PS Compaction and Quartz Cementation Modeling for Reservoir Quality Prediction in Sub-Salt Reservoirs of the Deepwater Gulf of Mexico*

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Abstract

We use the methods of Lander and Walderhaug (1999) to make pre-drill predictions of reservoir quality on deepwater Gulf of Mexico subsalt prospects by modeling the compaction and quartz cementation of sandstone throughout its burial. The procedure combines 1D basin models with petrographic point count data.

Compaction can be modeled through the effective stress history and the intergranular volume, a measure of grain packing. Porosity is reduced exponentially between the endpoints of depositional porosity and the lower limit of intergranular volume, found to be about 26% in the quartz-rich mid to lower Miocene intervals. Quartz cementation is modeled with the Arrhenius equation and the extent is largely dependent on the reservoirs thermal exposure. The process is assumed to be 'rate limited' meaning abundant quartz is available for precipitation but the reaction rate is limited by the parameters specified in the equation. The sand composition and textural grain size determine the available surface area for nucleation of quartz cement.

Good reservoir quality has been found in deep sub-salt reservoirs due to the salts ability to dissipate heat. The geothermal gradient in salt is found to be roughly one-third of the gradient in sand/shale. Since reservoir quality is largely temperature dependent at these depths, the cooler thermal conditions preserve porosity by slowing down the rate of quartz precipitation.

The workflow for reservoir quality prediction is to calibrate the burial history and quartz kinetics parameters by comparing predicted porosity with actual on wells with petrographic and petrophysical data. We modeled the reservoir in a deep lower Miocene well and then forward modeled the porosity at a prospect location. Results help to quantify resource estimates as well as assess reservoir quality risk.

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ABSTRACT

We make pre-drill predictions of reservoir quality on deepwater Gulf of Mexico subsalt prospects by modeling the compaction and quartz cementation of sandstone throughout its burial using the methods of Lander and Walderhaug (1999). The procedure combines 1D basin models with petrographic point count data.

Compaction can be modeled through the effective stress history and the intergranular volume, a measure of grain packing. Porosity is reduced exponentially between the endpoints of depositional porosity and the lower limit of intergranular volume, found to be about 26% in the quartz-rich mid to lower Miocene intervals. Quartz cementation is modeled with the Arrhenius equation and the extent is largely dependent on the reservoirs thermal exposure. The process is assumed to be 'rate limited' meaning abundant quartz is available for precipitation but the reaction rate is limited by the parameters specified in the equation. The sand composition and textural grain size determine the available surface area for nucleation of quartz cement.

