Using Mass-Balance Organic Geochemistry to Spatially Delineate the Spectrum of Hybrid Unconventional Plays in the Lower Green River Formation, Uinta Basin

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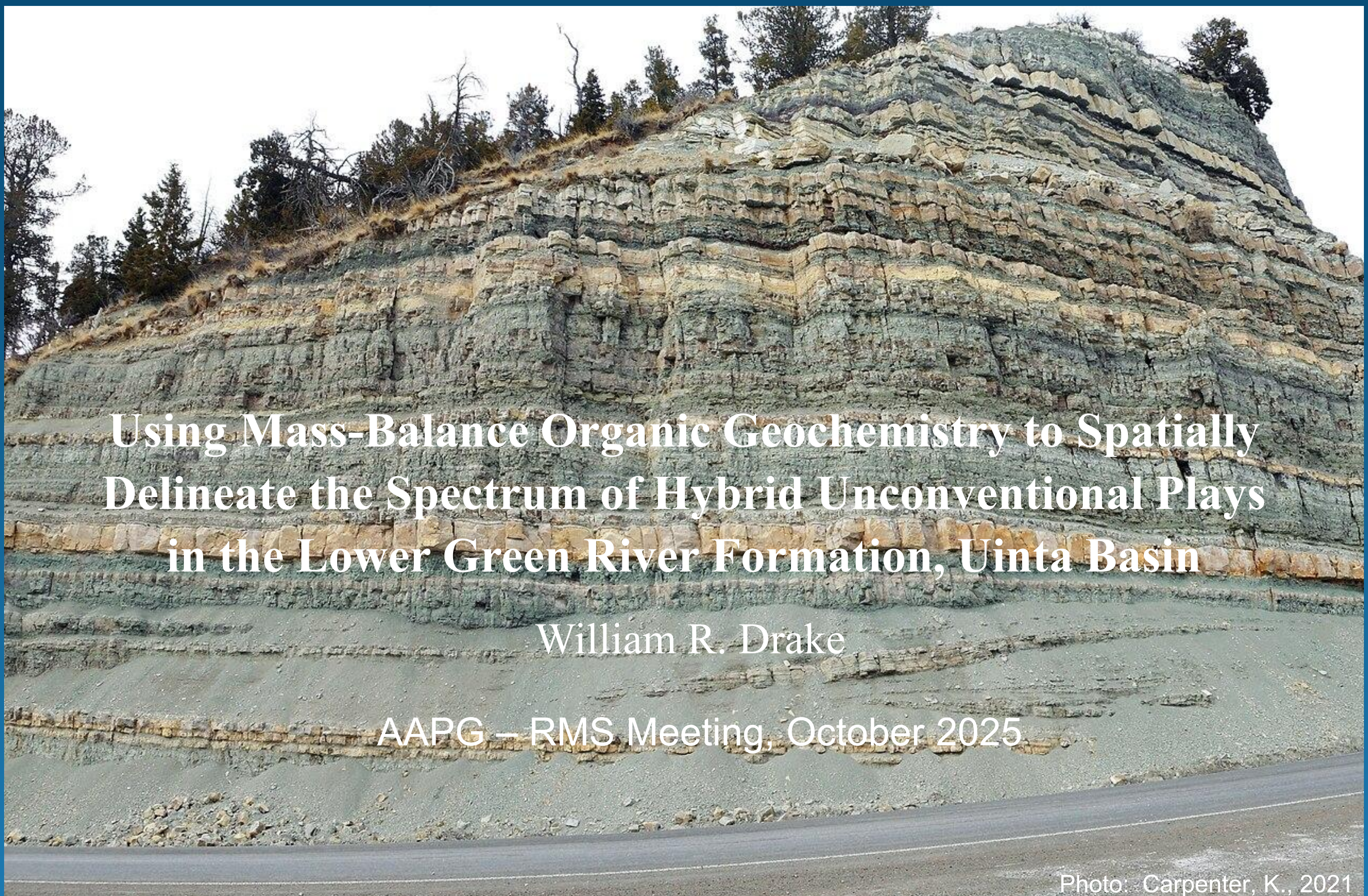
[1]Kimmeridge Energy

Abstract

Unconventional oil and gas plays range from true source-rock mudstones with little to no reservoir lithofacies to tight conventional reservoirs with little to no source rock potential. Most unconventional target formations fall somewhere along this spectrum and can be considered hybrid plays. Quantifying the degree of self-sourcing and hydrocarbon migration are critical for spatially characterizing the variability of hybrid systems. The primary horizontal drilling target in the Uinta Basin is the Uteland Butte, which is one of a series of interbedded dolostones, siltstones, dolomitic sandstone, and organic-rich shales that comprise the lower Green River Formation. These units exhibit important facies, reservoir quality, and thermal maturity variations along the structural ramp of the asymmetric basin. The unique transformation kinetics of the highly oil-prone Type I kerogen is a critical element within this petroleum system framework. Several mass-balance organic geochemistry techniques ranging from nanoscale to basin scale are employed here to highlight where lateral changes in hybrid character occur across the basin. Source-rock hydrocarbon generation and storage are compared to conventionally reservoired resource-in-place volumes and produced oils. Two broad end-member petroleum systems are revealed: 1) the deeper, more thermally mature region is characterized by excess hydrocarbon generation and local reservoir charge, and 2) the shallower, less mature region is dominated by migrated hydrocarbons. This case study highlights the importance of correctly characterizing the spatial variability in unconventional systems and suggests implications ranging from identification of migration pathways to horizontal well-placement strategy.



Using Mass-Balance Organic Geochemistry to Spatially Delineate the Spectrum of Hybrid Unconventional Plays in the Lower Green River Formation, Uinta Basin

William R. Drake

AAPG – RMS Meeting, October 2025

Photo: Carpenter, K., 2021

Characterizing Unconventional Hybrid Plays

Unconventional oil and gas plays range from true source-rock mudstones with little to no reservoir lithofacies to tight conventional reservoirs with little to no source rock potential.

Most unconventional systems fall somewhere along this spectrum and can be considered **hybrid plays**.

Quantifying the degree of self-sourcing and/or hydrocarbon migration are critical for **spatially characterizing the variability** of hybrid systems.

Mass balance organic geochemistry techniques can quantify hydrocarbon generation for comparison to resource in place and the produced oils, but **resourceful formation-specific problem solving is necessary**.

Correctly characterizing unconventional systems: implications range from identifying migration pathways to horizontal well-placement strategy.

