Reservoir Facies Modeling: Past, Present and Future

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Reservoir Facies Modeling: Past, Present and Future

• Why do we need to model facies?
• Past: variogram-based and object-based modeling
• Present: training image-based modeling (MPS)
• Future: remaining challenges and perspectives
Reservoir Facies Modeling: Past, Present and Future

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From Exploration to Production

Exploration Geology: Oil/Gas discovery

• How much oil/gas is there?
• Where is it located?
• How many wells do we need and where should we drill them?
• How much oil/gas will we produce and when?

3D Numerical Reservoir Modelling helps answer those questions

Reservoir Engineering: Oil/Gas Production

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Petrophysical Property Modeling

Building numerical 3D reservoir models of porosity, permeability, and water saturation allows:

- **Estimating oil/gas reserves:**
  Compute hydrocarbon volume in place:
  \[ \text{Oil-in-place} = \text{rock volume} \times \text{porosity} \times (1 - \text{water saturation})/Bo \]

- **Forecasting oil/gas production:**
  Run flow simulation using porosity/permeability/water saturation models provide well production profile and oil/gas recovery

- **Optimizing field development plan:** number and locations of new wells
  Analyze models along with seismic to optimize well drilling locations

But why do we need to model facies?
Simple Porosity Modeling Exercise

Reservoir horizontal layer
(map view)

Well 1: 20%
Well 2: 23%
Well 3: 2%

Typical answers without additional information:

- Average value from all wells: \((20 + 23 + 2) / 3 = 15\%\)
- Distance-weighted average: \((2 \times 2 + 1 \times 20 + 1 \times 23) / 4 = 12\%\)
Conventional Geostatistical Approach

Reservoir horizontal layer (map view)

Well 1: 20%
Well 2: 23%
Well 3: 2%

Direction of Major Continuity

Account for distance to data, data redundancy, trends: Kriging

- Developed in the 40’s for gold mining; adopted by Petroleum industry in 80’s
- East-West trend: 18%
Facies-Based Approach

Reservoir horizontal layer (map view)

Well 1: 20%
Well 2: 23%
Well 3: 2%

Geological interpretation: Fluvial environment with EW oriented channels

Only porosity data from channel should be used!

New answer using facies interpretation: 22%
Why do we Need Facies Modeling as an Intermediate Step to Model Poro/Perm?

- Porosity/permeability spatial distribution is derived from depositional history, i.e. deposition of successive geobodies with different poro/perm ranges, e.g.:
  - High poro/perm sand channels during low-stand system tract
  - Low poro/perm shale drape during high-stand system tract

- Facies modeling consists in identifying and modeling those main poro/perm geobodies, and then poro/perm will be simulated within each individual facies

Well log permeability histogram           Facies-based permeability model
Facies Definition

• **Facies:**
  “A body of rock characterized by a particular combination of lithology, physical and/or biological structures that bestow an aspect different from the bodies of rock above, below and laterally adjacent” (Walker and James, 1992).

• 2 main types of facies:
  – **Depositional Facies:** large-scale, characterized by geometry and relative position
    e.g: fluvial channels, transgressive sands

  – **Lithofacies or rock types:** medium-scale, characterized by petrophysical property ranges, i.e. using poro, perm, Vshale cut-offs
    e.g: sand, shale
Depositional Facies

Interpreted from cores, well log motifs and seismic:

With depositional conceptual model in mind:

Deepwater

Wave-Dominated Shoreline

Fluvial

Floodplain
Lithofacies or Rock Types

Characterized by porosity, permeability, Vshale cut-offs:

- Non-Sand
- Non-Reservoir
- Low Quality Sand
- Medium Quality
- High Quality

Delta front
Tidal Channel
Need for Facies Models

• Facies models allow capturing main reservoir connectivity structures: low poro/perm flow barriers, high poro/perm preferential flow paths.

• Those modeled flow barriers and flow paths drive reservoir flow performance: water breakthrough, plateau length, …

• Special cases: facies models may not be needed in homogeneous systems, or in systems where poro/perm is greatly impacted by diagenesis
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Variogram-Based Modeling (SIS)

- In most reservoirs, permeability heterogeneity is primarily controlled by depositional facies and/or lithofacies.
- Facies modeling should be the first step of the reservoir modeling workflow.
- Traditional facies modeling techniques based on variograms.

