Derivation of Scaled Hydrocarbon Head Potential, A New Workflow for Petroleum System Analysis: Application to the Eagle Ford Formation, SE Texas*

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Abstract

Hydrocarbon charge assessment in hybrid systems has presented challenges for petroleum system analysis and modeling the resource potential still retained within self-sourced and near-sourced tight liquids. In tight liquids, regional trends of key controlling properties such as pressure regimes, fluid phase, density, and maturity, and geomechanics result in preferential “sweet spots” where well performance far exceeds the formation mean. We built and calibrated a basin model for the Eagle Ford Formation, to match retained fluid properties and volumes. We present a new workflow for estimating Hydrocarbon Head Potential (HCHP), a function of fluid pressure, density, Gas Oil Ratio (GOR), and source rock and fluid maturity that has a direct correlation with well performance and our understanding of seal capacity and pressure evolution in the subsurface. Well performance is here defined as the initial best month rate of production, normalized by lateral wellbore length and barrels of oil equivalent (BOE) per day. HCHP is a property derived through basin modeling and calibrated to the observations at the wellhead in terms of produced fluid volumes, density, and GOR. This study shows that pressure and fluid properties are main drivers behind well performance in tight liquid systems. For this study, well performance (BOE/d), GOR, and density of the fluid were evaluated for 12,000 wells producing from the Eagle Ford Formation. Average rock properties obtained for 8,000 locations, including total organic carbon content, clay volume, hydrocarbon pore volume, and net thickness were used as inputs in the basin model. The basin model estimated hydrocarbon fluid density and gas oil ratio of both the retained and expelled fluid volumes from the source rock, and its associated rock and fluid maturities. We developed a GOR-fluid density function by modelling recombined fluids from 18 PVT reports. Statistical analysis via principal component analysis and clustering techniques supports that fluid properties and pressures have a strong correlation to BOE recovered in the first three months of production. Results show that HCHP can predict the volume and initial production rate of hydrocarbons in the subsurface, and be used as a surrogate for fluid pressure. Integration of the HCHP property into the basin modeling workflow may provide insights into seal capacity, fluid maturity trends, and the impact of multiple charge events on bulk fluid properties.

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Derivation of Scaled Hydrocarbon Head Potential

A New Workflow for Petroleum System Analysis:
Application to the Eagle Ford Formation, SE Texas

Chevron Basin Modeling Center of Research Excellence
Chevron CoRE

By: **Carlos Varady, Dr. Ursula Hammes, Dr. John Pantano**

2017 AAPG ACE – Houston, TX

Outline

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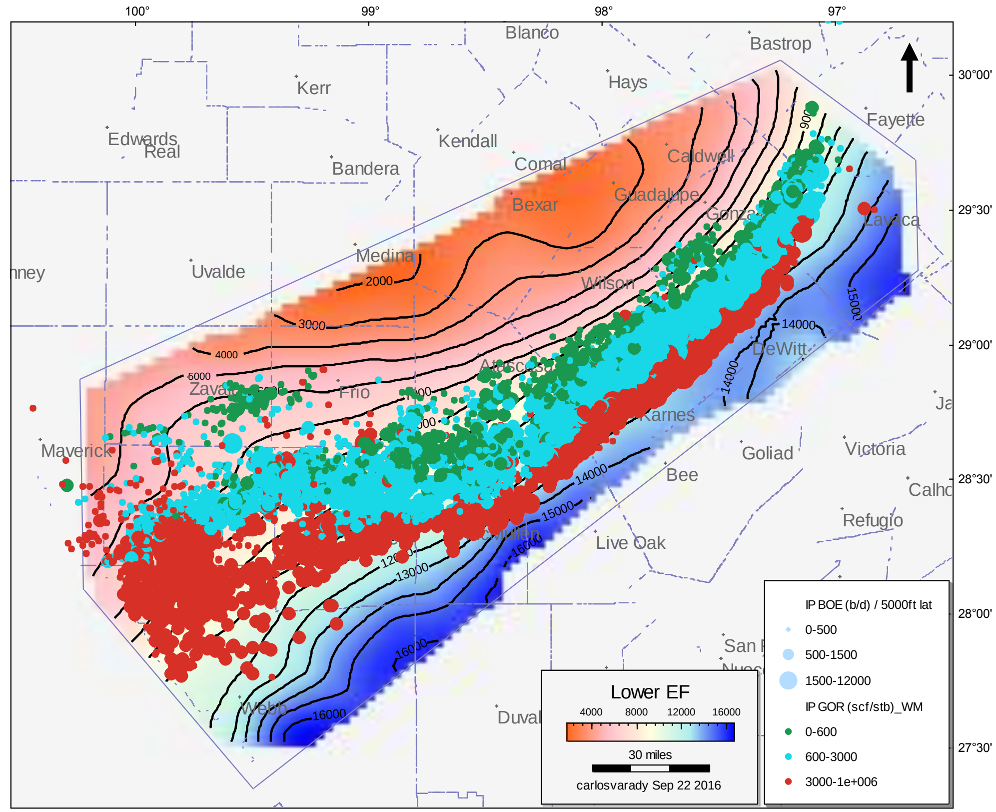
Introduction

Scaled Hydrocarbon Head Potential: A New Tool for Petroleum System Analysis

- Study area: **Eagle Ford** Fm., TX
- Method: Calibrated a **basin model** of the Eagle Ford and tied production volumes and fluid properties recorded at the wellhead.
- Selected observation/finding: Scaled Hydrocarbon Head Potential: A new tool that relates **maturity**, **pressure** evolution and **seal** capacity to **fluid** properties and **production** volumes.



