Are we able to estimate the subsurface elastic properties quantitatively?

Expert Answer – 2 by Miguel Eduardo Bosch Blumenfeld*

INTRODUCTION

Before we delve into this intriguing question, it's important to consider the different contexts in which it emerges. The initial scenario is in laboratory settings, where rock samples from subsurface formations are analyzed, typically at a centimeter scale. Elastic properties are determined by the elastic tensor within the mechanical theory of continuum media, which includes 21 independent elastic constants. For simplicity, mass density can be counted among these constants, as it is relevant for reservoir characterization and for understanding mechanical wave phenomena such as seismic waves, which are vital in exploration. Generally, this results in a total of 22 parameters, referred to as 'elastic parameters.' Each of these parameters can be measured in the laboratory. Therefore, in this setting, we can indeed estimate the elastic properties of a rock sample with significant uncertainties through various laboratory tests. Since rocks are heterogeneous, these estimations will differ across samples from different locations and even within the same sample at different scales.

We now consider the scenario of subsurface resource exploration, aimed at identifying and developing reservoirs containing oil, gas, water, or those used for CO_2 sequestration, mining, or geothermal applications. Geophysicists have devised a multitude of technologies to measure the elastic properties of the subsurface medium, employing sensors on the Earth's surface, underwater, or in boreholes. This discussion will examine the potential of these methods to estimate underground properties. Specifically, it will address whether our existing geophysical technologies can determine these properties with enough accuracy and precision to aid decision-making in engineering processes for resource production and management.

Transitioning from laboratory to field settings poses significant challenges due to the spatial dimensionality required for estimation. For our objectives, we seek to map these properties in three dimensions at the necessary spatial resolution. This necessitates complex sensor arrays and mathematical models to identify the properties at specific locations or within a 3D grid. Given the complete elastic tensor and mass density, the answer to our general question is negative. Present geophysical methods are neither equipped nor designed to estimate the 22 elastic rock parameters concurrently.

ISOTROPY VERSUS ANISOTROPY

Fortunately, the origin of Earth's subsurface rocks means that within the spatial resolution achievable by geophysical estimation methods, it's not necessary to estimate the full elastic tensor, which has 21 components. Rocks that form as random mixtures of grains show elastic behavior that is independent of sample orientation. Sedimentary, metamorphic, and igneous rocks are, to a good first approximation, isotropic, exhibiting isotropic elasticity; the elastic tensor thus has only two degrees of freedom, depending on just two elastic parameters. Including mass density, only three parameters are needed to characterize isotropic elastic rocks. Some Earth processes introduce weak anisotropic effects in rocks, typically axisymmetric anisotropy, with examples including the gradual deposition of fine grains, compaction, stratification, and fractures. The weak anisotropic elastic tensor, as described by Leon Thomsen, involves the two isotropic parameters mentioned before, plus three for weak anisotropy, and two describing the orientation of the axis of symmetry, along with mass density, making a total of eight parameters to describe subsurface media within the weak anisotropic framework. Isotropic and weak anisotropic models are the two models currently used in practical applications. Higher degrees of anisotropy are observed in geological processes when multiple axisymmetric anisotropic processes overlap over geological time.

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ELASTIC PARAMETERS FROM SEISMIC DATA

Seismic surveys are the primary source for estimating the elastic properties of the subsurface to a depth of a few kilometers. Mapping strata via seismic imaging, which uses reflectivity, is a key application. Three main methods are typically used to estimate elastic properties from seismic data: (1) seismic tomography, using travel times to estimate velocities, (2) reflection seismic inversion, using pre-stack reflection amplitudes, and (3) elastic full waveform inversion, utilizing the complete seismic record.

Seismic tomography and acoustic full waveform inversion offer reliable, albeit low-resolution, estimates of the seismic velocity field, a crucial elastic parameter for seismic processing and inversion. However, this parameter alone cannot provide a joint estimation of elastic parameters and mass density. Elastic seismic inversion, whether it employs reflection amplitudes or the full waveform, is vital for this joint estimation. In the realm of isotropic elasticity, from both theoretical and practical perspectives, the answer to the posed question is strongly in the affirmative. Elastic seismic inversion can indeed determine the isotropic elastic parameters of the media, comprising three parameters: two for elasticity and one for mass density. This is feasible because reflection coefficients can separate the effects of these three parameters in the incidence angle domain. Nonetheless, the accuracy of this estimation is contingent on various factors, including the quality of the seismic survey and the subsurface structure, with the incidence angle range being one of these factors.

