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Porosity and permeability of Green River oil shale and their changes during retorting



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HIGHLIGHTS

G R A P H I C A L A B S T R A C T

- Estimate compaction and porosity during diagenesis as a function of organic content.
- Calculate porosity as a function of oil shale grade and kerogen conversion during in-situ retorting.
- Estimate permeability from porosity using simple engineering correlations.



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ABSTRACT

Oil shales are organic-rich mudstones that generally have little porosity and permeability until kerogen is transformed into oil and gas. A simple mathematical model is reported for how porosity and permeability values for the Green River Formation change during retorting under confinement. Unlike when retorted unconstrained, during which numerous fractures occur due to the limited tensile strength of retorted oil shale and the permeability increases from micro or nano-Darcy levels to Darcy levels, fracture permeability is minor when constrained by lithostatic loads typical of in-situ retorting, so permeabilities increase only to the milli-Darcy level. The permeability increase is related to an increase in both porosity and pore diameter, and measured permeabilities are consistent with measurements and calculations of those properties and inter-relationships developed for naturally matured petroleum source rocks.

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1. Introduction

Although oil shale retorting has been a source of small amounts of shale oil for centuries and is important in certain localities, global interest in oil shale as a potential source of shale oil waxes and

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wanes every few decades as the price and perceived supply issues for conventional crude oil rise and fall. More recently, production of natural petroleum (oil and gas) from mature source rocks and adjacent or interbedded fine-grained yet more permeable layers has greatly increased the knowledge of porosity and permeability of organic-rich fine-grained rocks. The combination of historical and recent information gathered for oil shale processing and for production of tight oil and shale gas purposes provides some more general insights that can be useful for both applications, although



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the primary intended application for this work is to develop a new algorithm for permeability as a function of grade and extent of kerogen decomposition for modeling fluid flow during in-situ oil shale processing.

As in any field, measurement methodologies improve over time. Consequently, historical information must be critically evaluated. However, measurements from the 1960s and 1970s are still among the best available for some conditions. The current paper attempts to combine the best of the old literature with more recent measurements to draw a more comprehensive picture of how porosity and permeability evolve over the transformation of kerogen under lithostatic load typical of in-situ retorting, which can be approximated as constant volume. This information is used to develop and validate a new, simple algorithm for how porosity and permeability evolve during retorting at constant volume. More general relationships for volume versus mechanical load during retorting are still in the development stage.

The approach developed here combines three simple aspects to calculate permeability as a function of grade and extent of retorting. First, an empirical relationship is developed to account for how the greater ductility of kerogen affects initial porosity as a function of kerogen content. Second, a correlation is developed between total porosity and the matrix permeability of both raw and retorted shales as expected by Kozeny-Carman and similar relationships. Third, it is shown that retorting under lithostatic load corresponding to a few hundred meters overburden yields porosities as a function of kerogen conversion roughly equal to those calculated at constant volume. These three relationships are used to create an algorithm for and a plot of permeability as a function of conversion for various oil shale grades, which is needed to model the dissipation of pore pressure generated within the formation during in-situ oil shale retorting.

2. Porosity versus grade

Many years ago, Tisot [1] reported porosities for several samples of Green River oil shale from the Mahogany Zone. Porosity was determined by comparison of bulk and grain densities for cores, although the procedure for measuring grain density was not described in enough detail to be sure all porosity was accessed. The porosity was about 10% for lean oil shale with ~1 wt% Total Organic Carbon (TOC) and dropped linearly to zero for organic content greater than 6 wt% TOC. However, subsequent helium pycnometry measurements at Lawrence Livermore National Laboratory (LLNL) on a variety of samples from the Piceance and Uinta Basins indicated that porosity of 1–5% still existed for samples with ~7 wt% total organic carbon (TOC) [2]. So Tisot's data should not be considered definitive.

Rock porosity can also be determined from well logs. Smith et al. [3] estimated porosity over 50-ft intervals by comparing grain density measurements with neutron log densities. Values from 1 to 9% were obtained, with the higher values attributed to dissolution of nahcolite nodules. More recently, characterization of a wellbore near the center of the Piceance basin by Schlumberger Combinable Magnetic Resonance (CMR) provided a more direct measurement of the porosity via free water content over a 1500-ft thickness of the Green River Formation [4]. Results for a few selected intervals are shown in Fig. 1. The wt% TOC is approximately half the grade in gal/ton. The middle portion of the formation (including the leached zone) is not shown, because the porosity has major contributions due to dissolved nahcolite nodules.

Using the USGS L-R nomenclature [5], the intervals are separated into two groups, which have zero-organic-matter intercepts of about 16 and 26%, respectively. The porosity is not simply related to either depth or mineralogy. The R0-R2 zones are typi-



Fig. 1. Porosity versus grade for five intervals in the Green River Formation in the Piceance Basin.

cally 5–15% carbonate and 20–40% illite by weight, but the R0 and L0 zones have noticeably lower porosity. The upper zones are typically 20–40% carbonate and less than 15% illite [6], and the porosity trends are almost inversely related to depth, which may be related to nahcolite deposition and dissolution. For the purposes here, the effect of organic matter on porosity is qualitatively the same for all depth and mineralogy variations.

The porosity of shale versus depth is often described by Athy's law, or more rigorously, as a function of effective stress via Terzaghi's principle [7]. Given that immature kerogen, particularly Type I, is softer than mineral grains, it is plausible that compaction might be greater for shale with more organic content, although variability with mineralogy also occurs. Young's modulus and compressive strength calculated from the sonic log (Schlumberger SonicScanner, chirp sampling ~300 Hz to 8 kHz) using correlations of Horsrud [8] are shown in Fig. 2 for the R0-R2 interval of the Garden Gulch Member. Similar values for Young's modulus were provided in the logging report using shear and compressive wave velocities in classical elastic wave propagation equations. These properties are for a wellbore temperature of 40–45 °C, based on temperature logs of the measurement interval, which softens the organic matter much more than the inorganic crystals.

Both modulus and strength decrease as oil shale grade increases, which is consistent with both the literature [9] and nanoindentation studies showing that the inorganic crystals are stiffer and stronger than kerogen [10]. The grade dependence is more pronounced for the carbonate-rich Piceance Creek Member than for the clay-rich Garden Gulch Member. Typical mineral moduli at zero porosity are 30–50 GPa, which indicates the effect of porosity on the sonic log moduli at low grade. The high-grade modulus limit of 0.8 GPa, for which kerogen is the continuous phase, is the same as high-density polyethylene at 40 °C [11] and less than polystyrene, polycarbonate, polyethylene terephthalate, Download English Version:

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