Produced **fluids** from the Eagle Ford range from **black oil to dry gas**. **High rates** and volumes are associated with **high pressure gradient** and **correlate** to the **uplift, erosion** and **seal** capacity estimations for the **mobile** retained **fluid**.

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Objectives

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- 1) Develop new tools for basin modeling of unconventional resources and hybrid systems
- 2) Incorporate well behavior and surface measurements into a basin modeling workflow
- 3) Through basin modeling, estimate pressure and well performance in tight liquid systems

A Bottom-Up & Top-Down Approach

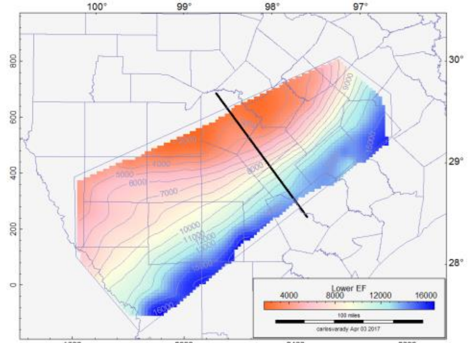
Basin Model

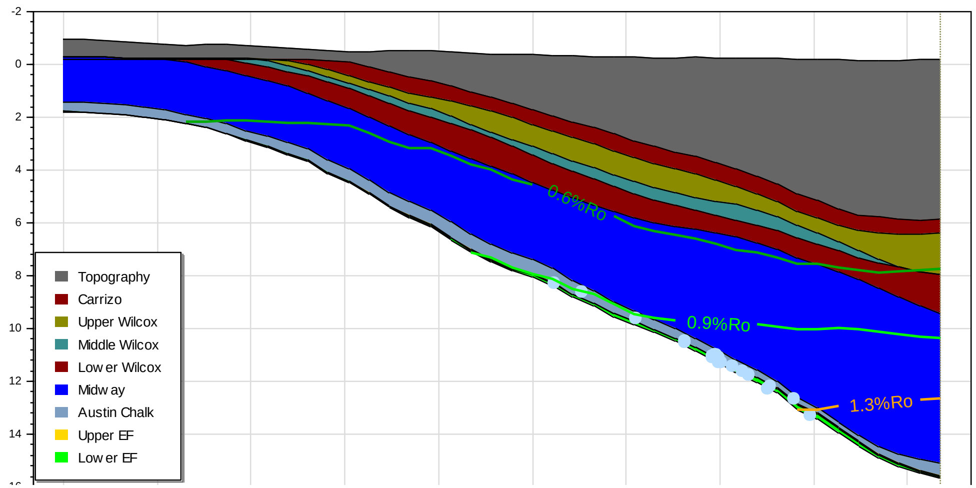
- Anchor:
  - SR properties
  - Geohistory
  - Regional trends
- Comparison:
  - Expelled and retained fluid properties
  - Pressure
  - **Model** SHCHP

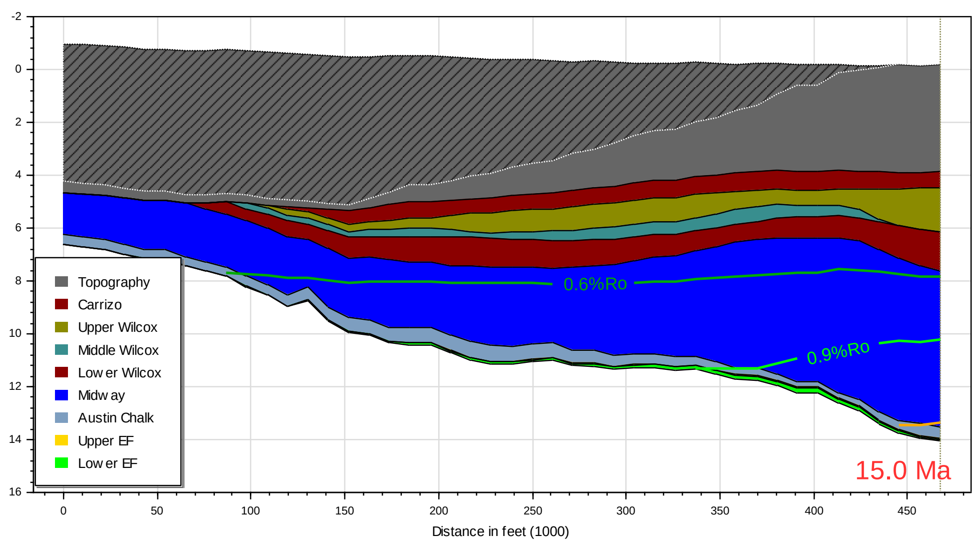
Production Data Observed

- Anchor:
  - Well rates
  - Bulk fluid properties
  - Pressure
- Comparison:
  - Regional trends
  - Geohistory
  - HC density function
  - **Observed** SHCHP

