Geostatistical Determination of Production Uncertainty: Application to Firebag Project

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Abstract

Geological heterogeneities contribute to uncertainty in well productivity and affect development planning. Geostatistical reservoir modeling, flow simulation, and decision analysis tools are being increasingly used to quantify production uncertainty and translate that uncertainty into development planning. This paper presents a case study to the firebag *project in Northern Alberta.*

Exact reservoir dimensions, flow properties, and production predictions have been modified; however, the methodology is illustrative. The methodology consists of statistical analysis, geostatistical modeling, ranking of results, input to flow simulation, calibration of flow simulation results, and presentation of uncertainty.

Introduction

Uncertainty is an inherent aspect of petroleum exploration and production. It is impossible to establish the unique true distribution of lithofacies, porosity and permeability between widely spaced wells. Geostatistical techniques allow alternative realizations of the reservoir properties to be generated. The varying productivity or each realization could be combined in a histogram of uncertainty.

The main objective of a geostatistical study is to determine the uncertainty in future production due to uncertainty in subsurface geologic architecture and continuity. There are related objectives that can be addressed including (1) the value of additional delineation wells, seismic data, and well test data, and (2) the optimal location of production and injection wells. These objectives are met by constructing a set of equally probable realizations of reservoir properties. The difference between the realizations is a measure of geological uncertainty. Running a flow simulation on some of these realizations allows an assessment of the consequences; the difference in the flow simulation results is a measure of production uncertainty.

There are many sources of uncertainty: the geostatistical model itself, scale up from high resolution geostatistical models, the numerical approximations made in the flow simulator, fluid properties, economic predictions and so on. Nevertheless, the uncertainty captured by geostatistical facies, porosity, and permeability models are the most significant in many situations.

This paper documents a geostatistical study to quantify geological uncertainty and determine the consequent production uncertainty. The main steps are (1) statistical analysis, (2) variogram study for spatial continuity analysis, (3) construction of geostatistical realizations, (4) post-processing these realizations for flow simulation, (5) flow simulation on selected realizations, (6) calibration of flow response to geological measures, and (7) uncertainty analysis. Details of the flow simulation are not included in this paper; we primarily discuss the methodological approach to geostatistical modeling.

Firebag Project

The firebag project is a potential SAGD (steam assisted gravity drainage) project in Northern Alberta. In short, the idea is to drill pairs of horizontal wells where the upper well is a steam injector and the lower well is primarily an oil producer. We are concerned with the production rate and steam oil ratio of each candidate well pairs. The reservoir thickness and spatial distribution of shale, oil saturation, porosity, and permeability affect production. Vertical coreholes are drilled ahead of time to delineate these geological variables. 41 coreholes are in area of interest.

The available coreholes and geological interpretation provide a good understanding of the reservoir structure, that is, the top surface, reservoir thickness, and bottom surface. The main source of uncertainty is in the distribution of shales, which would impede oil flow to the producer. For this reason, geostatistical models of the volume fraction of shale, porosity, oil saturation, horizontal permeability, and vertical permeability are constructed.

Flow simulation is CPU-expensive due to the relatively complex geological heterogeneities and thermal modeling. For this reason, relatively few flow simulations can be performed. It is not possible nor necessary to process many geostatistical realizations through flow simulation. Selected *low*, *median*, and *high* realizations are simulated, which permits us to infer the flow response of the other realizations.

The calibration of flow response to geological heterogeneity also permits us to predict the flow response at locations where no flow simulation was performed. Of course, it is not possible to exactly predict the flow behavior; however, we can quantify the uncertainty associated with this extrapolation.

The uncertainty in well productivity can be used to determine the number and location of wells. Within physical constraints of well placement, areas of high production can be drilled first. Then, other locations can be chosen and the production uncertainty evaluated ahead of time.

Additional coreholes would permit more accurate well planning. Fewer well pairs, in more optimal locations, would need to be drilled for the same productivity. This improvement in well planning must be balanced against the cost of acquiring more coreholes (both direct cost and time to process and use the additional information). A geostatistical or Monte Carlo study defines the reduction in uncertainty with additional coreholes.

