INTEGRATED RESERVOIR CHARACTERIZATION AND MODELING

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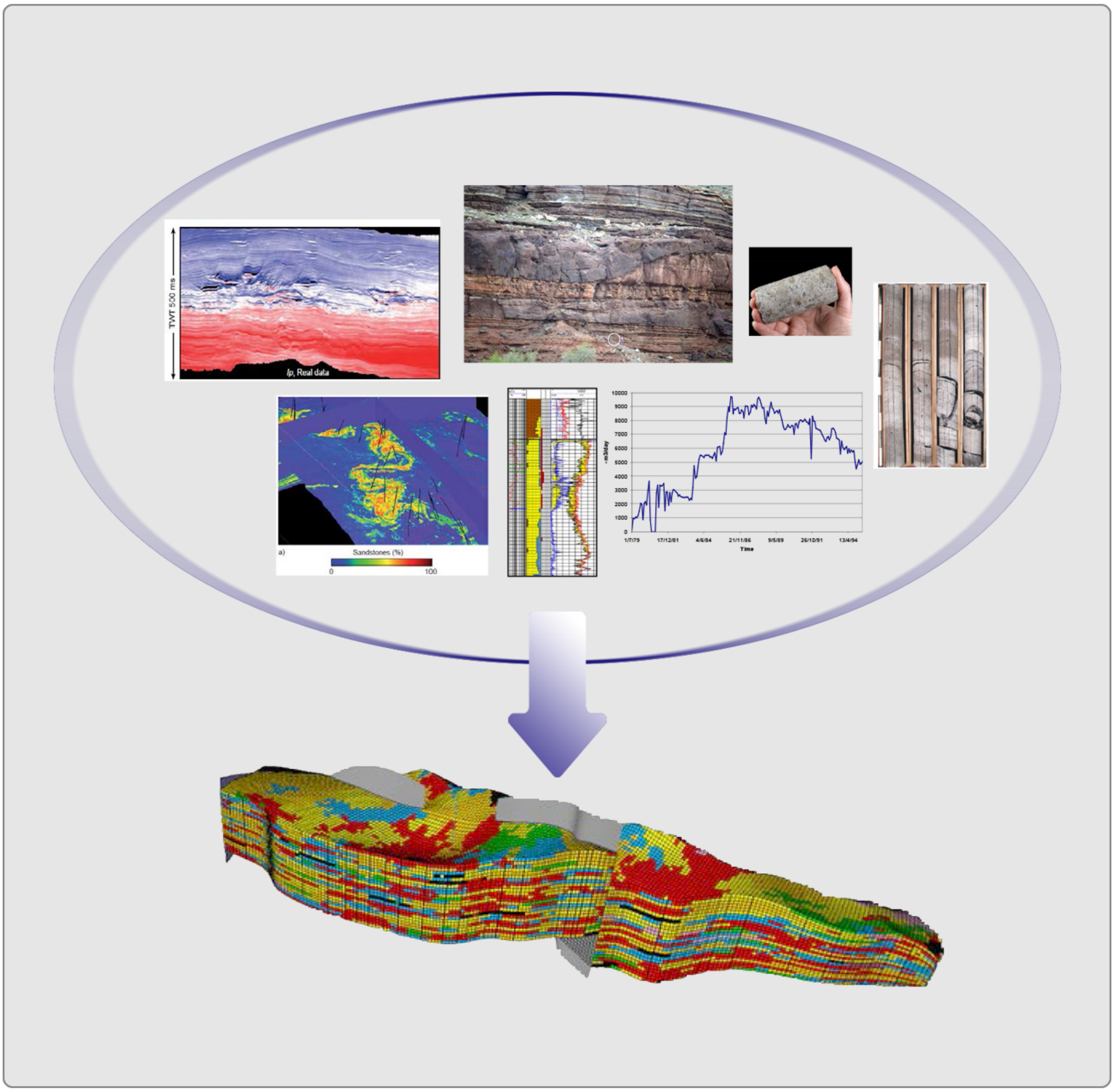
Chapter 3



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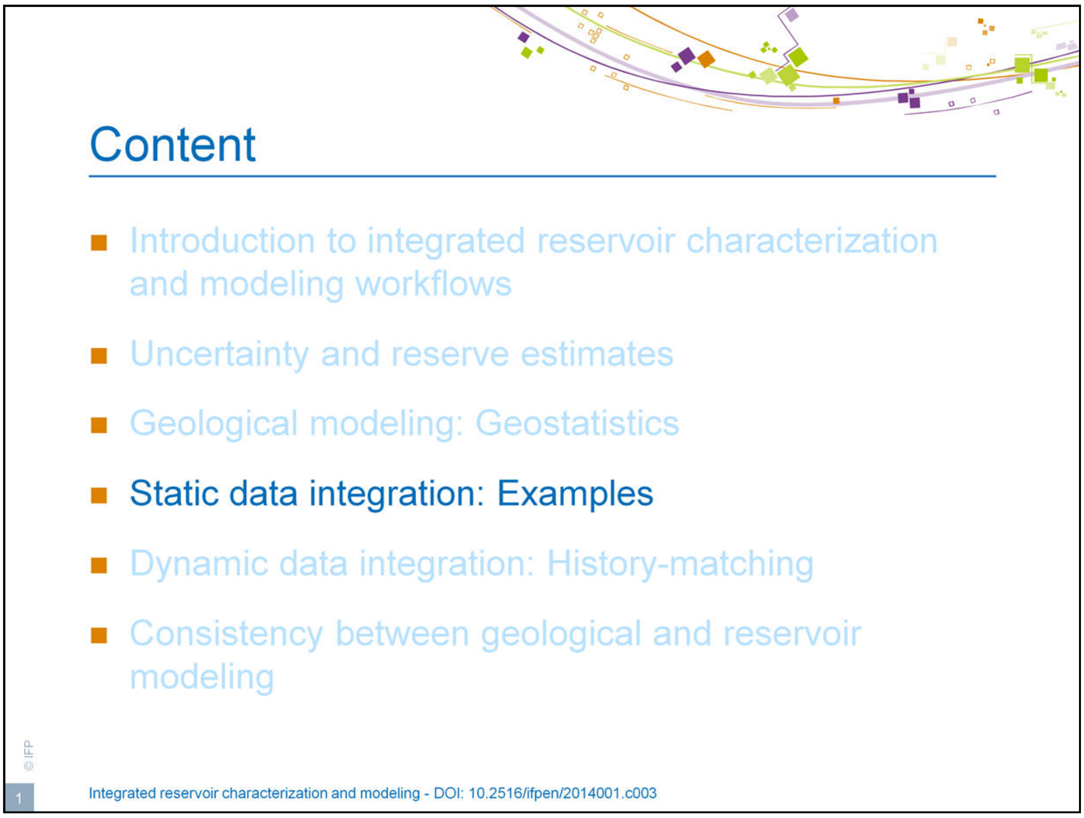
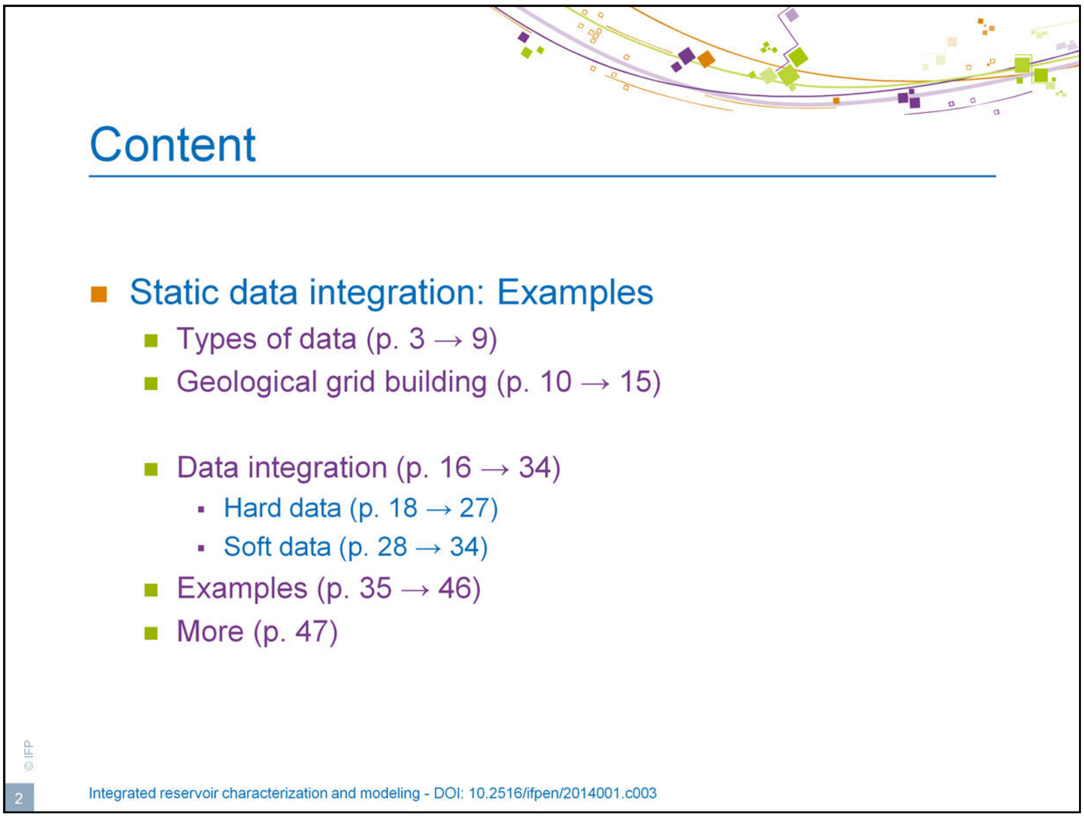


Chapter 2 introduced the basics of geostatistics for geological modeling. In particular, we showed how to characterize the spatial variability of a given property from data. Then, various techniques were presented to generate realizations representing the spatial distribution of this property within the geological or reservoir models.

Up to that point, the integration of static data remained elusive. By data integration, we mean that the randomly drawn realizations have also to honor data at locations where there are data. This is the topic of this third chapter.

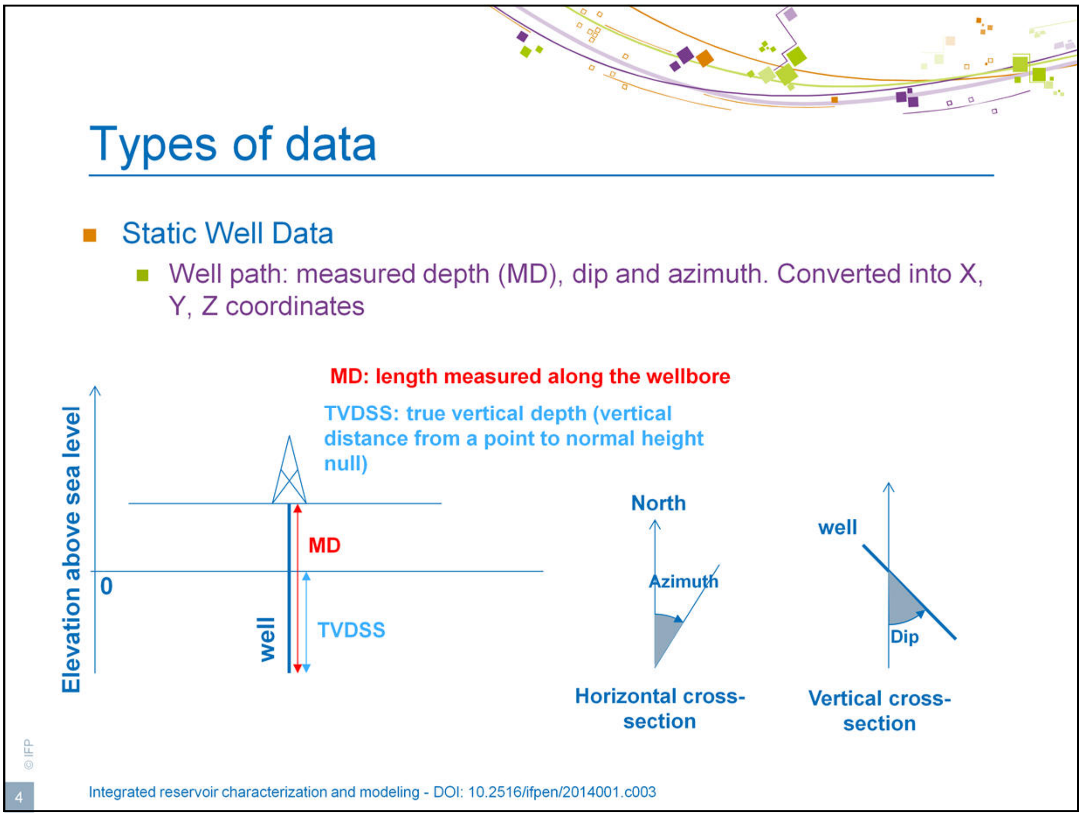


The main points covered in this chapter include the types of data that are considered, the building of the grid supporting the geological model, the techniques developed to integrate data and the description of a few examples illustrating how static data are incorporated into the geological model.

Content

- Static data integration: Examples
  - Types of data
  - Geological grid building
  - Data integration
    - Hard data
    - Soft data
  - Examples
  - More

This first section lists the data of interest. At this stage, we restrict our attention to static data.



As pointed out in Chapter 2, p. 5, geostatistics can handle variables of any dimension, irregular and incomplete data collections as well as external information to supplement the direct measurements of the property studied. For example, porosity measurements are direct measurements that can be complemented by external information such as an impedance map. The measurements quantifying the target property are often called hard or primary data. The external information is called soft or secondary data.

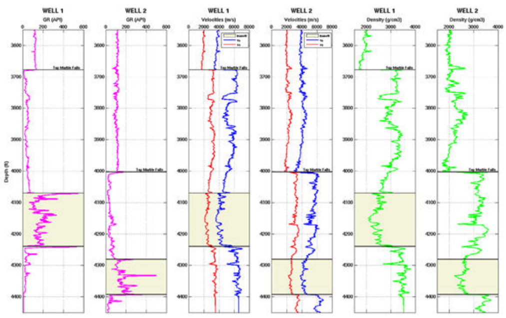
A crucial issue to reduce the uncertainty associated with a geological or reservoir model is to account for all data that can be of very distinct natures. They consist of static and dynamic data. The dynamic data are beyond the scope of this chapter. As for the static data, they consist of well and seismic data.

Well data include:

- the definition of the well trajectory from the measured depth (MD), the dip and azimuth. The measured depth is the length measured along the well; the azimuth is an angle (degrees) typically measured clockwise from north; the dip (degrees) characterizes the deviation of the wellbore from the vertical axis (the dip is 0° for a vertical well and 90° for a horizontal well). These data are converted into X, Y, Z coordinates.

Types of data

- Static Well Data
  - Logs
    - Porosity: neutron, density, and sonic logs + cores
    - Permeability: porosity logs + cores
    - Saturation: resistivity and porosity logs



Examples: gamma ray, sonic and density logs for 2 wells (Adelinet *et al.*, 2013)

Well data also consist of logs.

Various logs are used for reservoir characterization.

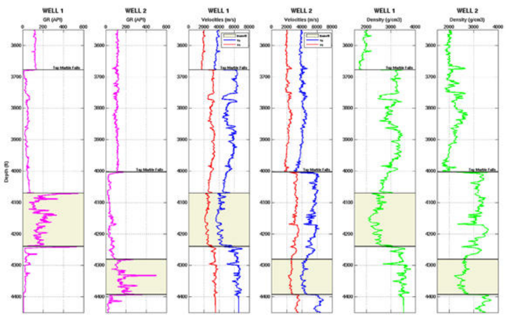
- Porosity ϕ is a measure of the fluid storage capacity of a porous medium. As such, it is a key factor to quantify oil and gas reserves as stressed in Chapter 1. There are three main types of logging tools to estimate the amount of pore space in rocks: the neutron, the density and the acoustic velocity (sonic) logs. These logs are often called porosity logs. They can also be complemented by measurements performed on cores.

- Permeability describes how easily a fluid is able to move through a porous medium. It is usually determined from the porosity logs and cores. An obvious control on permeability is porosity. The larger the pores, the broader the pathways for fluid flow. The plot of permeability (on a logarithmic scale) against porosity usually yields a trend with some scatter (due to other factors influencing permeability). Even though dynamic data will be considered in a subsequent chapter, it is worth mentioning that dynamic data (well tests or production data) are very useful to better characterize permeability.

- Saturation: water saturation S_w is estimated from the total porosity and the resistivity log (Archie, 1942). The hydrocarbon saturation is 1-S_w.

Types of data

- Static Well Data
  - Logs
    - Facies: logs (porosity, gamma ray) + cores + outcrops
    - Net to gross: cutoffs applied to porosity, Vsh…

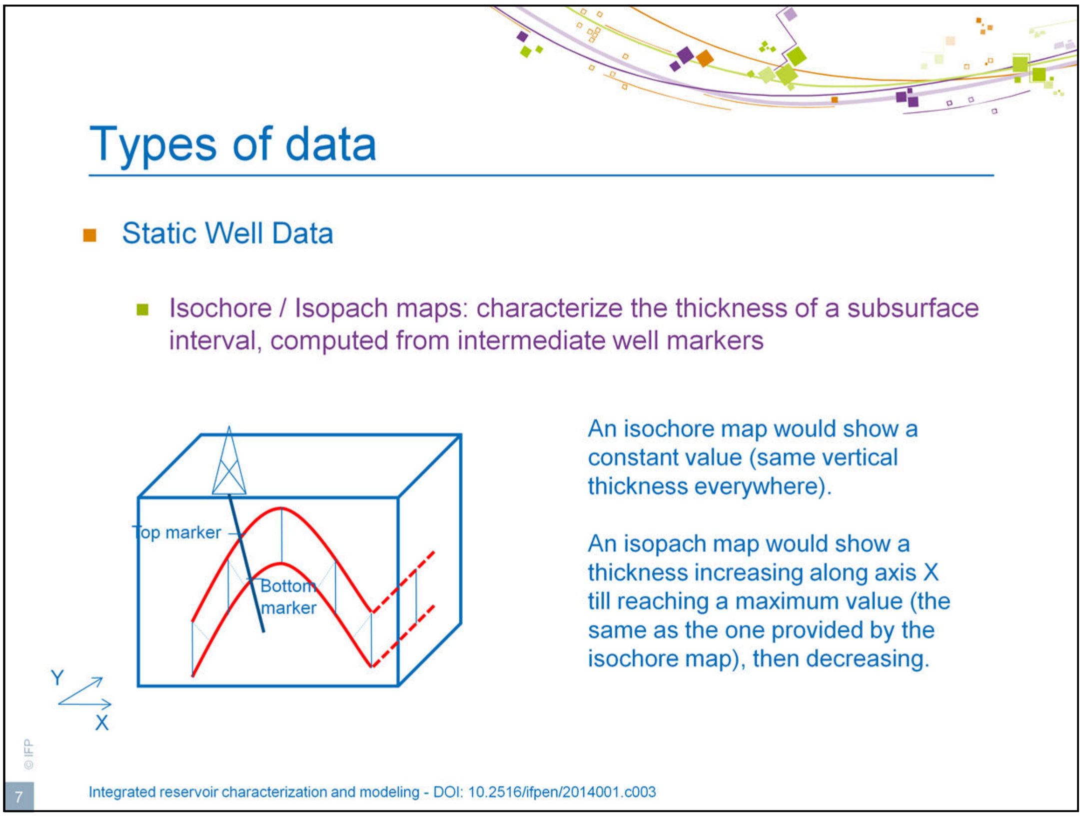


Examples: gamma ray, sonic and density logs for 2 wells (Adelinet *et al.*, 2013)

Logs also yield useful information to characterize facies.

