Integrated Static-Dynamic Reservoir Modeling for a Deep-Water West African Reservoir Utilizing an Efficient Decision Tree-Based Workflow*

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Abstract

This case study demonstrates the use of a multi-disciplinary decision-based methodology to evaluate geologic uncertainty in a highly heterogeneous reservoir. The reservoir consists of levee confined channels characterized by core-calibrated log data, high-resolution 3D seismic data, analogs and well tests. The field has been producing oil for a year with support from water injection.

In the framing phase, key uncertainties were identified and combined in a decision tree to define multiple scenarios with various levels of complexities. Elements affecting flow and their implementation in the models were considered, such as channel stacking pattern and geometry, distribution of sandy petrofacies and baffles/barriers, and variability of porosity/permeability. Models were built over a small but representative area in order to accelerate learnings from dynamic simulation and iterative updates of the seismic interpretation and static models.

Models with detailed seismic stratigraphic mapping, layers honoring the channel axis-margin-levee geometries, and multiple facies having distinct porosity/permeability trends showed better history matching results than more simplistic models. These findings narrowed the range of uncertainty by constraining the methodology for mapping channels and representing subseismic baffles and barriers. Second order uncertainties were represented by equally likely models, used as input in an integrated static-dynamic uncertainty workflow. The study defined an efficient workflow to create low-mid-high case models for the full field that are not anchored to a base case. This was achieved in a limited amount of time with the geologist, geophysicist, petrophysicist, and reservoir engineer working concurrently on a limited set of data, rather than sequentially over the full field. We believe this represents a more efficient, decision-based alternative to the standard interpretation and modeling workflow.

Anadarko Petroleum Corporation

INTEGRATED STATIC-DYNAMIC RESERVOIR MODELING FOR A DEEP-WATER WEST AFRICAN RESERVOIR UTILIZING AN EFFICIENT DECISION TREE-BASED WORKFLOW

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May 21, 2018

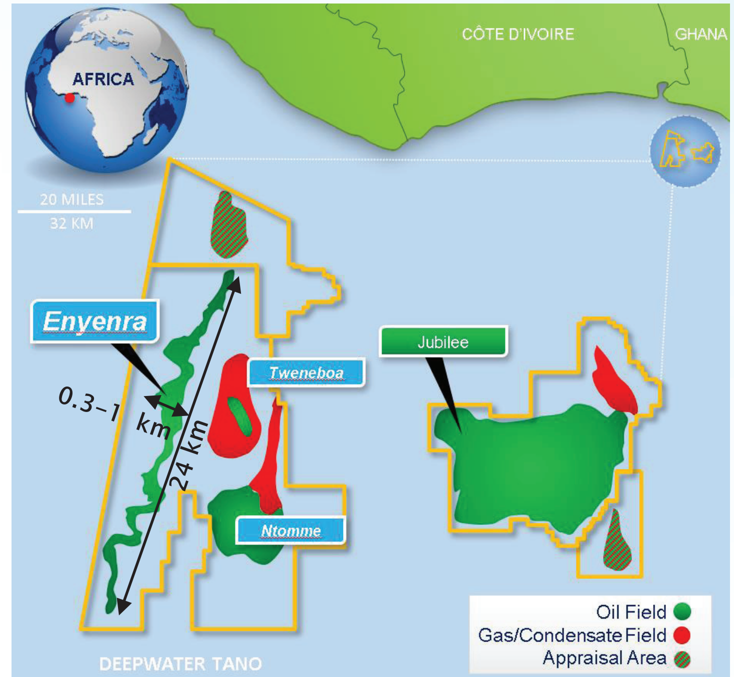
Outline

- **Introduction**
  - Field overview
  - Development challenges
  - Reservoir heterogeneities
- **Methodology**
  - Decision tree
  - Sector model
  - Discipline integration
- **Results**
  - Sector model results
  - Full field results
- **Conclusions**

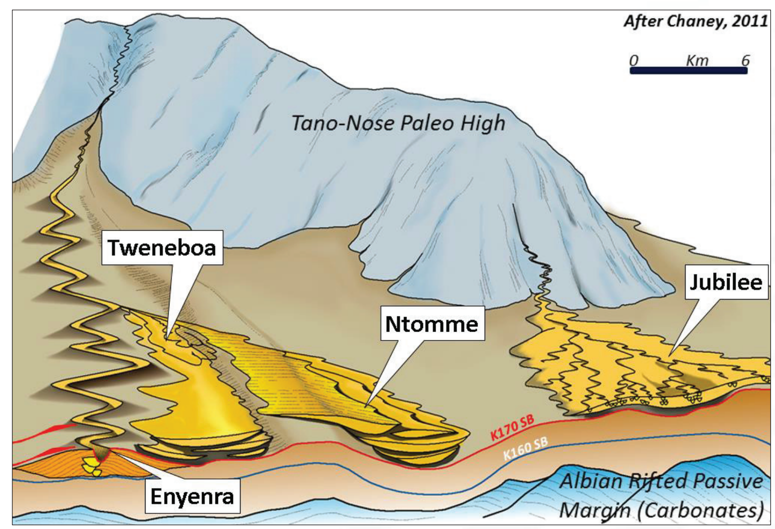
Enyenra field overview

- **Location**
  - 60 km offshore Ghana, 25 km west of Jubilee
  - Water depths: 1400–1700m
  - 24 km long and 0.3–1 km wide
- **Discovery**
  - 2010, with 46 m of pay in discovery well
- **Wells**
  - 11 wells, 3 with core
  - 3 injectors & 3 producers with 2 km spacing online since August 2016
- **Seismic**
  - Dual azimuth seismic acquired in 2014
- **Production**
  - Pre-production DSTs and interference tests
  - Current recovery factor: 4%
- **Depositional Setting**
  - Sediments shed from paleo-high into Tano Basin during Late Cretaceous (Turonian)
  - Enyenra developed in the lower to middle slope as a levee-confined channel complex

Location Map



Paleogeography of Tano Basin



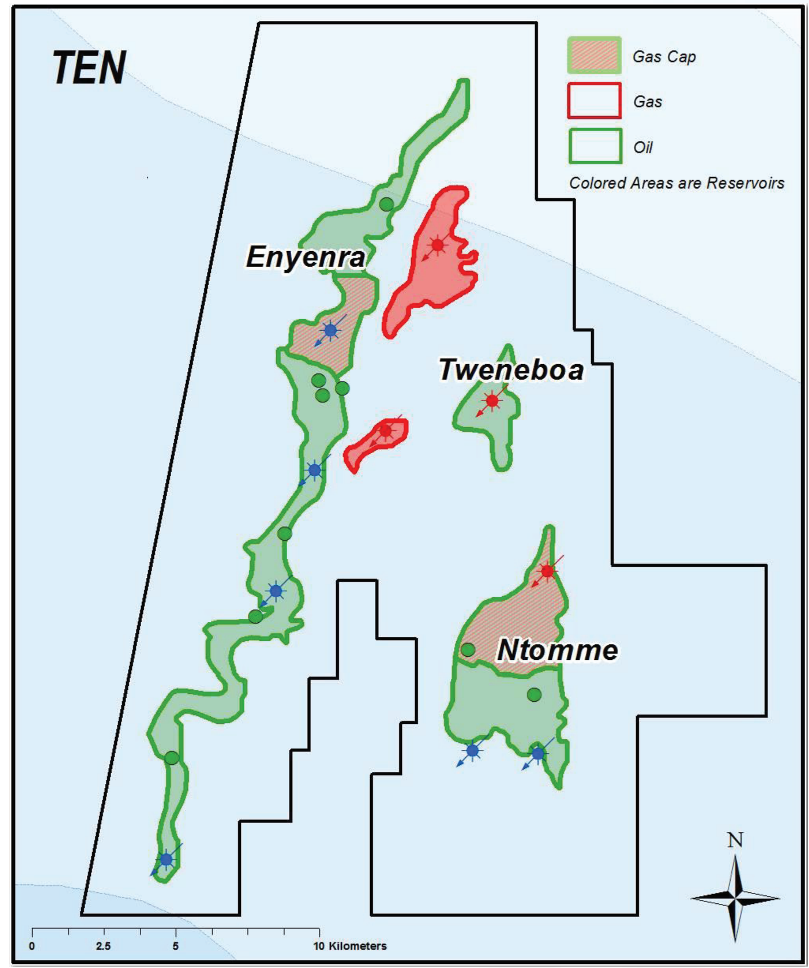
Goals and challenges in modeling Enyenra

Goals:

- Define field development strategy to accelerate production, maximize EUR and increase reserves while mitigating risks
  - Identify possible baffles and barriers
  - Locate unswept reservoir
  - Optimize locations and trajectories of in-fill wells

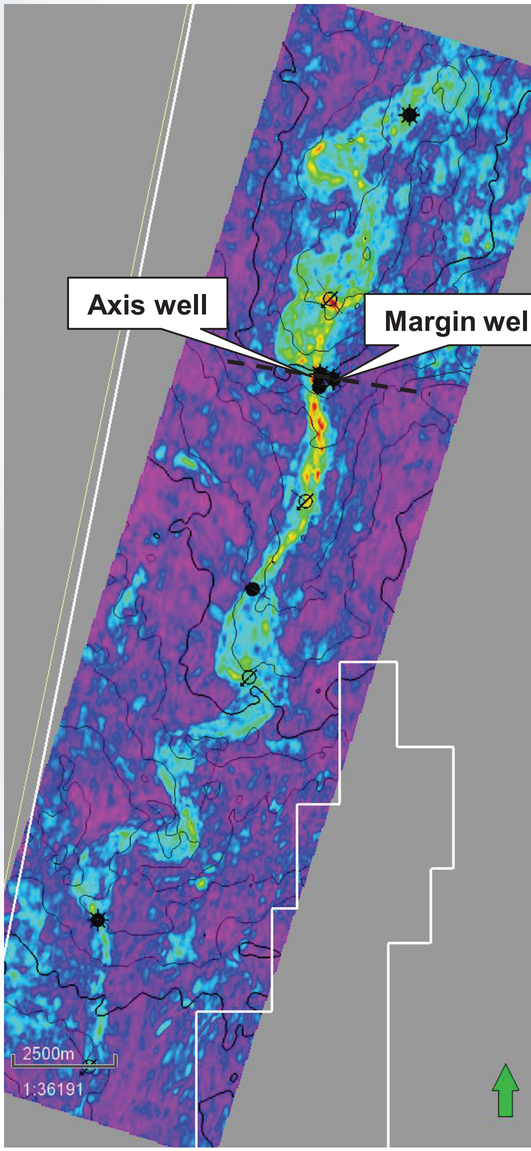
Challenges:

