Maximizing Image Data to Minimize the Uncertainty of the Geological Model for Horizontal Well Fracturing*

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Abstract

Multistage fracturing technology for horizontal wells has opened up development of not only shale, but also tight sand reservoirs worldwide. Accurate sand distribution models can be used to optimize a pumping strategy (rate, proppant, fluid technology, etc.) for each stage based on the 3D heterogeneous sand characterization. In contrast to previous geological modeling workflows, the improved methodology presented in this paper utilizes image data in order to accurately characterize the subsurface and sedimentary structure accurately to minimize the uncertainty of the geological model. The shale layers picked from the image data are used to generate a verifiable and direct measurement of the sand distribution located within the near wellbore structure by using a novel modeling plug-in application in a commercial E&P software platform. The uncertainty of the 3D structure model will be minimized by integrating the near wellbore surface. The sand model is then built using a sequential indicator simulation method based on the image data and wellbore lithology. Based on image data, a reliable limit for a set of parameters are defined to create the sand variogram needed for the set of realizations required in order to improve the accuracy of the sand model.

A field wide paleocurrent analysis is done using data from several wells and the depositional environment was determined to be a unidirectional cross bedding environment. The structure analysis and sand description from image data then set the depositional anisotropy. For each fracturing stage, the pump schedule is optimized individually based on the near well bore sand distribution. Seven wells fractured with the procedure detailed in this text have had 30% increased productivity when compared to adjacent wells previously completed. The workflow presented can be directly applied to other tight sand reservoirs around the world.

Geology Background

The area of investigation is located in Changling faulted depression, southern section of the Song Liao basin (Figure1). The target zone is lower Cretaceous showing high gas prospecting potential (Li et al., 2014). Core data analysis indicated the lithology is mainly gray to light gray fine sandstone with shaly siltstone and shale. Regional depositional environment was determined to be a braided river and braided river delta plan, the channel sand distribution is highly heterogeneous with low porosity 2% ~ 7% and permeability ranging from 0.01 ~ 0.3 md (Wang et al., 2011).

Field development includes 20 wells, 13 vertical and 7 horizontal wells. Five of the seven vertical wells were logged with image date. During the early field development, the client completed and fractured 3 horizontal wells with several completion strategies and spotty production performance. A pump schedule optimization method needed to be developed for each individual well and even well segments, depending on the sand structure. Increased completion complexity, modeling uncertainties and high risk associated to tight sand reservoirs require a high level of expertise from the very beginning of the development phase in order to produce a profitable project (Holditch et al., 2008). The novel integrated methodology presented here was introduced to the client and segmented into seven steps (Figure 2). An accurate geological model is the critical foundation for a successful stimulation.

Workflow

This workflow can be divided into three parts: structure model, sand model and probability model (Figure 3). There are three highlights in the workflow: dips data, depositional environment and sand distribution. For a traditional structure model, the geological layer data is used to make a surface by interpolation method. Then the structure model is built from these surfaces (Figure 4a, 4b and 4c). The dip orientation can be picked from image data (Figure 4d). The dip orientation is extrapolated 50 – 100 meters away from the wellbore, (Figure 4e, 4f). A small surface is created near the borehole by using the propagated points, (Figure 4g). Finally, the small surface data is used as a near wellbore constraint in order to build the final surface (Figure 4h).

When comparing the traditional structure model, Figure 4c and the improved structure model presented in this paper, Figure 4i, there is a clear difference between the two methodologies, especially near wellbore where image data was available as the arrow indicated. The improved methodology creates a structure model with less uncertainty by adding an additional, direct measurement constraint surrounding the wellbores with image data.

A precise sand characterization is important before sand modeling. To ensure an accurate sand model, the following analysis is implemented: facies analysis, sand distribution analysis, sand geometry analysis. From the image data, the sedimentary structure can be identified such as cross bedding, scour surface and fining upward structure. The gamma ray shape is mainly box type and bell type; this reflects the character of channel sand deposition. Several depositional cycles are observed vertically as well, combined with the regional environment analysis leads to the conclusion that the depositional environment was a braided river. The cross bedding picked from the image data can also be used for a paleocurrent analysis. The paleocurrent analysis from multi-wells indicates the main sand distribution is a NE-SW direction.

The average sand length, width and thickness can be defined by a variogram analysis. These parameters will be used as input for 3D sand modeling (Figure 5). Then the 3D sand distribution model is generated through sequential indicator method (Figure 6). The wellbore lithology as the hard data is used as input.

