Fluid Substitution Model to Generate Synthetic Seismic Attributes: `FluidSub.exe`

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Geostatistical data integration is a mature research field and many of algorithms have been developed in petroleum reservoir modeling. Seismic data and its derived attributes are widely used secondary variables. The selected data integration algorithm must be tested and evaluated using control data before applying with real data. However, it is not easy to acquire real seismic data and its derived attributes such as acoustic impedance and seismic velocity. One can generate primary data, e.g., porosity by unconditional simulation, and then generate acoustic impedance being negative correlated to the simulated porosity. This is a purely statistical generation of secondary variable with no physical relation. This short note is for introducing fluid substitution model to provide synthetic seismic attributes based on physical model. Gassmann equation is a representative fluid substitution model and it provides P-wave velocity, acoustic impedance and seismic trace given porosity, fluid saturation and rock type. Synthetic data generation program `fluidsub.exe` *is provided as well.*

Introduction

Secondary data integration has been an active area in modern petroleum reservoir modeling. Well data is a direct measurement on petrophysical properties, however, it is collected sparsely in horizontal direction. Secondary data is an indirect measurement, but it contains reservoir property information with lateral continuity in most petroleum applications. Seismic attributes such as amplitude, acoustic impedance and P-/S-wave velocity or their ratio, are widely used secondary variables in reservoir modeling. Incorporation of primary and secondary data is able to provide plausible reservoir modeling with less uncertainty.

Many geostatistical techniques have been developed to integrate seismic secondary data. They are needed to be evaluated using test data before applying in the field. Access to a real seismic data, however, is difficult in case of attempting to test new methodology. Besides, real data does not allow users to test several data conditions, e.g., different level of noise and data correlation between primary and secondary.

Controlled or synthetic data might be a good test example before applying to real case. One can evaluate his/her proposed algorithm and perform sensitivity analysis using synthetic data. In this note, we introduced process and small program to generate seismic attributes which is based on well-known physical model. Gassmann's fluid substitution model is adopted as a physical model. The Gassmann fluid substitution model requires porosity, fluids saturation, fraction of shale as input parameters, then P-wave velocity, P-wave impedance, seismic traces are generated as output seismic attributes. Figure-1 schematically illustrates the process of testing data integration algorithm using synthetic data.

Gassmann's Fluid Substitution Equation

Fluid substitution is an important part of the rock physics, which provides a way to identify fluid saturated rock. The Gassmann equation is a widely used model as fluid substitution. Elastic rock properties change with porosity, fluid type and saturation, rock mineral fraction change. Gassmann equation generates seismic responses based on changed elastic rock properties resulting from various reservoir rock conditions. The Gassmann theory allows us to calculate P-wave velocity

$$V_P = \sqrt{\frac{1000 m_{sat}}{\rho_{sat}}} \quad \text{in m/sec} \tag{1}$$

Density of the porous fluid saturated rock obeys the mixing law:

$$\rho_{sat} = \rho_m (1-\phi) + \rho_f \phi \tag{2}$$

where the quantities are:

ϕ porosity in fraction

ρ_m pure mineral density in g/cc

ρ_f pore fluid mixture density in g/cc

Provided that different types of fluids are saturated density of fluid mixture can be obtained by combining fluid saturation fraction and fluid density such as,

$$\rho_f = So\rho_o + Sw\rho_w + Sg\rho_g \tag{3}$$

where So, Sw and Sg are fractional fluid saturation of oil, water and gas. m_{sat} is a P-wave bulk modulus of fluid saturated rock, which is obtained by:

$$m_{sat} = m_m \frac{m_d + Q}{m_m + Q} \quad \text{in mPa} \tag{4}$$

where, m_m is P-wave modulus of rock forming mineral (possibly mixture of different minerals) in mPa. m_m is derived from pure mineral bulk modulus (in mPa) and shear modulus (in mPa)

$$m_m = K_m + \frac{4}{3}\mu_m \quad \text{in mPa} \tag{5}$$

where,

K_m pure mineral bulk modulus in mPa

μ_m pure mineral shear modulus in mPa

There is rare case where single rock forming mineral is dominant over the reservoir. More than two rock minerals are mixed. For example sandstone is often inter-layered with shale and main mineral components of sandstone and shale are quartz and clay, respective. Of course, two rock minerals have different elastic properties resulting in different modulus. Thus, mineral bulk and shear modulus are derived from inverse proportion of pure mineral modulus K_{m1} and K_{m2},

$$K_m = \left(\frac{C_{m1}}{K_{m1}} + \frac{1 - C_{m1}}{K_{m2}} \right)^{-1} \quad \text{in mPa} \tag{6-a}$$

$$\mu_m = \left(\frac{C_{m1}}{\mu_{m1}} + \frac{1 - C_{m1}}{\mu_{m2}} \right)^{-1} \quad \text{in mPa} \tag{6-b}$$

where C_{m1} and C_{m2} are fraction of mineral 1 and 2.

