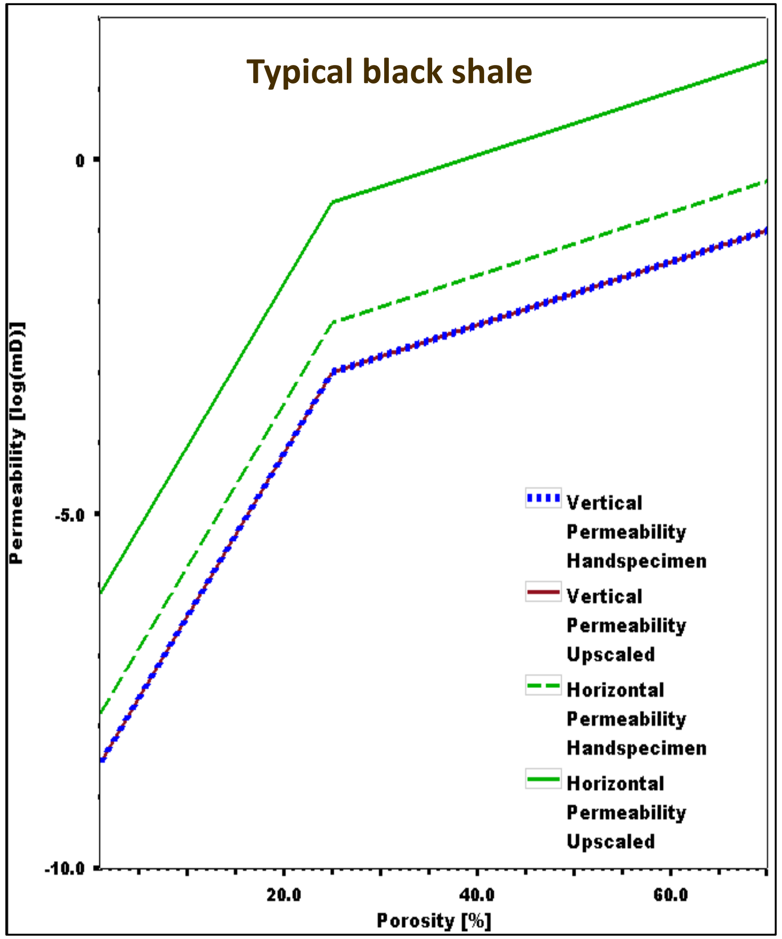
- Hydrocarbon generation and presence influences density and sonic compressional velocities.
- Variation in compaction and uplift requires consideration of “unloading paths” in pressure prediction methods, which complicates interpretation.
- Prediction is still possible using logs that are less influenced by these factors – e.g., shear sonic.

PORE PRESSURE MEASUREMENTS FOR UCR

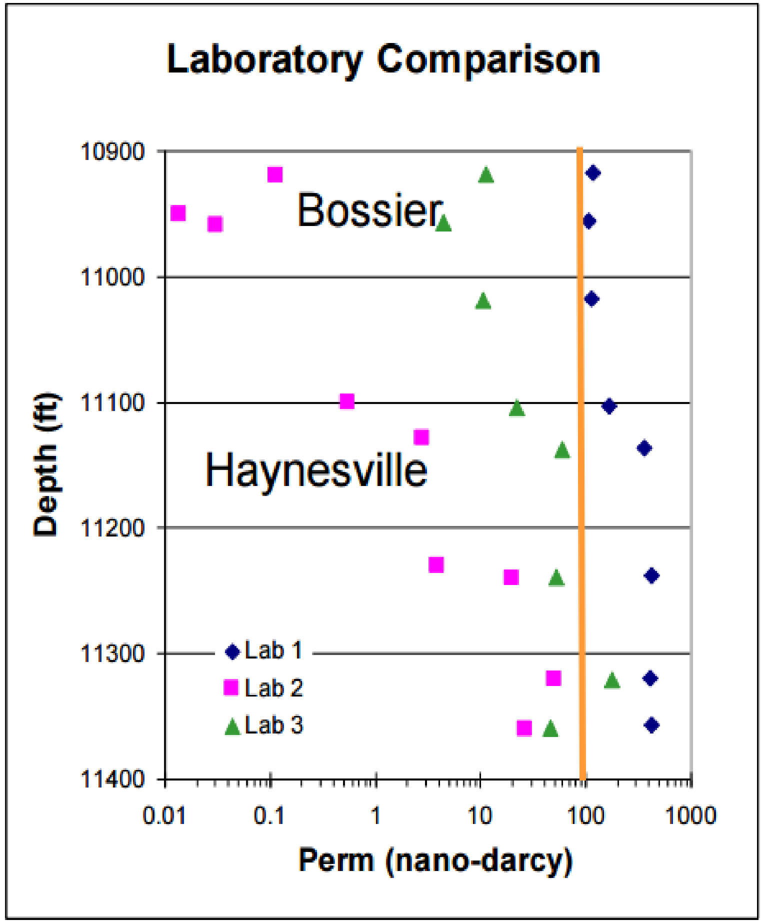
- Accurate pressure measurements are needed for calibration to all pore pressure prediction methods.
- Conventional techniques of pore pressure measurement for conventional reservoirs (>1 mD permeability), such as MDT (modular dynamic tester), RFT (repeat formation test), DST (drill stem test), etc. don't work for unconventional reservoirs due to the latter's low permeability
- Unconventional play pressure measurements:
  - Diagnostic fracture injection test (DFIT)
  - Instantaneous shut-in pressure (ISIP)
  - Electric submersible pumps (ESP)
  - Mud weights and drilling events (kicks, etc.)