But two-point correlation measure (variogram) does not allow modeling realistic facies geobody shapes and facies interactions.
Limitations of SIS

- SIS generates maximum entropy (disorder) models beyond variogram, resulting in shapeless facies geobodies

- Cross-variograms provide very limited control on facies interactions
Alternative to Variogram-Based Geostat: Object-Based Models

Used when reservoir facies have characteristic geometrical shapes

But *conditioning is limited* in object-based models:
- Difficult to integrate large number of wells
- Poor integration of 3D seismic
- Modeling facies interaction can be extremely tedious
A New Geostatistical Approach

Propose a new geostatistical approach that combines:
- Speed, flexibility and easy data conditioning of variogram-based algorithms
- Ability to reproduce “shapes” of object-based algorithms

→ Multiple-point geostatistics (MPS)

Well data → Geological interpretation (well logs and analogs) → 3D Training Image = Collection of facies patterns → Pattern reproduction conditional to available data → MPS model
Definition of a Training Image

• Training Image = 3D numerical rendering of conceptual geological model defining:
  – Facies body relative dimensions and shapes
  – Associations between facies

• Training Image = Collection of Facies Patterns
• Contains no absolute (only relative) spatial information (not conditioned to wells)
Stratigraphic Input

Well log

- Facies shapes/interactions from conceptual geological model
- Facies geobodies dimensions from:
  - reservoir data bases associated with conceptual geological model
  - Actual field data: well logs (thickness), and seismic (width, length, sinuosity, orientation...)

Conceptual Geological Model
Generation of Training Images

- Potential training images: aerial photographs, pictures of outcrops, hand-drawn sketches… but only 2D
- In practice: non-conditional object-based algorithms

First describe relative dimensions and shapes of each facies:

Map view/cross-section shapes:

- Ellipse
- Lobe
- Semi-ellipse
- Sigmoid

Dimensions, orientation, sinuosity:

- Orientation
- Width
- Length
- Thickness
- Sinuosity amplitude and wavelength

Then specify associations among facies:

Facies erosion rules:

Vertical/horizontal constraints:
Training Image Examples

Fluvial-deltaic system

Deepwater Channels

Deepwater Lobes

Alternative training images may need to be built as an uncertainty parameter
MPS Simulation

- **Goal of MPS Simulation**: Extract facies patterns from the training image, and select/reproduce those patterns that match the reservoir well facies data.

  - Idea initially developed at Stanford University in the 90's
  - First practical implementation: snesim (Strebelle, 2000)
  - Chevron, first company to adopt it
  - Now available in most geomodelling softwares
Stationarity Assumption

- Actual reservoirs are not stationary: facies proportions and geometries vary in space because of topographic constraints, structural constraints...

Seismic-derived sand probability map

High sand Proportion region
Variable Deposition direction

More realistic model
External Constraints

- External constraints are used to better control spatial variations of facies geometries and facies proportions in MPS models.

Geometry Constraints

- Azimuth field
- Object size field

Proportion Constraints

- Facies proportion map
- Facies proportion curve
- Regional Facies proportions

Facies Probability Cube from geological interpretation or seismic calibration
Impose target facies proportions in each grid layer

Facies Proportion Constraints: 1D Facies Proportion Curve

Facies proportions

Grid layer index

Training Image

MPS model

Layer 20 (10% sand)

Layer 7 (60% sand)

Layer 1 (30% sand)
Simulating Petrophysical Properties Within Facies

• In facies models, porosity/permeability heterogeneity is primarily controlled by depositional facies elements.

• Traditional variogram-based techniques (e.g. SGS) are usually used to populate petrophysical properties in each facies.
MPS Reservoir Modeling Workflow

0. Build SGrid and interpret facies at wells

1. Build Training Image

2. Build Geometry and Proportion Constraints

3. MPS Simulation

4. Populate Facies with Poro/Perm

Build alternative scenarios To account for uncertainty (Workflow Manager)
Impact on Flow Performance Estimation: Connectivity Enhancement of DW Model

- Sand probability cube from PCA
- Active cells in variogram-based model
- Training Image
- MPS model
Oil Recovery Improvements with MPS

Res. 1 Recovery is increased by at least 10% in MPS model compared to variogram-based model.

Res. 2 Recovery is increased by at least 5% in MPS model compared to variogram-based model. Early recovery differences are significant.
### MPS vs. Variogram-Based and Object-Based Modeling

<table>
<thead>
<tr>
<th></th>
<th>Variogram-based</th>
<th>Object-based</th>
<th>MPS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conditioning to well data</td>
<td>++</td>
<td>+ (sparse wells) to – (dense wells)</td>
<td>++</td>
</tr>
<tr>
<td>Use of modeling constraints</td>
<td>++</td>
<td>+ to -</td>
<td>++</td>
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<tr>
<td>Speed</td>
<td>++</td>
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<td>Reproduction of connectivity patterns</td>
<td>-</td>
<td>++</td>
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<tr>
<td>User-acceptance</td>
<td>++</td>
<td>+</td>
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Research going on to improve speed, and better reproduce patterns (e.g. perfect channel connectivity)
When Should You Use MPS?

Heterogeneity/Connectivity vs. Well Density

- **Object-based MPS**
  - Complex
  - Sparse

- **Variogram-based MPS**
  - Simple
  - Dense
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MPS allows capturing geological heterogeneity features in reservoir models to make reliable flow forecasts.