Calibrating Top to Bottom







- Leverage on Eagle Ford source-reservoir characterization (Hammes et al., 2016)
  - TOC, HI
  - NTG, PHI, API, PVT
- Robust geohistory that can match:
  - Retained and expelled fluid volumes
  - Regional pressure changes
  - Well rate and bulk fluid observations

Pressure, Rock and Fluid Properties through Time:

<u>S</u>caled <u>H</u>ydro<u>C</u>arbon <u>H</u>ead <u>P</u>otential (SHCHP)

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Scaled HydroCarbon Head Potential

$$SHCHP = \frac{\Delta P_{over}}{\Delta P_{G_{HC}} * 100}$$

$$\Delta P_{over} = Overpressure$$

$$\Delta P_{G_{HC}} = Hydrocarbon\ pressure\ gradient$$

*Pressure and Gradient difference taken with respect to hydrostatic

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Implication within SHCHP

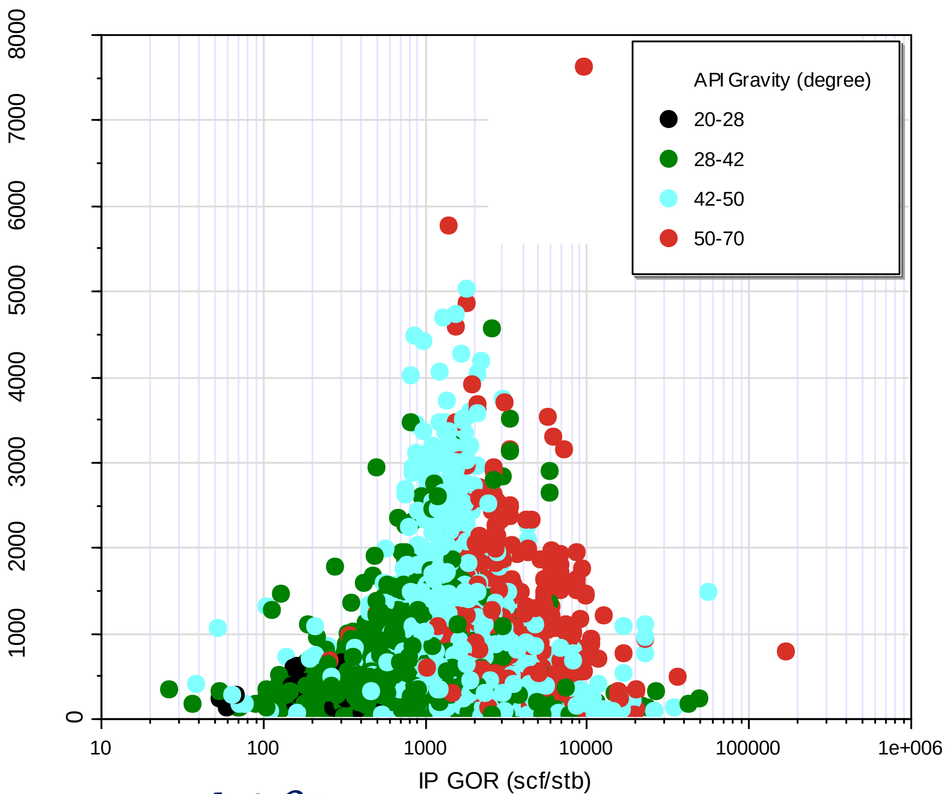
Overpressure

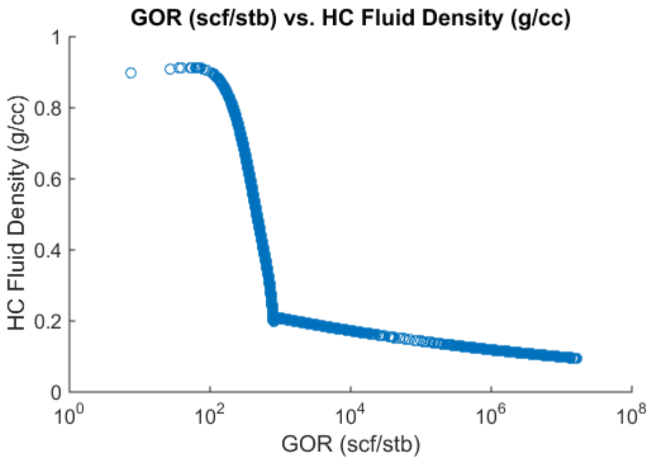
- Petroleum generation
  - Thermal
  - Volumetric expansion
- Compaction disequilibrium
- Seal capacity & preservation

Hydrocarbon gradient

- A function of GOR and density
- Tied to fluid mobility
- Strong relationship with source rock maturity
- Pressure dependency