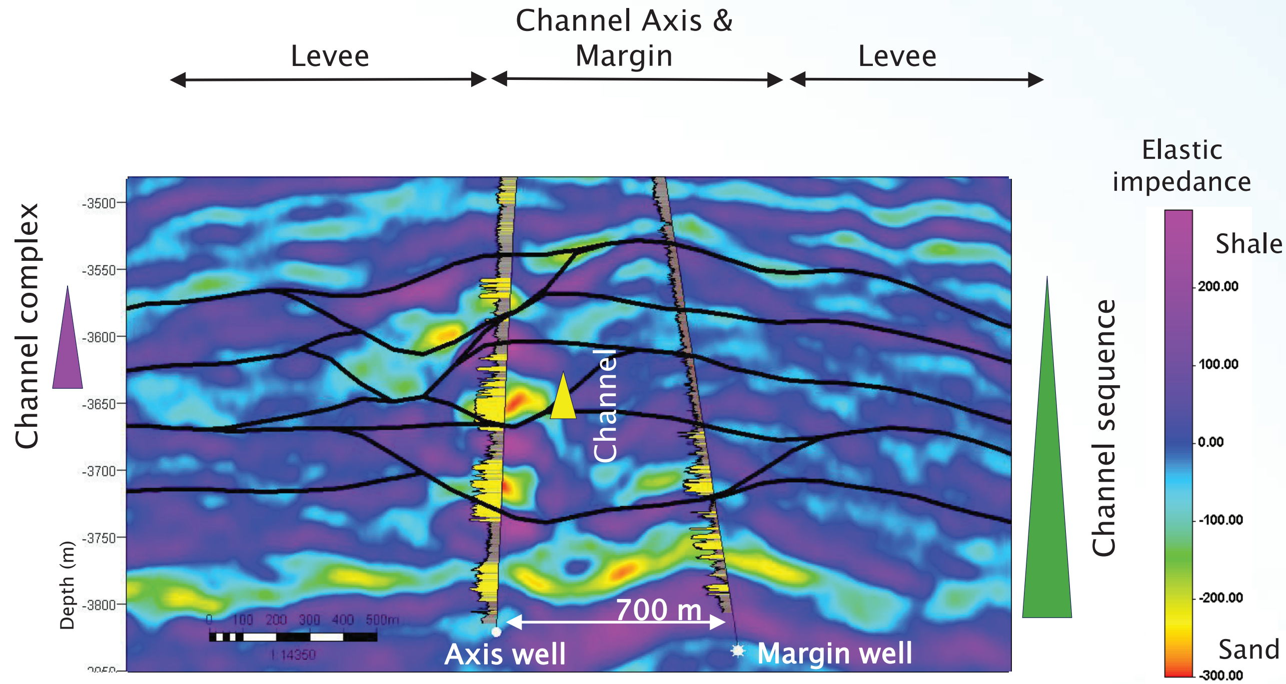
- How to capture reservoir heterogeneities and connectivity in the model?
- Short production and injection data, no water breakthrough
- Hydraulic fractures due to high water injection rates



Seismic-scale heterogeneity 1

Channel complexes



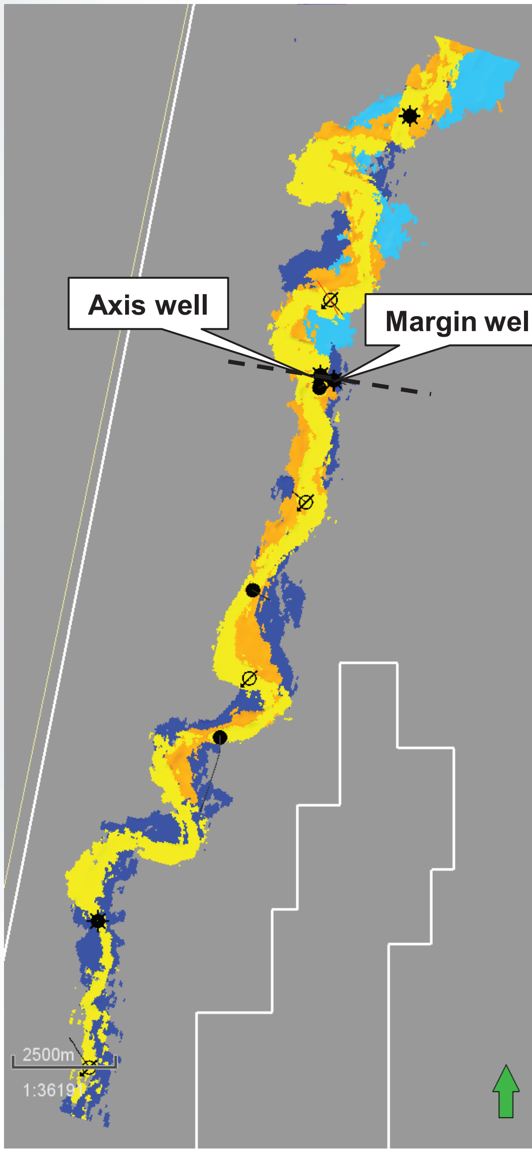


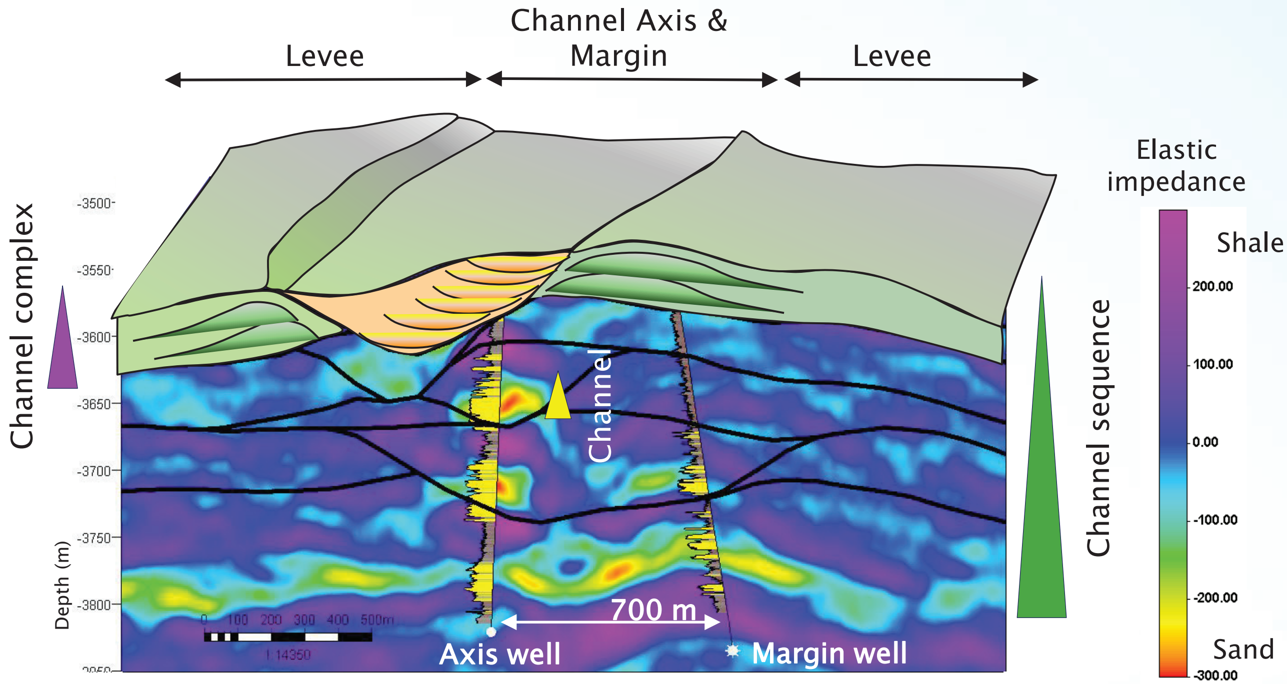
- Large variation in net to gross over small distances
- Repeated fining upward sequences which vertically separate channels
- Baffles and barriers in lateral extent

Presenter's notes: Seismic-scale heterogeneity 1 (slide 5): This slide shows examples of large scale heterogeneities based on the seismic data. Extended elastic impedance was the primary interpretation product and has a dominant frequency of 15 to 20 Hz and tuning thickness of about 40 m at the reservoir interval. Red is negative impedance and a good indicator of sand. In the map view, an amplitude extraction shows the outline of multiple stacked channels very well. The seismic strike line through the channel crosses 2 wells: one in the channel axis and one in the margin. This view shows the good correlations between sands in wells and negative extended elastic impedance values.

