ISAPP (Integrated Systems Approach to Petroleum Production) is a joint project of TNO, Delft University of Technology, ENI, Statoil and Petrobras.

Document title: Description of OLYMPUS reservoir model for optimization challenge

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Introduction

A synthetic reservoir model, OLYMPUS, inspired by a virgin oil field in the North Sea, was developed for the purpose of a benchmark study for field development optimization. The field is 9 km by 3 km and is bounded on one side by a boundary fault. The reservoir is 50m thick for which 16 layers have been modeled. In addition to the boundary fault 6 minor faults are present in the reservoir. The reservoir consists of two zones, separated by an impermeable shale layer. The top reservoir zone contains fluvial channel sands embedded in floodplain shales. The bottom reservoir zone consists of alternating layers of coarse, medium and fine sands with a predetermined dip similar to a clinoformal stratigraphic sequence.

Model Dimensions

The model consists of grid cells of approximately 50 m x 50 m x 3 m each. No upscaling procedure has been performed; all the geological and petro-physical properties have been modeled on this same grid. The model has approximately 341,728 grid cells of which 192,750 are active. The inactive cells are mostly associated with the single-layer shale barrier in the model.

Facies and Property Modeling

4 different facies types were modeled in the different layers. An overview of the different facies types in the different zones is provided in Table 1. Geological properties such as porosity, permeability and Net-To-Gross (NTG) were generated using standard geostatistical techniques for the different facies types. No porosity-permeability relationship was used, based on the assumption that insufficient data is available at the early stage of field development.

Table 1. Summary of facies properties.

Facies Type	Zones Present	Porosity Ranges	Permeability Ranges	Net-To-Gross
Channel Sand	Top	0.2-0.35	400-1000 mD	0.8-1
Shale	Top and Barrier	0.03	1 mD	0
Coarse Sand	Bottom	0.2-0.3	150-400 mD	0.7-0.9
Sand	Bottom	0.1-0.2	75-150 mD	0.75-0.95
Fine Sand	Bottom	0.05-0.1	10-50 mD	0.9-1

The permeability values in the X and Y directions are identical. The permeability in the Z direction is 10% of the permeability in the X direction.

Oil Water contact and Model Initialization

From the available exploration well logs the depth of the Oil-Water Contact (OWC) was determined to be at 2090 m, with an in-situ hydrostatic pressure of 206 Bar. Each facies has its own relative permeability curve, so the initial water saturation distribution is different for each realization as the facies distribution is different for each realization.
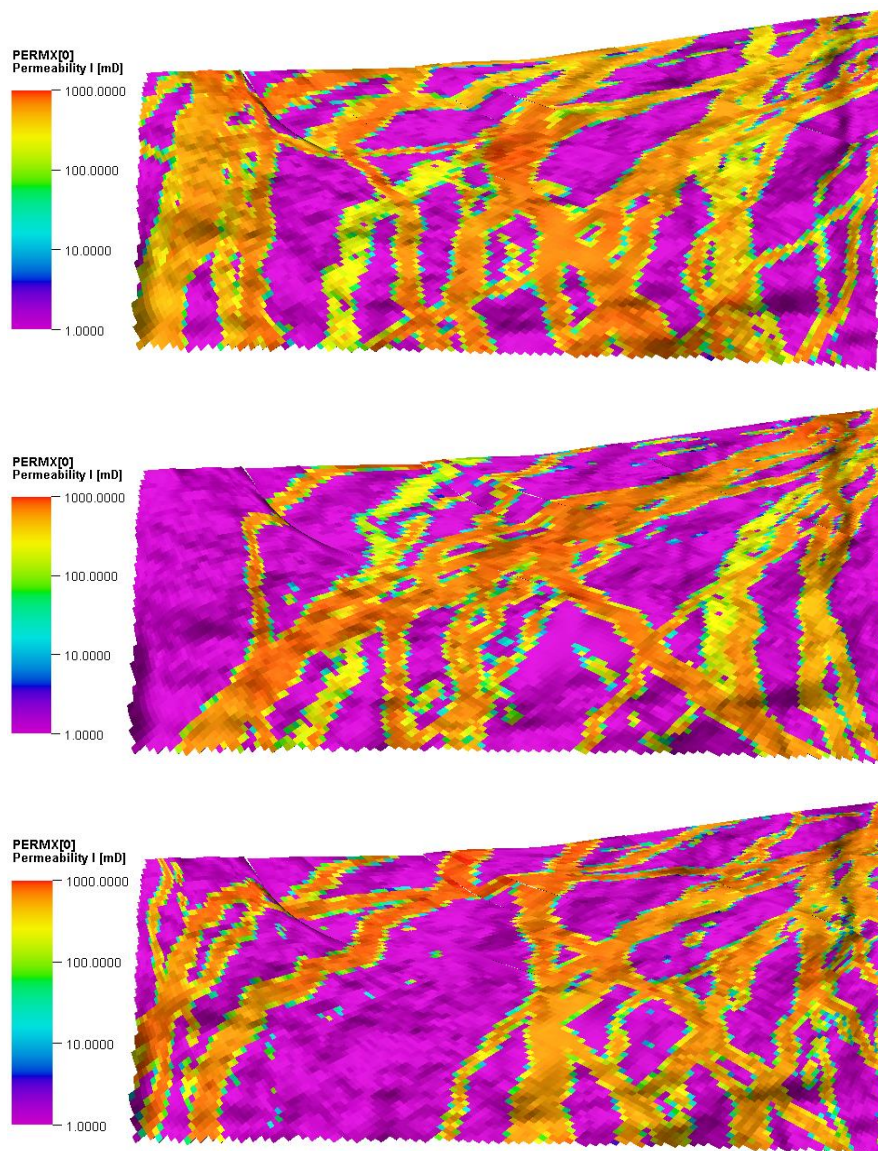
Model Realizations