Flow Rates in Unconventionals





- SHCHP is a new tool that relates **maturity**, **pressure** evolution and **seal** capacity to **fluid** properties and **production** volumes.

$$*Q = \frac{kA}{\mu}\frac{\partial P}{\partial x}$$

∗Black oil to wet gas, not for high pressure dry gas w/ nano scale physics and forces

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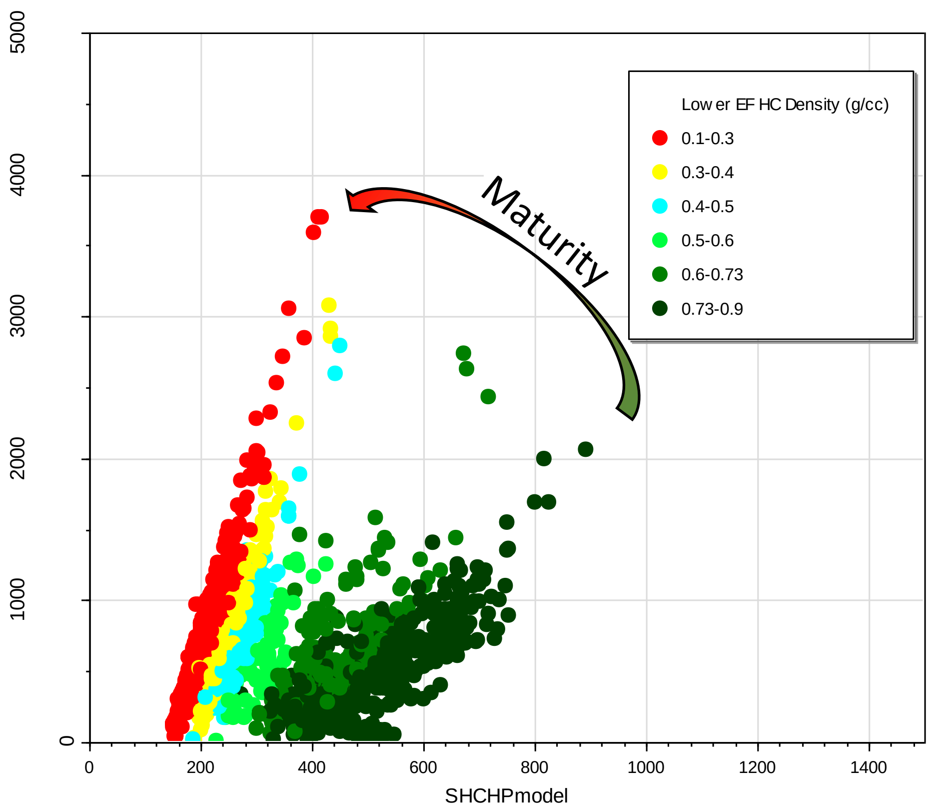
Results

Estimating Well Performance



- From black oil to wet gas, SHCHP is able to estimate initial month well rate (IP boe/d)
- Possible due to physics behind the relationship between:
  - Maturity
  - Density, GOR
  - Flow Rates, Pressure

P/Z = gas wants out, oil more affected by K and Completions
SHCHP shown difference of Hydrostatic-HC Density