Methodology

GSLIB was used for model construction. Detailed geostatistical models were constructed and then imported to EarthVision for visualization and validation. The steps for geostatistical modeling: (1) assemble the relevant data within the formation of interest and determine a stratigraphic vertical coordinate system, (2) determine the statistical characteristics of the data variables, (3) establish a 3-D variogram model for each variable, and (4) create multiple realizations of each variable, which honor all available data.

A number of different well location scenarios are chosen for analysis. The scenarios are located in good, average, and poor locations so that we can better interpolate the flow behavior at locations where scenarios are not examined in detail. The geostatistical models are "extracted" in the vicinity of each scenario to create mini-models that would be appropriate for flow simulation.

The geostatistical realizations must be processed through the flow simulator to establish the link between geologic heterogeneity and productivity. Ideally, all realizations for all scenarios would be simulated at a high resolution; however, this is intractable. Flow simulation is significantly more computer intensive than geostatistical simulation due to the equations being solved.

In practice, flow simulation is performed on selected realizations based on a "geostatistical goodness" measure. The relationship between the well productivity and geostatistical goodness can be established with relatively few flow simulations and then the well productivity at locations may be inferred on the basis of the geostatistical ranking alone. Of course, using the geostatistical goodness for prediction of productivity entails some uncertainty.

Data Preparation / Preliminary Investigation

The data were reformatted into an ASCII file compatible with GSLIB. There are nine variables for each data point: X - the east coordinate location, Y - the north coordinate, Z - the elevation, $Zrel$ - the stratigraphic coordinate, Vsh - the volume fraction of shale in percent, Por - the porosity in percent, Bit - the oil or bitumen saturation in percent, KH - the horizontal permeability in milliDarcies, and KV - the vertical permeability in milliDarcies. Merging and reformatting the data is necessarily followed by significant verification and validation steps.

The top structure is not flat and the thickness is not constant. A stratigraphic vertical coordinate that restores or flattens the structure must be considered for geostatistical modeling. Such stratigraphic coordinates capture our understanding of the overall stratigraphic correlation within the study area accounting for structural deformation, differential compaction, erosion, and onlap geometry. After inspection of the well data and consideration of the depositional processes, the stratigraphic coordinate is made parallel to existing elevation. That is, geostatistical modeling (and visualization) will be done using elevation in meters above sea level. This rather simple vertical coordinate accounts for the "space-filling" at the base and "accumulation" at the top of the thicker channel sand.

Figure 1 shows two EW sections looking North through the structural model. Note the undulating top structure, variable thickness, and onlap onto the base structure.

