Building Highly Detailed, Realistic 3D Numerical Models of Rock and Reservoir Properties using Prestack or Full Stack Seismic Data

Rigorous incorporation of all data reduces uncertainty

Uncertainty will always play a dominant role in oil field exploration and development. Because uncertainty drives costs, quantifying and minimizing that uncertainty is a primary goal for asset teams. To achieve this goal, geologists and geoscientists must make sense of disparate data, bringing together a myriad of information from different sources and with varying measurement scales. To further complicate the analysis, the data are always sparse and incomplete, leaving vast areas of the subsurface unmeasured. Fields that require an understanding of fluid properties captured in prestack data add another level of complexity, requiring the simultaneous analysis of multiple properties.

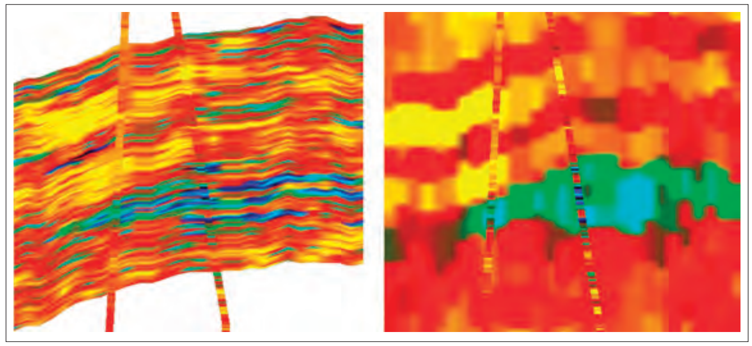

Figure 1: P-impedance from Geostatistical Inversion (left) versus deterministic inversion (right). Geostatistical Inversion produces sharp boundaries, is realistic, and contains accurate details. The large-scale features are the same between the two methods, as expected. This is a blind well test.

Rising to this challenge is a new best practice: combining well, seismic and other data through 3D Geostatistical Inversion. Validated by leading industry experts, this best practice has proven its value in producing highly-detailed, realistic 3D numerical reservoir models of prestack and full stack data with more accurate estimates of uncertainty and less bias than other reservoir modeling and characterization methods.

The Role of Geostatistics

Geostatistics was first introduced in the E&P industry as a means of interpolating and extrapolating petrophysical properties from available well data. Its ability to model spatially continuous features with heterogeneous properties proved to be a key differentiator from other statistical methods. Geostatistics has since become the standard for analyzing and integrating data from various sources with different scales as well as for increasing the reliability and objectivity of uncertainty estimates.

Popular geostatistical methods such as Sequential Gaussian Simulation have traditionally been applied to information coming from well log and core data. Early approaches for incorporating seismic data into the analysis generally relied on using seismic as trend information, often in the form of seismic attribute maps. This typically resulted in simulations with less uncertainty than those constrained to well logs only—especially away from well control. However, the loss of information incurred in reducing 3D seismic data to 2D representations meant that uncertainties and bias remained inadequately quantified.

Geostatistical Inversion

The next logical improvement in geostatistics for reservoir characterization and modeling came with integrating the full 3D seismic data volumes directly into the process. This is referred to as Geostatistical Inversion—a process that subsumes both deterministic inversion and geostatistical modeling, as it effectively does both simultaneously and in a statistically rigorous way. Geostatistical inversion is far more than simply constraining simulations to seismic data. It is about using geostatistical information in addition to a convolutional model and a wavelet and truly inverting from the measured 3D seismic data to the rock properties of interest.