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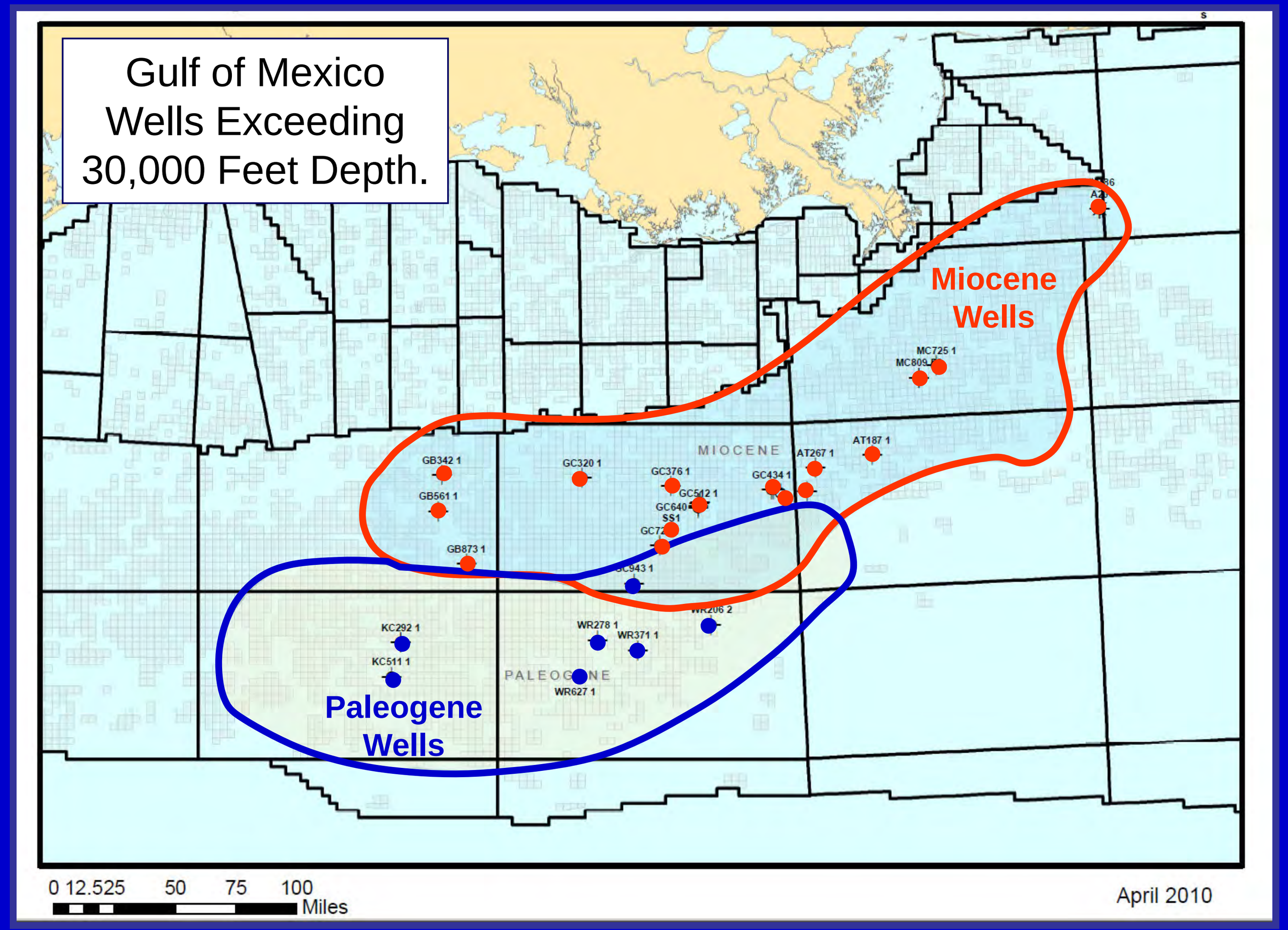
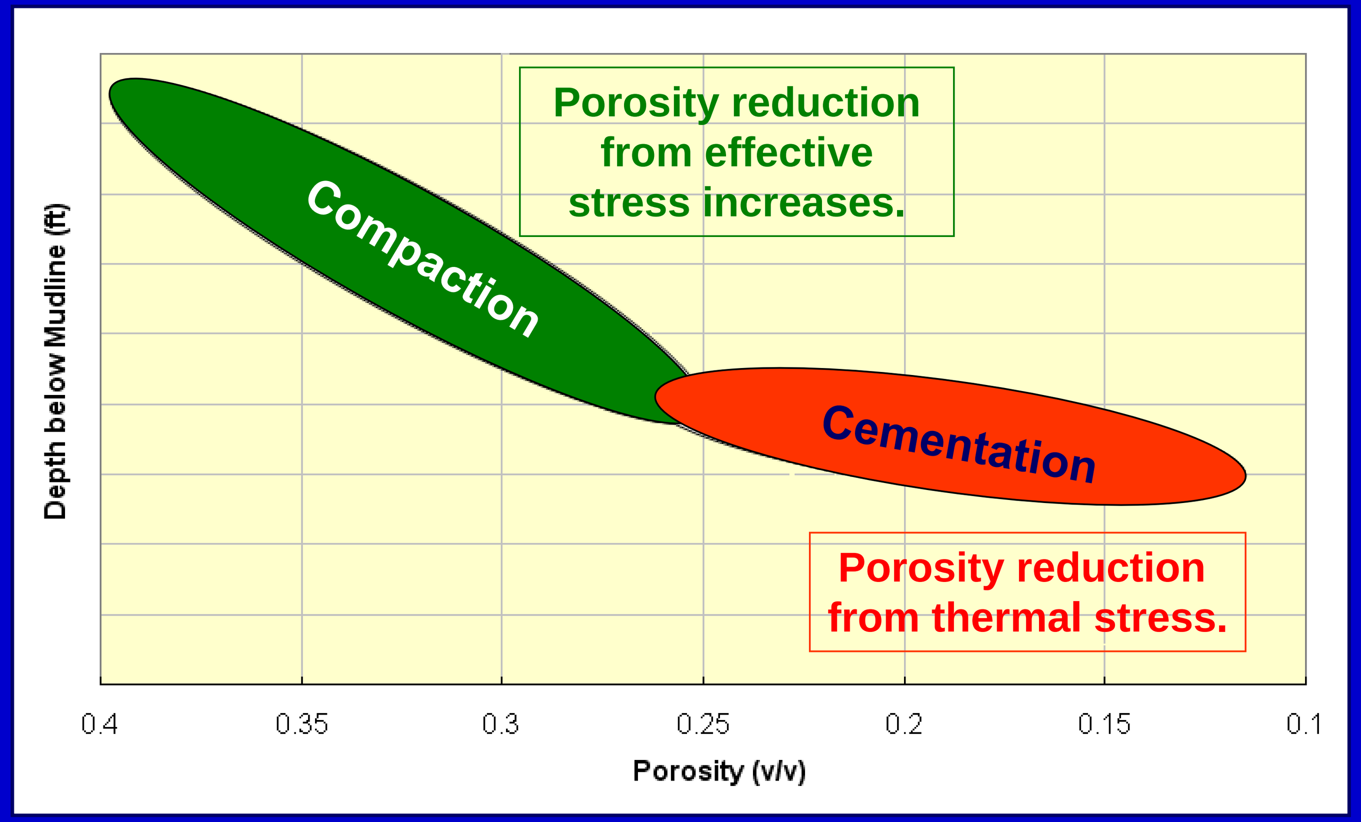
DRILLING TO EXTREME DEPTHS



Exploration drilling in the Gulf of Mexico has seen wells reach extreme depths in recent years. This map of wells drilled to depths greater than 30,000 feet. Reservoir quality can be quite variable at these extreme pressures and temperatures. Pre-drill risk assessment of reservoirs at these extreme conditions requires knowledge of the processes that control reservoir quality.

PROCESSES THAT AFFECT RESERVOIR QUALITY



A plot of porosity vs. depth below mudline on a deepwater GOM well reveal two primary mechanisms controlling porosity loss in quartz rich sands. During deposition, increases in effective stress cause reorientation and packing of grains resulting in compaction. As thermal stress increases, precipitation of quartz cement on grain surfaces will further reduce porosity.