PERMEABILITY MEASUREMENTS FOR UCR

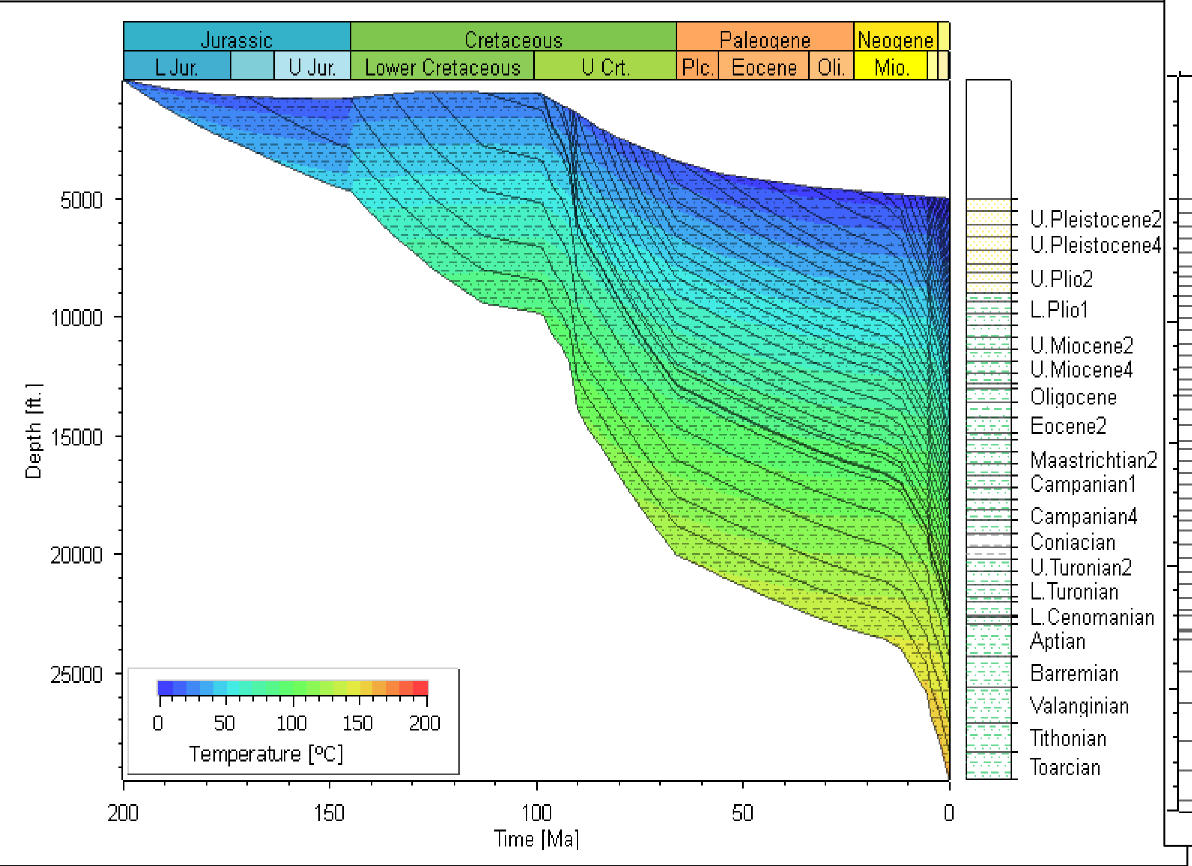


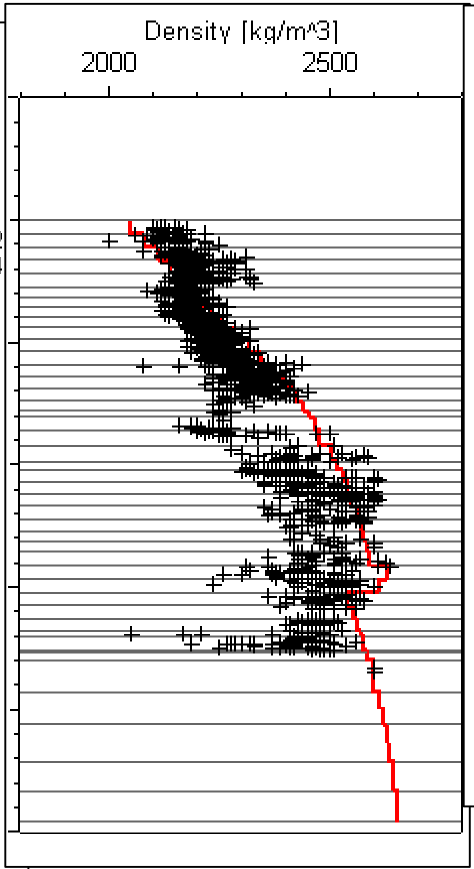
- Porosity-permeability relationship essential for pore pressure prediction in basin modeling
- Two primary methods: steady state or pressure pulse
- With different gases: helium, nitrogen, or methane
- Performed on core plugs, core chips or drill cuttings
- On native samples or solvent extracted
- Particle size effect
- Impact of micro-fracture presence
- Matrix permeability vs bulk permeability
- Laboratory procedure variations

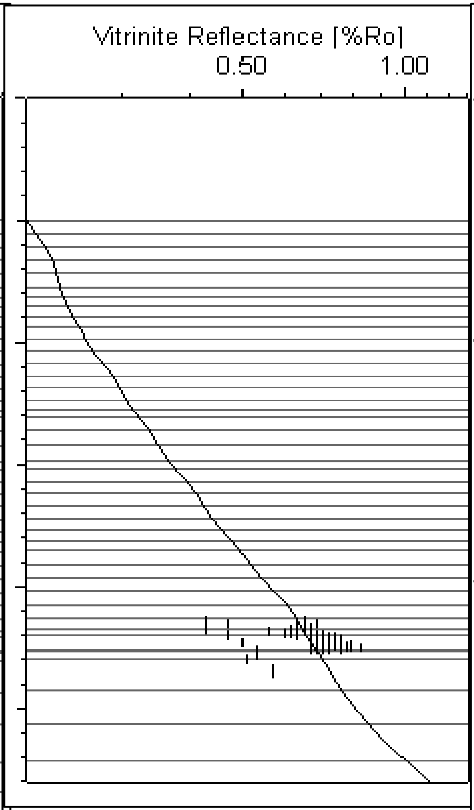


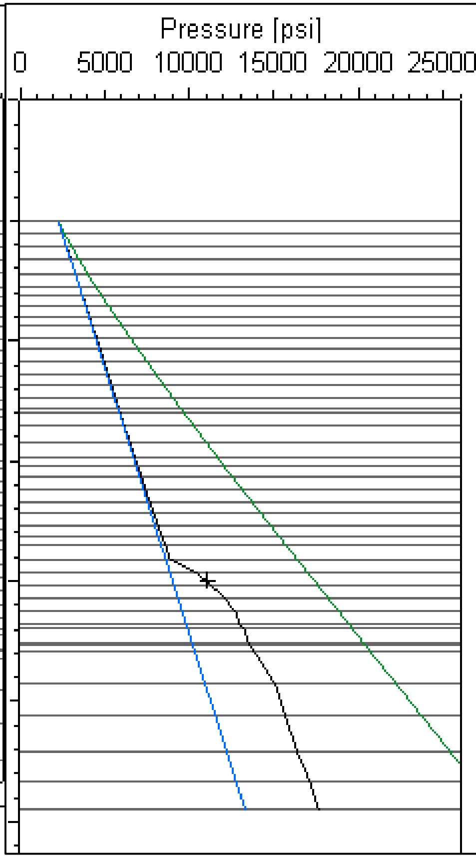
EXAMPLE 1: TERTIARY BASIN DEEPWATER

- A Tertiary basin at deepwater location with significant late sedimentation
- Fairly low temperature in the well and a Turonian source rock around 22,000' is in early maturation window
- Pore pressure generation is likely dominated by under-compaction disequilibrium within high clay mudstone