Limited field information during the exploration and appraisal phase, makes managing uncertainties in the reservoir model is a challenging task (Salinas et al., 2014). No seismic data was available for the field; seismic data is normally used to constrain the sand distribution trend among the wells. This could lead to very high uncertainty of sand distribution among wells, even using the same model parameters and constraints as input because the random simulation path requires a random initial seed. Model 1 and Model 2 in Figure 7, shows the highly variable sand distribution from two randomly generated realizations with the same input parameters. Therefore, realistic quantification of uncertainty is essential in decision making (Konstantin et al., 2013). One hundred sand model realizations are created in order to evaluate the sand uncertainty among wells. Based on these realizations, the probability model of sand distribution was calculated using a simple arithmetic mean. This probability model shows where sand is most likely to be throughout the whole field. . The different color along well section represents the different probability of sand distribution (red signifies high probability, Figure 7). Based on the probability model, the optimistic, neutral, pessimistic model can be provided for subsequent fracture optimization.

Case Study

Borehole breakouts and drilling induced tensile fractures revealed by wellbore image logs are often used to determine the orientation of principal stressed and to constrain stress magnitudes. The maximum principal horizontal direction is E-W from image analysis.

Traditionally, the fracturing design of the target well is based on the lithology along the target well and offset well information. Now, with the help of a probabilistically accurate sand distribution model, the sand distribution along the well is clearly described. Therefore, the fracturing design work can be tailored for each stage.

For the stage 1-6, the sand distribution is contiguous and homogeneous, whereas for stage 7-15, the lithology is predominated by sand laminations. This leads to two contrasting fracture treatments. The first for stages 1 – 6, the high sand section, similar to a conventional fracture treatment. The second for stages 7 – 15, the laminated section, similar to an unconventional treatments schedule, Figure 8. Stage 7 is a transitional environment between the thick sand section and the lamination section.

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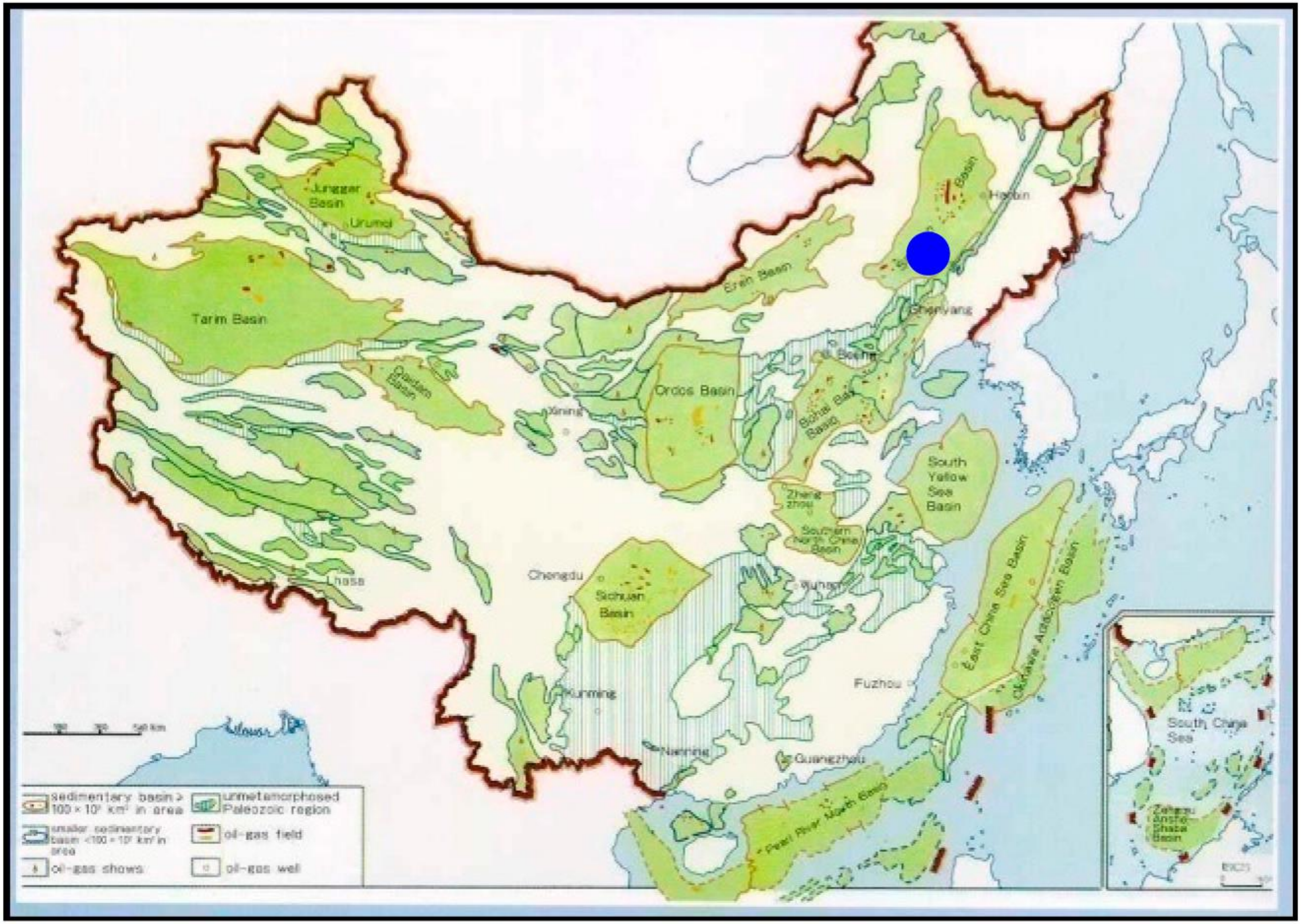

