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Temperature, differential pressure, and porosity inversion for ultradeep carbonate reservoirs based on 3D rock-physics templates

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ABSTRACT

Ultradeep carbonate reservoirs have high temperatures and pressures, complex pressure/tectonic stress settings, and complex pore structures. These conditions make their seismic detection and characterization difficult, particularly if the signal-to-noise ratio is low, as is the case in most situations. Moreover, the high risk of deep-drilling exploration makes it impractical to carry out normal logging operations. We have developed a temperature-differential pressure-porosity (TPP) rock-physics model based on the Biot-Rayleigh poroelasticity theory to describe the wave response of the reservoir. A preliminary analysis indicates that temperature, pressure, and porosity are well correlated with wave velocity and attenuation. On the basis of this theory, we have built 3D rock-physics templates that account for the effects of TPP on the P-wave impedance, V_P/V_S ratio, and attenuation. The templates are calibrated with laboratory, well-log, and seismic data of the S area (Shuntuoguole uplift, Tarim Basin, Xinjiang, China). Then, the template is used to obtain the properties of the reservoir at seismic frequencies. The predicted results are consistent with the field reports (high temperature, low differential pressure, and high porosity) indicating high production rates. The methodology will be useful for hydrocarbon exploration in ultradeep carbonate reservoirs.

INTRODUCTION

With the decline of shallow petroleum discoveries, the exploration prospects are gradually moving from medium-deep to ultradeep layers, as is the case of unconventional oil-gas resources around the world (Pang et al., 2015; Guo et al., 2019). An ultradeep carbonate reservoir in China is the S area of the Tarim Basin, Xinjiang, where the Ordovician limestone is rich in oil and gas resources (Qi, 2016; Wan et al., 2017; Jiao, 2018; Ding et al., 2020). Temperature and pressure affect the distribution of hydrocarbons, and porosity and cracks are important factors controlling their migration and accumulation. Temperature is a good fluid indicator for ultradeep carbonate fault-karst reservoirs (Lei et al., 2020). Compared to shallow reservoirs, ultradeep reservoirs generally exhibit higher temperatures and a complex pressure setting and pore network, so the use of conventional rock-physics models may not be appropriate (Yao et al., 2018; Gu et al., 2019; Tian et al., 2019).

Jaya et al. (2010) analyze the effects of temperature on seismic wave velocity and attenuation by using a modified Gassmann equation and show that the fluid properties are important. P-wave velocity decreases with increasing temperatures and attenuation increases due to the formation of bubbles and microfractures. Batzle et al. (2006) find that the P- and S-wave velocities of dry samples do not depend on temperature and that the S-wave velocity increases with the increasing fluid viscosity. The effect of differential pressure (confining minus pore) is considered in many works (Liu et al., 1998; Pham et al., 2008; Pimienta et al., 2015, 2016; Chapman et al., 2016, 2017). The results show that the wave velocity increases and attenuation decreases with differential pressure, effects dictated by the microstructure of the rock. Agersborg et al. (2009) consider the effects of pore geometry on the P- and S-wave properties. Kern et al. (2001) conduct experiments on ultradeep reservoir cores to study the effect of temperature and pressure on velocity. They find a nonlinear and a linear trend at low and high confining pressures, respectively, and they find a linear decrease at high pressures and temperatures. The effects of cracks are significant, and their characteristics can be obtained from the elastic-moduli dependence on pressure (Cheng and Toksöz, 1979; Tran et al., 2008; Cheng et al, 2020). Smith et al. (2010) study the effects of confining pressure and pore structure on

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the wave velocity at ultrasonic frequencies and find that there is no appreciable change in stiff (equant) porosity with the increasing confining pressure. The observed increase in P-wave velocity can only be ascribed to the closure of compliant (soft) pores.

Differential-medium theories are used to relate elastic properties to the microstructure (Walsh, 1965; Mori and Tanaka, 1973; Kuster and Toksöz, 1974). David and Zimmerman (2012) extend the Zimmerman (1991) method, based on the Mori and Tanaka (1973) theory, to obtain the distribution of crack aspect ratios from the dry-rock velocity. Batzle and Wang (1992) establish the pressure and temperature dependencies of pore fluids. The Biot-Gassmann theory (Gassmann, 1951; Biot, 1962) is often used for fluid substitution, but Gregory (1976) finds inconsistencies due to the fact that it is a low-frequency limit and ignores local fluid effects that induce wave dispersion and attenuation (Murphy, 1984). Pride et al. (2004) describe wave propagation in patchy-saturated rocks with a double-porosity theory, and Ba et al. (2011, 2012, 2017) consider mesoscopic fluid-flow effects and derive wave-propagation equations for a heterogeneous porous medium to model attenuation at different frequency bands.

Most research on formation-pressure prediction is based on the compaction effect and has been applied in conventional shale formations (Hottman and Johnson, 1965; Eaton, 1972). However, due to the complexity of carbonate rocks, the compaction effect is not evident. Fillippone (1979) combines the formation velocity with log and seismic data to develop a formation-pressure prediction model independent of the compaction trend. The principle of effective stress proposed by Terzaghi (1943) is an important theoretical basis for the prediction of formation pressure in carbonate reservoirs. Xia et al. (2005) use log data to predict the pore pressure of carbonate reservoirs at eight wells, based on the principle of effective stress. Cheng et al. (2013) use the effective-stress principle combined with ultrasonic experiments to establish a new pore-pressure prediction model suitable for carbonates. Liu et al. (2020) predict the temperature in deep and ultradeep strata and find that the spatial distribu-

tions are mainly controlled by the basement structural pattern. The temperature ranges at 6, 7, and 8 km depths are 118°C–172°C, 136°C–198°C, and 190°C–224°C, respectively. Rock-physics templates (RPTs) are a useful tool for lithology and pore fluid interpretation, based on well-log data and elastic inversion (Odegaard and Avseth, 2004). Ba et al. (2013) build multiscale RPTs based on the Biot-Rayleigh theory to predict the porosity and saturation of carbonate gas reservoirs. Li et al. (2019) use 3D RPTs based on the effective-medium theory and Gassmann equations to predict theoretical porosity, pore aspect ratio, and fluid saturation in carbonates.

Here, we establish the relation between the dry-rock moduli and the micropore structure at different differential pressures and temperatures, based on the Mori-Tanaka theory, and the fluid properties are obtained with the Batzle-Wang equations. Then, we develop the temperature-differential pressure-porosity (TPP) rock-physics model based on the Biot-Rayleigh theory (Ba et al., 2011) and 3D RPTs, which are calibrated with ultrasonic, log, and seismic data from the S area of the Tarim Basin, Xinjiang, China. The templates are then used to predict the TPP of the area.

ROCK-PHYSICS MODEL

Ultradeep carbonate reservoirs, such as the Shuntuoguole uplift of the Tarim Basin (S area), have depths greater than 7 km, temperatures exceeding 150°C, and a complex formation system with pressures greater than 60 MPa. The flowchart is shown in Figure 1. The target reservoir rocks are mainly limestones with high calcite content and a small amount of dolomite, and we use the Voigt-Reuss-Hill average to estimate the grain elastic moduli. We consider stiff pores and compliant cracks, which have spherical and oblate shapes, and we use the Mori-Tanaka theory to analyze the effects of temperature and pressure on the moduli and pore structure. The Batzle and Wang (1992) equations provide the properties of fluids. Finally, we use the Biot-Rayleigh theory (Ba et al., 2011) to obtain the wave velocities and attenuation of the oil-saturated rocks at different frequency bands.