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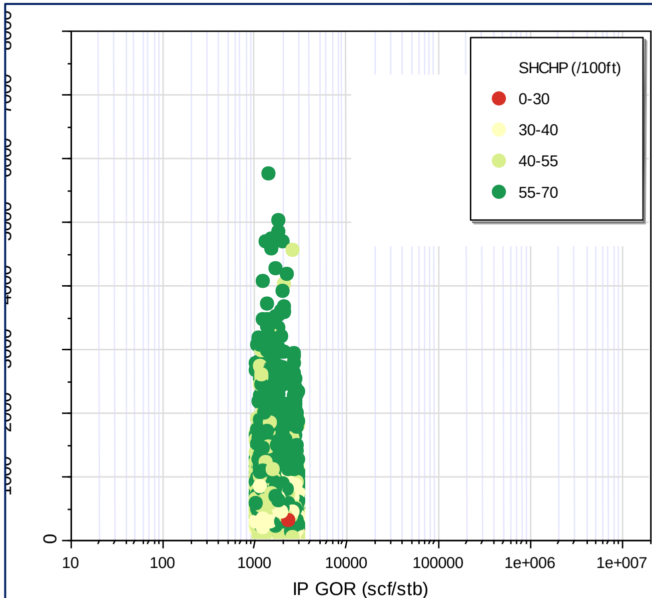
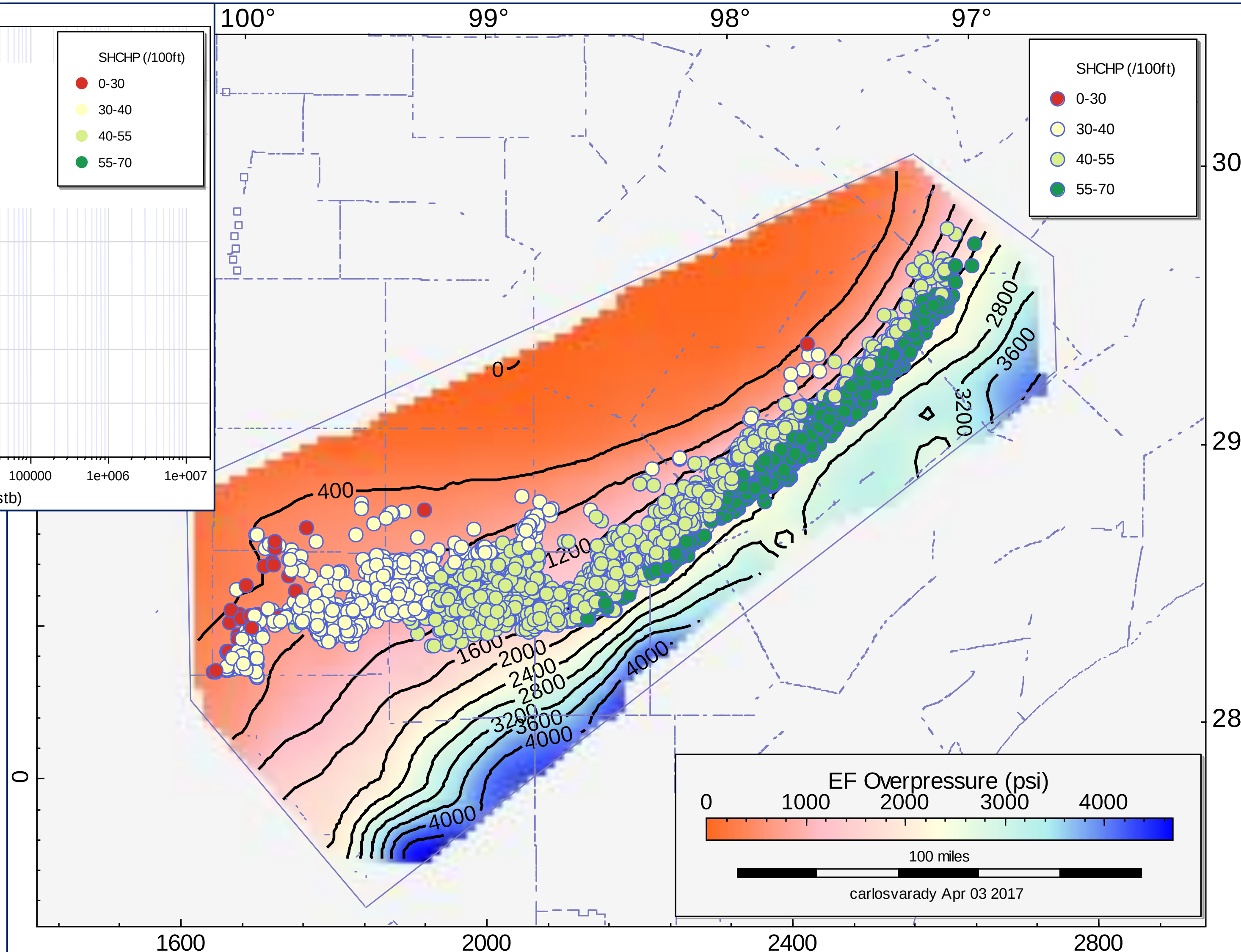
Well Rates Inspected by SHCHP





- HC **Density** trends correlate to retained fluid **maturity**. It can also be observed from **Gas-Oil ratio** and API of **produced fluid**.
- **Overpressure** from **generation** & rapid **burial**, are related to the formation or facies **seal** capacity, structural evolution and regional stresses that led to punctuated **expulsion** events in **exhumed** basins.