Figure 1. Changling fault depression of Songliao basin.

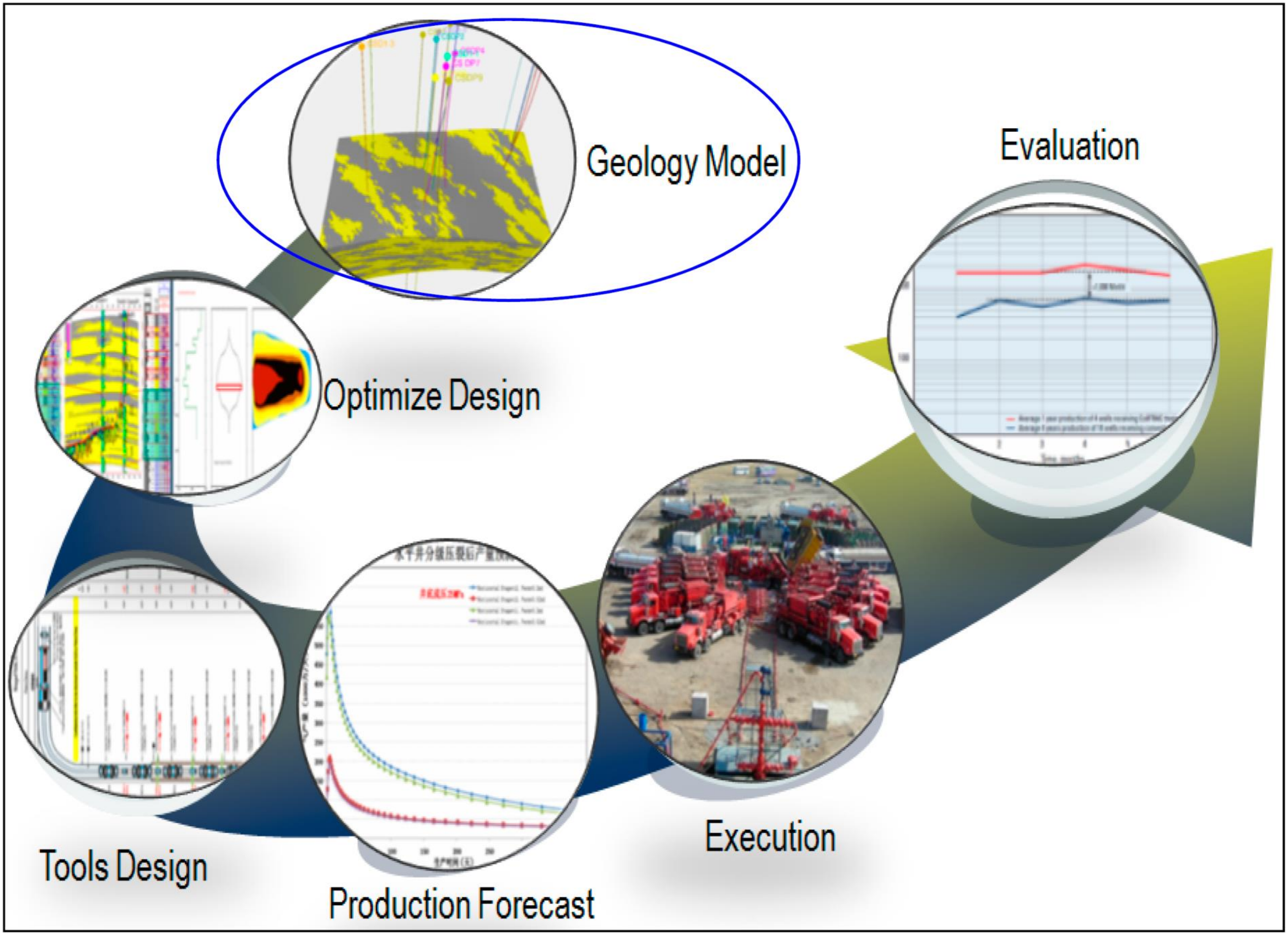

Figure 2. Novel integrated methodology of multiple fracturing designs.

