GEOMODELING: A TEAM EFFORT

Part 2: The Geomodeling Workflow

By Thomas Jerome, Jun Yang and Suzanne Gentile, RPS

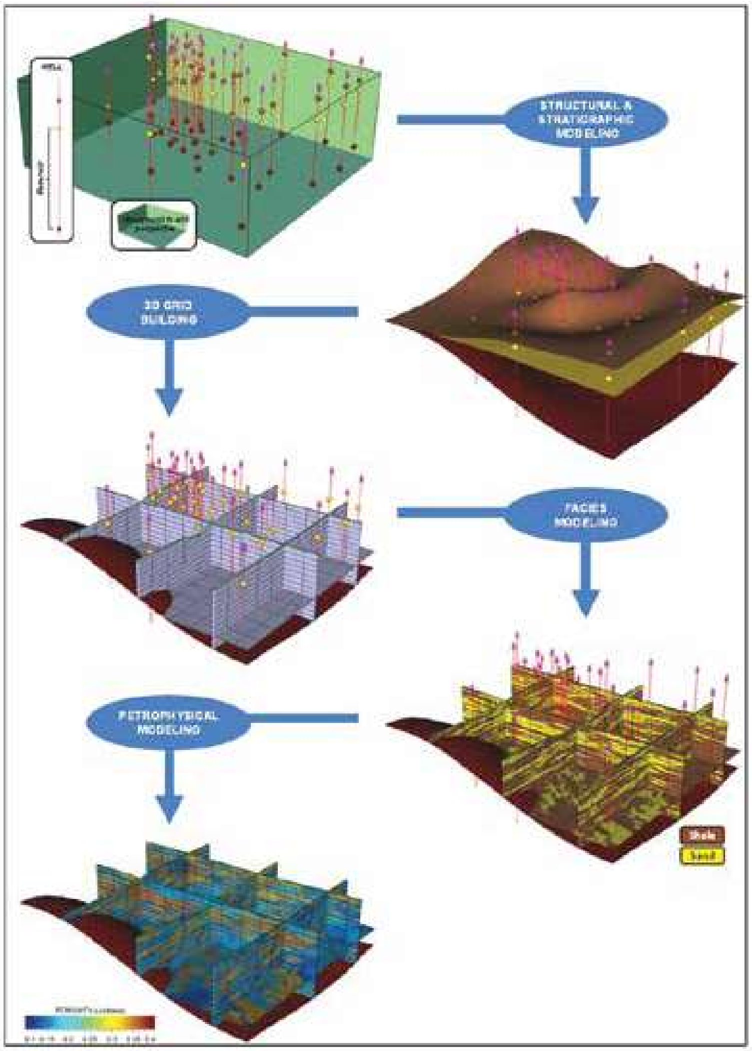

Figure 1. *Geomodeling workflow. Example of a clastic reservoir.*

INTRODUCTION

Simagni volore reprovi digent ut ullam eosa The core of any reservoir modeling workflow includes five steps: gathering the data, structural and stratigraphic modeling, three-dimensional (3D) grid building, facies modeling and petrophysical modeling (Figure 1). This paper gives an overview of each step and an idea of how the team members contribute to such work, either in providing input data or in defining what the model is needed for. The team members' contributions will be detailed in the remaining articles of this series, starting with the May issue of the Reservoir.

One key element of reservoir modeling will be left aside at this time: geostatistics. Geostatistics provide a powerful set of mathematical tools to interpolate any type of properties, using diverse constraints. These tools will be described in the third part of this series, published in the April issue of the Reservoir.

RESERVOIR STUDY = DATA AND KNOWLEDGE INTEGRATION

The goal of an exploration or development asset team is to characterize the dimension, the rock properties and the fluid distribution of the reservoir they are studying. This knowledge is a key factor for a company to decide what to do next with its asset. The company might push the exploration further or start its development. If the resource is determined to be uneconomical to produce the company might drop the area.

To define the dimension of the reservoir, the team must understand the geometry of the horizons and the faults (if any) delimiting the play as well as the depth of the different fluid contacts (oil-water contact, gas-oil contact…). The rock properties of interest will be those controlling the amount of hydrocarbons in the reservoir (facies, porosity, fluid saturations…) as well as those controlling how the rock and the fluids will behave once engineers start production (permeability, geomechanical properties…).

