Controls on Petroleum Phase and Water Production in the Wall Creek Resource Play, Powder River Basin, Wyoming*

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Abstract

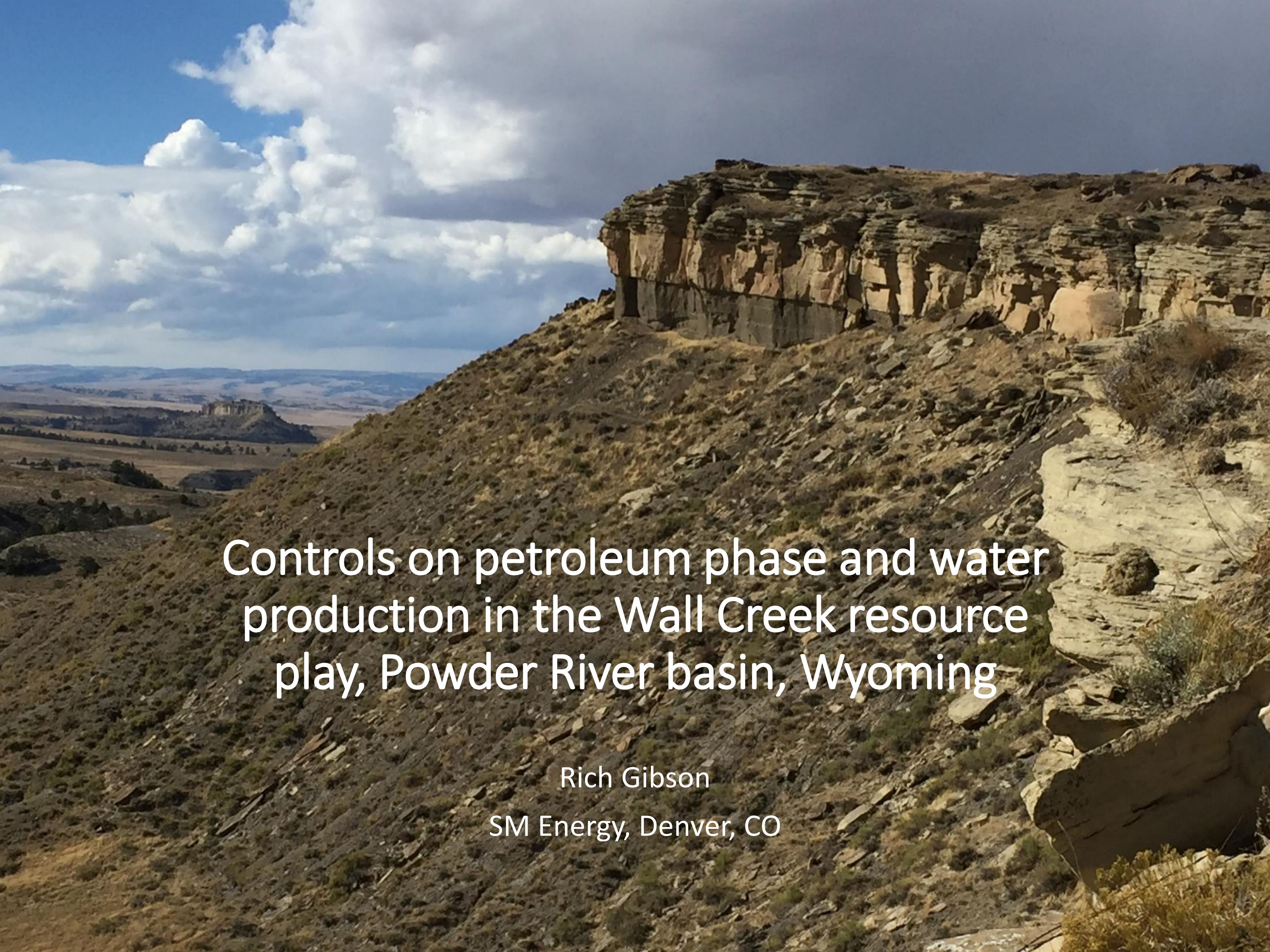
The Wall Creek Member of the Frontier Formation, originally developed by vertical wells along NNW-SSE high phi- k sandstone trends, has been the target of horizontal drilling for the past several years in the deepest part of the Powder River Basin. The basin is asymmetric with a gently dipping east limb and steep west flank that is only locally faulted at Wall Creek level. The sands are continuous from outcrop on the west flank into the productive basin center, but transition into mudstone updip toward the east. Oils within the Wall Creek are derived from the Niobrara, which is 250-700’ above the top of the reservoir. Petroleum properties (phase and GOR) and water production vary within the confines of the play. Vertical wells in the highest quality reservoir trends typically produced with <10% water cut. Horizontal wells drilled into intervening lower quality reservoir areas have water cuts ranging from <10% to >80% that do not vary systematically with calculated pay thickness, PhiH, or SoPhiH. Log calculated water saturations are lowest on the east flank and basin center, but gradually decrease westward up the west flank despite the apparent lack of either a structural or stratigraphic trap in this direction. Variations of petroleum phase and GOR do not conform to a simple depth-dependent relationship. A temperature map at the top of the Wall Creek, generated from DST temperatures, shows contours that do not parallel structural contours due to regional gradient variations. Temperature and vitrinite reflectance data were used to calibrate 1D burial history models by simultaneously solving for basal heat flow and the amount of erosion since ~40Ma. A relationship between present-day temperature and vitrinite reflectance derived from the model results was used to convert the temperature map to maturity. Oil maturity data, early-life GOR values, visual appearance of the oils, and gas isotope values all show clear relationships to this map, with the highest maturity fluids confined to a

sub-circular area located generally east of the basin axis. KINEX modeling of the Niobrara source verifies that the observed range of GOR values can be explained by thermal maturity variation between ~1.1 and 1.4 %Ro at the Wall Creek level. Oils are inferred to have migrated downward into the reservoir and continued maturing in-situ so that they match present-day reservoir maturity levels. Sequential flattening of a regional E-W 2D seismic line across the basin shows that the area that is now the deep basin was on the west flank of a low-relief paleo-high in latest Cretaceous to early Tertiary time. Based on the 1D basin models, migration of oil and gas from the Niobrara source occurred in the early Tertiary, coincident with the presence of this paleo high. These observations suggest that petroleum in the Wall Creek was originally captured in a regional, westward-dipping stratigraphic trap and maintained there through mid-Tertiary deep burial. Subsequent uplift of the west flank allowed petroleum to leak westward, being replaced by imbibed water. Since reservoir quality had already been degraded by diagenesis during deepest burial, the rate of leakage was probably very slow and may be continuing today. Log-calculated Sw values and horizontal well water cuts follow a regional pattern consistent with this model. Wells located east of the present-day basin axis have <20% water cut. An intermediate domain of flat to gentle eastward dip is characterized by 20-60% water cut, whereas wells on the steeper dipping west flank have water cuts >70%. Although the variation in log calculated Sw values is dominated by reservoir quality, a 20% overall Sw increase in rocks of consistent reservoir quality from east to west is also clearly evident. The observed Sw and production behavior can be understood in terms of a capillary drainage and imbibition curves. Rocks east of the basin axis, which have stayed in closure throughout basin evolution, remain on the drainage curve and produce the most water-free. Rocks west of the basin axis that are no longer in closure have undergone partial leakage and moved down imbibition curves to varying degrees. Since imbibition curves are steep relative to drainage curves, water influx has a relatively small impact on increasing Sw while having a dramatic impact on phase mobility due to partial or complete ‘snap off’ of the non-wetting oil phase in pore throats. As a result, production behavior in the domains west of the basin axis are not well predicted based on log calculated parameters.

References Cited

Chen, Z., and C. Jiang, 2015, A Data Driven Model for Studying Kerogen Kinetics with Unconventional Shale Application: Examples from Canadian Sedimentary Basins: Marine and Petroleum Geology, v. 67, p. 795-803. doi:10.1016/j.marpetgeo.2015.07.004

Shanley, K.W., and R.M. Cluff, 2015, The evolution of pore-scale fluid-saturation in low-permeability sandstone reservoirs: AAPG Bulletin, v. 99/10, p. 1957-1990.



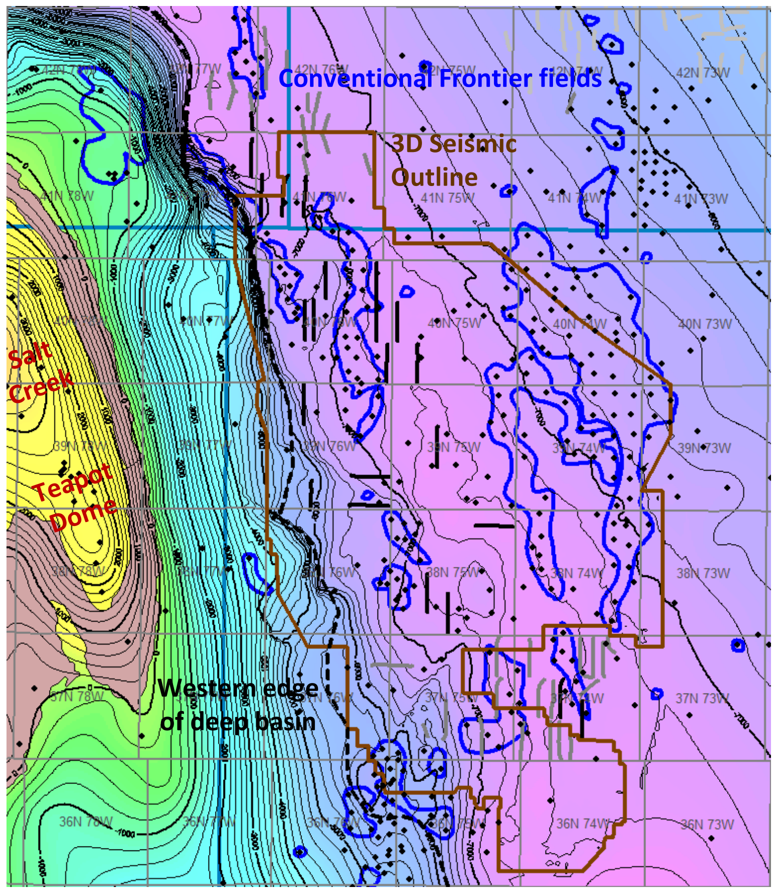
Controls on petroleum phase and water production in the Wall Creek resource play, Powder River basin, Wyoming

Rich Gibson

SM Energy, Denver, CO

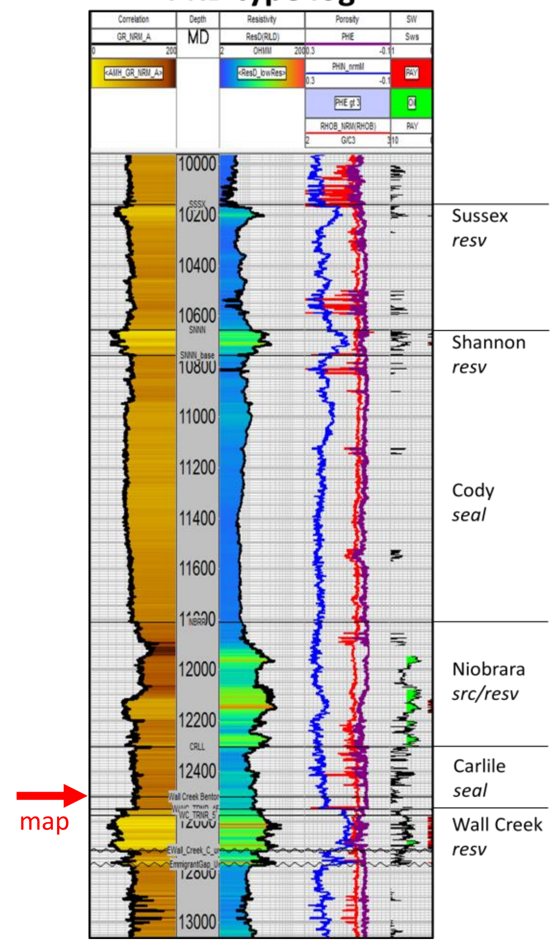
Overview: Wall Creek resource play

- Basin-centered oil + gas accumulation in low-permeability, marginal marine sandstones of the Wall Creek Member, Frontier Fm.
- Legacy vertical production along linear high-quality sand trends with low water production.
- Pervasive oil saturation (40-49 API) sourced from overlying Niobrara mudstones.
- Normal to slightly over-pressured (.45-.6 psi/ft.); increases eastward with net sand decrease.



