Geothermal Reservoir Architecture of the Trenton-Black River Gas Fields, NY

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1. Background and Motivation

- The Trenton-Black River gas fields of New York state were discovered in the early 2000s and are one of the largest-producing gas plays in the state.
- Previous work (Smith, 2009; Davies and Smith, 2006) determined these fields are hydrothermally dolomitized grabens in which gas is produced from **fractures and vugs** in the Upper Ordovician Black River Formation.
- **Reservoir architecture of these fields has not been documented previously**. Our work focuses on the Quackenbush Hill field to better understand how this play could perform as geothermal reservoirs. We tie together well logs, core data, and core descriptions to:
  - ✓ Understand the **relationship between porosity and permeability**, if any
  - ✓ Determine whether **vertical or horizontal permeability** dominates in the reservoir
  - ✓ Determine the role of **fractures and vugs** in permeability distribution
  - ✓ Quantify the **distribution** of porosity and permeability within the producing zone

2. Location, Geology, and Temperature

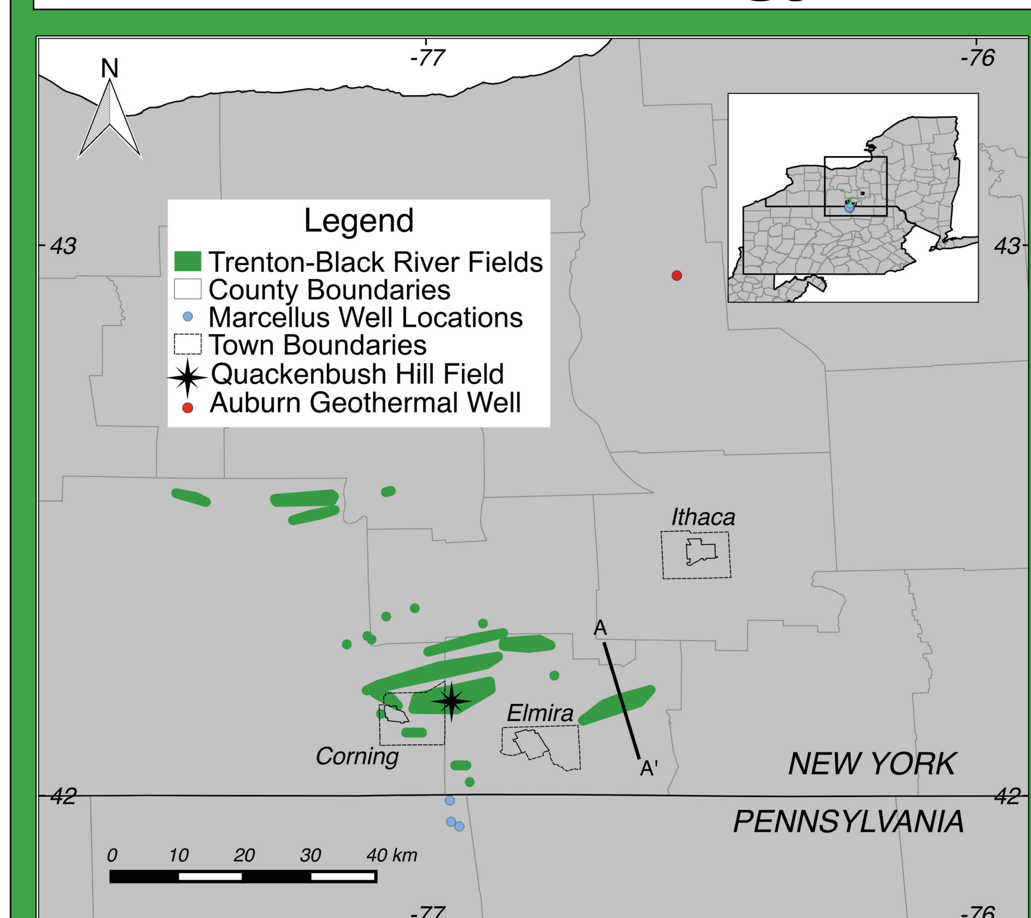


Figure 1. (left) Map of the Trenton-Black River fields in southern NY. These fields strike WNW to west. Cross section A-A' is shown in Fig. 2. This work's research is conducted on Quackenbush Hill field, shown in this map by the black star, near Elmira and Corning.