Green River Formation

Age: Eocene

Basin: Uinta Basin

Depositional setting: Lacustrine

Lithology: Interbedded organic-rich shales and dolomitic sandstones

Organic content: Rich, commonly up to ~6%

Kerogen type: Mainly Type I lacustrine

Organic porosity: Important

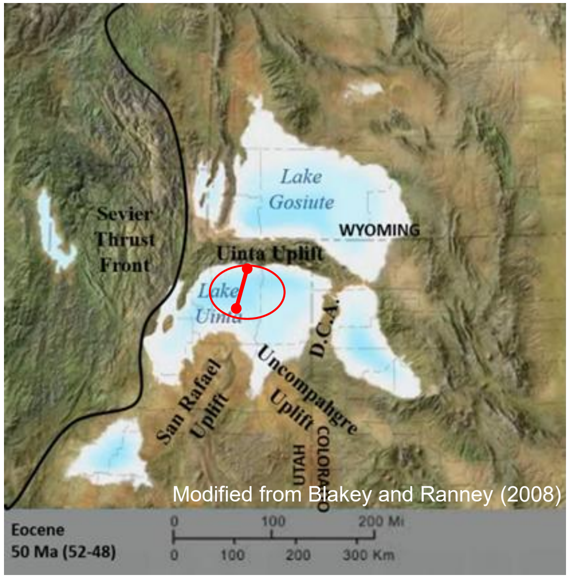
Uteland Butte Member

Photo: Vanden Berg, M. in Schamel, 2015

The Green River Formation

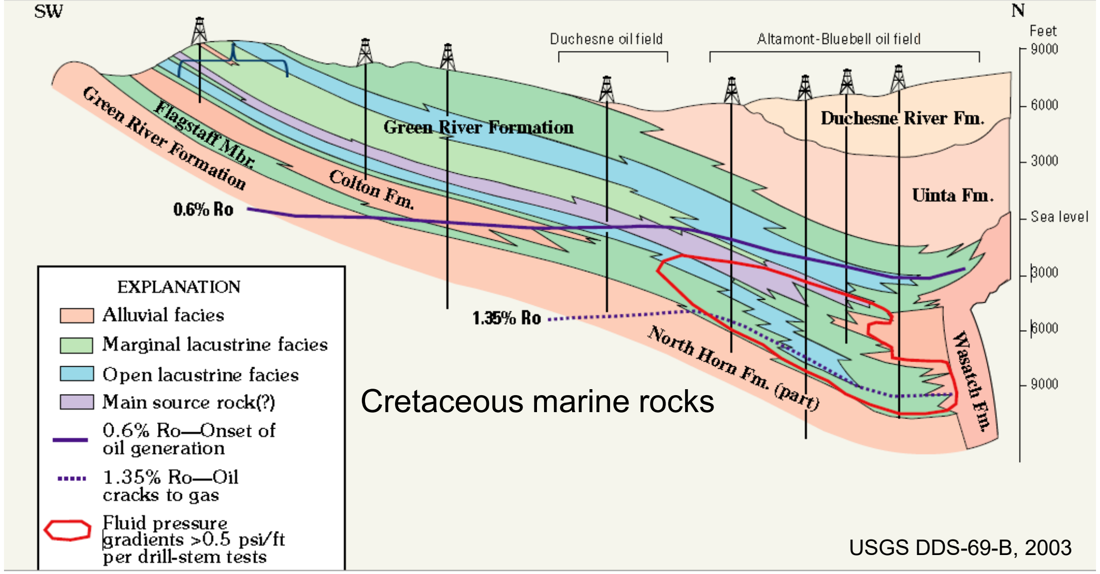
The Green River Formation is Eocene in age and were deposited between ~54 to 48 Ma in a lacustrine environment. Units consist of **interbedded organic-rich shales, dolostone, siltstone, dolomitic sandstone**. As thick as 2500 ft with numerous members. The **kerogen type is primarily Type I which is highly oil prone**. The maturity ranges from 1.33 Ro to thermally immature in the shallower south. **TOC ranges from ~0.5 to 10%**, with an average of ~3%.

Lake Uinta Paleogeography



Modified from Blakey and Ranney (2008)

Modern Asymmetric Uinta Basin

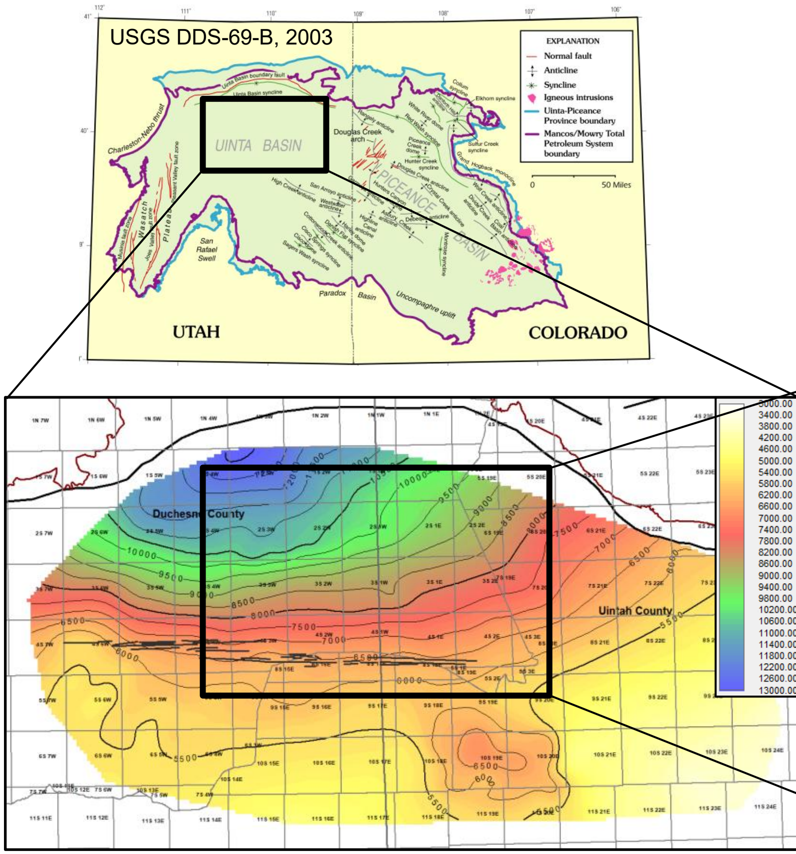


USGS DDS-69-B, 2003

Regional Green River Characteristics

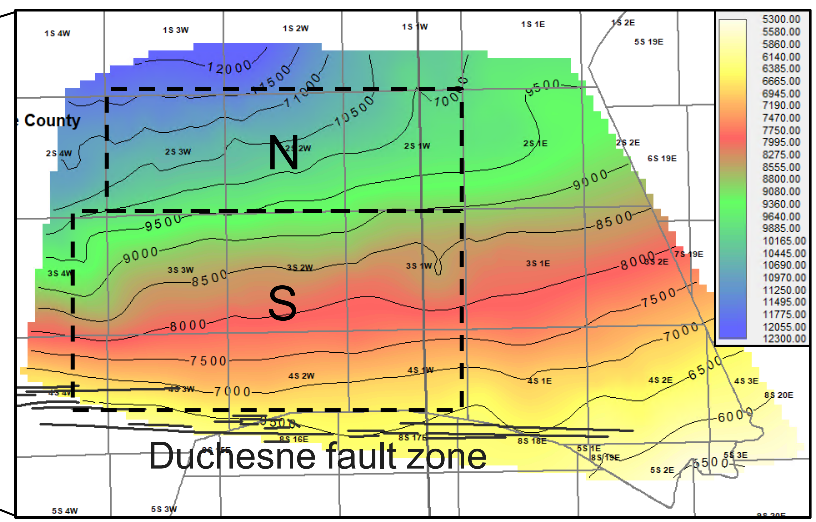
To what degree is the **lower Green River** a continuous, basin-centered petroleum system? Did the shales generate sufficient hydrocarbons to charge the entire system? What is the role of migration? Can we characterize the spatial variability?

Location and Depth Structure



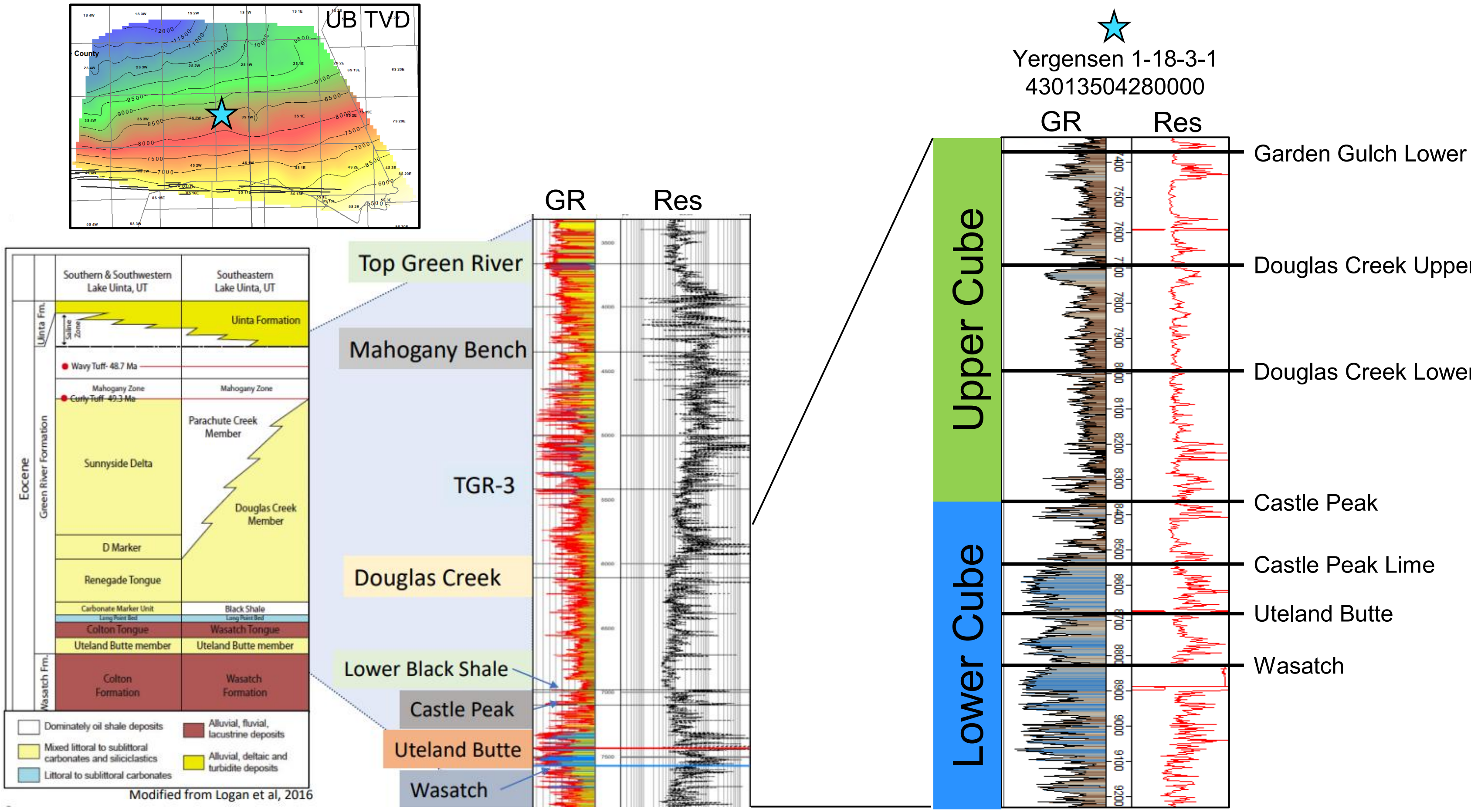
Study Area

- Lower Green River forms NNW-dipping ramp that **spans wide facies and thermal maturity endmembers**.
- The study area is **the focus of recent industry acquisitions** (northern acreage position: XCL→SM, southern acreage position: OVV→FourPoint) due to excellent horizontal well results, continuous acreage blocks, and outstanding inventory.