Due to the underground depth of reservoirs they are difficult to describe. To characterize its asset, the team has to integrate all the possible data available. Well data will provide a lot of details near the wellbores (logs, core, cuttings, image logs, well testing…). Seismic data will complete this by giving a general image of the full reservoir, but with a limited level of resolution. The team's knowledge about geological concepts (depositional environment, basin evolution…) and engineering concepts (fluid mechanics, geomechanics…) help to organize all of the different data so they can characterize the reservoir as best as possible.

Data and knowledge integration has been at the core of reservoir characterization long before reservoir modeling started to be developed in the 1980s. The concept is explained in domains such as geological mapping (Tearpock and Bischke, 2003) or geophysical interpretation (Lines and Newrick, 2004). Geomodeling didn't "invent" data and knowledge integration, but it provides a new set of tools to push it beyond what was done previously.

PLACE OF RESERVOIR MODELING IN A RESERVOIR STUDY

Geomodeling is also called "reservoir modeling" or "static modeling". This latest expression emphasizes the fact that geomodeling focuses on quantifying the current state (rocks + fluid distribution) of the reservoir. "Dynamic modeling", run by engineers, focuses on how fluids (injected/produced) will move and how the rocks will react during production. Dynamic modeling can be thought of as modeling the reservoir "through time".

Research on reservoir modeling started in the late 1970s to the beginning of the 1980s and it has continued to grow ever since as computers became more popular, powerful and affordable. Reservoir modeling algorithms rely on visualization techniques that are also used in 3D computer games, 3D animated movies and CAD (Computer-Aided Design) tools that are used in the manufacturing industry to model goods (cars, buildings, planes, etc.). Reservoir modeling has one essential difference though: while other industries build their 3D models by drawing (movies, video games…) or through the application of mathematical equations (geometry of the wing of an airplane for example), geomodeling has to define the geometry of complex objects (horizons, geobodies) from a limited amount of data points (well tops, seismic interpretation…). Interpolation and extrapolation techniques are keys in this process (see the next article for more information on geostatistics).

The development of computers lead also to the development of complex 3D models in the domains of geophysics and flow simulation among others (Figure 2). These tools are very complementary to those found in reservoir modeling packages. Many studies first involve a stage of 3D seismic interpretation and seismic inversion, these results are used as input to the reservoir modeling workflow, which itself feeds complex flow simulation computations. The tools from those different domains are increasingly integrated. It began with the definition of standardized file formats to transfer data and results from one domain to the next. Nowadays, many software providers are linking, if not merging, their different proprietary solutions into a single platform to further facilitate the integration between the different disciplines.

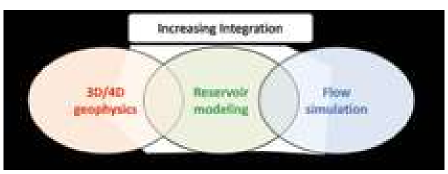

***Figure 2.** Integration between geophysics, geomodeling and engineering.cv.*

As mentioned in the introduction, the core of any reservoir modeling study is made of five steps, described in the remaining of this paper: gathering the data, structural and stratigraphic modeling, three-dimensional (3D) grid building, facies modeling and petrophysical modeling (Figure 1).

INPUT DATA

Every reservoir modeling project starts with defining the extent of the model and what data should be included. This task seems straightforward and yet many modeling projects do not meet their deadlines because this phase did not involve enough the whole team. Figure 3 gives an example of the type of problem any team might face.

A company's lease covers three sections (Figure 3A and C, orange squares). Two horizontal wells are to be drilled soon (H1 and H2) and management asked for a flow simulation model to be run around those future wells. To do so, the engineers ask their geologist to build a reservoir model around the two horizontal wells. Engineers need the model to be ready in one month. The geologist agrees on their deadline and gets started. Data is available on all of the vertical wells (blue triangles) and there is no seismic. The geologist decides to model the reservoir within the red polygon (Figure 3 A). Her choice is motivated by two things. Firstly, there is no need to include the whole lease as only the zone around the future horizontal wells is of interest. Secondly, the polygon includes the well W1, even if it is outside the company's lease, to get a better control during the interpolation of the facies and the petrophysics on the North-West of the well H1. On the contrary, the vertical wells W2 and W3 located South of the lease are excluded. W2 is considered too far to be relevant while the South-East corner of the chosen polygon already contains a vertical well, making W3 redundant.