Mineral stiffness moduli

The reservoir of this study is a limestone, dominantly calcite, with a small amount of dolomite. The Voigt-Reuss-Hill average (Voigt, 1910; Reuss, 1929; Hill, 1952) is used to calculate the elastic modulus of the composite mineral:

$$K_s = \frac{1}{2}\left(\sum_{i=1}^{N} f_i K_i + 1/\sum_{i=1}^{N} \frac{f_i}{K_i}\right), \quad (1)$$

$$G_s = \frac{1}{2}\left(\sum_{i=1}^{N} f_i G_i + 1/\sum_{i=1}^{N} \frac{f_i}{G_i}\right), \quad (2)$$

where K_s and G_s are the bulk and shear moduli of the grains, respectively; f_i, K_i, and G_i represent the volume ratio, and bulk and shear moduli of mineral i, respectively; and N is the number of minerals.
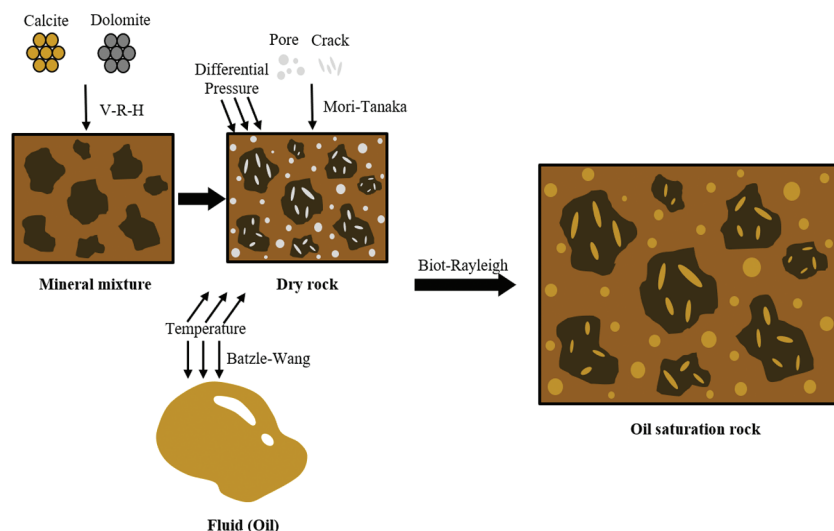

Figure 1. Flowchart of the ultradeep carbonate rock-physics modeling. We use the Voigt-Reuss-Hill average and the Mori-Tanaka theory to estimate the grain and dry-rock elastic moduli, respectively. The Batzle and Wang equations provide the properties of the fluids, and the wave velocities and attenuation of the oil-saturated rocks are obtained with the Biot-Rayleigh theory.

Dry-rock moduli

Because the reservoir is buried below 7 km, the pore structure is greatly affected by temperature and differential pressure. There are many combinations of pore volumes and shapes. A simple method is to consider two void spaces and use the effective medium theory (Duran et al., 2019). We consider stiff pores and compliant cracks (Ruiz and Cheng, 2010). The bulk and shear moduli without cracks are given by (Mori and Tanaka, 1973)

$$K_{\text{stiff}} = K_s / \left(1 + \frac{\phi_{\text{stiff}}}{1 - \phi_{\text{stiff}}} P(\alpha_{\text{stiff}}, v_s)\right), \qquad (3)$$

$$G_{\text{stiff}} = G_s / \left(1 + \frac{\phi_{\text{stiff}}}{1 - \phi_{\text{stiff}}} Q(\alpha_{\text{stiff}}, v_s)\right), \qquad (4)$$

where ϕ_{stiff} is the stiff porosity and P and Q are the shape factors (see Appendix A).

When the cracks are completely closed under high differential pressures, only the stiff pores are present and the stiff porosity can be estimated. The corresponding bulk and shear moduli, K^{hp} and G^{hp}, respectively, are obtained from the P- and S-wave velocities as

$$K^{\text{hp}} = \rho\left((V_{\text{p}}^{\text{hp}})^2 - \frac{4}{3}(V_{\text{s}}^{\text{hp}})^2\right), \qquad (5)$$

$$G_{\text{dy}}^{\text{hp}} = \rho(V_{\text{s}}^{\text{hp}})^2, \qquad (6)$$

where the superscript "hp" denotes the high differential pressure and ρ is the mass density. Combining equations 3–6, the aspect ratio of the stiff pores α_{stiff} is obtained by a least-squares algorithm applied to these moduli.

The effective dry-rock bulk and shear moduli with cracks are (Mori and Tanaka, 1973), respectively,

$$K_{\text{eff}} = K_{\text{stiff}} / \left(1 + \frac{16(1 - (v_{\text{stiff}})^2)\Gamma}{9(1 - 2v_{\text{stiff}})}\right), \qquad (7)$$

$$G_{\text{eff}} = G_{\text{stiff}} / \left(1 + \frac{32(1 - v_{\text{stiff}})(5 - v_{\text{stiff}})\Gamma}{45(2 - v_{\text{stiff}})}\right), \qquad (8)$$

where $v_{\text{stiff}} = (3K_{\text{stiff}} - 2G_{\text{stiff}})/(6K_{\text{stiff}} + 2G_{\text{stiff}})$ is the Poisson's ratio of the stiff pores and Γ is the crack density.

The temperature and pressure dependence of the effective moduli are closely related to the crack density (Sarout et al., 2017; Wei et al., 2020). When this is specified, the elastic moduli can be obtained from equations 7 and 8, and vice versa. The elastic modulus at different temperatures and pressures can be obtained from the wave velocities. Then, the crack density at each temperature and differential pressure $\Gamma(T, p)$ can be computed by least-squares regression based on the elastic moduli.

The relation between the pore aspect ratio and the differential pressure is (Zhang et al., 2019)

$$\alpha_p = \frac{4[1 - (\nu_{\text{eff}})^2]p}{\pi E_{\text{eff}}}, \qquad (9)$$

where E_{eff} is the effective Young modulus, defined as $E_{\text{eff}} = 3K_{\text{eff}}[1 - 2\nu_{\text{eff}}]$.

The relation between crack porosity and crack density is (David and Zimmerman, 2012)

$$\phi_2 = \frac{4\pi\alpha_p}{3}\Gamma_p. \qquad (10)$$

Equation of motion and dispersion equation

Because the temperature in the study area is greater than 150°C, the fluid modulus (k_f), viscosity (η), and density (ρ_f) are highly affected, which can be estimated by the Batzle and Wang (1992) equations under variable temperatures (see Appendix B). We use the Biot-Rayleigh equations (Ba et al., 2011) to obtain the properties of the saturated rock,

$$N\nabla^2\mathbf{u} + (A+N)\nabla\varepsilon + Q_1\nabla(\zeta^{(1)} + \phi_2\varsigma) + Q_2\nabla(\zeta^{(2)} - \phi_1\varsigma)$$
$$= \rho_{11}\ddot{\mathbf{u}} + \rho_{12}\ddot{\mathbf{U}}^{(1)} + \rho_{13}\ddot{\mathbf{U}}^{(2)} + b_1(\dot{\mathbf{u}} - \dot{\mathbf{U}}^{(1)}) + b_2(\dot{\mathbf{u}} - \dot{\mathbf{U}}^{(2)}),$$
$$(11a)$$

$$Q_1\nabla\varepsilon + R_1\nabla(\zeta^{(1)} + \phi_2\varsigma) = \rho_{12}\ddot{\mathbf{u}} + \rho_{22}\ddot{\mathbf{U}}^{(1)} - b_1(\dot{\mathbf{u}} - \dot{\mathbf{U}}^{(1)}),$$
$$(11b)$$

$$Q_2\nabla\varepsilon + R_2\nabla(\zeta^{(2)} - \phi_1\varsigma) = \rho_{13}\ddot{\mathbf{u}} + \rho_{33}\ddot{\mathbf{U}}^{(2)} - b_2(\dot{\mathbf{u}} - \dot{\mathbf{U}}^{(2)}),$$
$$(11c)$$

$$\phi_2\left(Q_1\varepsilon + R_1(\zeta^{(1)} + \phi_2\varsigma)\right) - \phi_1\left(Q_2\varepsilon + R_2(\zeta^{(2)} - \phi_1\varsigma)\right)$$
$$= \frac{1}{3}\rho_f\ddot{\varsigma}R_{12}^2\frac{\phi_1^2\phi_2\phi_{20}}{\phi_{10}} + \frac{1}{3}\frac{\eta\phi_1^2\phi_2\phi_{20}}{\kappa_1}\dot{\varsigma}R_{12}^2, \qquad (11d)$$

where $\mathbf{u}$, $\mathbf{U}^{(1)}$, and $\mathbf{U}^{(2)}$ are the displacement vectors of the solid, fluid phase 1 (fluid in stiff pores), and fluid phase 2 (fluid in microcracks), respectively; ε, $\zeta^{(1)}$, and $\zeta^{(2)}$ are the variations of fluid contents; ς is the fluid increment caused by the local flow process; ϕ_{10} and ϕ_{20} are the local porosities of the main skeleton (only stiff pores) and crack; $\phi_1 = v_1\phi_{10}$ and $\phi_2 = v_2\phi_{20}$ are the absolute porosities of the two types of pores; v_1 and v_2 are the corresponding volume ratios; R_{12} is the radius of the microcrack; b_1 and b_2 are the Biot dissipation coefficients related to the absolute porosities ϕ_1 and ϕ_2 and permeabilities κ_1 and κ_2 of the main skeleton and crack, respectively; $\rho_{11}, \rho_{12}, \rho_{13}, \rho_{22}$, and ρ_{33} are the density components; and A, N, Q_1, Q_2, R_1, and R_2 are the stiffness coefficients (see Appendix C). Substituting a plane-wave kernel into equation 11, we obtain the P- and S-wave complex wavenumbers (see Appendix D), V_P and V_S, respectively, of the wet rock (Ba et al., 2011).