m_d in equation (4) is bulk modulus of dry porous rock frame and it is estimated in terms of mineral modulus and porosity as following,

$$m_d \approx m_m (a + b\phi^c) \tag{7}$$

User input parameters a, b and c are free parameters to adjust the relation between m_d and m_m. It can be obtained by lab experiments.

Q term in equation (4) is related to fluid bulk modulus, which is derived by,

$$Q = \frac{K_f (m_m - m_d)}{\phi(m_m - K_f)} \tag{8}$$

K_f is pore fluid mixture bulk modulus in mPa. Multiple types of fluids are saturated then K_f is weighted sum by fluid bulk modulus and its fractional saturation.

$$\frac{1}{K_f} = \frac{S_o}{K_o} + \frac{S_w}{K_w} + \frac{S_g}{K_g} \tag{9}$$

There is no doubt physical parameters of fluids and minerals depend on reservoir conditions. For example, density of oil is affected by reservoir temperature, pressure, oil gravity (°API) and gas specific gravity. Density of water depends on temperature, pressure and salinity. Those parameters are currently hard-coded in the source code; however, one can use the reservoir temperature, pressure, salinity, oil and gas specific gravity as input parameters in `fluidsub.exe` program.

Workflow

Given information:

1. Reservoir pressure, temperature, salinity, oil and gas specific gravity (hard coded in the program)
2. Mineral bulk modulus in mPa (K_m)
3. Mineral shear modulus in mPa (μ_m)
4. Mineral density in g/cc (ρ_m)
5. Fluid bulk modulus in mPa (K_o,K_w,K_g)
6. Fractional fluid saturation (S_o,S_w,S_g)
7. Fluid density in g/cc (ρ_o, ρ_w, ρ_g)
8. Fractional porosity
9. Calibration parameters (a,b,c)

Calculate:

1. Pore fluid mixture density (ρ_f) using equation (3)
2. Saturated rock density (ρ_{sat}) using equation (2)
3. P-wave modulus of rock forming mineral (m_m) using equation (5)
4. Bulk modulus of dry porous rock frame (m_d) using equation (7)
5. Pore fluid mixture bulk modulus (K_f) using equation (9)
6. Q term using equation (8)
7. Bulk modulus of fluid saturated rock (m_{sat}) using equation (4)
8. P-wave velocity using equation (1)
9. P-wave acoustic impedance by V_p (step 8) × ρ_{sat} (step 2)

Final resulting seismic attributes are P-wave velocity and acoustic impedance. To generate seismic trace, acoustic impedance should be convolved with pre-defined wavelet function like as Ricker wavelet. This convolution process is not implemented in fluidsub.exe program. Given mineral bulk and shear modulus depends on the reservoir rock type. Quartz mineral is dominant in sandstone reservoir. Clay mineral is abundant in shaly reservoir. Quartz and clay minerals are interblended between clean sand and shaly reservoir. `fluidsub.exe` program considers the reservoir between sand and shaly reservoir depending on the fraction of vshale. Thus, pure bulk modulus of quart (clean sand) and clay mineral (shale) are used to calculate equation (6)-a and (6)-b depending on vshale fraction. In equation (6)-a and (6)-b, subscript m_1 and m_2 are illite and quartz mineral, respectively. Illite was chosen as dominant clay mineral in shaly rock. Hard coded mineral modulus and mineral densities are following:

	K_m in mPa	μ_m in mPa	ρ_m in g/cc
Quartz	37900	44300	2.65
Illite	76800	32000	2.71

Figure-2 shows the parameter file to `fluidsub.exe` program. Porosity, vshale and fluid saturation are input files (line 5 – line 7). Line 12 implements the controlled noise level. Gaussian random noise will be added in the resulting seismic attributes unless this value is set as 0.