THEORETICAL BACKGROUND

- **We used BasinMod software developed by Platte River and Associates to generate 1D basin models at drilled and prospect locations.**
- **We used Exemplar software for our porosity modeling. Exemplar was developed through the Geologica Consortium (Lander and Walderhaug, 1999)**

The model simulates compaction by decreasing intergranular volume (IGV) exponentially as a function of effective stress.

$$IGV = IGV_f + \left(\phi_0 - IGV_f\right)\exp^{(-\beta \times \sigma_{es})}$$

where:

IGV is the sum of pore space, cements and matrix material (v/v)

IGV_f is the 'stable packing arrangement' (v/v)

$Ø_0$ is the depositional porosity (v/v)

β is the exponential rate of IGV decline (1/Mpa)

σ_{es} is the maximum effective stress (Mpa)

The model simulates the rate of quartz cement precipitation with the Arrhenius equation.

$$k = A_0 \exp\left(\frac{-E_a}{R \times T}\right)$$

where:

k = rate of quartz precipitation per unit surface area (mol/cm^2*s)

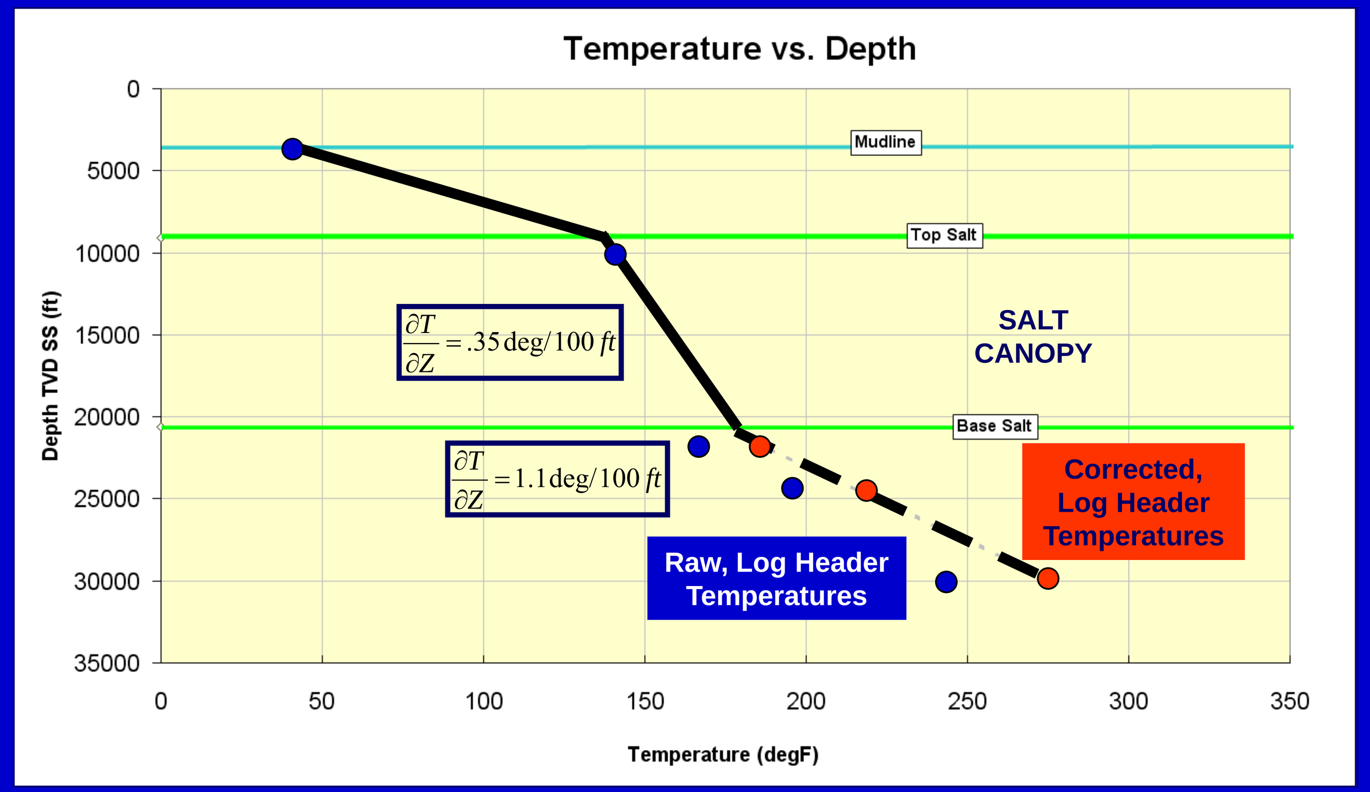
A_0 = pre-exponential constant (mol/cm^2*s)

E_a = activation energy (J/mol)

R = real gas constant (8.314 J /mol*K)

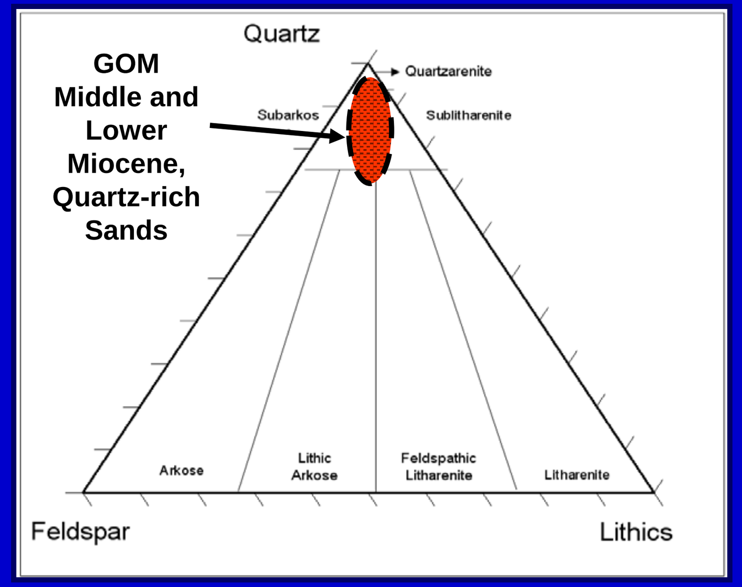
T = absolute temperature (K)

