

Introduction

A commercial hydrocarbon pool can be defined as a closed body of hydrocarbon-bearing rocks in which porosity, hydrocarbon saturation, recoverable reserves, and production rate simultaneously exceed economic cut-off values, making future drilling and production commercially viable. Reliable identification of such pools prior to drilling requires an accurate subsurface model describing both the geometry of geological boundaries and the spatial distribution of reservoir properties. In practice, construction of such models relies on solving geophysical inverse problems using gravity, seismic, well-log, and other geological and geophysical data. Despite significant advances in exploration geophysics, the global efficiency of hydrocarbon exploration remains moderate, and the discovery rate of large new fields has shown limited growth in recent decades. One of the main reasons is the theoretical non-uniqueness of geophysical inverse problems, where multiple subsurface models can produce identical observed geophysical fields. Conventional inversion methods attempt to stabilize the solution by applying Tikhonov regularization and smoothing constraints (Tikhonov & Arsenin, 1977). However, such approaches typically lead to solutions that are mathematically unique but not necessarily geologically meaningful. In gravity inversion, the mathematically unique solution corresponds to harmonic functions whose extrema occur only at model boundaries, preventing the formation of internally closed density anomalies. As a result, regularized solutions often represent a compromise between a mathematically stable harmonic function and a predefined geological model that acts as a stabilizing prior.

This study presents a new approach for quantitative mapping of commercial hydrocarbon pools and estimation of their total reserves, recoverable reserves, and expected production rate. The methodology is based on geologically meaningful, regularization-free joint 3D inversion of gravity, well-log, seismic, and other geological–geophysical data.

Main theoretical and technological features of proposed approach

The proposed approach restricts the inversion solution space to a geologically meaningful subspace of density models. This subspace includes only those geological models that are consistent with known structural boundaries, stratigraphic relationships, lithological constraints, and physical limitations governing geological formation processes. Within this subspace, each observed gravity field corresponds to a single physically meaningful density model, establishing a one-to-one relationship between the geological model and the observed gravity field. This formulation eliminates the need for artificial mathematical regularization and ensures that the inversion process operates entirely within geologically plausible solutions. To ensure stable inversion results, the modeling region must extend beyond the area of reliable geological interpretation. When the horizontal dimensions of the model are expanded to a distance equal to the maximum depth of investigation, approximately 90% of the gravitational signal energy from any point within the exploration area is included in the model. Increasing this distance to 1.5 or 2 times the maximum depth allows capturing approximately 96% and 99% of the signal energy, respectively. The spatial discretization of the model is determined by geological and geophysical considerations. The horizontal dimension of the elementary cell corresponds to the horizontal size of the geological structures, while the vertical dimension is selected according to the minimum thickness of geological layers, including reservoir and seal beds. When well-log density data are available, the vertical cell size can be reduced to values as small as one meter.

Based on the known accuracy of gravity measurements and the analytical relationship between anomaly amplitude, source mass, and depth, the minimum hydrocarbon reserves detectable by gravity inversion can be estimated. The effective density contrast between hydrocarbon-saturated rocks and the surrounding rock matrix is negative and depends on both fluid type and depth. Typical values range from -2.0 to -1.9 g/cm³ for gas accumulations, -1.85 to -1.70 g/cm³ for condensate and oil

accumulations, and -1.55 to -1.45 g/cm³ for water-saturated reservoirs. For a minimum high-accuracy measured anomaly of approximately 6.4 μ Gal, the minimum mappable reserves increase with depth from about 0.1 Bcm of gas or 0.1 Mt of oil at 1 km depth to approximately 5 Bcm of gas or 9–10 Mt of oil at 7 km depth, values corresponding to commercially attractive reserve volumes.

The inversion workflow solves two coupled inverse problems. First, a nonlinear structural inverse problem determines the geometry of geological boundaries while accounting for density heterogeneity within geological layers. Second, a linear inverse problem estimates the 3D density distribution within each geological unit. Real rock density values from well-log measurements are directly incorporated into the inversion process. The methodology is implemented in GCIS (Geophysical Complex Interpretation System), a multiprocessor software platform for joint inversion of gravity, well-log, seismic, and other geological–geophysical data. GCIS supports construction and visualization of high-resolution 3D geological models and enables forward and inverse problem solution for 1D, 2D, 3D, and 4D media in complex geological environments.

Within the resulting 3D density model, commercial hydrocarbon pools are delineated as closed bodies of low-density anomalies, where rock density values are always below the cut-off rock density value corresponding to the saturation and porosity cut-offs. The lowest density values correspond to rocks with the highest porosity, hydrocarbon saturation, recoverable reserves, and initial production rate.

Success Rate of the Proposed Method

Commercial drilling success rate is the proportion of discoveries relative to the total number of drilled wells. The global commercial success rate for wildcat wells ranges from 45% to 65%, for 2D seismic, 28–29%, for 3D seismic, and 54–55% when Direct Hydrocarbon Indicators (DHI) are applicable.

Application of the proposed geologically meaningful gravity inversion methodology led to the discovery of ten new hydrocarbon fields and additional pools within known fields, as well as new exploration targets in mature basins. Statistical analysis of 176 well tests in 84 new wells, drilled over about twenty years in three oil- and gas-producing regions of Ukraine, demonstrates strong predictive performance. The correlation between 3D-modeled and well-log-measured rock density ranges 68–84%, with about 3% relative density error. Wells drilled within mapped commercial pools achieved 86–100% commercial success, while multilayer well-testing success 79–100%. Prediction accuracy was 84–95% for porosity and saturation, 86–90% for recoverable reserves, and 85–98% for initial production rate. In contrast, wells drilled outside mapped commercial pools showed only 36% commercial success, and well tests outside mapped pools were successful in only 16% of cases (Fig. 1).

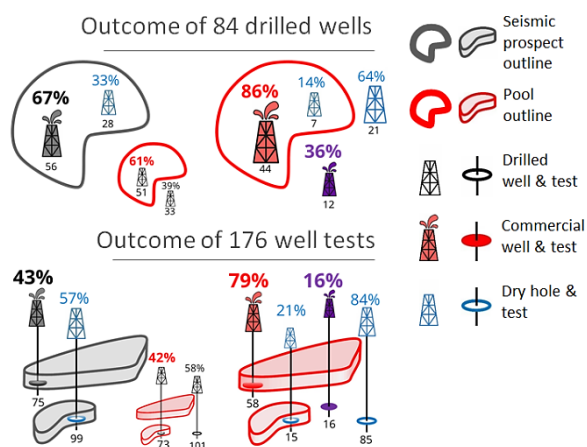


Figure 1 Commercial Drilling Validation.

Conclusions

Geologically meaningful, regularization-free 3D gravity inversion provides a quantitative framework for prior to drill direct mapping of the commercial hydrocarbon pools and estimation its properties. This approach is applicable both offshore and onshore, to structural and non-structural, conventional and unconventional, as well as diagenetic commercial hydrocarbon pools at any drilling-accessible depth.

References

Tikhonov, A.N., & Arsenin, V.Y., 1977. Solutions of Ill-Posed Problems. Winston & Sons.