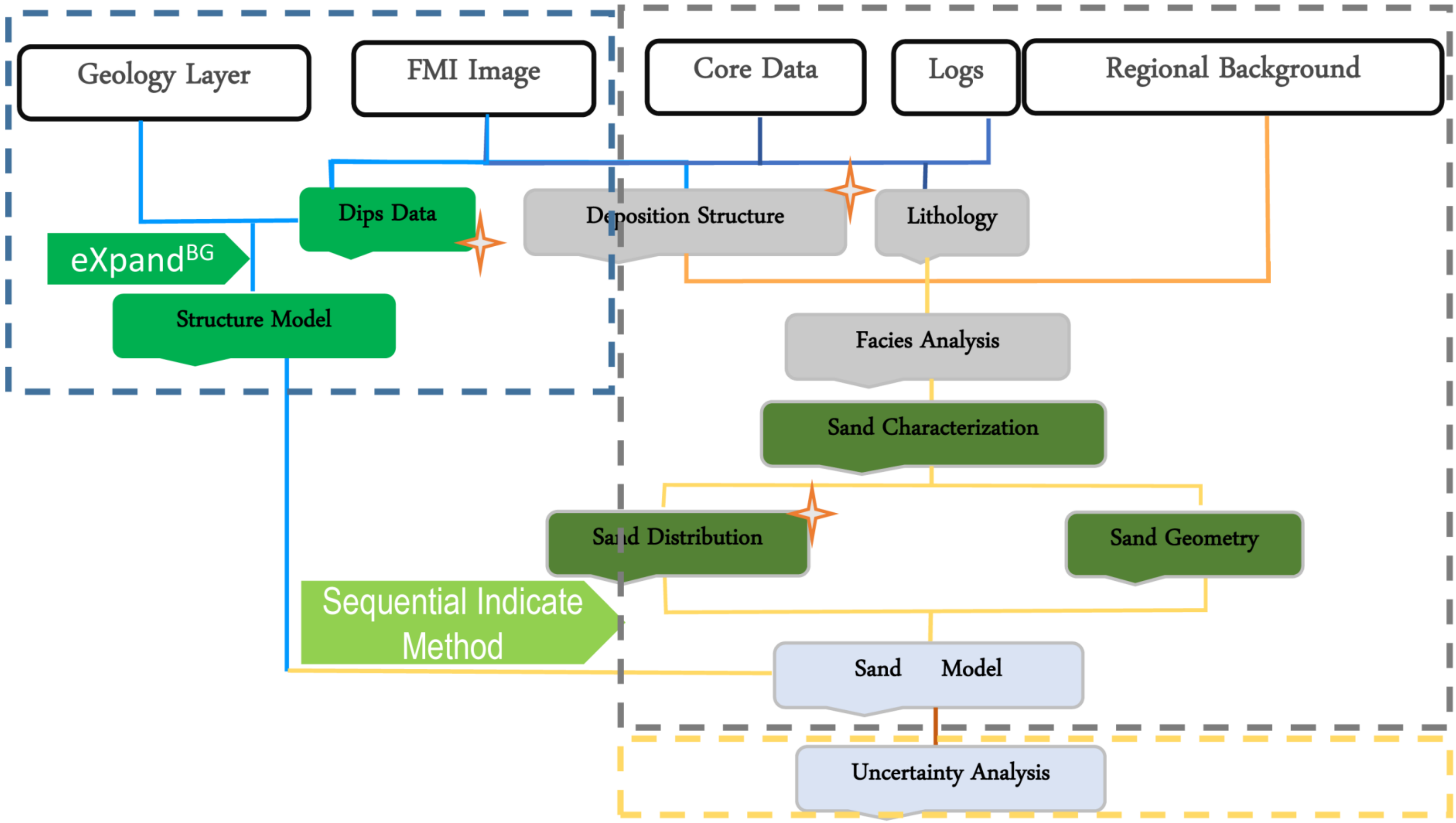

Figure 3. Workflow for geology modeling.