An ensemble of 50 realizations was generated wherein the facies are regenerated by altering the random seed and thus all the properties are generated. The grid, faults and oil water contact are

considered to be known for this case and are therefore the same in all realizations. Thus the uncertain properties are

1. Porosity
2. Permeability
3. Net-To-Gross
4. Initial Water Saturation

Upscaled permeability fields for four different realizations for layer 6 are illustrated in Figure 1. The orientation and number of channels varies in the top reservoir section while in the bottom reservoir section the clinoformal stratigraphic sequence is varied.
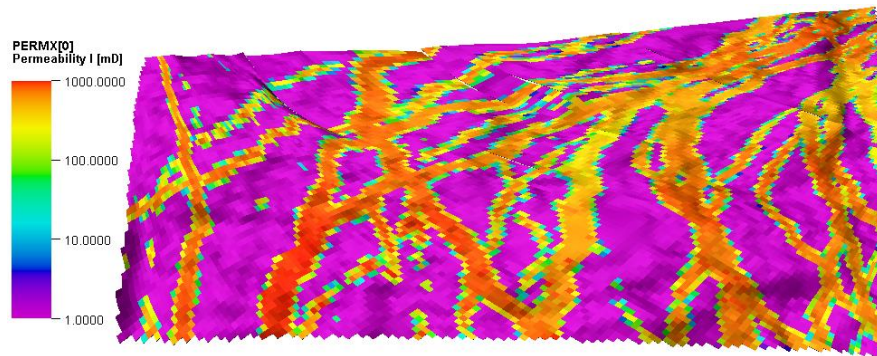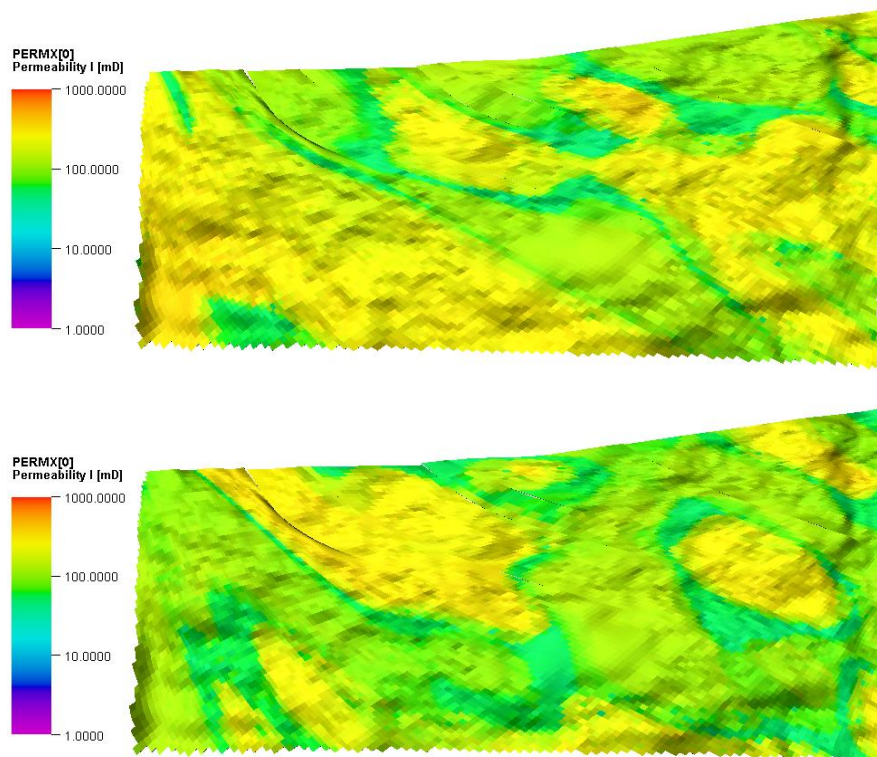
Figure 1. Upscaled permeability fields for layer 6 in the top reservoir section for four different model realizations from the ensemble of 50 model realizations.