Seismic–scale heterogeneity 2

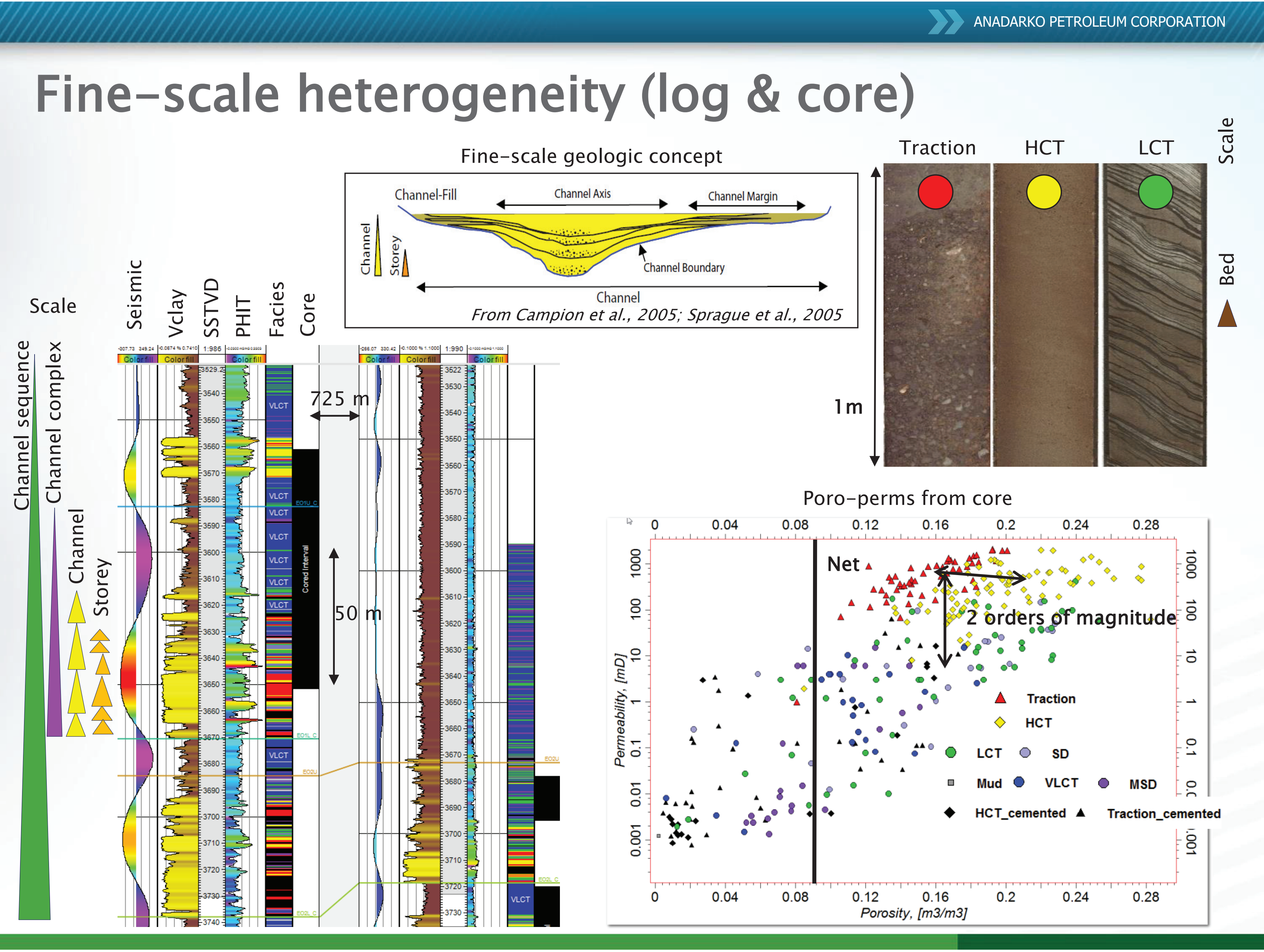
Channel complexes





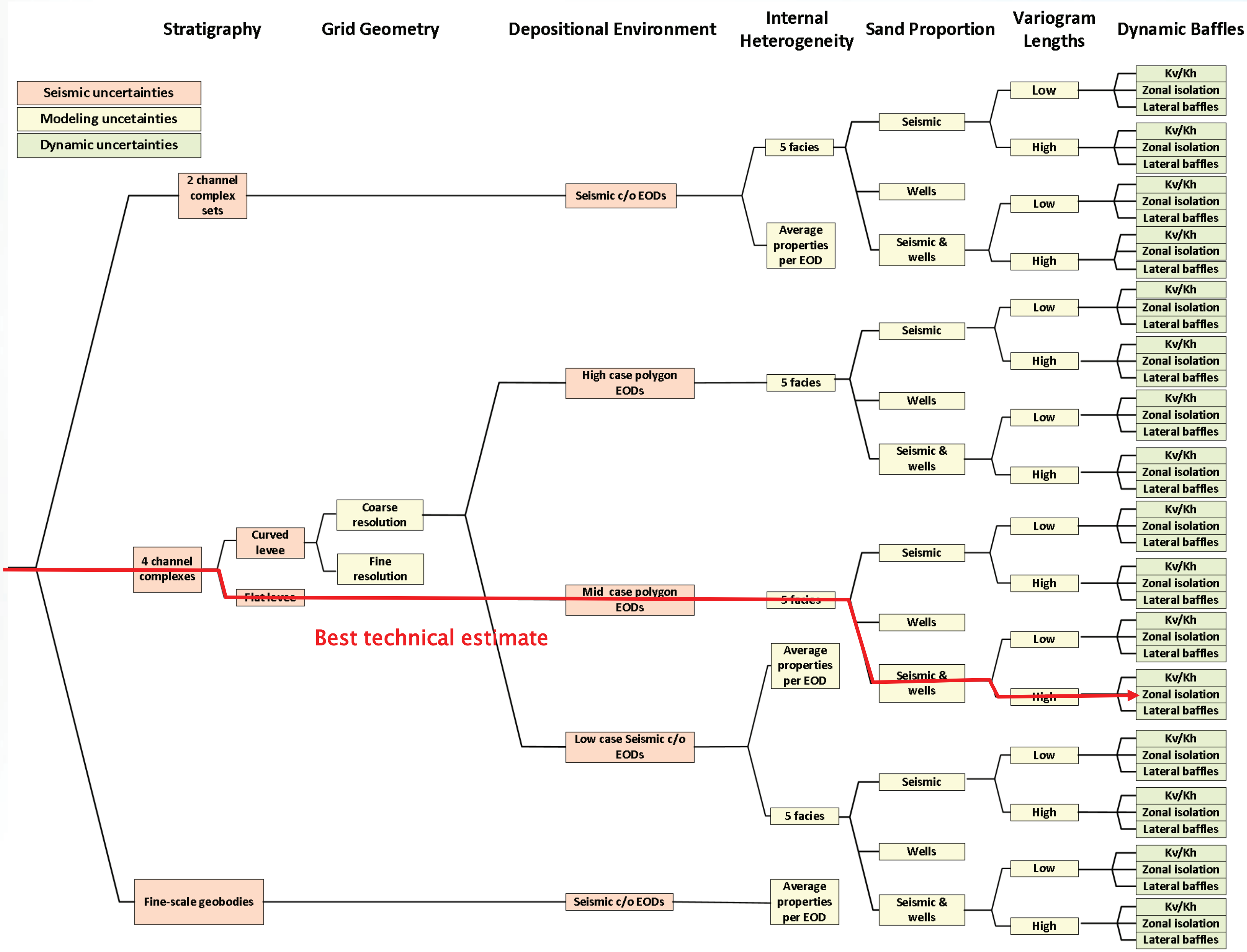
- Large variation in net to gross over small distances
- Repeated fining upward sequences which vertically separate channels
- Baffles and barriers in lateral extent

Presenter's notes: Seismic-scale heterogeneity 2 (slide 6): Based on outcrop analogs, the seismic response likely represents a succession of levee-confined channels with lateral and vertical aggradation and some amalgamation. At the seismic scale, various levels of heterogeneity are observed which introduce uncertainties in the interpretation. These include a large variation in net to gross from the channel axis to levee seen in variations of seismic amplitude strength. Repeated fining upwards sequences vertically separate channels. Static pressure data guided the vertical scale of seismic interpretation. Amplitude extractions in map view show potential baffles and barriers, and interference tests defined the lateral extent of channels.