Lower Green River Units

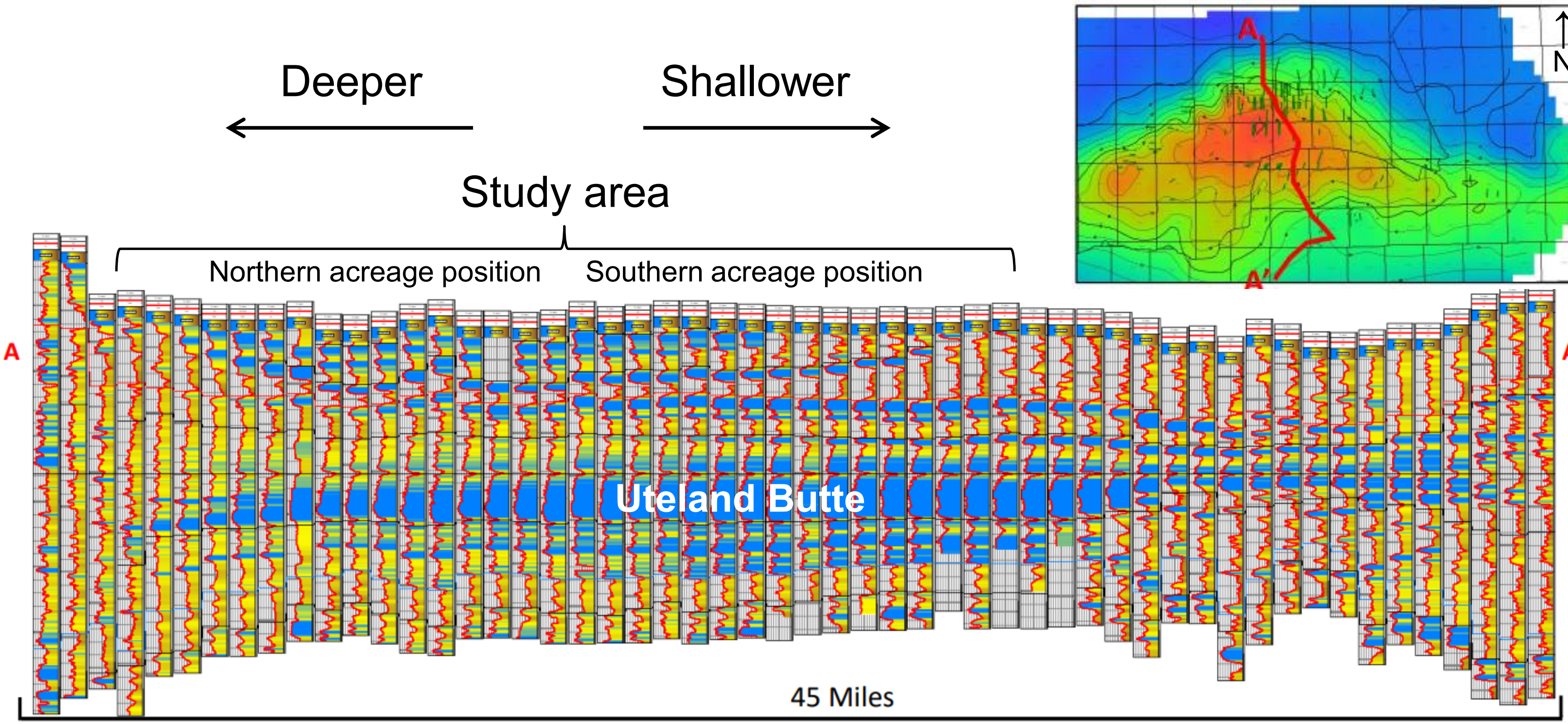
The lower Green River consists of numerous stratigraphic units that represent proved and potential horizontal targets. The vertical and lateral character of the source rocks and reservoir rocks of **"Lower Cube" and "Upper Cube"** is critical to understanding the spatial variability of the petroleum system.



Lower Green River Facies

Lateral facies changes of source-prone shales (yellow) and reservoir-prone rocks (blue) occur across the ramp profile of the deeper Uinta Basin. Note net source-rock and net reservoir-facies from shallow to deep: organic-rich shale dominates the northern acreage position (left), and conventional reservoir rock dominates the southern acreage position (right).

Uteland Butte Carbonate Thickness

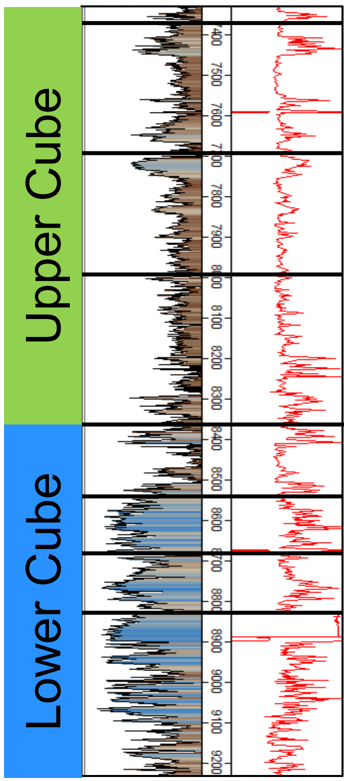


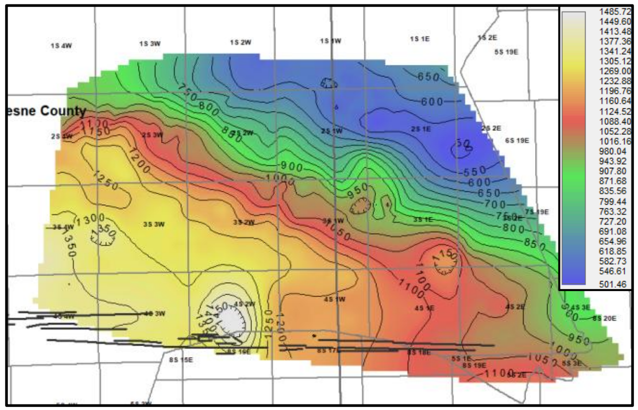
Modified from Brinkerhoff et al., 2022

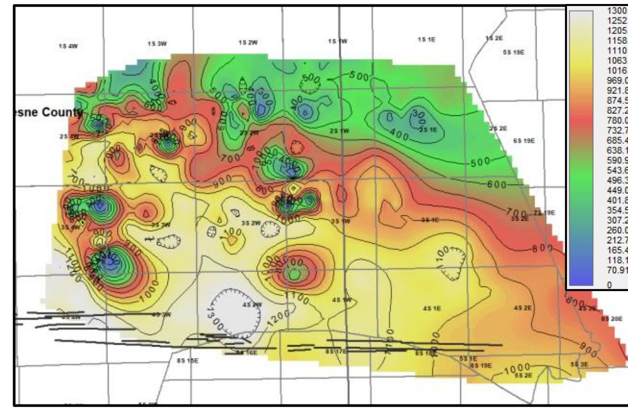
Gross Thickness and Net Shale

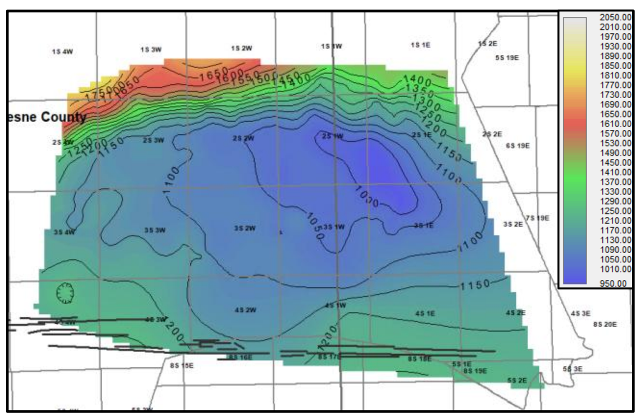
Upper Cube thickness and net shale (GR>70 api) increase to the southwest, with significantly **more shale than Lower Cube.** Importantly, favorable net shale occurs in the deeper north area. Lower Cube thickness is homogeneous, with higher net shale restricted to the south. Increased organic-rich shale in the south (in both cubes) is, however, in a shallow, low thermal-maturity window.