APPLICATION OF THE MODEL

Geologic setting

The study area is located in the S area, Shuntuoguole uplift, Tarim Basin, Xinjiang, China. The Ordovician carbonate fault-karst reservoirs are currently the main exploration horizon of this area, which is composed of the Yijianfang and Yingshan Formations. Karst caves, pores, and microcracks caused by multistage strike-slip faulting and dissolution develop in the reservoirs. The complex interconnectivity generates the complexity of the fluid flow dynamic with potential geothermal sources. The Lower-Cambrian hot-alkaline brine may be the heat source, and strike-slip faulting provides channels for hydrothermal fluid upwellings (Liu et al, 2020).

Carbonate samples

The rock samples and data are from the deep-carbonate S area. As shown in Figure 2, a thin section of a limestone sample contains multiple microcracks with different apertures in the range of 0.01–0.03 mm, and the surface porosity is less than 1%.

The ultrasonic experiment consists of a digital oscilloscope (Tektronix TDS 420 A) and a pulse generator (Panametrics 5077PR) (Guo et al., 2009). The measuring system has independent temperature and pressure (pore and confining) control units. The limestone sample is saturated with oil by means of the vacuum and pressure saturation method and placed on a rubber jacket. The porosity (with rare clay and dissolved intergranular pores) is 2.5%, the permeability is 0.023 mD, and the dry-rock density is 2.66 g/cm^3. Differential pressures (confining minus pore) of 15, 20, 25, 30, 40, 50, 60, and 70 MPa are applied up to 140°C and maintained for 30 min by heating the fluid with a wire within the high-pressure vessel. A stress-temperature path sketch is shown in Figure 3. The ultrasonic pulse transmission method is used to obtain the waveform at each differential pressure, and velocities are computed from the first arrival. The P-wave quality factor Q is obtained with the spectral-ratio method using an aluminum rod as a reference (Toksöz et al., 1979; Pang et al., 2020), and then the so-called P-wave dissipation factor is $1/Q$.

The sonic-log data are selected from oil well B of the S area, which is located in the northern margin of the Shuntuoguole low
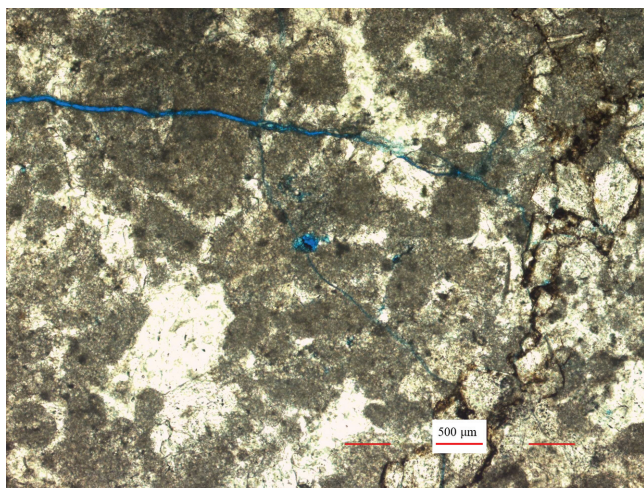
uplift. The completion horizon is the Yingshan Formation, and the drilling depth is 7647 m. The terms V_P and V_P/V_S are extracted from the seismic traces at the borehole location after a three-term inversion by using prestack angle gathers (Aki and Richards, 1980). The porosity for seismic data calibration is obtained from the log data and the traces around the well. To extract the attenuation from the seismic data, a time-frequency analysis is first used to obtain the amplitude spectrum based on the generalized S transform. Then, the layer with a higher centroid frequency is selected as a reference. Comparing the reference spectrum with those of the other layers, the dissipation factor (inverse of Q) is obtained by the improved frequency-shift method (Tu and Lu, 2009; Pang et al., 2019, 2020):

$$Q = \frac{\sqrt{\pi^5} t f_{c1} f_{c0}^2}{16(f_{c0}^2 - f_{c1}^2)}, \tag{12}$$

where t is the propagation time and f_{c0} and f_{c1} are the centroid frequencies of the signal before and after propagation, respectively.

There is the problem of uncertainty in attenuation estimation. To obtain $1/Q$, Quan and Harris (1997) propose a centroid-frequency-shift method, in which the systematic errors increase with attenuation. Zhang and Ulrych (2002) present a peak-frequency-shift method, which is more accurate, but it is unstable due to the noise. Tu and Lu (2009) compare the two methods and propose an improved version, which we use in this study. Their results show that the error range is 0.2%–4.06% and the standard deviation range between the estimated and true Qs is 0.05–2.12. Although the attenuation estimation suffers from uncertainty and deviations, the results are instructive and the general trend can effectively guide the seismic identification of in situ reservoir properties.

Model analysis

The bulk modulus, shear modulus, and density of calcite are 63.7 GPa, 31.7 GPa, and 2700 kg/m^3, and those of dolomite are 76.4 GPa, 49.7 GPa, and 2870 kg/m^3, respectively (Mavko et al., 2009). Assuming that the volume ratio of calcite (f_1) is 100%, 90%, 80%, 70%, and 60%, we obtain the curves shown in Figure 4. When

Figure 2. Thin section of a limestone sample containing multiple microcracks with different apertures.
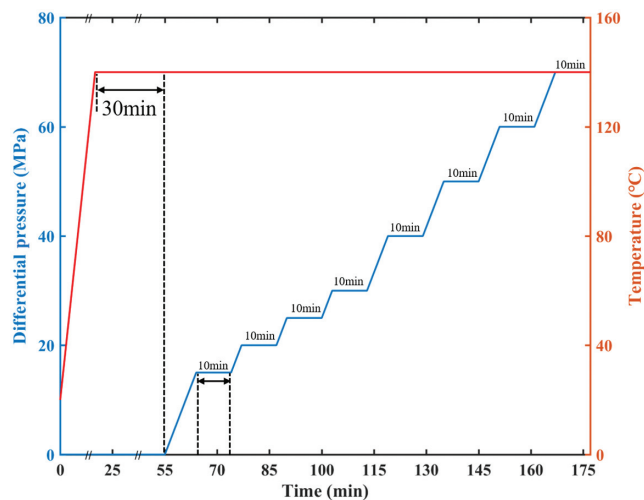

Figure 3. Stress-temperature path sketch. The blue and red lines refer to the differential pressure and temperature, respectively, under different times.

this ratio is 90%, the curve is in good agreement with the ultrasonic laboratory data. In this case, the bulk modulus, shear modulus, and density of the grains are 64.9 GPa, 33.2 GPa, and 2716 kg/m³, respectively.

We obtain the elastic moduli at dry and full saturation and in situ conditions, and we compare the results with Gassmann's equations (Gassmann, 1951). Figure 5 shows that the moduli depend on the differential pressure and that those estimated with the Biot-Rayleigh theory (Ba et al., 2011) are in good agreement with the ultrasonic data at full oil saturation, whereas the shear moduli estimated with the Biot-Rayleigh theory and Gassmann's equations are the same at dry and full-oil saturation conditions.