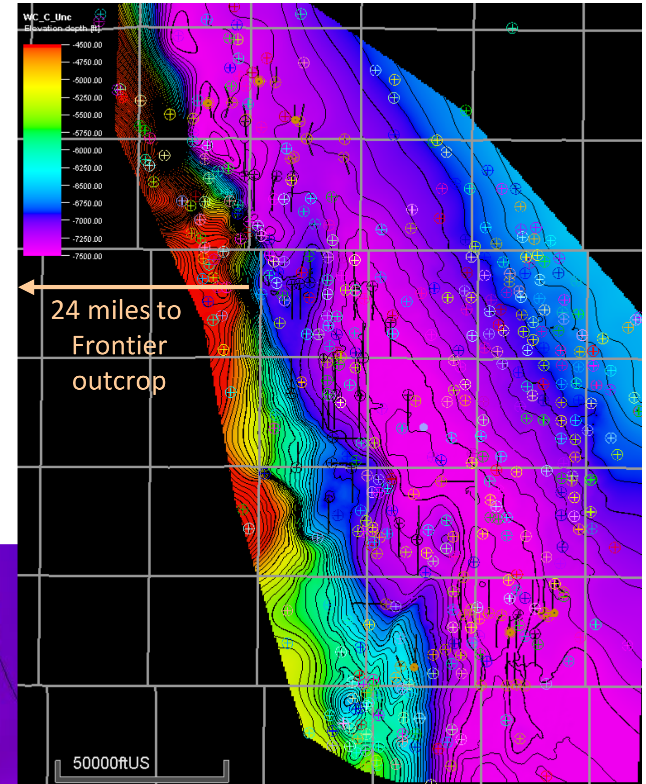
Wall Creek Bentonite structure map

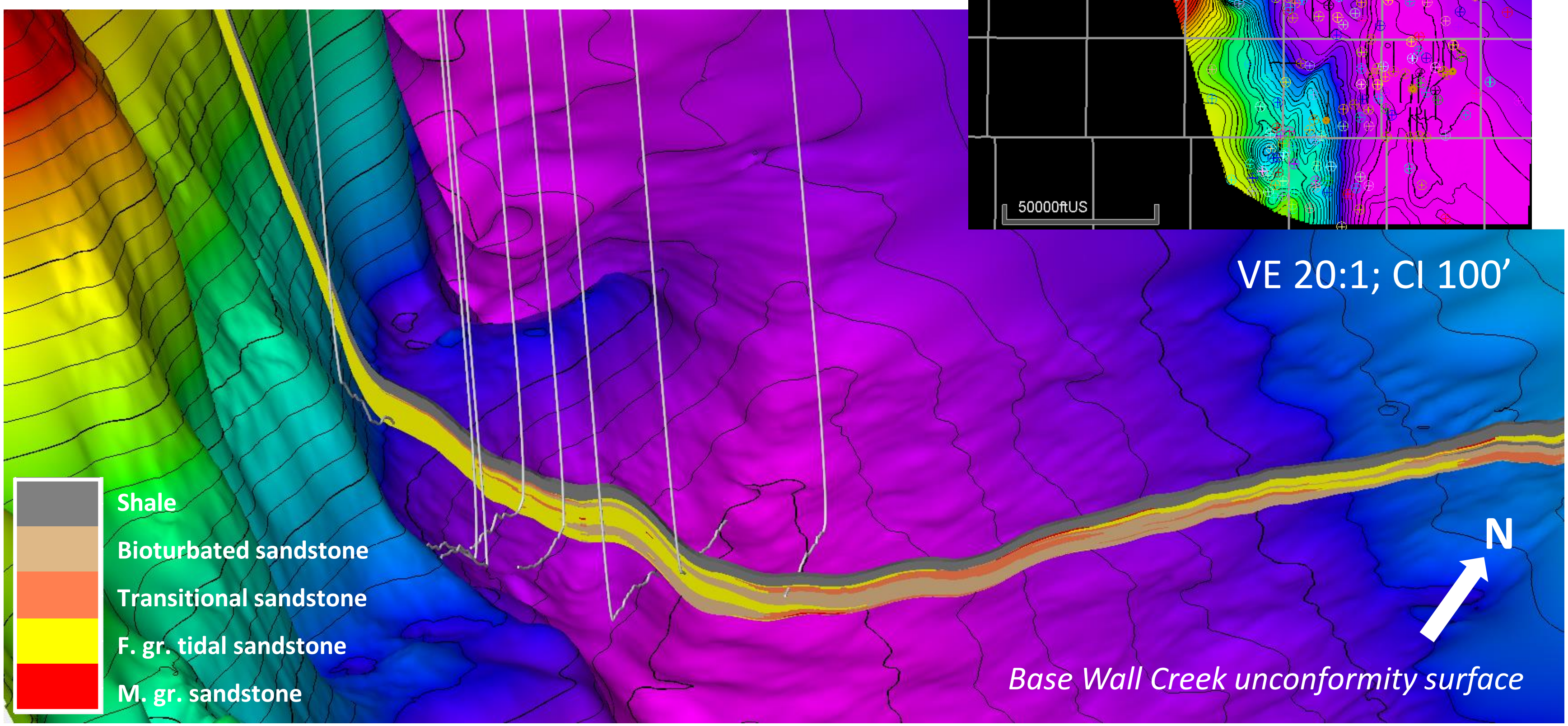
PRB type log



Wall Creek reservoir architecture

- Unconformity-bounded <200’ sand package with internal W-to-E prograding clinoforms
- Alternating high-energy tidal sands and lower-energy bioturbated, wave-dominated sands
- Sands are continuous updip to outcrop 20-30 mi west of producing area





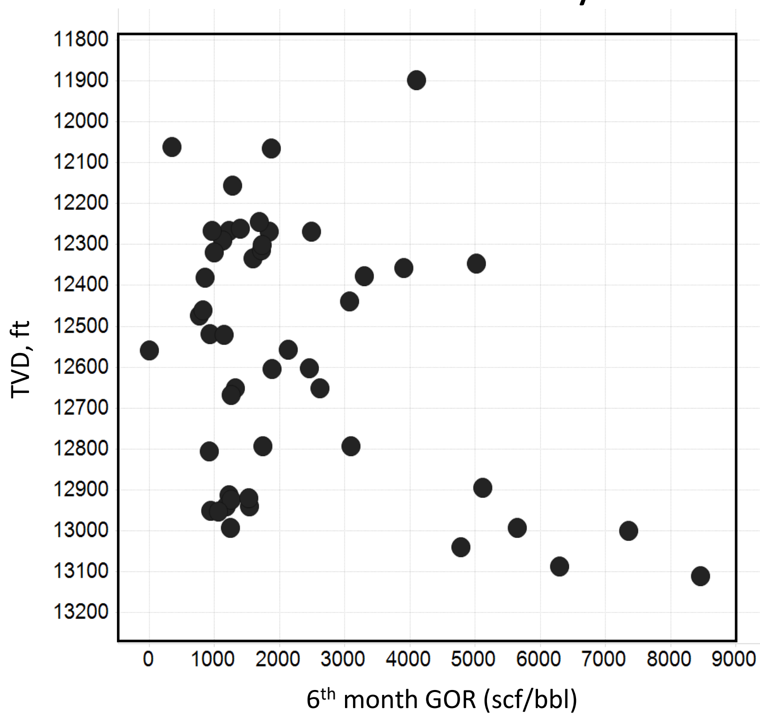
Key issues and questions

- Gas-oil ratio:
  - Substantial variation in GOR regionally in vertical and horizontal wells
  - Impacts oil recovery and well economics
  - Can we understand why and define areas to avoid?

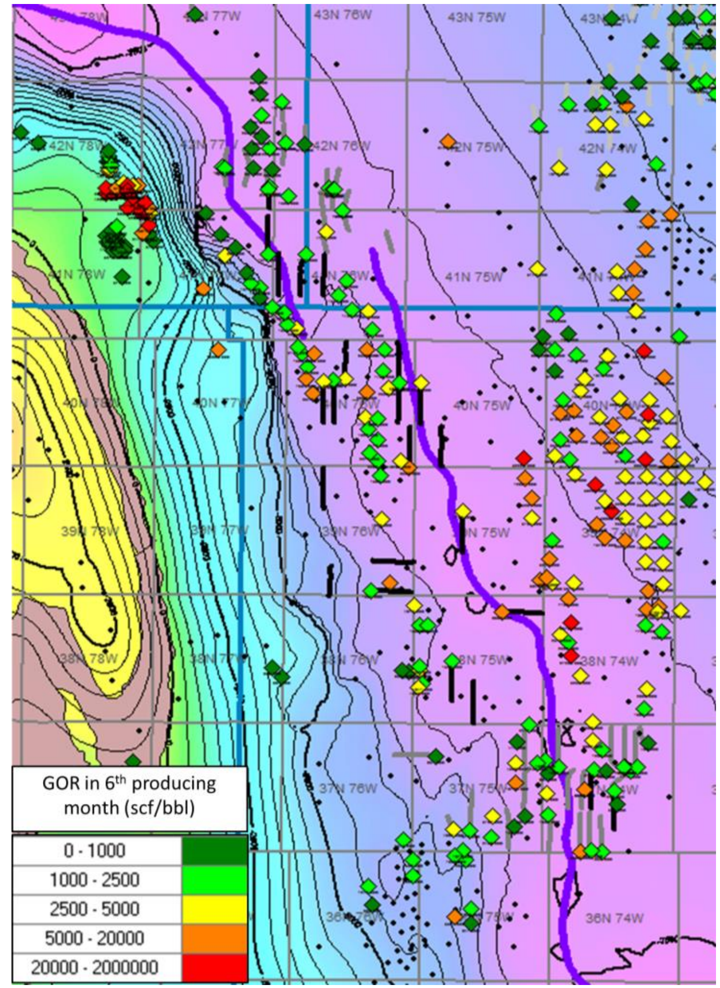
- Water production:
  - Vertically developed fields had low water production
  - Horizontal wells have higher water production that varies dramatically (20-80+%)
  - What causes this variation and how do we avoid areas of high water cut?

Gas-oil ratio variation

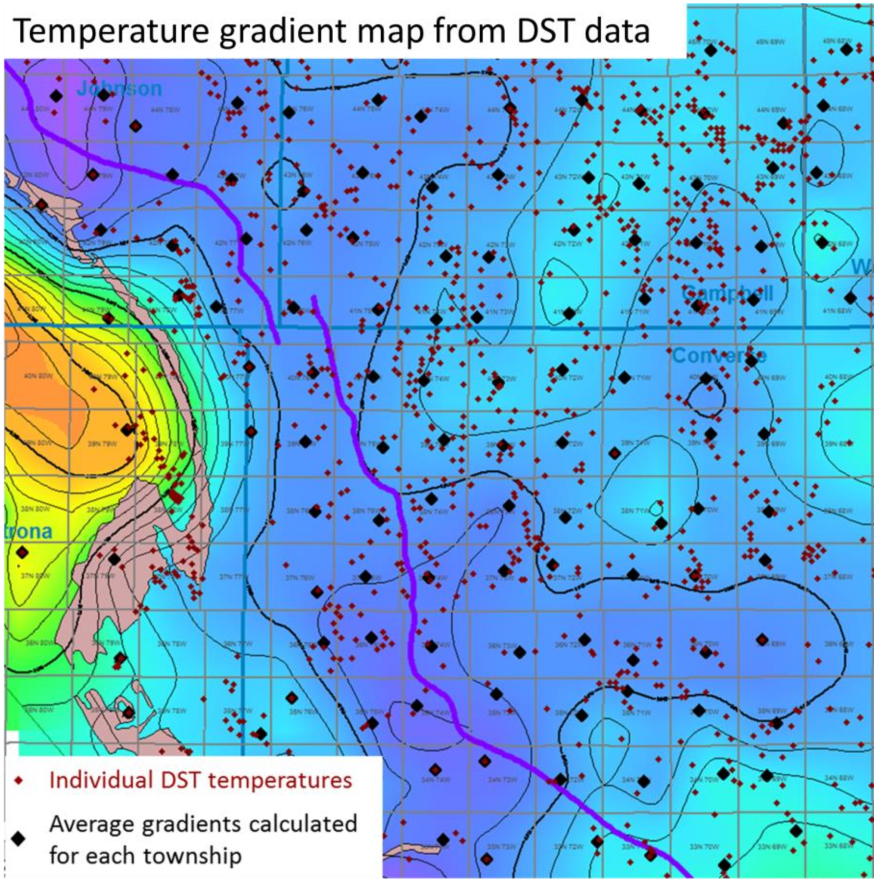
Horizontal wells only

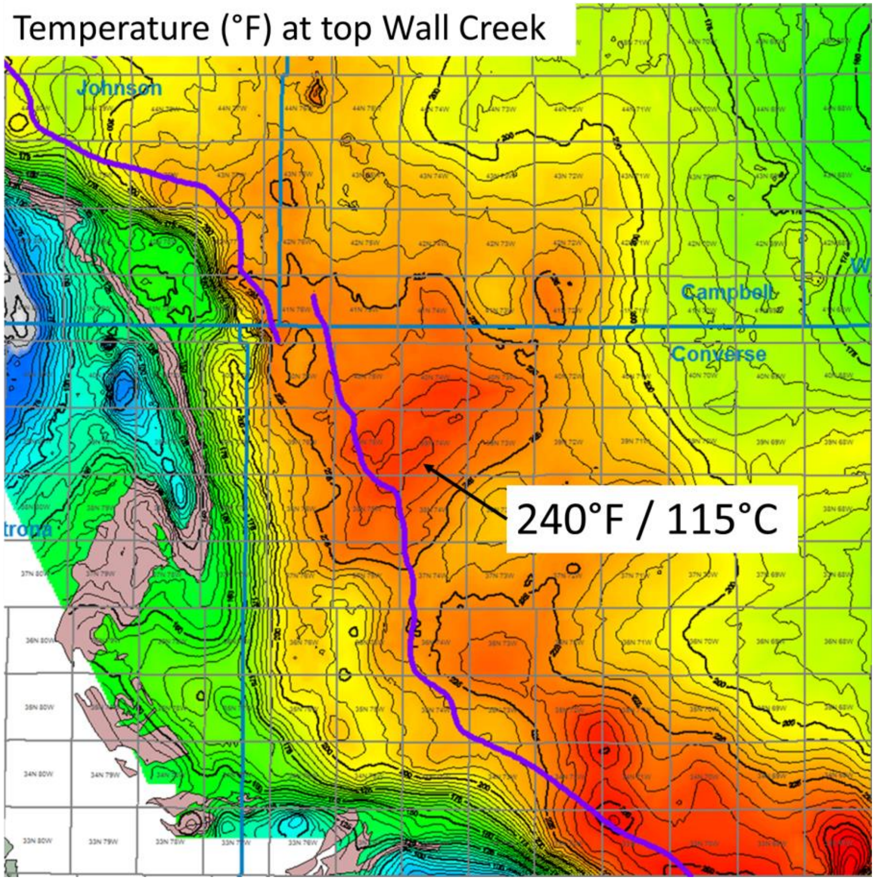


Vertical and horizontal wells



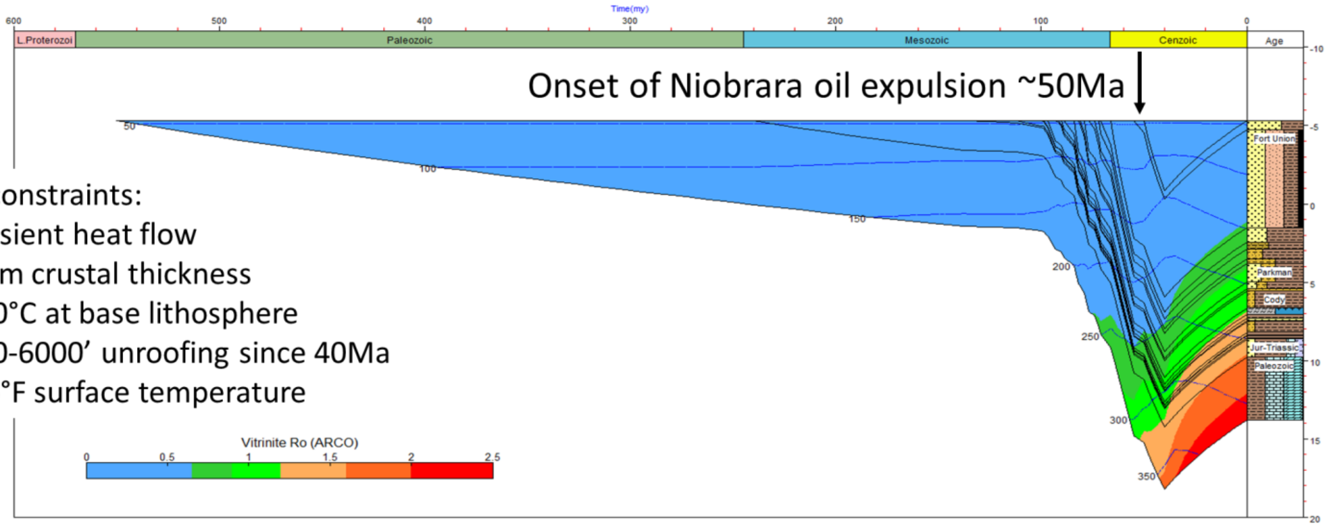
Temperature map constructed from DST data





