

Commercial Hydrocarbon Pool Location, Recoverable Reserve and Production Rate Using Regularization-Free Geologically Meaningful 3D Gravity Inversion

Introduction

A commercial hydrocarbon pool is defined as a closed-up area of hydrocarbon-bearing rocks that have a porosity, hydrocarbon saturation, recoverable reserves, and production rate all simultaneously higher than their cut-off values, thereby making future drilling and production commercially viable.

Reliable prediction of commercial hydrocarbon pools requires a detailed subsurface model of both the geometry of geological boundaries and the spatial variability of reservoir properties. In practice, such a model can be derived from geophysical data only through geophysical inverse problem solution. Despite significant advances in geophysical technologies, the global efficiency of commercial hydrocarbon pool mapping remains moderate, and the rate of discovery of large new fields has shown limited growth in recent decades.

Inverse problems in geophysics are theoretically non-unique for all geophysical methods since multiple possible models may produce the same observed fields. Conventional inversion workflows mitigate this ambiguity using Tikhonov's regularization and smoothing constraints (Tikhonov & Arsenin, 1977). The application of regularization assumes that the inverse problem solution is required to be unique, but may be unstable. While uniqueness alone does not ensure geological meaningfulness. In 3D gravity, the subspace of mathematically unique inverse-problem solutions consists of three-dimensional harmonic functions with extrema located at the model outline. As a result, impossible to have inside the 3D model any internally closed density localizations, positive or negative. Another issue is the use of relative densities, which do not permit these data to be utilized for future estimates of rock properties. The regularized solution is a superposition of two components: a mathematically unique but geologically non-informative model that fits the geophysical field, and a geologically meaningful initial model that does not fit the gravity field but serves as a stabilizing prior. As a result, depending on the regularization parameters, the final model will either be a harmonic function or the initial model, modified by a harmonic function that limits the emergence of new closed density localizations (Fig. 1).

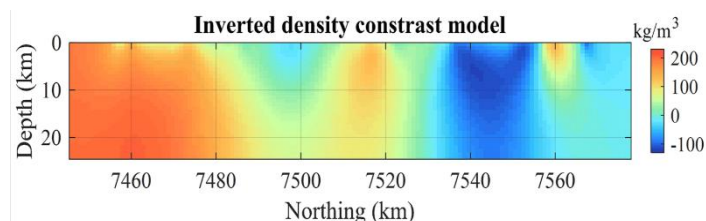


Figure 1 Harmonic function as the result of inverse problem solution – “Results from separate inversions using smallness and smoothness constraints. The starting and prior models are equal to zero, and the smoothness constraint is applied homogeneously” (Giraud, J., 2021)”.

This study introduces a workflow for mapping commercial hydrocarbon pools and estimating their total reserves, recoverable reserves, and expected production rate for proposed wells. It is based on the geologically meaningful, regularization-free 3D inversion of gravity, well log, seismic, and other geological and geophysical data within the geologically meaningful subspace of the density models.

Main theoretical and technological features of proposed approach

This subspace represents the set of all possible geological models consistent with the current structural geological boundaries, the sequence of stratigraphic and lithological events during the formation of geological layers, and the geologically and lithologically influenced constraints on changes in both the geometric and physical parameters of the model.

Within this geologically meaningful subspace, each possible gravity field corresponds to a single possible geologically meaningful 3D density model, establishing a one-to-one relationship between the observed field and the geological model (Li & Oldenburg, 1998).

In order to ensure obtaining a stable solution to the inverse problem at any point of the outline and depth of the area of reliable geological structures, it is necessary to expand the size of the outline to a value equal to the maximum depth. In this case, at least 90% of the energy of the gravitational signal from any point within the area of reliable geological structures will be included in the 3D model. If necessary, to have 96% or 99% of energy, the size must be 1.5 or 2.0 times the maximum depth.

The horizontal dimension of the elementary cell in the model is defined by the gravity field's horizontal resolution. The vertical cell dimension is selected in correspondence to the minimum thicknesses of the beds, including the reservoir and seal layers, so that at least one vertical cell is in the thinnest part of the bed. When well data are available, the vertical size may be reduced to as little as 1 m. When choosing the minimum cell size, it is necessary to consider the computer memory required for storage and the time required for calculations.