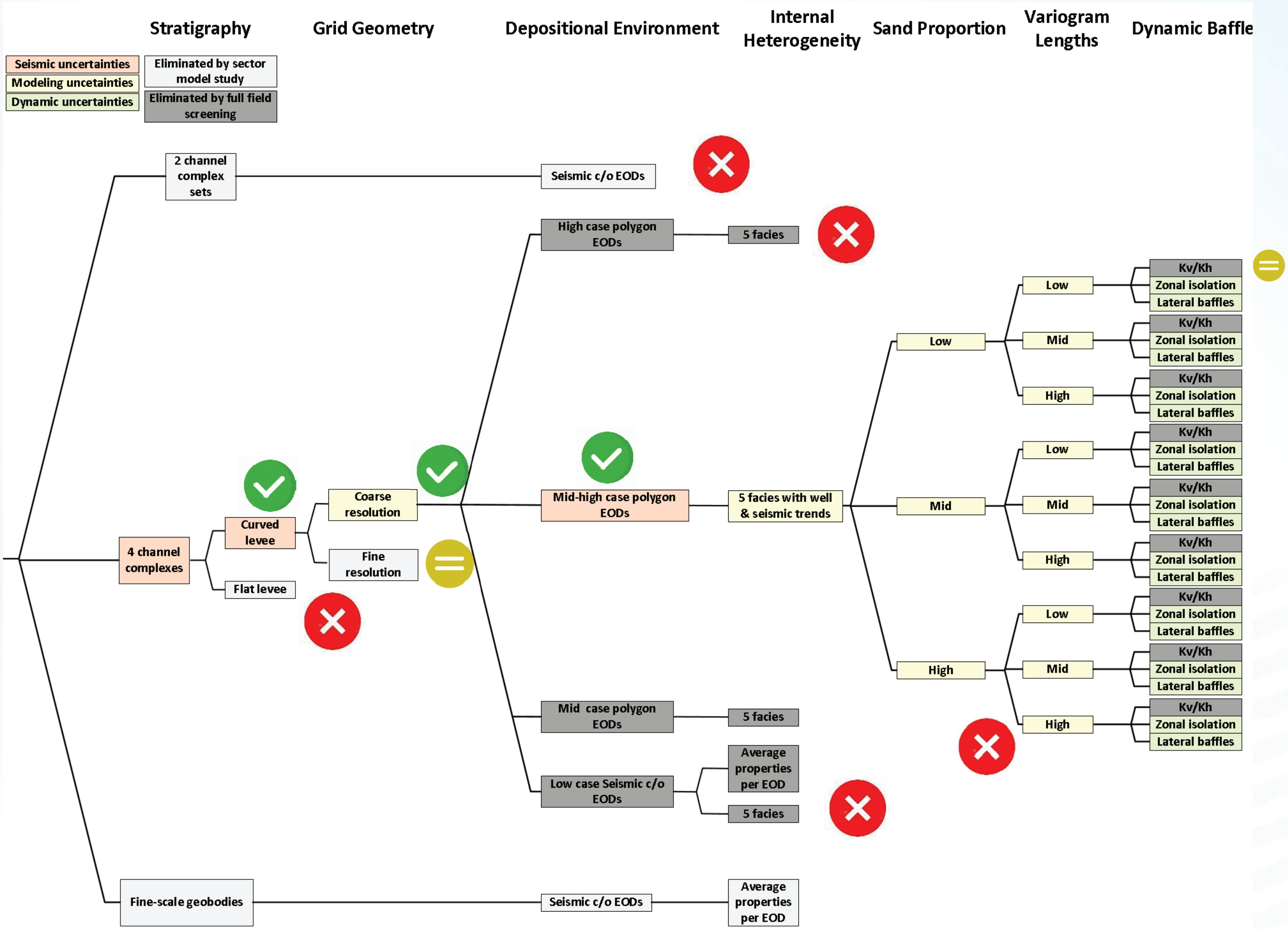
Presenter's notes: Fine-scale heterogeneity (slide 7): At a finer scale, there are a variety of heterogeneities in log and core. The same fining upwards patterns define smaller scales such as channels, storeys and beds. From core, 8 distinct rock types were identified such as traction, high concentration turbidites (HCT), and low concentration turbidites (LCT). These were based on differences in sorting, grain size, and bed organization. Some of the rock types were then grouped together based on similarities in porosity-permeability relationships, reducing the number of rock types to 5 for modeling.

Decision Tree



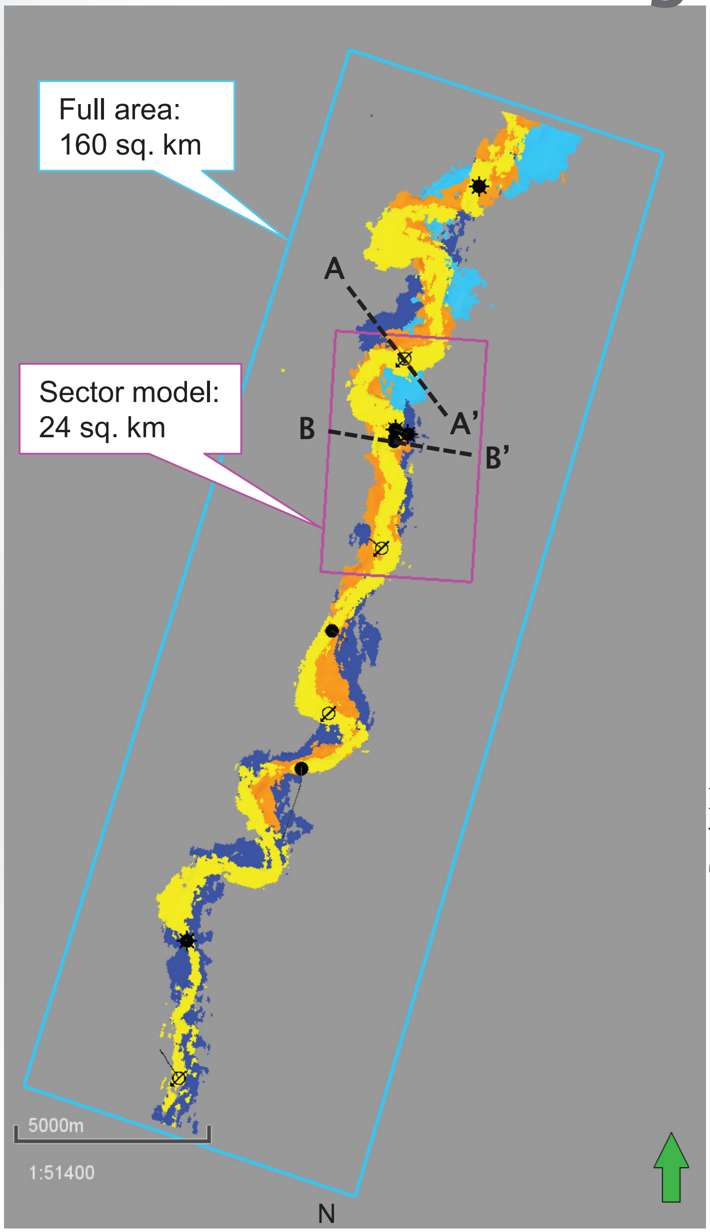
Presenter's notes: Decision tree (slide 8): Given the degree of heterogeneity in this reservoir, it is important to understand which are the most important factors affecting fluid flow. To do so, uncertainties are organized in a decision tree. These include seismic uncertainties in orange, modeling uncertainties in yellow and dynamic uncertainties in green. For each uncertainty, a range of scenarios are considered and form the various branches of the tree. Each branch represents a distinct model which can be tested dynamically. In the more traditional approach of making a best technical estimate model, a single case is selected for each uncertainty without considering the range of possible scenarios.

Remaining uncertainties

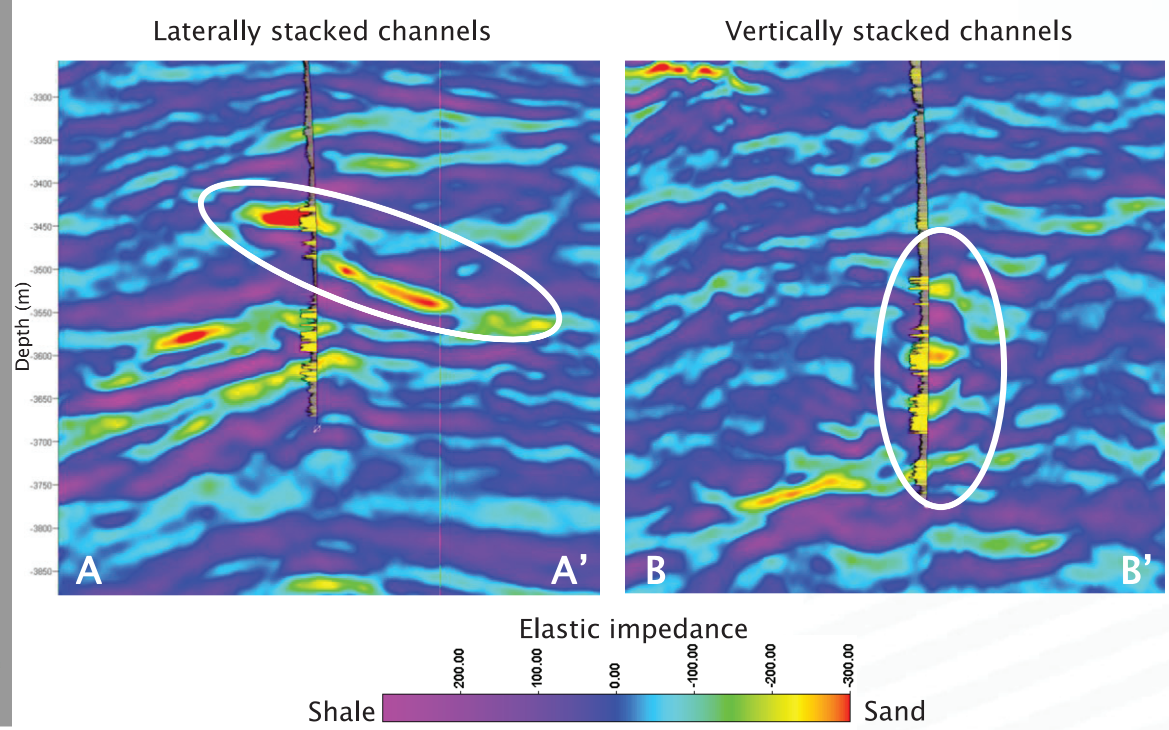


Presenter's notes: Remaining uncertainties (slide 9): After dynamically testing the models shown in the previous decision tree, several branches were eliminated because simulations failed or the history match was very poor. These are shown by the red circles. Models which worked are shown in green and model parameters which had little impact on fluid flow are shown in yellow. A smaller range of plausible models were the final output from this decision tree. The following slides illustrate how various scenarios were retained or discarded for each uncertainty.