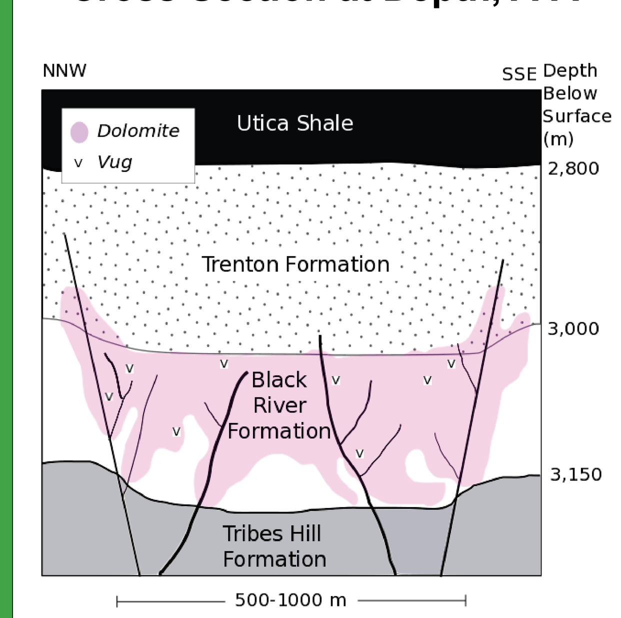


Figure 2. (above) Generalized cross section A-A' (see Fig. 1) at the depth of a Trenton-Black River field. These fields are negative flower structures within a Riedel shear zone. The reservoir quality rock is found in and around the dolomite (pink), which hugs faults and fractures. Vugs are known to be present, but the exact locations shown in the figure are approximate.