Based on the known accuracy of gravity measurements and the analytical relationship between the mass of a point source, anomaly amplitude, and depth – taking into account density contrasts between reservoir fluids under in-situ conditions and the rock matrix density – we estimated the minimum hydrocarbon reserves that can be reliably identified by gravity inversion. The effective density contrast between the hydrocarbon pool and the surrounding rock matrix is negative and varies with both fluid type and depth, typically ranging from approximately -2.0 to -1.9 g/cm³ for gas accumulations, from -1.85 to -1.70 g/cm³ for condensate and oil accumulations. For the for water-saturated reservoirs anomaly from approximately -1.55 to -1.45 g/cm³. As illustrated, hydrocarbon-saturated pools are characterised by higher anomaly magnitudes than water-saturated. This systematic difference in density-contrast magnitude is a physical background for distinguishing of water-saturated from hydrocarbon-saturated pools within the inverted 3D density model. For a minimum detectable anomaly of approximately -6.4 μ Gal and hydrocarbon-bearing rock density contrast, the corresponding mappable reserve volumes increase with depth from ~ 0.1 Bcm of gas and ~ 0.1 Mt of oil at about 1 km depth to 5 Bcm and 9–10 Mt correspondingly at 7 km depth. These values are consistent with commercially attractive reserve volumes for future commercial viability drilling and production.

The workflow solves two coupled inverse problems (Kobrunov & Petrovskyy, 1990; Petrovskyy, 2004). First, a nonlinear structural inverse problem is solved to estimate the geometry of geological boundaries, accounting for the full inhomogeneous distribution of the rock density in the geological bed. Second, a linear inverse problem is solved to estimate a fully 3D inhomogeneous density distribution within every geological bed of the structural geological model. The iterative gravity inversion scheme and joint interpretation logic are implemented according to the principles described in earlier works (Kobrunov & Petrovskyy, 1990; Petrovskyy et al., 2003).

For each model parameter of the initial model – boundaries depth, and density properties, assign a probabilistic error to their measurements. For each property constraints are specified. In addition, well-log density is incorporated directly into joint gravity inversion (Petrovskyy, 2004). Real rock density values are used directly in the inversion process without normalized or pseudo-density properties.

For the practical implementation of geologically meaningful inverse problem solutions in 1D, 2D, 3D, and 4D, a multiprocessor, multi-machine technology called GCIS (Geophysical Complex Interpretation System) was developed (Petrovskyy et al., 2003). The software system allows the construction and visualization of high-resolution, geologically meaningful three-dimensional structural and property models, as well as the solution of forward and inverse problems for joint inversion of gravity, well-log, seismic, and other geological–geophysical data, and the mapping of hydrocarbon commercial pools.

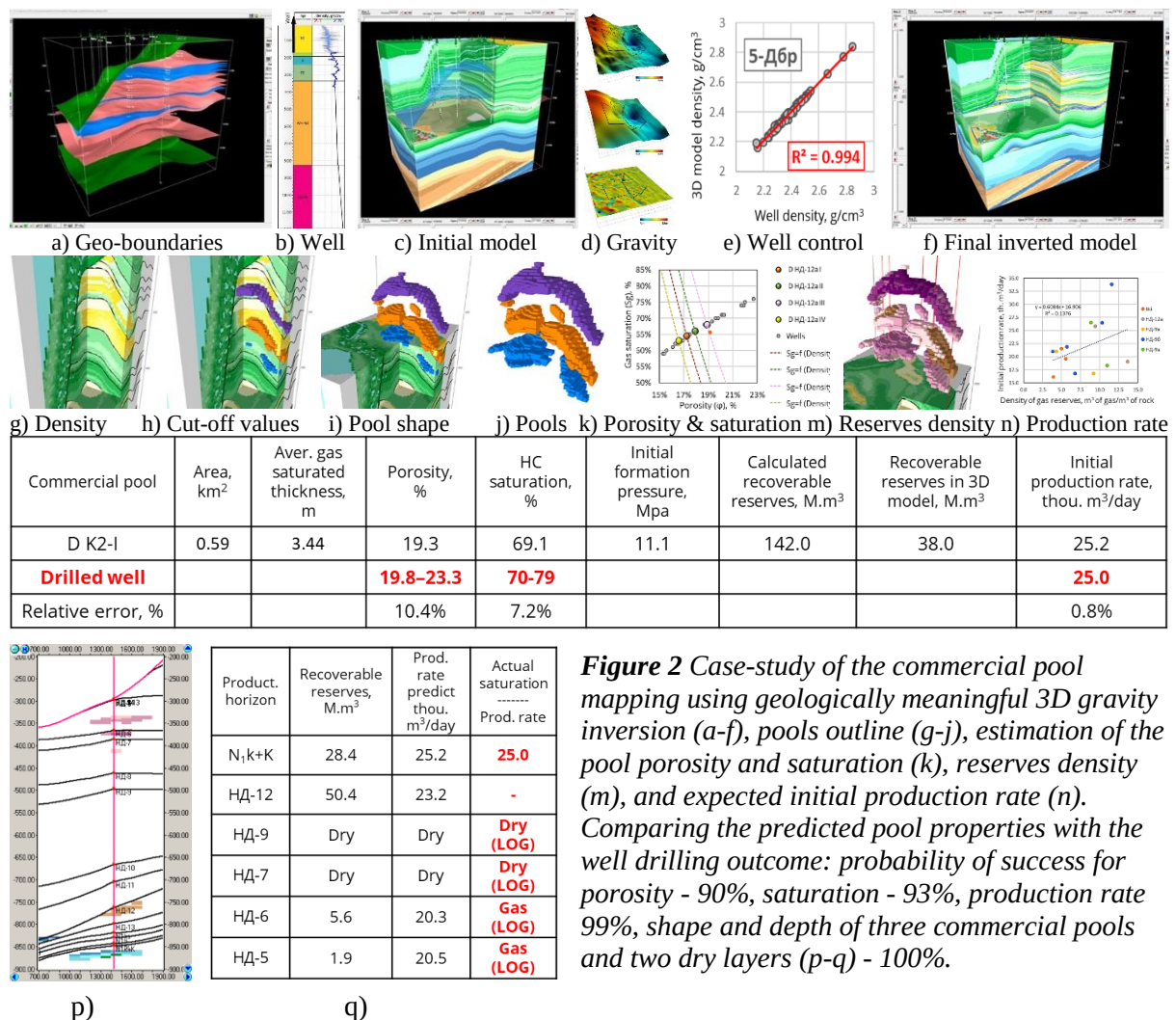
3D shape of the pool delineated as a maximum closed outline of the local low-density area. Within the pool, rock density will always be lower than the cut-off density. The lowest rock density in the pool is directly associated with the highest porosity, saturation, recoverable reserves, and production rate.