Note: a high fidelity base case model of approx. 5 million grid cells was generated as a first step. Five wells were drilled into this base case model and synthetic logs were generated for each of these wells. These logs were then used to constrain the generation of the ensemble of 50 high fidelity models. Each of these high fidelity models were upscaled for the purpose of flow simulations using the flow based upscaling method.
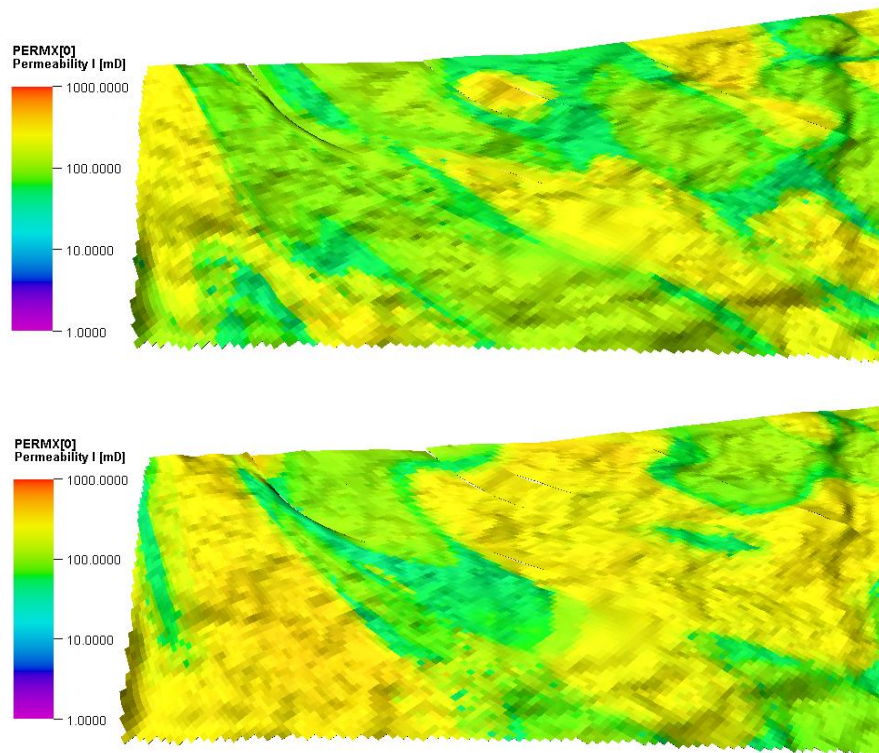
Figure 2. Upscaled permeability fields for layer 10 in the lower reservoir section for four different model realizations from the ensemble of 50 model realizations.