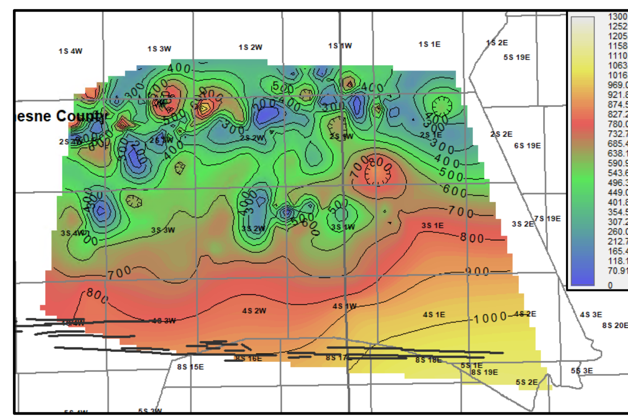
Cubes	Thickness (TVT)	FT Shale











Max Hydrocarbon Generation and OM Porosity Methods

Goal: Determine **generative potential** and **organic-matter (OM) porosity** vs **resource in place** in order highlight areas of **in-situ** vs **migrated hydrocarbons**. Analyze in map form to best capture known geologic complexity. Key map elements are highlighted in blue.

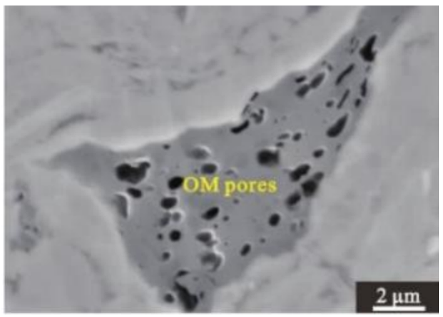
Equations	Required Elements
Transformation ratio (TR) as a function of maturity	**Thermal maturity map**, kinetics curve
Convertible carbon (Cc) = $(0.085 \cdot HI_o)/100$	Hydrogen Index (immature) from core
$\mathbf{TOC_{pd}}$* = (100*((2.685-RhoB)/RhoK))/ (4.655-3.055*(2.685-RhoB)/RhoK)	
$\mathbf{TOC_o}$ = TOC_{pd}/(1-(TR*Cc))	**TOC_{pd} map (shales)**
Full generative potential $S2_o = (HI_o \cdot TOC_o)/100$ mg HC/g rock	
Full generative potential $S2_o$ in OOIP **HCPV** (MMRBO/Sec) = ($S2_o$ mg HC/g rock map*20.082*640*thickness map)/1,000,000	**Basin-scale OOIP maps (reservoirs)**
Hydrocarbons generated = Generative Potential map*Transformation Ratio map	Produced oils data
Avg OM Porosity = ((${TOC_o}$/100)*Cc*TR)*k*(RHOB/RHOK)	**Kerogen density (RhoK) map** **RHOB maps (shales)**
k = 0.95/0.85 = 1.118; assumes ~95% TOC_o is from kerogen, Cc mass is ~85% of convertible kerogen mass.	
OM HCPV (MMRBO/Sec) = (Phi_{OM}*7758*640*net shale map)/1,000,000	**Basin-scale OOIP maps (reservoirs)**

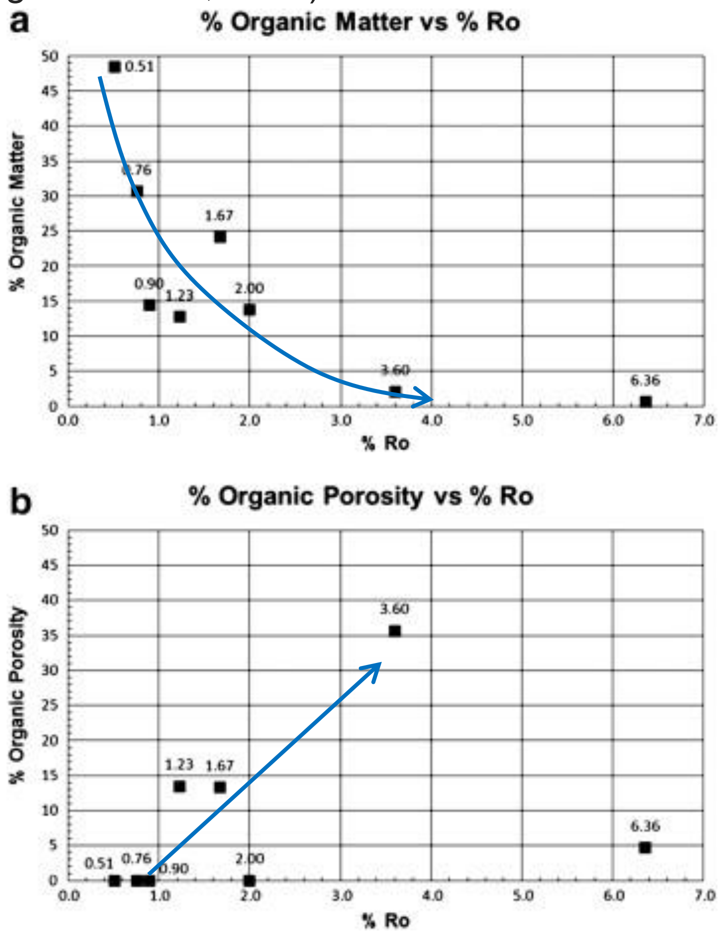
*Modified from Drake, 2019

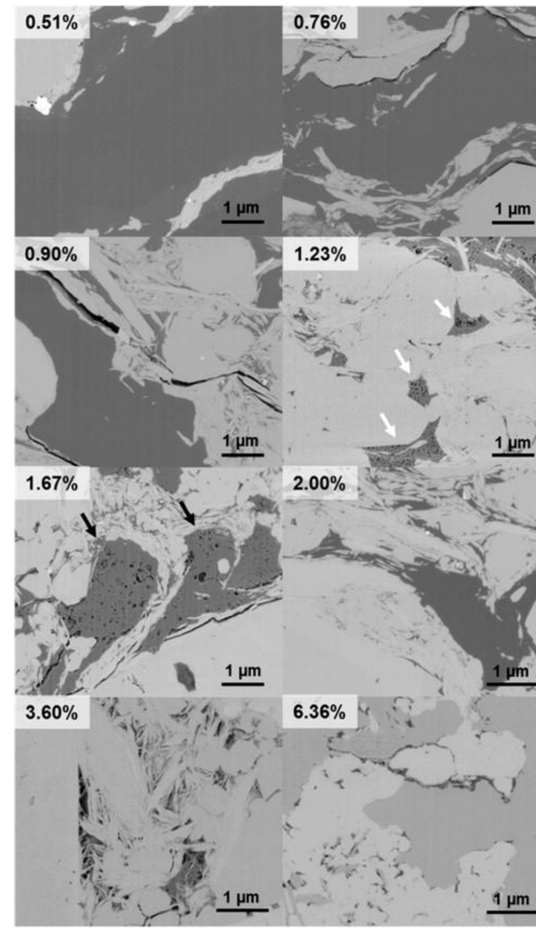
Organic Matter Porosity

Kimmeridge

Organic porosity plays a key role on hydrocarbon storage, migration, and production, particularly in massive source-rock reservoirs. OM porosity, like shown in the Woodford example below, is considered an important contributor to production in the lower Green River horizontal targets (e.g., Brinkerhoff et al., 2022). **The storage capacity of OM porosity can be significantly higher than that of the inorganic matrix and fracture pore network** (Arango and Katz, 2019).







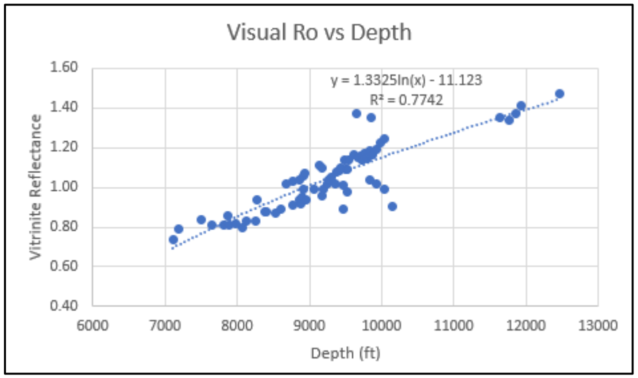
Curtis et al. (2012) documented a positive relationship between organic porosity and thermal maturity in the Woodford Shale. Organic porosity degrades in highest thermal maturity.