Geostatistical Inversion enables asset teams to simultaneously incorporate all field data—including well logs, cores, and seismic—into an analysis that results in multiple highly-detailed and realistic models, each of

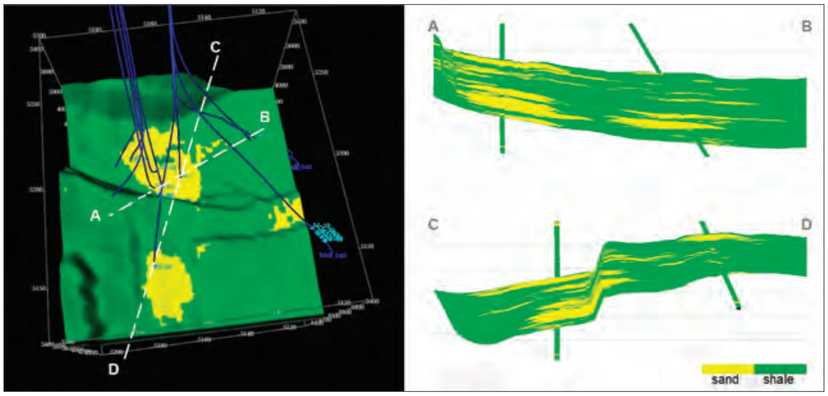

Figure 2: Map and sections of inverted lithology through the middle of a reservoir layer.

which honors all of the data known about the reservoir. These models are built from prestack or full stack data, are accurate near and away from wells, have realistic detail beyond the seismic bandwidth, and together provide more accurate estimates of uncertainty and bias than other methods.

Lateral Detail Away from Well Control

A great deal of data is available for individual wells, coming from measured logs, cores and various other sources. Unfortunately, the areal coverage of well data is extremely poor, thus making it difficult to reliably model the entire reservoir based on well data alone. Assumptions can be made, of course, but these are invariably associated with a high degree of subjectivity and uncertainty.

The difficulty in achieving accuracy away from well control can be significantly mitigated by using the seismic data, as it offers particularly dense areal coverage (on the order of tens of meters). By combining these dense areal measurements with the dense vertical measurements coming from the wells (on the order of centimeters), Geostatistical Inversion can be used to produce realistic, highly-detailed and accurate models both near and away from well control.

Another key advantage of Geostatistical Inversion is that the dependency on the number of wells is greatly diminished. Studies have demonstrated that models based on well logs alone can be very sensitive to the specific data included. In some examples, removing a single well from the analysis can completely alter the resulting reservoir model. Thanks to the inclusion of seismic data, this is not the case for models produced using Geostatistical Inversion.

Vertical Detail Beyond Seismic Bandwidth

While the areal coverage of seismic data is extremely dense compared to that of well logs, the vertical resolution is quite poor (tens of times coarser). As a result, the presence of entire reservoirs in thin sand regions can be missed by the seismic measurements.

Geostatistical Inversion overcomes the limited vertical resolution of the seismic by incorporating the statistical information obtained from the highly-detailed well logs. Because the detail exists in the well data, applying these statistical representations as constraints in the Geostatistical Inversion process yields realistic models even away from well locations. The statistical representations are controlled with histograms and variograms also obtained from well logs, thus ensuring that the detail beyond the seismic bandwidth is consistent with all known information.

Realistic Geological Shapes

To be effective, numerical models of reservoirs must exhibit geologically-plausible depositional shapes. This proved difficult with conventional geostatistical techniques, as these generally relied on the assumption of an underlying linear spatial correlation model. With such an assumption, only the most basic geometric shapes (e.g., ellipses) are reproducible. Naturally occurring geological patterns such as sinuous meandering channels are too complex to be captured. More complex geostatistical modeling techniques have recently been proposed to model curvilinear shapes, but these are difficult to use and largely dependent on subjective parameter settings (e.g., training images).

By fully integrating 3D seismic data in the Geostatistical Inversion process and simultaneously inverting impedance and lithology, it is possible to produce far more objective and geologically-plausible models than with other methods. The seismic contains a tremendous amount of specific information regarding the shapes of geobodies in the subsurface. The direct physical sampling provided by the seismic far outweighs the potential benefits that can come from explicitly specifying what these shapes should look like via the input geostatistical constraints.