THE 'COOLING' EFFECT OF SALT

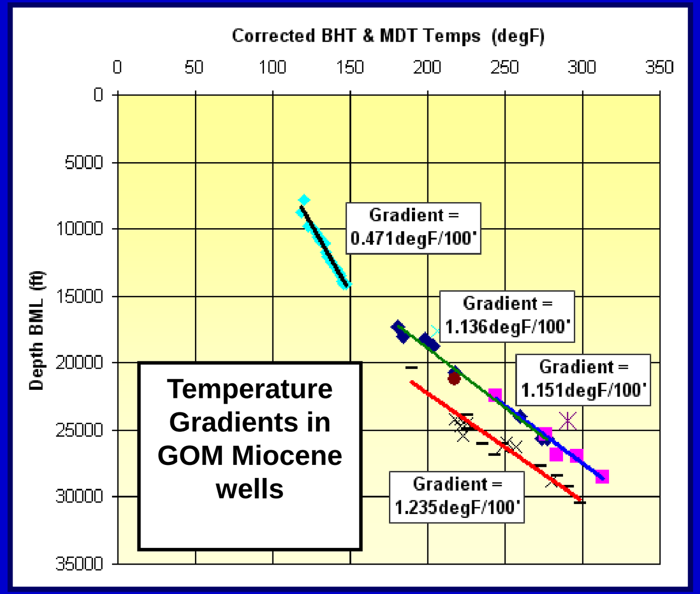


The well was drilled to 30,000' TVD and penetrated salt from 9,000' to 20,500'. Temperatures from log headers are in blue and corrected temperatures in red (Waples and Ramly, 2001). The gradient below salt is 1.1 degF/100'. A temperature near the top of salt was recorded by a cased hole log. Connecting the points through the salt yield a gradient of .35 degF/100', roughly 1/3 of that below salt. Cooler temperatures could be encountered beneath thick salt sections due to the high thermal conductivity of salt relative to sandstone / shale. Since temperature drives the rate of quartz cementation, a thick salt section could 'preserve' porosity in the sediment below it.

CALIBRATION DATA



We used petrographic data from multiple sub-salt Middle and Lower Miocene age reservoirs in the deepwater GOM. Samples used in the models are predominately quartz rich (subarkose and sublitharenite), very fine to medium grain size, and poor to well sorted.



We used temperature data from well headers of multiple subsalt wells in the deepwater GOM to constrain the heat flow and thermal history in 1D basin models. We note different temperatures in adjacent salt mini-basins, but gradient remains similar.

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POROSITY MODELING WORKFLOW

BASIN MODEL: BURIAL / THERMAL HISTORY

Lithology
Porosity
Pore Pressure
Temperature

PETROGRAPHIC DATA

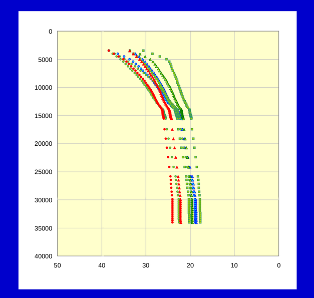
Composition
Grain Size
Sorting

INPUT

MODEL PARAMETERS

Compaction
Quartz Kinetics

MODELED POROSITY



MODELED POROSITY = LOG/CORE POROSITY?

N

Y

CALIBRATION

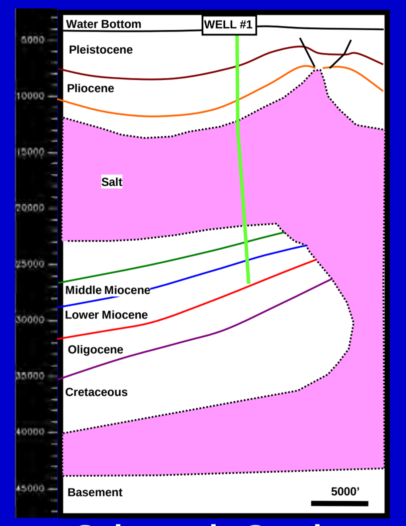
FORWARD MODEL

OUTPUT

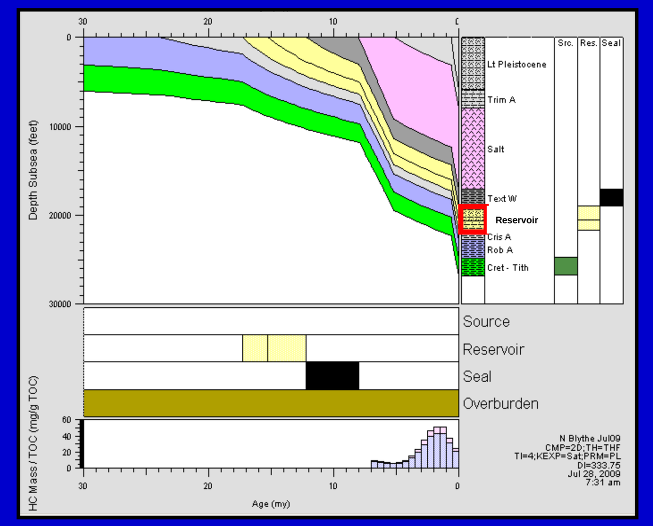
CALIBRATION MODEL #1

Basin Model

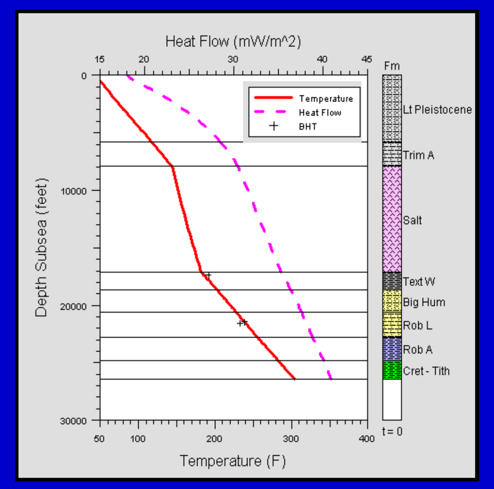
- Subsalt, Miocene reservoirs with 8000' of shallow sediment and 12000' of salt overburden.
- 1D Burial history modeled using 3D seismic data and well biostratigraphy.
- Salt canopy inflation and deflation was modeled.
- Heat flow model was calibrated using corrected well header temperatures.
- Pore pressure model was calibrated using drilling mud weights.