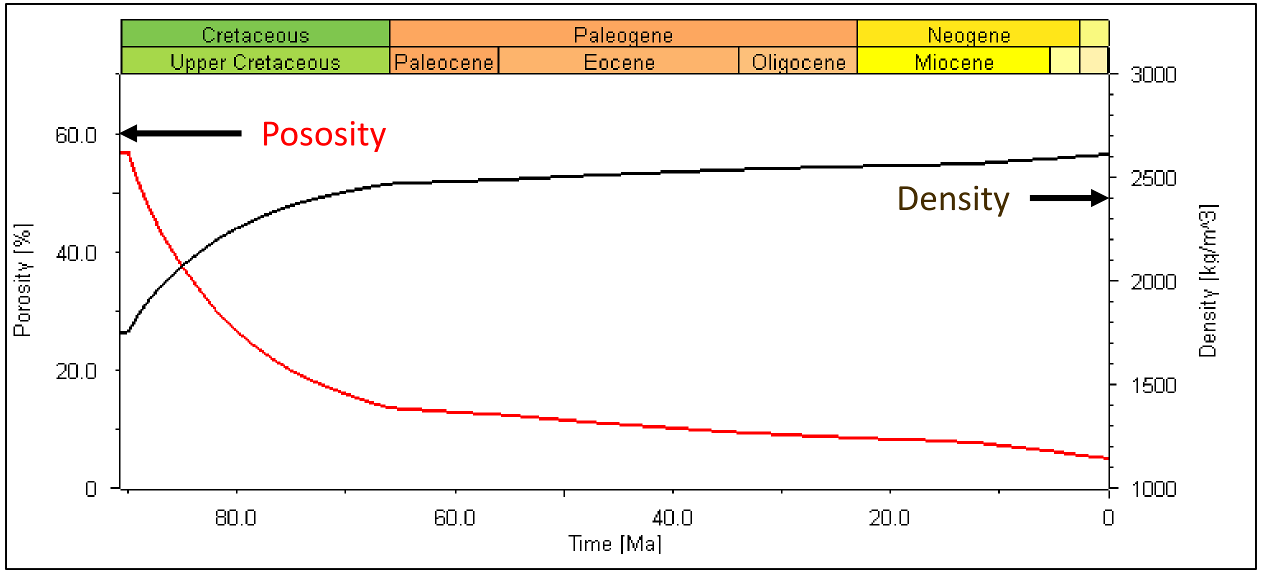


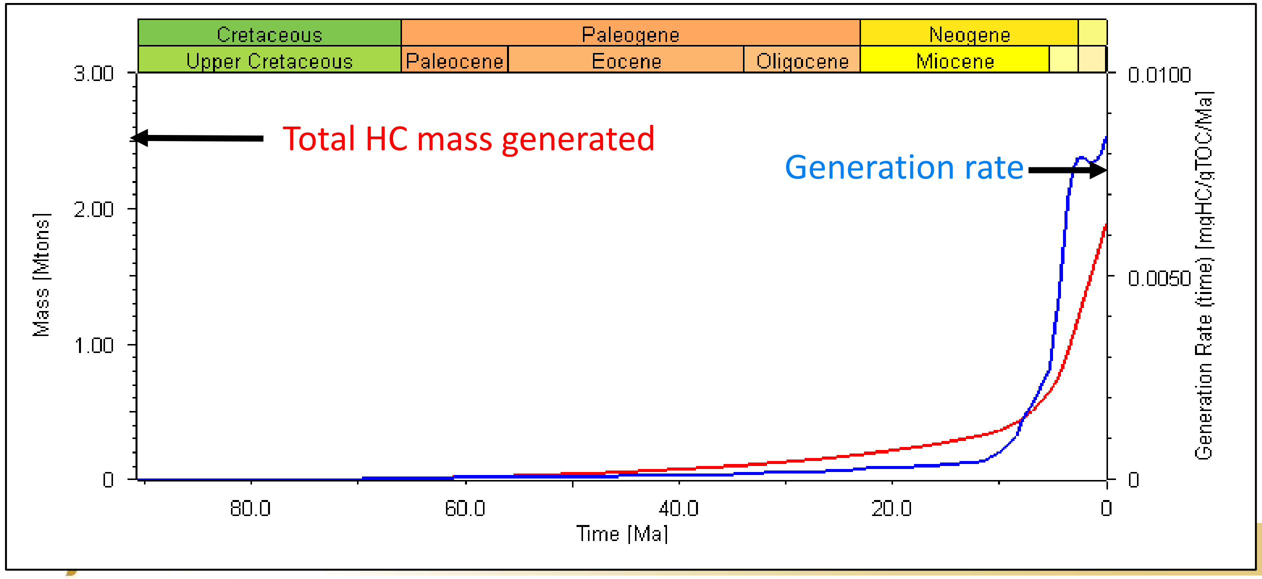


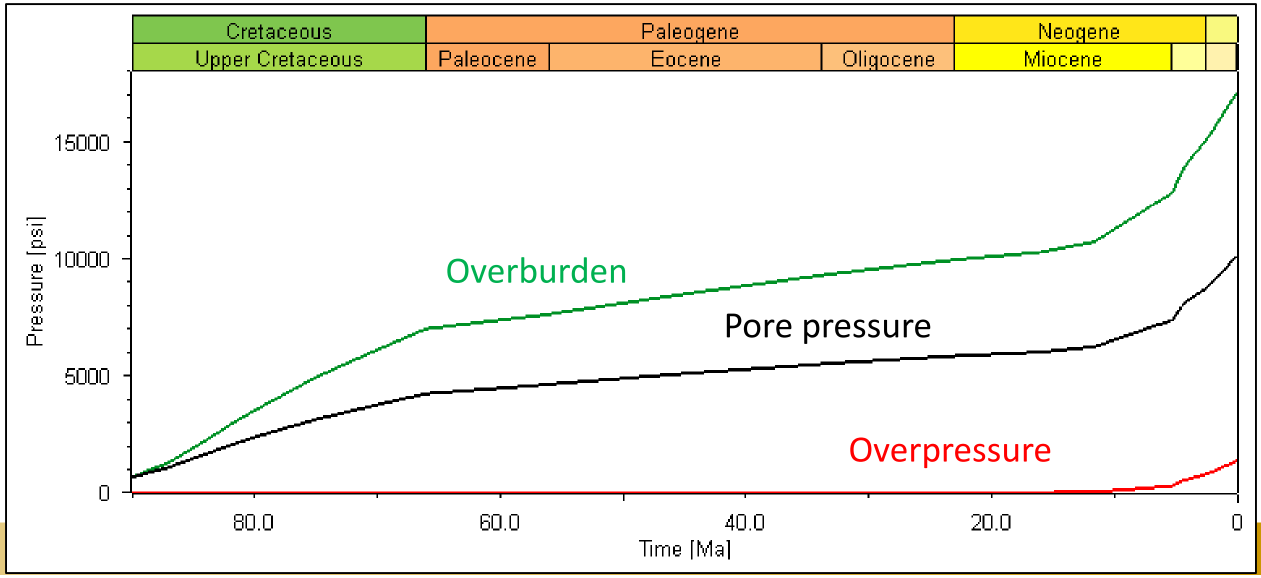


EXAMPLE 1: TERTIARY BASIN DEEPWATER

- Rock matrix properties responded to initial burial and increasing sedimentation rates late Neogene
- Overpressure at top of Mesozoic reservoir developed very late in response to late Miocene and Quaternary sedimentation, so is the source rock maturation and generation
- Source rock is below the reservoir, and HC generation is unlikely source of overpressure.