The reservoir modeling moves forward and the geologist delivers the model to the engineers on time. To her surprise, the engineers reject it: it does not include the horizontal well H3 located East of the lease. While not needed to model the rocks around H1 and H2, and so rightfully ignored for the geomodeling, this well is producing and to the engineers **it was obvious** that they needed this well in the model for their flow simulation. As it was obvious to them, they did not see the point at saying it aloud at the beginning of the project.

Our geologist goes back to her office, adjusts the extent of the geomodel as needed (Figure 3 C, green polygon) and she delivers an updated geomodel a month later, completely missing the engineers' deadline.

Years of consulting has shown that this type of problem happens often: a misunderstanding in the scope of work is spotted only at the end of the project when the model is reviewed. It is then necessary to redo everything. The issue is a lack of communication in the team at the beginning of the project. In my example (Figure 3B), engineers did not spend time – or were not asked to spend time – in defining which data was needed. Had they been (Figure 3D), engineers would have had a chance to mention the well H3 and the misunderstanding would have been lifted before causing any damage.

horizons (stratigraphic modeling) and potential faults (structural modeling). If each surface is only defined by well tops, the interpolation will likely be poorly constrained and the model will be highly uncertain far from the wells. If those surfaces were also interpreted on seismic, the interpolation will respect both the well tops and the seismic interpretation making the result will be more reliable: not certain, but at least "less" uncertain.

Structural and stratigraphic modeling involves more than just interpolating data. The modeler must choose an interpolation technique that properly mimics the geological context of the reservoir. Figure 4 illustrates this – this simple reservoir will also be used in the next sections of this paper.

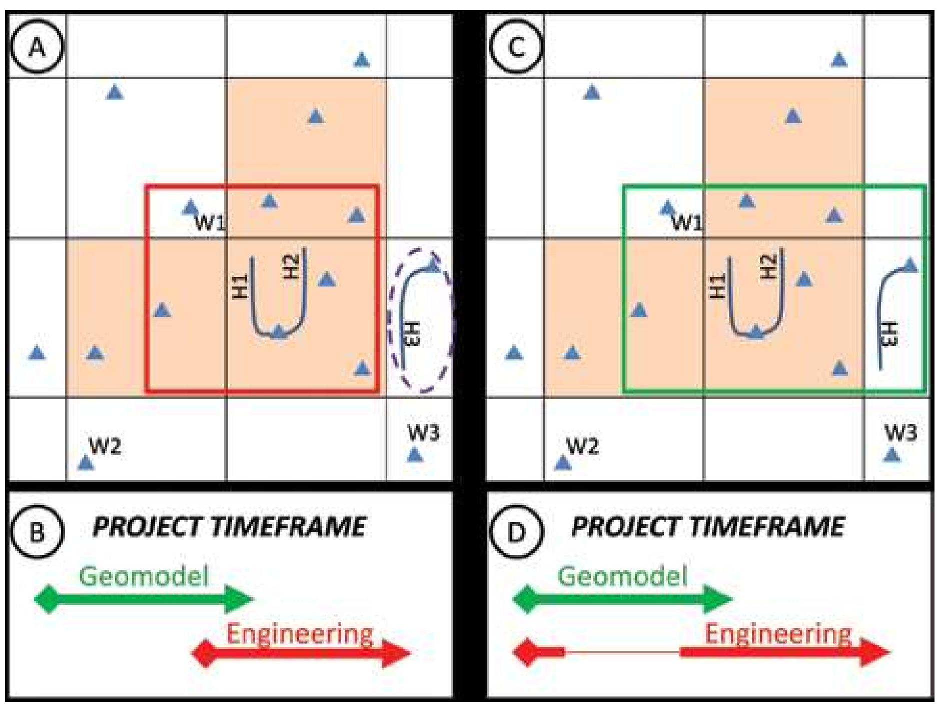

***Figure 3.** Defining the lateral extent of a model A) based on reservoir modeling criteria only, or C) taking also into account engineers' requests. Project timeframe: B) leading to the initial decision (A) and D) leading to the needed modeled area (C).*

The reservoir is made of a single geological unit delimited by two horizons A and B. Three wells have been drilled and picked (W1, W2 and W3). W2 is not deep enough and it doesn't reach the horizon B. The top horizon A is easily built by interpolating the TVDSS values of the three well picks. How shall the horizon B now be modeled?