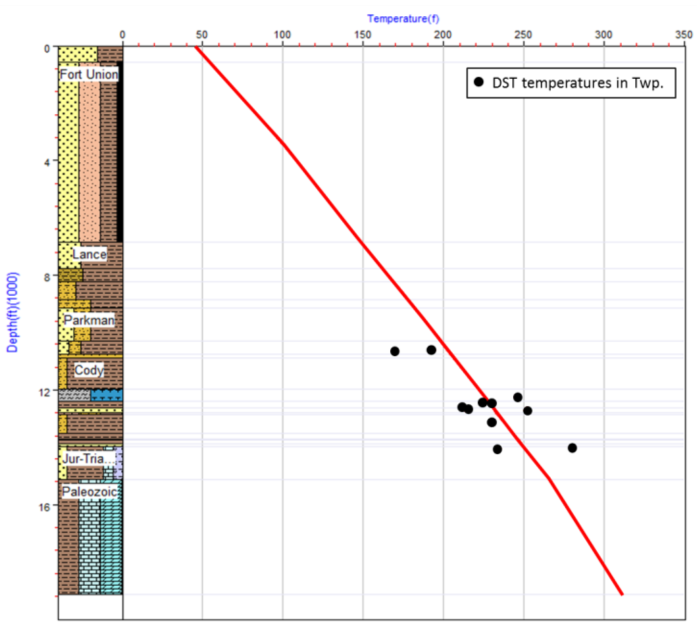
CI = 5°F

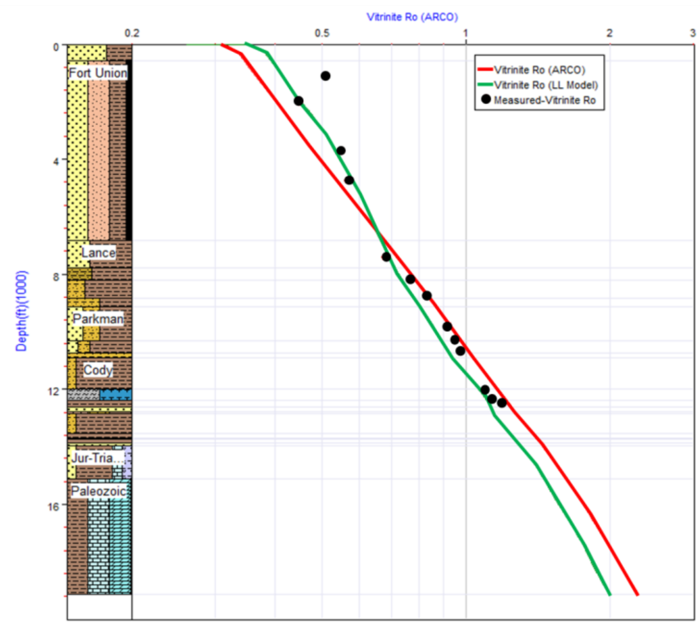
GENESIS 1D models calibrated to T and %Ro data at selected well locations



Model constraints:

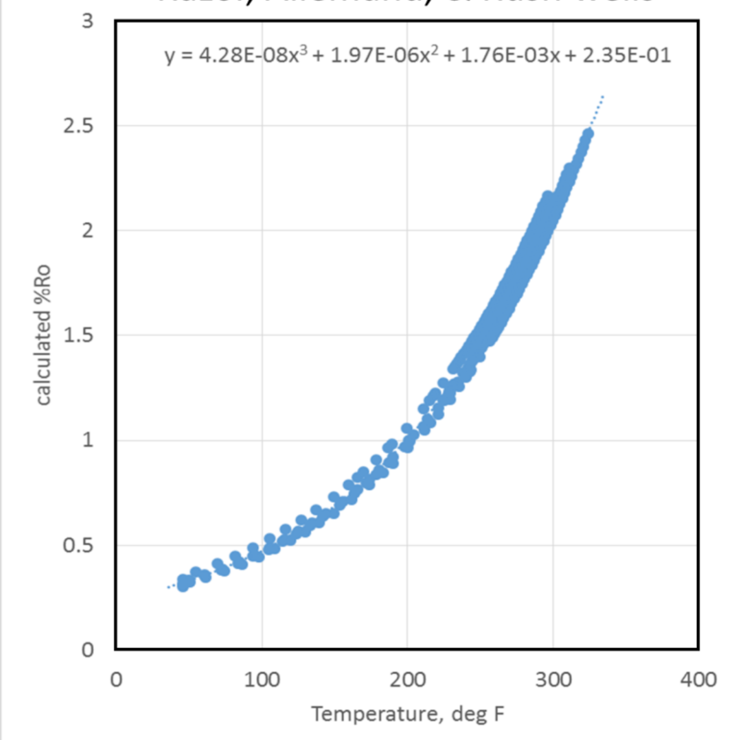
- Transient heat flow
- 42 km crustal thickness
- 1330°C at base lithosphere
- 4000-6000’ unroofing since 40Ma
- 45.6°F surface temperature

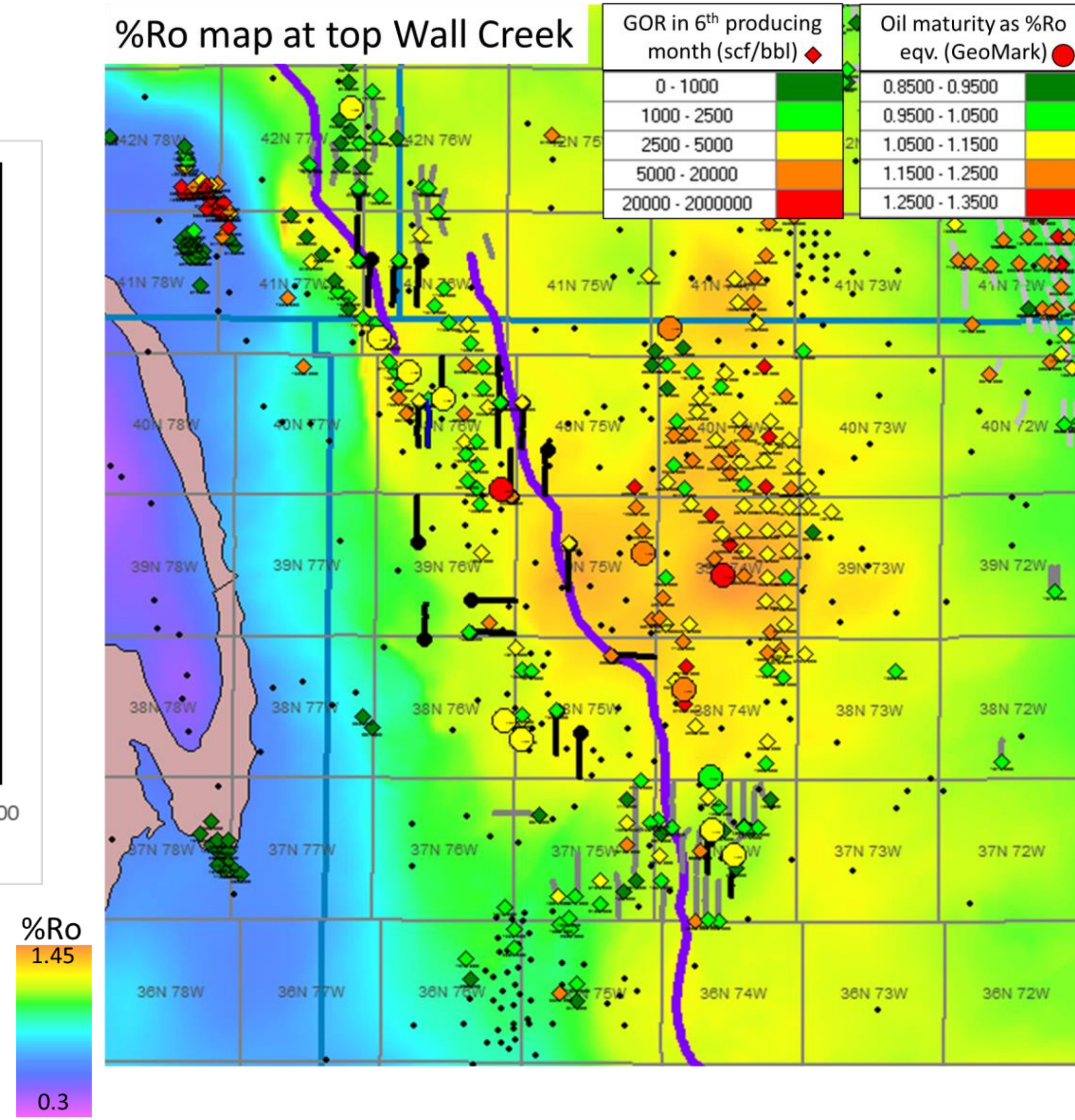




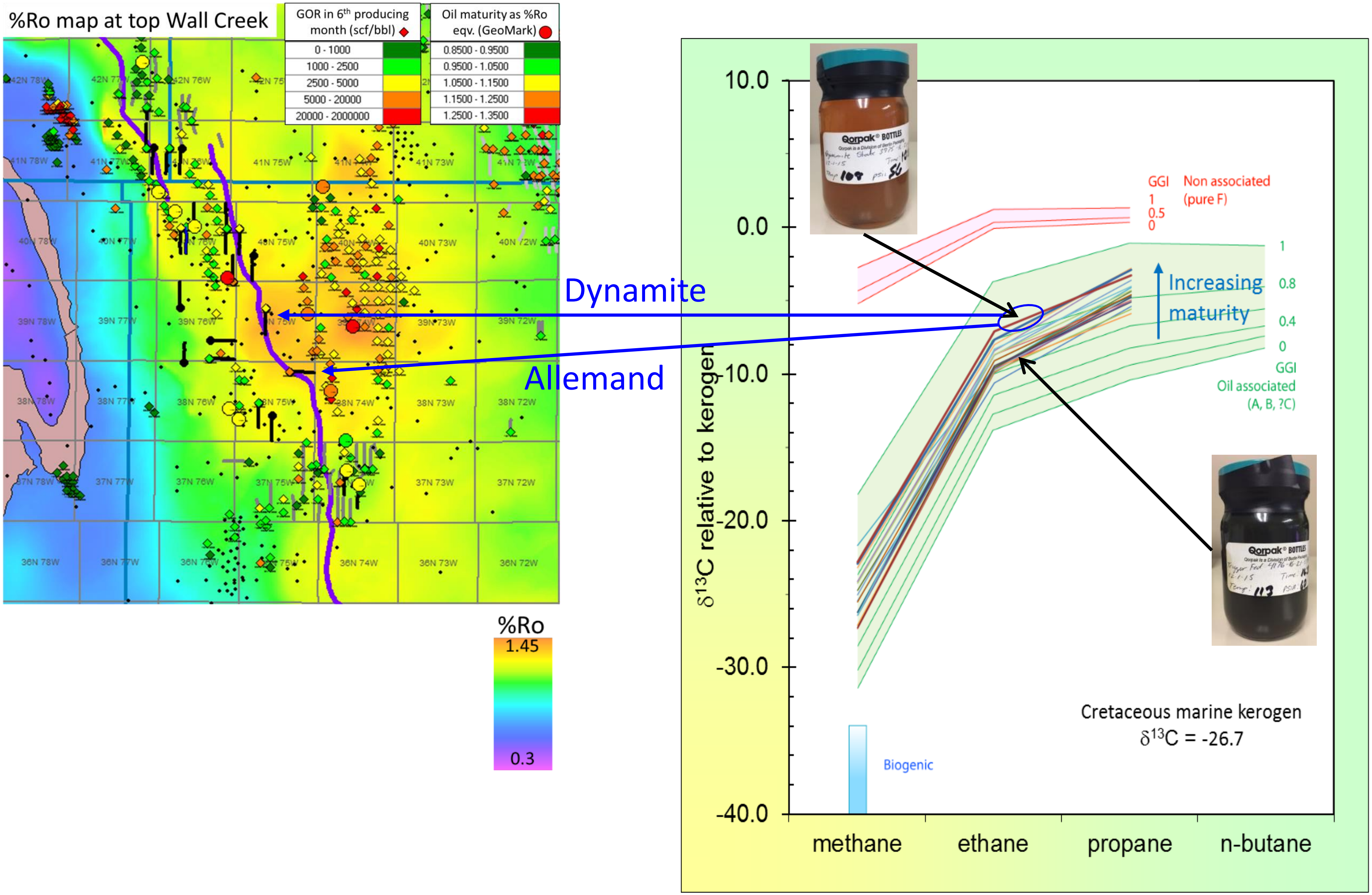
Transform present-day temperature map to %Ro

Temp. vs. %Ro relationship from calibrated 1D models at Blackjack, Razor, Allemand, & Rush wells

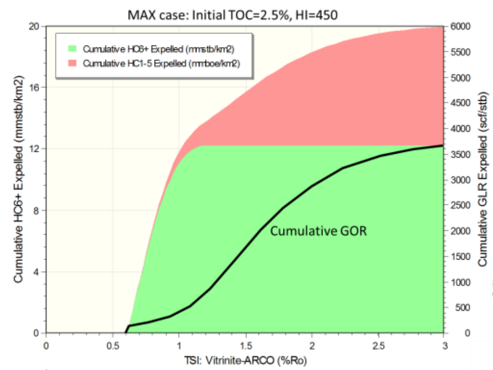


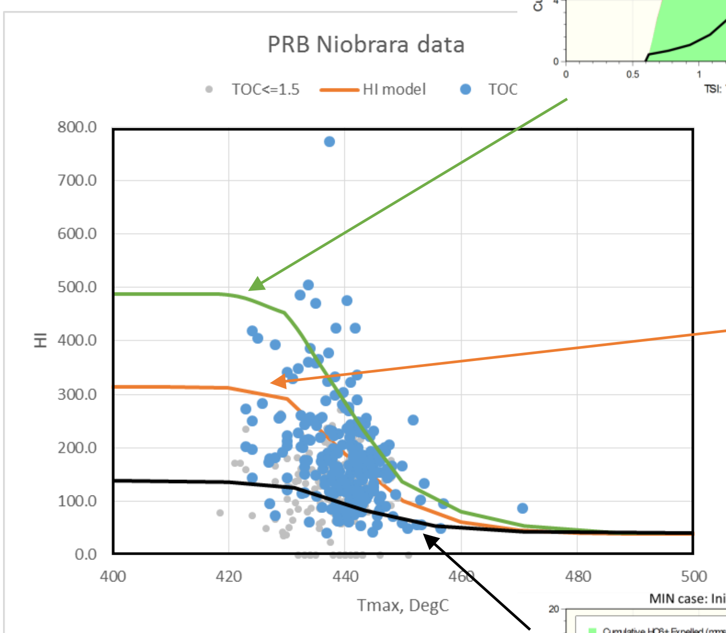


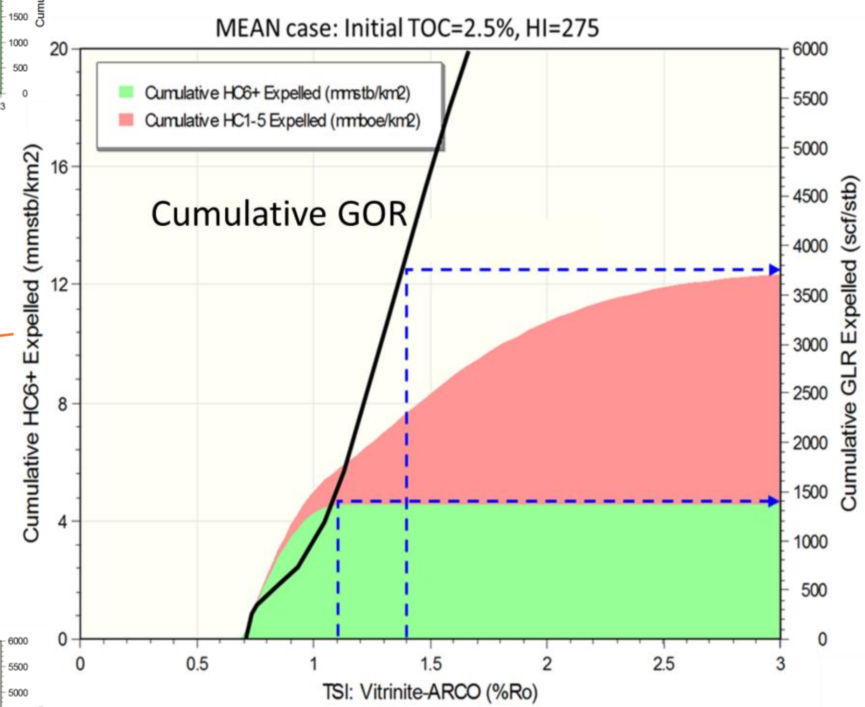
Model verification with gas and liquid maturity data