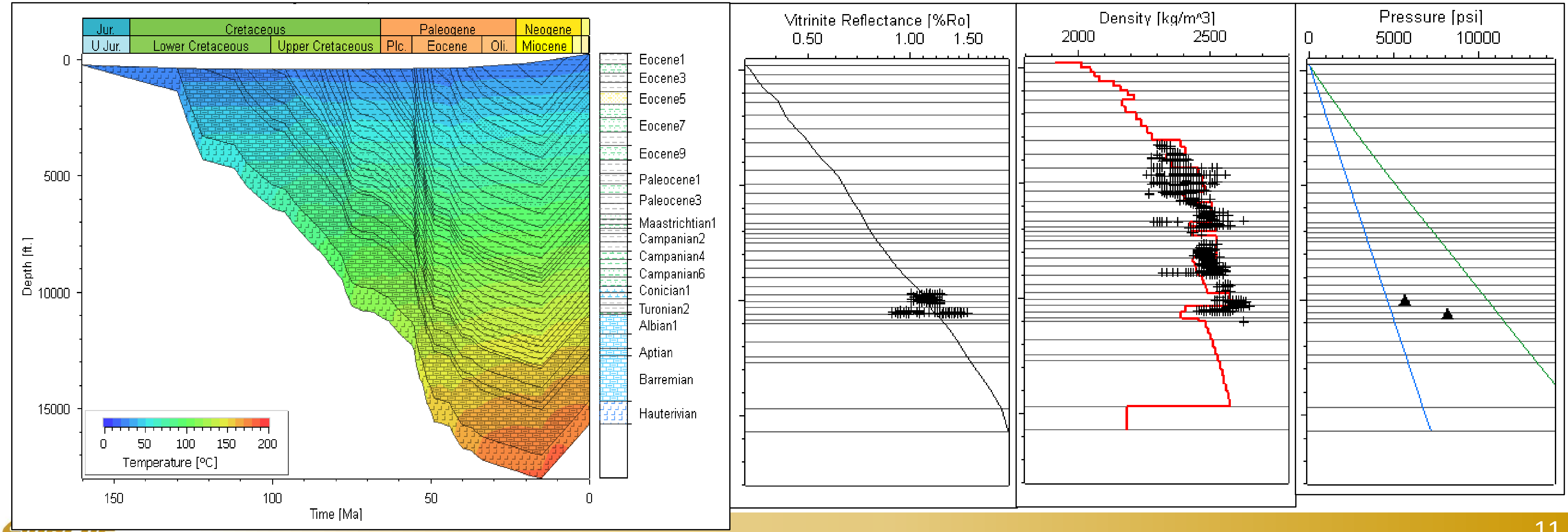






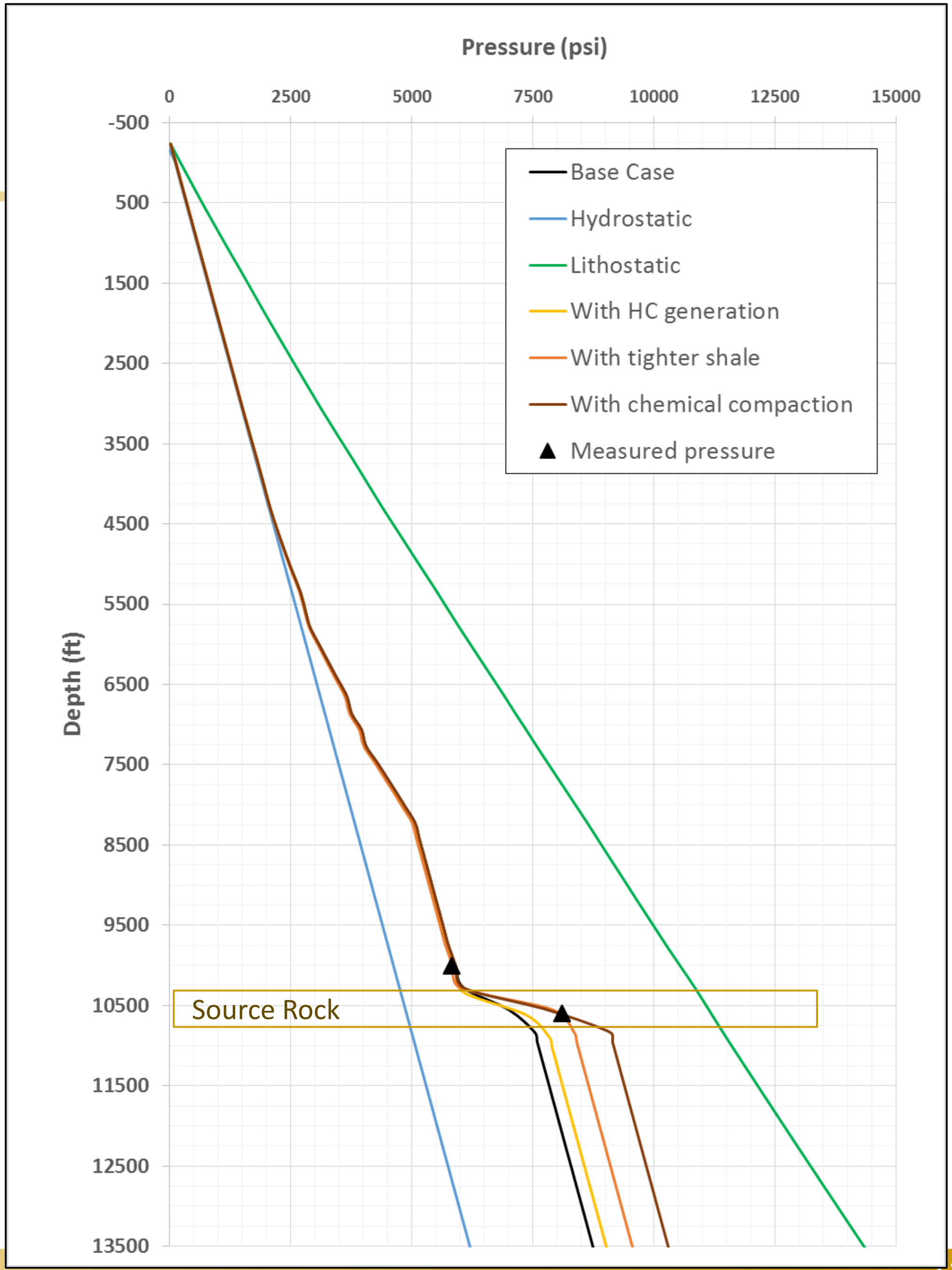
EXAMPLE 2: ONSHORE MESOZOIC BASIN

- Consistent sedimentation from Cretaceous to early Miocene
- Significant uplift and removal of overburden up to 2000 ft
- A Turonian source rock is in late oil to condensate generation window
- There is a sharp pressure transition from chalk above (0.55 psi/ft) to within the source rock (0.75 psi/ft)