Two mathematical approaches are possible. With approach 1, the TVDSS of the two well picks B are interpolated, in the same way the horizon A was modeled. With approach 2, the thickness of the unit is interpolated and then the TVDSS of the horizon B is defined as being equal to the TVDSS of horizon A minus the local thickness of the unit. As shown on Figure 4, the resulting geometry of the horizon B varies a lot depending on the technique being applied. Furthermore, the well picks alone (the data) can't help us decide which approach should be used. Only a geologist could answer this. Based on his/her understanding of the geological context and on his/her work on the logs, the cores and the surrounding area, he/she might conclude that:

- Unit A was deposited above an unconformity (Unit B). The two horizons should be modeled separately (approach 1). Or…
- Unit A and Unit B are conformable one to the other. The two horizons should be modeled together (approach 2).

In case the data is inconclusive, then two models might be needed to capture this uncertainty: one is following the approach 1 and one following the approach 2.

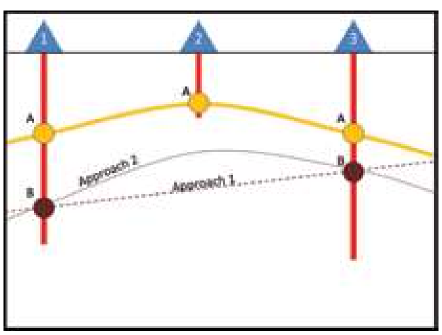

Figure 4. Stratigraphic modeling. How shall we model the horizon B based on the well picks? As illustrated with the modeling of the Teapot Dome (Figure 5), faults are also modeled as surfaces.

3D GRID BUILDING

Once the stratigraphic and the structural modeling is done, the 3D grid can be built. The 3D grid is representing the volume of rocks inside each geological unit. The 3D grid is divided into cells, each cell representing a small piece of the reservoir. Typically, a cell is between 25m*25m and 100m*100m horizontally and 0.1m to 1m vertically. Each cell will contain a specific value for the different properties (facies + petrophysics).

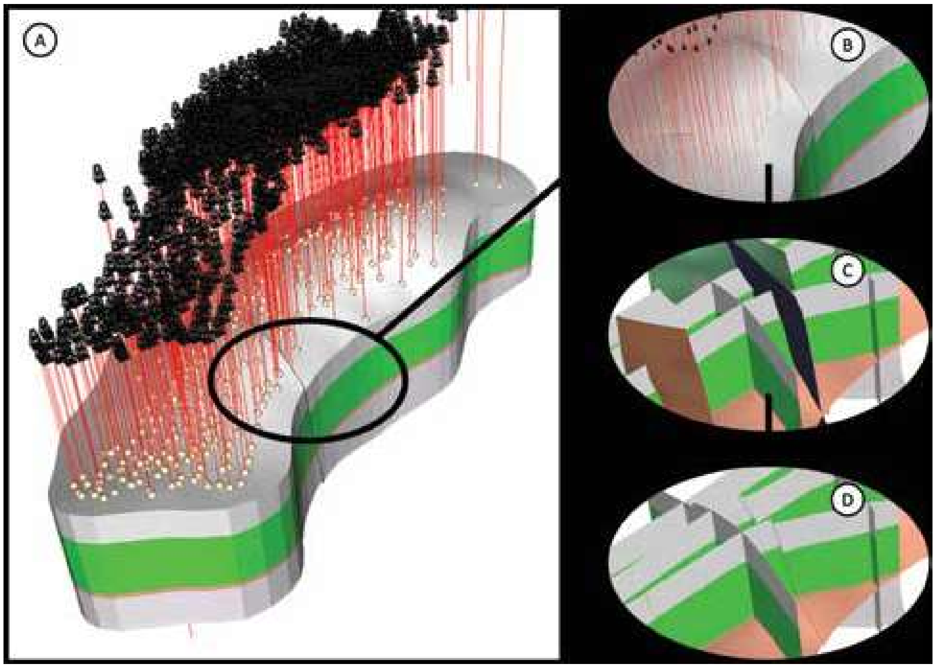

Figure 5. Teapot Dome model. A) Global view of the structural and stratigraphic model. B) Zoom to the model. C) Focus on the fault network. D) Focus on sections of the resulted faulted 3D grid.

Defining the orientation of the mesh of the 3D grid is an essential step of the modeling process. Most interpolation techniques will tend to populate the properties following the main directions of the mesh. Figure 6 illustrates this point with the vertical layering of the 3D grid.