- Facies: a facies is a rock with specific properties (see introduction, p. 24)
  - If defined only from lithological criteria, it is called lithofacies.
  - A sedimentary facies is a distinctive rock unit formed under given conditions of sedimentation.
  - Sedimentary facies or lithofacies are determined from cores and outcrop observations.
  - Electrofacies or log types are identified from logs (porosity logs, gamma ray).

- Net to gross ratio: based upon the definition of various criteria relative to porosity, volume fraction of shale, permeability. For instance, the reservoir rock can be defined from criterion $\phi > 0.10$. The net pay at each data point along the well has a value of either 1 (pay) or 0 (nonpay). The net to gross ratio (N/G) is the total amount of pay footage divided by the total thickness of the reservoir interval. A N/G of 1.0 means that the entire reservoir interval is pay footage.



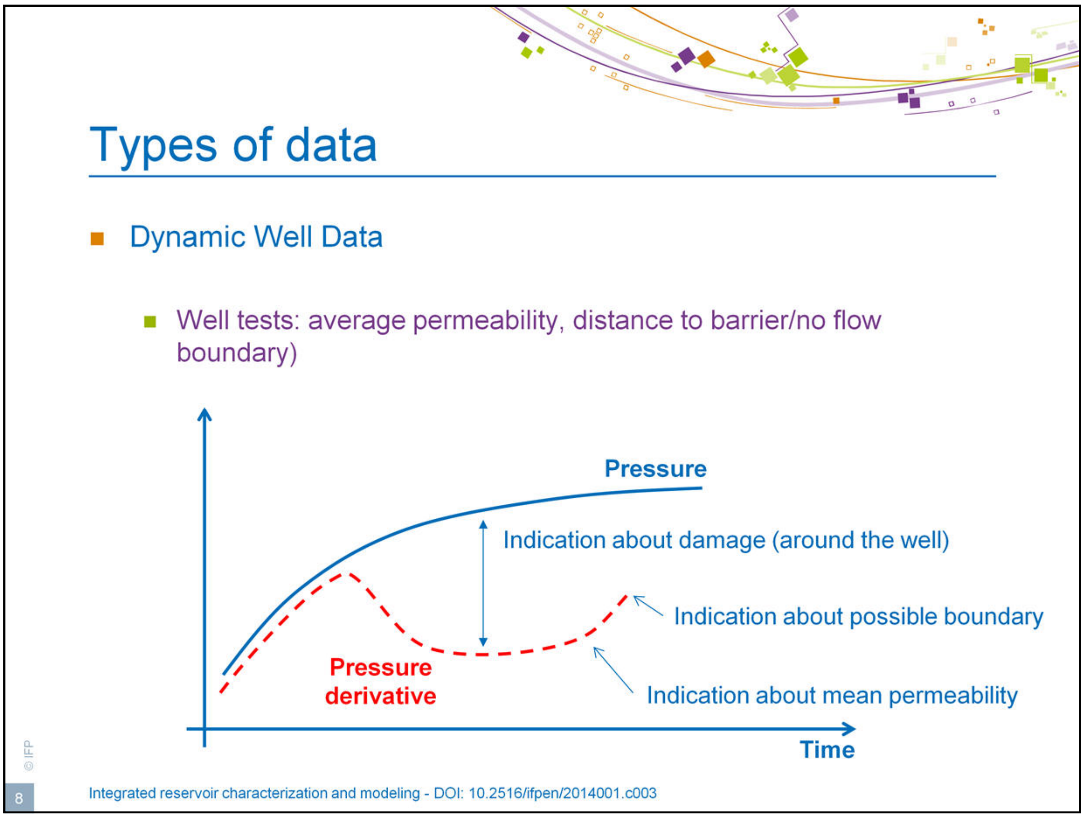
Thickness maps can also be derived from well data.

Isochore / Isopach maps provide information about thickness variations and trends of a given subsurface interval (*e.g.,* stratigraphic unit, reservoir layer). This helps determine ideal locations for new wells: wells can be drilled where the net pay thickness is the highest.

The geologists usually refer to isochore and isopach maps that are two different types of thickness maps. An isopach is a line connecting points of equal true thickness (thickness being measured perpendicular to bedding). Isopach maps are also referred to as true stratigraphic thickness (TST) maps. On the other hand, an isochore is a line connecting points of equal vertical thickness. Isochore maps are also called true vertical thickness (TVT) maps.

Isochore thickness is greater than isopach thickness for dipping layers.

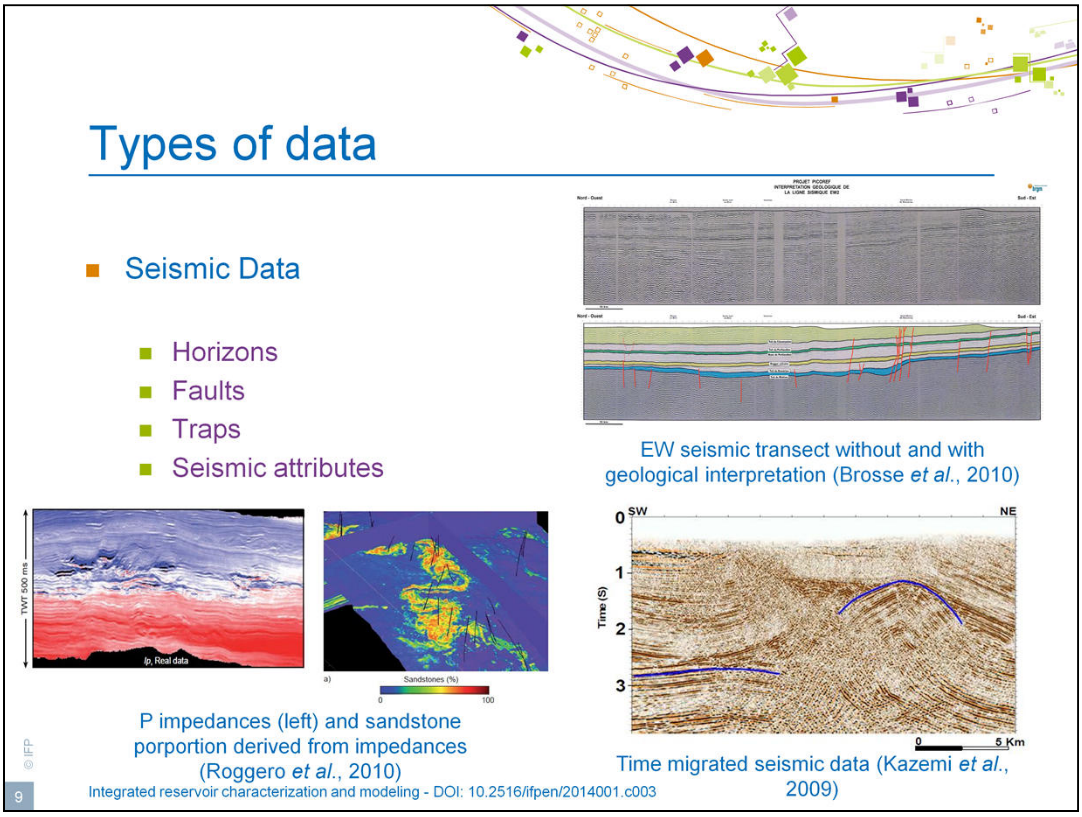
The isochore and isopach maps generally boil down to smooth surfaces computed from intermediate well markers.



Last, well data include the pressure variations recorded in wells during well tests (Gringarten, 2008). Strictly speaking, these pressure responses are dynamic data, not static data.

Basically, we test a well by creating a step change in rate, for instance by closing a producing well (this test is known as a buildup). The rate change induces a pressure change in the well. Then, the pressure response and its derivative with respect to time are used for estimating the average permeabilities around the tested wells and for determining the producing-formation limits (channel pinchout, fault, *etc*.).

This information, even though derived from dynamic data, is incorporated in the reservoir model at the same level as the static data already mentioned. This is the reason why well tests are listed in this section.

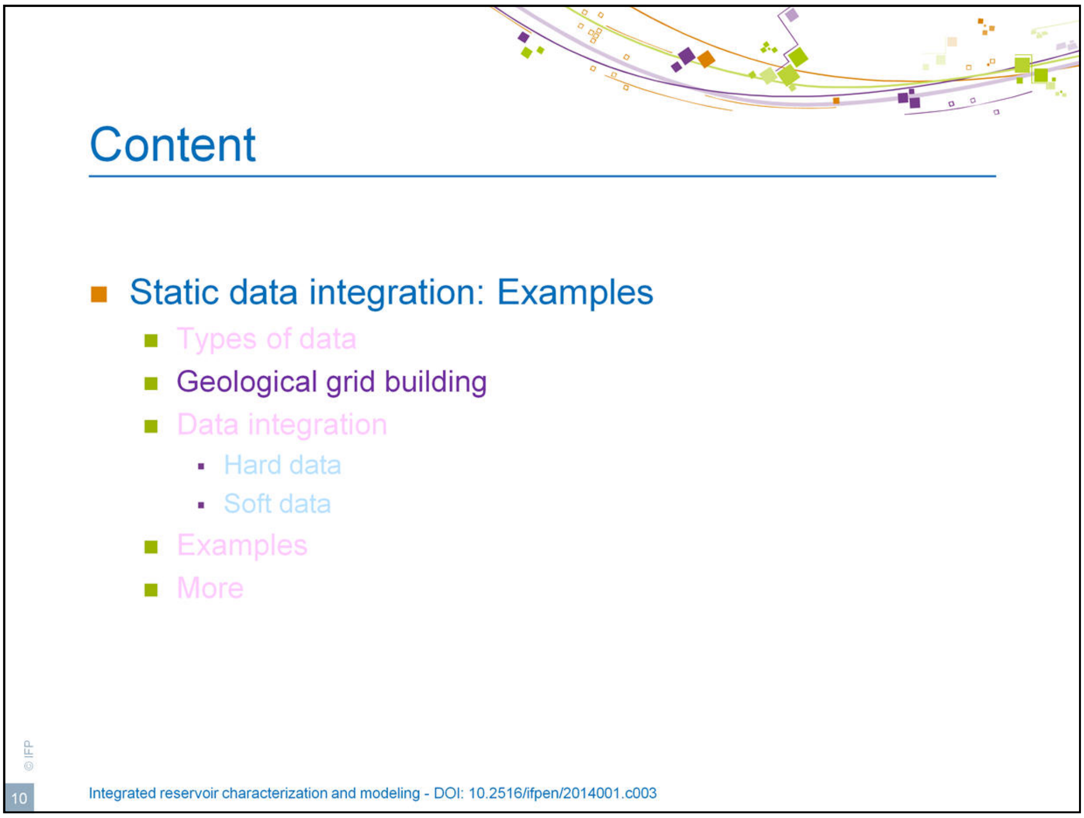


Another essential source of static data is seismic. Seismic data contribute to the geometric description of the structural and stratigraphic aspects of the reservoir. A mandatory primary step is the migration of seismic data in the depth domain since the primary geophysical seismic data are recorded in time.

Seismic is used to determine the locations of horizons and faults (*e.g.*, Brosse *et al*., 2010). This is usually referred to as **structural analysis**. The locations of the target objects are defined from picking and time to depth conversion. They are identified with good lateral definition, but poor accuracy (12.5 to 25m in XY, ~3000m/s × 4ms = 12m in depth).

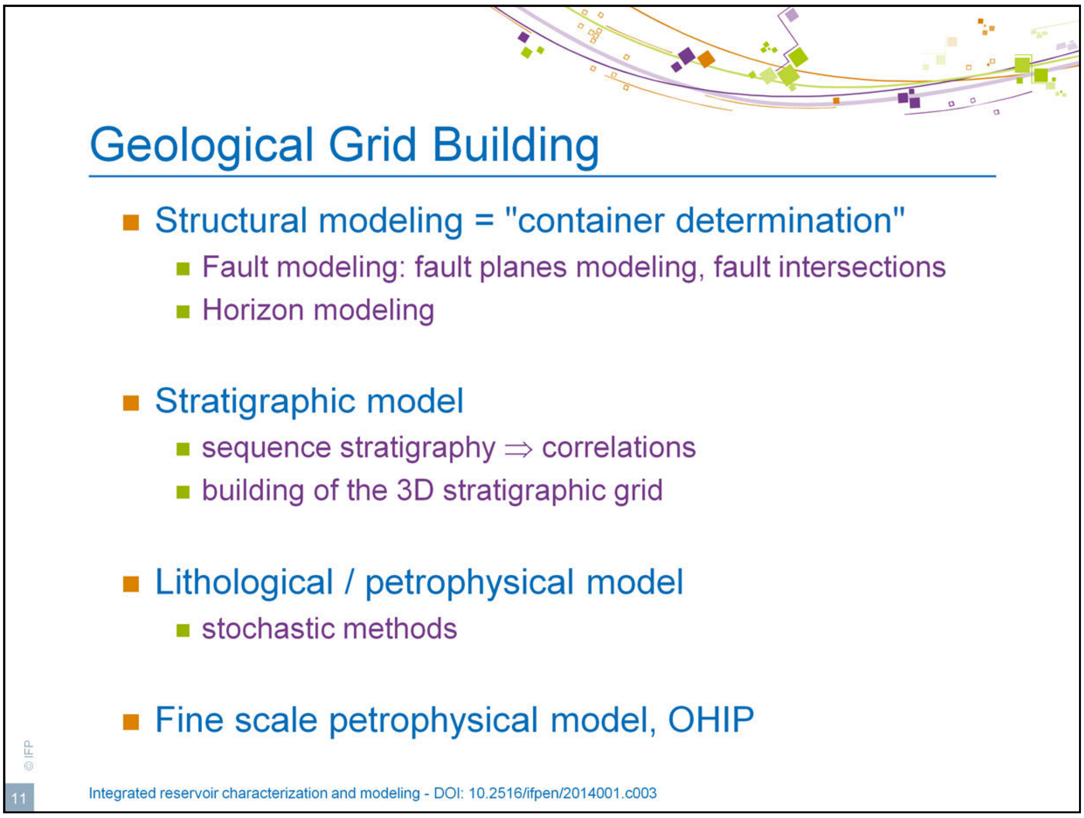
A second application based upon seismic data is known **as seismic sequence stratigraphy**. It is used to locate stratigraphic traps and to define the facies framework of structural traps.

Seismic data are also used to define **seismic attributes**, which yield information about structure, stratigraphy and reservoir properties (*e.g.*, Roggero *et al*., 2012). A seismic attribute is a measurement derived from seismic data. For instance, it can be an impedance. Seismic attributes reveal features and patterns that otherwise could not be detected. The analysis of multiple attributes can be automatically performed using geostatistic tools, principal component analysis, classification analysis. This results in seismic facies maps, porosity maps, net to gross maps…



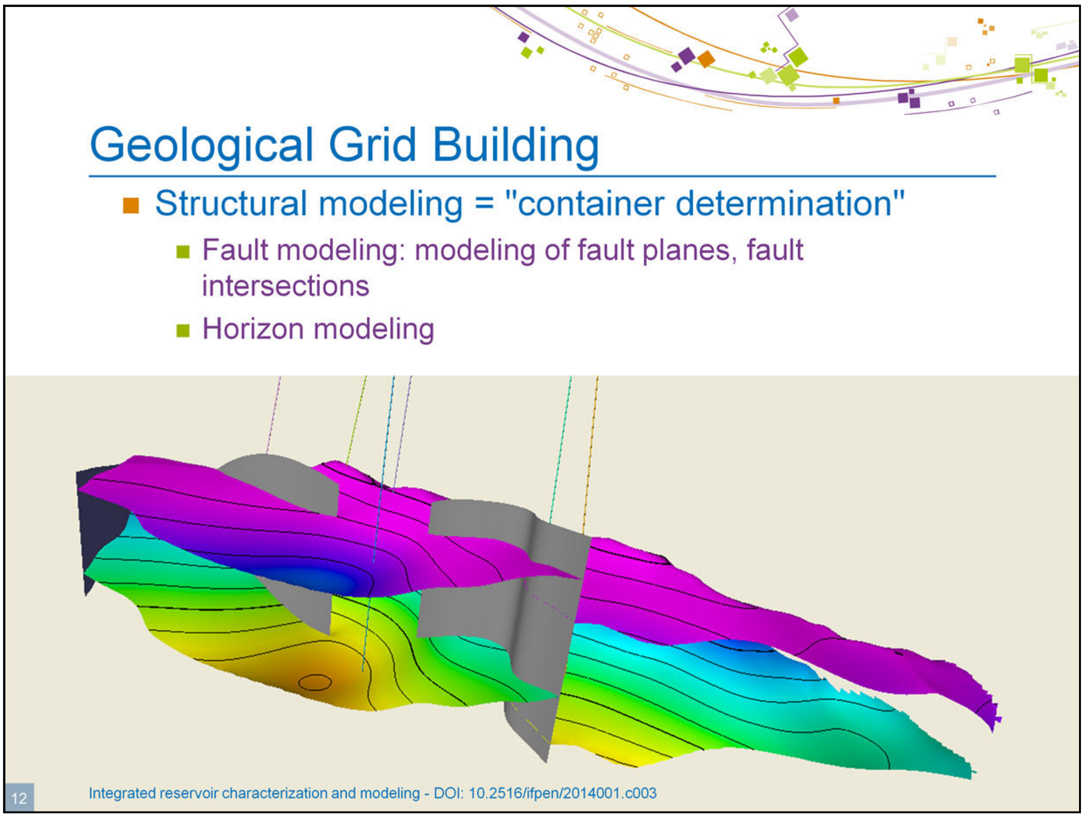
A crucial step of geological modeling is the construction of the geological grid. This involves

1) the definition of a structural model that describes the main boundaries (horizons, faults, intrusion, unconformities due to erosion) and
2) the definition of a three-dimensional mesh that respects the structural model.

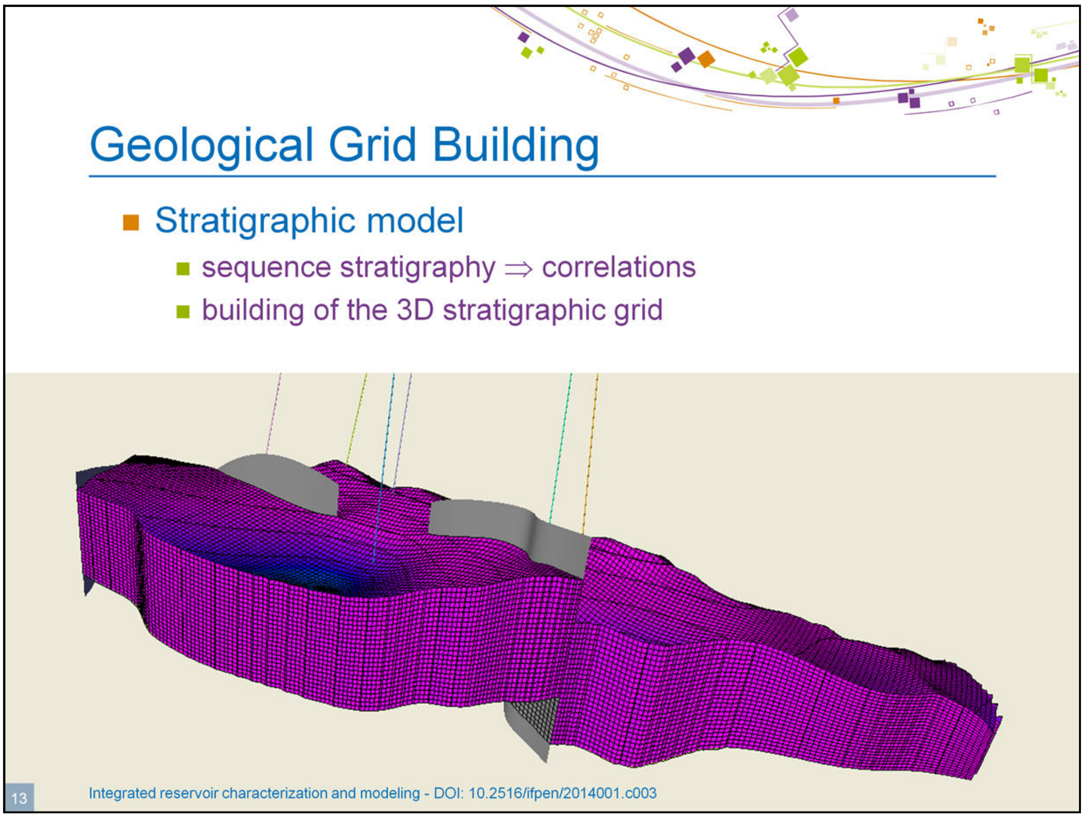


The reservoir simulation workflow is part of a far more complex workflow and data integration process where each step contributes to the final results and the associated uncertainties. Depending on tools and workflows, several terminologies and models are considered.