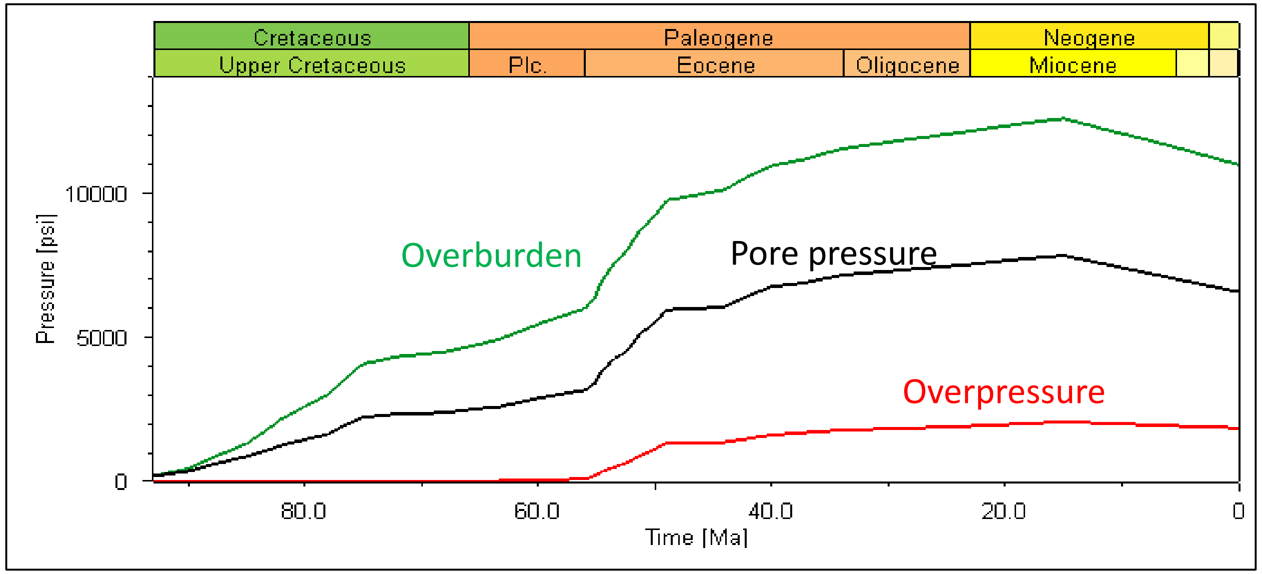


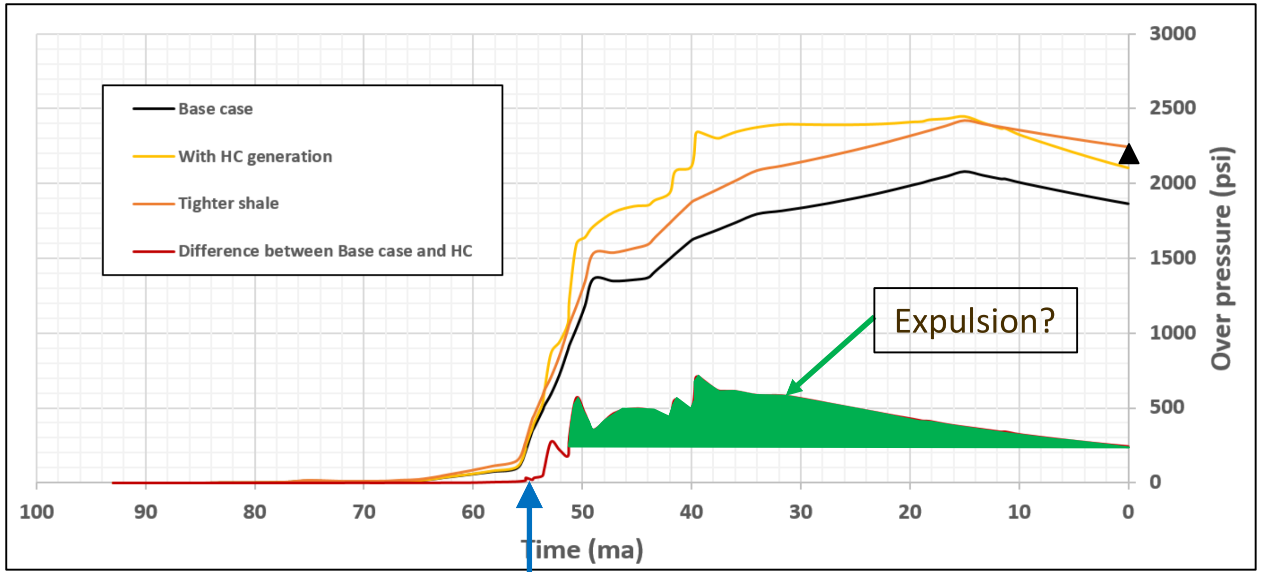
EXAMPLE 2: MESOZOIC BASIN

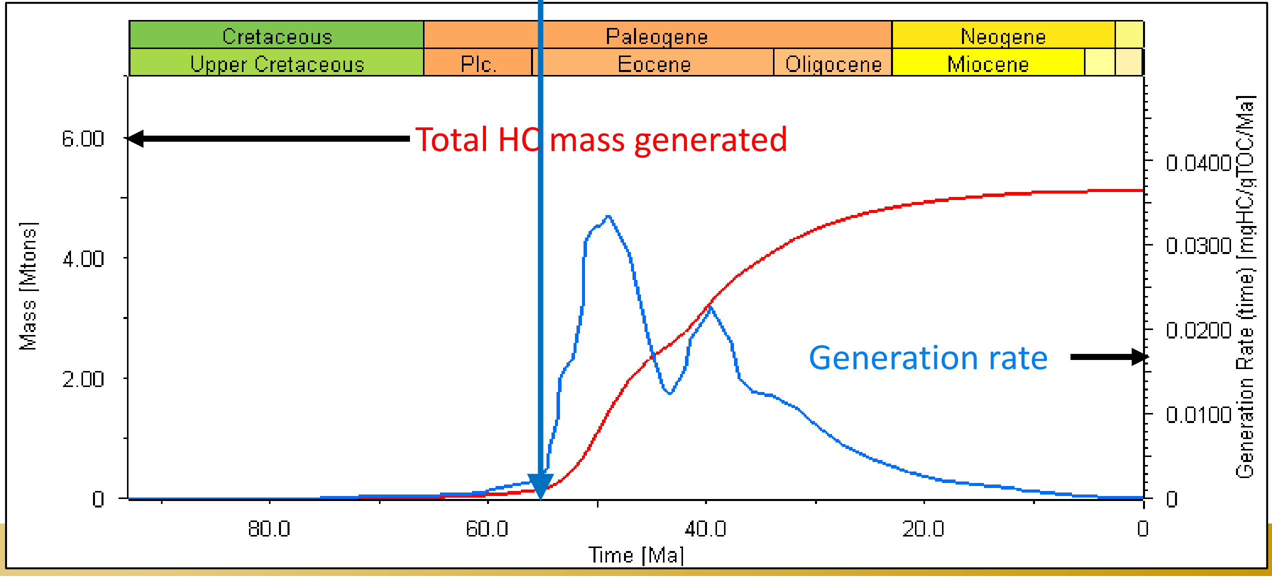
- Multiple scenarios are tested to understand OP generation mechanisms
  - Base case with default organic rich shale in Turonian source rock
  - 2nd case with hydrocarbon generation from distal marine source rock, no secondary cracking due to temperature
  - 3rd case with a slightly tighter shale for the source rock layer: permeability reduction from 10^{-3} to $10^{-3.2}$ mD at 25% porosity and $10^{-8.52}$ to $10^{-9.3}$ at 1%
  - 4th case with chemical compaction activated for the source rock only: Schneider's pressure solution and overgrowth as a function of thermal stress resulting in porosity reduction
- The HC generation contributed to about 10% of the overpressure within the source rock, not enough to explain the sharp pressure transition.
- A simple tighter shale for the source rock will suffice to generate enough overpressure into the formation.
- A regular shale with chemical compaction even extends that overpressure further into the base of the source rock.



EXAMPLE 2: ONSHORE MESOZOIC BASIN



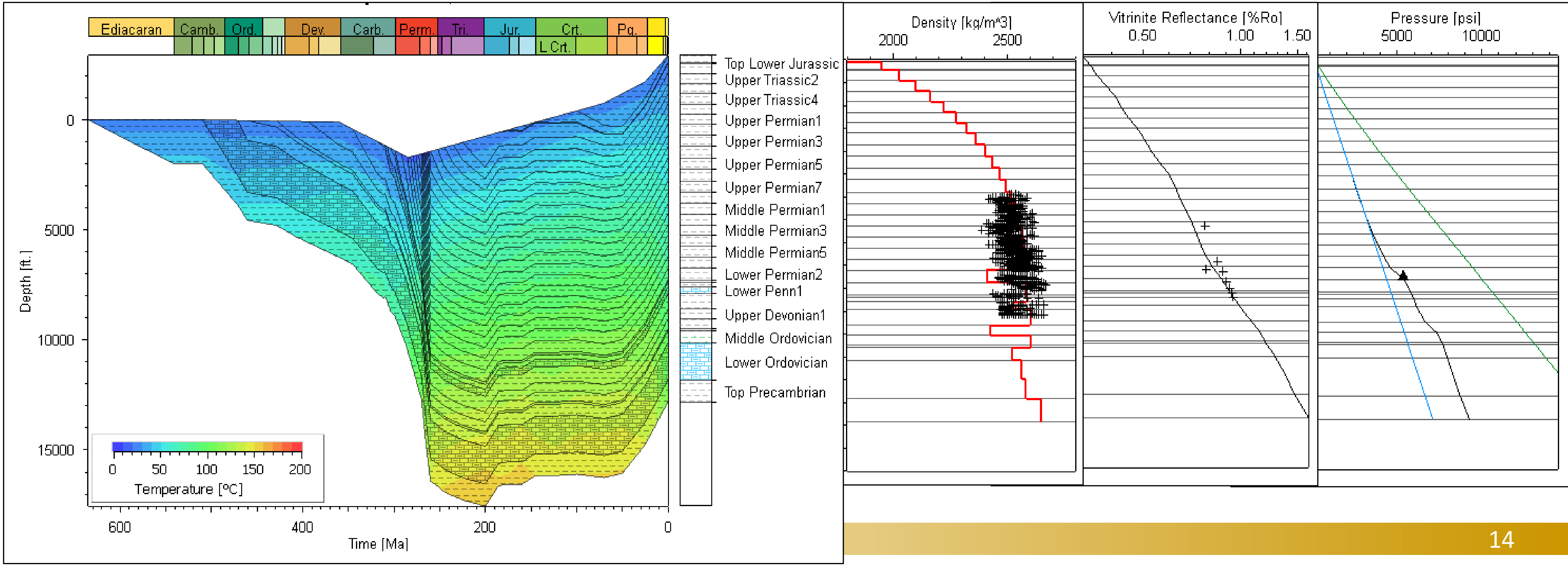




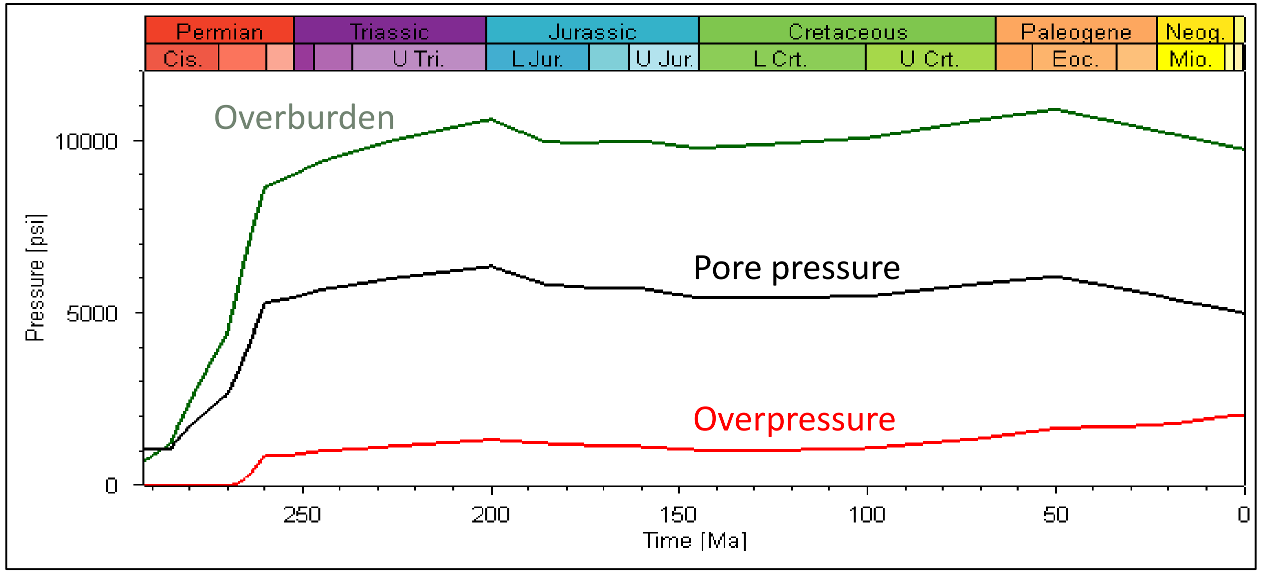
- Overpressure initiated with increasing Paleogene sedimentation rate.
- The Neogene uplift and erosion reduced the overburden by ~1600 psi and overpressure by 200-400 psi.
- Additional overpressure from HC generation consistent with source rock generation rate curve.
- Expulsion of HC expressed as the overpressure decline?