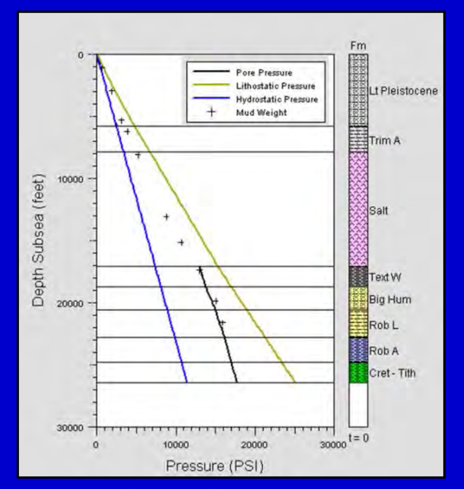
Schematic Section



Burial History

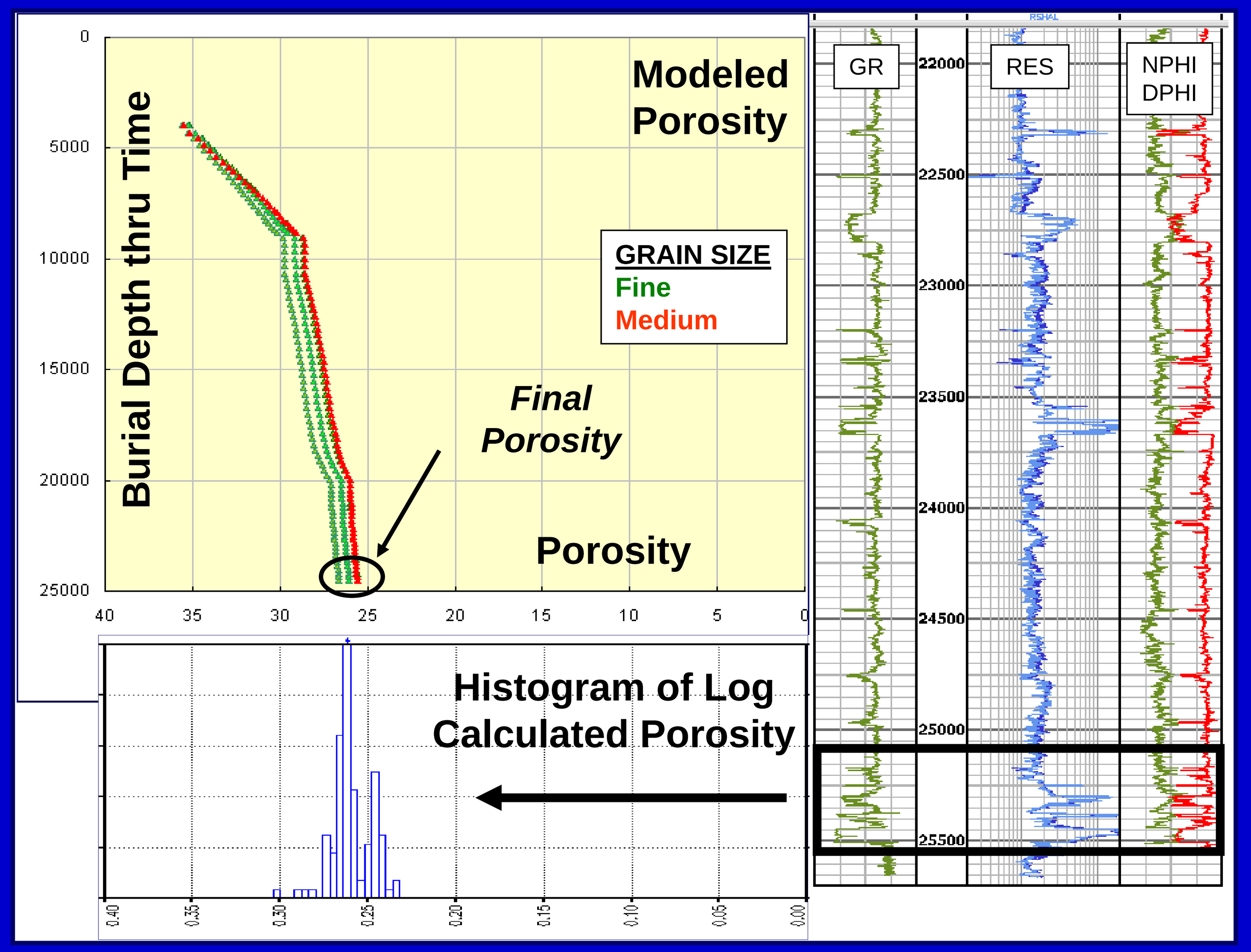


Thermal History



Pore Pressure

Reservoir Porosity Model

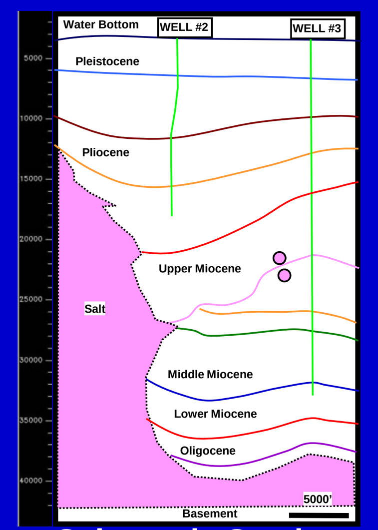


Porosity model #1 for calibration. Relatively cool bottom hole temperatures (<200 degF). Porosity loss primarily due to compaction. Good agreement with log calculated porosity.