Wave properties

The rock-physics model described in the previous section is used to obtain the effects of TPP on the wave properties at different frequencies. We consider $\phi_{20} = 0.6\%$, $\kappa_2 = 0.1 \times 10^{-17}$ m², $R_{12} = 2.8 \times 10^{-6}$ m, and $\kappa_1 = 1.11 \times 10^{-18}$ m². Figure 6 shows the wave response at ultrasonic frequencies for TPP, where the porosity of the rock sample is 0.025 and the temperature is 140° C, with the colors corresponding to different differential pressures. In this case, the velocity agrees well and the attenuation has some discrepancies, which could be related to errors in processing or in the experimental measurements. Note that the P-wave velocity decreases and the attenuation increases with increasing temperature and porosity, whereas with the increasing pressure, the velocity gradually increases and the attenuation decreases. When the differential pressure is less than 40 MPa, the P-wave velocity increases more rapidly. At 80 MPa, the attenuation at the same porosity and different temperatures tends to be the same, and the smaller the porosity the weaker the effect of temperature on the attenuation is. This is mainly caused by the closure of microcracks at high differential pressures.

Figure 4. (a) Bulk and (b) shear moduli as a function of differential pressure. Different lines indicate different mineral contents. The circles are the ultrasonic laboratory data at different differential pressures (indicated by the color bar).
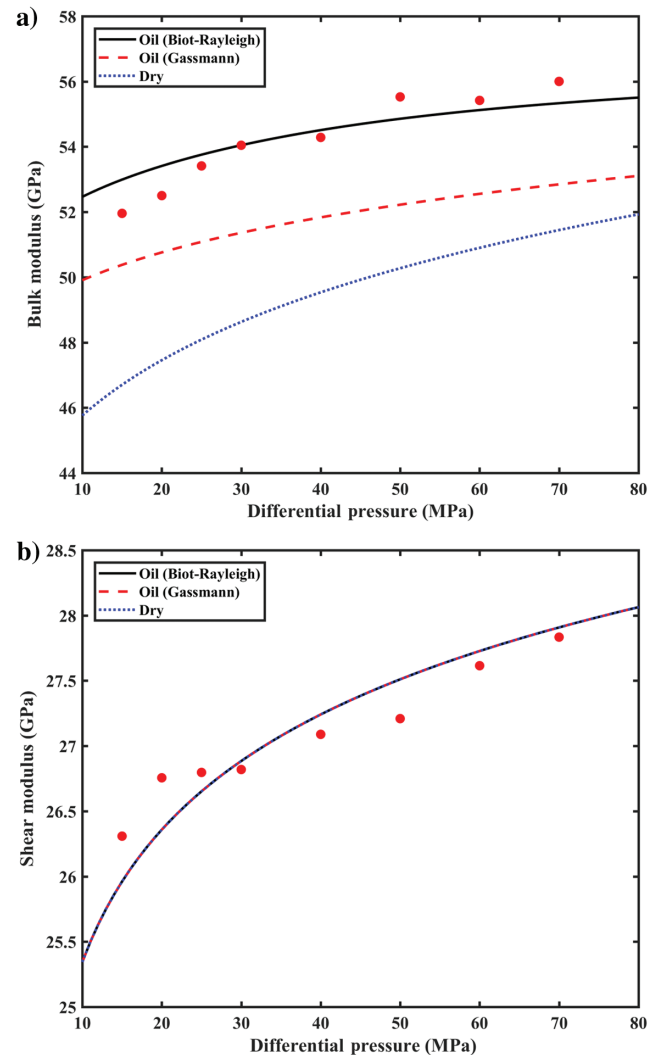

Figure 5. (a) Bulk and (b) shear moduli as a function of differential pressure. The solid black and dashed red lines represent the oil-saturated moduli obtained with the Biot-Rayleigh theory and Gassmann equation, respectively. The blue dotted line refers to the dry-rock moduli, whereas the circles are the ultrasonic laboratory data.

To illustrate the properties at sonic frequencies, we consider $\phi_{20} = 1\%$, $\kappa_2 = 0.1 \times 10^{-16}$ m^2, $R_{12} = 7.5 \times 10^{-5}$ m, and $\kappa_1 = 1.11 \times 10^{-17}$ m^2. The results, presented in Figure 7, show that increasing porosity or temperature and decreasing differential pressure imply decreasing velocity and increasing attenuation. However, the combined effect of pressure and temperature yields different outcomes; e.g., the velocity at 100 MPa and 180°C (the dashed line) is higher than that at 60 MPa and 160°C (the solid line).

Regarding the seismic frequency band, we consider $\phi_{20} = 1\%$, $\kappa_2 = 0.1 \times 10^{-15}$ m^2, $R_{12} = 2.8 \times 10^{-3}$ m, and $\kappa_1 = 1.11 \times 10^{-16}$ m^2. Figure 8 shows the results. As previously, the P-wave velocity decreases and attenuation increases with the increasing temperature and porosity and decreasing pressure. The standard deviation between the predicted and seismic P-wave velocity is 33.1848 m/s, and that of $1/Q$ is 0.0045.

Because the classic 2D RPTs are unable to predict more than two parameters of the reservoir accurately, 3D RPTs are built to consider wave attenuation, P-wave impedance, and the P- to S-wave velocity ratio as a function of TPP.

RPT AND CALIBRATION

Ultrasonic frequencies

The P-wave impedance, V_P/V_S ratio, and attenuation of a 3D RPT at 1 MHz are shown in Figure 9a. The red, black, and blue isolines correspond to the TPP properties. The plot shows the expected behaviors, e.g., an increasing temperature, the V_P/V_S ratio and P-wave impedance decrease and attenuation increases as well as increasing differential pressure, and the V_P/V_S ratio and attenuation decrease and the P-wave impedance increases. The V_P/V_S ratio decreases and then increases with porosity. It can also be observed that the higher the pressure, the smaller the change in attenuation, which means that the influence of temperature and porosity on attenuation is smaller, which is consistent with the results shown in Figure 6b. Figure 9b shows a temperature-pressure template at a porosity of 2.5%, showing that the model agrees with the data (circles). For

Figure 6. (a) The V_P and (b) dissipation factor as a function of differential pressure at ultrasonic frequencies. The temperatures are given. The dashed, dotted, and solid lines correspond to porosities of 0.04, 0.025, and 0.015, respectively. The circles are the ultrasonic laboratory data at different differential pressures (indicated by the color bar).
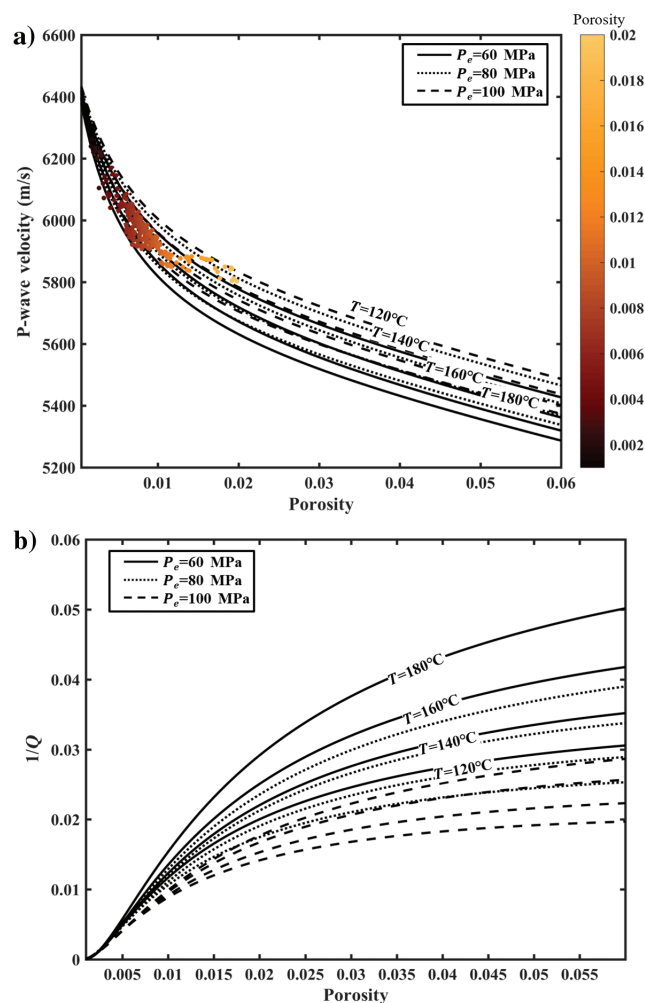