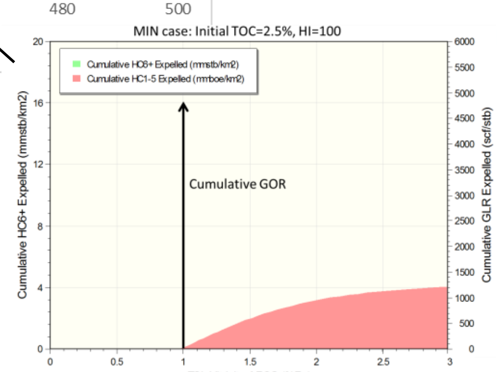
KINEX model of Niobrara source rock







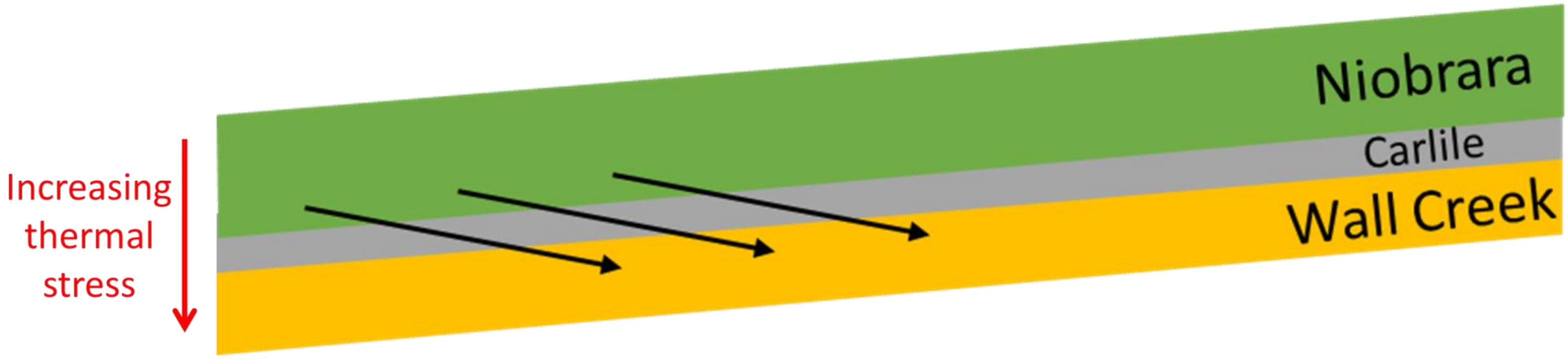
HI vs. Tmax curves derived using methodology of Chen & Jiang (2015)



Gas-oil ratio conclusions

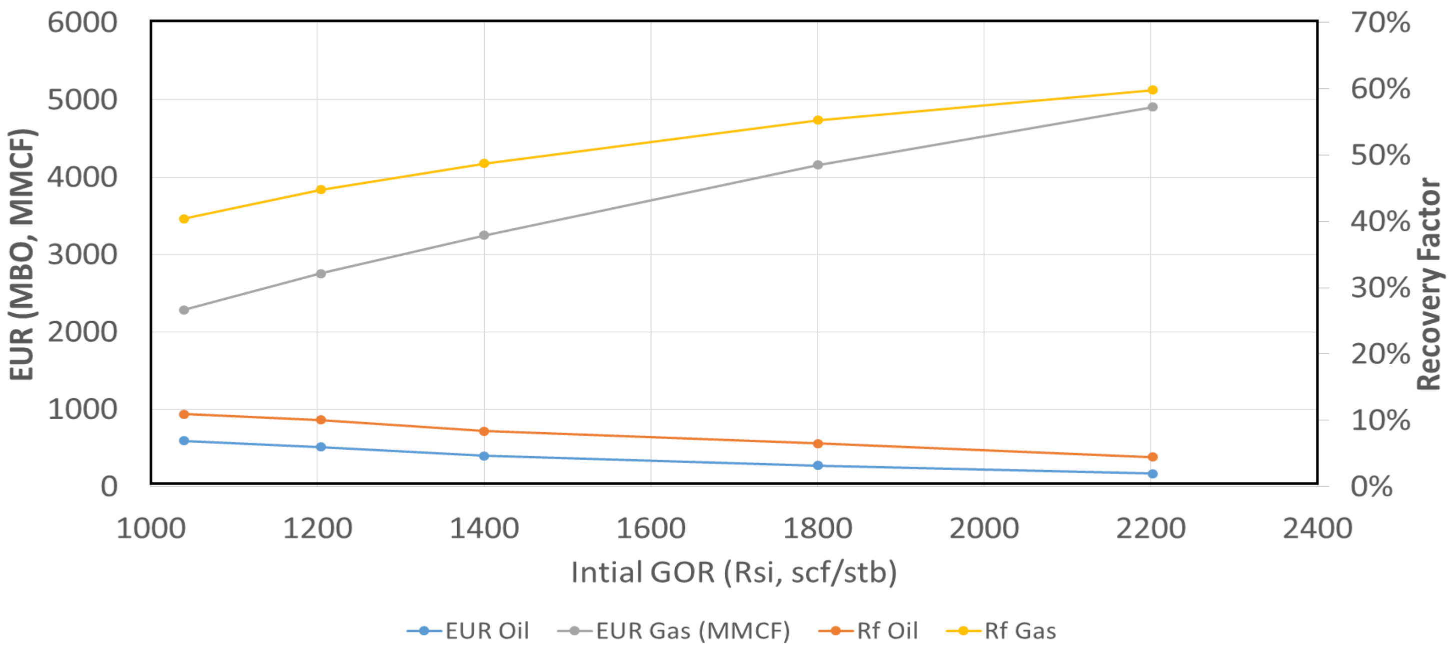
- Oils in Wall Creek generally type to Niobrara source (GeoMark)
- Downward migration from source into reservoir

  - probably driven by overpressure differences?
- Oils likely continued to mature after arriving in the reservoir as they were exposed to greater thermal stress
- Current GOR variation of oils reflects reservoir maturity variation



Impact of GOR variation on recovery

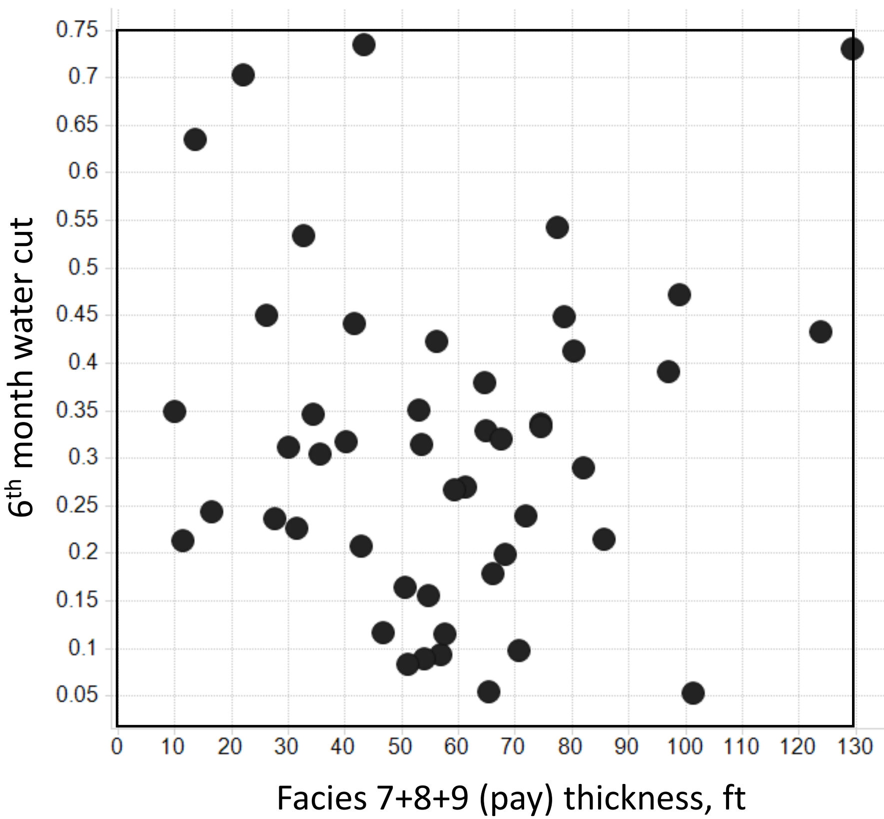
Simulation model of single stage upscaled to 10000' lateral length
HARMONY modeling by Paul Button

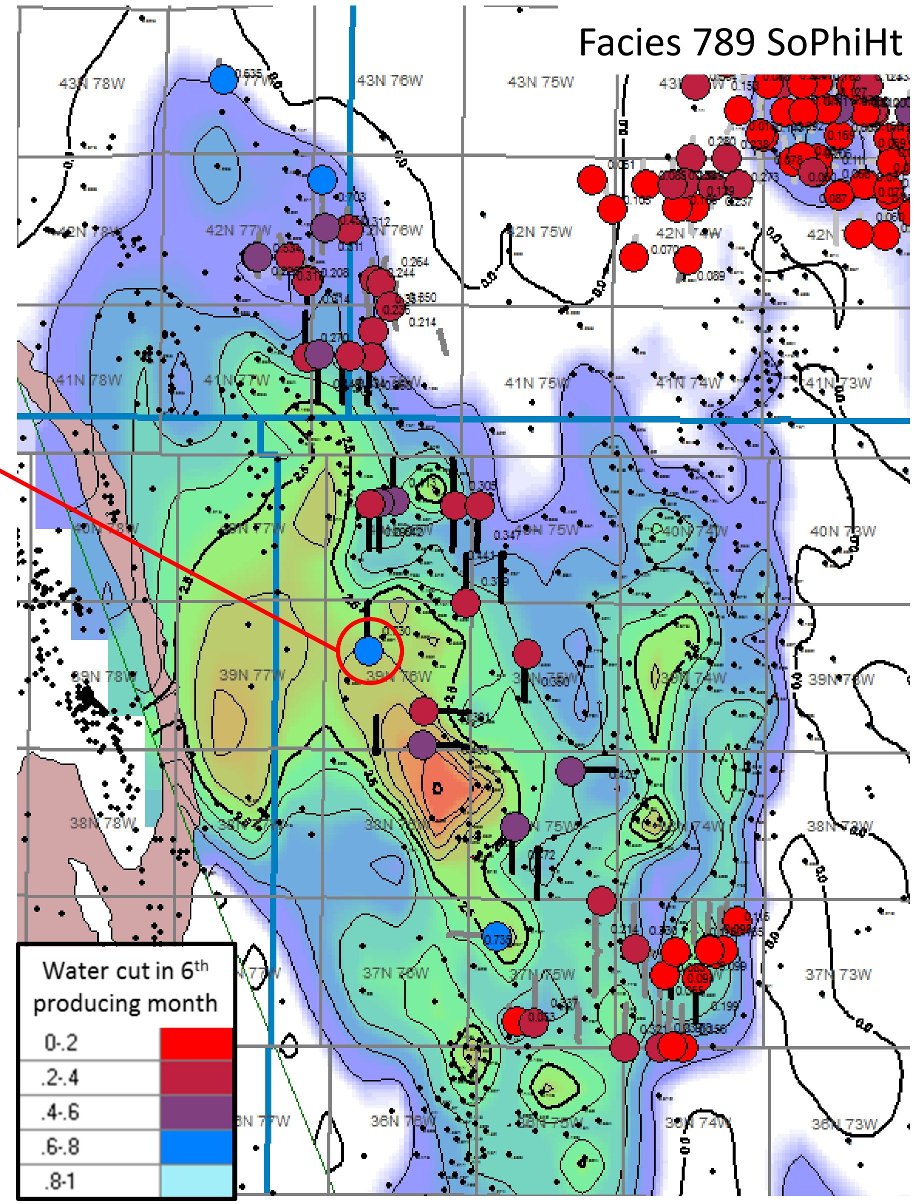


- GOR increase from 1000 to 2200 SCF/STB
  - 32 % reduction in OOIP based on Bo changes
  - 72% reduction in EUR
  - Recovery Factor drops from 11% to 4 %

Water cut variation

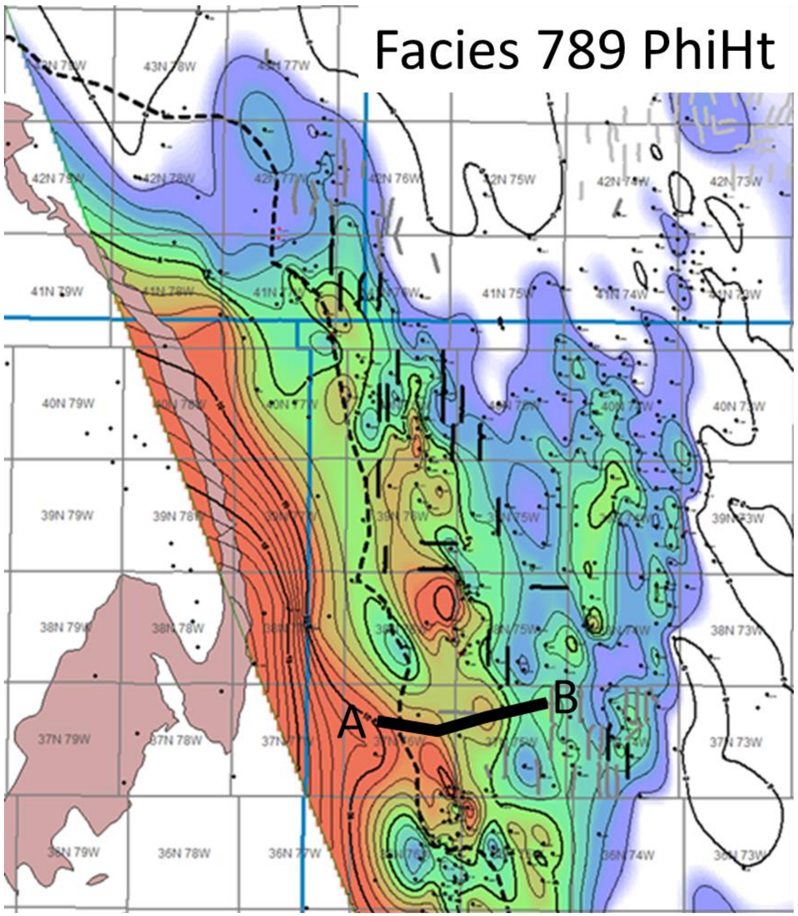
Water production from horizontal wells in the Wall Creek play is not strongly related to calculated pay thickness, PhiH, or SoPhiH. What controls water cut?