We may distinguish 4 main steps with structural modeling, stratigraphic modeling, lithological/petrophysical modeling and hydrocarbon volume computation. The first two steps actually provide the geological grid. The third one refers to stochastic methods to assign properties to every cells (see Chapter 2). This yields the geological model that is finally used to estimate the volumes of oil in place (see Chapter 1).



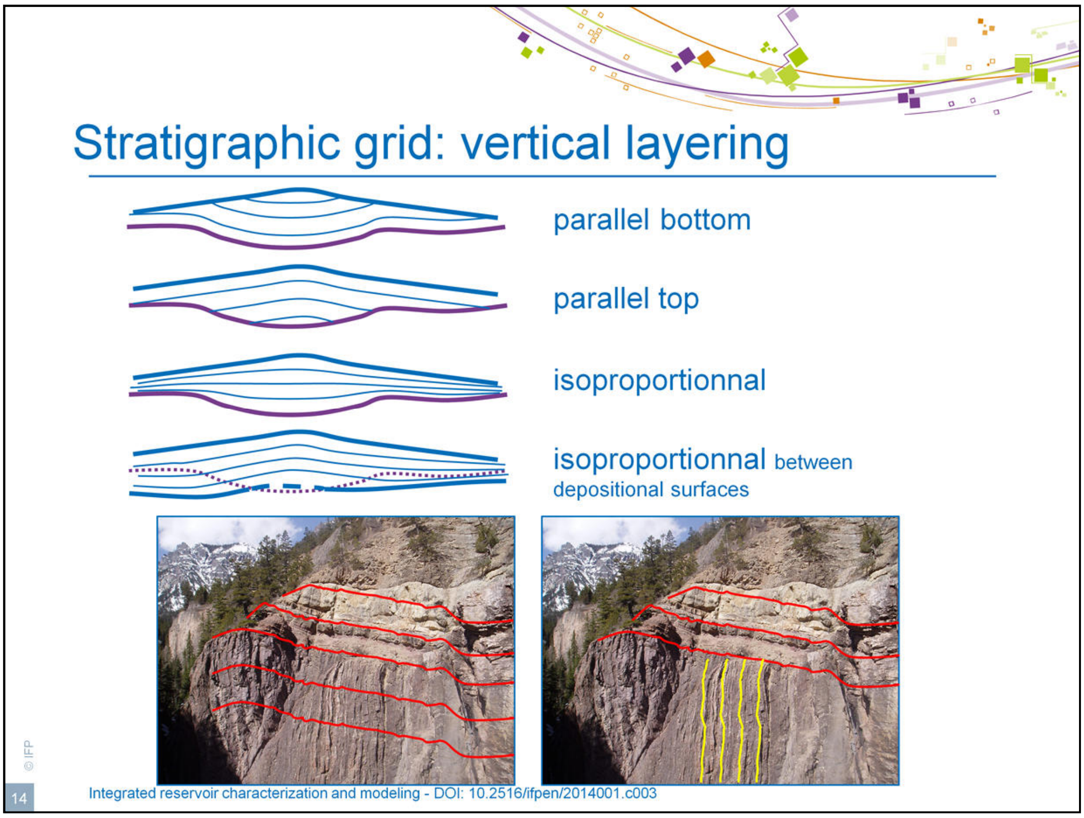
Structural modeling consists in defining the shape, volume and structural complexity of the studied domain. Primary components are the major horizons and faults recognized from seismic picking and time-to-depth conversion. They contribute to the skeleton of the geological grid.



The structural model being known, it is used to create the stratigraphic model, hence the geological grid.

The stratigraphic model is directly linked to the interpretation of sequence stratigraphy: it identifies the stratigraphic units, the reference horizons and time lines, which are associated to the correlation levels in the numerical process.

This grid entails corner-point cells with possibly irregular geometry. It is appropriate to represent complex geological structures: it conforms to strata, faults, intrusion, *etc*. The main stratigraphic units are split into layers with distinct geometries defined with respect to the bounding surfaces.



The figures above emphasize the need for consistency between the numerical model and the geologic stratigraphic model. A basic assumption is that seismic events (*e.g.*, horizons) follow stratigraphy. Therefore, the stratigraphic model is built with simple depositional rules such as proportional and parallel to top (or bottom or another surface), according to chronostratigraphy with a link between depositional mode and time lines.

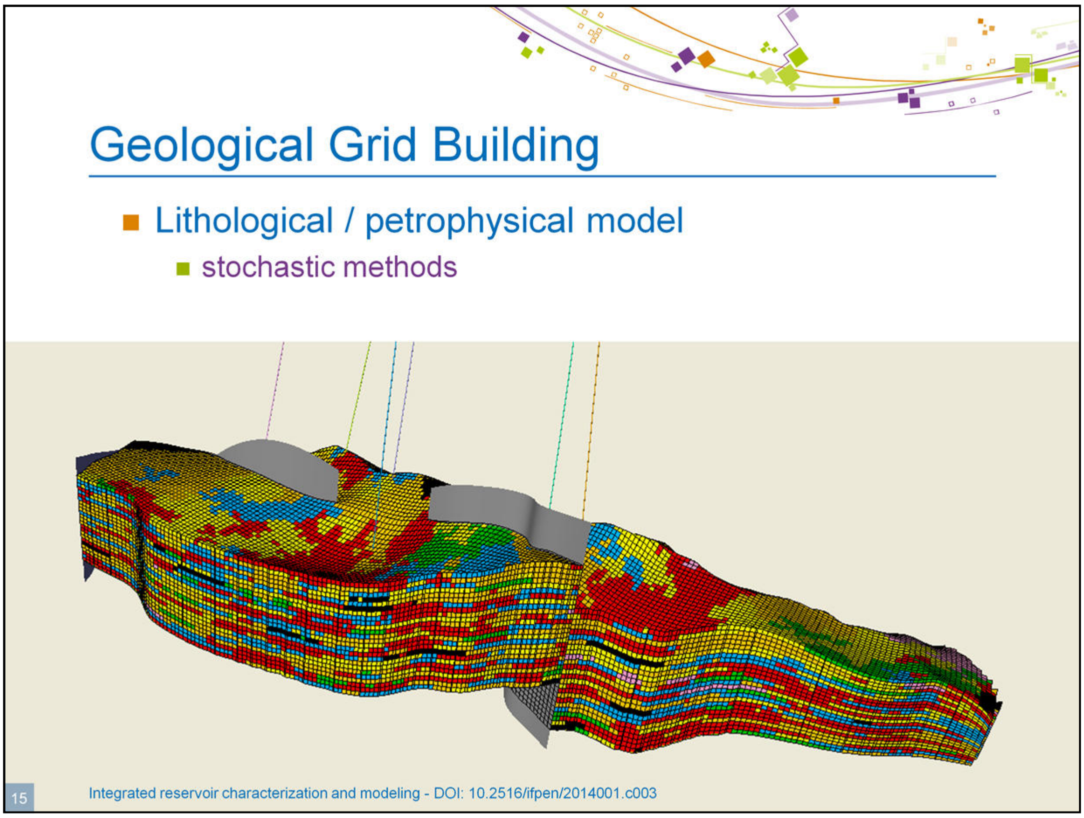
A layering parallel to the bottom represents sediment draping over an erosional surface. It is also used when an erosion surface truncates the upper part of the stratigraphic unit. Layers are cut by the top surface, thus resulting in a “toplap” configuration.

On the other hand, a layering parallel to the top mimics a depositional mode by infill of a depression. The most common case is the channel infill. Layers are oblique to the bottom surface, exhibiting a “downlap” configuration.

The choice for a proportional (or isoproportional) layering is made for specific depositional modes where the space available for sedimentation is filled during its creation. This is the case for instance for syntectonic sedimentation or for some bio-constructions in carbonated environments.

The proportional layering can be defined between two depositional surfaces. This configuration can be used for the layering of a channel-levee association. It makes the layers continuous inside and outside the channel.

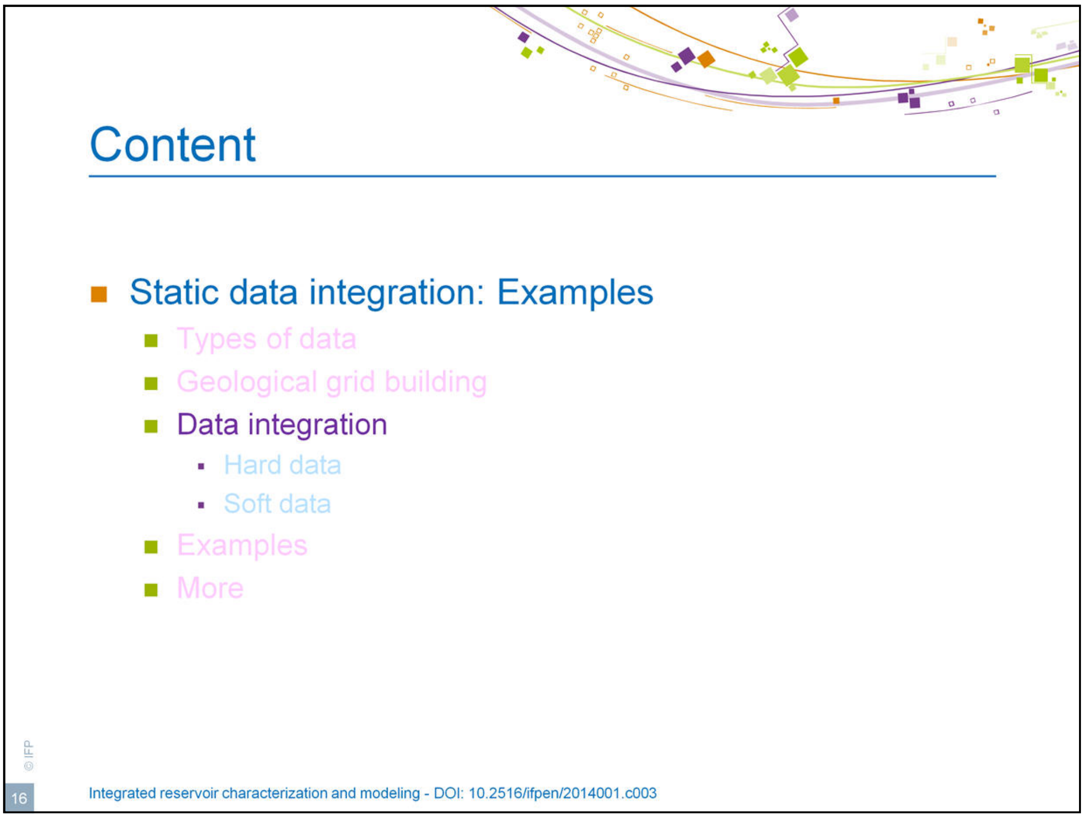
The schematic layering on the bottom pictures (Ouray uncomformity, CO, USA) stresses that distinct beddings must be considered for the two displayed stratigraphic units.



Then, the following step involves the stochastic simulation of lithological/petrophysical properties to populate the grid blocks.

The lithological model is not a mandatory step, but it is powerful tool to drive the spatial distribution of petrophsyical properties if relevant. It is built integrating a conceptual representation (sedimentological model), a classification phase (facies definition), and a probabilistic approach to describe the lithological distribution (stochastic model). The facies classification needs a facies identification based upon some key wells, cores if available, and complete set of logs, in the sequence stratigraphy framework.

Last, the petrophysical model is randomly generated conditionally (or not) to the facies model.

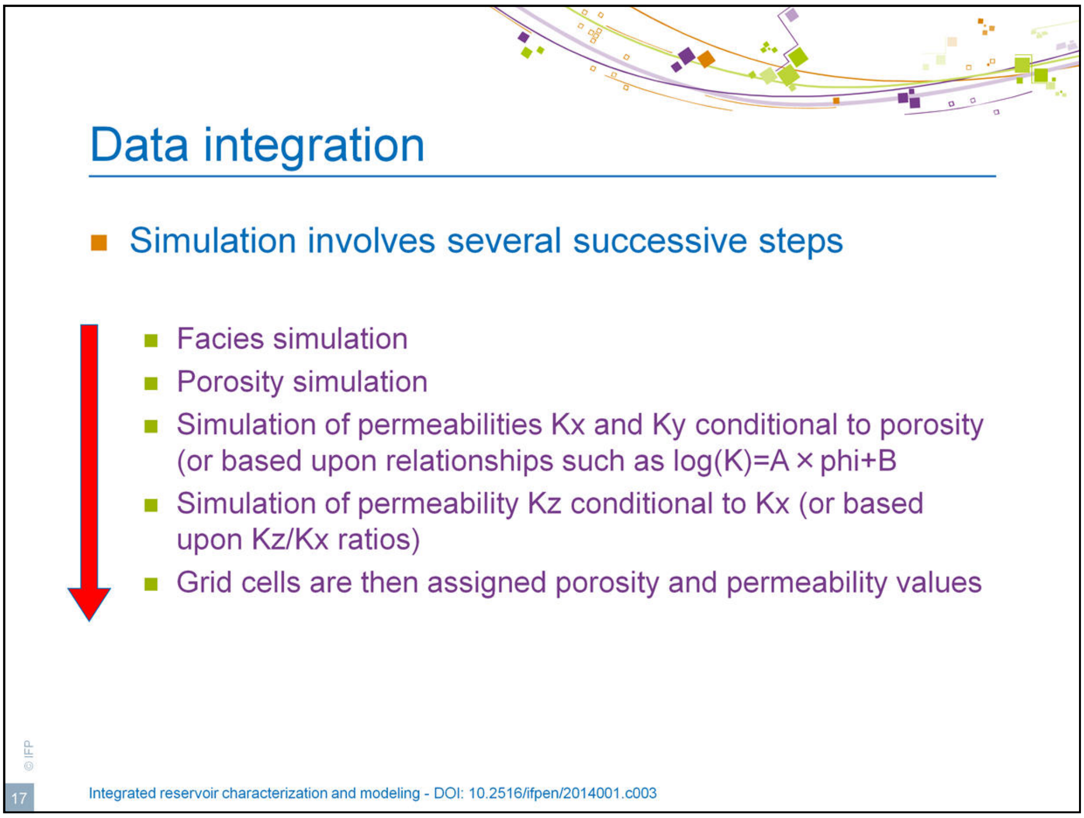


Chapter 2 introduced various geostatistical techniques to simulate multiple possible models representing the spatial distributions of facies/petrophysical properties within the geological formations under consideration. The purpose of this section is to examine more closely the constraints imposed by the static data.

Static data can be subdivided into hard and soft data.

Hard data are direct measurements of the property of interest: they comprises logs and core measurements and are usually considered as more accurate and reliable than soft data.

Soft data provide insights about the variations in the studied property, but are not direct measurements of it. For instance, the information derived from seismic (*e.g.*, impedances) is called soft data.



Let us recap the main outlines followed to simulate facies and petrophysical properties (Journel *et al*., 1998; Doligez *et al*., 2007).

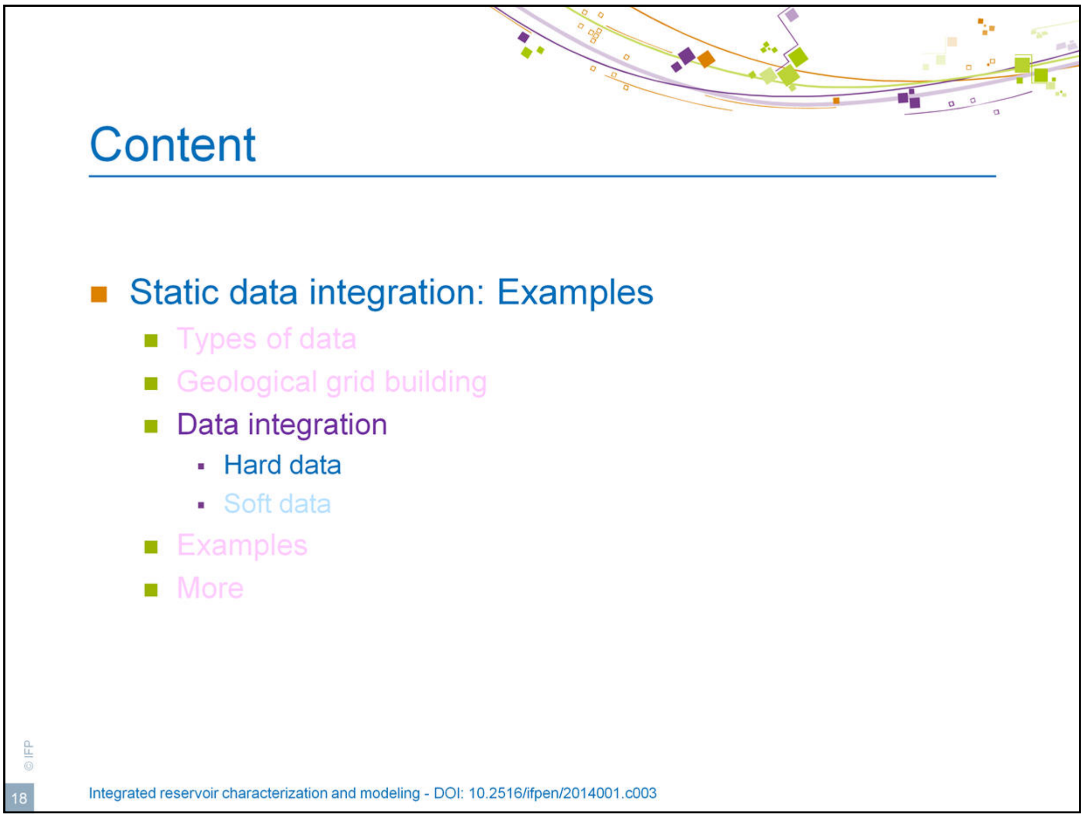
First, we generate a facies realization, which respects the observations at wells and the facies proportions estimated from logs and seismic.

Porosity realizations are then drawn conditionally to the available porosity data to populate the facies realization.