Based on his interpretation of the data, the geologist decides that horizon B is an unconformity. This leads the geomodeler to build the surface representing horizon B following the first approach (Figure 4). Analysis of the core data shows that the reservoir is made of a massive fluvial sand channel surrounded by shale (Figure 6A). The sand is only visible on well 1. Regional data shows that it should extend further toward wells 2 and 3. How shall we interpolate the sand? If the vertical layering of the 3D grid is made horizontal (Figure 6B), the sand channel will be interpolated horizontally. If the vertical layering is made parallel to horizon B (Figure 6C), the sand channel will dip like horizon B does. If the vertical layering is made parallel to horizon A (Figure 6D), the channel will have a more complex, curved geometry.

The choice again lies in the hands of the geologist. Similarly to the problem of the construction of the horizons, the answer isn't found in the data alone (the core data here). The geomodeler also needs the involvement of the geologist. In case the geologist has no way to be sure of which geometry should be built for the horizon building, the reservoir modeler might have to carry forward several models, one for each possible internal geometry of the 3D grid.

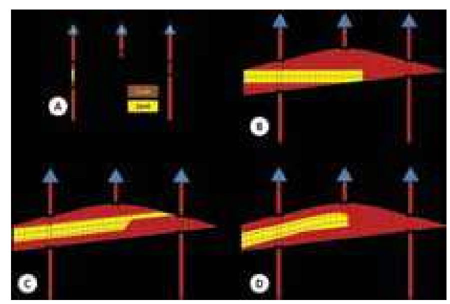

Figure 6. A simple reservoir (A). Three possible geometries for the vertical layers of the 3D grid (B, C, D).

Over the last few years a new set of techniques, coupling the structural modeling, the stratigraphic modeling and the 3D grid building, have gained popularity. Such integrated techniques simplify and improve the construction of the structural model, which has always been difficult for complex fault networks. These techniques also allow the ability to align the mesh of the 3D grid to complex trends. For example, (Thenin and Larson, 2013) used these techniques to integrate the complex geometry of Inclined Heterolithic Strata (IHS) found in oil sand reservoirs into the mesh of the 3D grid. Such workflow can be extended to any reservoir in which seismic stratigraphy has been interpreted (Veeken and van Moerkerken, 2013). The details of the solutions implemented by the different software vendors are not yet all known. Implicit modeling seems to be at the core of at least some of those new tools. At this time, readers interested in the some of the mathematical details should refer to (Mallet, 2014) which has recently been published.

FACIES AND PETROPHYSICAL MODELING

Facies modeling and petrophysical modeling will be detailed in the April issue focusing on geostatistics.

Geostatistics allow the creation of multiple possible spatial distributions of the facies (and the petrophysics). Each respects the input data. It's an efficient way to study the uncertainty associated to rock properties distributions. Figure 7 gives an example of two such spatial distributions given facies data at well locations along with information about the global facies proportions and the general orientation of the facies geobodies.

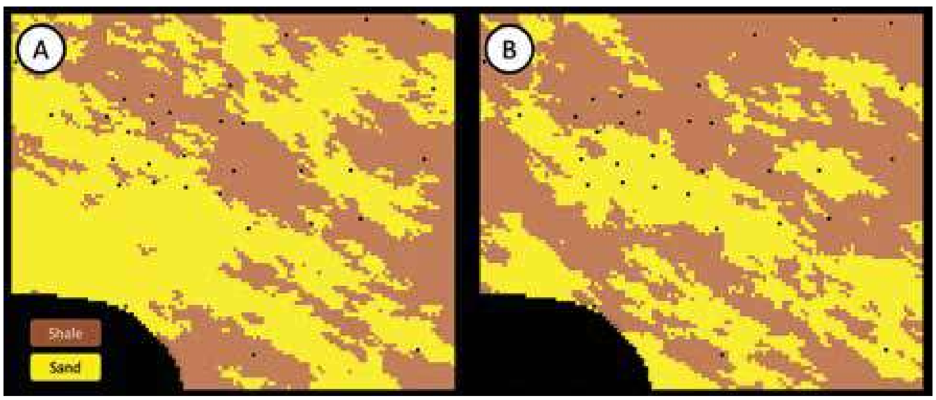

Figure 7. Two possible distributions of the sand and shale between wells (black dots)..