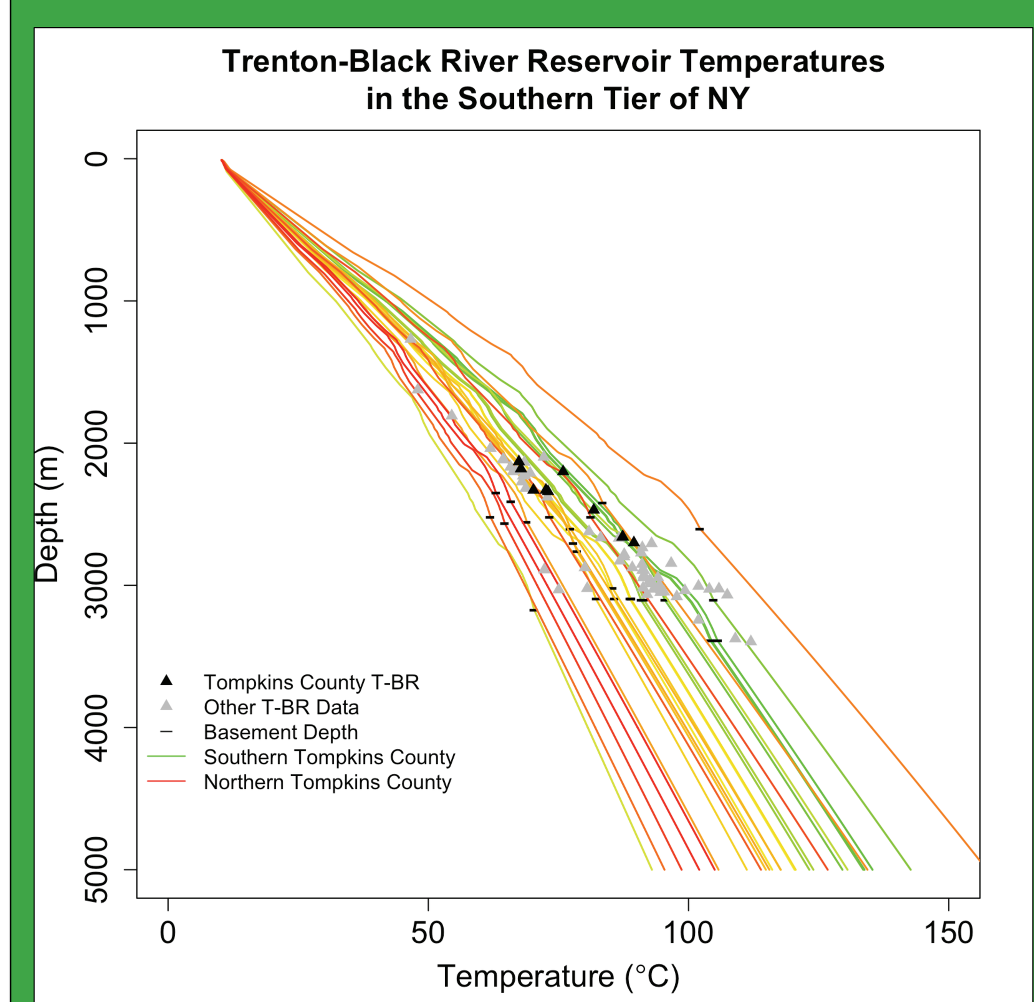


Figure 3. (above left) Plot of geotherms and BHT data for wells that penetrate the Black River Formation. Temperatures in the fields range from 50-120ºC. BHT data were corrected using a local drilling fluid-based correction (Whealton et al., 2015). Temperature at the depth of the reservoirs was calculated using the depth to the top of dolomite (from well logs); geotherms were calculated using a model developed by Smith et al. (2015).

3. Well Log Data

Well log data was collected from the gas-producing intervals of the Black River Formation in the Quackenbush Hill field. Outliers were removed, and dolomite was distinguished from limestone using the photoelectric factor log. Neutron porosity was adjusted where the matrix was dolomite. Where density porosity exceeded neutron porosity, the gas excavation effect was corrected using the iterative process described by **Bassiouni (1994)**. For the remainder of the readings, true porosity was calculated using

$$\phi = \frac{(\rho_{ma} - \rho_b) + \phi_N}{\rho_{ma}} \qquad (1)$$

where ϕ_N is neutron porosity, ρ_{ma} is matrix density, and ρ_b is bulk density log reading.