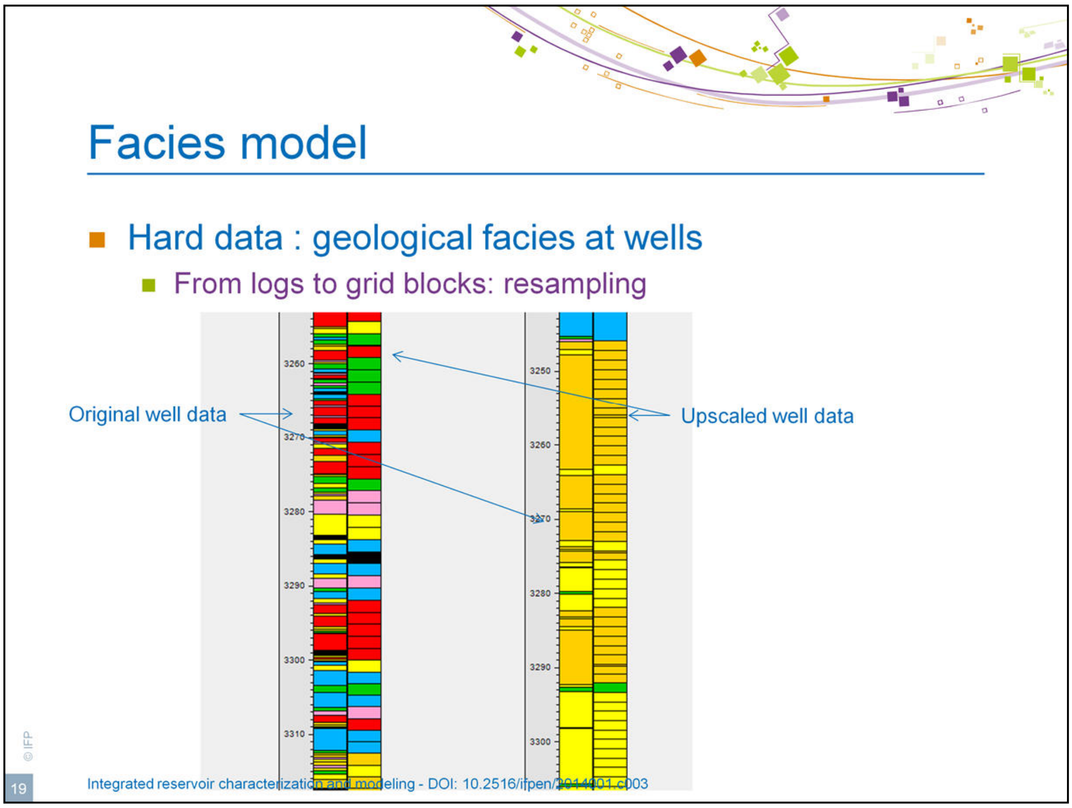
At this point, horizontal permeability (Kx and Ky) is either (1) computed from empirical relationships between porosity and permeability or (2) simulated conditionally to the previously simulated porosity realization. These realizations are also constrained to the available horizontal permeability data.

Last, the vertical permeability (Kz) is either (1) computed from empirical ratios established between vertical and horizontal permeabilities or (2) simulated conditionally to the previously simulated permeability or porosity realizations. The resulting realizations are also constrained to the available vertical permeability data.

The terms “with respect to” and “conditionally to” mean that data are incorporated into models.



We first focus on the hard facies and petrophysical data obtained at wells.



Log data are collected along well trajectory with a much higher resolution than the size of grid blocks. It is then required to resample these data in order to allocate values or data to the grid blocks crossed by the well. This results in a simplification of the complex geological reality.

There are various choices to attribute a data to a given grid block. We may select:

• the prominent facies in the grid block;

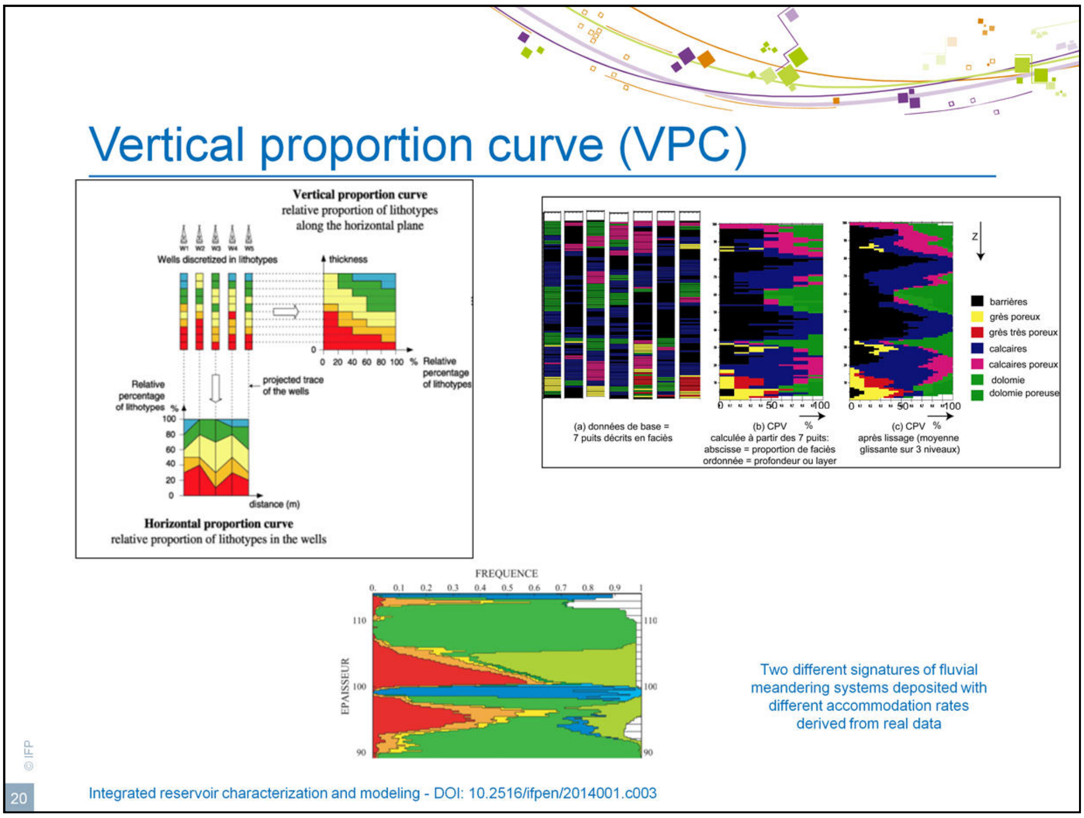
• the facies associated to the center of the grid block;

• the facies associated to the top of the grid block;

• the facies associated to the bottom of the grid block.

This finally yields the set of data that will be used to compute the probability distributions and to constrain the realizations. This resampling step is essential for the subsequent reservoir modeling steps and has to be carefully checked.

The top figures display two examples.



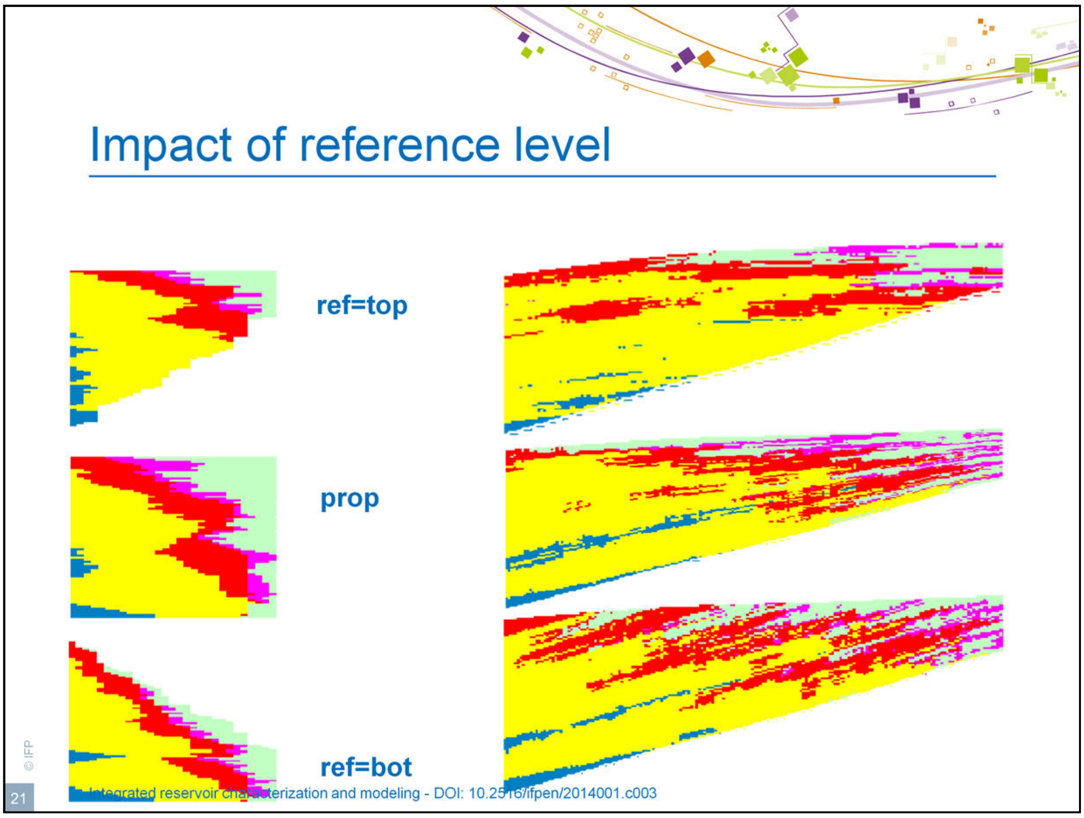
A **vertical proportion curve** (VPC) is computed from the facies data mapped to the grid. It characterizes the proportions of the different facies in the different layers of the stratigraphic grid. In a nutshell, polygons are discretized grouping one or several wells. The VPCs are calculated from the wells within each polygon and attributed to their centroids.

Therefore, the VPC is first a sequence stratigraphy tool. It summarizes the vertical sequence of facies (or lithologies) in a geological unit (Ravenne *et al.*, 2002). A key point is to figure out how to "layer" the unit, using the sedimentological knowledge and conceptual model. When done, well data are used to determine the relative proportions of facies in each layer. These VPCs are a visual tool that characterizes the sequential evolution of the studied geological unit.

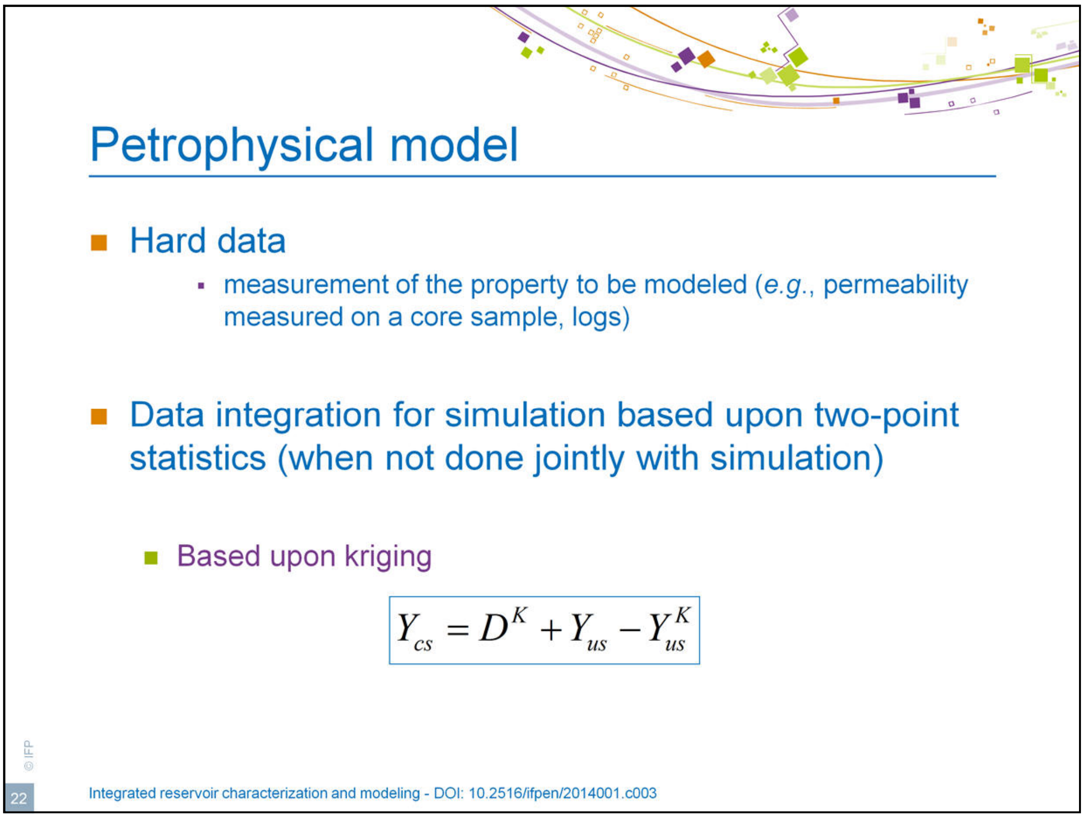
Sedimentation is cyclic by nature due to the relative variations in the sea level. This provides a framework to check well facies analysis, reference marker hypothesis, and environment interpretation.

VPCs are very useful for facies simulation as they are used as a direct constraint. For instance, they provide the required facies proportions when applying the Sequential Indicator Simulation technique. They also contribute to the definition of the truncation scheme for the PluriGaussian method.

In addition, a horizontal proportion curve can be computed from the projection of facies proportions at wells along a given direction. It shows the lateral variability of facies distribution along the selected direction. Horizontal proportion curves are used to analyze geological stationarity in the field.



Another important point is the choice of the reference level (paleo horizontal depositional surface). This figure illustrates the impact of different layering hypotheses relative to grids (left) on the simulation results (right) while using the same set of initial wells.

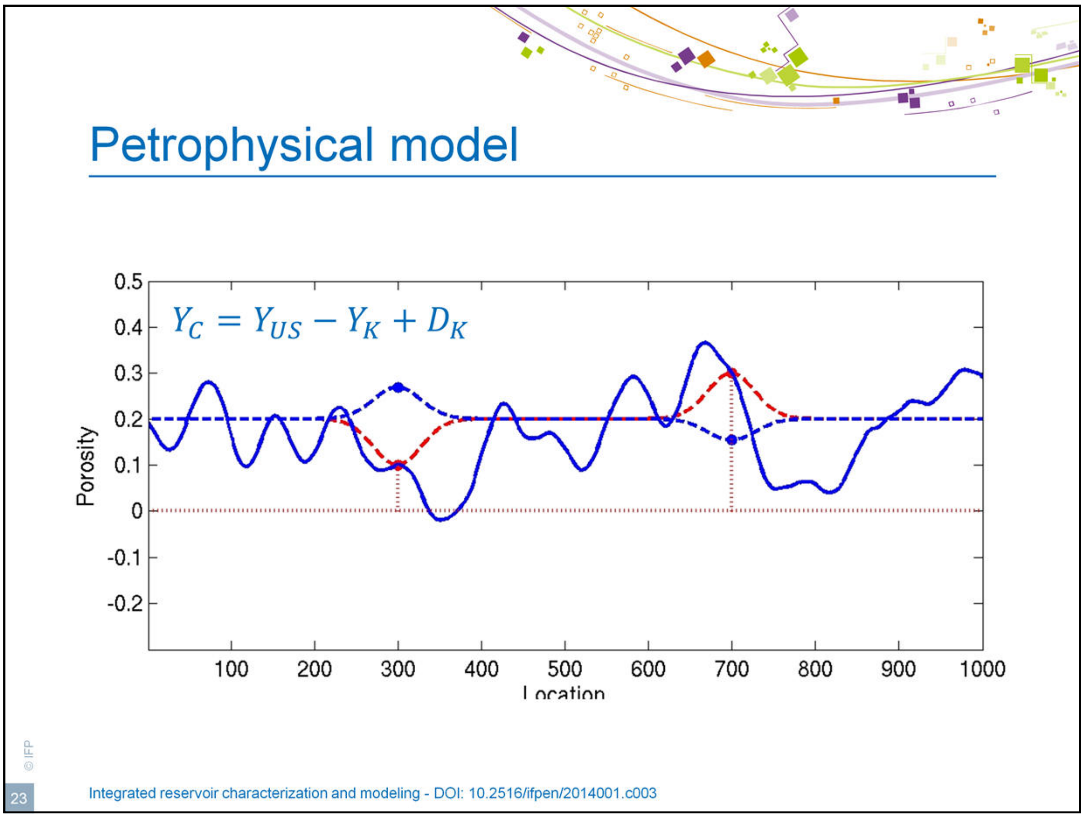


Besides facies observations, we also have to handle measurements of petrophysical properties at wells. This section recaps the basics for conditioning realizations of continuous random functions to such measurements.

For simplicity, we consider the case of two-point statistics based simulation (see Chapter 2).

Some simulation techniques, of which sequential simulation techniques, directly produce realizations constrained to the data. Some others, for instance the FFT-MA method, call for an additional step to make sure that the simulated realizations respect the data.

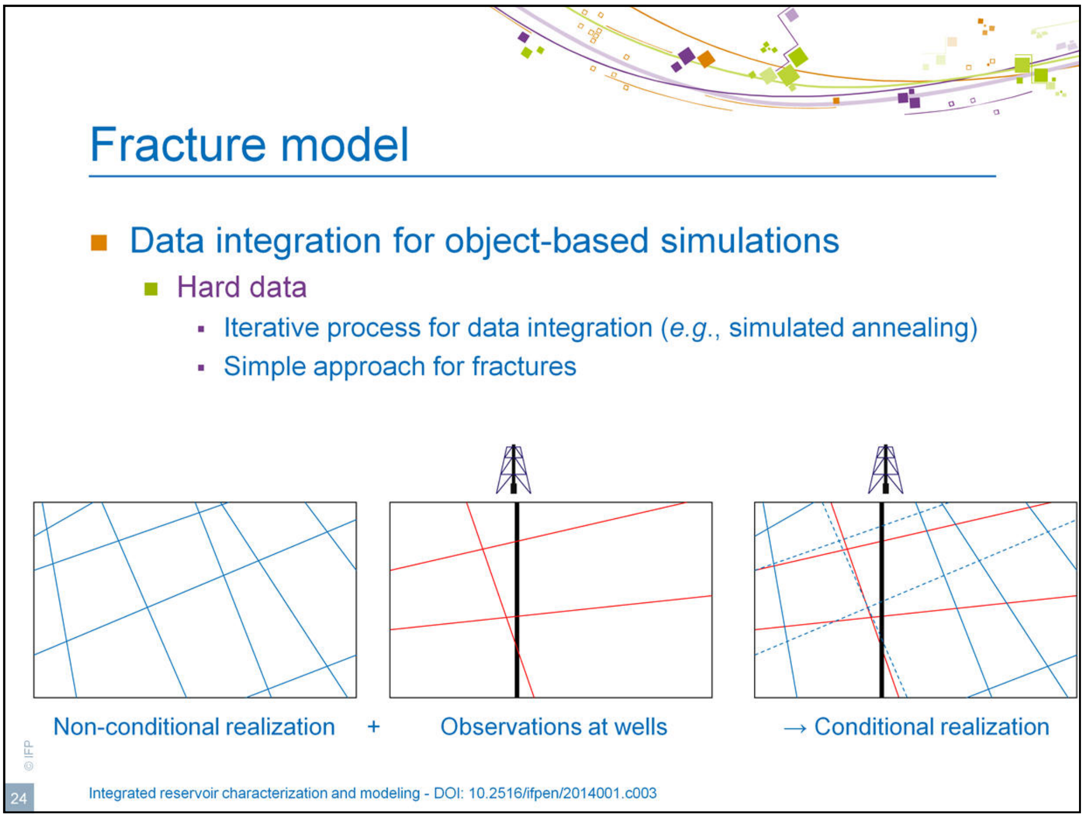
This additional step is usually based upon double-kriging (Delhomme, 1979) (see equation above). Y_{cs} and Y_{us} are the conditional and unconditional random functions, respectively. D^K is the kriging estimate derived from data and Y^K_{us} is the kriging estimate built from the values of Y at data locations.



The above sketch shows how double-kriging works. We aim to simulate one one-dimensional porosity realization respecting two measurements: 10% and 30% at locations 300 and 700, respectively. The process is as follows.

1) We simulate an unconditional realization *Yus*.
2) We calculate the kriging estimate from the two porosity data, this is *Dk*.
3) We identify the values of *Yus* at data locations (300 and 700) and compute a new kriging estimate from these two values: this is *Yk*.
4) We calculate *Yus*-*Yk*.
5) We finally end up with *Yc*=*Yus*-*Yk*+*Dk*.