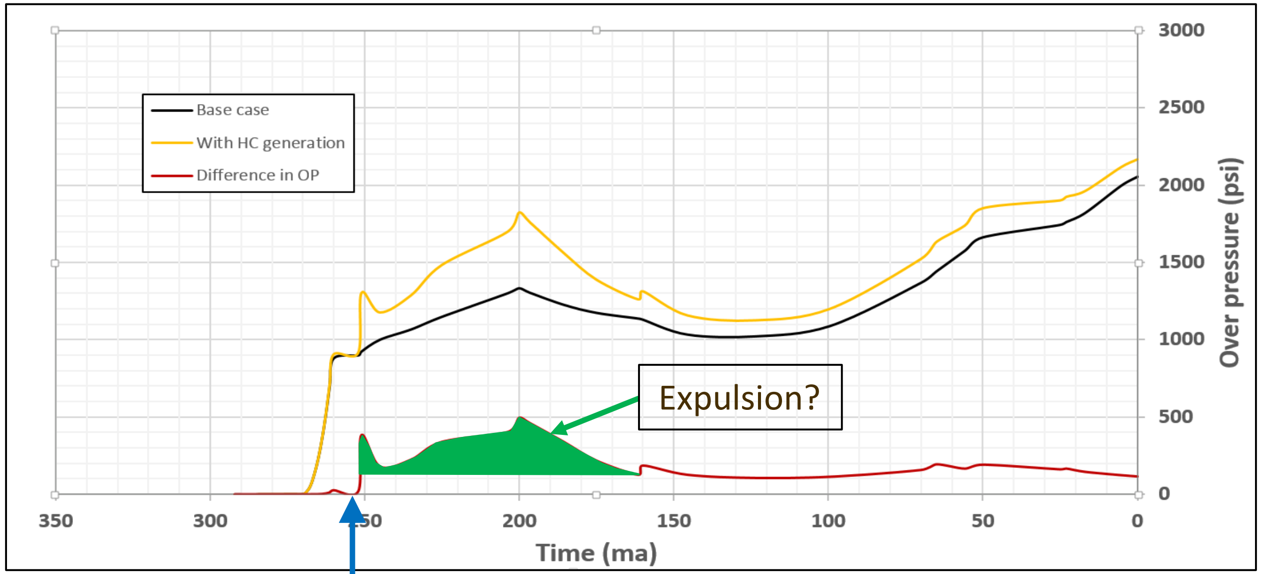
EXAMPLE 3: ONSHORE PALEOZOIC BASIN

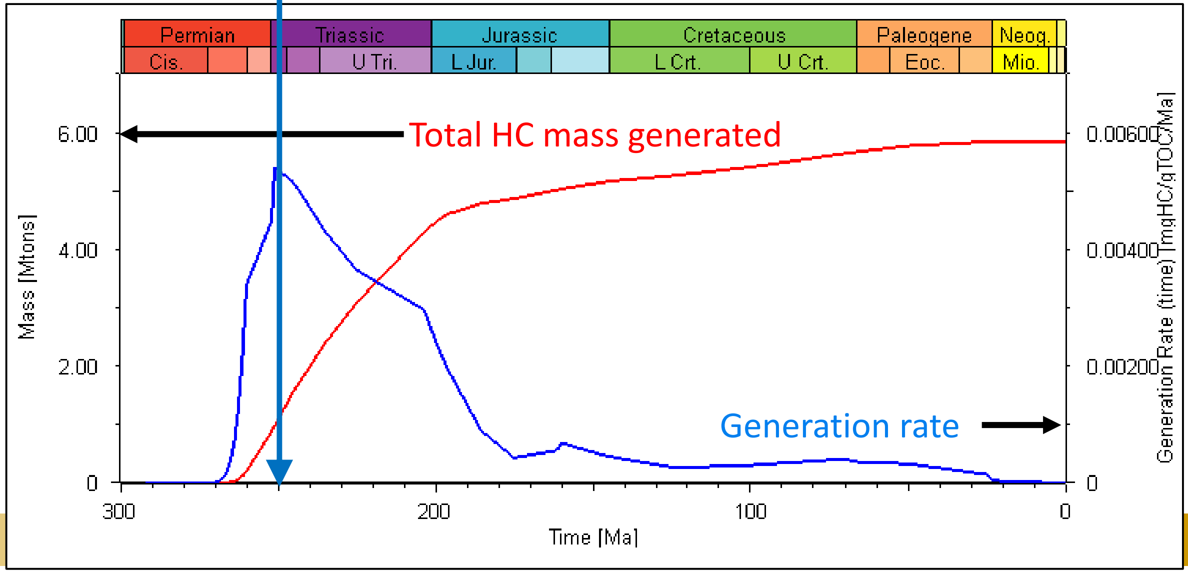
- This Paleozoic basin experienced significant depositional event pre-Triassic time.
- The basin was uplifted for the most part of Mesozoic time.
- A Permian aged resource play has variable over-pressure developments from hydrostatic to over 0.7 psi/ft.



EXAMPLE 3: ONSHORE PALEOZOIC BASIN



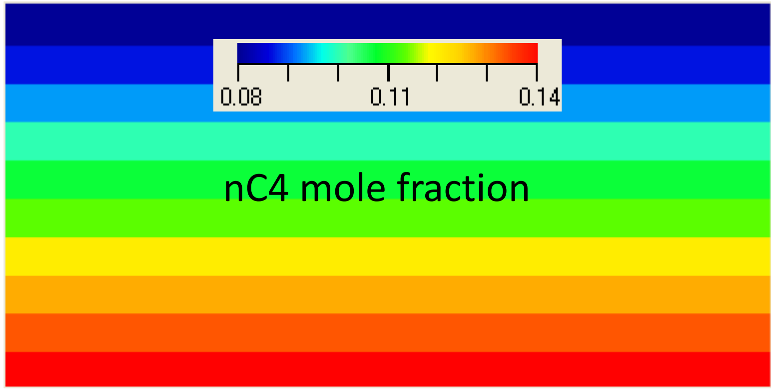


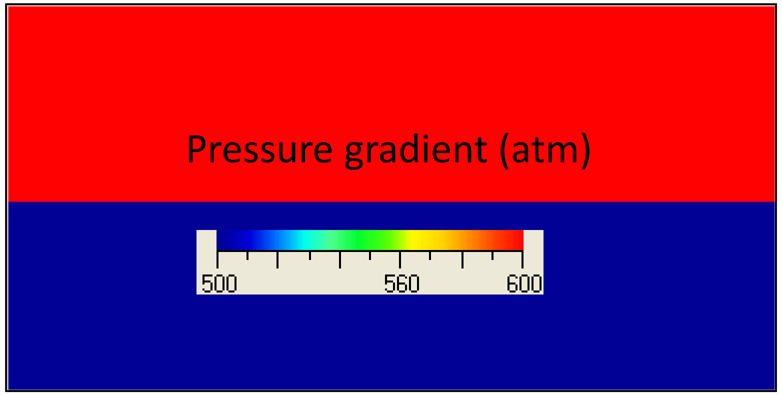


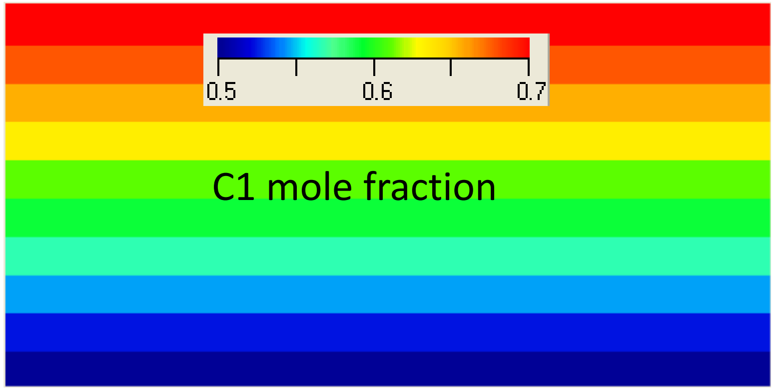
- After its development at late Permian time, overpressure magnitude remained and values reflected basin evolution with uplift and overburden variation (Cretaceous seaway development).
- HC generation contributes less than 5% of the total overpressure today, and the magnitude more or less corresponded to HC generation rate which was minimal since 150 ma.
- Persistent overpressure over 250 myr needing explanation.