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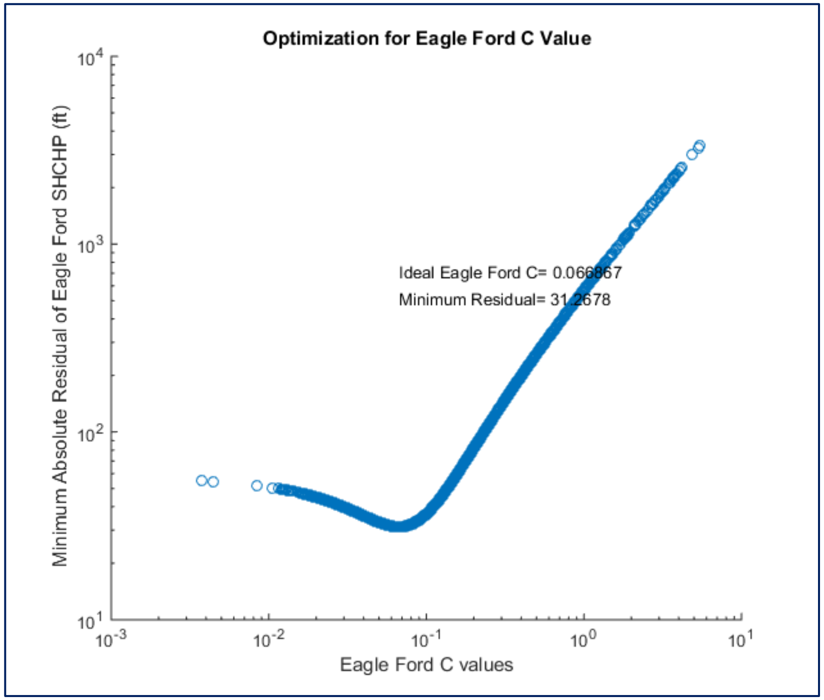
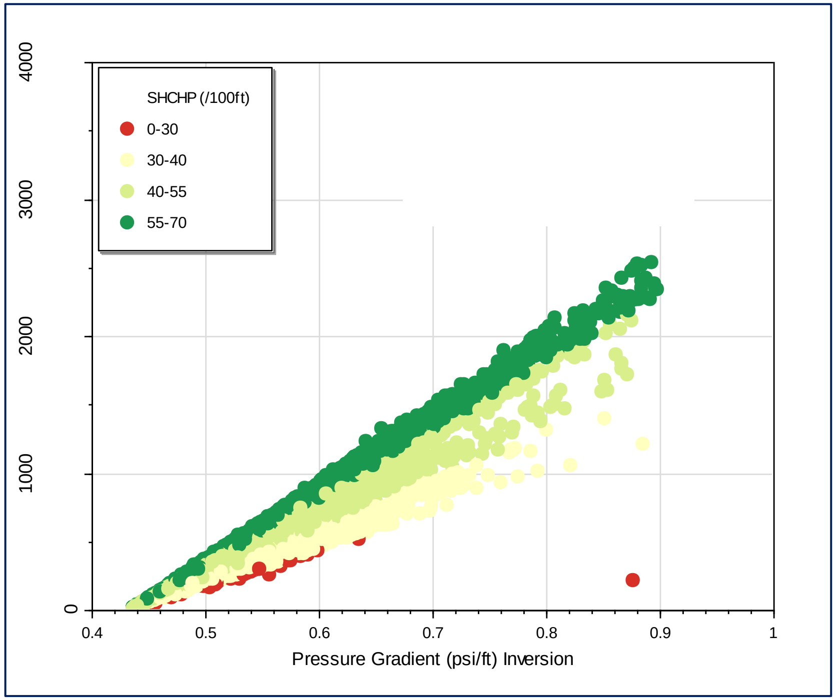
Inversion for Pressure

Through a Minimum Absolute Residual (MAR)

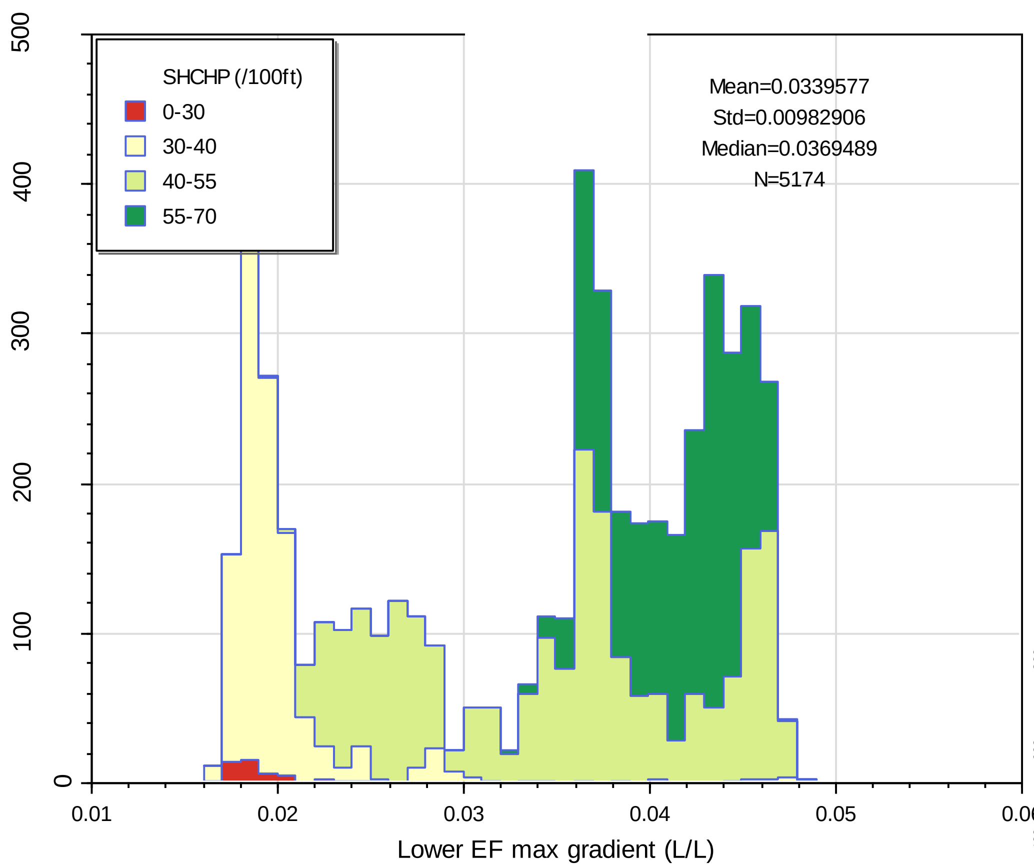
$$IP\ BOE\left(\frac{boe}{d}\right) * C = SHCHP$$