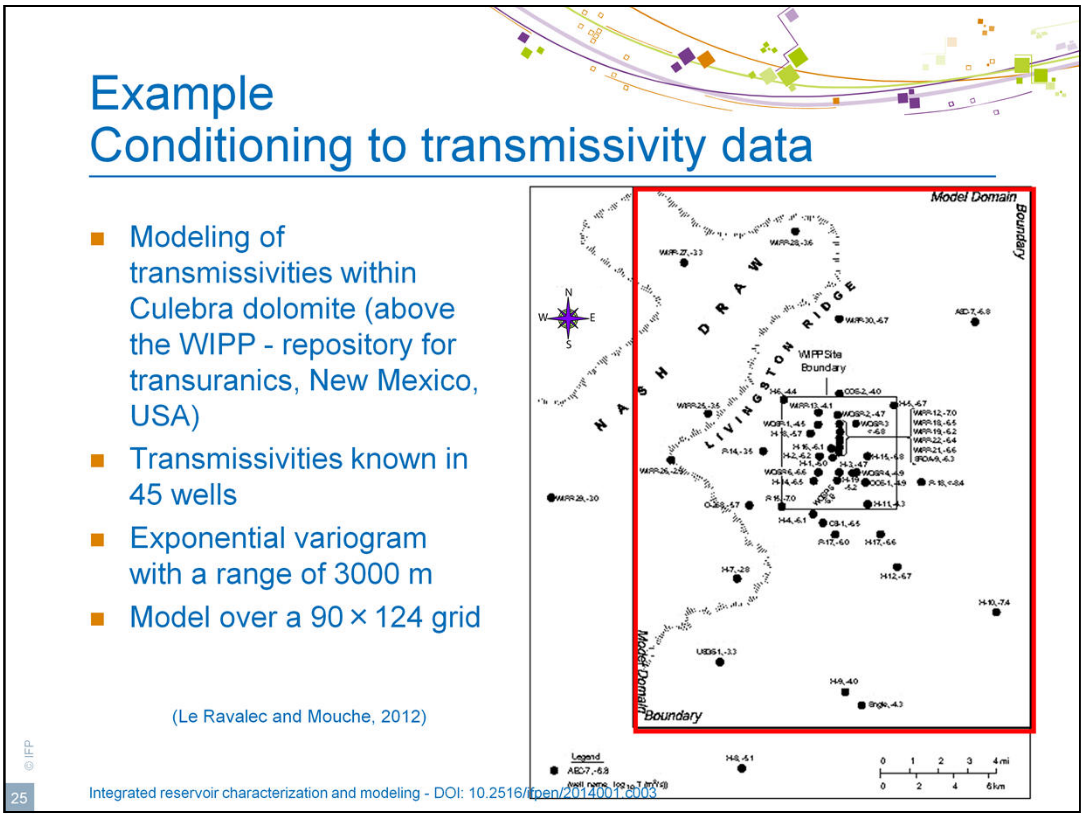
Yc is a conditional realization that respects the required porosity data.



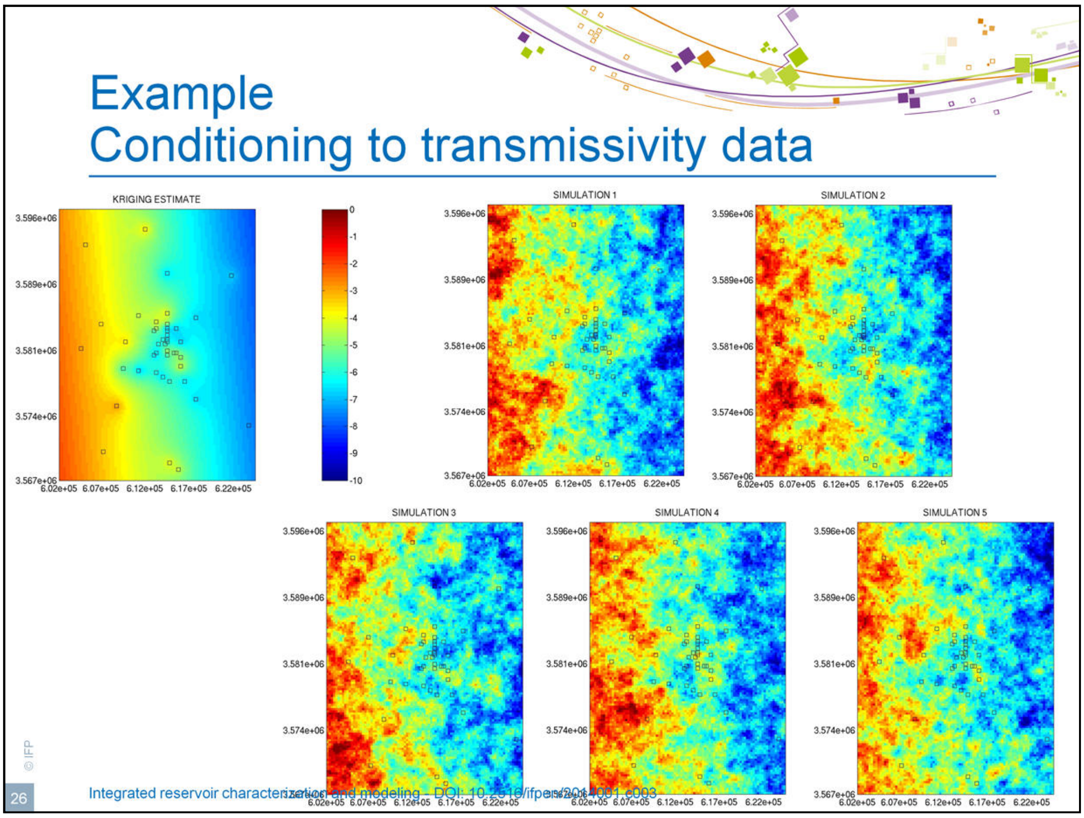
The case of Boolean models is a bit more complex. This type of techniques is suitable for representing geological objects. In short, the simulation process consists in dropping the objects at random locations.

Generally speaking, conditioning a Boolean model to data observed at wells is a very arduous task. This issue can be addressed through an iterative process, *e.g.,* simulated annealing.

However, for simple objects like fractures, Chilès and Delfiner (1999) described the following procedure. First, a non-conditional realization is generated. Then, the conditioning to fractures observed in wellbores is achieved by simply placing these fractures at the wellbore intersections with the correct fracture orientation. Last, the simulated fractures that intersect the wells, but were not observed, are simply removed.

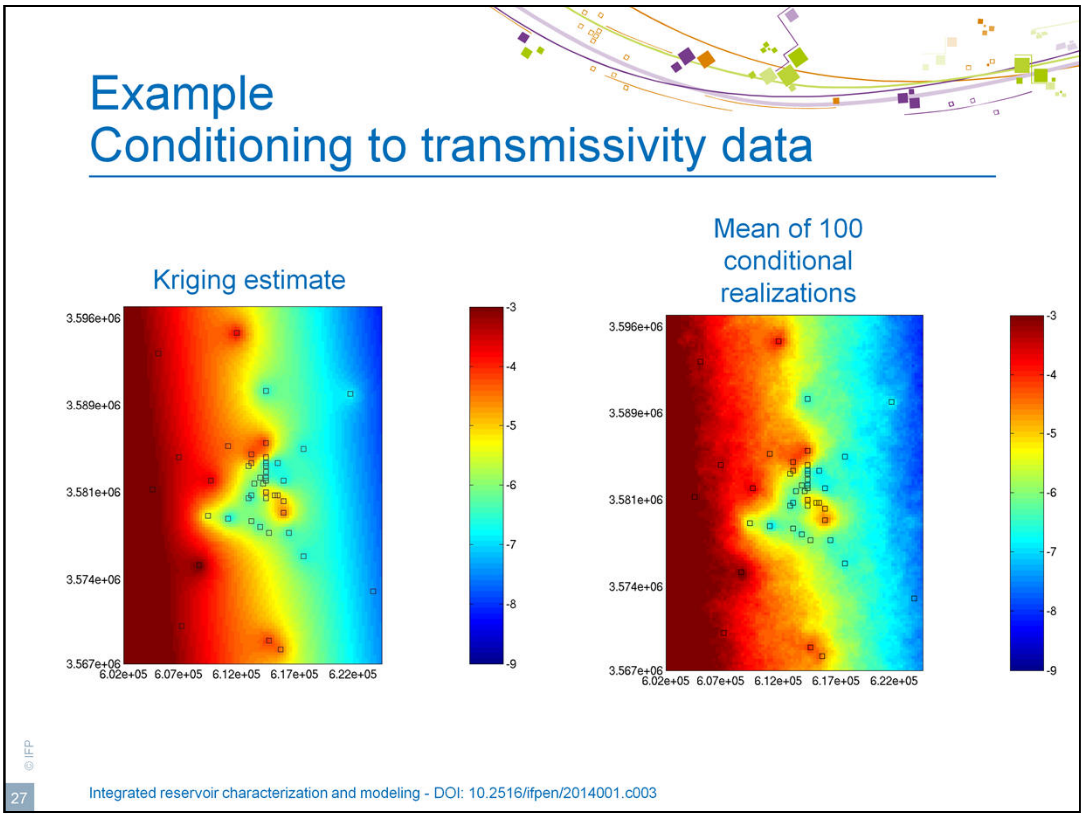


Regarding the Waste Isolation Pilot Plant (WIPP) case introduced in Chapter 2 (p. 44), remember that transmissivities were known in 45 wells. Up to now, we used this data set to characterize the spatial variations in transmissivity. Our current objective is to integrate these data in the transmissivity model (using double-kriging).

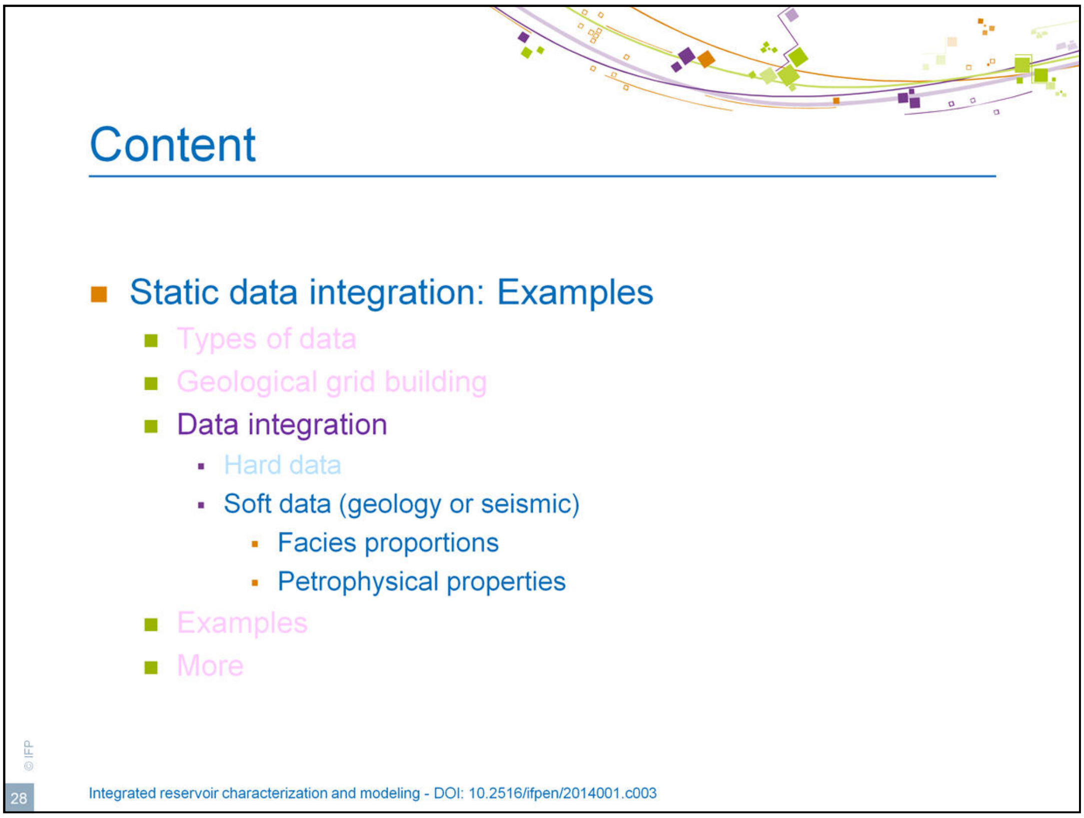


Transmissivity models are built using both estimation (top, left) and simulation (the 5 other models) techniques.

The 5 simulated models are all conditional: they reproduce the transmissivity values at wells. These 5 models are equally probable realizations. They are different because they correspond to different seeds.



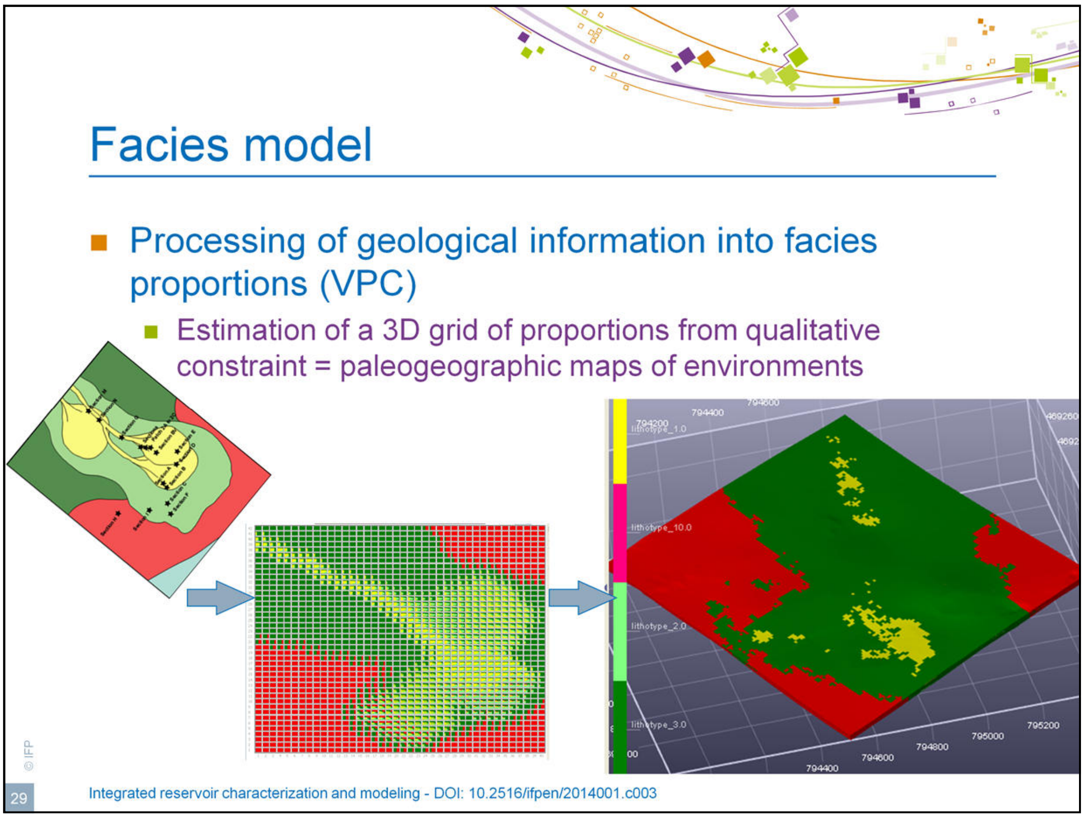
It is worth mentioning that the mean and variance of a huge number of such conditional realizations tend toward the kriging estimate and the kriging variance.



Seismic is usually the only source of information throughout the field. The reason for using both seismic and wells instead of just wells is that seismic is used to interpolate between wells. It is essential to simulate facies and petrophysical models conditionally to seismic-related data in order to reduce the uncertainty in geological or reservoir models. As seismic-related data are not directly linked to the studied property, they are called soft data.

Seismic-related data encompass distinct attributes derived from seismic data. These attributes are usually calibrated with well control (when available).

Just as shown for hard data, seismic attributes can be used to make the facies proportions or the petrophysical properties more realistic and relevant. Another option is to drive the variations in facies proportions using geological information.

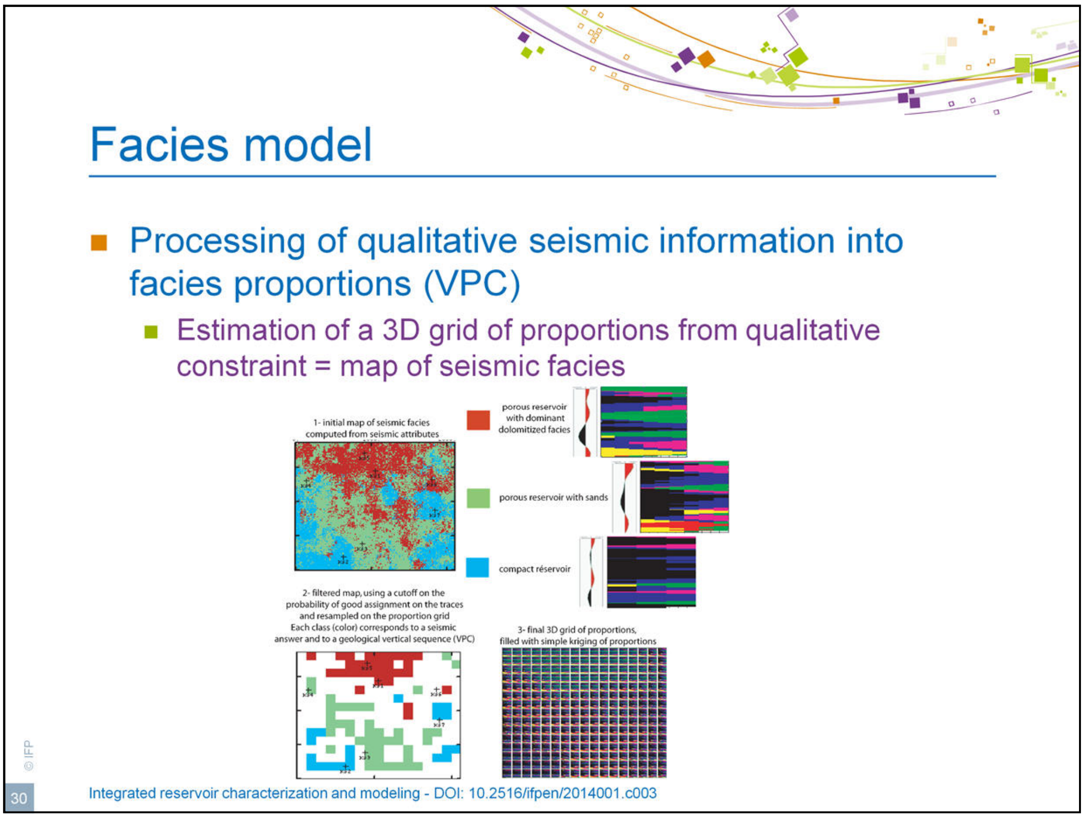


There are several techniques to convert geological or seismic information into facies proportions.

A first possibility consists in estimating a 3D grid of proportions from a qualitative constraint such as a **map of geological environments**.