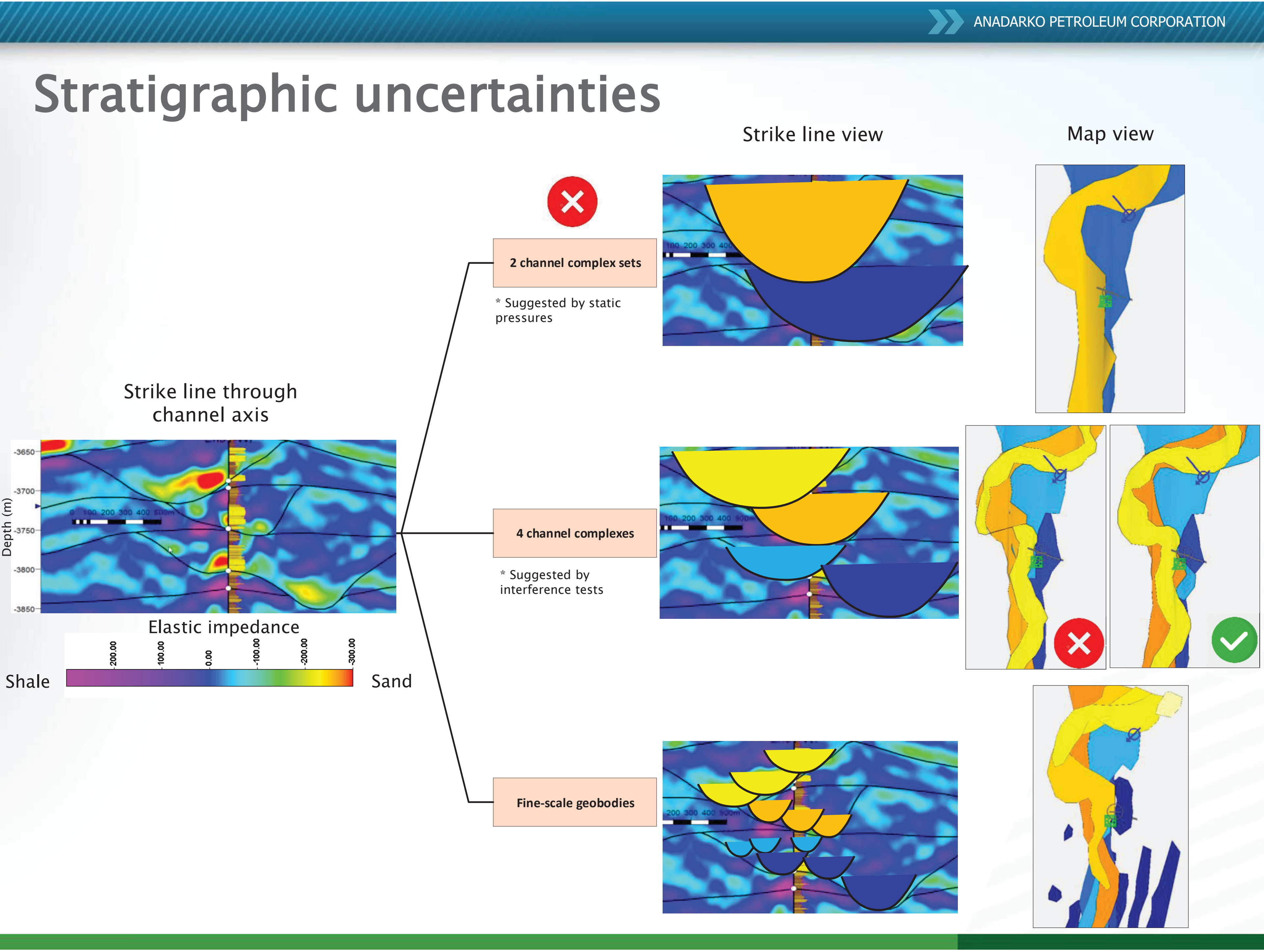
Efficient screening of scenarios



- Common scale model
  - 40x40x1m
  - 80x80x2m
- Sector model area selected to be representative of a variety of stacking patterns

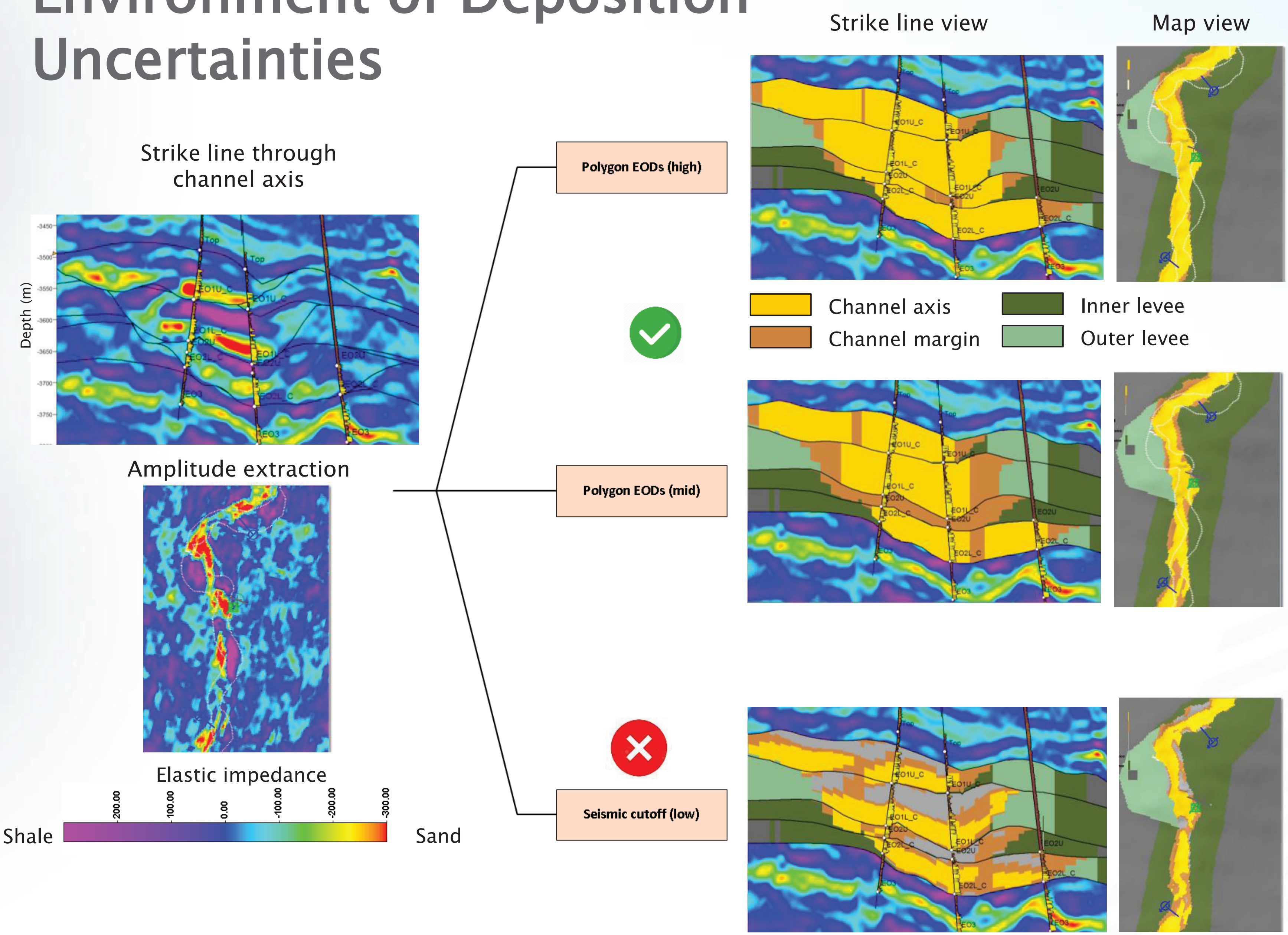


Presenter's notes: Efficient screening of scenarios (slide 10): To efficiently test a large number of models, a small area of the field about 15% of the total size was used for testing. A coarse grid resolution was selected to speed up the dynamic simulation. This area is representative of the full field with a variety of stacking geometries and rock types.



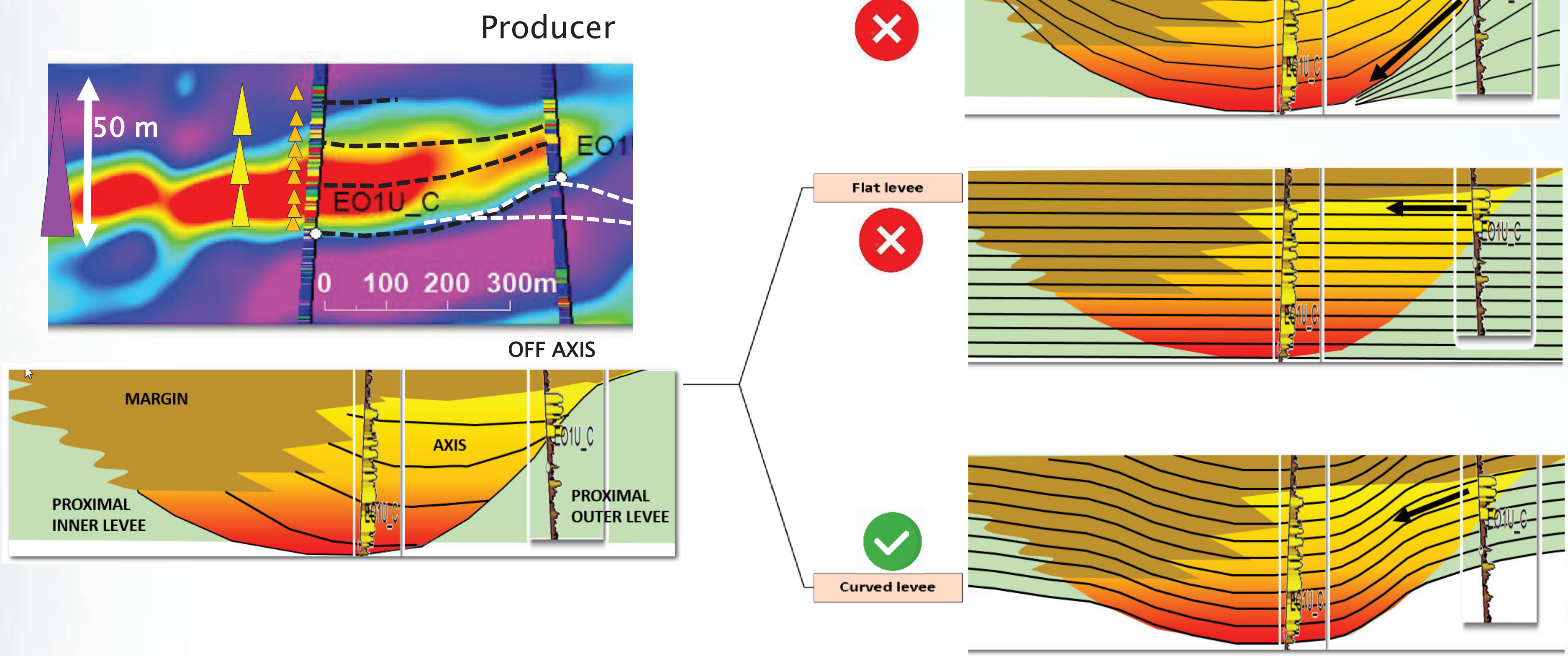
Presenter's notes: Stratigraphic uncertainties (slide 11): An important seismic uncertainty tested was the level of detail needed in the stratigraphic architecture. A coarse-scale interpretation of 2 channel complex sets was supported by static pressure data. However, these models did not represent the connectivity effectively because seismic amplitudes were used for the facies distribution. A highly detailed interpretation using fine-scale geobodies at the channel scale led to models which were too disconnected. An moderately detailed interpretation of 4 channels complexes produced the best history matches and was supported by interference tests.