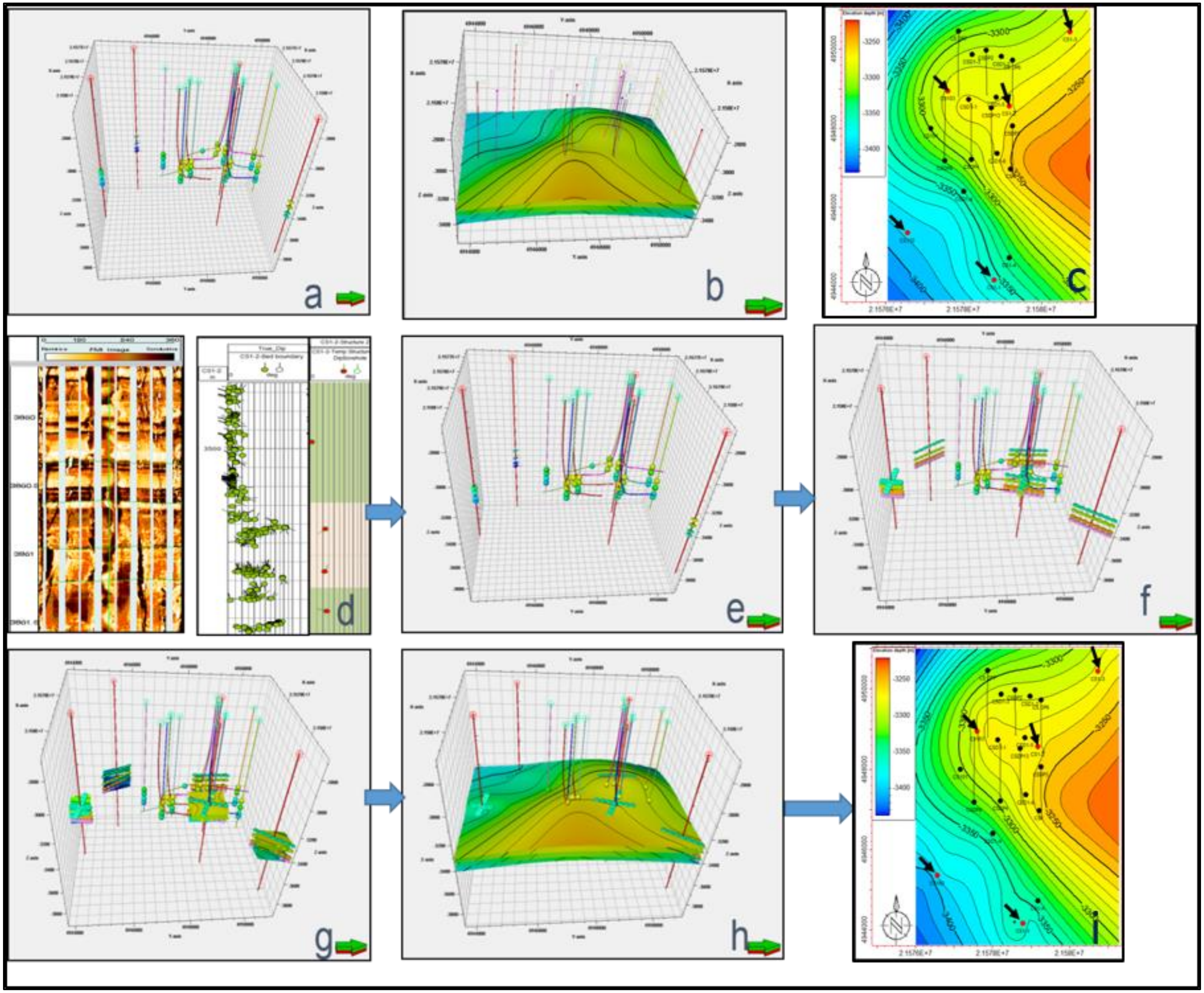

Figure 4. Accurate structure model using plug-in application in a commercial E&P software platform Petrel.