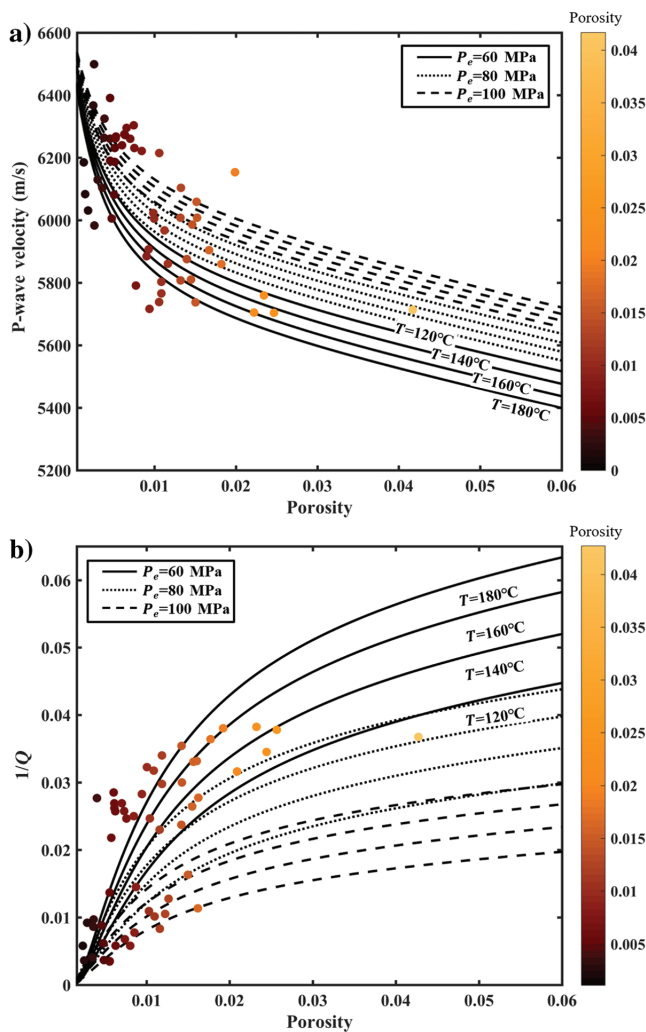Figure 7. (a) The V_P and (b) dissipation factor as a function of porosity at sonic frequencies. The temperatures are given. The dashed, dotted, and solid lines correspond to differential pressures of 100, 80, and 60 MPa, respectively. The circles are the sonic log data at different porosities (indicated by the color bar).

constant porosity and temperature, the V_P/V_S ratio and P-wave impedance of the data increase and the attenuation decreases with pressure.

Sonic frequencies

Figure 10a shows the RPT at 1 kHz. In this case, there are no attenuation data and only P-wave impedance and V_P/V_S ratio are used for calibration (Figure 10b). The color bar in Figure 10b corresponds to the porosity of the log data. The porosity variation of the data is in good agreement with the distribution of the P-wave impedance and V_P/V_S ratio with porosity in the template. The P-wave impedance of the template and log data increase with decreasing porosity, whereas the V_P/V_S ratio decreases.

Seismic frequencies

Figure 11a and 11b shows the 3D RPT and the calibration at 30 Hz, respectively. The symbols in Figure 11b correspond to the experimental V_P/V_S, P-wave impedance, and estimated attenuation by using the seismic data near the borehole (well B), with porosity ranging from 0 to 0.04, roughly corresponding to the porosity of the template. The data are within the calibrated template boundary, and the trend of the seismic porosity agrees with the theoretical curves, so that the template can be applied for the prediction of the TPP properties.

PREDICTION OF TEMPERATURE, DIFFERENTIAL PRESSURE, AND POROSITY

Seismic inversion

We invert the P-wave impedance and V_P/V_S ratio for a seismic line crossing three wells (A, B, and C), shown in Figure 12, in which the black line indicates the log porosity at well B. Porosity is closely related to the elastic properties; i.e., high porosity correlates with low P-wave impedance. However, in Figure 12b, the relationship between V_P/V_S and the porosity is not clear. Figure 13b shows the attenuation estimated with the improved frequency-shift method (Pang et al., 2019). The oil production reports at wells A, B,

Figure 8. (a) The V_P and (b) dissipation factor as a function of porosity at seismic frequencies. The temperatures are given. The dashed, dotted, and solid lines correspond to differential pressures of 100, 80, and 60 MPa, respectively. The circles are the seismic data with different porosities (indicated by the color bar).
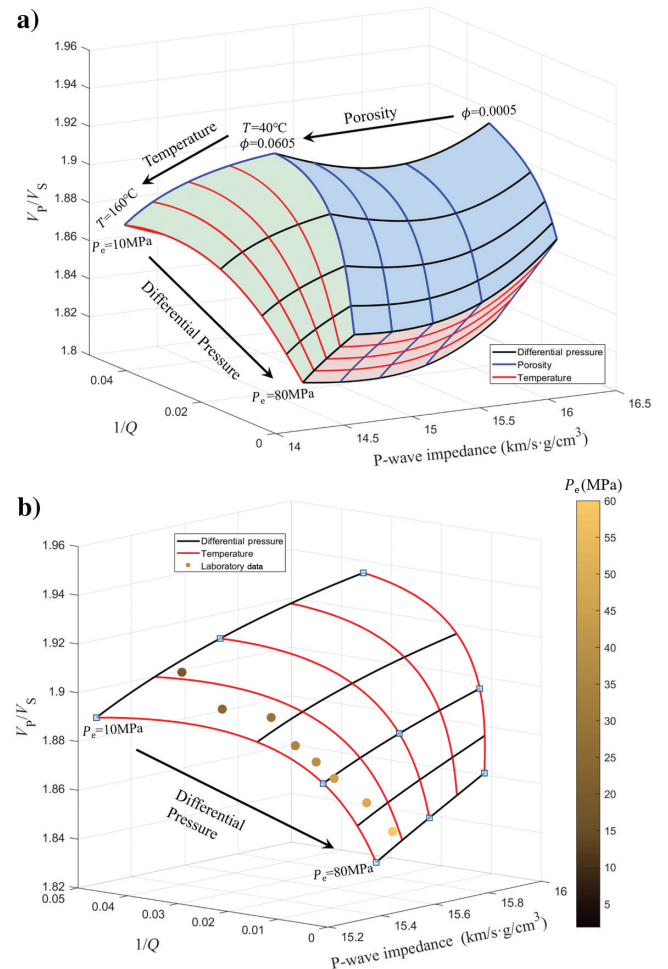
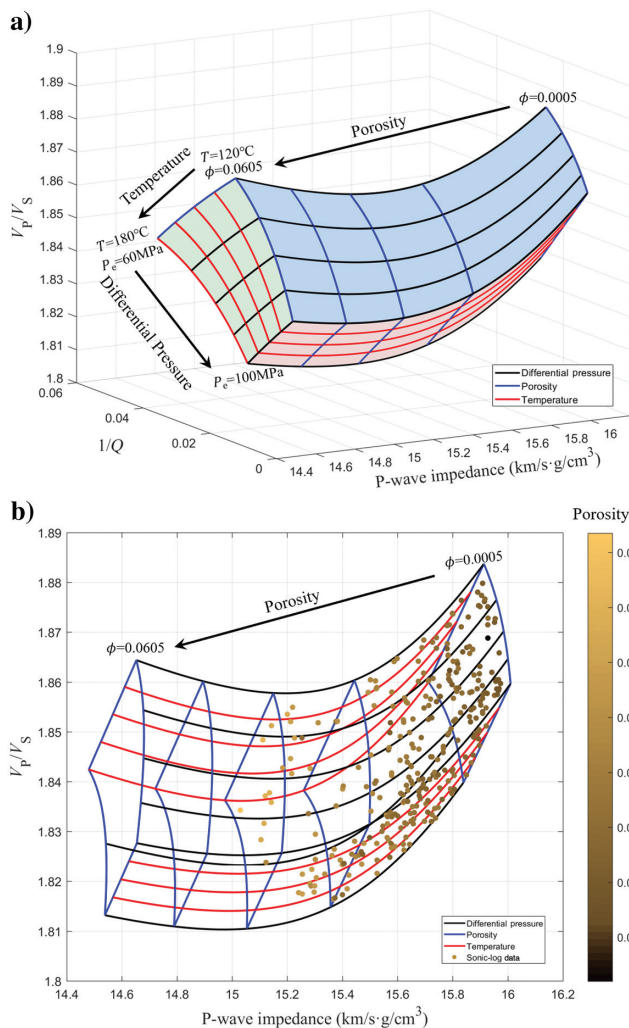Figure 9. (a) The TPP-RPT at ultrasonic frequencies and (b) calibrated template with laboratory data (circles). The red and black lines correspond to isolines of temperature and differential pressure, respectively. The blue lines in (a) indicate isolines of porosity. The color bar indicates the differential pressure of the data.

and C are 49.72, 90.26, and 50.31 tons per day, respectively. We can see that seismic attenuation decreases from well B to well A to well C, which is consistent with the reported values; i.e., high attenuation correlates with high oil production.