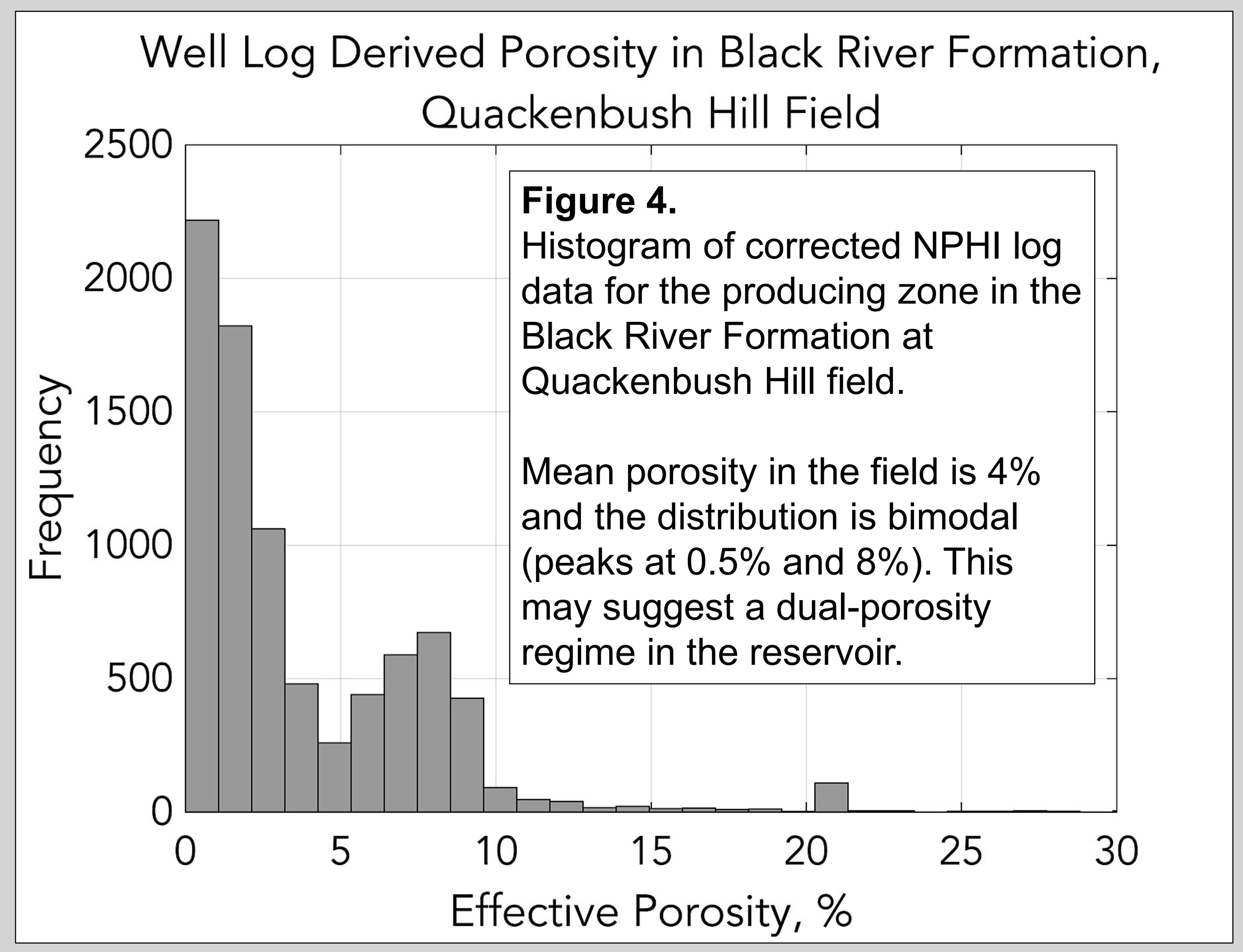


Figure 4. Histogram of corrected NPHI log data for the producing zone in the Black River Formation at Quackenbush Hill field.

Mean porosity in the field is 4% and the distribution is bimodal (peaks at 0.5% and 8%). This may suggest a dual-porosity regime in the reservoir.

4. Core Data

Core data is available from a field adjacent to Quackenbush Hill. We Klinkenberg-corrected the air permeability data using the correlation from Al-Jabri et al. (2015). A power law was fit through the data (R^2=0.6), excluding vertical permeability.

Power Law Relationship*:

$$y = 0.3941x^{2.8745}$$

*excludes vertical perm.