BOX MODEL FOR FLUID MIXING STUDY

- To understand the relative significance of fluid data (pressure and composition) to reservoir segmentation studies
- A miscible fluid mixing simulator implemented Darcy flow, advection, and molecular diffusion (Klinkenberg effects)
- To determine different time scales of equilibrium with these mechanisms
- Results validated with analytical solutions and other numerical simulations







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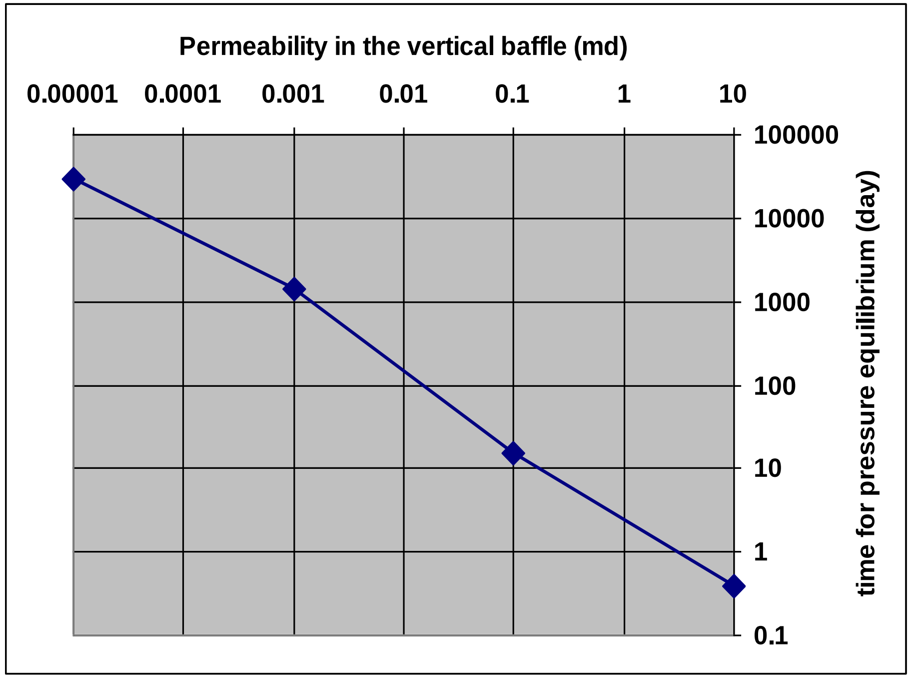
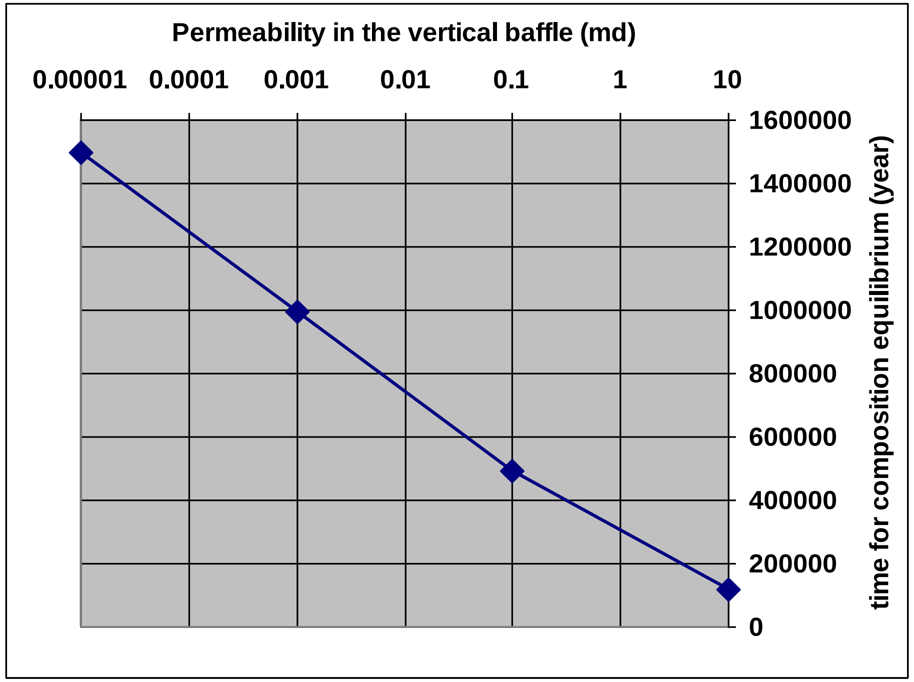
PRESSURE/COMPOSITION DEPENDENCY ON PERMEABILITY