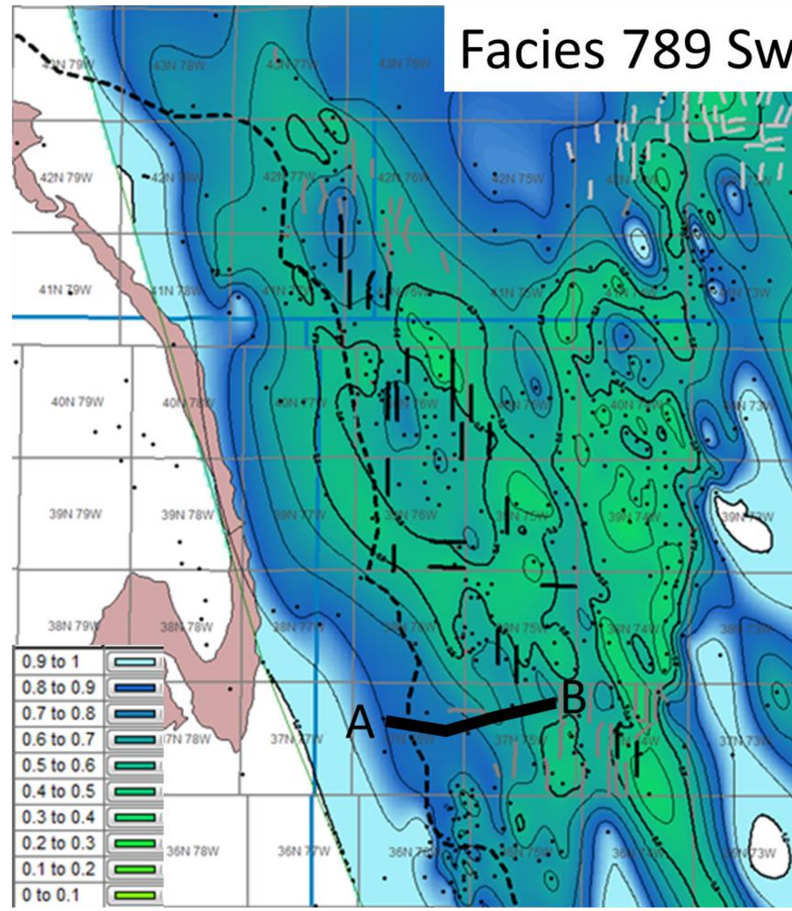




Geographic variations: map views

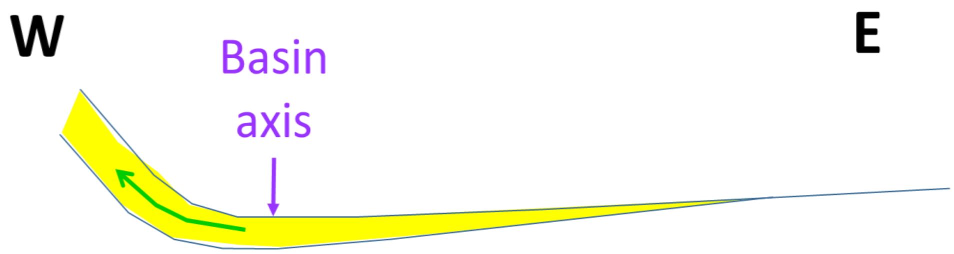
- Sw increases gradually toward west
- No structural or stratigraphic trap on west side of play

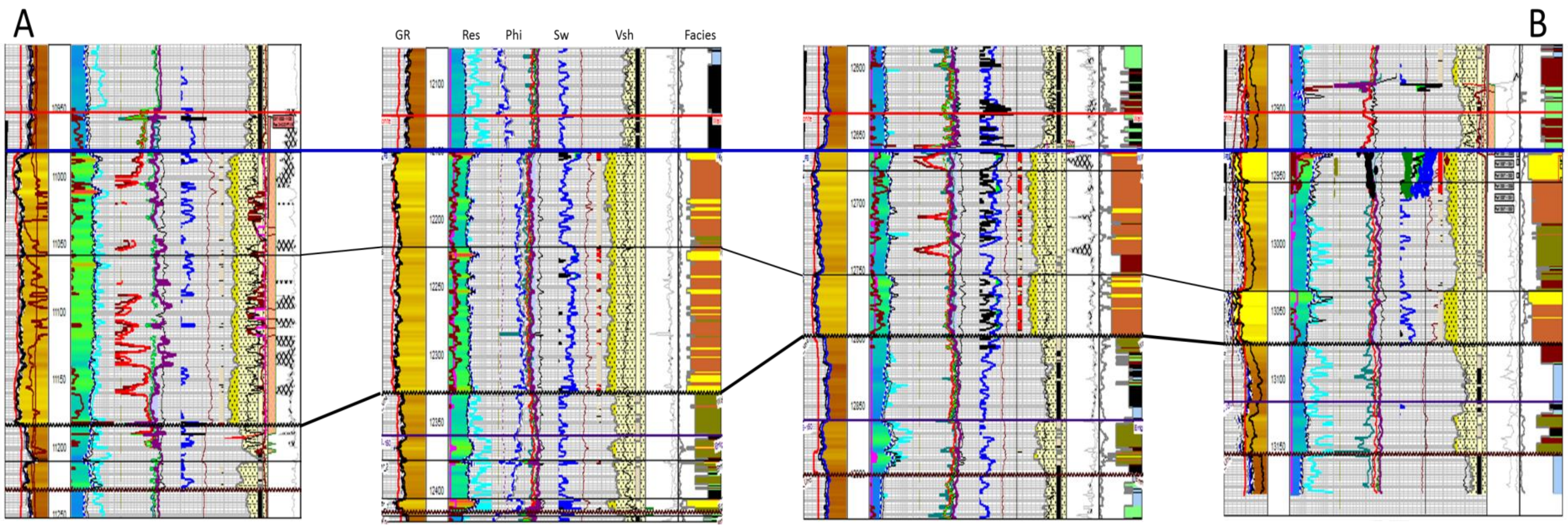




Geographic variations: cross sections

- Sw increases gradually toward west
- No structural or stratigraphic trap on west side of play
- What keeps the petroleum in place?

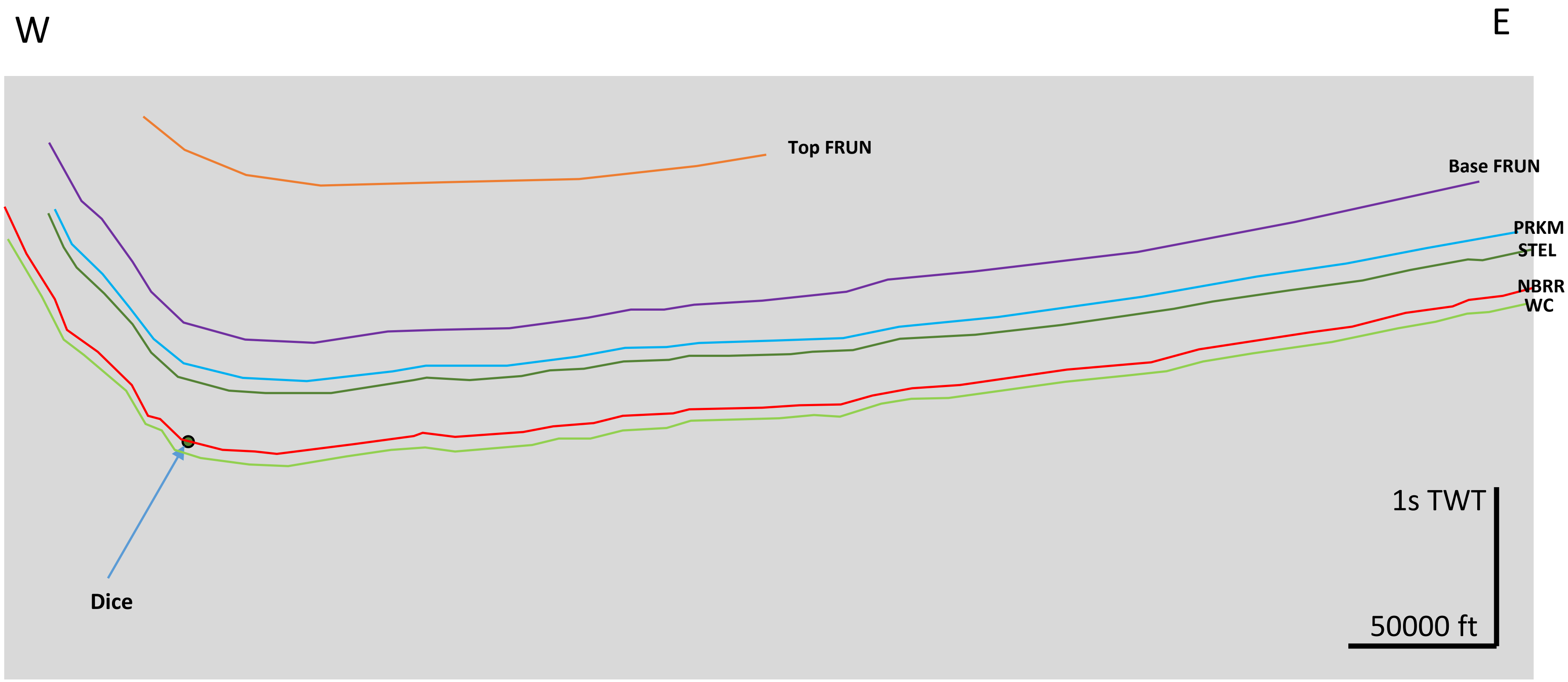




Approximately 10 miles

Current basin geometry on 95 mi long seismic line

Only interpretive line drawing shown



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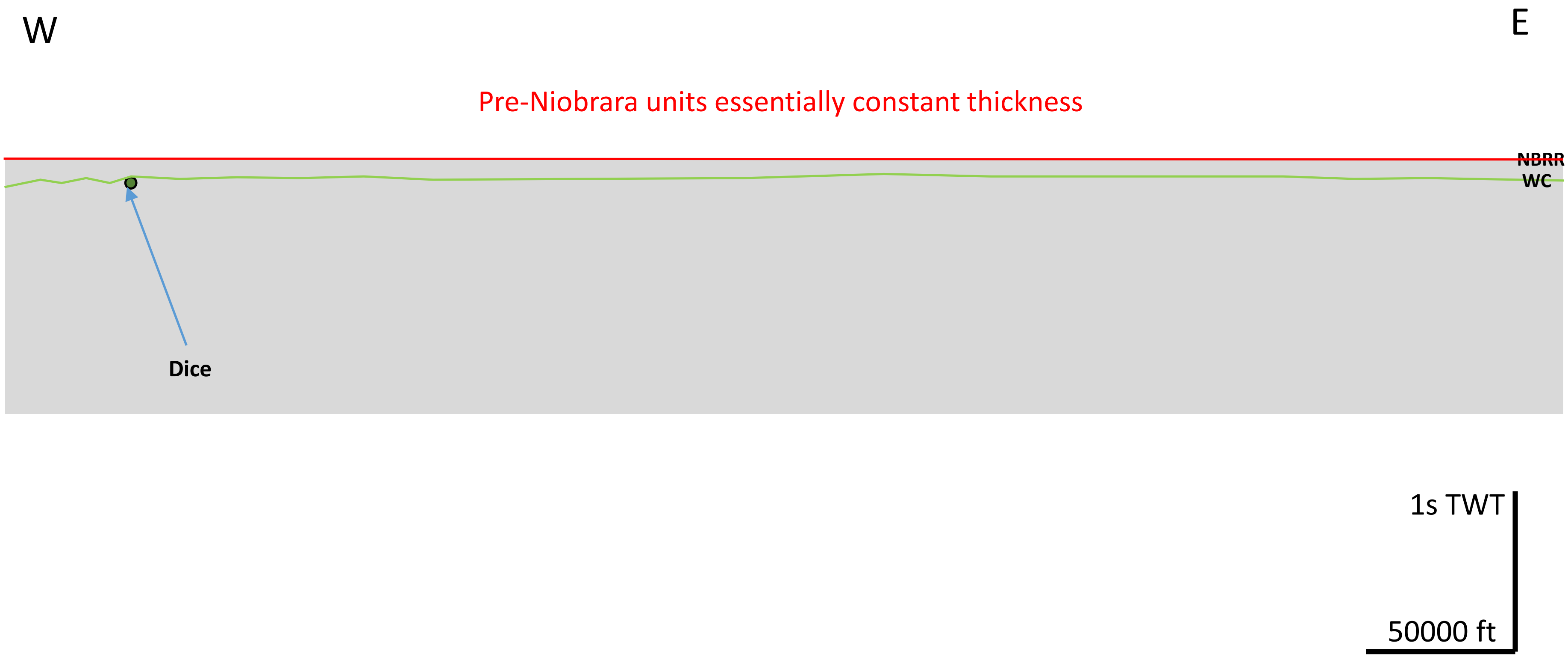
Flattened on Niobrara (~84Ma)

Only interpretive line drawing shown



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Flattened on Steele (~82Ma)