The location of the oil water contact is kept constant in all the model realizations. Figure 3 illustrates the initial water saturation distribution for one realization. The layer number increases from left to right and from top to bottom. The areas in dark blue indicate water.
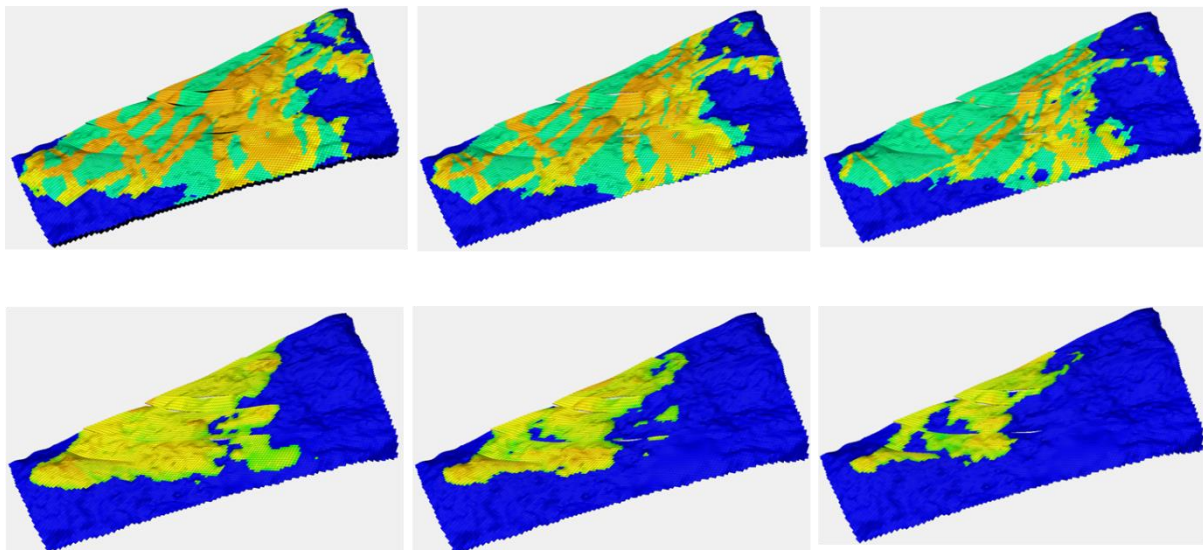

Figure 3. Initial water saturation for one realization in different layers.

We observe from Figure 3 the bottom section of the reservoir has much less oil in place compared to the top reservoir section. The ratio between the STOIIP values for the two reservoir sections is approximately 2, i.e. there is twice as much oil in the top reservoir section than in the bottom reservoir section.