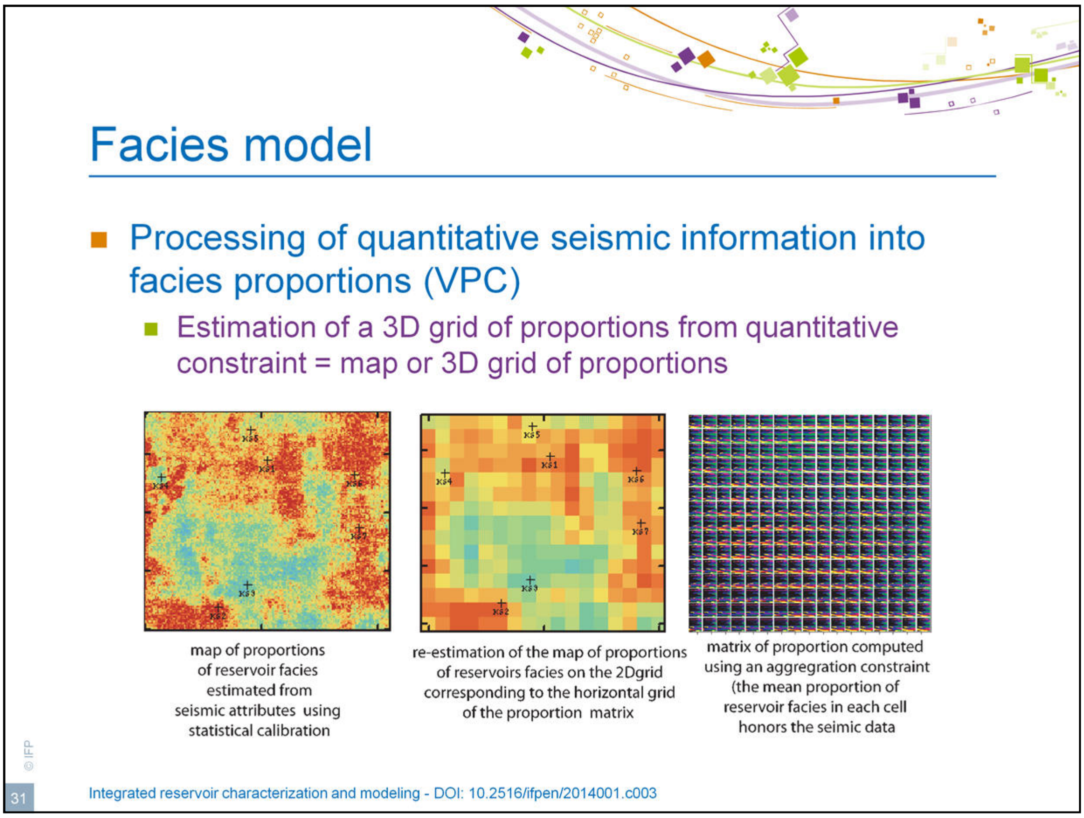
The basic approach entails the use of well data and local vertical proportion curves (VPCs) calculated at wells to estimate facies proportions throughout the entire field without any other constraint. This is traditionally performed with ordinary kriging.

A bit more refined technique calls for additional information. This may be a two-dimensional map of paleogeographic environments. The advantage of the map of paleogeographic environments is that it delineates regions with very specific VPCs. These ones are computed from the wells included in the target regions. The final grid of facies proportions is obtained by kriging the local VPCs within each area, and with a possible smoothing between the areas.



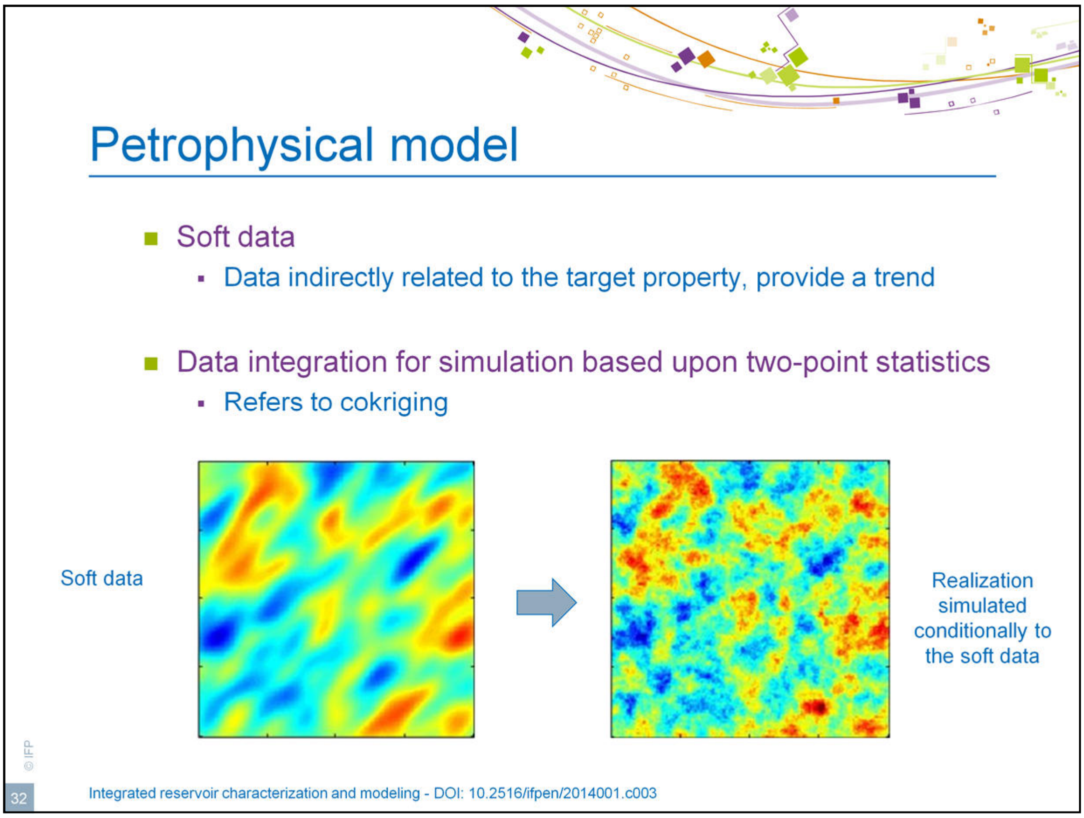
A second possibility to get the grid of facies proportions is based upon the use of another constraint, that is the **map of seismic facies**.

In this case, we refer to a map of seismic facies instead of the map of geological environments. A seismic facies is a package of reflectors with similar seismic characteristics. The map of seismic facies is used as a background to identify the areas associated to a given seismic facies. The following step is dedicated to the computation of the VPCs from the wells belonging to the defined regions. The 3D grid is then completed by kriging the proportions for each level of the grid and each facies (Beucher *et al*., 1999, Doligez *et al*., 2002).



A third technique is briefly recapped hereafter yet aiming to define facies proportions throughout the reservoir. It involves **a 2D or 3D constraint given in terms of proportions**. Compared to the approach proposed in the previous page, it goes one step ahead.

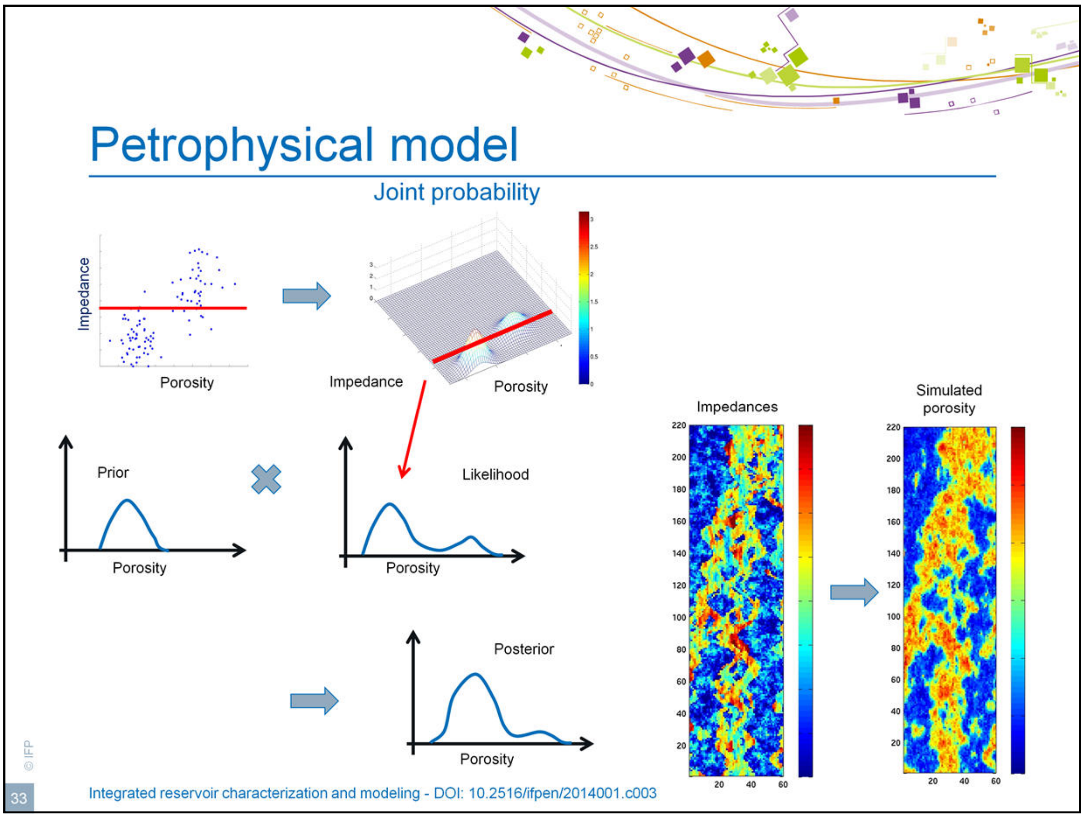
The idea behind is to write the kriging system (referred to in the page right before) with an aggregation constraint relative to the sum of facies proportions in each cell of the proportion grid (Moulière *et al*., 1997). Therefore, the additional information is expressed as a 2D map or a 3D grid populated with mean lithofacies thickness or proportions derived either from stratigraphic modeling techniques (Granjeon *et al*., 1998) or from statistical calibration techniques using seismic attributes. The resulting 2D map or 3D grid are viewed as a constraint that is used to estimate VPCs.



As previously explained, we can apply kriging to integrate hard data into realizations generated from two-point statistics simulation techniques. We proceed more or less the same to account for soft data, but use cokriging instead of kriging. This is also why we usually refer to cosimulation instead of simulation.

The advantage of cokriging is that is uses the hard data available as well as the existing soft data. This is of interest when hard data are sparse while the soft ones are abundant.

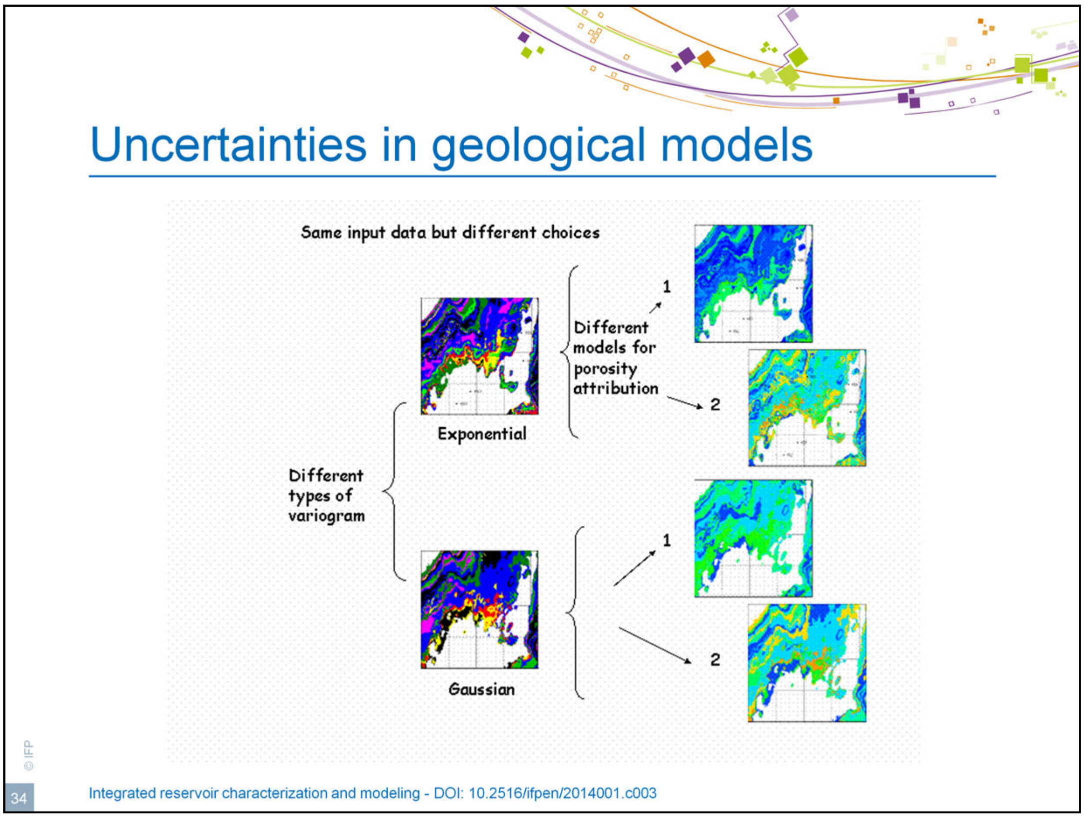
The various simulation algorithms introduced in Chapter 2 can be extended to cosimulation (Soares, 2001; Oliver, 2003; Emery, 2008; Le Ravalec and Da Veiga, 2011). The realizations simulated conditionally to given soft data capture the trend provided by these soft data.



A major drawback with cokriging is the need for cross-covariances.

Doyen *et al*. (1996) proposed another simulation technique that does not require any such cross-covariances. This is the sequential Bayesian simulation approach: it is mainly based on traditional sequential Gaussian simulation with the added use of Bayesian formula. Additional refinements were proposed by Dubreuil-Boisclair *et al*. (2011).

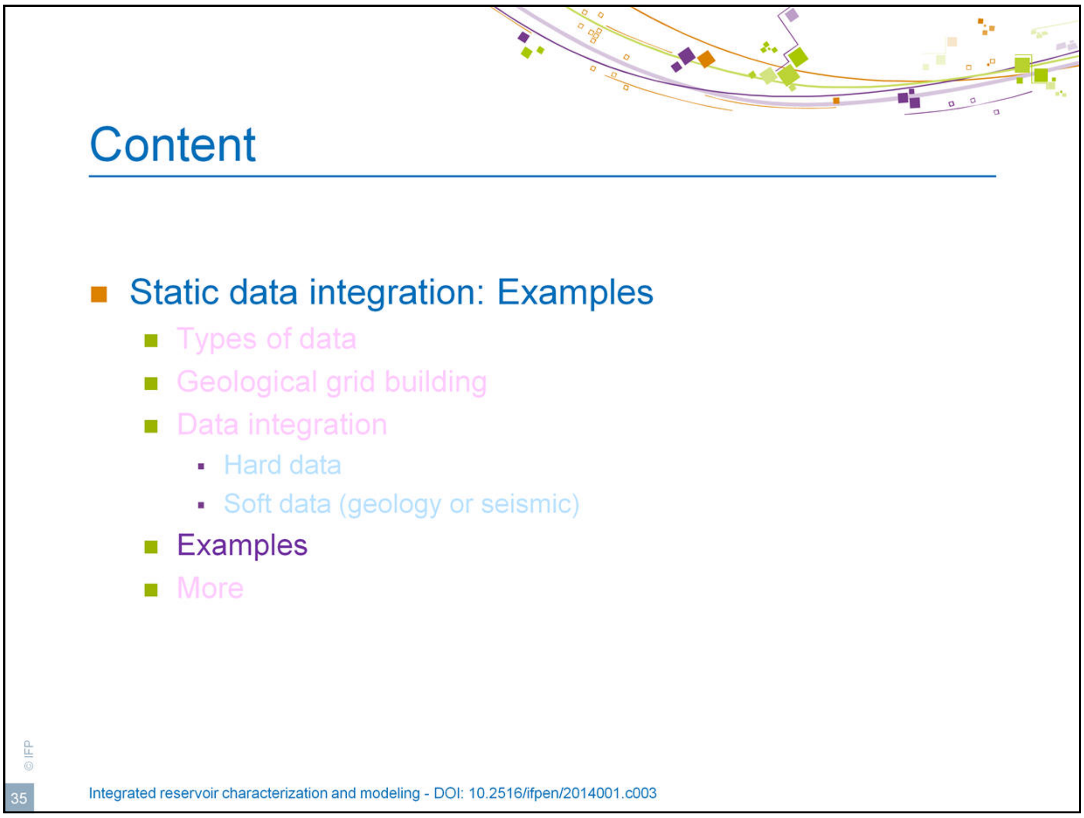
In short, the simulation process can be recapped as follows. It consists in (1) selecting a cell that has not been visited yet, (2) applying simple kriging under a Gaussian assumption to estimate the expected mean and variance that define the prior distribution at the visited cell, (3) defining the likelihood distribution obtained from both the available soft data (*e.g*., seismic impedance) at the selected cell and the joint distribution derived from hard and soft data (*e.g.*, porosity and impedances at wells), (4) inferring the posterior probability distribution by applying Bayes' rule to update the prior distribution with the likelihood distribution (by calculating their product), (5) drawing a value for the property of interest (*e.g*., porosity) from the posterior probability distribution for the selected cell and adding it to the available set of hard data before visiting the next cell, and (6) repeating the above steps until all the selected cells have been visited.



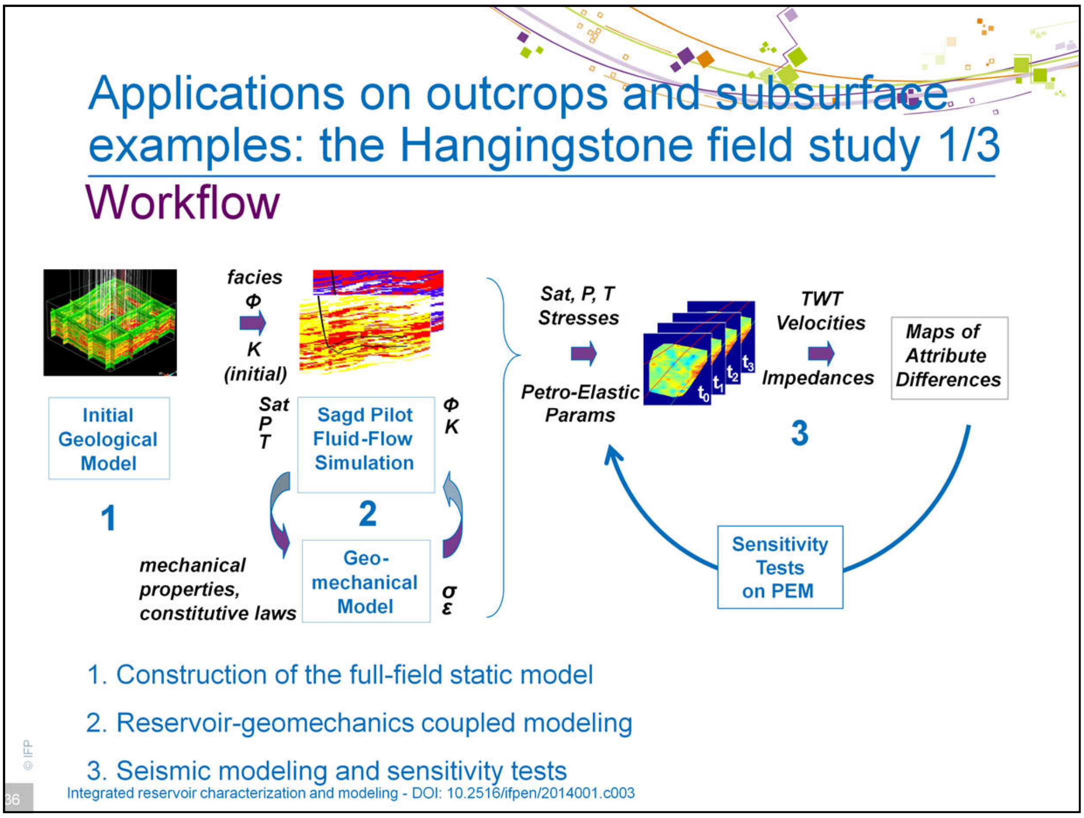
Even though geological models are conditioned to all available hard and soft data, there are still uncertainties.