Only interpretive line drawing shown

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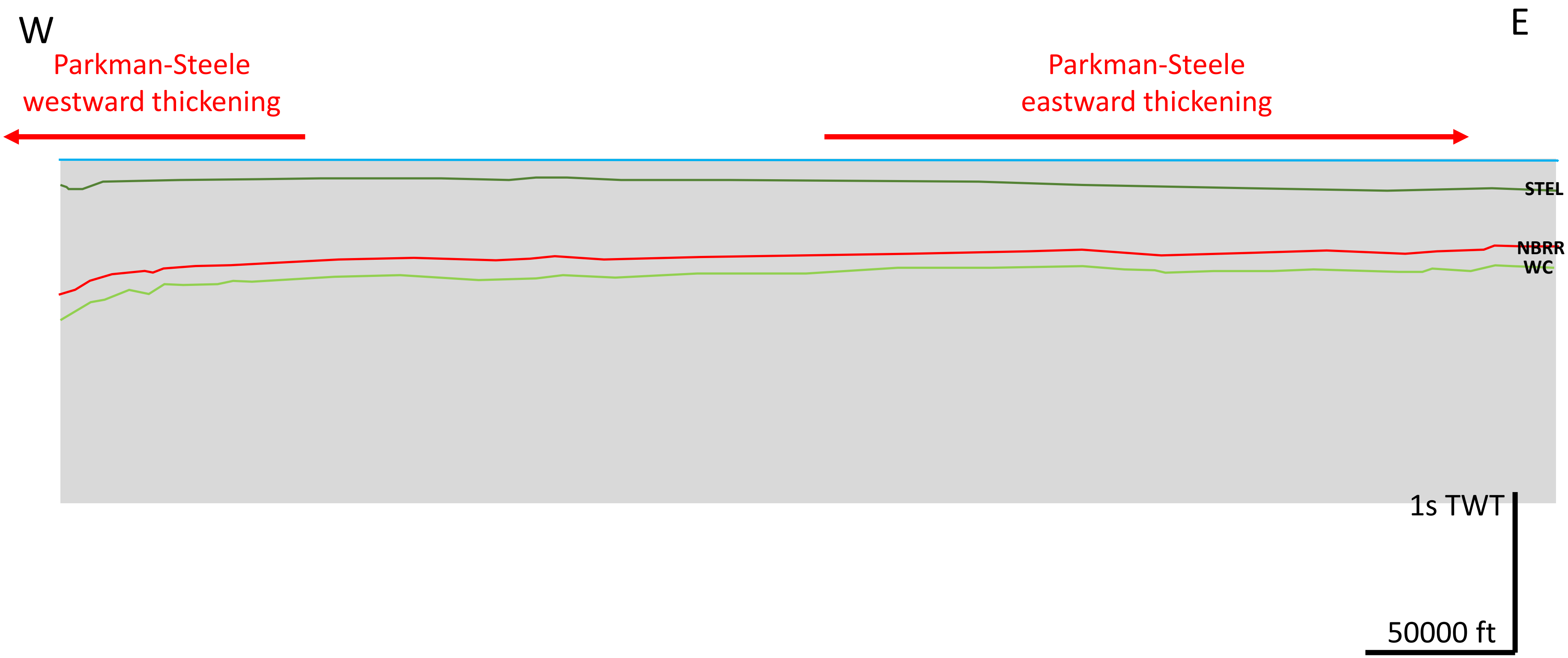
Flattened on Parkman (~77Ma)

Only interpretive line drawing shown



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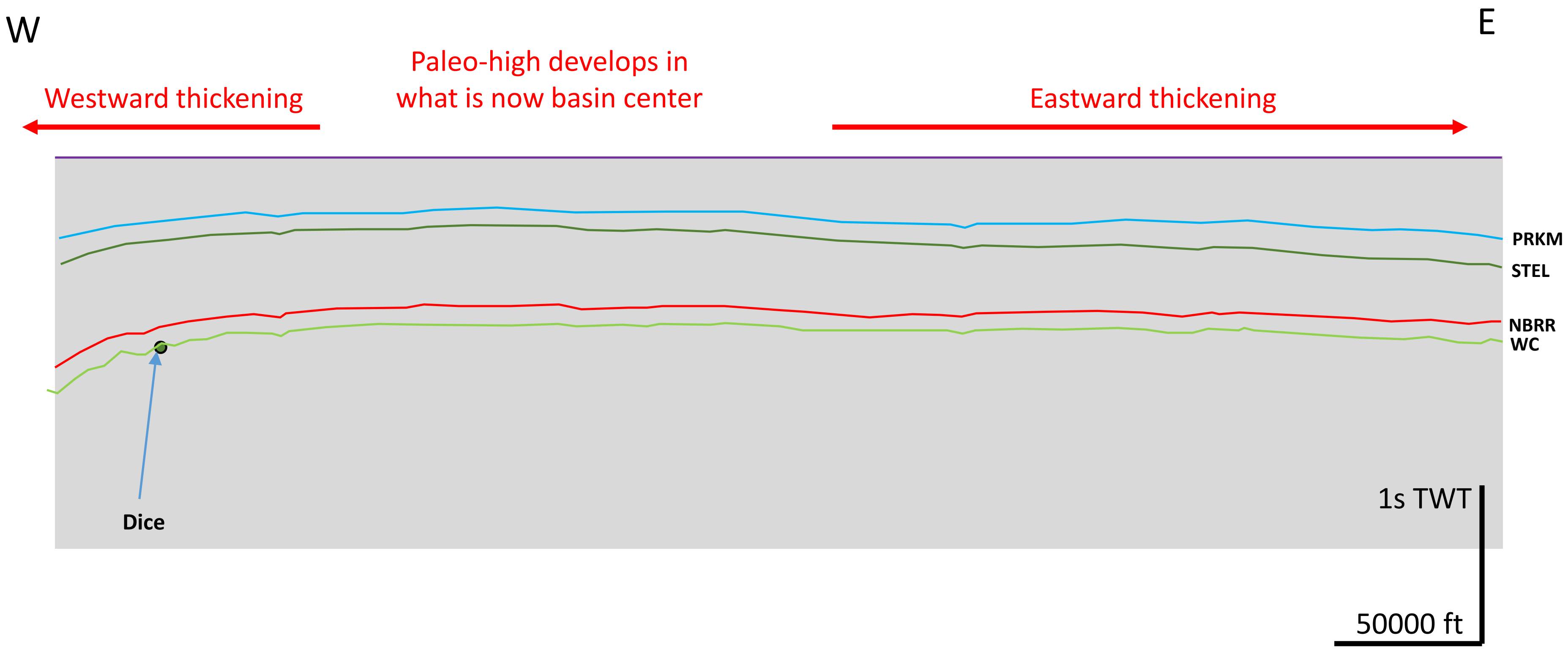
Flattened on Base Ft. Union (~66Ma)

Only interpretive line drawing shown



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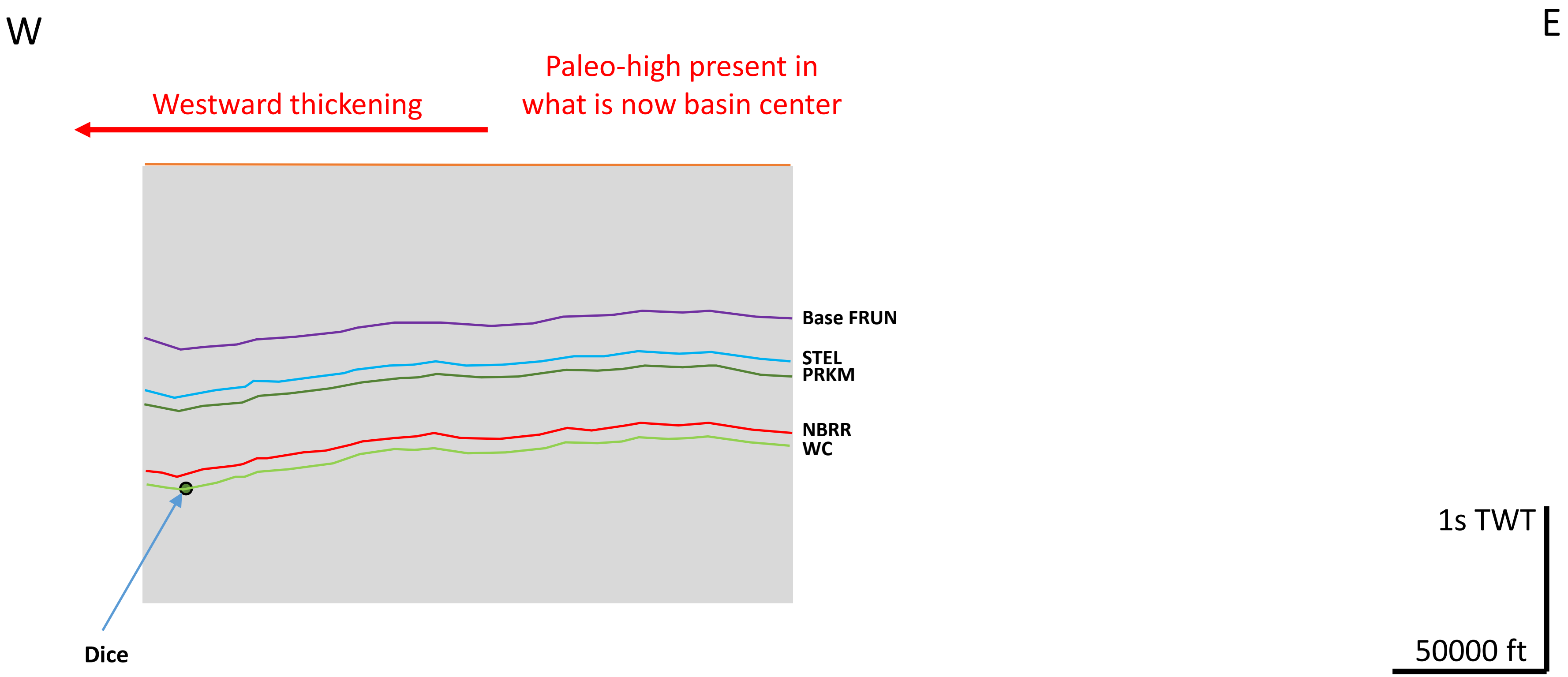
Flattened on Top Ft Union (~55 Ma)

Only interpretive line drawing shown



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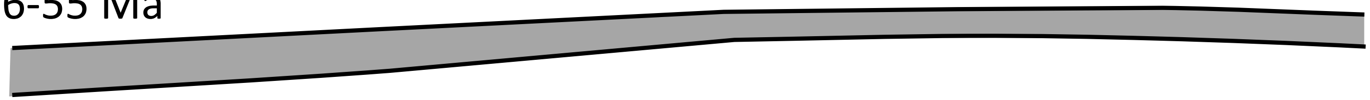
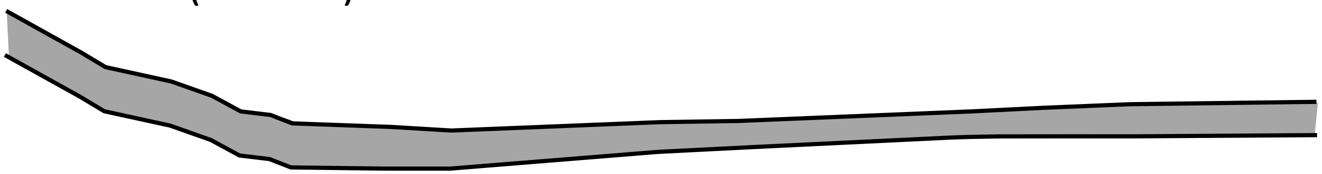
Structural evolution and burial history

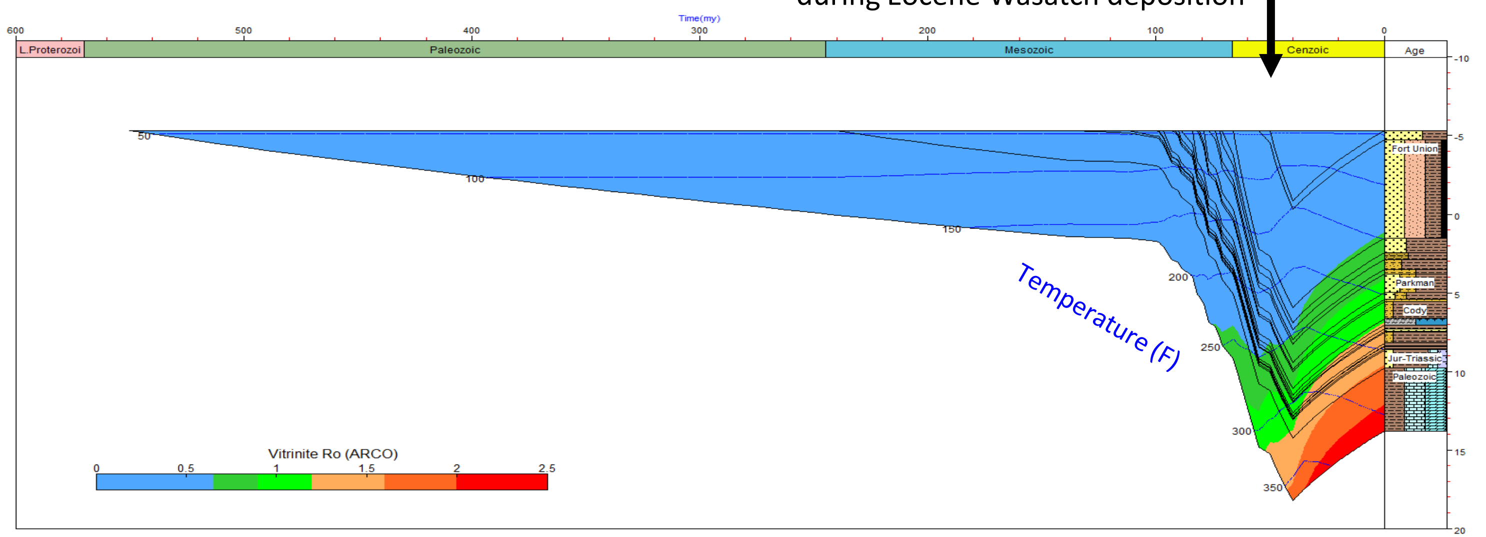
66-55 Ma



Post 55 Ma (40-ish?)