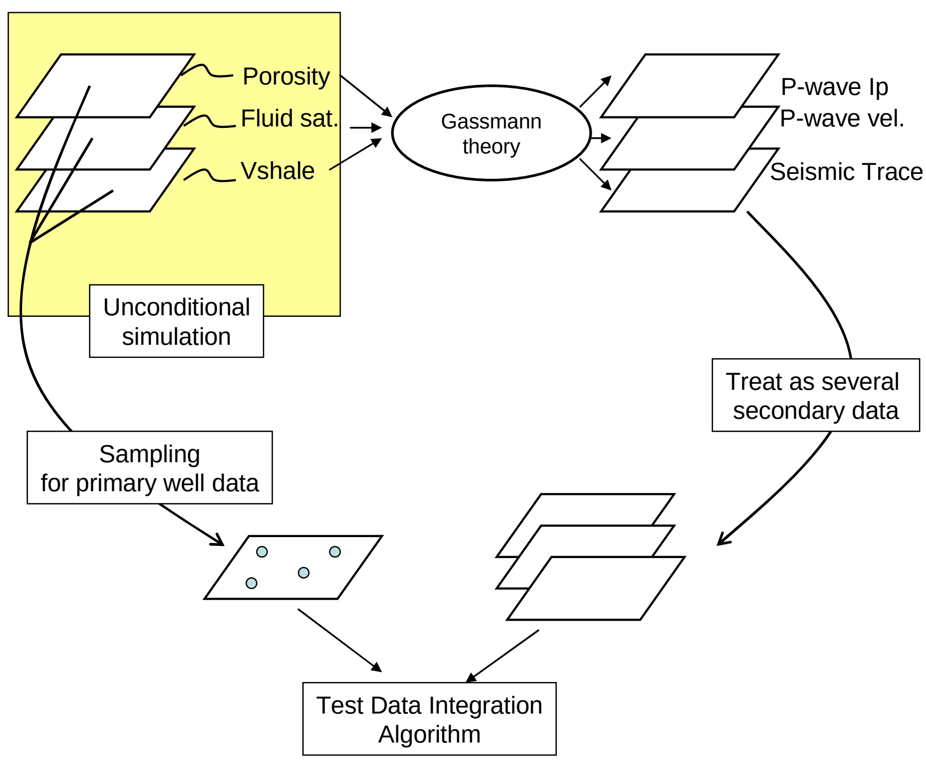

Figure-1: The process of testing data integration algorithm using synthetic seismic data generated by physical model

```
                Parameters for fluidsub.exe
                ******************************

START OF PARAMETERS:
porosity.out            - Porosity in [0,1]
vshale .out             - Vshale in [0,1]
saturation.out          - Fluid saturations of Oil/Water in [0,1]
50    0.5   1.0         - nx  minx  xsize
50    0.5   1.0         - ny  miny  ysize
50    0.5   1.0         - nz  minz  zsize
0.5                     - Additive Gaussian noise level
seis.out                - Output seismic attributes
```

Figure-2: Parameter file for the `fluidsub.exe` program

Numerical Results

Porosity, water saturation and vshale data were generated by 50×50×50 grids. Correlation among input variables are shown Figure-3. It is noted that correlation between porosity and clay, and porosity and water saturation is negative. Water saturation is positively correlated to vshale. P-wave velocity and P-wave impedance were produced using the input variables and parameters (without additive random noise). Figure-4 illustrates the input variables and resulting P-wave impedance. 50 vertical grids were averaged to create 2-D map. It should be physically ensured that correlation between P-wave velocity and porosity, porosity and impedance. In rock physics, P-wave velocity is positively correlated with porosity and impedance is negatively correlated with porosity. Figure-5 shows the correlation between input porosity and seismic attributes. They have clear negative correlation due to no interrupting by random noise.

Conclusions

Fluid substitution model is considered to generate synthetic seismic attribute based on physical model. Gassmann equation was implemented in `fluidsub.exe` program. As input variables, porosity, fluid saturation and vshale data (previously prepared by simulation or kriging) are used in the program. Resulting seismic attributes are seismic wave velocity (P-wave), acoustic impedance and seismic trace. Random noise can be added with user defined noise level.

References

Liner, C. L., 2004, Elements of 3D Seismology, PennWell, Tulsa, Oklahoma.

Mavko, G., Mukerji, T. and Dvorkin, J., 1998, Rock Physics Handbook, Cambridge University Press.