Environment of Deposition Uncertainties



Presenter's notes: Environment of deposition uncertainties (slide 12): Environments of deposition (EOD) such as channel axis, margin and levee will have different proportions of rock types in the models. Defining the location and extent of these is an uncertainty. They can be defined by seismic amplitudes. The high amplitudes define the channel axis and low amplitudes define the margin and levee. Using a seismic amplitude cutoff led to models which were too disconnected. They can be also be defined manually by digitizing polygons based on seismic amplitudes/thicknesses and dimensions from analogs. Mid and high case polygons were created and produced feasible models.

Layering style

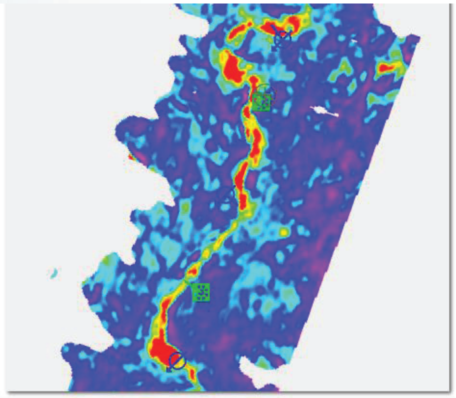


- Easier to match well pressure in the core of the axis (layers follow base along dip section)
- Hard to match wells in off-axis or margin (questionable layers geometry along strike section). Model predictability away from well control?

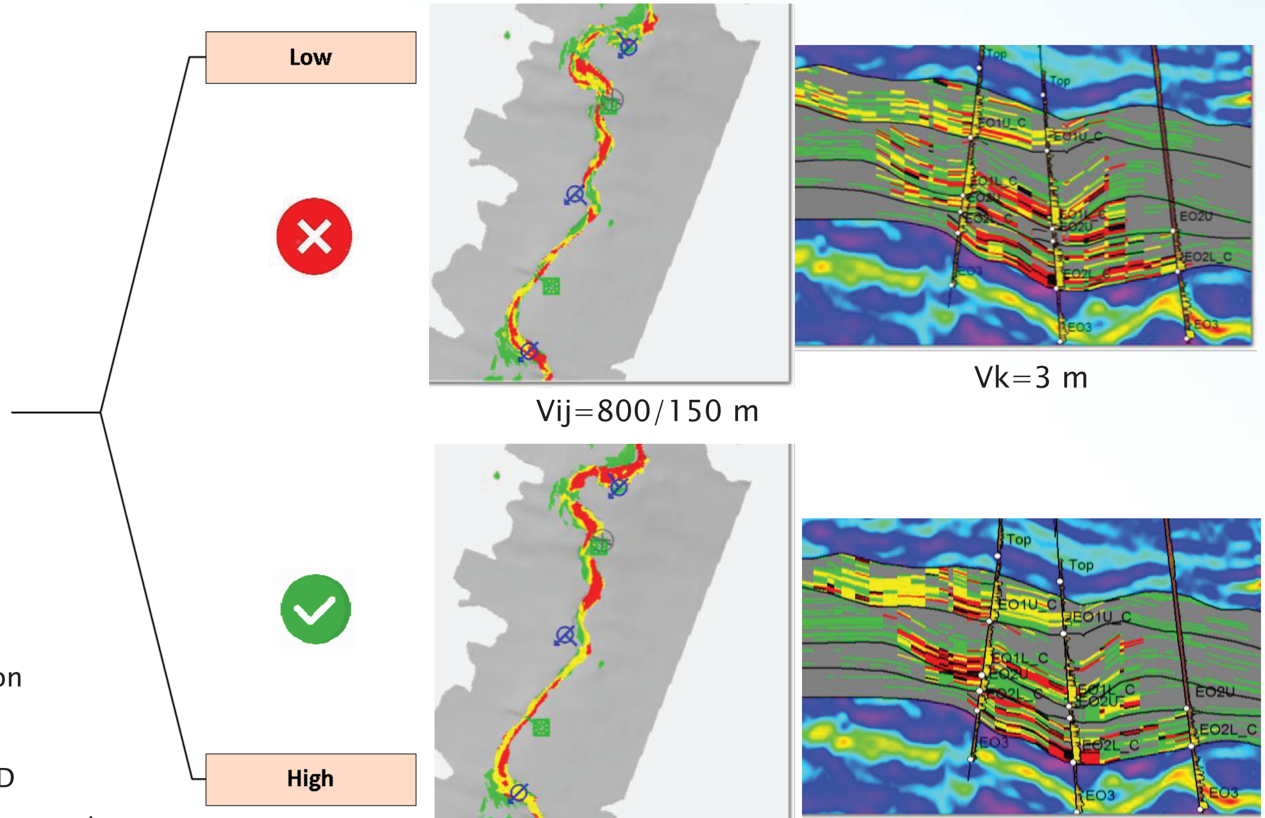
Presenter's notes: Layering style (slide 13): The 2 most closely-spaced wells in the field and their petrofacies logs are plotted against the extended elastic impedance. The axial well (on the left) has 3 channels with fining upward sequences separated by shale drapes. Correlation with the nearby producing well in the margin is uncertain. In the center of the channel complex axis, layers following the base allow the representation of amalgamated highly permeable and storeys at the base and more baffled lower NTG storeys at the top. However, for wells located off-axis like the producer, multiple geometries had to be evaluated. The upper right picture shows the channel and the levee separated into 2 zones, with their own separate layering. The middle and lower right diagrams show channel and levee merged into one zone. Layers follow a simple flat base (middle picture) or a curved base (lower picture). Each scenario represents different connectivity between the axis, off-axis, and levee. The scenario shown in the lower right provided a better representation of connectivity for this producer. An important learning from these tests was that the model is sensitive to grid geometry. This suggests the model will have poor predictability in off-axis/margin areas.

Variogram length uncertainties

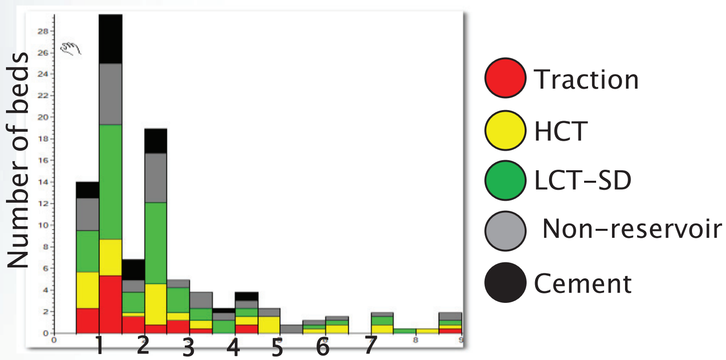
Lateral extent from seismic



Geobodies	
Dip extent	650–850 m
Strike extent	160–315 m

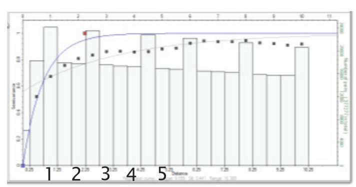


Vertical extent from well



Thickness (m)