Source: Arango and Katz, 2019; Zhao et al., 2022; Curtis et al., 2012

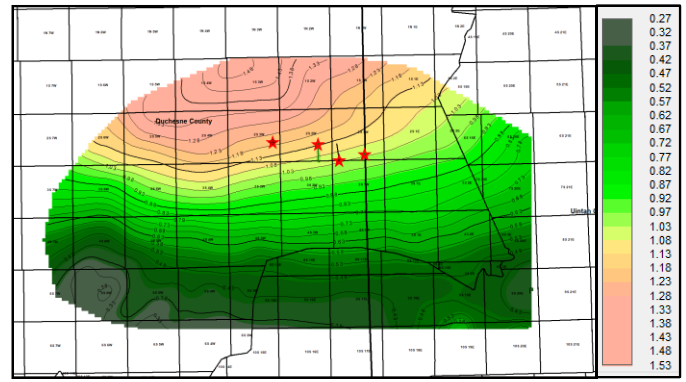
Green River Fm Thermal Maturity and Transformation Ratio

Thermal maturity to depth relationship is based on **vitrinite reflectance, rather than Tmax**. Type I kerogen kinetics for the Green River Fm is used to create the transformation map. **Type I kerogen initiates oil generation at ~0.76 Ro** (a higher value than other kerogen types), which corresponds to just ~5% kerogen transformation (Waples and Marzi, 1998).

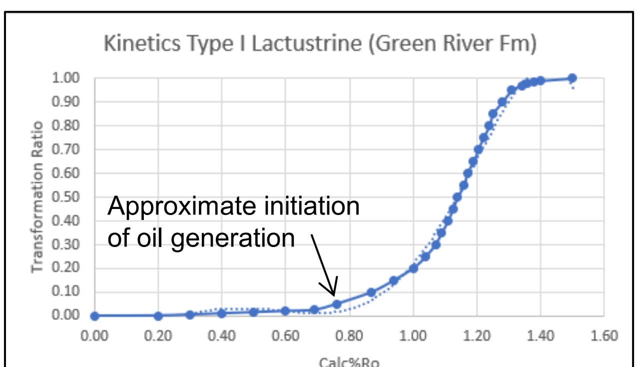
Vitrinite Reflectance and Depth



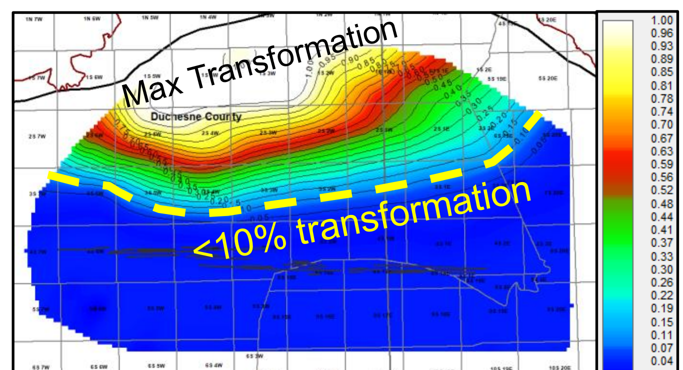
Uteland Butte Thermal Maturity



Transformation Ratio and Maturity



Transformation Ratio Map

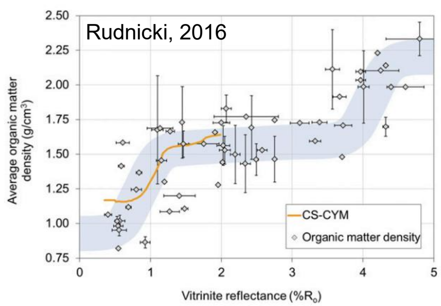


Note: thermal maturity and pressure are tied to depth.

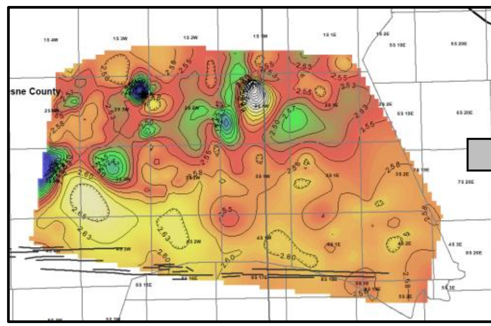
Lower Green River Shales Density and Present Day TOC

Average present-day **TOC is calculated by transform from bulk density** (RhoB) and **organic matter density** (RhoK), which varies with thermal maturity. Note that the calculated average TOC_{pd} for the net shales of both cubes is broadly homogeneous across the study area despite a major north-south gradation in thermal maturity.

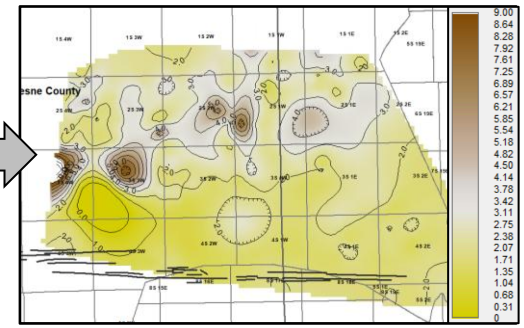
RhoK and Maturity



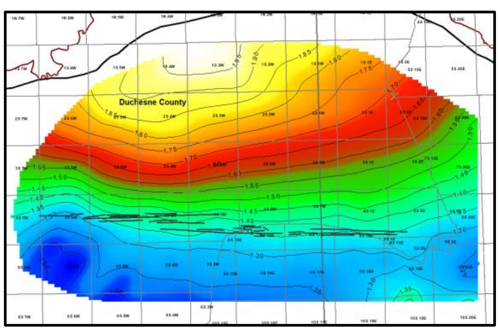
Avg RhoB Upper Cube Shales



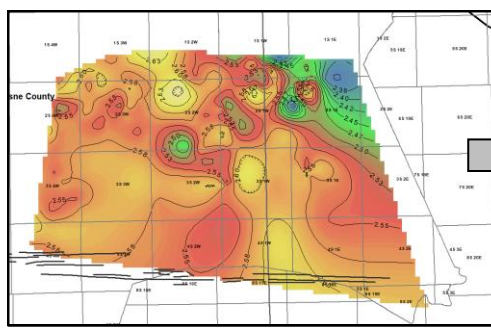
TOC_{pd} Upper Cube Shales



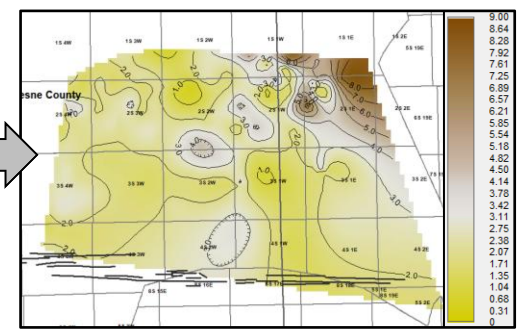
RhoK Map



Avg RhoB Lower Cube Shales



TOC_{pd} Lower Cube Shales

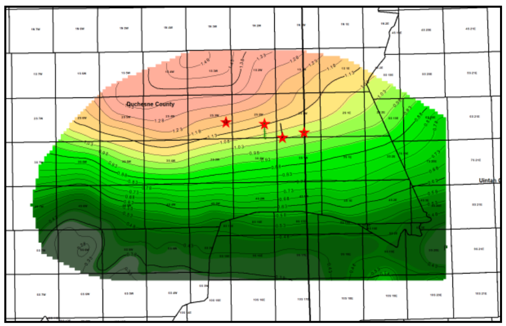


TOC_{pd} = (100*((2.685-RhoB)/RhoK))/(4.655-3.055*(2.685-RhoB)/RhoK); 2.685 is the dry grain density of siliciclastic shale with TOC of ~0% at this density value and higher. RhoK varies with thermal maturity.

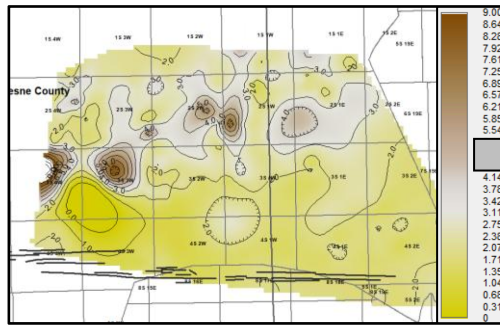
Restoring Original TOC from Present-Day TOC

Average TOC_{pd} of Lower Cube shales (2.55%) is very similar to Upper Cube shales (2.56%). Due to maturity/TR trends, **restoration of original TOC is minimal across much of the study area**. **Highest TOC_o occurs in the highest thermal maturity region (deep basin).** This suggests broad depositional conditions for OM preservation in the deepest portion of the basin before thermal maturation took place.