Figure 4 to Figure 7 illustrate the impact of uncertainty in the 50 model realizations represented in terms of Field Oil Production rate and cumulative Oil Production, Field Water Cut (WCT), Field Oil in Place (STOIP), for the same reference operating strategy. The reference strategy consists of 10 producers and 6 injectors which are operated on a pressure constraint. The placement of the wells in this reference strategy was a result of a manual trial and error exercise based on engineering judgement for a chosen realization. Thus the well placement strategy is probably not optimal over all the realizations. This is further confirmed in the results shown below which illustrate a large spread in the volumes and rates produced. The results were obtained by running the ECLIPSE simulator for each realization. As can be observed in the figures the uncertainty can be visually classified as relatively large, which can be interpreted as representative of a green field development scenario. Table 2 provides the minimum, maximum and average value for the different properties plotted which can be a way to substantiate the degree of uncertainty.
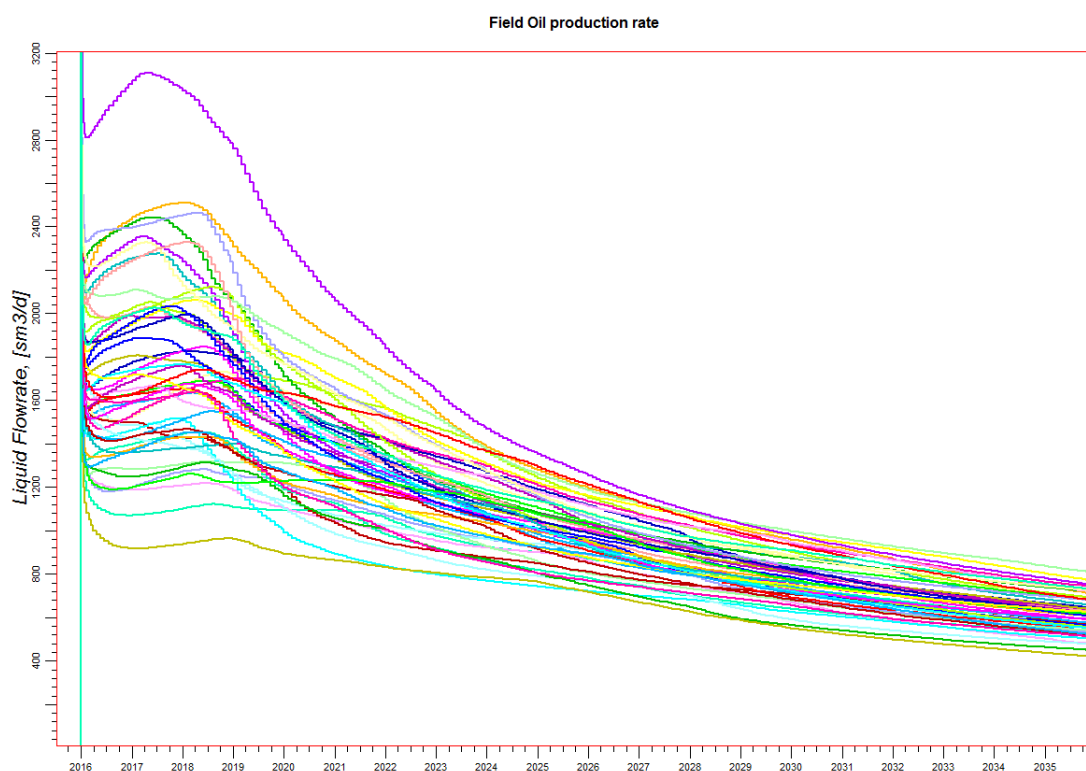