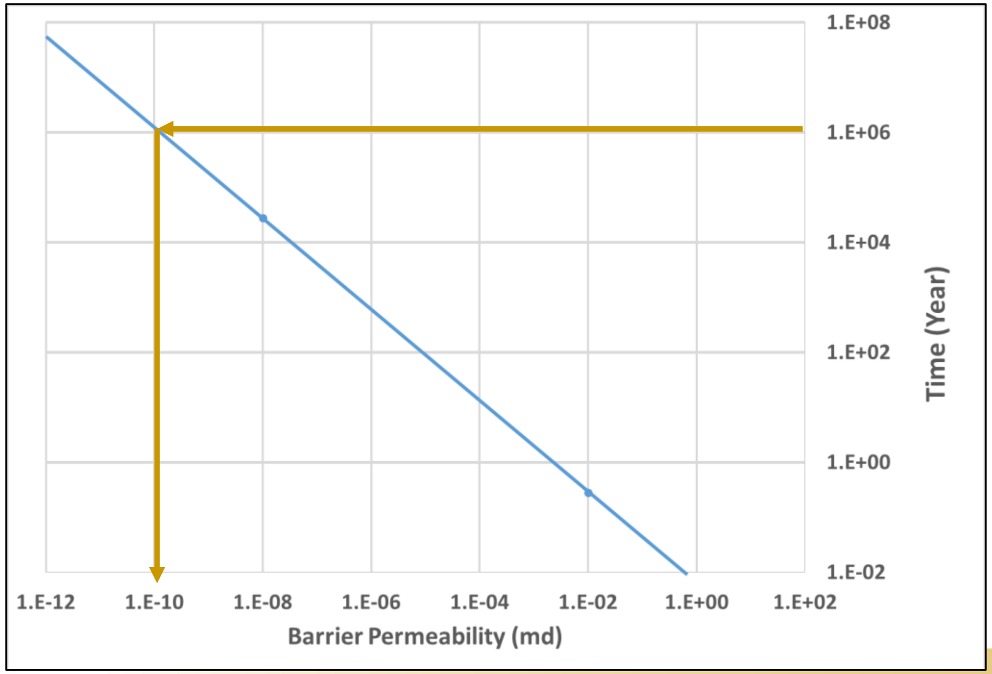


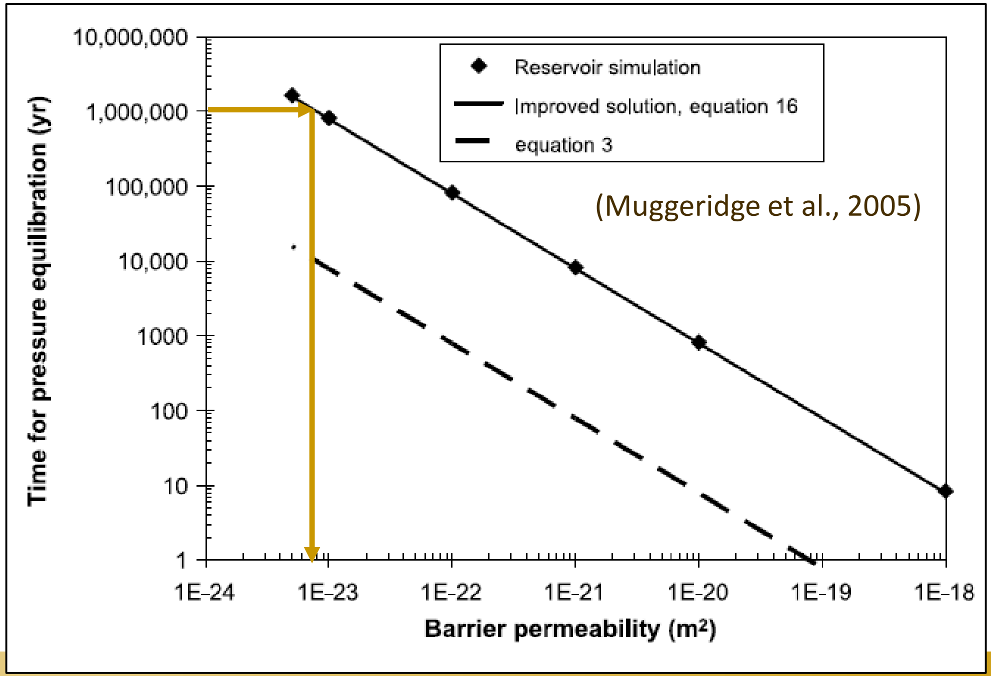


- Simulations of reservoir models with n-component compositions and pressure gradients suggests pressure equilibration is the fastest and is several orders of magnitude shorter in time scale than compositional equilibrium/steady states. **Where is hydrocarbon expulsion and migration**?
- With decrease in vertical permeability, equilibration time increase significantly.
- Time needed for pressure dissipation is log-log proportional to barrier permeability, and semi log proportional for compositional equilibration.

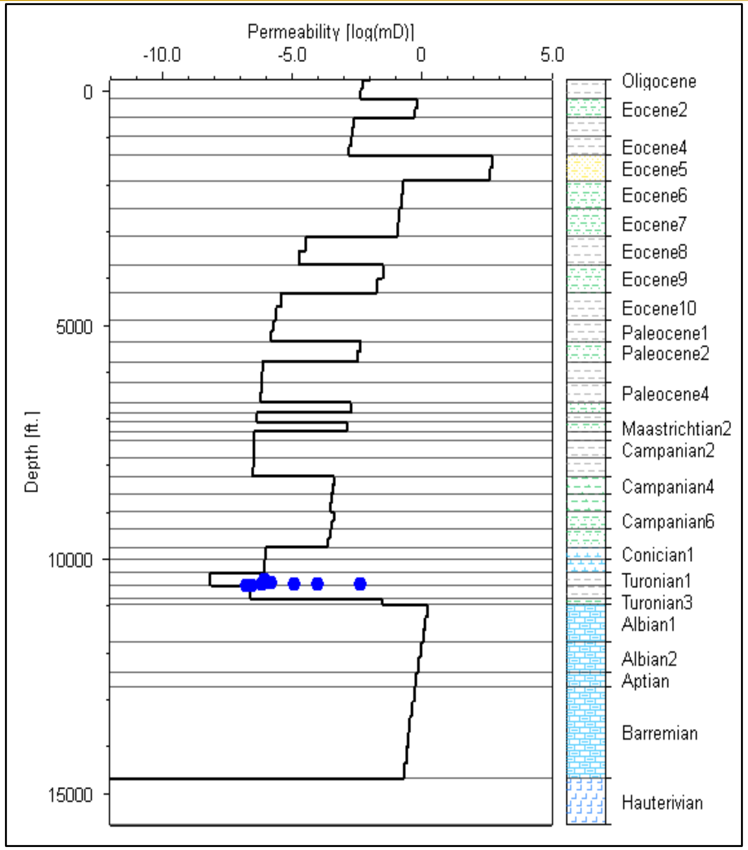
PRESSURE DISSIPATION TIME SCALE AND PERMEABILITY

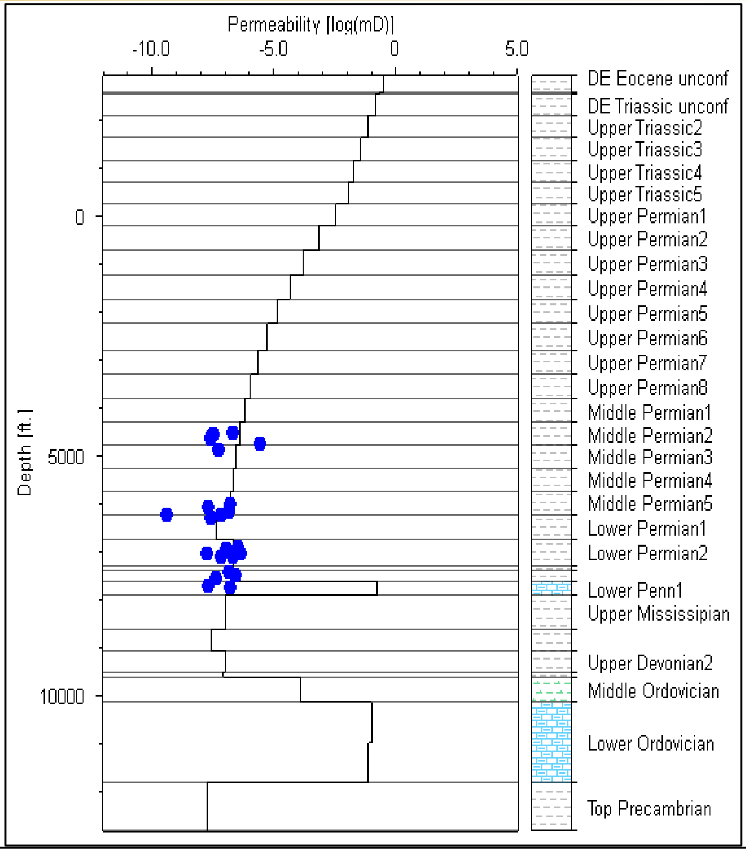
- Extending the above simulation results to lower permeability barriers suggests that 10^{-10} mD permeability is needed to maintain overpressure over 1 million years.
- Other analytic studies (Muggeridge et al, 2005; Deming, 1994) suggests 10^{-6} to 10^{-9} mD permeability for pressure dissipation in 1 million years.
- For old basins such as Permian basin and Anadarko basin where there were no significant sedimentation and hydrocarbon generation for the last 200 myr, this requires really tight shale formation (10^{-8} -10^{-12} mD) to hold significant over-pressure in place.





PERMEABILITY RANGES AND PREDICTION





- Permeability data in the Turonian samples were measured by steady state method on core samples
- The wide range of values may reflect the presence of micro-fractures
- Overall these values are very optimistic and higher than permeability required for pore pressure generation

- Permeability data in the Permian source rock samples were measured by pulse methods on powdered core samples
- The range of values (10^{-6} to 10^{-10} mD) may be due to lithology variations
- Basin model results have a good agreement with the trend
- However even the lowest value permeability may still be too high for preserving overpressure for >200 myr

CONCLUSIONS AND IMPLICATIONS

- Overpressure contributes to resource play production rate and ultimate recovery, but hinders fracture stimulation.
- Very tight nature of shale play makes it very difficult to acquire accurate pressure and permeability data which are essential for pore pressure prediction.
- Unloading of overburden and multiple possible overpressure generation mechanisms provide additional challenges for petrophysics and seismic velocity/frequency based pore pressure prediction methods.
- Pore pressure prediction based on basin modeling is challenged by proper calibration of physical properties and knowing the relative magnitudes of different mechanisms.
- Several case studies suggest under-compaction disequilibrium is the primary overpressure generation mechanism and hydrocarbon generation can only contribute a small portion of overpressure.
- Chemical compaction may have a stronger effect on abnormal pressure generation than previously thought.
- Prolonged overpressure in older basins requires very low matrix permeability in shales.
- Implications on the inter-connectivity of subsurface pore systems, and on the hydrocarbon charge and migration in and out of unconventional shales.

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