Fluid Modeling

When S-impedance data is available from well log data, it can be used to determine the presence of gas or oil-filled sand within the reservoir. This is particularly useful in complex geologies with thin reservoirs. The prestack data is inverted simultaneously, in any combination of P-impedance, S-impedance and density.

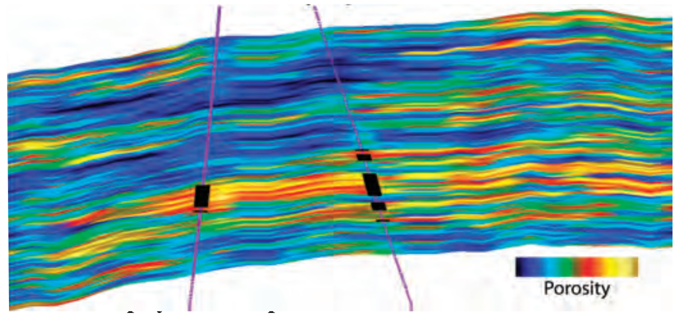

Figure 4: Cosimulation results of porosity from P-impedance. Black markers on the well tracks indicate pay in the wells. This is a blind well test.

There is a great deal of interdependency between the various properties. Simulating them in a dependent manner improves the interpretation because there is a better constrained inversion. For some fields there is greater stability in the process by using a combination of P-impedance and S-velocity while others may work best using a ratio of P-velocity to S-velocity.

Prestack inversions use either the Knott-Zoeppritz modeling technique or Aki-Richards. Multi-component data can also be included in the inversion if PS seismic data is available.

Because prestack inversion takes shear data into account, the resulting model can show the presence of fluids, the type and even how it has changed over time (if a seismic time series is available).

Prestack inversions are better constrained but they are also more compute intensive and susceptible to bias. To address the added compute strain, multi-threading and multiple CPUs are often employed. To minimize bias, additional quality control steps must be followed.

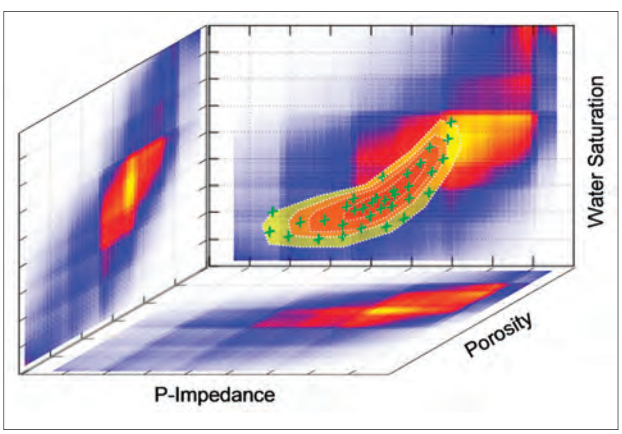

Figure 3: Multivariate distribution for P-impedance, porosity, and water saturation. The green crosses are the samples obtained from the wells. The three density plots are projections of the distribution onto the respective planes.

A challenge when integrating 3D seismic into geostatistical modeling is the lack of a direct physical relationship between petrophysical properties and seismic measurements. This limitation can be largely mitigated by using a two-step statistical process known as cosimulation. The first step consists of establishing a proper multivariate statistical relationship between the elastic and the petrophysical properties of interest (e.g., impedance and porosity). This is generally done by analyzing well log data in conjunction with rock physics modeling. The second step consists of simulating the petrophysical properties of interest by constraining them to this derived multivariate distribution and to previously inverted volumes of impedance and lithology.

Combined with Geostatistical Inversion results, cosimulation yields highly-detailed models of lithology-dependent petrophysical properties. These models can be either static (e.g., porosity) or dynamic (e.g., fluid saturation), the former being of interest for target identification; and the latter being of clear interest for modeling plausible fluid movements using time-lapse seismic data.