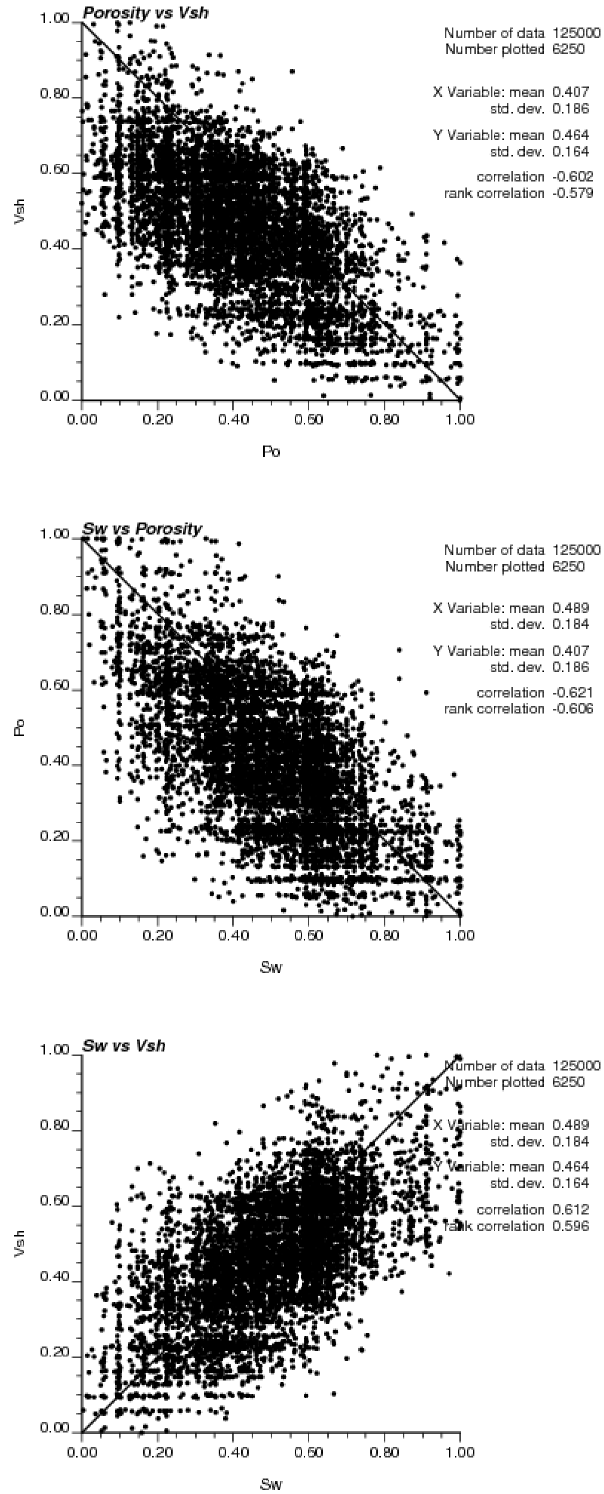

Figure-3: Correlation between input variables (Porosity, water saturation, vshale fraction)