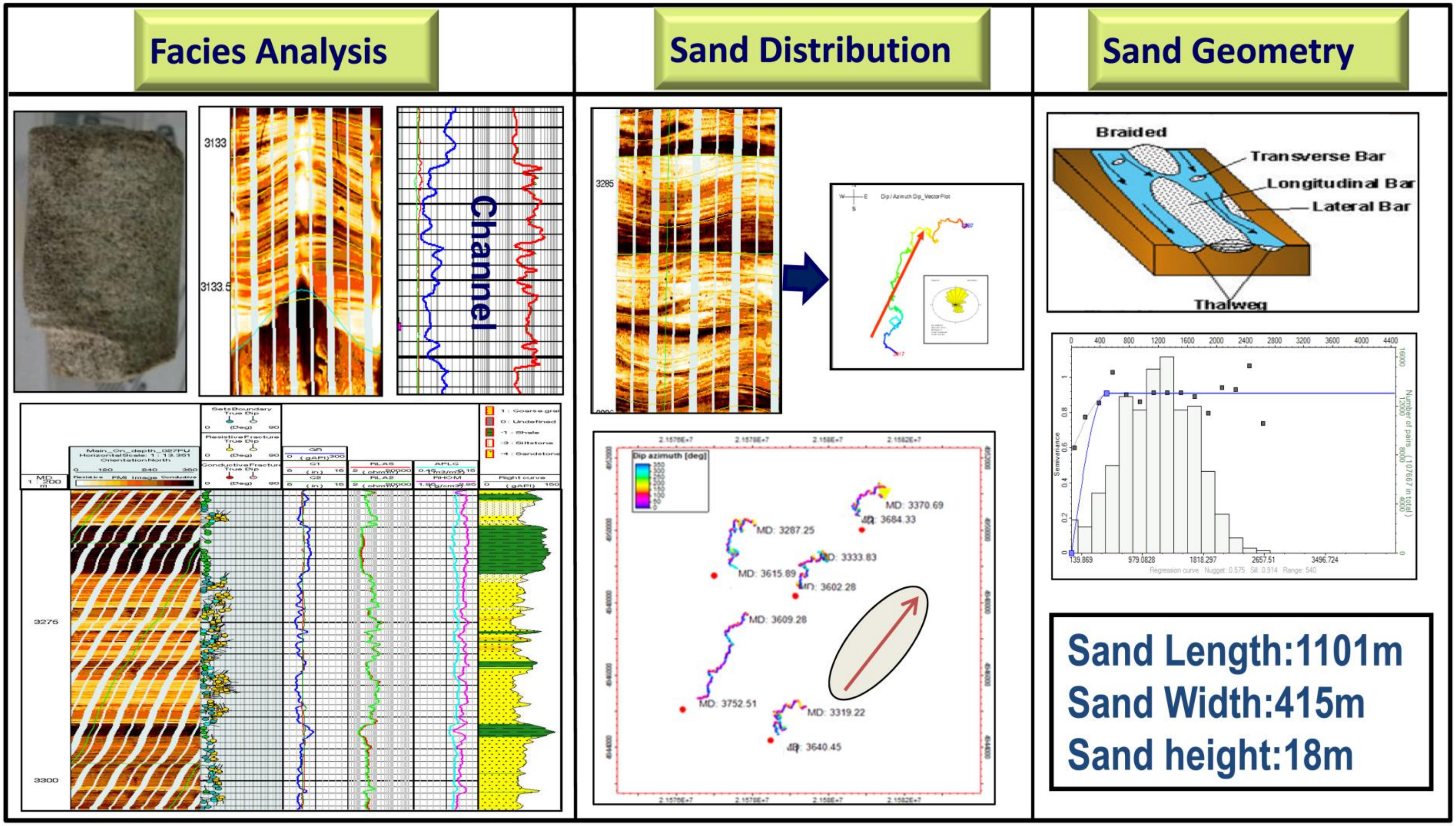

Figure 5. Sand characterization from the image data.