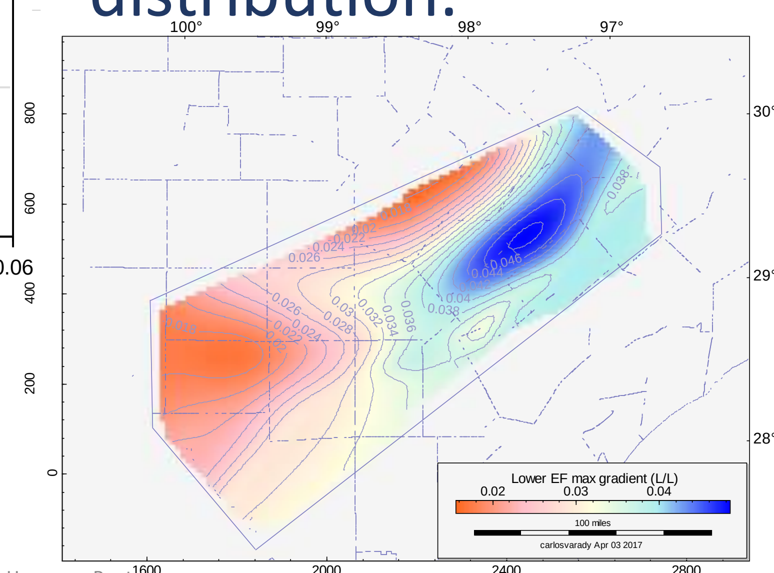


∗Variability in the volatile to condensate window,1−3k GOR wells

Exhumation and Pressure Evolution



- Exhumation can lead to permeability enhancements and punctuated expulsion events, that affect present day pressure distribution.



Eagle Ford, in terms of production **rates** relations to: **pressure**, **rock** and **fluid** properties, often exhibits a bimodal distribution, showcasing the **geohistory** and **depositional environment** changes in the basin