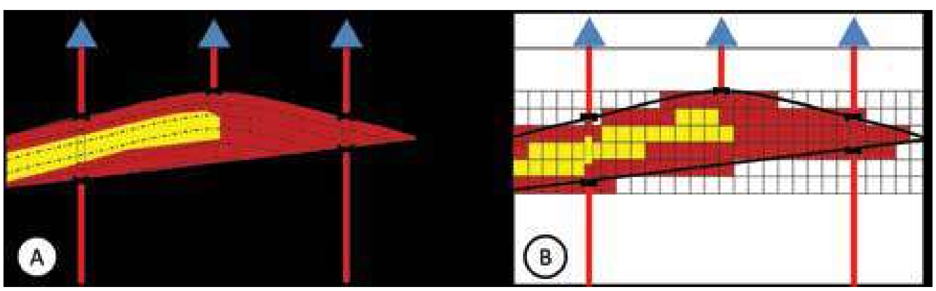

***Figure 8.** Upscalling a facies model from the 3D grid made for the reservoir modeling (A) into the 3D grid optimized for flow simulation (B).*

OUTPUT

A geomodel is built for multiple reasons. As such, the output provided back to the team can be varied.

The geomodel is a 3D visualization tool that helps the entire team see the different hypotheses made by them translated into 3D. Seeing the model in 3D sometimes leads to a revision of the interpretation, which leads to a revision of the model. The loop continues until the interpretation of the reservoir is validated by the team and the model properly captures what the team had in mind regarding the reservoir.

If the model is meant to feed a dynamic modeling study, the output will often be a 3D simulation grid. While the internal geometry of a 3D grid made for reservoir modeling reflects the depositional space (Figure 6), the internal geometry of the 3D simulation grid is made to optimize fluid flow computations. Simulation grids (Figure 8) have often a "sugar box" mesh. The facies and petrophysical properties, populated in the 3D geological grid (Figure 8A), are transferred into the cells of the 3D simulation grid (Figure 8B) mostly with upscaling techniques.

Engineers sometimes ask why reservoir modelers don't model directly the properties into the 3D simulation grid. Why do we need a specific grid for reservoir modeling? Comparing Figure 6A and Figure 8B illustrates why: there is no easy way of getting a dipping channel body if sugar grid geometry is used. Similarly, geologists sometimes ask why engineers can't use the 3D geological grid for the flow simulation. Such complex grids would slow down the flow simulation and would create numerical instabilities. Engineers need a grid optimized for their needs too.

More details about the different outputs needed by engineers will be given in the three issues on engineering (reservoir engineering in September, reserves in October and production engineering in November).

CONCLUSION

Reservoir modeling did not invent data and knowledge integration, but it can be seen as one of its modern implementations. As illustrated in this paper, and further investigated in the next issues, a reservoir model cannot be good if the modeler does not collaborate with his/her team.

Uncertainty management is the second important notion. With limited data available, a lot of unknowns remain about our reservoirs. Reservoir modeling is tailored to capture those uncertainties. Uncertainty will be also discussed in each remaining paper of this series.

Before the contribution of each team member is further investigated, the next issue will focus on geostatistics, an essential set of techniques for every reservoir modeler.

TO GO BEYOND…

We highly recommend (Ringrose and Bentley, 2015) which was published a few weeks ago. It gives an excellent overview of the reservoir modeling workflow, without being heavy on the mathematics.

ACKNOWLEDGMENTS

The authors would like to thank the RMOTC and the U.S. Department of Energy for providing access to the Teapot Dome dataset (www.rmotc.doe.gov/datasets.html).

REFERENCES

Lines, L.R. and Newrick R.T., 2004. Fundamentals of Geophysical Interpretation. SEG, Geophysical monograph series number 13. 274 pages.

Mallet J.-L., 2014. Elements of Mathematical Sedimentary Geology: the GeoChron Model. EAGE. 374 pages.

Ringrose, P. and Bentley, M., 2015. Reservoir Model Design – a Practitioner's Guide. Springer. 260 pages.

Tearpock D. J. and Bischke R.E., 2003. Applied Subsurface Geological Mapping. 2nd edition. Prentice Hall. 822 pages.

Thenin D. and Larson, R., 2013. Quantitative seismic interpretation – an earth modeling perspective. CSEG Recorder. Vol. 38, Number 9, Nov 2013. Pages 30-35.

Veeken, P.C.H. and van Moerkerken, B., 2013. Seismic Stratigraphy and Depositional Facies Models. EAGE. 494 pages.

TO CONTACT THE AUTHORS

Feel free to contact us if you have questions about this paper or about the series.

Thomas Jerome
Thomas.Jerome@rpsgroup.com

Jun Yang
Jun.Yang@rpsgroup.com

Suzanne Gentile,
Suzanne.Gentile@rpsgroup.com