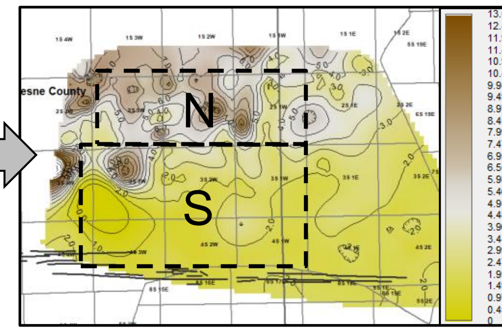
Thermal Maturity Uteland Butte



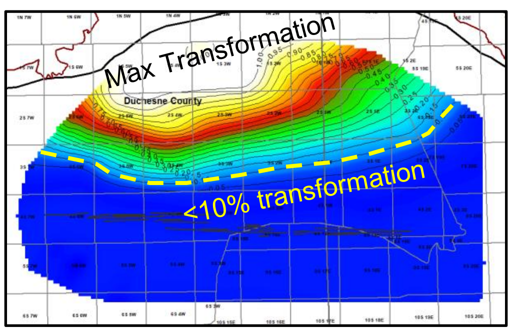
TOC_{pd} Upper Cube Shales



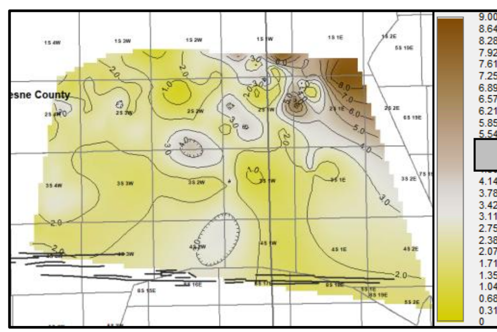
TOC_o Upper Cube Shales



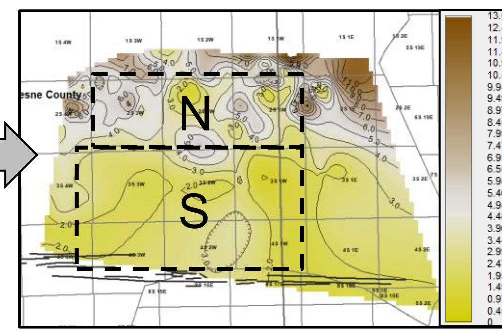
TR (Type I Green River Fm)



TOC_{pd} Lower Cube Shales



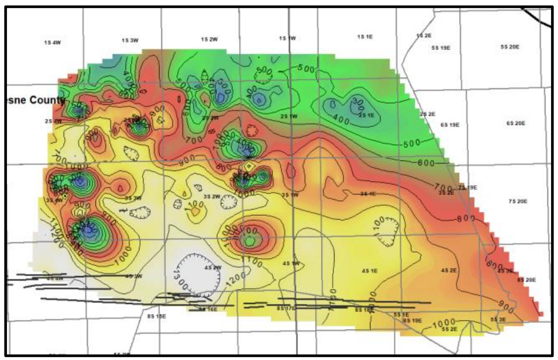
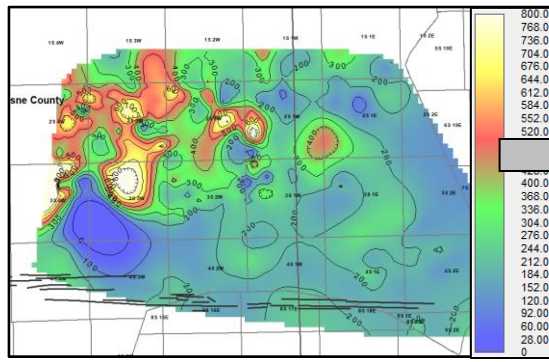
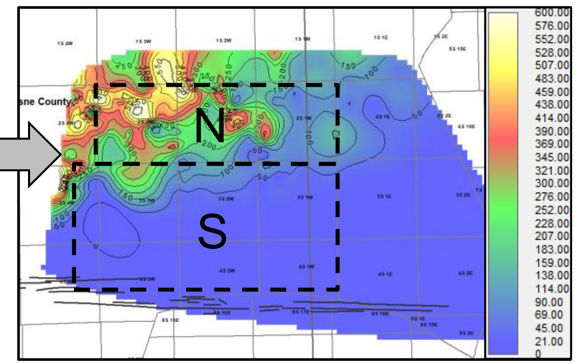
TOC_o Lower Cube Shales

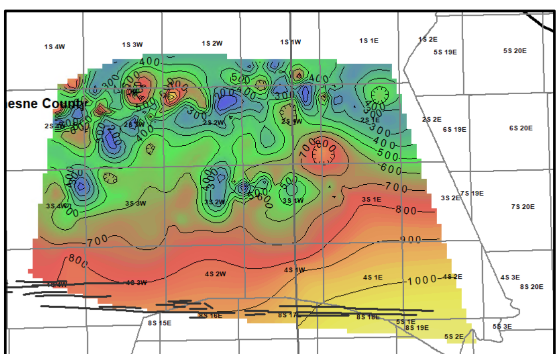
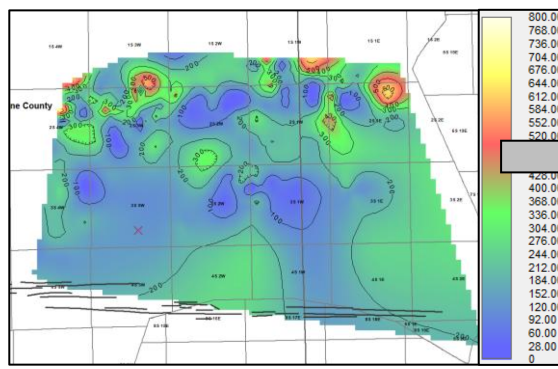
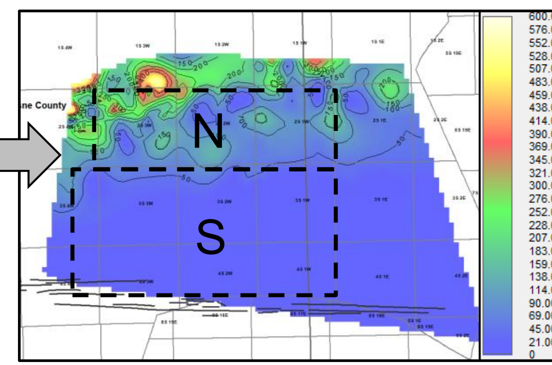


$TOC_o = TOC_{pd}/(1-(TR*Cc))$, Cc = 0.68

HCs Generated by Lower and Upper Cube Source Rocks

Total hydrocarbons generated is a function of TOC_o, thermal maturity, kerogen type (Type I, lacustrine), kinetics and transformation ratio, and net shale thickness. Note that respective **shales of southern half of study area each generated less than 50 MMRBO/Sec, far less than to the north for each cube.**

Upper Cube Net Shale	Max Generative Potential	Upper Cube HCs Generated
		

Lower Cube Net Shale	Max Generative Potential	Lower Cube HCs Generated
		

$S2_o = (HI_o * TOC_o)/100$ mg HC/g rock

$S2_o$ OOIP HCPV (MMRBO/Sec) = ($S2_o$ mg HC/g rock map*20.082*640*net thickness map)/1,000,000

Hydrocarbons generated = Max Generative Potential map*Transformation Ratio map

OOIP (MMRBO/Sec) in Organic Matter Porosity

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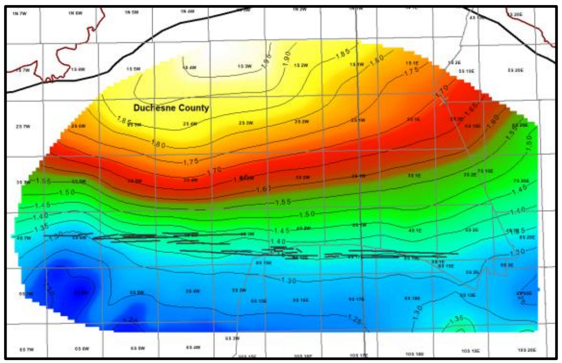
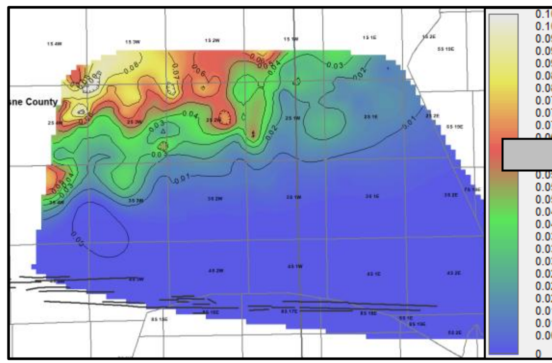
Where thermal maturity and TOC_o are optimal, **avg OM porosity ranges from ~2 to over ~7%** in shales, and OOIP ranges from ~40 to over 200 MMRBO/sec. **Southern study area has essentially no organic porosity in either the upper or lower cube shales and therefore negligible OM-hosted OOIP.**