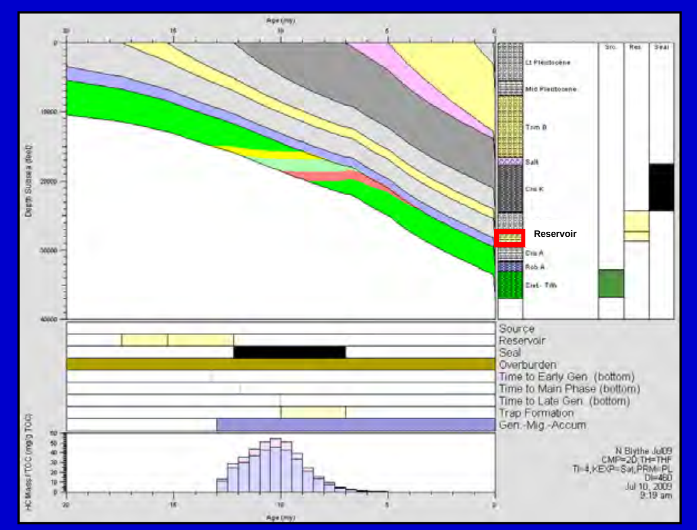
CALIBRATION MODEL #2

Basin Model

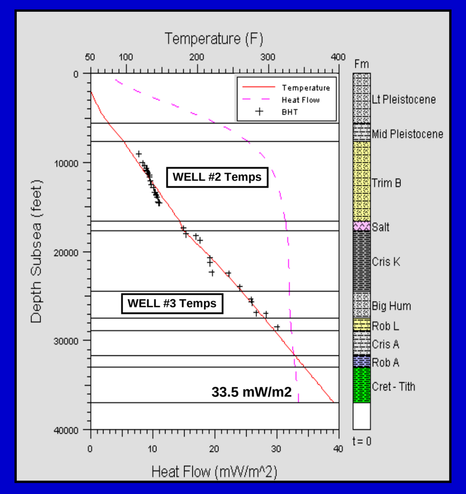
- Miocene reservoirs with 25000' of sediment and minor salt overburden.
- 1D Burial history modeled using 3D seismic data and well biostratigraphy.
- Heat flow model was calibrated using corrected well header temperatures from 2 wells.
- Pore pressure model was calibrated using drilling mud weights, RFT, and MDT measurements from 2 wells.