Petrofacies	Vertical variogram range
Traction	2 m
HCT	3m
LCT+SD	1m



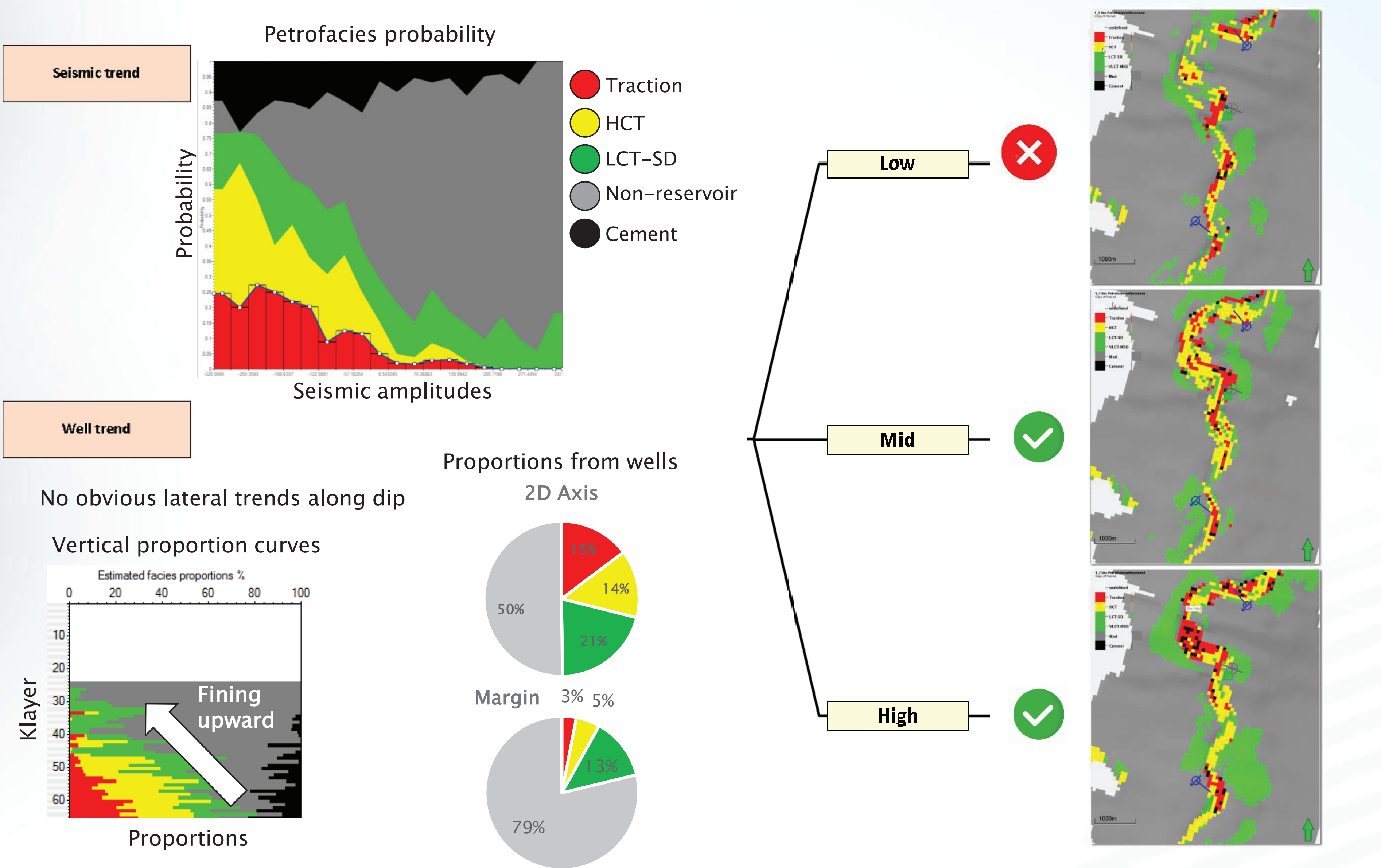
Distance (m)

Presenter's notes: Variogram length uncertainties (slide 14): The correlation length of the petrofacies (variogram ranges) can be derived from the data in several ways:

- dimensions of seismic geobodies
- correlation between closely spaced wells (300 meters apart)
- layer thicknesses and vertical variograms from the wells

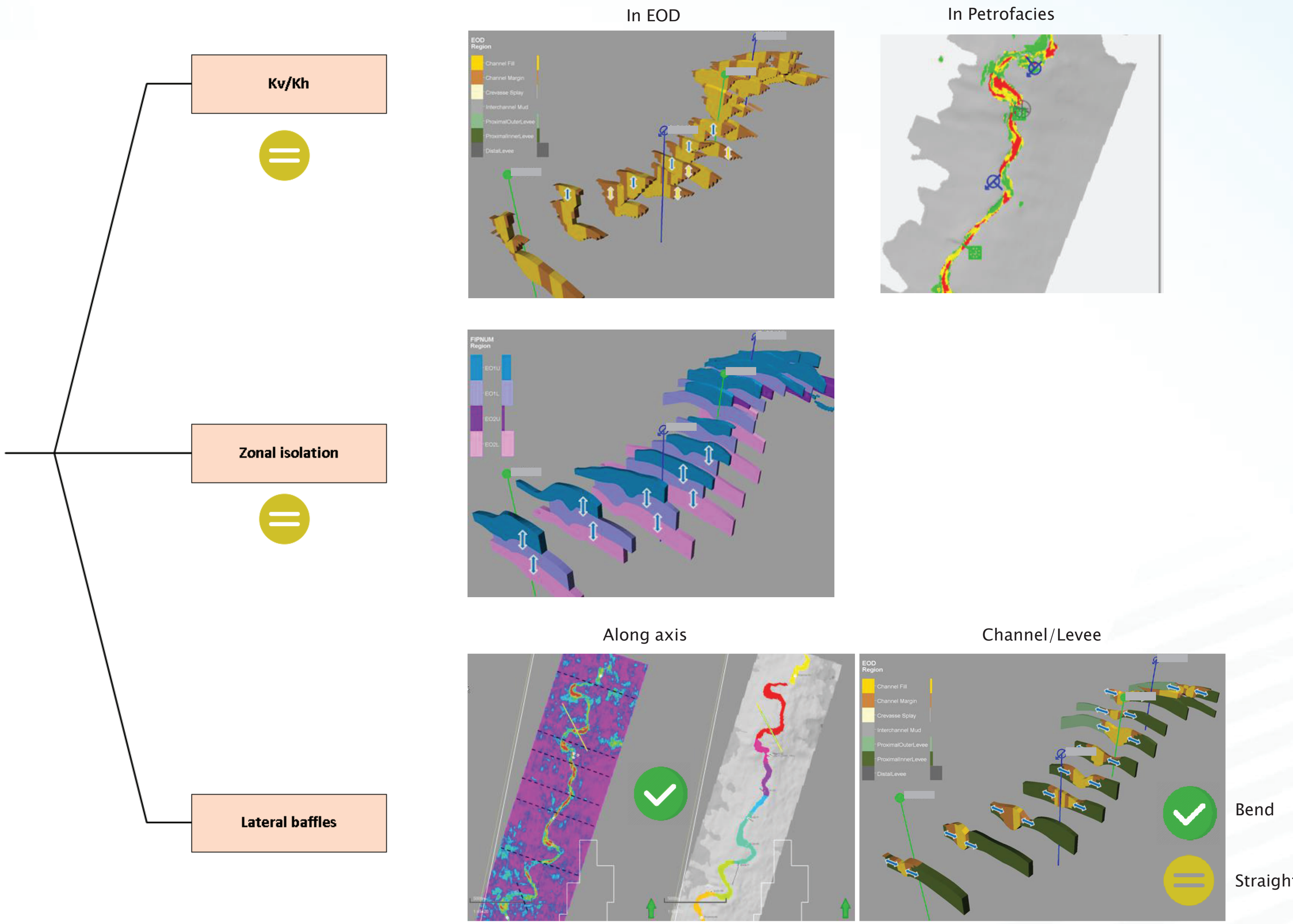
Models using these statistics were too discontinuous. A better history match was obtained by shifting the variogram ranges toward the high side, approaching the well spacing laterally and the storey thickness vertically.

Sand proportion uncertainties



Presenter's notes: Sand proportion uncertainties (slide 15): Average facies proportion and vertical proportion curves were calculated for each environment of deposition (EOD) from well logs. Vertical proportion curves are an important trend to position traction preferentially at the base and represent the fining upwards patterns. Petrofacies probabilities may be estimated as a function of seismic amplitude from the wells and seismic data and used as a soft trend. Given the limited well sampling, petrofacies proportions is a major uncertainty.

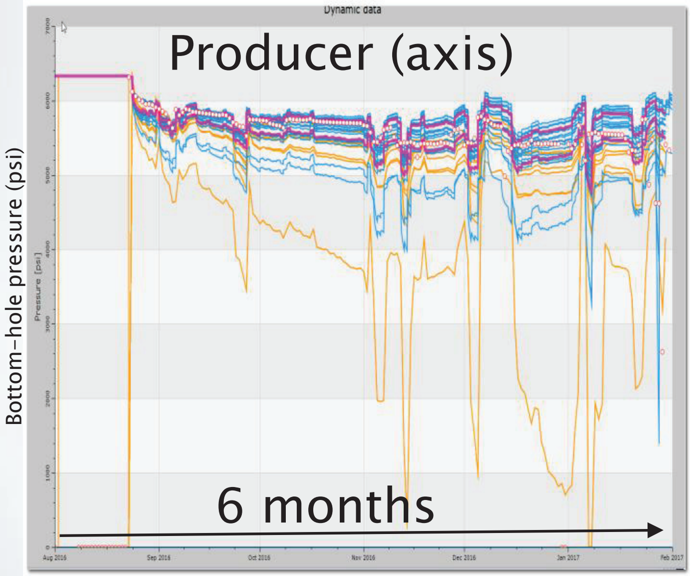
Dynamic Baffle Uncertainties

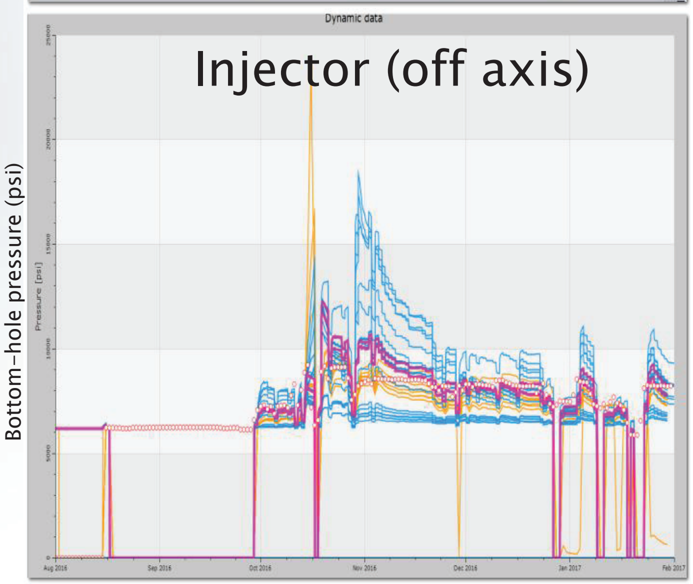


Presenter's notes: Dynamic baffle uncertainty (slide 16): Reducing vertical permeability at various scales (petrofacies, EOD, zones) had little impact on simulation as it was built into the static model. However, the dynamic model was sensitive to:

- lateral baffles, defined along the channel based on seismic amplitudes
- permeability modifications in straight or sinuous parts of the channel

Sector model scenario screening





- Measured Pressures
- Coarse seismic interpretation
- Fine seismic interpretation
  - Flat layers
  - Curved layers

6 months of production data.