An example of such an integrated approach for salt diapir geometry and near-salt commercial pool was demonstrated in recent studies (Petrovskyy et al., 2025).

Success rate of the proposed method basing on drilling results

The actual commercial drilling success rate, commonly referred to as Probability of Success (PoS), is defined as the proportion of discoveries relative to the total number of drilled wells (Milkov, 2021). Statistical analyses of exploration drilling over approximately three decades indicates that the global commercial success rate for wildcat wells typically ranges between 45% and 65%, with regional averages of approximately 52% (Milkov, 2021). Importantly, these studies also show that the commercial success rate has remained essentially unchanged over the past thirty years despite technological progress. The actual commercial success rate for wells drilled based on 2D seismic is approximately 28–29%, increasing to approximately 39–40% for 3D seismic, and reaching approximately 54–55% when direct hydrocarbon indicators (DHI) are integrated with 3D seismic interpretation (Rudolph & Goulding, 2017).

Practical application of the described approach resulted in the discovery of ten new hydrocarbon fields and new pools within known fields (one example is shown in Fig. 2). Besides, completely new exploration targets were identified in mature oil and gas basins (e.g. Petrovska et al., 2021).



We performed statistical analysis of 176 well tests and 84 wells drilled during the 20 years of technology practical application within three oil and gas-producing regions of Ukraine. For wells drilled inside previously mapped commercial pools, the correlation coefficient between modelled and measured density ranges from 68% to 84%. The commercial success rate of encountering a commercial reservoir during drilling ranges from 86% to 100%, while the multilayers well testing from 79% to 100%. Prediction accuracy for porosity and hydrocarbon saturation ranges from 84% to 95%, for recoverable

reserves from 86% to 90%, and for the expected initial production rate of new wells from 85% to 98%. In contrast, for wells drilled outside the mapped commercial pools, the commercial success rate was 36%, while for well tests conducted outside the previously mapped pools it was only 16%.

Conclusions

Geologically meaningful and regularization-free 3D gravity inversion provides a practical framework for quantitative hydrocarbon prospect evaluation extending beyond traditional qualitative gravity interpretation. Solution of the coupled non-linear structural inverse problem and the constrained linear density inversion within a geologically meaningful solution subspace enables stable density modelling and reliable trap delineation.

From an economic and decision-analysis perspective, the proposed geologically meaningful regularization-free 3D gravity inversion method can be effectively integrated with a broad range of seismic exploration workflows, including DHI and inversions, as an independent quantitative constraint on structural geometry, hydrocarbon fluid distribution, and volumetric estimates, thereby reducing geological uncertainty in prospect ranking and well-placement decisions.

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