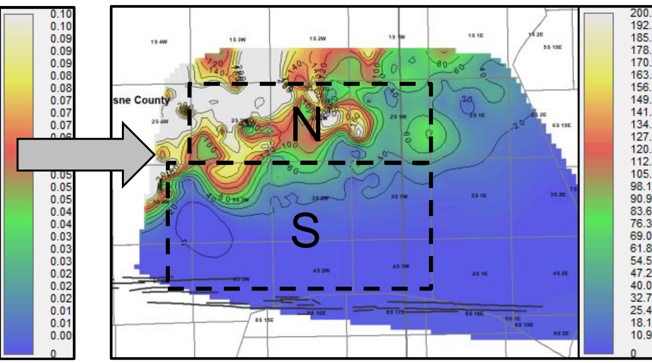
Lower Cube Shale RhoK



Upper Cube Shales OM Porosity



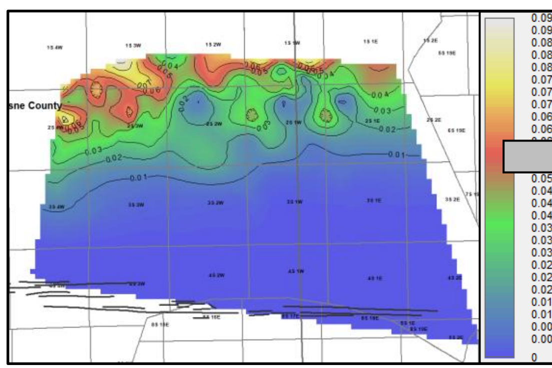
Upper Cube Shales OOIP



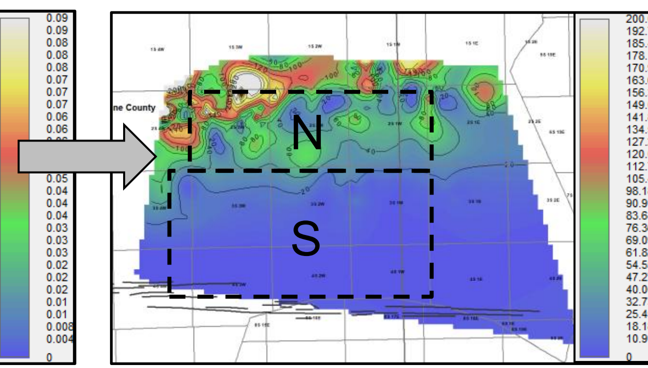
OM Phi and OOIP in Shales

- Kerogen density (RhoK) varies with thermal maturity
- Type I Kinetics
- HI_o of 800
- At reservoir conditions

Lower Cube Shales OM Porosity



Lower Cube Shales OOIP



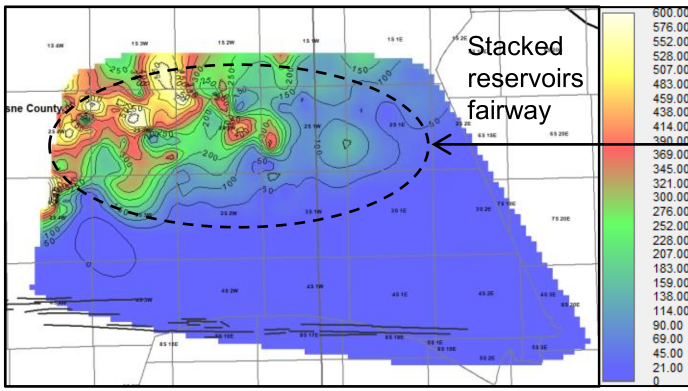
Avg OM Porosity = $((TOC_o/100)*Cc*TR)*k*(RHOB/RHOK)$, k = 0.95/0.85 = 1.118; assumes ~95% TOC_o is from kerogen, Cc mass is ~85% of convertible kerogen mass.

Source Rock HC Generation vs Reservoir OOIP (MMRBO/Sec)

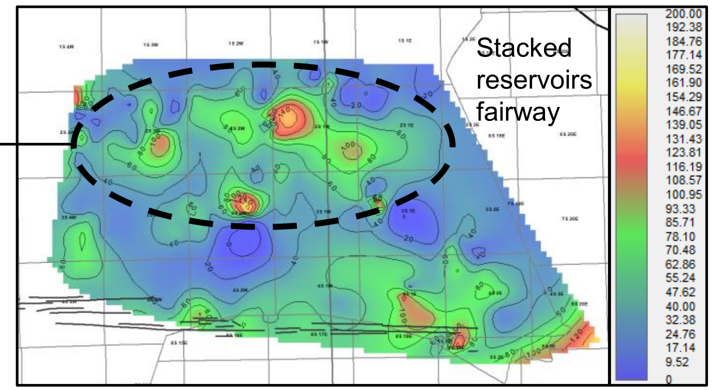
When comparing hydrocarbon generation to reservoired oil in place, stark contrasts are revealed from north to south.

- Upper Cube reservoirs are collocated with max HC generation. **HC generation is over ~5x reservoired OOIP.**
  → *Most of the generated oil has necessarily left the local system (migrated vertically and/or laterally).*
- Lower Cube reservoirs are south of max generation. **Reservoired OOIP is ~2x HC generated by shales in the south.**
  → *Oil migration is required to fill the hydrocarbon generation shortfall in the local system.*

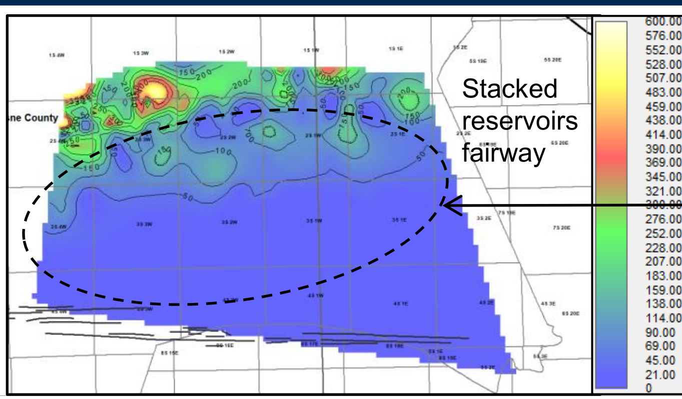
Upper Cube Max HC Generation



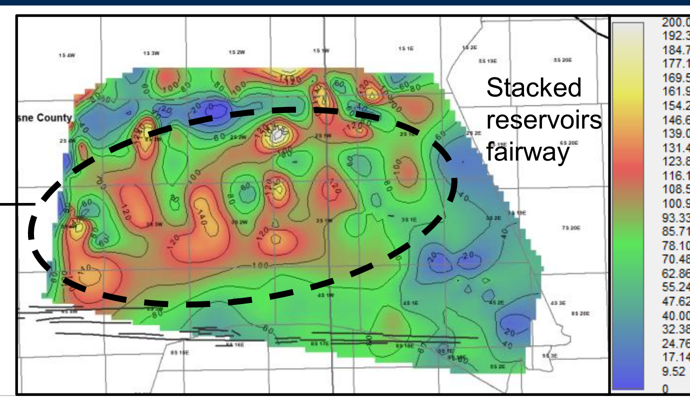
Upper Cube OOIP (Reservoirs)



Lower Cube Max HC Generation



Lower Cube OOIP (Reservoirs)