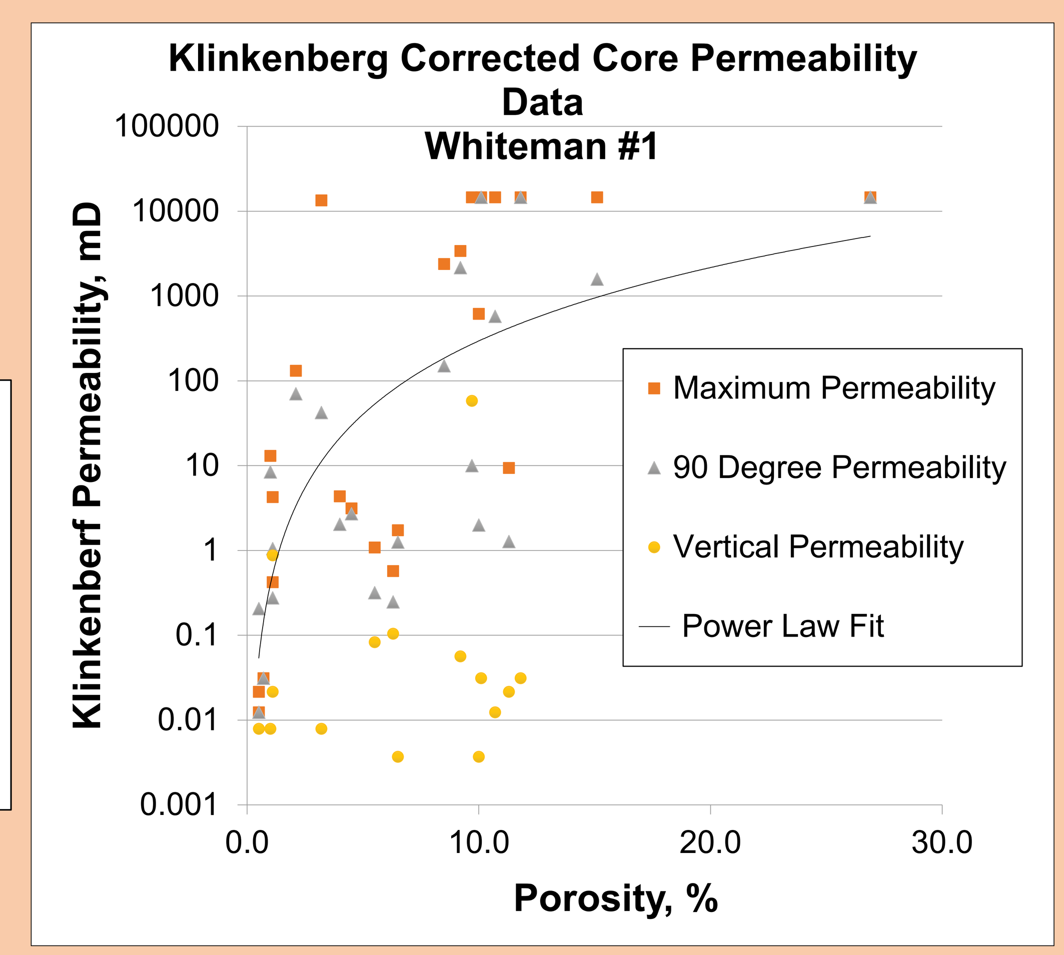


Figure 5. Porosity and klinkenberg-corrected permeability data of a core from the Whiteman #1 well. Vertical permeability is extremely low in the core, and was excluded from the fit.

Table 1. Statistics from core data.

	Porosity	Max. Perm (mD)	90deg Perm (mD)	Vertical Perm (mD)
Minimum	0.5	0.012	0.012	0
Average	7.0	4680	2100	2.6
Maximum	26.9	14590	14590	58.2

5. Reservoir Architecture

We applied the empirical porosity-permeability relationship (Fig. 5) to the well log porosity data in order to calculate the permeability distribution in the Quackenbush Hill reservoir zone.

Figure 6. (right) Plotted are the maximum permeability data from figure 5, together with the core feature descriptions of vugs and fractures. Points with similar core features group together on the plot. Fractures group at low porosity values (Φ<5%), whereas vugs group at higher porosity values. This supports the dual porosity theory shown by the well log porosity distribution.

