

H-13 DEVELOPMENT OF A HIGH RESOLUTION 3D RESERVOIR FLOW MODEL OF THE BIERWANG GAS STORAGE FIELD

J. HOELLWART¹, J. HABERLAND¹, S. VAN DELDEN¹, F. KLOAS², R. PEVERARO³, R. LARIJANI⁴,
Y. CHARREYRON⁴, A. SEMENTSOV⁴, P. TIJINK⁵, F. LINDEMAN⁵ and P. VAN RIEL⁵

¹RuhrGas AG

²then Schlumberger Data and Consulting Services

³Petrocomp Consulting

⁴Jason Geosystems, 4th Floor, Block D, Dukes Court, Duke Street, Woking GU21 5BH, UK

⁵Jason Geosystems

Summary

The Bierwang Field has been used for gas storage for around 20 years. To obtain a better understanding of the storage performance of the field, RuhrGas acquired 3D seismic data and has undertaken a full field integrated geostatistical modeling study to obtain high resolution reservoir flow models. These models form the basis for dynamic modeling.

A multi-disciplinary approach to the modeling was taken with special attention paid to proper integration of seismic with petrophysical and geological data to improve the confidence in the final reservoir models. The full 3D reservoir models incorporate structure, volumetrics, and properties for dynamic flow modeling (porosity and permeability) based on a detailed rock lithofacies model. Multiple models were generated using geostatistical simulation to capture modeling uncertainty. This set of final static reservoir models were transformed from a seismic grid representation to a cell-based POSC RESCUE (REServoir Characterization Using Epicentre) geologic model format to facilitate transfer to the reservoir model upscaler.

Introduction

The Bierwang Field was discovered in 1964, and was first exploited as a gas field. In the late seventies RuhrGas started using the field for gas storage. The field is charged and depleted annually. To better understand the field and its performance, 3D seismic data was acquired. The 3D seismic was used to enhance the field interpretation and for a multidisciplinary modeling study with the objective to build high resolution reservoir flow models for subsequent upscaling and dynamic simulation. The modeling study was phased into 3 parts:

1. Impedance trace inversion, refined impedance interpretation, and geologic modeling.
2. Geostatistical simulation to obtain high resolution models and quantify uncertainty.
3. Conversion of the seismic grid models to RESCUE cell models for export to upscaling.

Phase 1: Impedance trace inversion, impedance interpretation and geologic modeling

Prior to inversion, the 3D seismic data are calibrated to wells in the field. The inversion was preceded by a petrophysical analysis and processing step to obtain reliable well log suites to facilitate the seismic-well calibration. After calibration and using the produced wavelet (or laterally varying wavelet field), the seismic data are inverted to Acoustic Impedance (AI) using a constrained sparse spike inversion technique. Low frequencies may be stabilized by merging in an AI low frequency model. The method is described in Pendrel et al. (1997).

The utilized AI inversion method reduces wavelet sidelobes and tuning, and produces a data set which represents a layer property (rather than seismic reflection interface data). Latimer et al. (2000) describe the many benefits of interpreting impedance data over seismic data. The inverted AI data effectively provide us with AI logs at each seismic trace location, albeit at a lower frequency content than that from the wells. In this case the AI volume allows us to interpret the stratigraphic layering of the reservoir interval. This is achieved by tying the formation tops of the different sand units (A to E) interpreted from log analysis to the inverted AI traces around each well location and subsequently correlating throughout the AI cube. 4 horizons were interpreted in this way. One important result is that the AI data images the shale-out of the sand A and B members very well, supporting interpretation of this shale-out with more confidence (See Figure 1).