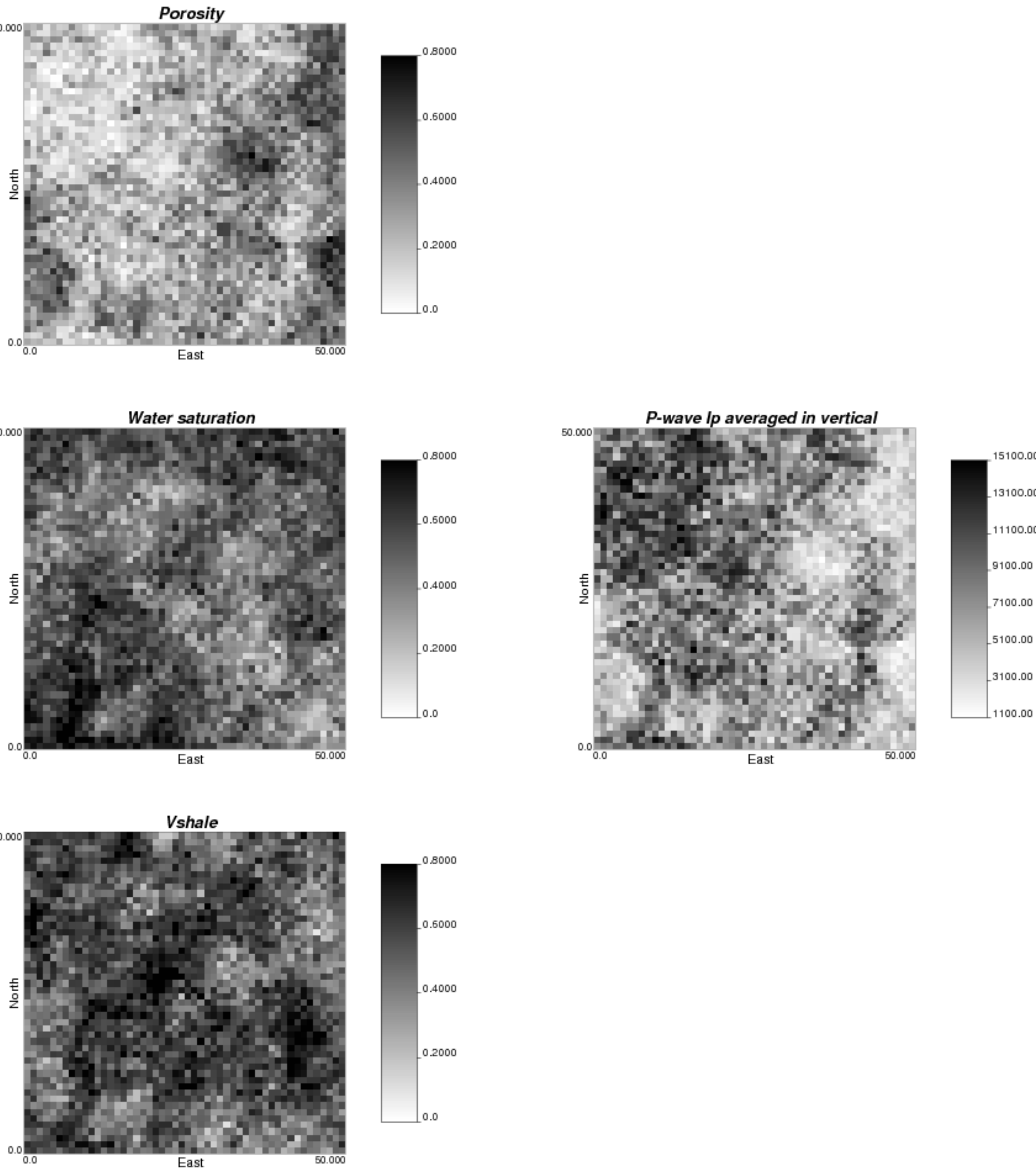

Figure-4: Input variables and resulting seismic attribute. Vertically averaged P-wave impedance is shown in the right.

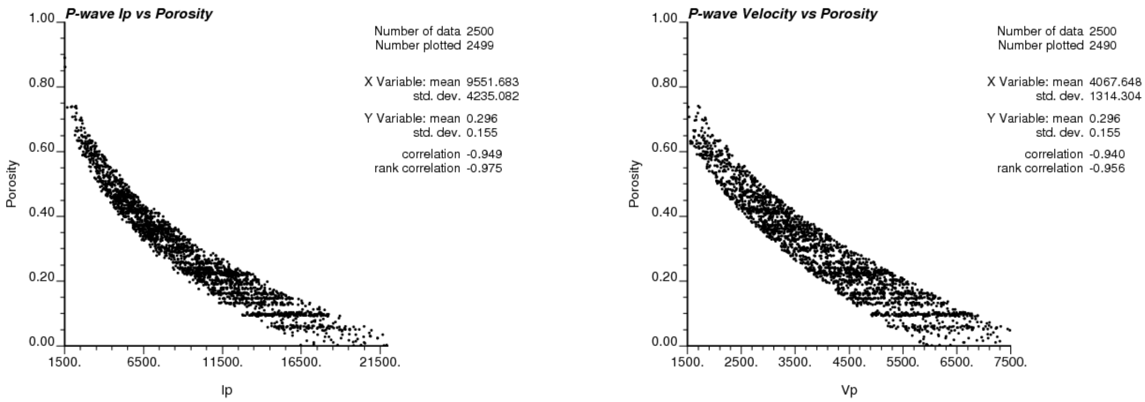

Figure-5: Correlation between seismic attributes and porosity