Prediction

The seismic data are superimposed on the template to predict the TPP properties, to obtain the distribution range of temperature, pressure, and porosity. The data symbols that lie outside the boundaries of the template do not correspond to typical carbonate rocks and are considered to be nonreservoir data (Ba et al., 2013). Figure 14 shows the TPP properties predicted by the template, showing that the temperature range is [125, 190]°C, the differential pressure range is [60, 100] MPa, and the porosity is less than 0.06. Compared with wells A and C, the more productive well B has the highest temperature and porosity and the lowest differential pressure. The predicted porosity at well B is in good agreement with the sonic

a)

b)

Figure 10. (a) The TPP-RPT at sonic frequencies and (b) calibrated template with sonic-log data (circles). The red, black, and blue lines correspond to isolines of temperature, differential pressure, and porosity, respectively. The color bar indicates the porosity of the data.
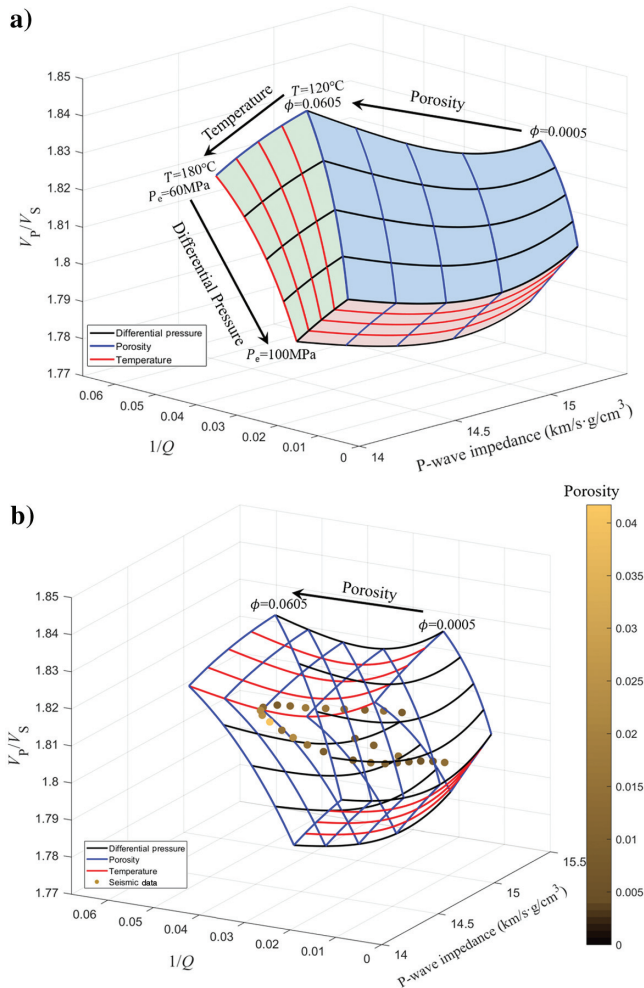

a)

b)

Figure 11. (a) The TPP-RPT at seismic frequencies and (b) calibrated template with the seismic data (circles). The red, black, and blue lines correspond to isolines of temperature, differential pressure, and porosity, respectively. The color bar indicates the porosity of the data.
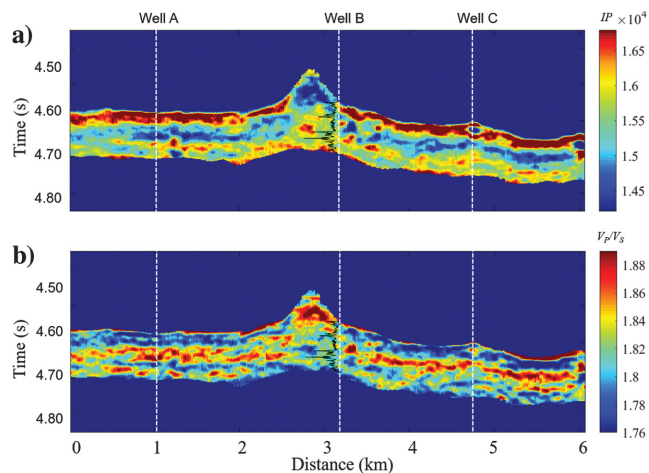

Figure 12. (a) The P-wave impedance and (b) V_P/V_S ratio profiles of the survey line crossing three wells (A, B, and C). The black line indicates the porosity of the log data at well B.

porosity (the black line in Figure 14c). Figure 15 shows the predicted porosity (the red line) and the log porosity (the black line). As can be appreciated, the trend is similar, which illustrates the reliability of the estimation process.

Prediction of pore pressure

The pore pressure P_P can be obtained from the principle of effective stress (Terzaghi, 1943),
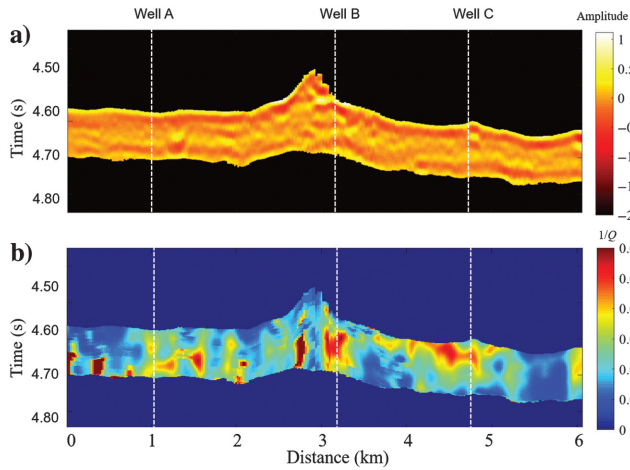
$$P_p = P_0 - P_e, \tag{13}$$

Figure 13. (a) Poststack seismic section and (b) seismic attenuation profiles of the survey line crossing three wells (A, B, and C).
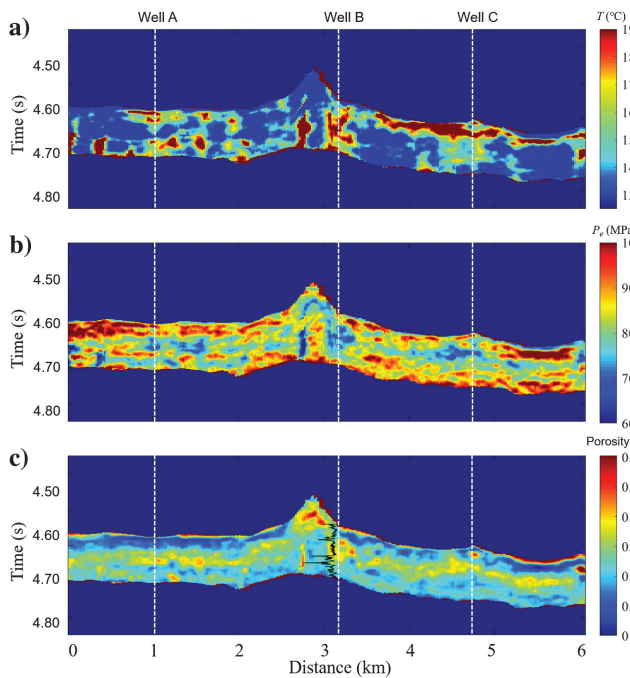
Figure 14. (a) Temperature, (b) differential pressure, and (c) porosity profiles of the survey line crossing three wells (A, B, and C). The black line indicates the porosity of the log data at well B.

where P_0 and P_e are the confining and differential pressures, respectively. The confining pressure can be estimated by integrating the density log with depth (Carcione et al., 2003):

$$P_0 = \int_0^z \rho_z g d_z, \tag{14}$$

where ρ_z is the density of the overburden at depth Z and g is the gravity constant.