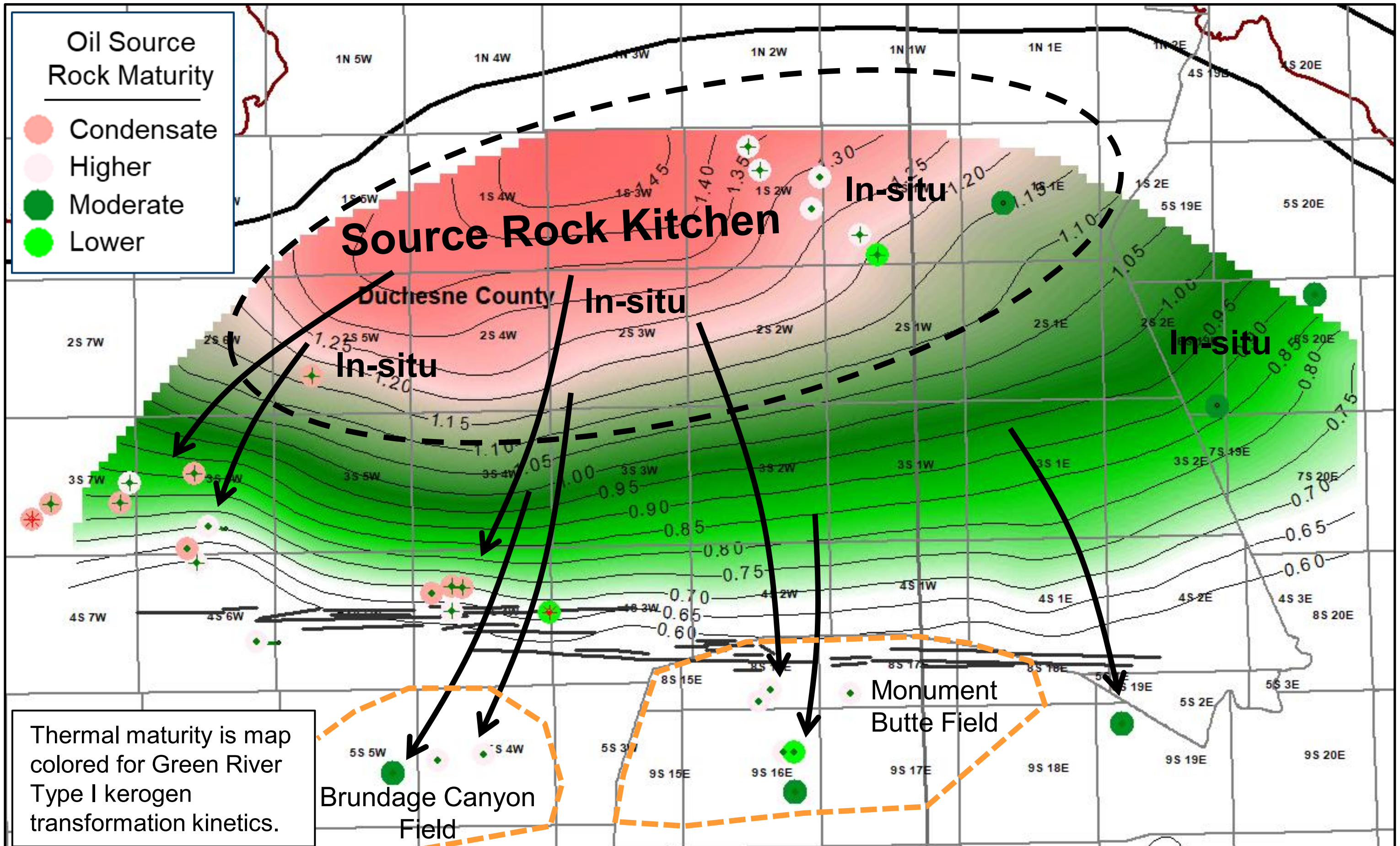


Petrophysical Methodology: Indonesian, <80% Sw, >6% PhiE

Variable Oil Migration with Thermal Maturity

Kimmeridge

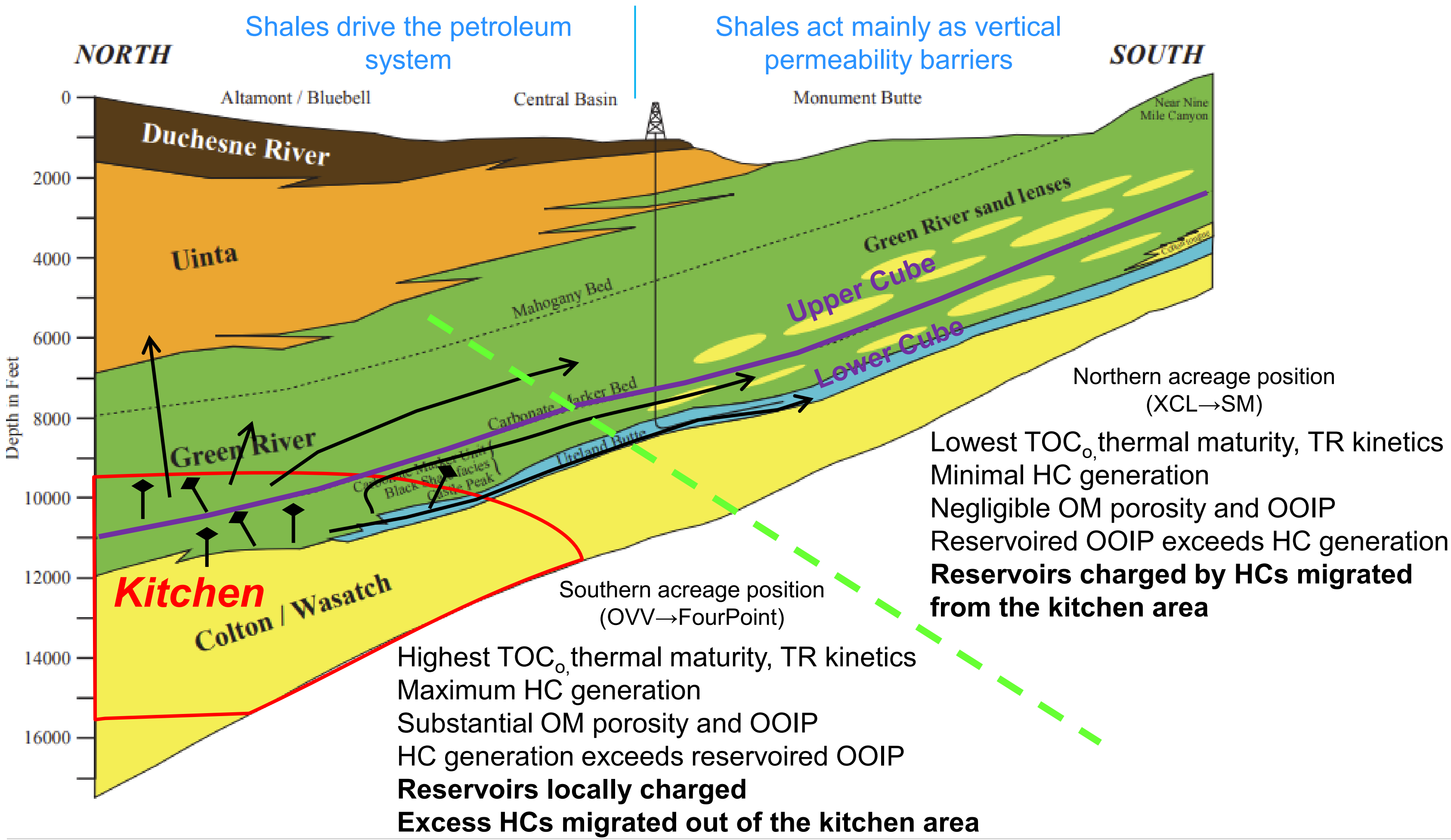
Oils produced from cube reservoirs are **typed to Green River Fm source rocks**, along with **estimated source-rock maturity at expulsion** (GeoMark). Oils of source-rock maturities that exceed local thermal maturity demonstrate hydrocarbon migration. Oils in the source-rock kitchen show little to no migration (i.e., the oils there are “in-situ”).



Conceptual Model of Green River Petroleum System

Kimmeridge

Two broad end-member petroleum systems are apparent: 1) the deeper, more thermally mature region is characterized by excess hydrocarbon generation and local reservoir charge, and 2) the shallower, less mature region is dominated by migrated hydrocarbons.



Source: Modified from Vanden Berg et al, 2014

Conclusions

Several **mass-balance organic geochemistry** techniques ranging from **nanoscale to basin scale** were employed here to highlight where lateral changes in hybrid play character occur across the basin

Implications of this study range from identification of **migration pathways** to selecting appropriate horizontal **well-placement strategies** (i.e., consideration to if OM porosity contributes or not)

Main Controls on Hybrid Variability

Complex **regional facies** changes from **shallow** basin to **deep** basin

Organic-rich interbeds, **Type I kerogen**

Organic porosity is significant at higher maturity

Hydrocarbon migration is spatially variable, depending largely on **maturity and facies**

Uteland Butte Member

Applications to Other Petroleum Systems

- Shales can range spatially from horizontal target contributors to permeability barriers and baffles
- Similar mass-balance workflows can be used in other petroleum systems to identify major contrasts in hydrocarbon generation, reservoir quality, OM porosity contribution, and hydrocarbon migration
- But basin-specific and formation-specific methodology is always required to properly characterize key elements such as TOC_{pd}, thermal maturity, and kerogen kinetics

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