Integration of Soft and Hard Data

Given that there is always uncertainty regarding the subsurface, there is a compelling need to inject experience into the reservoir characterization and modeling process. Qualitative data such as the understanding of the physical processes underlying the spatial distribution of the rock layers comes from professional experience. This 'soft' data can be extremely helpful if it is used in a controlled way that doesn't result in a highly subjective model.

Geostatistical Inversion techniques are well-suited for incorporating expert knowledge without over-

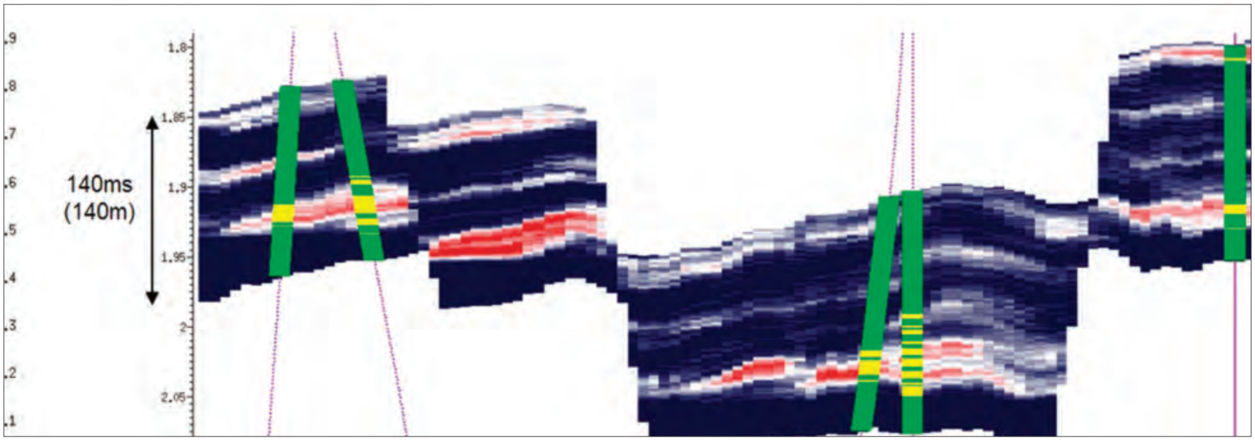

Figure 5: Section between two wells showing the uncertainty of predicted pay across 10 realizations of Geostatistical Inversion. Red means 10 out of 10 realizations predicted pay, while black means zero out of 10 realizations predicted pay. This is a blind well test—the wells shown were not used in the inversion.

constraining the solution. A confidence level is assigned to each input data source and the algorithm uses a probabilistic technique to balance and weigh the importance of all inputs within the specified constraints. The resulting numerical model integrates soft and hard data in the most unbiased and realistic form.

Reliable Estimates of Uncertainty

Geostatistical Inversion makes it possible to generate multiple predictions, each of which honors the known input information and is a plausible model of what the reservoir might look like. This is a significant advantage. Unlike the single best-guess prediction offered by other methods, multiple plausible predictions provide an intuitive understanding of uncertainty associated with any given model. Typical sources of uncertainty captured by proper geostatistical inversion methods include data sparseness, measurement and processing errors, simplifications in mathematical models, and limitations in knowledge of the mathematics of the underlying physical processes.

An accurate understanding of uncertainty is critical for risk assessment, scenario analyses and sensitivity analyses. These evaluations depend on the ability to identify which data sources are most likely to reduce the overall uncertainty prediction and to properly weight redundant data. For example, well data is almost always preferentially clustered in higher pay areas. The redundancy of the information coming from such wells needs to be properly accounted for in order to avoid biasing the predictions.

Once uncertainty is adequately captured, different realizations and scenarios can be ranked—only then can risk be evaluated and informed decisions be made.