But how to characterize those, most often sub-seismic, heterogeneity features?

- What are the sizes, shapes, distributions and spatial organizations of these heterogeneity features?
- What are the possible ranges of these heterogeneities? What are the extreme scenarios? What is the most connected case? What is the least connected case?
- Can we predict them? What is the key control of these heterogeneity features? e.g. water depth, sediment input, sea level variations, tidal range, wave amplitude, sediment basin geometries and configurations, …

Limited info from small number of 2D outcrops, difficult to transfer into 3D reservoir models
Forward Stratigraphic Models

Generation of fine-scale 3D Numerical Analogs

1. Fully based on the physics of fluid flow and sediment transport, no need for assumption on deposition model or processes.
2. Model parameters are all physical.
3. Abilities to apply all kinds of simple and complex boundary conditions

Governing Equations:

\[
\frac{\partial u_x h}{\partial t} + \frac{\partial u_x^2 h}{\partial x} + \frac{\partial u_x u_y h}{\partial y} = -\alpha Rg \frac{\partial C}{\partial x} h^2 - 2\alpha Rg C \frac{\partial h}{\partial x} h - Rg C \frac{\partial \eta}{\partial x} h + \frac{\tau_{bx}}{\rho} + \frac{\tau_{sx}}{\rho}
\]

\[
\frac{\partial u_y h}{\partial t} + \frac{\partial u_x u_y h}{\partial x} + \frac{\partial u_y^2 h}{\partial y} = -\alpha Rg \frac{\partial C}{\partial y} h^2 - 2\alpha Rg C \frac{\partial h}{\partial y} h - Rg C \frac{\partial \eta}{\partial y} h + \frac{\tau_{by}}{\rho} + \frac{\tau_{sy}}{\rho}
\]

\[
\frac{\partial h}{\partial t} + \frac{\partial u_x h}{\partial x} + \frac{\partial u_y h}{\partial y} = \epsilon_w - \delta_w
\]

\[
\frac{\partial C_i}{\partial t} + \frac{\partial u_x C_i}{\partial x} + \frac{\partial u_y C_i}{\partial y} = E_i - D_i \quad \text{for } i = 1, 2, \ldots, n
\]

Conventional uncertainty from outcrop analogs:

**Limited samples, unknown extremes**

Generation of 3D numerical analogs:

**Unlimited number of samples, full uncertainty range**
Simulations with Sea Level Variations and Subsidence
Fluvial Delta Simulation Results

Stratigraphy in dip sections, vertically x100
Fluvial Delta Simulation Results

Synthetic well logs and their locations

Comparing pseudo-well logs from forward stratigraphic models with actual reservoir well logs helps identify potential “reliable” training images.
Remaining Challenges and Perspectives

• Active research in MPS using advanced machine learning techniques should help to improve speed and training pattern reproduction

• Questions remain about training images:
  – How large should they be?
  – What features do we want to reproduce from them, what features would we like to filter out?
  – How to generate reliable training images?

• Forward stratigraphic models could be a good source of training images although those models:
  – require a lot of computing capabilities
  – need to be validated with actual outcrop data
  – may need to be simplified to be used as training images

Short-term solution could be a library of training images derived from forward stratigraphic models for each type of environment?
Conclusions

• **Facies Modeling** is a critical intermediary step in most reservoir characterization and modeling studies to provide reliable flow performance forecasts.

• **MPS** enables the simulation of geologically realistic facies geobodies while integrating large variety of data and constraints.

• **MPS** is available in most commercial geomodelling softwares, but also in academic softwares (SGEMS from Stanford University).

• Forward Stratigraphic Models are a promising source of training images.
Thank you!

More information on MPS:
- SPE paper 77425
- Geostatistical Reservoir Modeling book by Dr. Pyrcz
Pixel-based Sequential Simulation Program

Simulation grid

- Stochastic (multiple realizations)
- Perfect hard data conditioning
- General (not specific to channels)
- Fast using search trees to store/classify training patterns, and multiple-grid approach

Go to next grid node... (random walk)

Look for patterns matching conditioning data

<table>
<thead>
<tr>
<th>$u_1$</th>
<th>$u_2$</th>
<th>$u_3$</th>
<th>$u_4$</th>
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</table>

Draw simulated value

prob($u$ in sand) = $3/4$
prob($u$ in shale) = $1/4$
Facies Proportion Constraints: 2D Facies Proportion Maps

Impose target facies proportions along each vertical column

Training Image

Facies proportion map

0

Relatively high sand proportion areas

Low sand proportion area

MPS model horizontal sections

Layer 3

Layer 7

Layer 20
Simulating Petrophysical Properties: Special Cases

- In some cases, accounting for intra-geobody trends may lead to improve petrophysical property continuity:

  - Facies Model
  - SGS Porosity Model
  - More Realistic Porosity Model

Example of trend along channel axis (function of the local distance to the channel edges)