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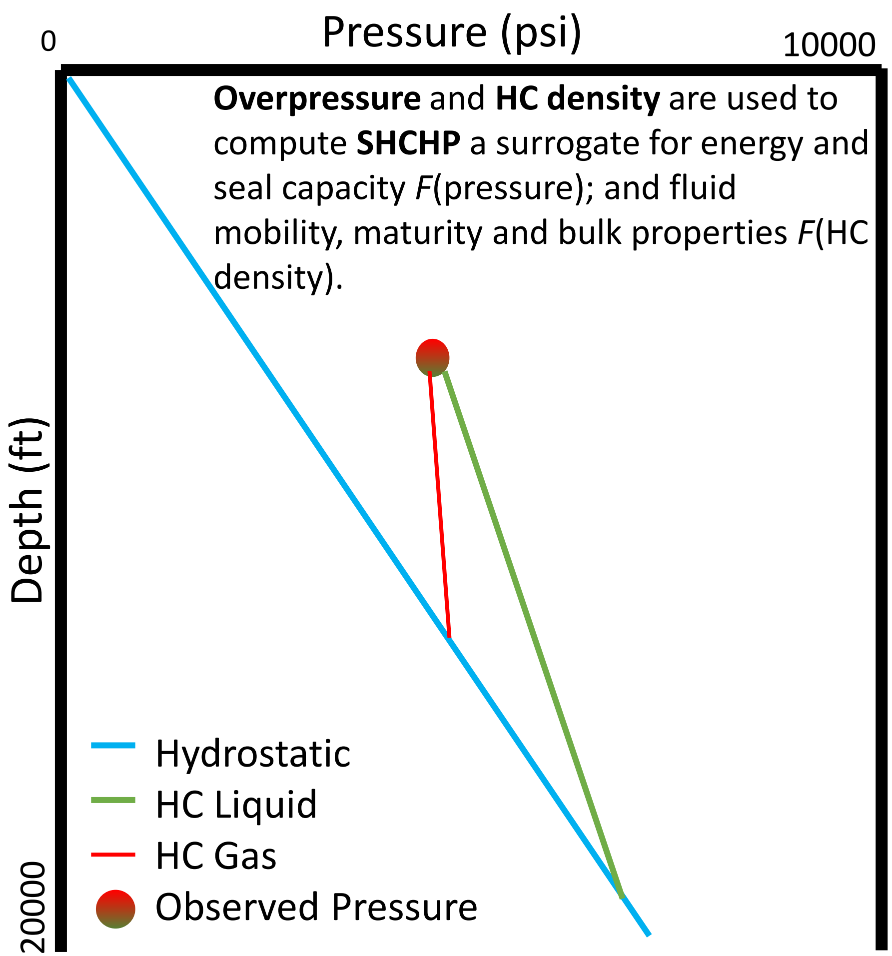
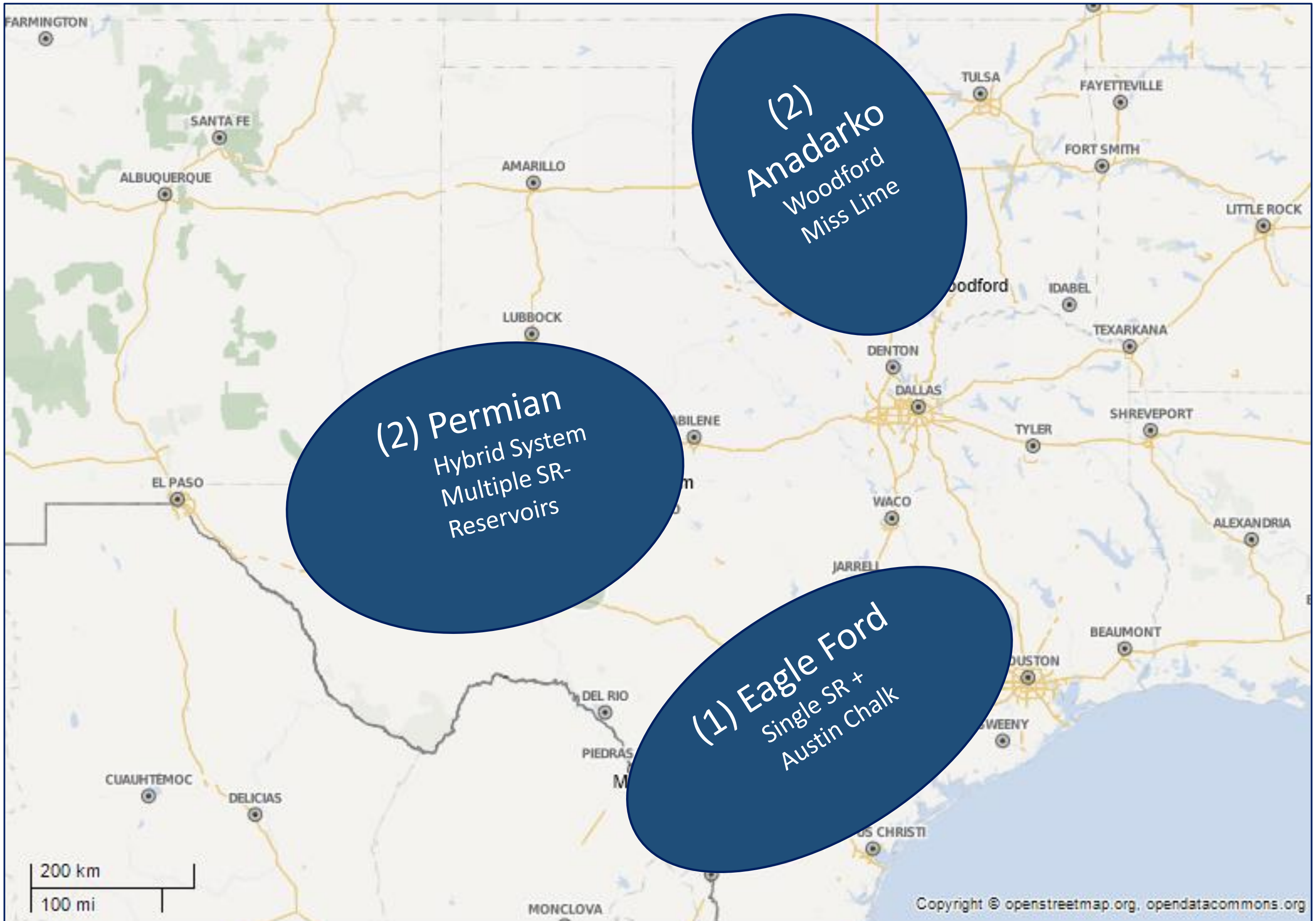
Summary

Scaled Hydrocarbon Head Potential



- **SHCHP is a function of HC Density & Overpressure.**
- Fluid pressure gradient is density dependent.
- HC density can be obtained from equations of state and basin model output.
- HC Density trends correlate to retained fluid maturity. It can also be observed from Gas-Oil ratio and API of produced fluid.
- Pressure is obtained through basin model. Pressure can also be calculated from production rates (IP Oil and IP Gas) and HC density through an inversion workflow.
- Overpressure from generation & rapid burial, are related to the formation or facies seal capacity, structural evolution and regional stresses that led to punctuated expulsion events in exhumed basins.
- Developed with the Eagle Ford basin model and data from BEG. Applied to the Delaware and Anadarko basins as a predictive and diagnostic tool.

SHCHP Across Hybrid Systems



Basins where SHCHP has been developed and tested.

Acknowledgments

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Pore-Level Reservoir Characterization
Formation Water Chemistry

Wood Mackenzie

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John Dolson
Director, DSP Geosciences and Associates, LLC

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- Texas A&M University
  - Department of Petroleum Engineering

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