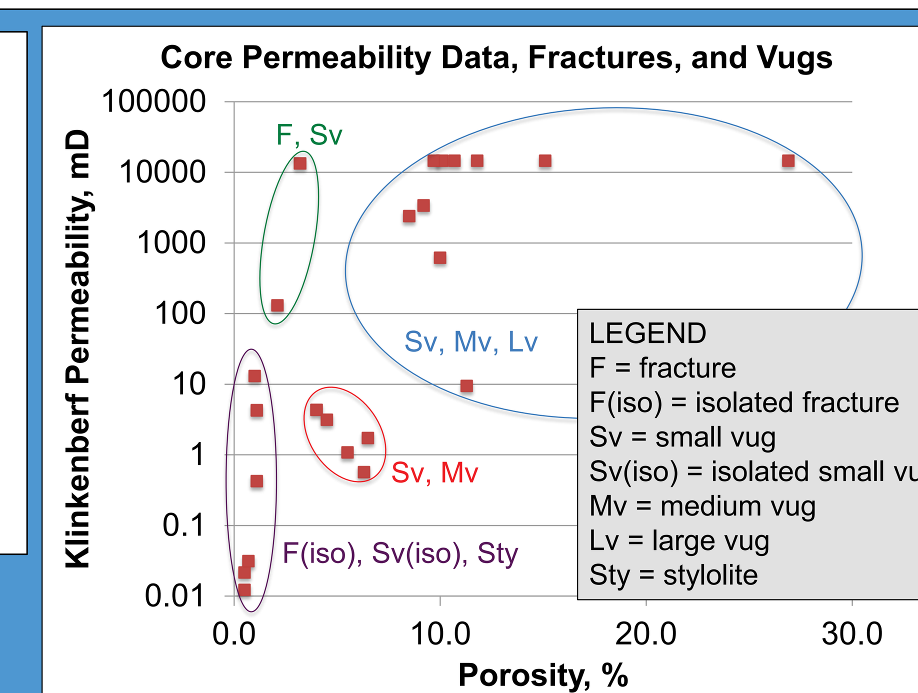
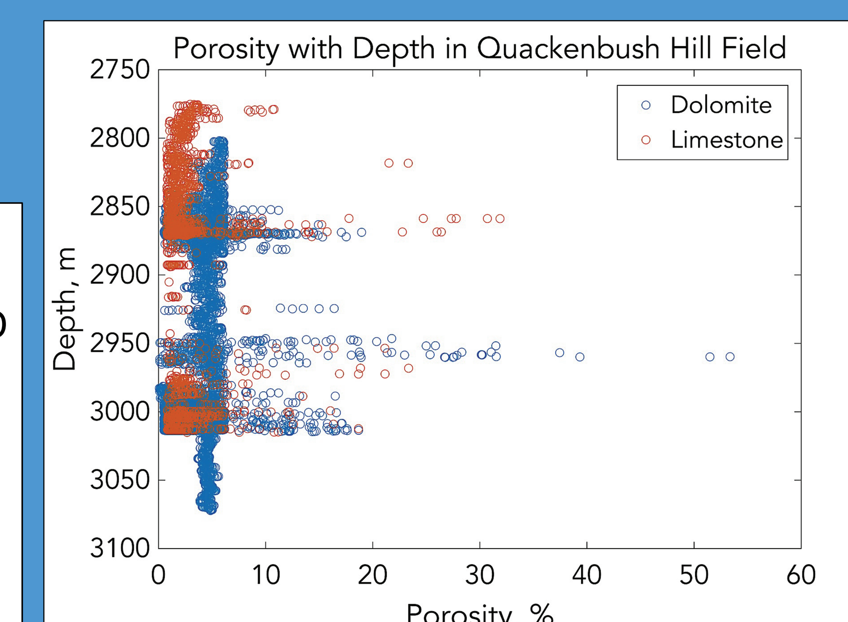


Table 2. (right) Porosity statistics from corrected NPHI logs; permeability statistics from application of the empirical core-derived poro-perm relationship to the well log porosity data. Average permeability in the reservoir is 120 mD. The two modes in the bimodal permeability distribution are 1.4 and 140 mD.

	Log Porosity	Log Permeability
Minimum	0.002%	2.87E-9 mD
Average	**3.85%**	**120 mD**
Median	2.27%	4 mD
Maximum	53.4%	36 D

Figure 7. (right) Porosity with depth, sorted by lithology. Many wells in this field are horizontal, so MD values were converted to TVD. Dolomite is associated with higher porosity zones than limestone. Best reservoir-quality zones are located between 2850 and 3000 meters depth, but seem to be segregated into two distinct zones.



6. Conclusions

- Gas effect impacted 30% of well log NPHI values
  - Did not affect mean porosity; did alter porosity **distribution**
- Porosity and Permeability distributions are **bimodal**
  - Bimodal aspect likely due to vug v. fracture porosity; fractures yield high permeability from low porosity, vugs yield high permeability from high porosity
- Horizontal permeability orders of magnitude greater than vertical
  - Consistent with high porosity zones found in horizontal depth bands at 2870 and 2960 meters depth, likely vuggy
- High porosity zones in reservoir most associated with dolomite
- ***Reservoir permeability sufficient for geothermal applications***

7. References

- Al-Jabri, R.A., Al-Maamari, R.S., and Wilson, O.B., 2015, Klinkenberg-corrected gas permeability correlation for Shuaiba carbonate formation: Journal of Petroleum Science and Engineering, v. 131, p. 172-176.
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