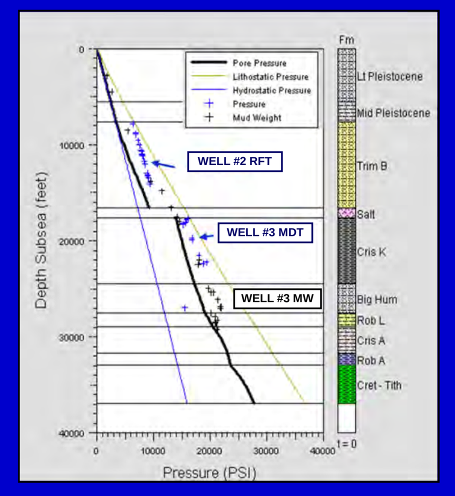
Schematic Section



Burial History

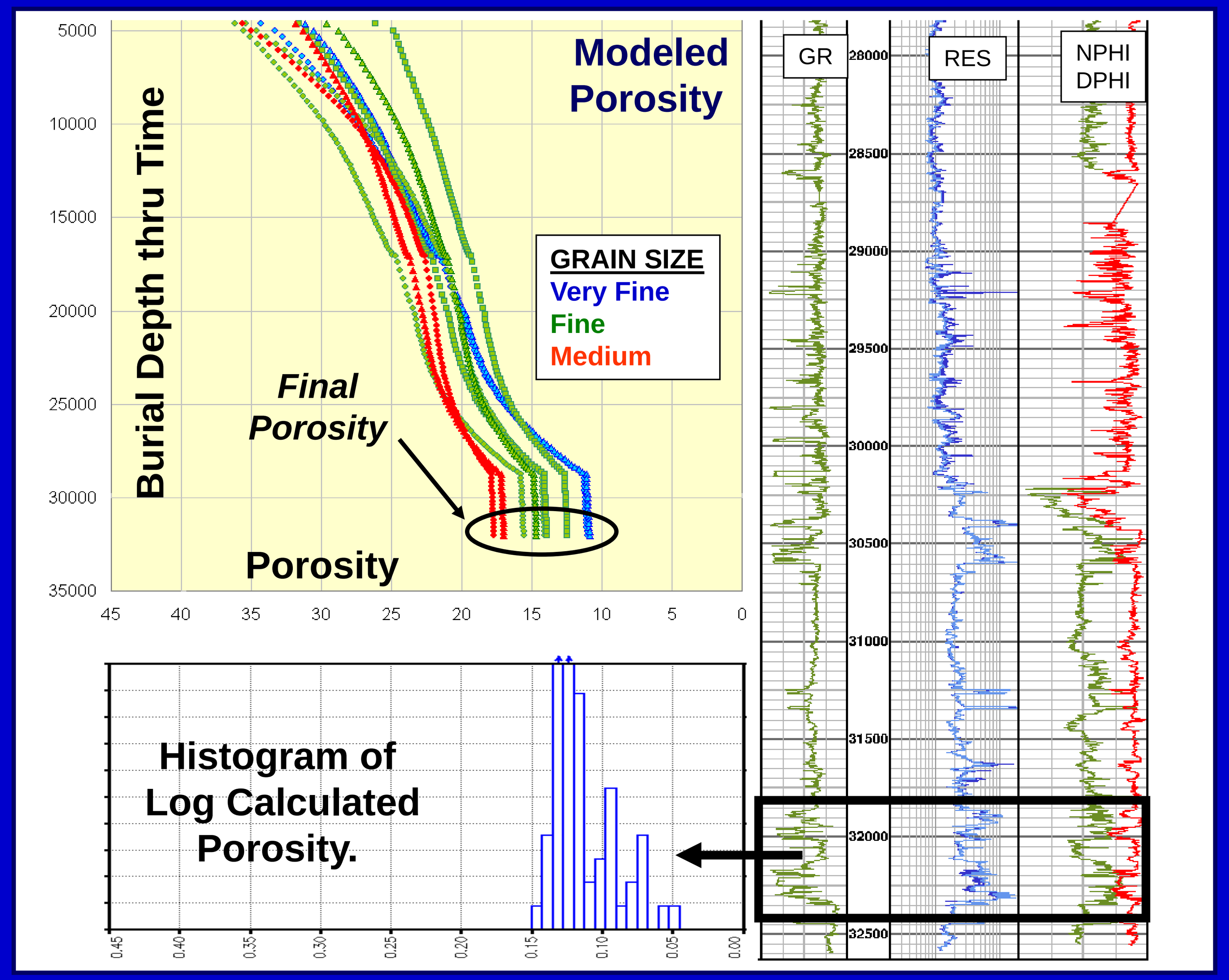


Thermal History



Pore Pressure

Reservoir Porosity Model



Porosity model #2 for calibration. High bottom hole temperatures (~300 degF). Significant porosity loss due to compaction as well as cementation. Good agreement with log calculated porosity indicating proper quartz kinetic parameters. Expected porosity 11-17%, depending on grain size and sorting.

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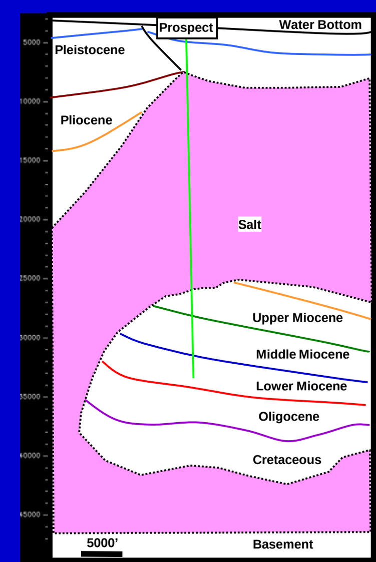
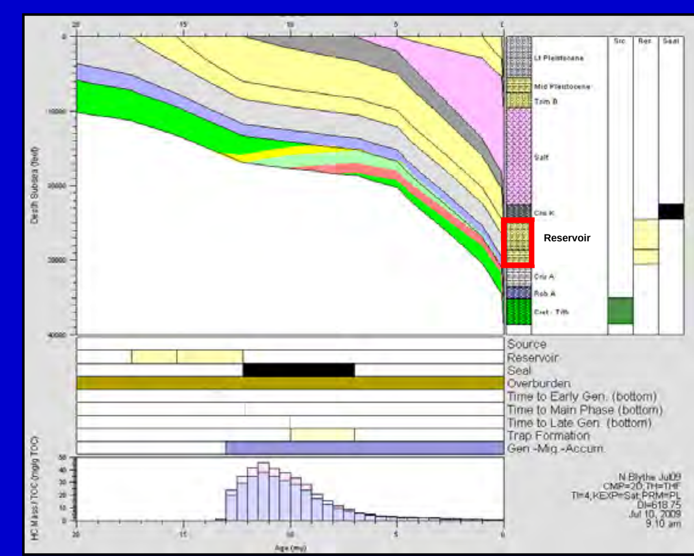
FORWARD MODEL

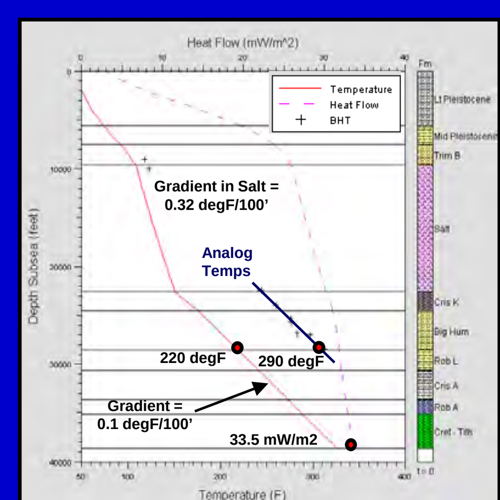
Basin Model

- **Prospective subsalt, Miocene reservoirs with 5000' of shallow sediment and 20000' of salt overburden.**
- **1D Burial history modeled using 3D seismic data and offset well biostratigraphy.**
- **Salt canopy inflation and deflation was modeled.**
- **Heat flow model using corrected well header temperatures from analog wells was applied.**
- **Pore pressure model was calibrated using drilling mud weights from analog wells.**