Figure 4. Field oil production rate for all 50 model realizations for the reference operating strategy.
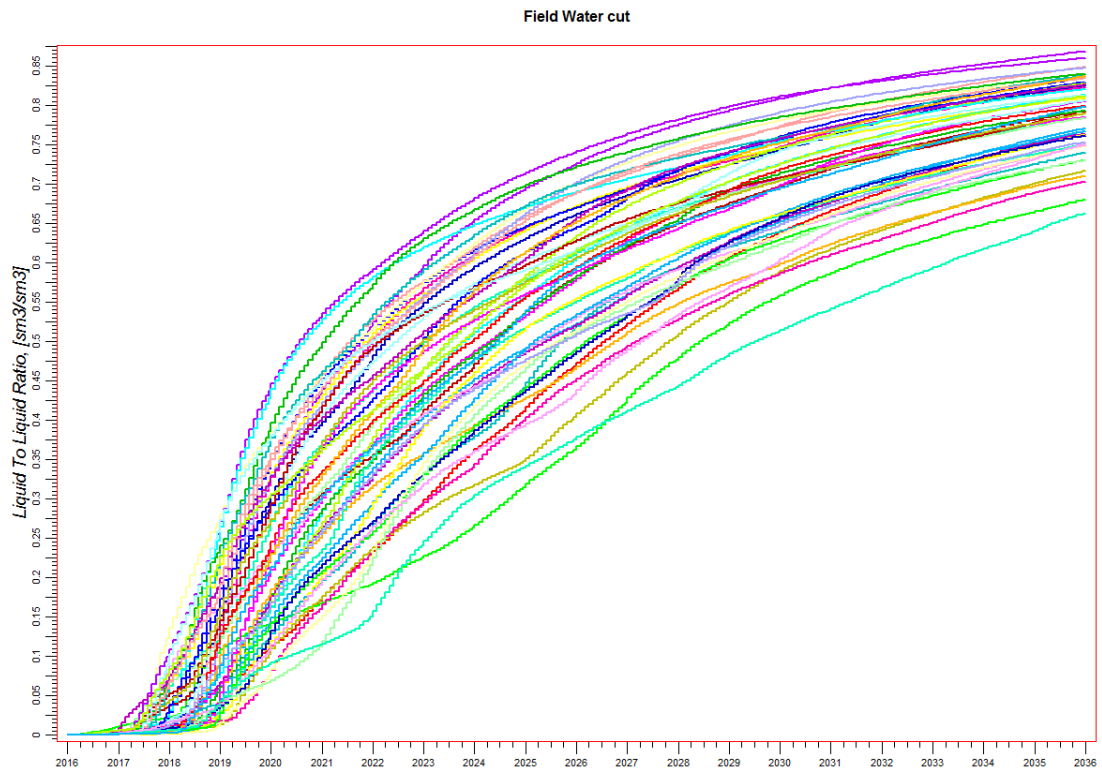
Field Water cut

Figure 5. Field Water-Cut (WCT) for all 50 model realizations for the reference operating strategy.
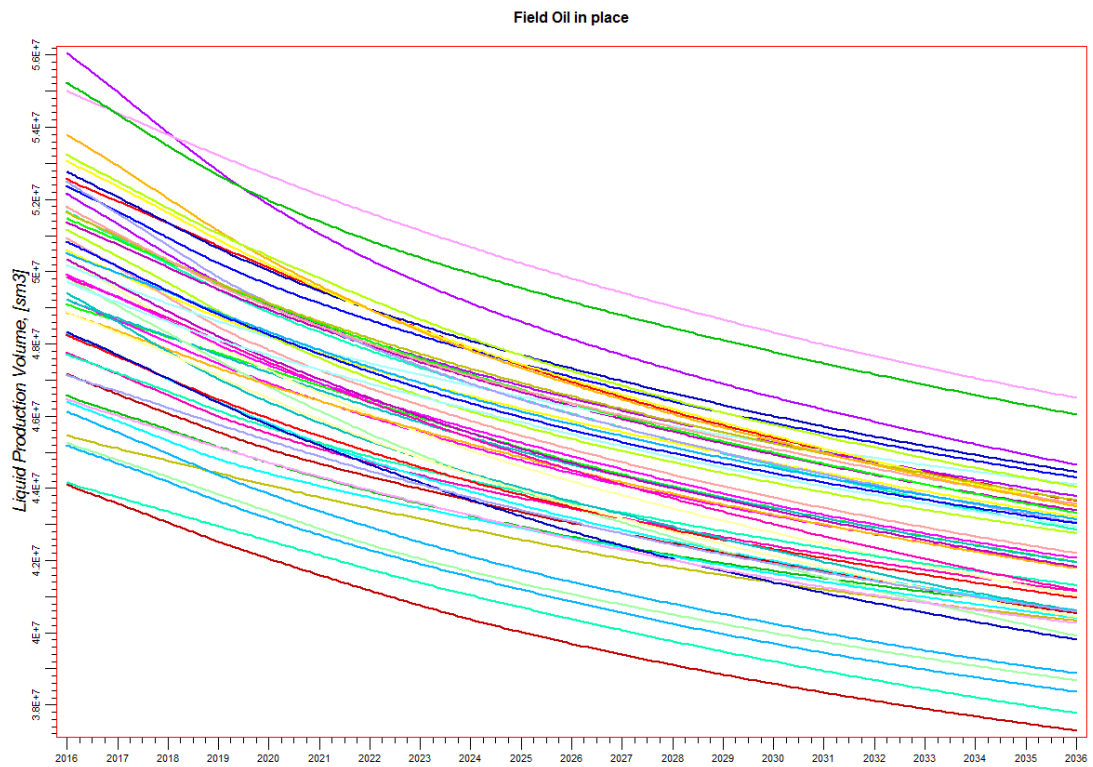
Field Oil in place