Introducing StatMod MD and RockMod

StatMod® MC combines geostatistics and advanced statistical physics with innovative seismic inversion methods to integrate disparate data from multiple sources and produce reservoir models that reliably quantify uncertainty for risk assessment and reduction.

StatMod MC goes beyond traditional geostatistics and seismic inversion to:

- Integrate high resolution well data with low resolution 3D seismic
- Improve the vertical detail over deterministic seismic inversions
- Produce reservoir property models with geologically-plausible shapes
- Quantify model uncertainty for scenario analysis and risk assessment
- Generate highly-detailed petrophysical models ready for input to reservoir flow simulation

With StatMod MC, geologists, geophysicists and other geoscientists can build highly-detailed realistic 3D numerical models with more accurate estimates of uncertainty and less bias.

RockMod® is specialized for interpreting prestack data, delivering all the value of StatMod MC plus identifying what fluids are where and their movement over time.

The StatMod MC Workflow

The StatMod MC workflow is an expanding loop that incorporates more and more constraints as it is built. Once data conditioning has been done, the initial runs are done without constraints, then the simulations are constrained to well data, and finally to the seismic data as well. Throughout the process, key QCs are automatically produced by StatMod MC.

Ultimately, StatMod MC simultaneously inverts the lithology and impedance properties to produce a series of realizations that honor all the input hard and soft data. These realizations are then used in cosimulation to produce the highly-detailed, realistic petrophysical properties desired, such as porosity and water saturation.

The StatMod MC workflow steps are:

1. **Statistical Modeling**. Each source of input information (e.g., wells, cores, seismic) is represented in the form of a probability density function (PDF) characterized in geostatistical terms (histograms and variograms). The histograms and variograms are obtained from log analysis, rock physics modeling and geological insight. The histograms define the likelihood of different values at any given point, while the variograms give essentially the 'characteristic scale' and texture of the geological features in lateral and vertical directions.

2. **Bayesian Inference**. Bayesian inference techniques are used to merge these individual PDFs together and obtain a posterior PDF conditioned on all known and inferred information. This posterior PDF represents the overlap between all of the input PDFs—think of it as some sort of 'evidence fusion'. The advantage of this approach is that the weight assigned to each input data source is automatically determined by the algorithm, thus removing subjectivity.

3. **Inversion and Cosimulation**. A customized Markov Chain Monte Carlo algorithm is used to obtain statistically fair samples from the posterior PDF. A fair sample in this case means volumes of rock and reservoir properties of interest (e.g., P-impedance, lithotype, porosity, water saturation). Because all of the input data is effectively inverted simultaneously, significant synergies can be exploited, thus producing models that are of greater detail, accuracy and realism than otherwise possible. The Geostatistical Inversion and cosimulation procedures are iterated until a model is found that matches all information, from geological expectations to well logs, seismic, and production history.

4. **Uncertainty Assessment**. Estimates of uncertainty are made by producing a series of slightly different realizations and scenarios. Different realizations are produced by repeating the above steps with different random seeds. Different scenarios are produced by targeting the uncertainty in the more sensitive parameters. Together, such analyses give an intuitive and accurate handle on development risk and uncertainty, given what is known about the subsurface.

StatMod MC is part of the Jason Geoscience Workbench® (JGW). JGW includes 3D seismic inversion, wavelet estimation, geostatistical inversion, AVA simultaneous inversion, rock physics, petrophysics, reservoir modeling and advanced analysis and 3D visualization. As a result, geological, geophysical, petrophysical and rock mechanics information integrates into a single consistent model of the earth.

The RockMod Workflow

RockMod® follows the same workflow as StatMod MC except that it works with multiple volumes of prestack data. RockMod simultaneously inverts lithology and impedance properties—including any combination of S-impedance, P-impedance, and density—to produce realizations that honor all hard and soft data. As with StatMod MC, these realizations are then used in cosimulation to produce the highly detailed, realistic petrophysical properties desired.