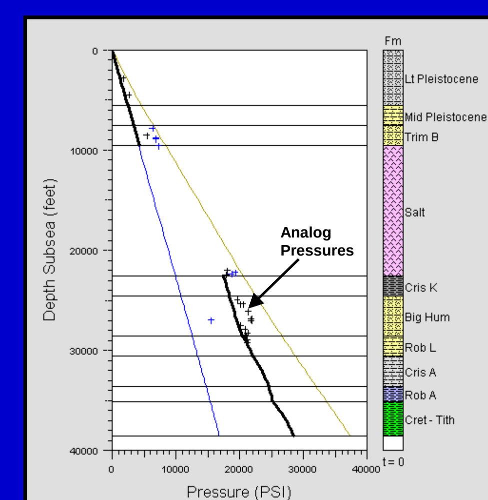


Schematic Section


Burial History

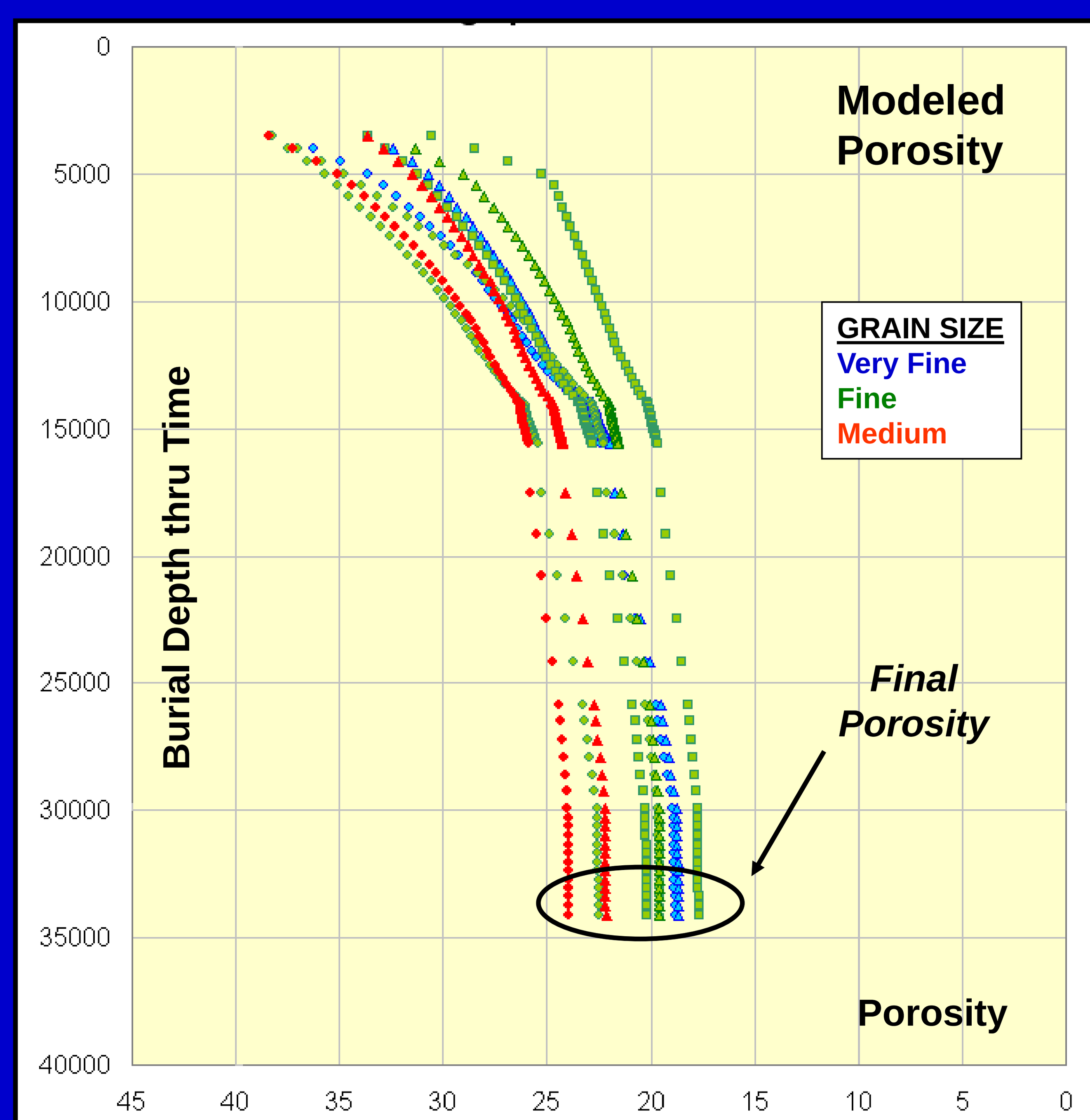


Thermal History



Pore Pressure

Reservoir Porosity Model



Forward Model. Similar depth of burial to Calibration Well #2. Lower predicted bottom hole temperature (~220 degF) due to salt canopy overburden. We predict better porosity compared to Calibration Well #2 (up to 6 porosity units) using same petrographic samples.

CONCLUSIONS

1) Reservoir quality predictions can be made on deepwater prospects by modeling the compaction and quartz cementation through petrographic date and burial history.

2) Deepwater prospects should be evaluated for reservoir quality in addition to reservoir presence.

3) Reservoir quality can be 'preserved' beneath thick salt sections due to a cooling effect of the salt.

4) Modeled porosities provide constraints for pre-drill reservoir characterization, impacting resource estimates. The integration of this technique may mitigate risk in expensive and challenging subsalt exploration wells.

5) Our 1D modeling approach produces results that agree with log measured porosity. However, the cooling effect of salt is a three-dimensional problem. Robust 3D basin modeling should be used to further constrain the thermal and stress history in forward models.

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ACKNOWLEGDEMENT

We thank Marathon Oil Co. for permission to present this work.