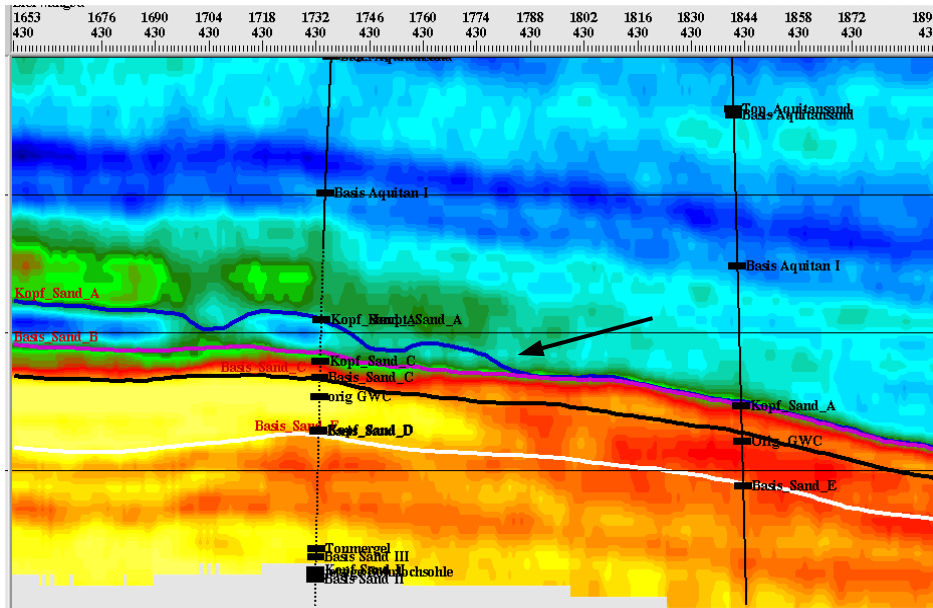


Figure 1. AI section. Notice the clear imaging of the shale-out of the sand A and B members (arrow).

The Base C sand corresponds to an abrupt transition to a hard layer and represents an important formation member boundary. It can be seen throughout the data set and is a very good intra-reservoir horizon to pick. Further, interpretation of the D and E sands, which are hard to track on the seismic data, is now feasible.

The AI data also better delineates faults and their intersections with the interpreted horizons, and, therefore, was used to enhance the fault framework interpretation.

The interpreted structure and reservoir layering was integrated in a 3D geologic model. The main layers are built from the interpreted surfaces and the fault network. Calibrated velocity logs are interpolated to produce a detailed 3D velocity model for depth conversion. An important result is that the updated and refined horizon and fault interpretation and subsequent depth conversion with the detailed 3D velocity model resulted in a new depth structural interpretation for the North East part of the hanging-wall block. The interpretation of the top reservoir structure from a previous mapping study based on 3D seismic interpretation shows a prominent 3-way dip closure against the North East ramp. From AI a sharp synclinal feature is interpreted, which then develops into a low relief extensive 4-way

dip closure. This revised interpretation has subsequently been confirmed by a new well. The 3D model is also used to update the deterministic reservoir description on the basis of correlations between AI and total porosity (PHIT) and volume of clay to predict effective porosity (PHIE). Horizontal permeability (Kh) to get a first flow model was computed from PHIE using a relationship based on the petrophysical analysis. Vertical permeability (Kv) was derived from Kh using a relationship based on core measurements. Finally, Net-to-Gross ratio was computed using an appropriate flow-based threshold for Kh (1 mDarcy) determined from the laboratory analysis of core samples throughout the field. (See Figure 2).

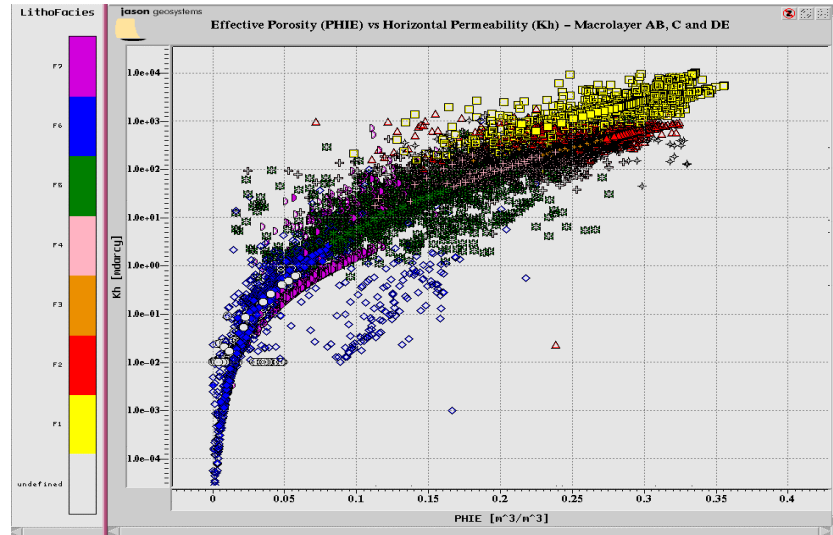


Figure 2. Effective porosity and horizontal permeability for different facies.