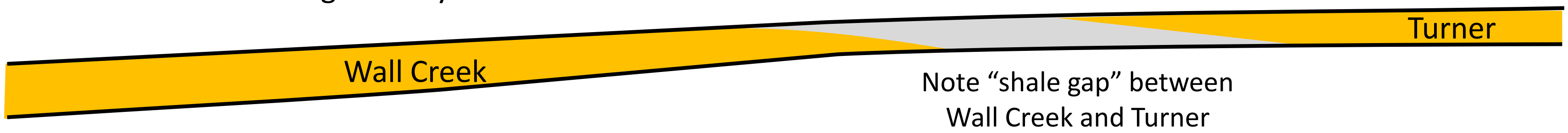


Onset of Niobrara oil expulsion ~50Ma
during Eocene Wasatch deposition



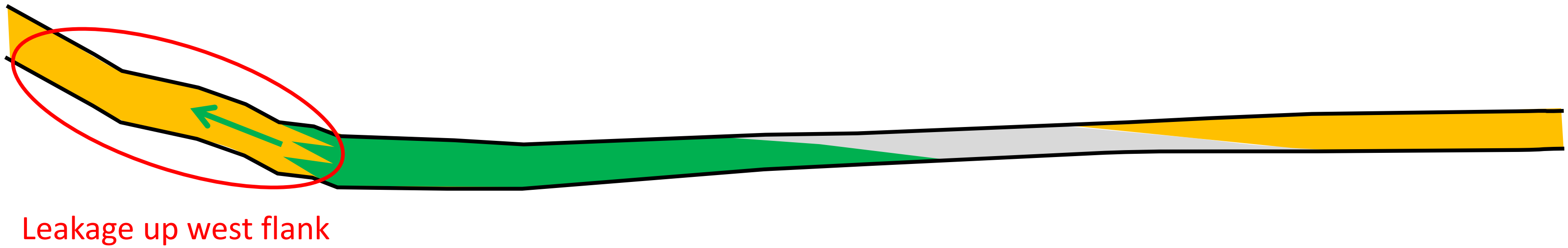
Evolutionary charge model

Late Cretaceous structural geometry with sand distribution

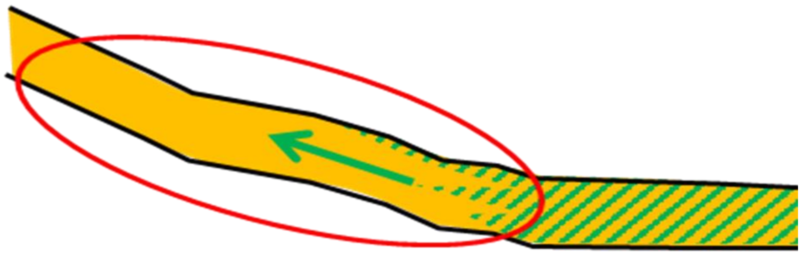


Oil charge during deepest burial (Mid-Tertiary)

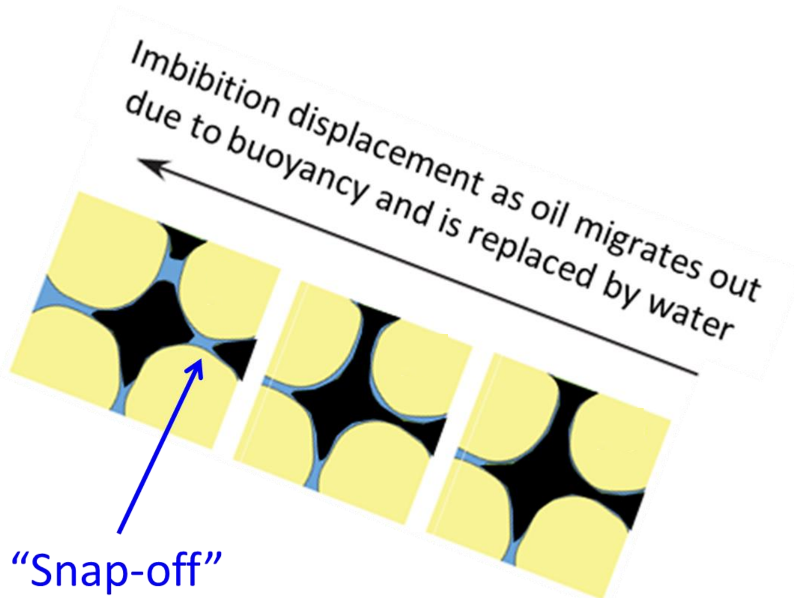
Modification of oil distribution following Mid-Late Tertiary uplift of west flank



Oil saturation on west flank approaches residual



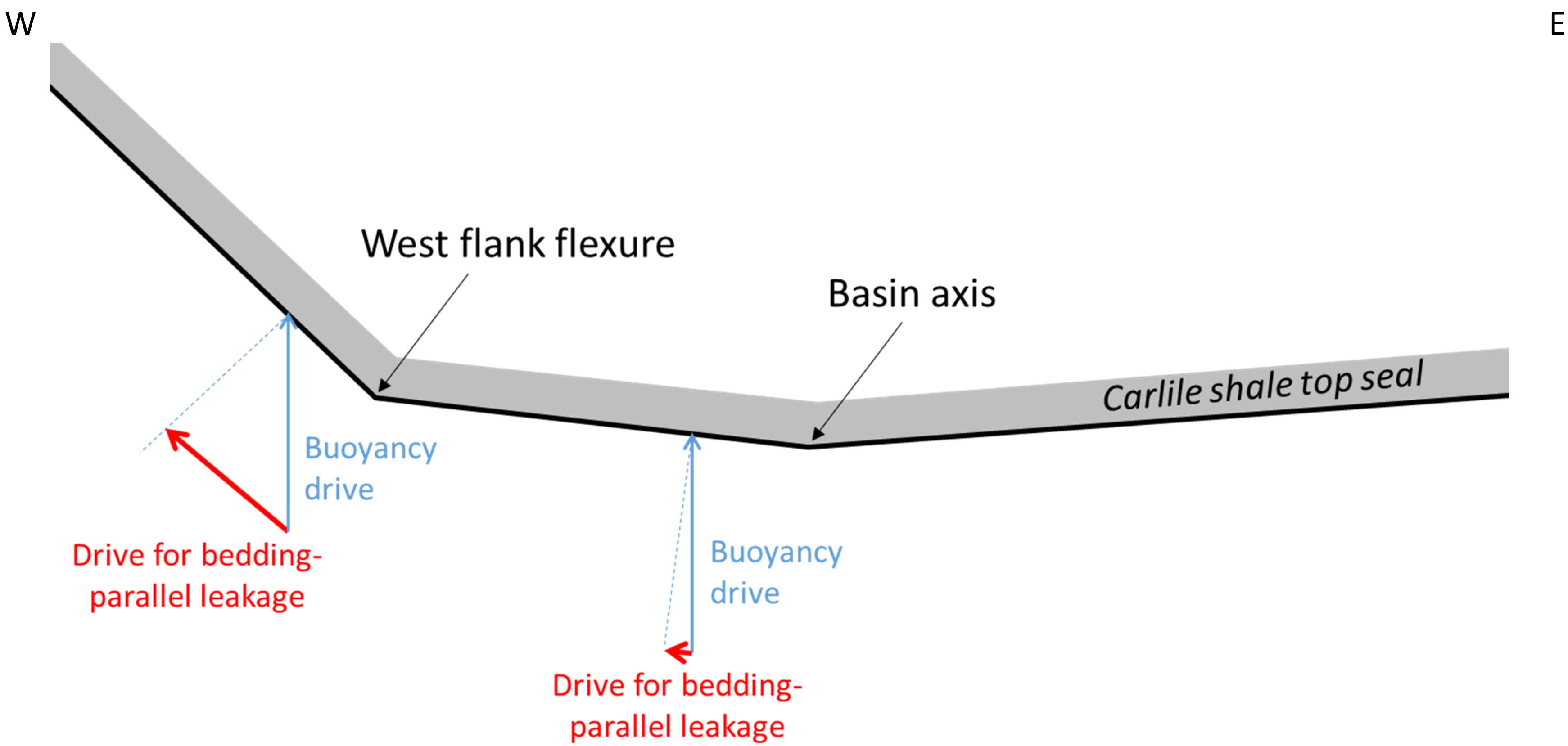
Rate of buoyancy-driven leakage up west flank is slow because of Wall Creek was deeply buried and low permeability prior to uplift. Low-rate leakage is probably continuing today.



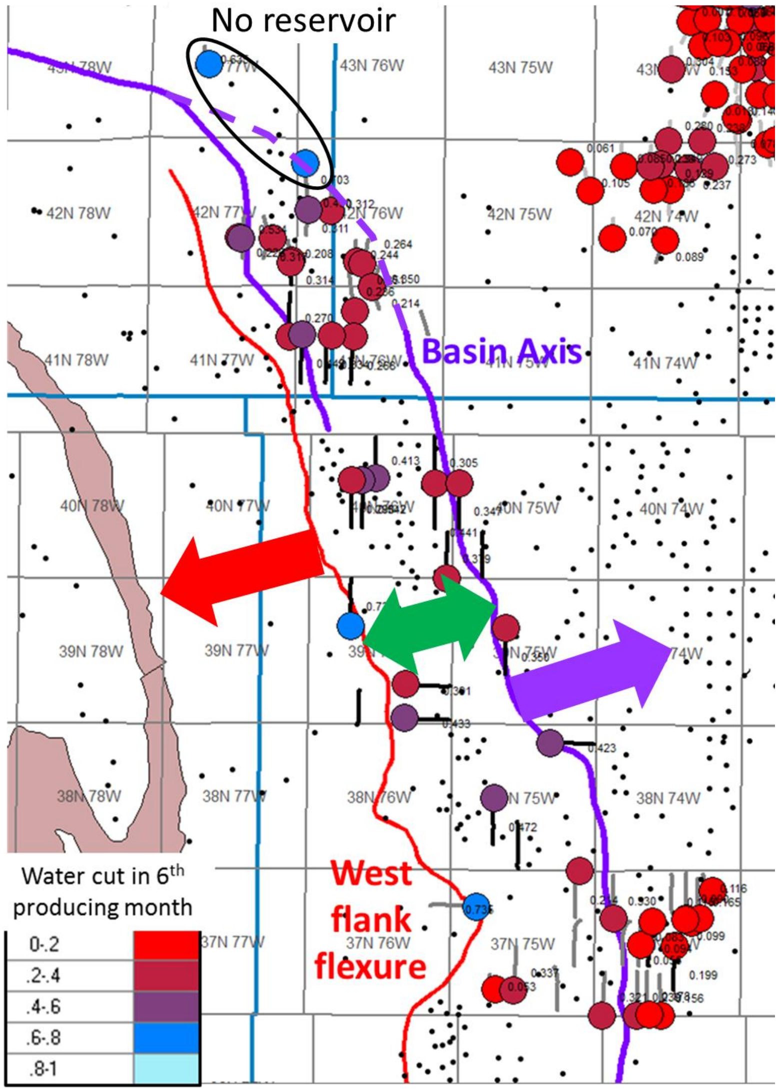
after Shanley & Cluff, 2015

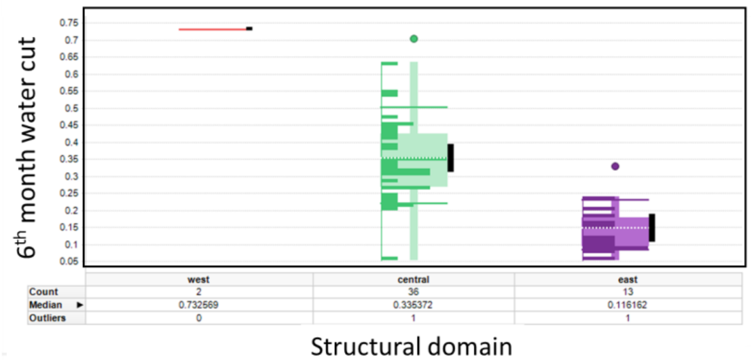
Water production reflects the fact that the residual oil in pores is no longer connected through the water-bearing pore throats.

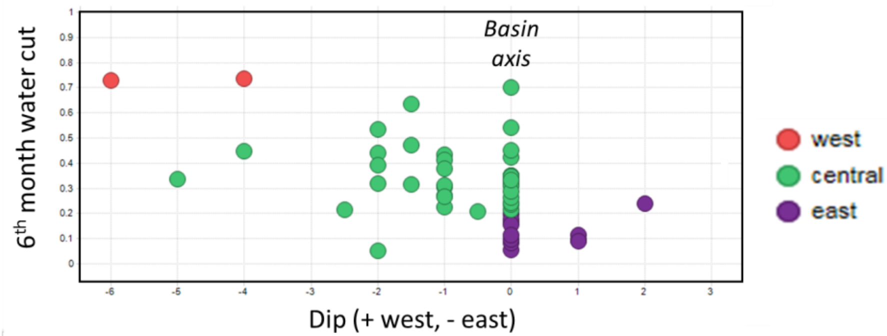
Why didn't all the oil west of the basin axis leak out?