On top of the uncertainties related to data measurements and interpretation (see Introduction), it is worth identifying the variogram model as another possible source of uncertainty. As already explained, the variogram model is selected in order to fit the experimental variogram. At this point, several variogram models or combinations of variogram models can be appropriate choices, thus leading to distinct spatial variabilities for facies and petrophysical properties.

In addition, assuming the variogram model is fixed, there are still uncertainties in the spatial distributions of facies and petrophysical properties. They can be assessed through the simulation of multiple equiprobable realizations.



The last part of this chapter encompasses various case studies that illustrate the ideas presented up to this point.

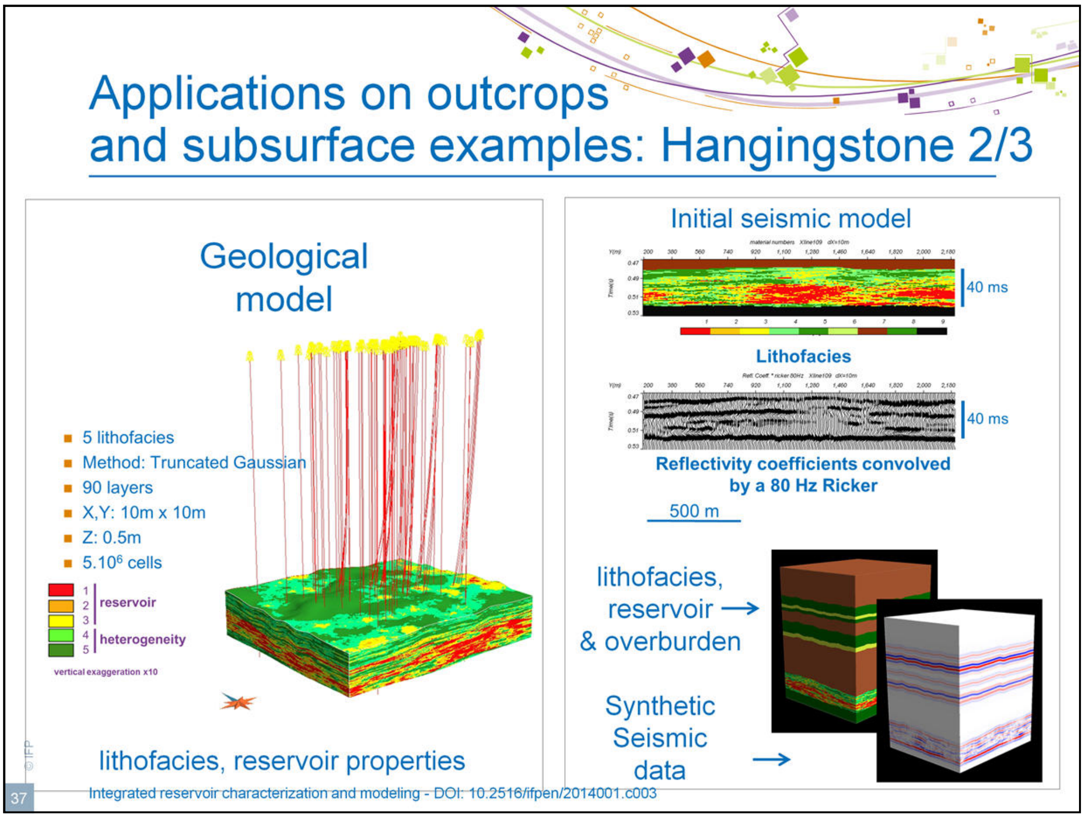


This first example (Lerat *et al*., 2010) introduces an integrated workflow aiming to use 4D seismic data to monitor the growth of a steam chamber in a field operated by steam-assisted gravity drainage (SAGD).

There are many difficulties to face in such a context: the usual issues related to geological heterogeneity, but also many other interacting factors that are specific of this thermal production process: changes in oil viscosity, fluid saturations, pore pressure, *etc*. All of them make the interpretation of seismic variations very challenging.

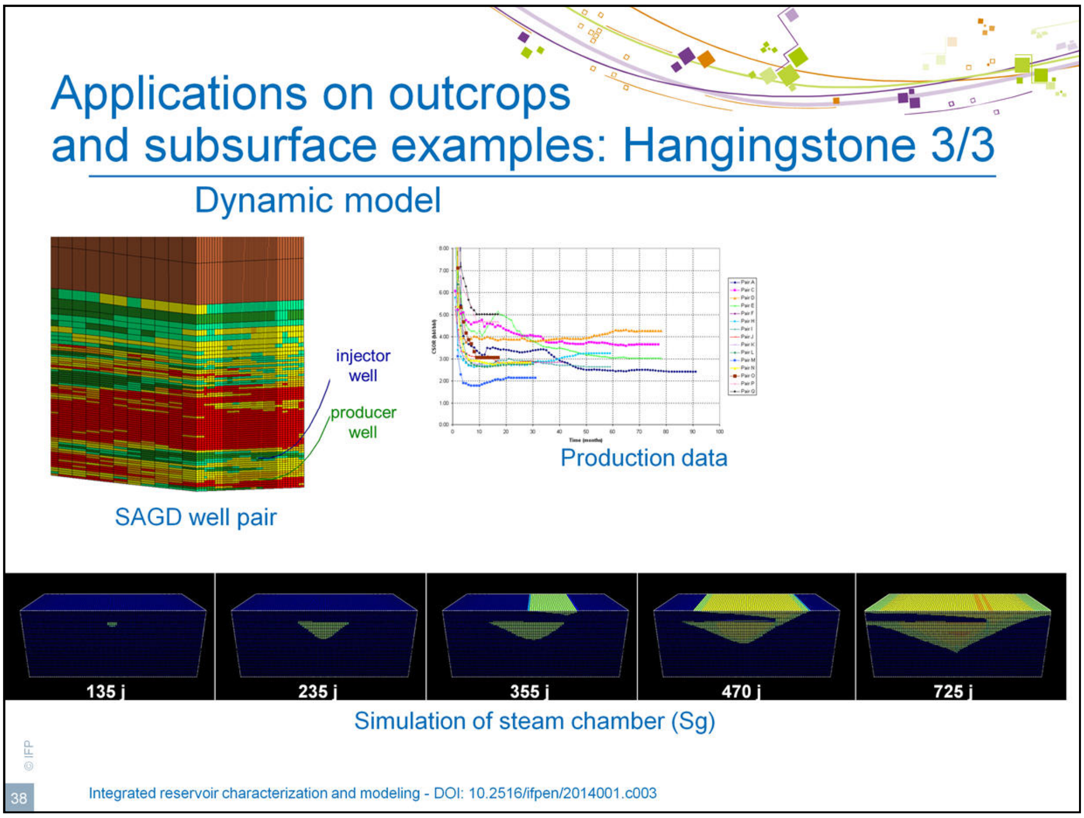
The objective is the generation of a geological model of a real field case of the McMurray formation in the Athabasca region. The followed approach consists of three steps.

1) Construction of an initial static model.
2) Simulation of thermal production of heavy oil using a fluid flow simulator coupled with a geomechanical model.
3) Production of synthetic seismic maps at different stages of steam injection.



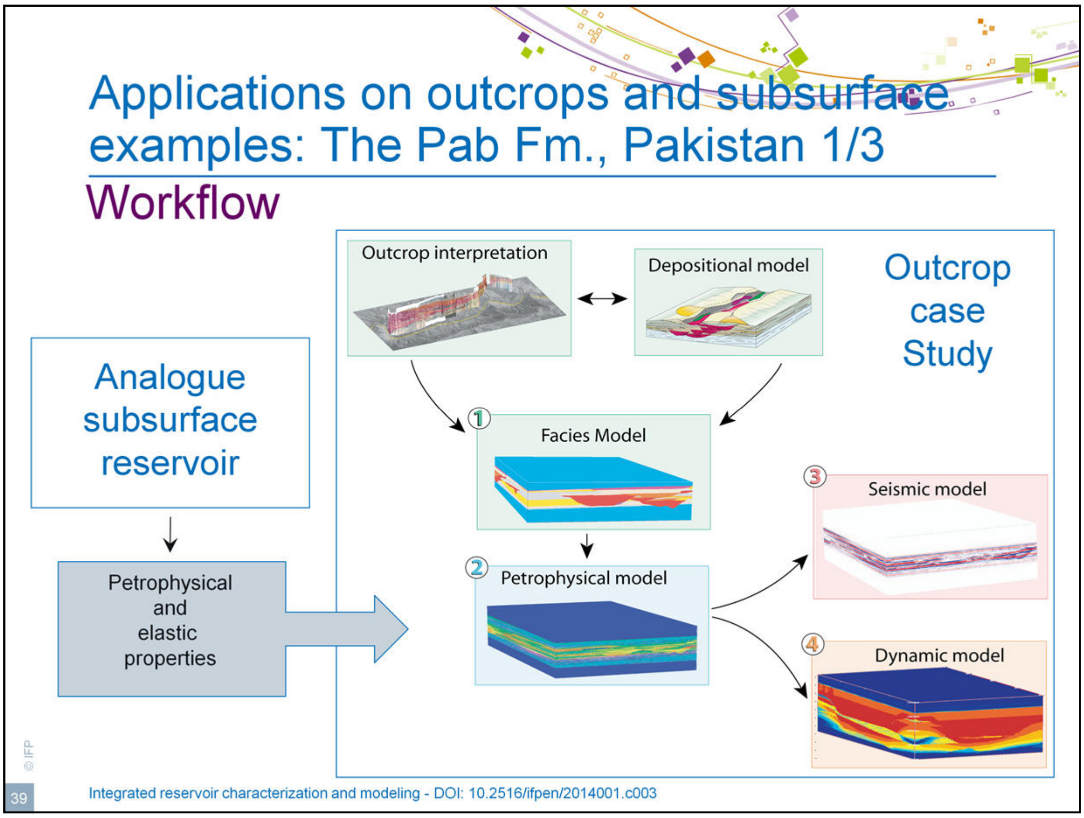
The distribution of geological facies was simulated on a very fine grid. The resulting realization was constrained to all available well data (50 wells).

The reservoir, geomechanical and elastic properties were characterized from logs and literature for an initial stage prior to production.



Production scenarios were run to evaluate pore pressure, temperature, steam and oil saturations on a detailed reservoir grid around a well pair at distinct stages of production. The direct coupling with the geomechanical model also provided the volumetric strain and mean effective stress maps. All of these physical parameters were given as inputs to Hertz and Gassmann formulas in order to compute synthetic seismic velocities and densities for every production stages. Then, reflectivities could be computed and new synthetic seismic images were generated for the successive production stages.

The influence of heterogeneities, production conditions and reservoir properties were evaluated for several simulation scenarios from the very beginning of steam injection to the final production stage of interest (after three years of production). It was shown that short-term seismic monitoring can help anticipate early changes in steam injection strategy. On the other hand, long-term periods make it possible to monitor the behavior of the steam chamber laterally and in the upper part of the reservoir.



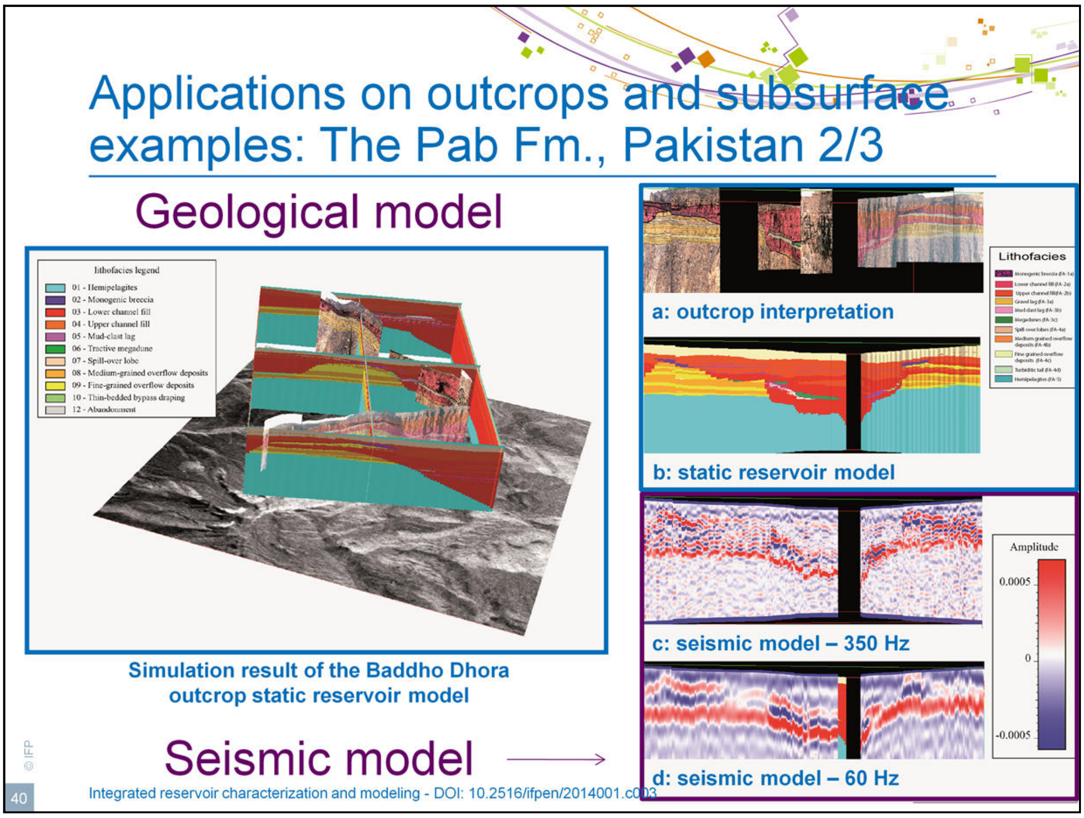
The use of seismic to visualize reservoir property changes due to production is a key decision tool to optimize well development plan and well design.

Within this framework, there is an obvious need for operational databases that provide the required input data for benchmarking reservoir characterization tools. As such database are rarely available, a synthetic, but realistic reservoir is very valuable. The advantage with synthetic reservoirs is that static and dynamic properties are known at every locations. This is crucial information for optimizing and validating reservoir characterization techniques.

The illustration above displays the workflow followed for building a synthetic reservoir model. It is inspired by the detailed 3D interpretation of an outcrop of a turbiditic channel complex (Pab Fm., Pakistan). The developed methodology entails four main steps.

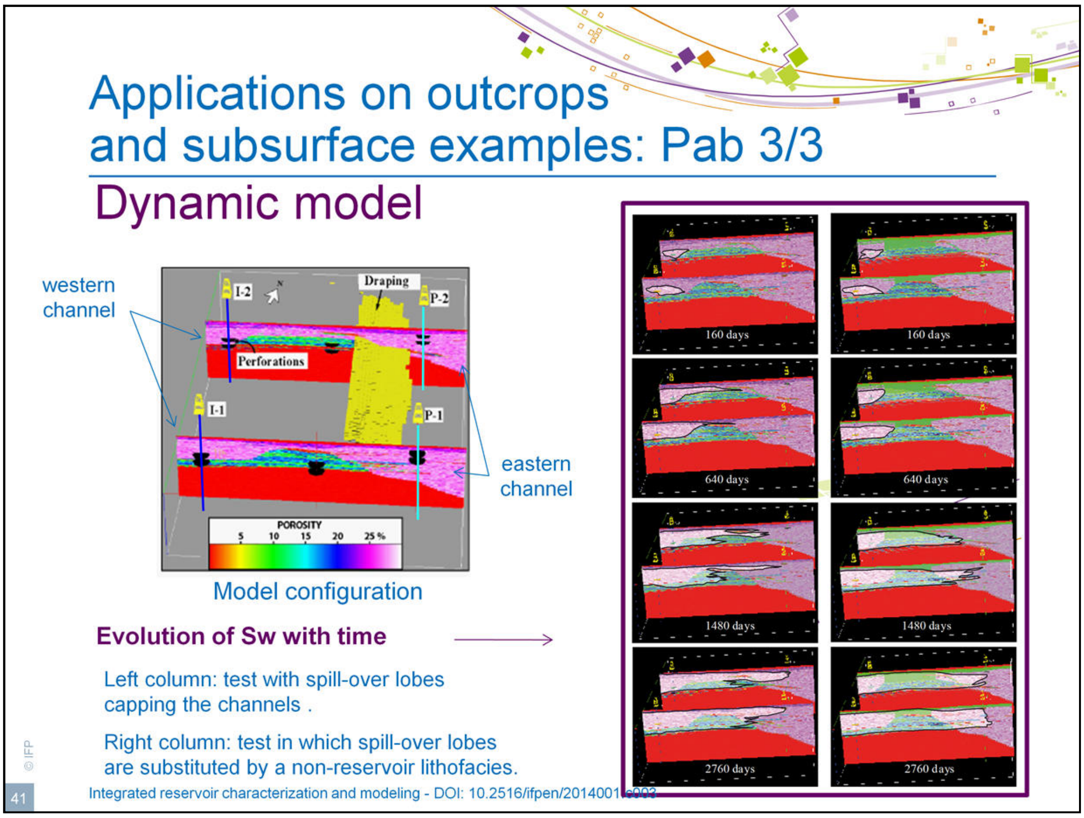
1) Construction of a fine-scale 3D geo-cellular model, populated with sedimentary facies.
2) Attribution of petrophysical and elastic properties to every cells of the model.
3) Seismic modeling applying the 1D convolution method with the model obtained at step 2 as input.
4) Dynamic modeling of water injection and oil production with the fine-grid model at the field scale.

Last, the elastic parameters could be also updated in order to take into account saturation and pressure variations due to production. This is the basis for time lapse seismic modeling (not shown on this workflow).

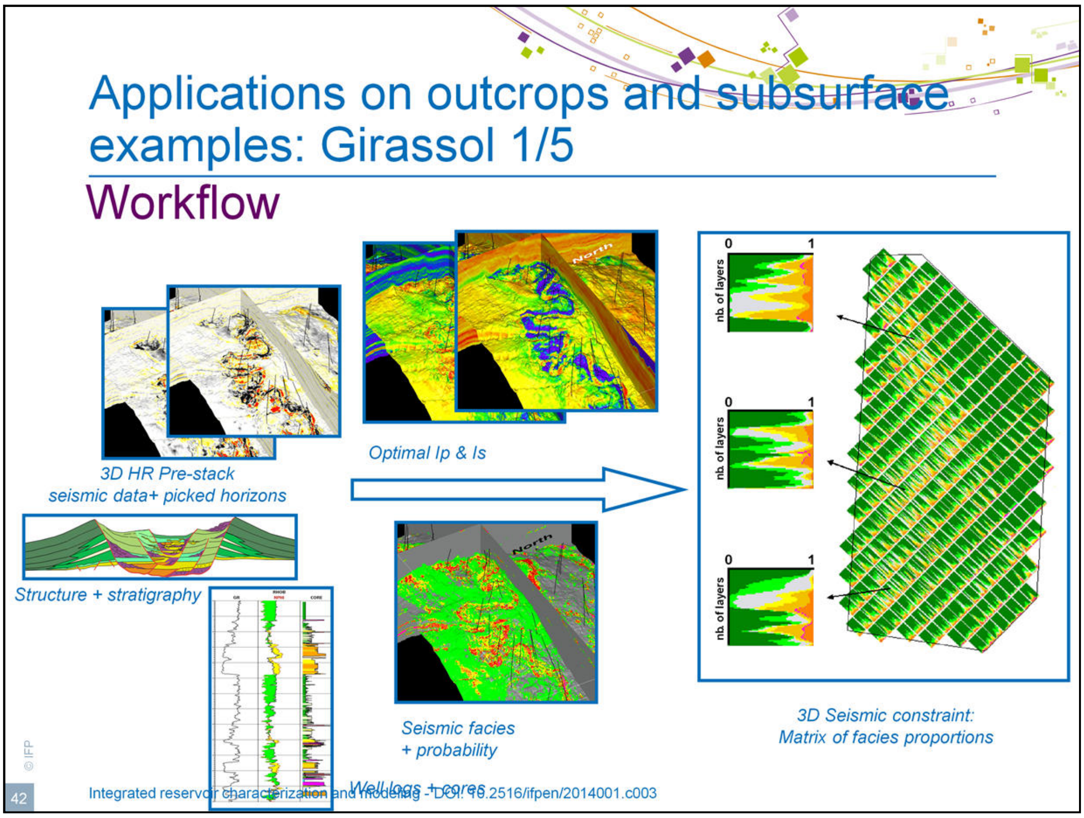


The outcrops of the Maastrichtian Pab Sandstone, in SW Pakistan display spectacular examples of turbiditic environments (Euzen *et al*., 2007; Eschard *et al.*, 2013). In this area, a basin floor fan was preserved from the platform to the deep basin setting. In the mid-fan setting, a channel complex crops out in three dimensions. It consists of a dozen of channels and their overflow deposits, including levees, crevasse lobes and spill over lobes. It was shown that the overbank deposits could directly be in contact with the channel-fill. In many cases, matrix supported debris-flow deposits created lenses close to the channel base. Heterolithic drapes of thin-bedded turbidite deposits were also preserved along the channel margins.

