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Full Length Article

Thermomechanical properties of the Garden Gulch Member of the Green River Formation

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ABSTRACT

Extensive well logging and laboratory rock mechanics experiments gathered within the context of in-situ retorting are used to derive an anisotropic thermomechanical model for deformation of oil shale from the Garden Gulch Member of the Green River Formation in the Piceance Basin of Colorado. Elastic moduli determined from sonic velocities are shown to be consistent with but about twice as high as those from static measurements at small strain. Porosity correlates inversely with organic content, and the relative contributions of kerogen, minerals, and porosity to sonic velocities are determined from a combination of new and literature data. Young's modulus of kerogen derived by extrapolation to high kerogen volume fraction is consistent with measurements from previous workers. The temperature dependence and anisotropy of the triaxial tests can be described fairly well by Reuss and Voigt averages for a laminar material. The intrinsic (end-member) static Young's moduli of the kerogen and mineral components are 1 and 7 GPa, respectively, with thermal softening of each described by apparent activation energies of 17 and 9 kJ/mol, respectively. Isostatic compression creep tests are used to further constrain the temperature dependence of the plastic deformation viscosity. The apparent activation energy for creep is about 35 kJ/mol. The thermochemical properties of the clay-rich Garden Gulch Member are compared to those of the dolomite-rich Parachute Creek Member. At low organic content, the Young's modulus of the Garden Gulch Member is about four times lower, and the properties of the two members approach each other for high organic content.

1. Introduction

The thermomechanical properties of organic rich mudstones and shales have been of interest for many years, initially in the context of oil shale processing and subsequently in the contexts of basin modeling and of unconventional oil and gas production. Although the time–-temperature conditions for these three applications are substantially different, the relevant thermomechanical properties are intimately related. In fact, accelerated maturation experiments under conditions of in-situ oil shale processing can be used in combination with geological observations to derive and calibrate compaction and expulsion models of natural petroleum formation.

This paper describes the results of field measurements and laboratory experiments done originally in the context of in-situ oil shale processing, including well stability and subsidence, but now being used to improve models of geological compaction and expulsion. Both applications require models that can calculate deformation as a function of time, temperature, kerogen content, and kerogen conversion. These models must accommodate the extreme vertical heterogeneity of the material and be consistent with the boundaries of ductile and brittle failures. The geological application is more difficult in some ways, because it involves the extrapolation of time-dependent thermochemical and thermomechanical properties over very large time frames, with all the uncertainties that normally accompany accelerated aging tests.

The current paper concentrates on the time–temperature regime prior to significant conversion of kerogen to bitumen, oil, and gas. Consequently, the basic thermomechanical model is developed using data at 150 °C and below. However, compaction is a kinetic process involving thermally activated creep, so experiments at temperatures up to 300 °C are used with the understanding that plasticization of kerogen by early decomposition products is likely accelerating the softening of that rock component.

2. Data sources

Mechanical property measurements used in this analysis come from largely unpublished data from American Shale Oil's (AMSO's) effort to

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demonstrate an in-situ oil shale process in the Piceance Basin of Colorado [1]. The appendix contains background information for context. In particular, well log data came from wells BH-1 and TM-1 at locations shown in the appendix, and core samples came from TM-1. Previous work had demonstrated the ability of well log methods to determine porosity and kerogen content [2,3]. More detailed mineralogical data was published earlier [4] for a depth interval of well CH-1 that overlaps the stratigraphic interval emphasized here. Well BH-1 was a borehole from which cuttings were taken for retorting studies [5,6], and the latter paper contains geological information relevant to this work. TM-1 was cored with a 6″ barrel through the Garden Gulch Member, and the core was preserved by injecting grout into the annulus between the core and the core barrel and capping the end of the core barrel. Smaller cores were taken from this material for rock mechanics experiments. AMSO contracted for many such experiments at Agapito Associates, Inc. (Grand Junction, CO), New England Research (White River Junction, VT), MetaRock, Inc. (Houston, TX), and Advanced Terra Testing (Lakewood, CO). Temperatures up to 300 and 450 °C, respectively, were explored at New England Research and MetaRock, but only data at and below 300 °C, where kerogen conversion is negligible, is considered here. The work at New England Research and MetaRock was conducted mostly under triaxial confinement of 12 MPa, but varying the confinement from 8 to 18 MPa showed no apparent effect. Much of that data was used in a previous study detailing an elastic–plastic model coupled with a simple chemical reaction model [7].