Figure 16a and 16b shows the density and pore-pressure profiles of the seismic line crossing wells A, B, and C, respectively.

Areal prediction

Figure 17 shows an areal prediction with a surface of 56.25 km^2. Well B has the highest temperature and porosity and the lowest differential pressure, whereas well A has the opposite situation. The inversion results are consistent with the actual oil productions,
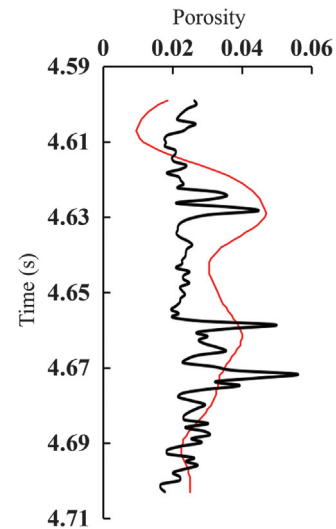

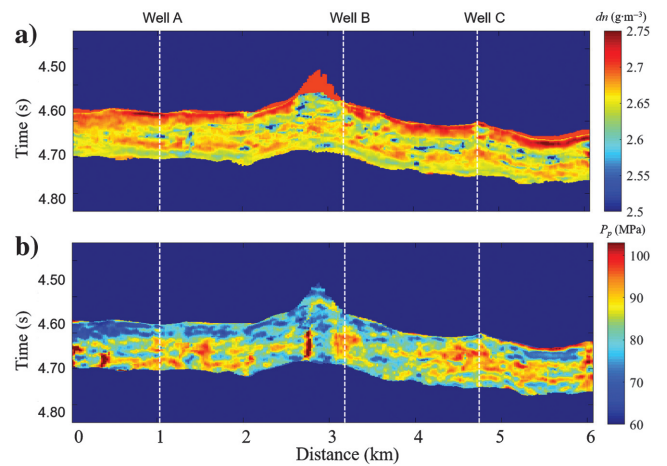Figure 15. Predicted porosity (the red line) and log porosity (the black line).

Figure 16. (a) Density and (b) pore pressure profiles of the survey line crossing three wells (A, B, and C).

and we have shown that the TPP properties can be estimated with confidence.

DISCUSSION

The ultradeep Ordovician carbonate reservoirs in the S area of the Tarim Basin have complex TPP conditions and formation properties, and a proper exploitation of their hydrocarbon resources requires a quantitative estimation.
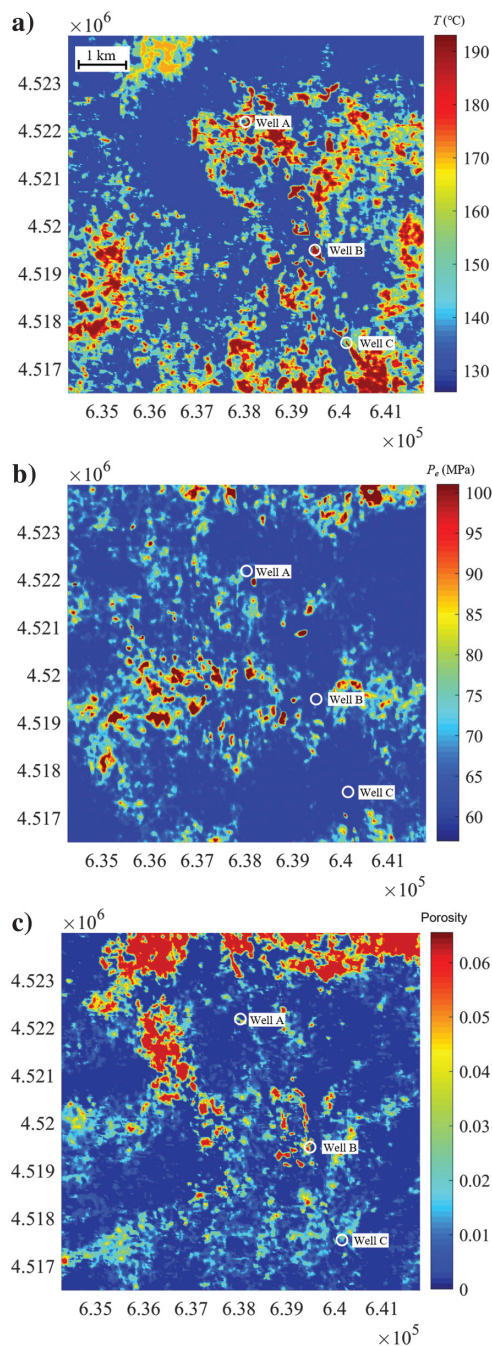

Figure 17. Areal prediction of (a) temperature, (b) differential pressure, and (c) porosity. The areal covers 56.25 km², and the scale is given.

The temperature prediction in this work is somewhat uncertain because there is no well data to validate the results. The temperature range at 7 km in Liu et al. (2020) is 136°C–198°C for an area of approximately 35,000 km², whereas in this work, we have 125°C–190°C on 56.25 km², i.e., three orders of magnitude smaller than that of Liu et al. (2020), but the temperatures are similar. Liu et al. (2020) calculate the temperatures at depth based on assumptions about the thermal conductivity and shallow data, although with low resolution. On the contrary, we use higher resolution geophysical data, i.e., seismic data (wave velocity and attenuation), which reflect changes in the reservoir properties and lithology on a smaller scale. Uncertainties in the modeling process, seismic and instrumental noise, and multiple solutions of the inversion may lead to an apparent higher resolution, but the main trend should be reasonable, at least on an average basis.

As indicated by Davies and Smith (2006), hydrothermal dolomitization occurs under burial conditions of elevated temperature and pressure in the presence of fluids, whose temperature exceeds that of the host minerals (typically limestone) (Davies and Smith, 2006). Because the effect of temperature is assumed to be mainly caused by the fluid, the method provides higher values where fluids are present. Even if the porosity is relatively low, the reservoir has a good pore connectivity and this is the reason for patches of high temperature. Regions with poor connectivity show lower temperatures.

The attenuation-estimation error is a well-known problem in geophysical inversion, which, in this case, affects the temperature prediction. However, despite the uncertainties, the utility of well data to validate and calibrate the results is confirmed by the fact that the predictions are consistent with the actual oil production reports.

Further research is required to verify the heat-flow trends and temperature fields via numerical simulations and to collect relevant ultradeep reservoir temperature well data to constrain and validate the temperature field.

CONCLUSION

We have developed a TPP rock-physics model to interpret ultradeep carbonate reservoirs, based on the Biot-Rayleigh theory. The model predicts the expected behavior of P-wave velocity and attenuation as a function of the above quantities, e.g., velocity and attenuation increase and decrease with differential pressure, and the effects of temperature are the opposite. Temperature has a significant effect on attenuation and differential pressure on V_P/V_S ratio, whereas porosity affects P-wave impedance. The V_P/V_S ratio first decreases and then increases with the increasing porosity.

Then, a multiscale 3D RPT is built, calibrated with laboratory, log, and seismic data to quantitatively obtain temperature, differential pressure, and porosity from seismic data. We consider three production wells of the S area in the Tarim Basin, China. Furthermore, we obtain profiles of the reservoir pore pressure from the differential pressure. We verify that the highest oil production is consistent with high temperature, low differential pressure, high porosity, and high pore pressure.

ACKNOWLEDGMENTS

DATA AND MATERIALS AVAILABILITY

Data associated with this research are available and can be obtained by contacting the corresponding author.