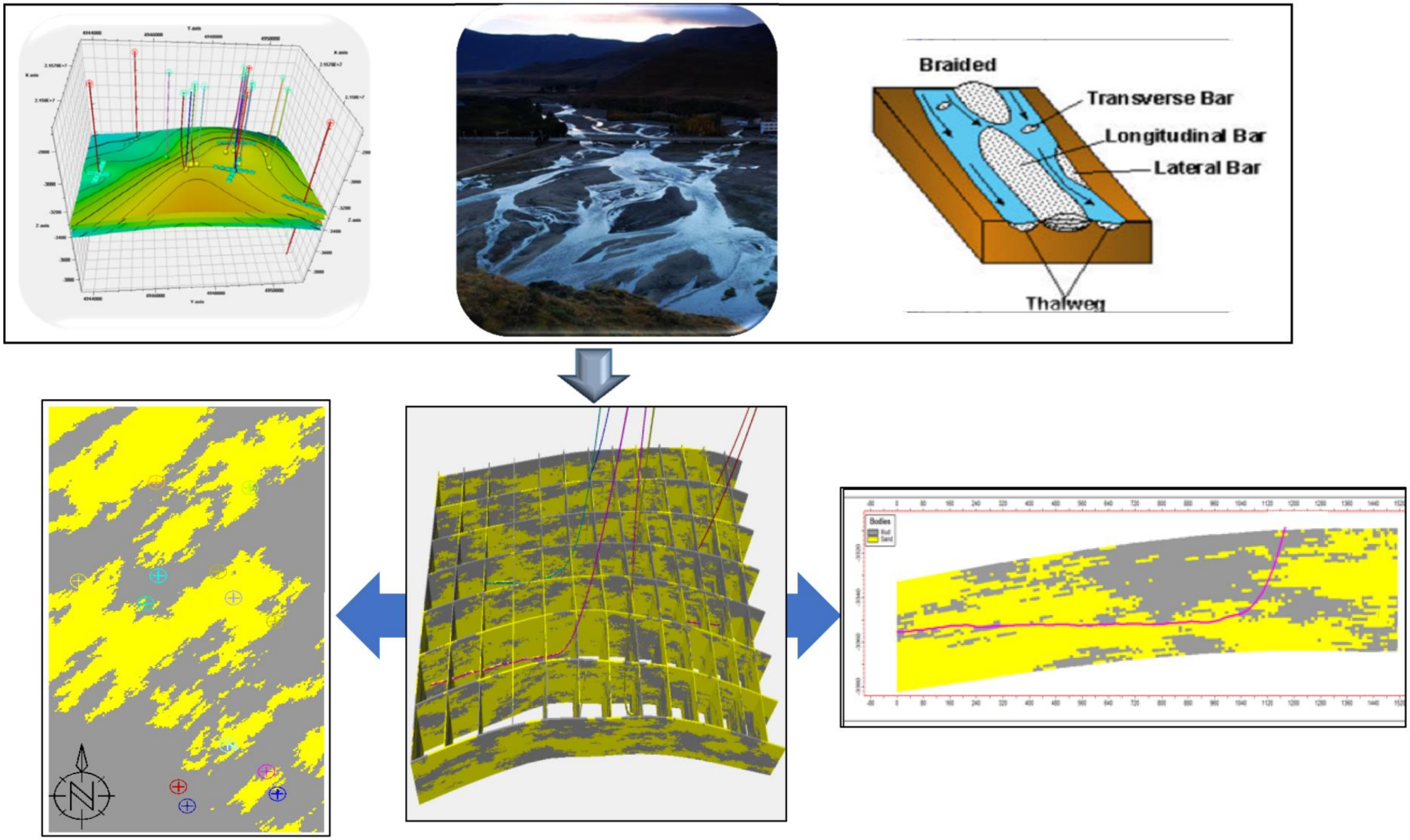

Figure 6. Stochastic modeling of 3D sand distribution model.