The selection of elastic parameters, typically determined through seismic inversion, is flexible, allowing for a variety of potential combinations. Commonly chosen parameter sets, which include density, are (V_P, V_S, and density) and (Z_P, Z_S, and density), where V_P and V_S are the compressional and shear seismic velocities, and Z_P and Z_S are acoustic and shear impedances, respectively. I prefer the first set, as it tends to provide an optimal joint resolution of the parameters. Nonetheless, poor seismic data quality and the lack of wide incidence angles can introduce uncertainty in the joint estimation process. To mitigate this, incorporating additional statistical data about the interrelationship of the parameters can enhance the quality of elastic inversion. Employing a covariance matrix, derived experimentally from well logs within the same or a similar area, is advantageous as it leverages local data and statistics. Alternatively, more rudimentary methods, such as inferring density from velocity (for instance, using Gardner's equation) or presuming a uniform or constant density, could introduce bias. Since density plays a pivotal role in determining fluid and lithology properties, I advise against these simplifications due to their potential to compromise estimation precision.

The role of elastic reflection seismic inversion in characterizing oil and gas reservoirs is well recognized, making it a standard tool for outlining prospects, developing field plans, and assessing exploration risks. Elastic full waveform inversion follows similar principles for estimating isotropic elastic properties, as shown by the angularly independent radiation patterns from variations in elastic parameters. This method promises greater accuracy in property estimation by accounting for the entire wavefield phenomena, including reflections, multiples, diffractions, and refractions, not just primary reflections. Despite its potential, elastic full waveform inversion is not yet fully adopted for reservoir characterization due to significant computational requirements. I believe we are approaching a pivotal moment where elastic full waveform inversion may soon become the leading technique for seismic data analysis. Indeed, the technology affirms a definitive yes to our query.

While the estimation of isotropic elastic parameters from seismic data, including mass density, has proven successful, determining weak anisotropy parameters still poses a significant challenge with existing techniques. Various geophysical methods, such as tomography and inversion, offer valuable insights into seismic velocity variations along the vertical axis and azimuth angle. Azimuthal variations, linked to pseudo-vertical faulting, assist in estimating the orientation and intensity of fracture systems. In contrast, velocity variations with inclination relate to stratification, enhancing velocity models for seismic imaging via migration. Furthermore, reflection coefficients exhibit variations in azimuth and inclination due to weak anisotropic parameters. Nonetheless, developing a robust inversion methodology for the joint and reliable estimation of weak elastic parameters, (eight parameters, including mass density), remains a technical challenge, with ongoing research in this field.

WELL-LOGS AND INTEGRATED ESTIMATION OF THE ELASTIC PARAMETERS

Well logging serves as an additional method for estimating the isotropic elastic parameters and mass density, characterizing rocks near the borehole. Our response remains positive: we can indeed quantitatively estimate elastic properties along boreholes. These estimations offer higher vertical resolution compared to seismic estimates but are limited spatially to the borehole trajectory. However, due to one-dimensional sampling limitations (along the well path), well logging cannot fully estimate weak anisotropic parameters, but it can estimate azimuthal velocity variations relative to the well axis. Estimation of elastic parameters from well logs is crucial for calibrating seismic inversion and rock physics models.

Enhanced accuracy in elastic parameter estimation is achieved by integrating all available data through a skilled combination of independent analyses, joint inversion, or other intelligent methodologies. For instance, geostatistical seismic inversion effectively combines log and seismic data to estimate elastic parameters, improving vertical resolution within the vicinity of the wells.

CONCLUSION

In summary, current geophysical methods enable the quantitative determination of subsurface isotropic elastic parameters with the necessary certainty for significant contributions to decision-making in resource reservoir exploration and development. Emerging methods such as elastic full waveform inversion and integrated seismic inversion show strong potential for further improving the accuracy and precision of these determinations. Moreover, seismic data analysis reliably estimates velocity variations with azimuth and vertically. Nonetheless, accurately estimating weak anisotropic elastic parameters continues to be a challenge and a focus of ongoing research.

Miguel Bosch is renowned in geophysical inversion, specializing in advanced seismic inversion techniques and data integration within intricate reservoir models. He has tackled inference issues across various scales of the earth. In oil and gas reservoir delineation, he innovates services and technology for the sector's upstream segment. Miguel has overseen numerous projects in seismic inversion, reservoir characterization, and integration, and has pioneered sophisticated technology and software in these domains. His latest research focuses on Full Waveform Inversion and constructing quantitative knowledge networks for data amalgamation. He earned his Ph.D. in geophysics from the Institut de Physique du Globe de Paris, under the mentorship of Albert Tarantola, and served as a full professor and head of the Applied Physics Department at the Universidad Central de Venezuela. He is an active member of the SEG, AGU, EAGE, IAMG, AAPG, and GSH, and serves as an associate editor for reservoir geophysics in the journal GEOPHYSICS. Currently, he is the Founder and CEO of Info Geosciences Technology and Services in Houston.