APPENDIX A

SHAPE FACTORS P AND Q

The terms P and Q are the shape factors related to the spheroidal aspect ratio α_{stiff} and the Poisson's ratio v_0 of the grains, given by (David and Zimmerman, 2012; Zhang et al., 2019)

$$P = \frac{(1-v_s)}{6(1-2v_s)}$$
$$\cdot \frac{4(1+v_s)+2\alpha^2(7-2v_s)-[3(1+4v_s)+12\alpha^2(2-v_s)]g}{2\alpha^2+(1-4\alpha^2)g+(\alpha^2-1)(1+v_s)g^2},$$
(A-1)

$$Q = \frac{4(\alpha^2-1)(1-v_s)}{15\{8(v_s-1)+2\alpha^2(3-4v_s)+[(7-8v_s)-4\alpha^2(1-2v_s)]g\}}$$
$$\cdot \left\{ \frac{8(1-v_s)+2\alpha^2(3+4v_s)+[(8v_s-1)-4\alpha^2(5+2v_s)]g+6(\alpha^2-1)(1+v_s)g^2}{2\alpha^2+(1-4\alpha^2)g+(\alpha^2-1)(1+v_s)g^2} \right.$$
$$\left. -3\left[\frac{8(v_s-1)+2\alpha^2(5-4v_s)+[3(1-2v_s)+6\alpha^2(v_s-1)]g}{-2\alpha^2+[(2-v_s)+\alpha^2(1+v_s)]g}\right] \right\},$$
(A-2)

where $v_s = (3K_s - 2G_s)/(6K_s + 2G_s)$ and

$$g = \begin{cases} \frac{\alpha}{(1-\alpha^2)^{3/2}}\left(\arccos\alpha - \alpha\sqrt{1-\alpha^2}\right) & (\alpha < 1) \\ \frac{\alpha}{(1-\alpha^2)^{3/2}}\left(\alpha\sqrt{1-\alpha^2} - \operatorname{arccosh}\alpha\right) & (\alpha > 1) \end{cases}.$$
(A-3)

APPENDIX B

BATZLE AND WANG'S EQUATIONS

According to Batzle and Wang (1992), the density of oil ρ_f is

$$\rho_f = \frac{\rho_0 + (0.00277P - 1.71\times10^{-7}P^3)(\rho_0 - 1.15)^2 + 3.49\times10^{-4}P}{0.972 + 3.81\times10^{-4}(T+17.78)^{1.175}},$$
(B-1)

where ρ_0 is the reference density of petroleum, which is measured at the atmospheric pressure and 15.6°C.

The wave velocity of oil V_f is

$$V_f = 2096\left(\frac{\rho_0}{2.6-\rho_0}\right)^{0.5} - 3.7T + 4.64P$$
$$+ 0.0115[4.12(1.08\rho_0^{-1}-1)^{0.5}-1]TP.$$
(B-2)

The modulus of oil k_f is

$$k_f = \rho_f \cdot V_f^2.$$
(B-3)

The viscosity of oil η_f is

$$\eta_f = (10^\wedge[0.505\times10^{5.693-2.863/\rho_0}\times(17.8+T)^{-1.163}]-1)$$
$$+0.145P\times10^\wedge[18.6\times0.1\lg\eta_0+(\lg\eta_0+2)^{-0.1}-0.985],$$
(B-4)

where η_0 is the viscosity measured at the atmospheric pressure.

APPENDIX C

ATTENUATION, DENSITY, AND STIFFNESS COEFFICIENTS

The dissipation coefficients of the two types of pores are

$$b_i = \frac{\eta\phi_i^2}{\kappa_i}, \quad i = 1, 2.$$
(C-1)

The density components of the dual-pore medium are

$$\rho_{11} = (1-\phi_1-\phi_2)\rho_s + \frac{1}{2}(2-\phi_1-\phi_2)\rho_f,$$
$$\rho_{12} = \frac{1}{2}(\phi_1-1)\rho_f,$$
$$\rho_{13} = \frac{1}{2}(\phi_2-1)\rho_f,$$
$$\rho_{22} = \frac{1}{2}(\phi_1+1)\rho_f,$$
$$\rho_{33} = \frac{1}{2}(\phi_2+1)\rho_f,$$
(C-2)

where ρ_s and ρ_f are the grain and fluid densities, respectively.

The stiffness coefficients are

$$\beta = \frac{\zeta^{(1)}}{\zeta^{(2)}},$$
$$N = G_b,$$
$$Q_1 = \frac{\beta(1-\phi_1-\phi_2-K_b/K_s)\phi_1 K_s}{\beta(1-\phi_1-\phi_2-K_b/K_s)+K_s/K_f(\beta\phi_1+\phi_2)},$$
$$Q_2 = \frac{(1-\phi_1-\phi_2-K_b/K_s)\phi_2 K_s}{1-\phi_1-\phi_2-K_b/K_s+K_s/K_f(\beta\phi_1+\phi_2)},$$
$$R_1 = \frac{(\beta\phi_1+\phi_2)\phi_1 K_s}{\beta(1-\phi_1-\phi_2-K_b/K_s)+K_s/K_f(\beta\phi_1+\phi_2)},$$
$$R_2 = \frac{(\beta\phi_1+\phi_2)\phi_2 K_s}{1-\phi_1-\phi_2-K_b/K_s+K_s/K_f(\beta\phi_1+\phi_2)},$$
$$A = (1-\phi)K_s - \frac{2}{3}N - (Q_1+Q_2)K_s/K_f,$$
(C-3)

where K_s and K_f are the grain and fluid bulk moduli, respectively. The dry-rock modulus K_b and G_b can be obtained from the equivalent moduli K_{eff} and G_{eff} of the effective-medium theory.

APPENDIX D

DISPERSION EQUATION

Substituting a plane P-wave kernel $e^{i(\omega t - k \cdot \mathbf{x})}$ into equation 11 yields

$$\begin{vmatrix} a_{11}k^2 + b_{11} & a_{12}k^2 + b_{12} & a_{13}k^2 + b_{13} \\ a_{21}k^2 + b_{21} & a_{22}k^2 + b_{22} & a_{23}k^2 + b_{23} \\ a_{31}k^2 + b_{31} & a_{32}k^2 + b_{32} & a_{33}k^2 + b_{33} \end{vmatrix} = 0, \quad \text{(D-1)}$$

where ω is the angular frequency and k is the complex wavenumber. Moreover,

$$a_{11} = A + 2N + i(Q_2\phi_1 - Q_1\phi_2)x_1, \quad b_{11} = -\rho_{11}\omega^2 + i\omega(b_1 + b_2),$$

$$a_{12} = Q_1 + i(Q_2\phi_1 - Q_1\phi_2)x_1, \quad b_{12} = -\rho_{12}\omega^2 - i\omega b_1,$$

$$a_{13} = Q_2 + i(Q_2\phi_1 - Q_1\phi_2)x_3, \quad b_{13} = -\rho_{13}\omega^2 - i\omega b_2,$$

$$a_{21} = Q_1 - iR_1\phi_2 x_1, \quad b_{21} = -\rho_{12}\omega^2 - i\omega b_1,$$

$$a_{22} = R_1 - iR_1\phi_2 x_2, \quad b_{22} = -\rho_{22}\omega^2 + i\omega b_1,$$

$$a_{23} = -iR_1\phi_2 x_3, \quad b_{23} = 0,$$

$$a_{31} = Q_2 + iR_2\phi_1 x_1, \quad b_{31} = -\rho_{13}\omega^2 - i\omega b_2,$$

$$a_{32} = iR_2\phi_1 x_2, \quad b_{32} = 0,$$

$$a_{33} = R_2 + iR_2\phi_1 x_3, \quad b_{33} = -\rho_{33}\omega^2 + i\omega b_2, \quad \text{(D-2)}$$

where

$$x_1 = i(\phi_2 Q_1 - \phi_1 Q_2)/Z, \quad x_2 = i\phi_2 R_1/Z, \quad x_3 = -i\phi_1 R_2/Z,$$

$$Z = \frac{i\omega\eta\phi_1^2\phi_2\phi_{20}R_0^2}{3\kappa_{10}} - \frac{\rho_f\omega^2 R_0^2\phi_1^2\phi_2\phi_{20}}{3\phi_{10}} - (\phi_2^2 R_1 + \phi_1^2 R_2). \quad \text{(D-3)}$$

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Biographies and photographs of the authors are not available.