Phase 2: Geostatistical modeling

In order to a) quantify the uncertainty intrinsic in the data and their interpretation b) take account of spatial relationships of the lithofacies and reservoir parameters and c) generate high resolution well-driven volumetric models integrated with seismic data, geostatistical modeling was carried out.

In this phase the electro-facies descriptions, herein termed lithofacies, developed from core data and petrophysical logs at the well locations in a preceding study, were integrated with the AI data and the stratigraphic/structural frame work generated in Phase 1. The lithofacies were defined based on core porosity and permeability criteria, i.e. the facies analysis was driven by flow-based properties rather than pure sedimentary geological considerations.

A geostatistical workflow was then used to distribute the lithofacies descriptions in the depth geologic model to a vertical resolution of 1.5ft to achieve the desired level of detail.

Sequential indicator simulation and Gaussian co-simulation with probability trend were used in combination to simultaneously generate lithofacies and total porosity values within the litho-facies. This was followed by sequential co-simulation of PHIE and Kh, using respectively PHIT and PHIE as secondary data. Kv was derived directly from Kh using the same core-based transform referred to above. Lithofacies and PHIT were simulated with respect to a background model of probabilities derived from the inverted 3D AI inversion cube. 5 realisations were generated to produce 5 different but equi-probable reservoir lithofacies models. Figure 3 shows lithofacies and property simulation results.

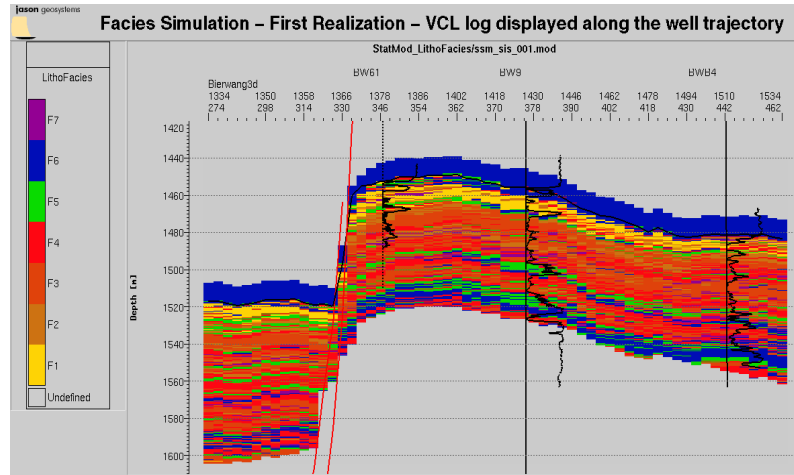


Figure 3. Example section through simulated high resolution litho-facies model.

The average Original Gas in Place (OGIP) calculated from the geostatistical reservoir model realizations is consistent with estimates derived from production history and is around 10% higher than that calculated for the deterministic model. A new well drilled subsequent to the geostatistical modeling phase is consistent with the predictions obtained with the geostatistical modeling.

Phase 3: Export to Reservoir Simulation via RESCUE

In order to perform dynamic simulation of gas flow in the 5 model realizations, these models need to be converted from a regular seismic grid format to cell-centered corner point grids which can be read by reservoir simulator upscalers. To fit in with Ruhrgas' upscaling software, the POSC RESCUE geologic model format was determined to be the best means of exporting the property models for reservoir flow layering and grid upscaling prior to dynamic simulation.

Conclusions

This multi-disciplinary integrated field study demonstrates impedance to be a superior basis for reservoir interpretation, both for stratigraphic and fault framework interpretation. A strongly revised interpretation was obtained relative to the initial 3D seismic interpretation. The ultimate study objective was to obtain multiple high resolution reservoir models to capture uncertainty and to form the basis for development of models suitable for dynamic simulation. High resolution static model realizations were successfully generated with geostatistical indicator and property simulation. To link the high resolution static models to upscaling software, the seismic grid based models were successfully converted to the RESCUE geologic model format.

The revised interpretation and geostatistical modeling results are consistent with the results from a new well drilled subsequent to the interpretation and modeling phases of the study.

References

- Buxton-Latimer, R., Davison, R., Van Riel, P., 2000, An interpreter's guide to understanding and working with seismic-derived acoustic impedance data. TLE, March 2000.
 Pendrel, J. and Van Riel, P., 1997. Methodology for seismic inversion and modeling: A western Canadian reef example, CSEG Recorder, 12.5, 5-15.