Figure 6. Field oil-in-place (STOIP) for all 50 model realizations for the reference operating strategy.
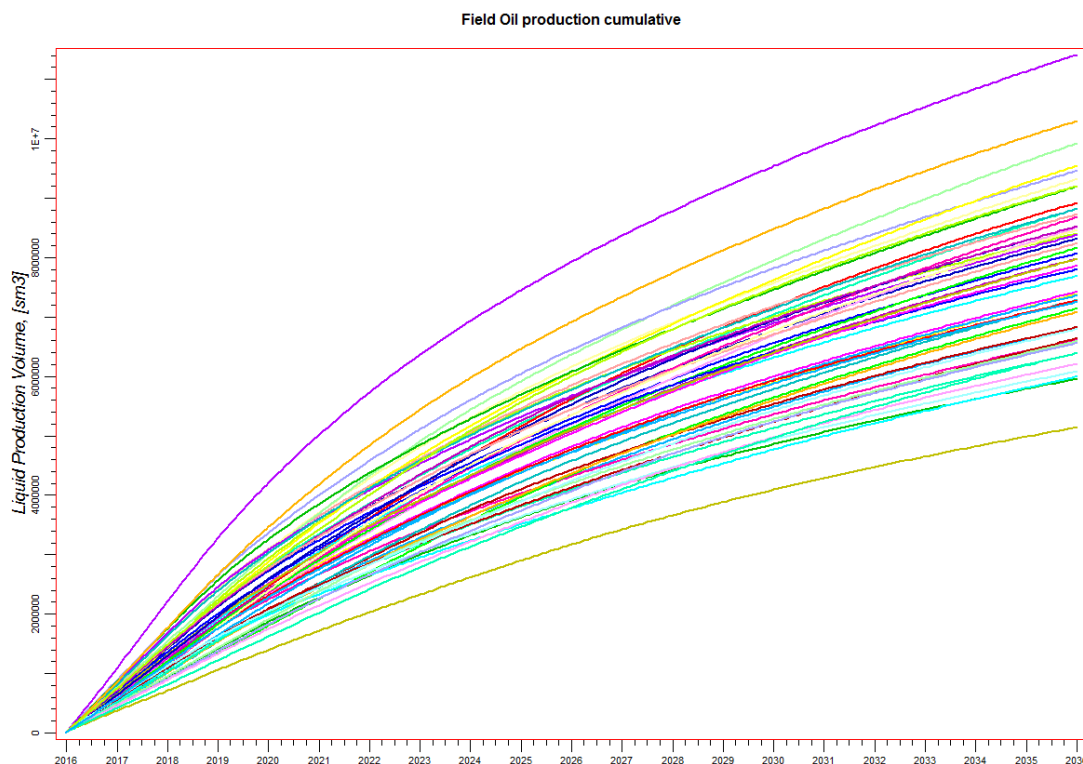
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Figure 7. Field cumulative oil production for all 50 model realizations for the reference operating strategy.

Table 2. Summary of ranges in STOIIP, oil production, water injection and Water-Cut (WCT) for the reference operating strategy due to geological uncertainty.

Property	Max Value	Min Value	Average
STOIIP	55 million m^3	44million m^3	49 million m^3
Cumulative Oil Prod.	11.4 million m^3	5.14 million m^3	8.3 million m^3
Cumulative Water Inj.	33.4 million m^3	9.17 million m^3	17 million m^3
Field Water Cut	87%	66%	78%

The figures and the table show that the realization show very different responses especially in terms of cumulative water injected and cumulative oil produced. The volumes of cumulative water injected would suggest that there exists significant scope to optimize a well control problem.