3. Dynamic mechanical properties

Propagation of sound waves through a medium depends on the compressional and shear properties of the material. The compressional and shear wave velocities, respectively, for an isotropic medium are given by

$$V_p = \sqrt{(K+4G/3)/\rho_b};\ V_s = \sqrt{G/\rho_b} \tag{1}$$

where K is the bulk modulus (response to isotropic stress), G is the shear modulus (response to shear stress), and ρ_b is the bulk density. Young's modulus (response to uniaxial stress) is related to K and G by

$$E = 9KG/(3K+G) = 2G(1+\nu) = 3K(1-2\nu) \tag{2}$$

where ν is Poisson's ratio, which is the ratio of radial to axial strain in response to uniaxial stress. The dynamic Young's modulus is related to the compressional and shear velocities by

$$E_{dyn} = \rho_b V_s^2(3V_p^2-4V_s^2)/(V_p^2-V_s^2) \tag{3}$$

and the dynamic Poisson's ratio is given by

$$\nu_{dyn} = (V_p^2-2V_s^2)/[2(V_p^2-V_s^2)] \tag{4}$$

The dynamic values can differ from the static values due to frequency response of the material. The dynamic Young's modulus and Poisson's ratio were calculated from Schlumberger Sonic Scanner log data and are shown in Figs. 1-3. Porosity in Fig. 4 is measured by Schlumberger Combinable Magnetic Resonance (CMR). Additional information about the location of the log data within the formation is given in the Appendix.

The first step in interpreting sonic velocities is to consider that they depend on both porosity and kerogen content. In fact, the two are coupled, as described earlier, apparently because kerogen's ductility enables it to enhance compaction. A plot of porosity versus kerogen volume fraction determined from a suite of Schlumberger logs is shown in Fig. 1 along with a calculated relationship of a form useful for basin modeling [8]. The chosen function is

$$\phi = 0.02 + 0.6\exp(-1/(1-f_{ker}^{0.7})) \tag{5}$$

where f_{ker} is the volume fraction of kerogen, the initial depositional porosity is 0.62 vol fraction, and the product of the compaction coefficient and burial depth given in [8] is unity in this case, which gives a porosity of 0.24 when f_{ker} is zero. This function fits the porosity of the R1 interval (see Fig. A6) better, but there is enough variability that one should consider this relationship to be only generally representative. The prediction could be improved easily for any specific

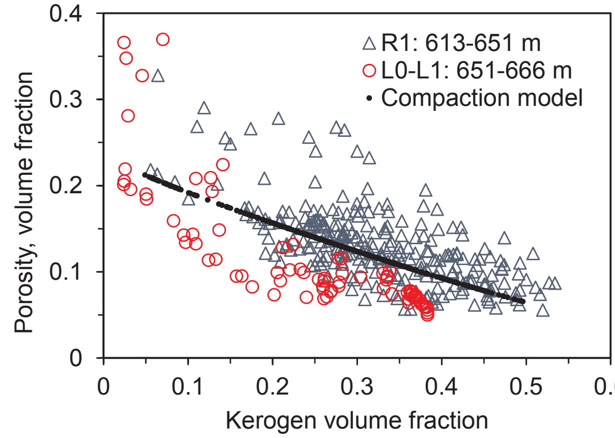

Fig. 1. CMR porosity as a function of grade for Garden Gulch Member oil shale. CMR porosity values greater than 25% are probably affected significantly by well breakouts (rugosity). There is a noticeable difference with lithology, which makes a master fit inappropriate, but both intervals show a decline in porosity with increased kerogen content.

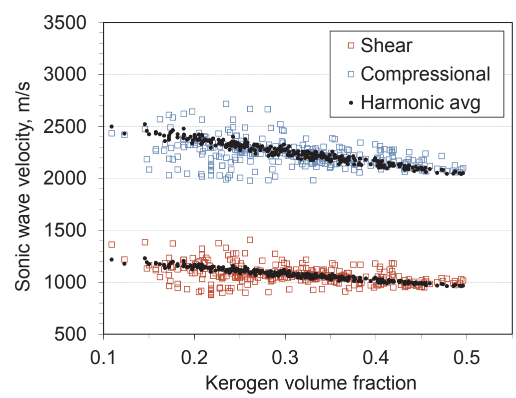

Fig. 2. Compressional and shear velocities for oil shale from the Garden Gulch Member at a formation temperature of about 40 °C and a lithostatic overburden stress of about 15 MPa. The harmonic average points are calculated from a weighted average of the reciprocal velocities to derive the respective velocities of the mineral and kerogen components.

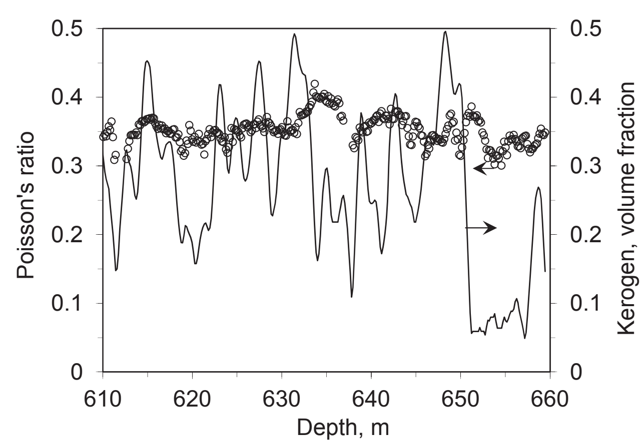

Fig. 3. Poisson's ratio (circles) calculated from compressional and shear velocities for Garden Gulch Member oil shale. There is no apparent relationship with depth or kerogen volume fraction (line).