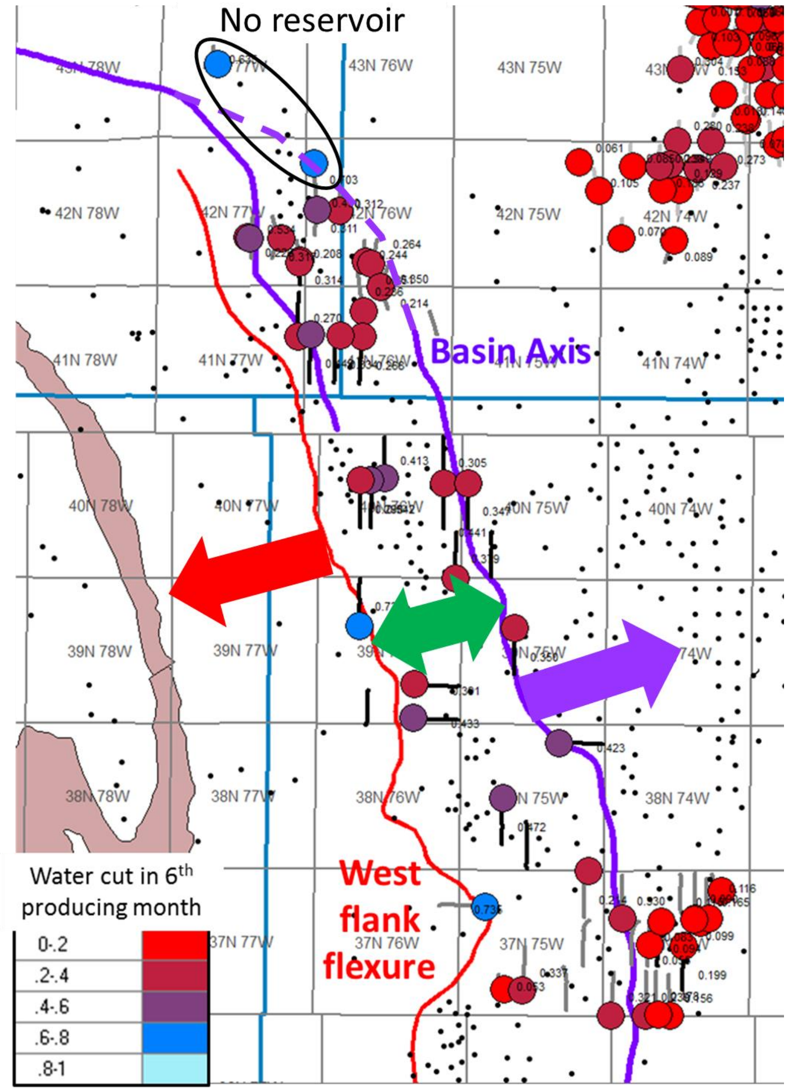
Structural domains and water cut

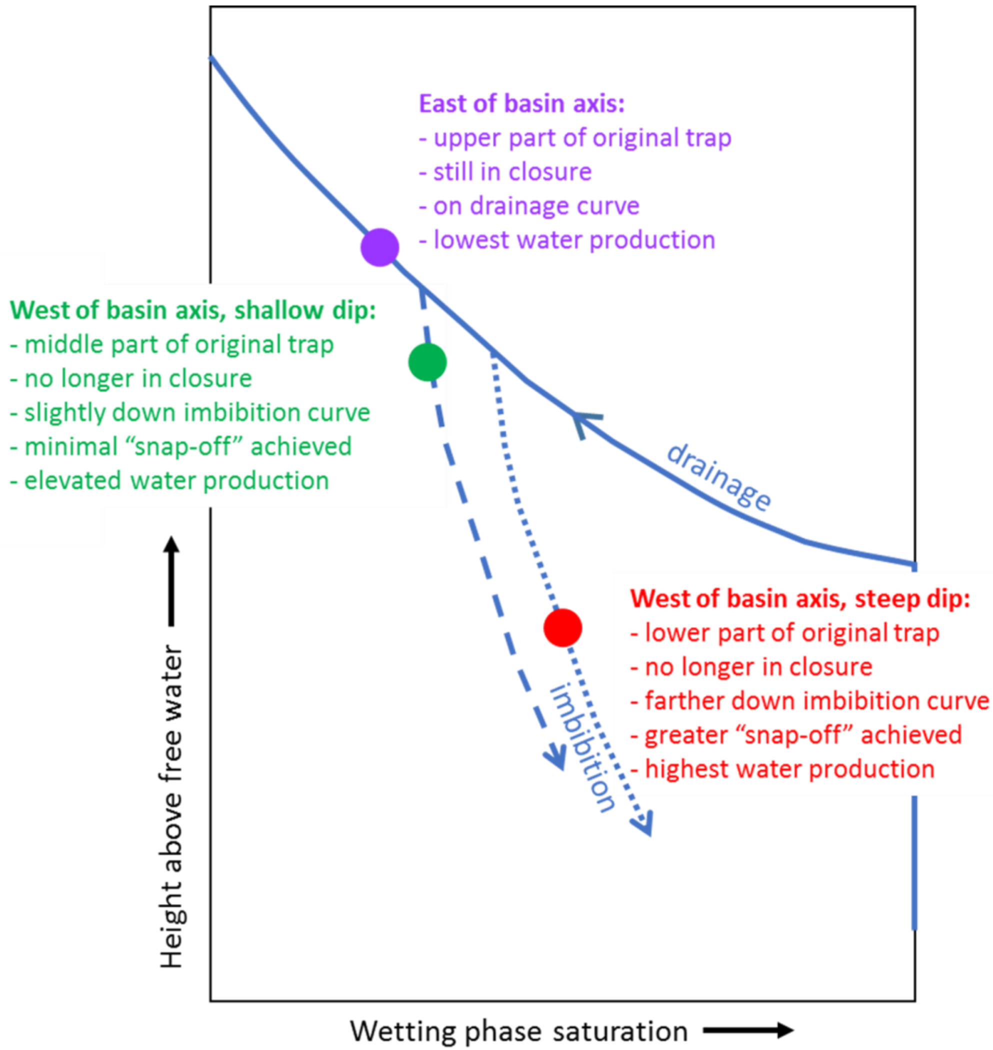




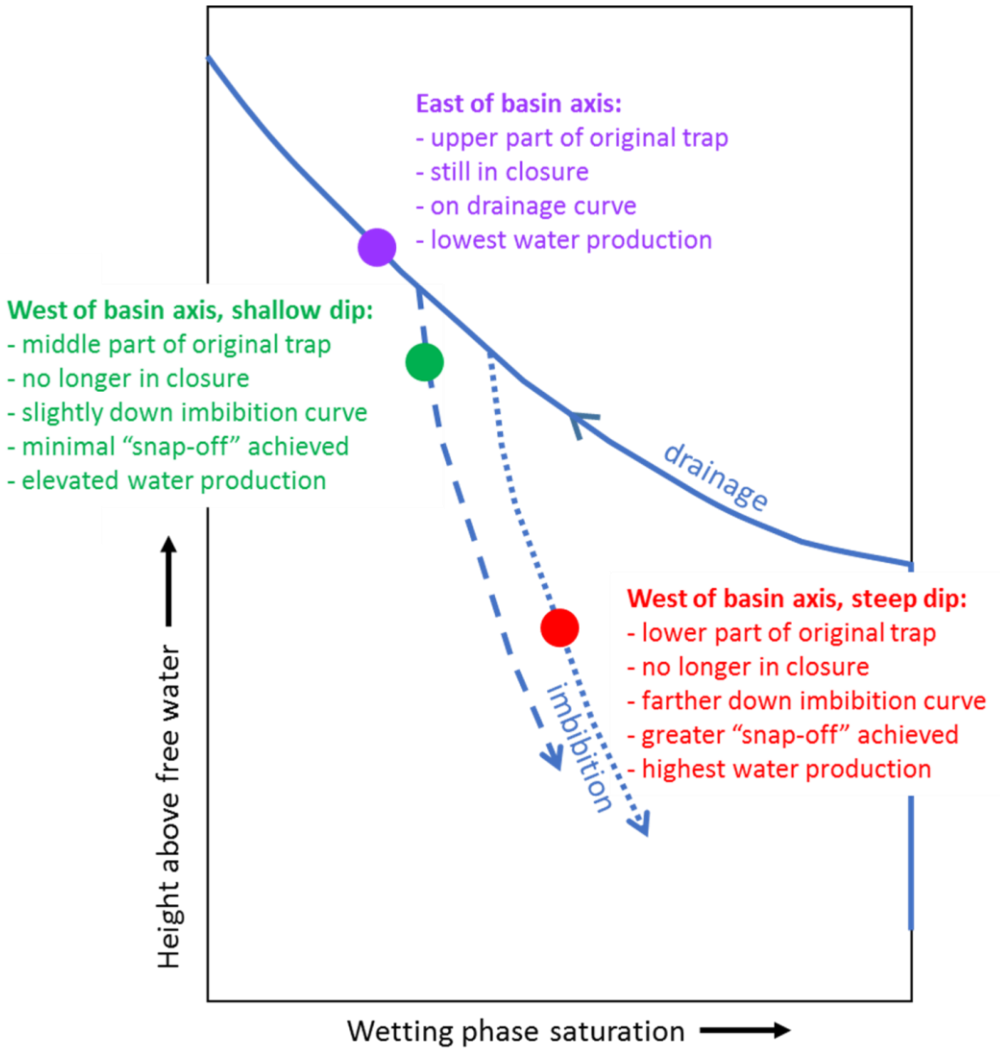


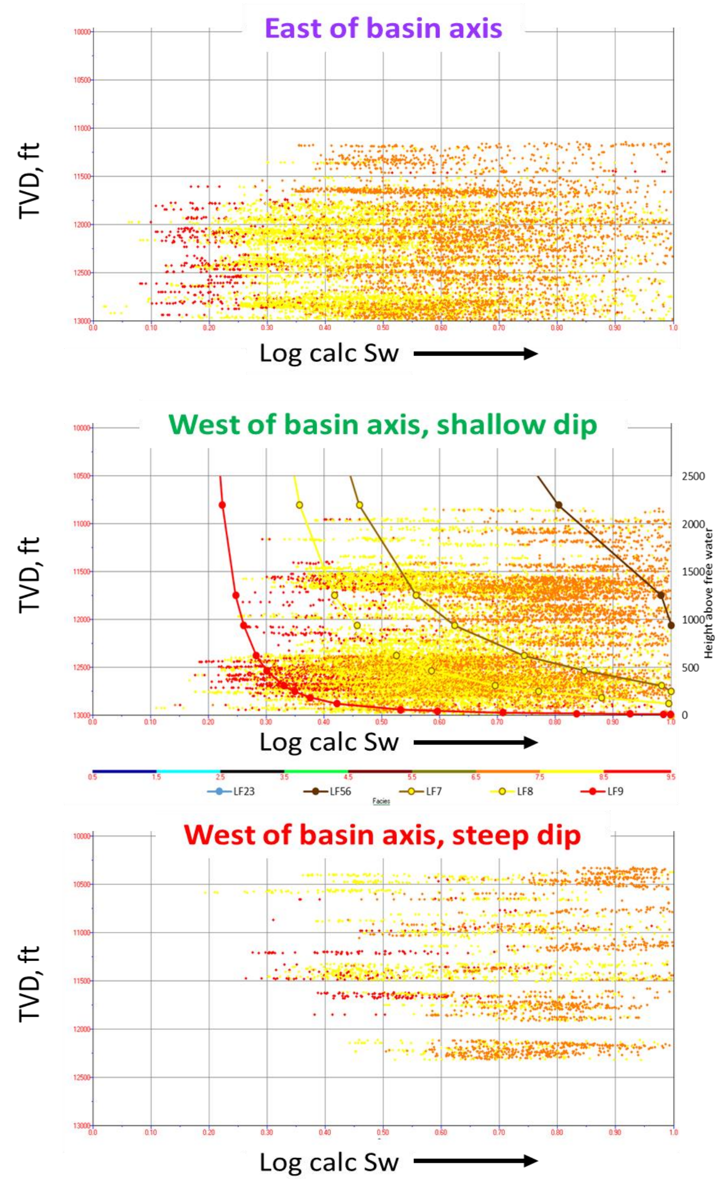
Structural domains and water cut





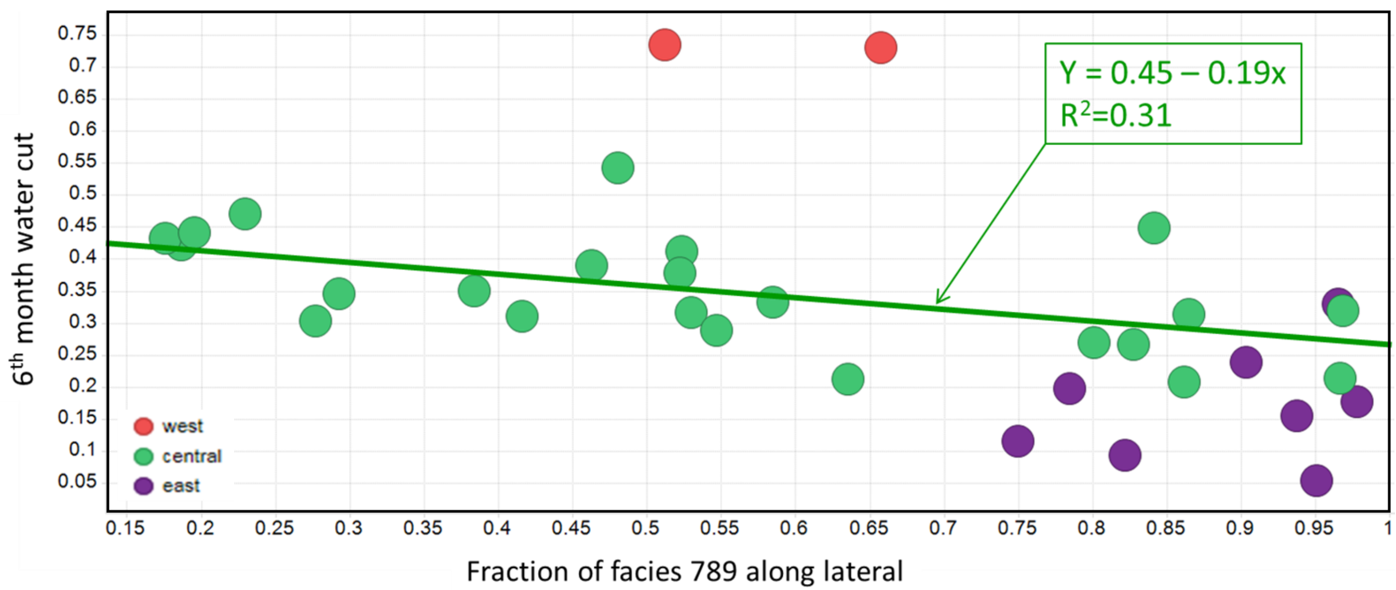
Capillary pressure model and calculated Sw





Water cut conclusions

- The Wall Creek deep basin accumulation is a structurally inverted stratigraphic trap.
- Dynamic leakage from the uplifted west basin flank led to variable water imbibition into originally oil-saturated reservoirs.
- Water cut from these reservoirs reflects the degree of leakage/imbibition and can be predicted based on structural position and % in pay facies along lateral.



Wall Creek play area refinement

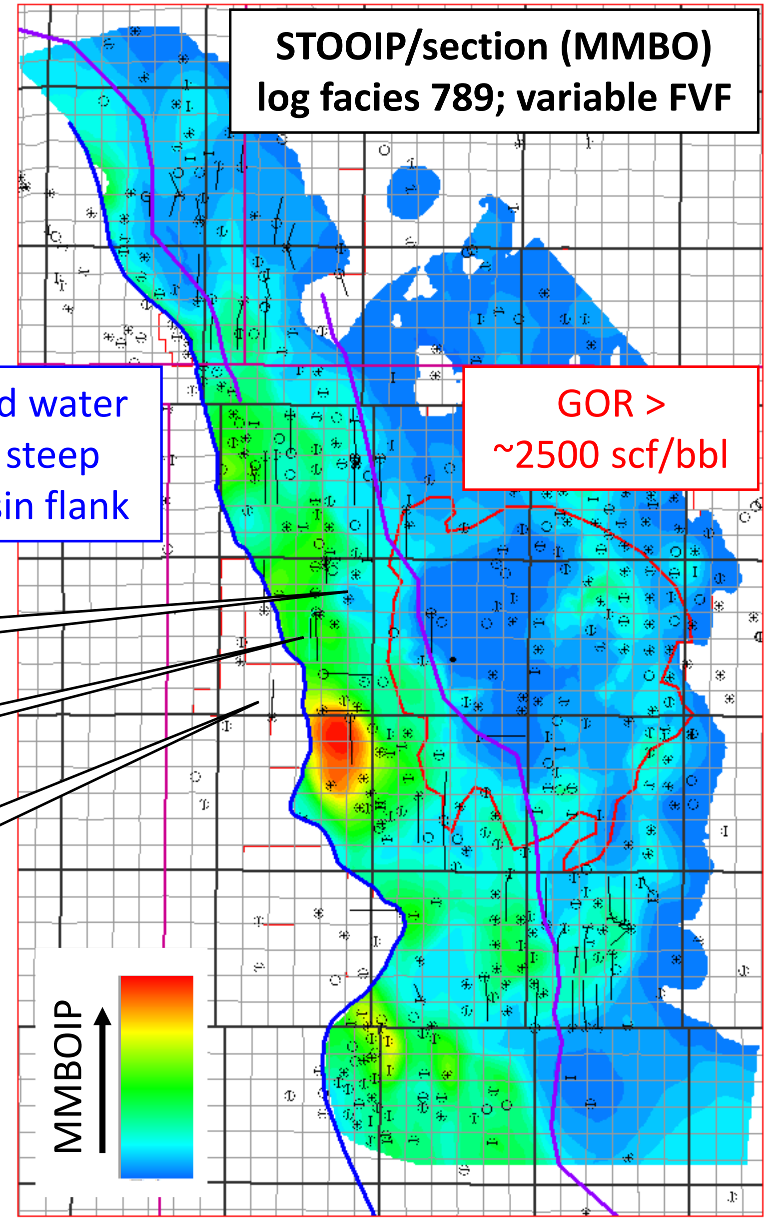
- West of flexure line has substantial water production risk.
- Highest thermal maturity area is likely to have elevated GOR which impacts reserves and well economics
- Play sweet spot can be defined by reservoir/pay parameters between these two boundaries.

Produced water risk on steep west basin flank

Init GOR = 3156 scf/bbl
5th mo water cut = 50%

Init GOR = 1428 scf/bbl
6th mo water cut = 24%

Init GOR = 975 scf/bbl
6th mo water cut = 73%



Acknowledgements

Seismic Exchange, Inc.: use of regional seismic line

GeoMark: oil-source correlation and biomarker-based oil maturity

Paul Button: simulation of GOR impact on recovery

Jeff Zawilla: seismic interpretation

SM Energy: permission to publish

Thanks for listening!