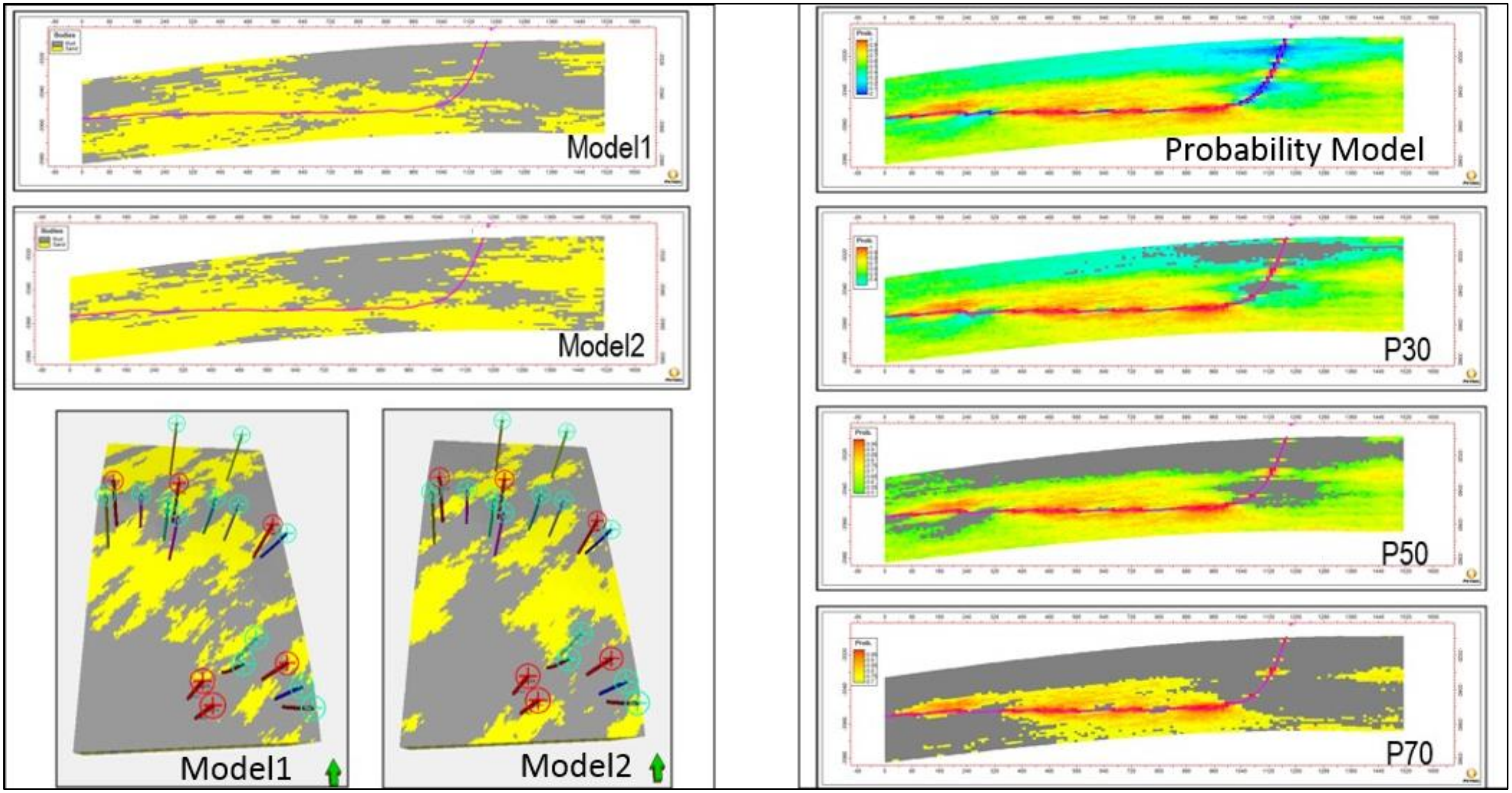

Figure 7. Probability Model calculated from 100 sand model realizations.

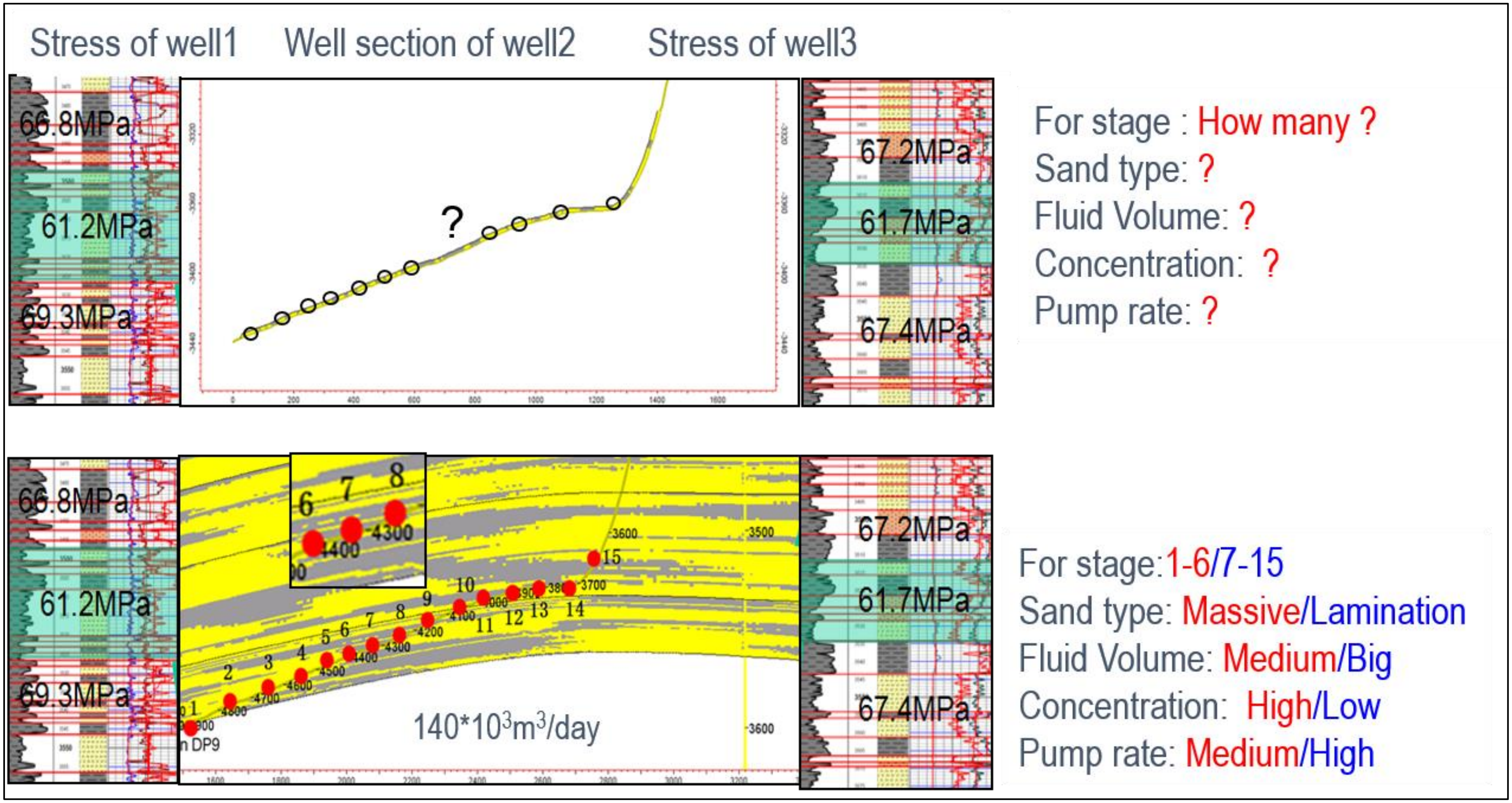

Figure 8. Guideline and optimize formation stimulation.