- Constrain by daily injection and production rate (allocated by zone)
- Match pressures at zone level (shut-in and flowing bottom hole).

Helped decision regarding

- Scale of seismic interpretation
- Layering style
- Optimum grid resolution

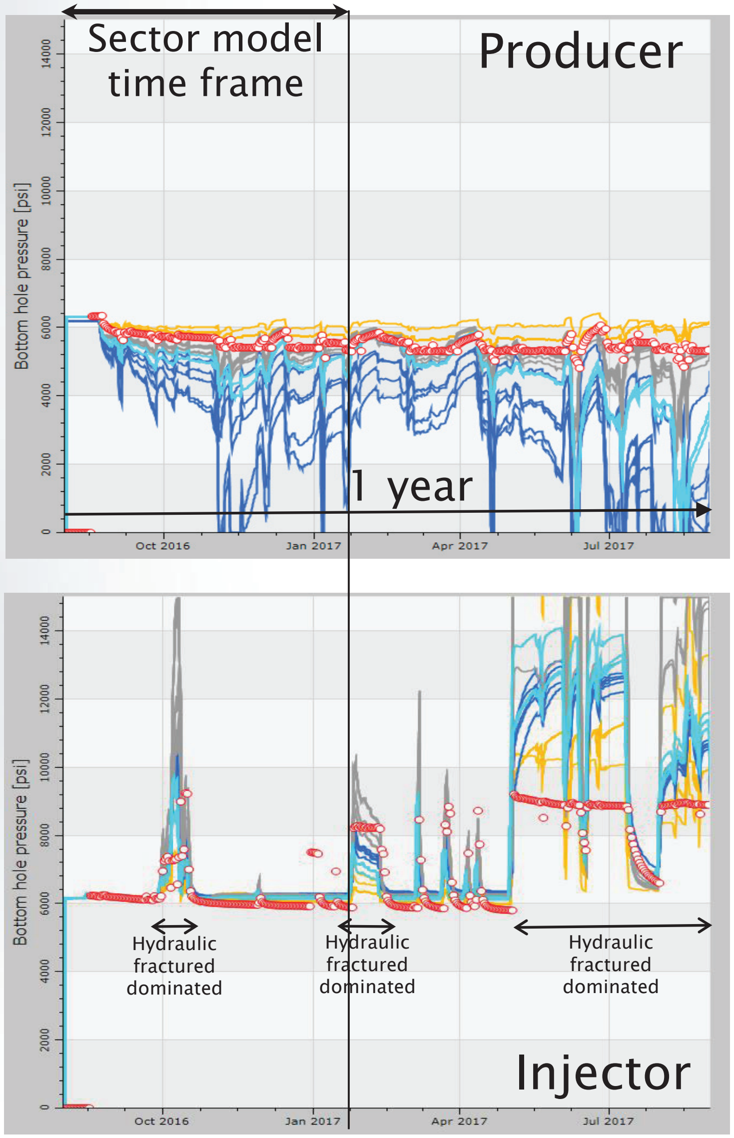
Testing accomplished in 6 weeks from framing, to interpretation to simulation.

Presenter's notes: Sector model scenario screening (slide 17): During the sector model study, 6 months of production data were used for history matching. The dynamic model was constrained with daily production and injection rates. Predicted pressure were compared with measured pressure data at each zone level. An initial set of models were generated using the decision tree. Rapid decisions were made regarding:

- the scale of seismic interpretation: pressures from the models interpreted at channel complex scale show a better history match than those at a coarser scale
- the layering style: better results were observed using curved levees for off-axis wells
- the grid resolution: a coarse grid 80x80x2m produced reasonable results

In less than 2 months, this sector model study established a workflow for mapping and modeling the full field.

Full field scenario screening



Measured Pressures

Combined Mid/high case EOD

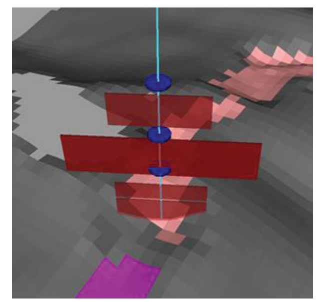
Mid case EOD

High case EOD, average properties

Seismic EOD, discontinuous upper complex, short variogram

1 year of production history showed impact of:

- Lateral stratigraphic boundaries between wells
- Hydraulic fractures at injectors → Convergence issues and failed runs



Hydraulic fractures

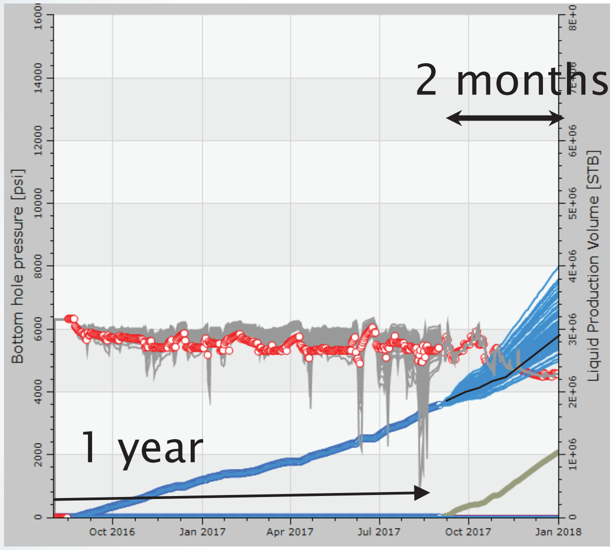
Helped decision regarding

- Continuity of channel complex
- Environment of deposition
- Fine scale heterogeneity

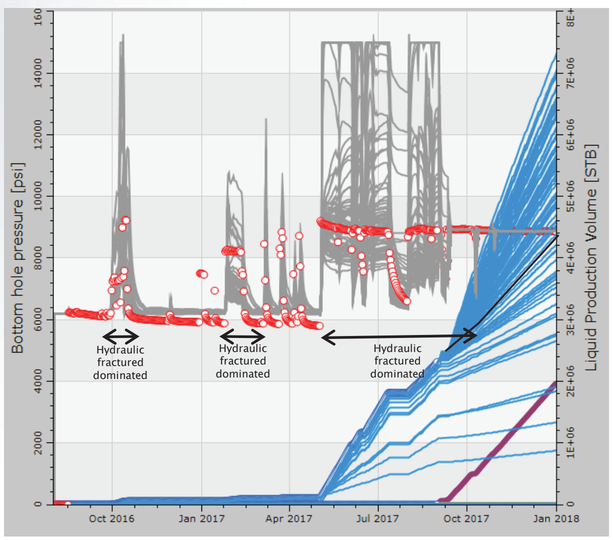
Full field screening accomplished in 4 months

Presenter's notes: Full field scenario screening (slide 18): A range of full field models were created using the decision tree. After 6 months of production, hydraulic fractures were induced around the injectors, allowing high injection rates at low pressure. Fractures had to be explicitly implemented in the simulation. However, the injector's pressure data are mostly dominated by the fractures and were difficult to use in calibrating reservoir models. A year's worth of pressure data from the producers was used instead. Based on history matching this data, models with too little or too much connectivity were eliminated. It was found that mid case EODs for the upper reservoir intervals combined with high case EODs for the lower reservoir units led to the best match models.

Full field Uncertainty Analysis



Uncertainty in oil production rates

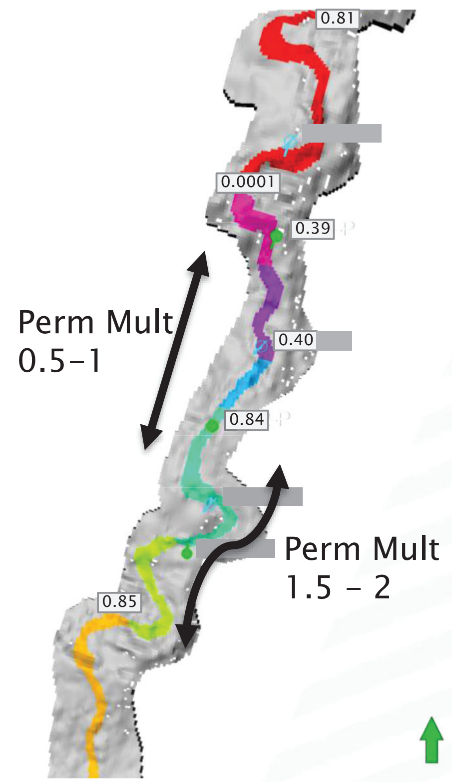


Uncertainty in water injection rates

- Stochastic sampling
- 2 months validation period

- Most sensitive uncertainties
  - % of HCT/Traction and Variogram range
  - Lateral stratigraphic baffles
  - Permeability multipliers (straight/bend section)

Channel regions with TM and K multipliers



Presenter's notes: Full field uncertainty analysis (slide 19): With remaining uncertainties that were not eliminated from the sector model testing, a range of stochastic models were created and a sensitivity analysis was conducted. The most sensitive variables are:
- the proportion of HCT/traction
- the dynamic baffles
- the permeability variation: the channel appears more permeable in sinuous section than straight sections. This due to better amalgamation of sand when aggradation is lateral rather than vertical.

A 2 month validation period was used to select best cases. From these cases, a range of production was forecasted.

Conclusions

- **Established an efficient uncertainty workflow for this complicated deep-water levee-confined channel system**
  - Discipline integration, with common scale model for static/dynamic
  - Decision-tree
  - Sector model
- **Generated a range of dynamically-calibrated models to be used for well planning, reservoir management and reserves**
  - Significant uncertainties remain (short calibration period-no water breakthrough)

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  - Kate Evans