A 3D static model describing the heterogeneity distribution was built from the study of a site with two channels laterally connected by overbank deposits, using a deterministic definition of the channels geometry and a stochastic simulation of their internal heterogeneities. Petroacoustic properties were then assigned to facies from a subsurface database to perform seismic simulation. The results obtained pointed out that the channel base could easily be misinterpreted...



The dynamic transition between channel and overbank deposits was investigated on the basis of well tests and streamline simulations. The results emphasized that the overbank deposits connecting the channel homogenize the pressure regime in the reservoir. It was also shown that the sweeping efficiency of water injection can be strongly weakened by the heterogeneities distributed along the channel margins (Figure on the top right). In addition, a significant volume of oil can be bypassed because of the occurrence of early water breakthrough through the spill-over lobes, or because the flow slows down when it reaches the heterogeneity along the channel margin.

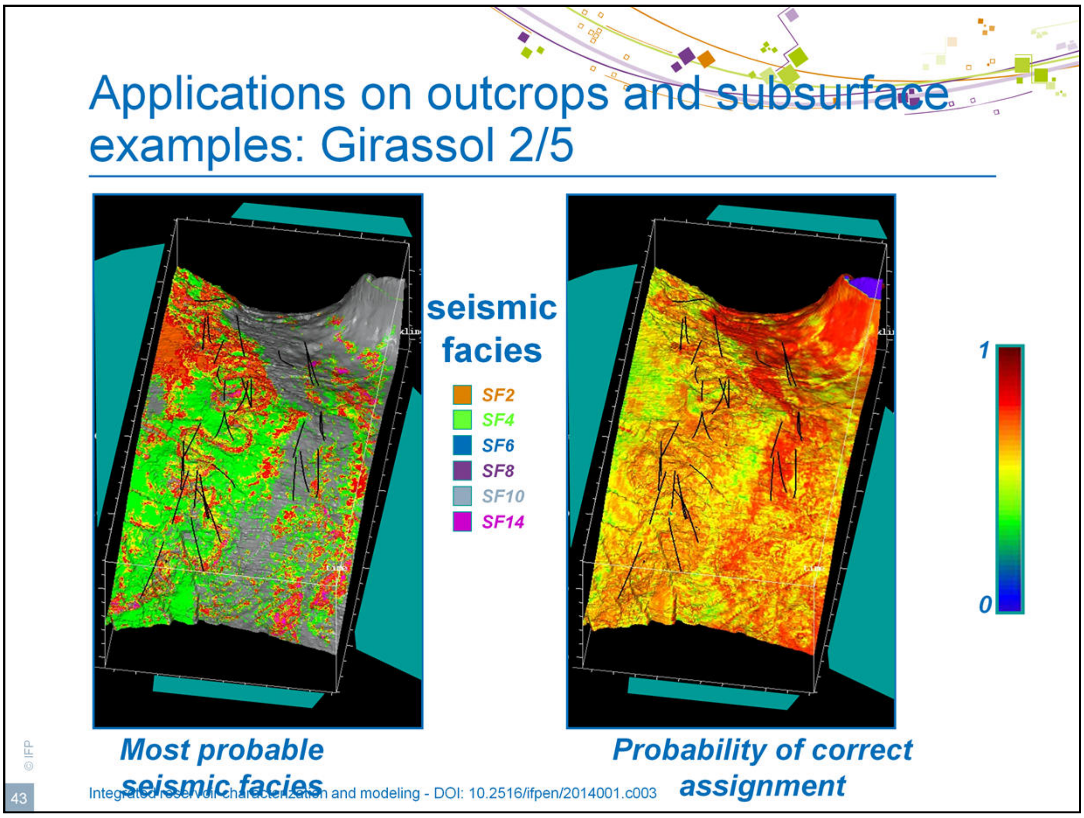


A specific workflow was developed to take the most from the seismic data of exceptional quality collected for the Girassol field, offshore Angola.

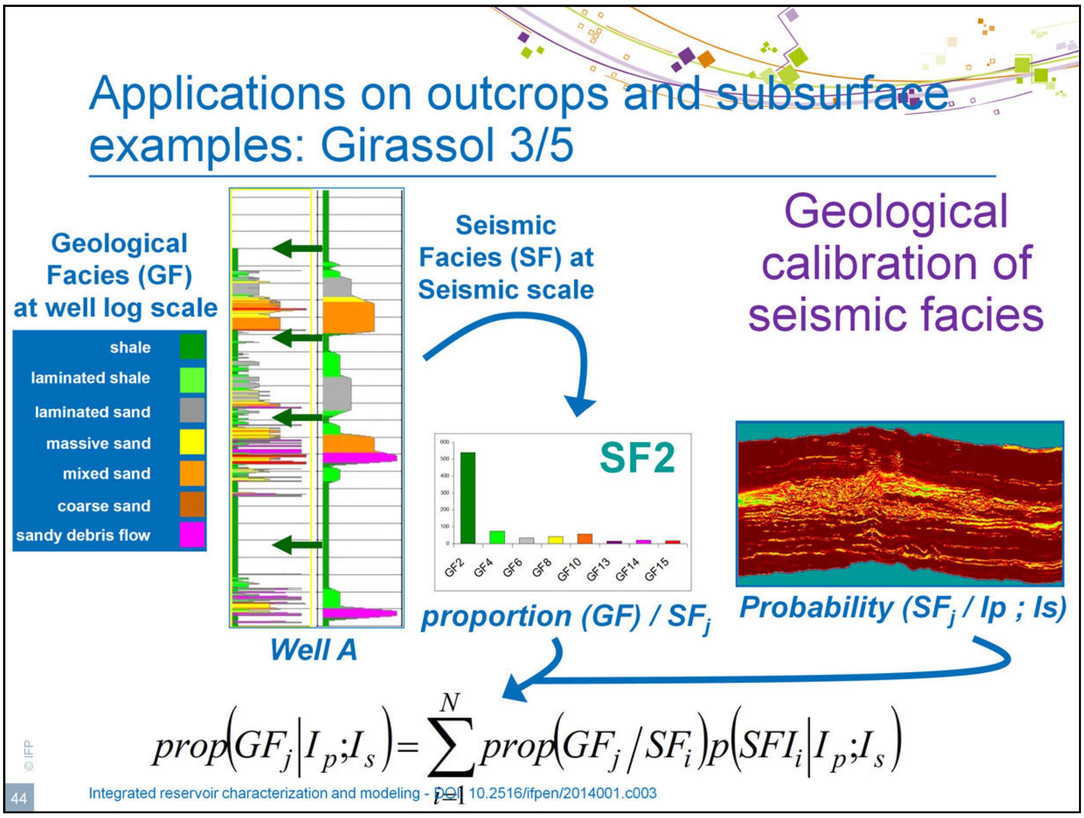
The first and critical step was the definition of the 3D grid of facies proportions from the 3D HR (High Resolution) seismic data (Nivlet *et al*., 2007). A novel approach was designed to account for scale differences between seismic and well data and to obtain a detailed geological facies description.

In a second step, Lerat *et al*. (2007) adjusted the geological facies proportions that were derived from the characterization of seismic facies in order to minimize the mismatch between the true impedances and the seismic impedances computed for the average stochastic model.

Last, the truncated Gaussian method was applied to generate realizations constrained to well data and geological facies proportions. The simulation of multiple realizations permitted to evaluate the uncertainty in the spatial distribution of facies.

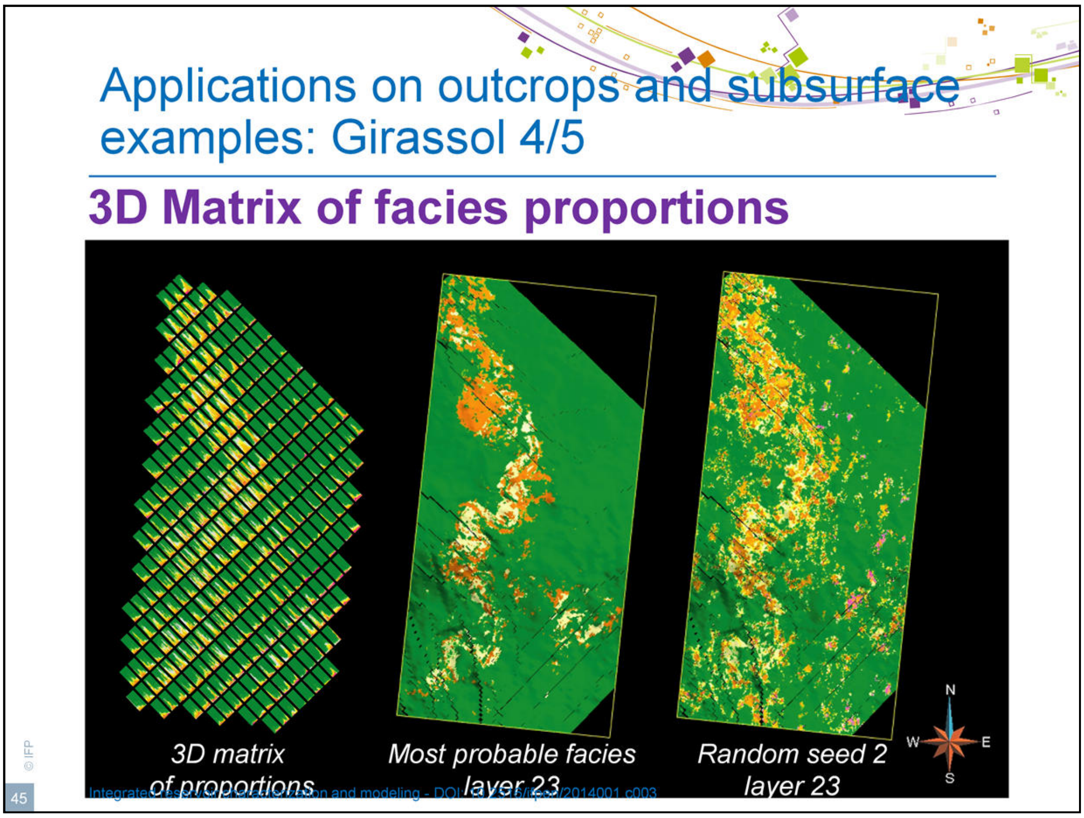


Let us first focus on the analysis of seismic facies. A first step is the classification of the geological facies from all available well logs and core data. Then, P-wave and S-wave impedances (Ip and Is, respectively) only are considered, both at the log scale and at the seismic scale, in order to determine which electrofacies classes may be discriminated from seismic attributes. Then, the classification function defined from well data is applied to perform a facies analysis using the impedances Ip and Is at the seismic scale. This makes it possible to assign probabilities of occurrence of seismic facies to the three dimensional grid of the reservoir.



The facies results derived from the analysis of well and seismic-related data are combined in a subsequent step to go back to the geological scale and populate the reservoir grid with geological facies proportions.

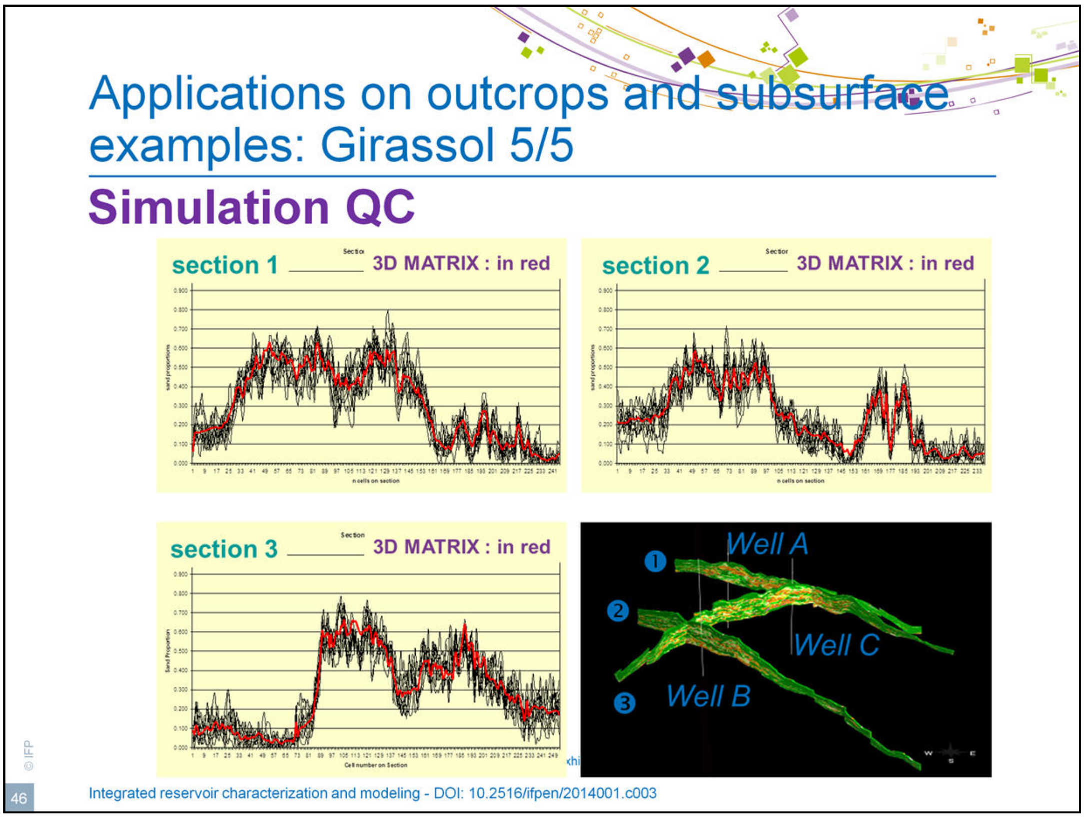
The distributions of the geological facies (*GF*) proportions can be estimated for each seismic facies (*SF*) from electrofacies well logs and seismic facies pseudo-logs extracted from well. According to the total probability axiom, these distributions can be combined with seismic facies probabilities in order to estimate the distributions of the geological facies proportions for each cell of the seismic grid (Barens and Biver, 2004). This is expressed by the equation above. *N* is the number of seismic facies, the vertical bars stand for “conditionally to”, *p* for probability and *prop* for distribution. Thus, prop(*GFj/SFi*) is the distribution of geological facies *GFj* in seismic facies *SFi*.



The input parameters required by the truncated Gaussian method are the curves or matrix of facies proportions and the variogram models.

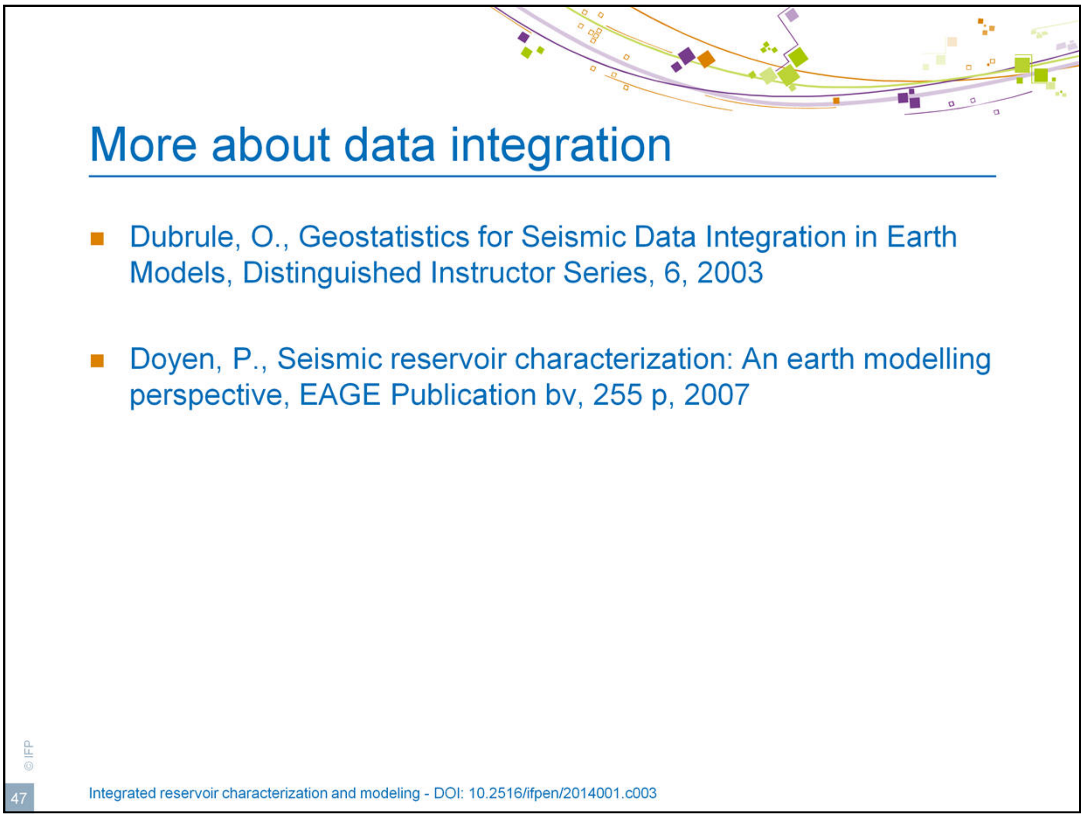
The matrix of facies proportions obtained for the second unit (named Unit2) of the Girassol field is displayed in the left figure. This information can be used to compute a deterministic image of the reservoir by assigning the most probable facies to the grid blocks (middle figure).

Realizations can also be randomly drawn in a stochastic framework using the Truncated Gaussian method (right figure). In this case, the 3D matrix of facies proportions is converted into thresholds that are used to truncate the underlying continuous Gaussian random function (Chapter 2).



The matrix of facies proportions is a constraint that is honored on average. This can be easily checked. The plots above display the sand proportion along three distinct vertical cross-sections. The black curves were computed for 10 realizations randomly generated from the process described on the previous pages. The red curves correspond to the sand proportions derived from seismic. It can be shown for each cross-section that the mean of the black curves tends towards the red curve and the dispersion is about 10%.

As a conclusion, the constraint provided by seismic is respected on average.



The interested reader can consult the above references to get more information about the integration of static data (mainly seismic or seismic-related data) into geological models.