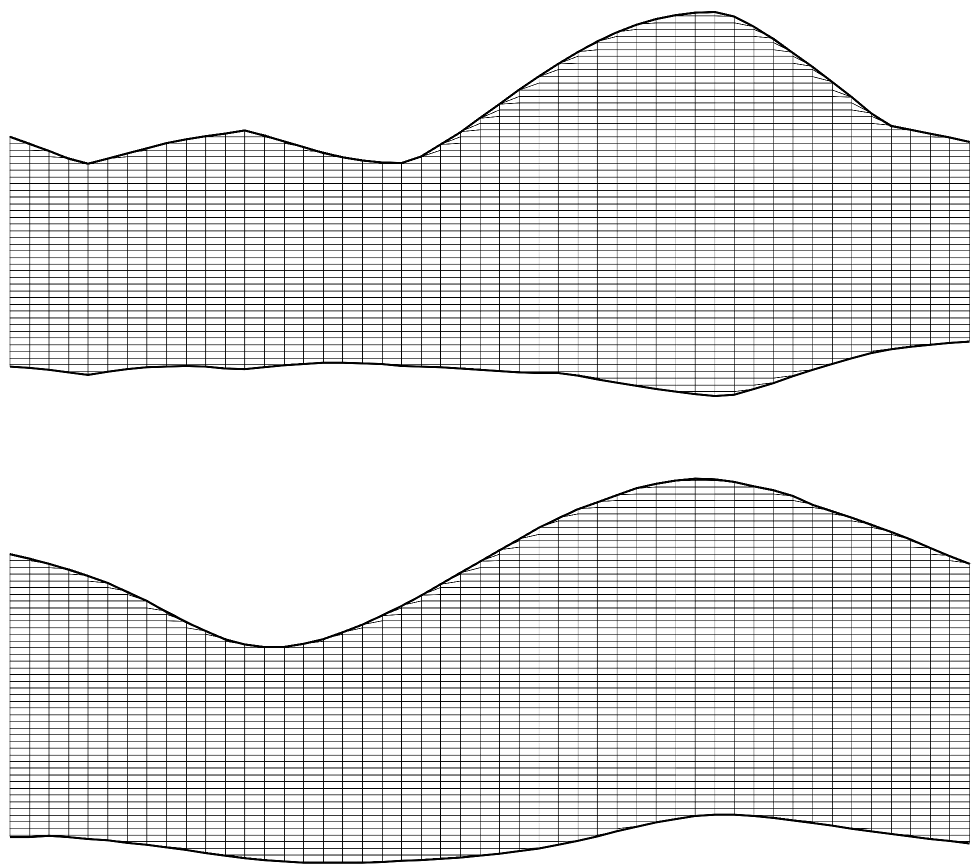

Figure 1: Two sections through the structural model (top and thickness). The sections have been vertically exagerated.

Basic Statistics

The available data were recorded at a 1m resolution in the vertical direction. Figure 2 shows histograms of all variables. All distributions show some bimodality. One mode (or spike) near 0% vshale corresponds to clean sand and the other near 100 % corresponds to pure shale. Note the significant overlap in the distributions, which indicates the presense of a significant amount of thin shales or shale clasts. On average there is 24% shale in the study area. The porosity distribution is also bimodal corresponding to shaley and sandy regions. The shale has 0% effective porosity and the sand apparently has about 32% effective porosity. The average porosity is 26%. The average bitumen value is 66%. The permeability data are based on some measurements and a visual assessment of the sedimentary structures, which explains the "spikes" in those histograms.

Figure 3 shows some of the bivariate relationships between the variables being considered. Note the excellent correlation between vshale and porosity and the reasonable correlation of these variables to bitumen. The bivariate relationships between these variables will be reproduced by the final geostatistical models.

Geostatistical Modeling

In many cases, it is necessary to "decluster" data, that is, assign each data point a relative weight that accounts for the fact that some coreholes are redundant. Coreholes drilled close to each other would receive less weight than an isolated corehole, which represents a larger volume. Cell declustering was performed with the firebag data, but there is no evident clustering that leads to unequal declustering weights.

Variograms quantify our understanding of the spatial correlation of spatially distributed variables. The first step in variogram analysis is to calculate and view the vertical and "omnidirectional" horizontal variogram. Figure 4 shows the variograms. The calculated variogram points are shown as dots and a fitted models are shown by the solid curves.

The variograms shown in Figure 4 were calculated with the normal score transform of vshale, porosity, and bitumen. The normal score transform is used in anticipation of using normal (or Gaussian) geostatistical techniques for stochastic simulation. The strong correlation between vshale and porosity imply that each variable *must* have similar spatial structure. The vertical coordinate used for variogram calculation was the stratigraphic coordinate, that is, the depth below the top coordinate in the well file.

Permeability variograms were not calculated because some of the data are synthetic, that is, assigned by hand on the basis of sedimentary structures. The permeability variograms will be inferred from the vshale varigorams due to the excellent correlation of permeability to vshale. An attempt was made to discern horizontal anisotropy with little success; the omnidirectional horizontal variogram fits all directional variograms quite well.

The variogram models for vshale, porosity and bitumen (given in this order below) have no nugget effect and three nested variogram structures,

$$\gamma(\mathbf{h}) = 0.40 \cdot Sph_{ah=450,av=3.0}(\mathbf{h}) + 0.35 \cdot Sph_{ah=450,av=15.0}(\mathbf{h}) + 0.25 \cdot Sph_{ah=3500,av=25.0}(\mathbf{h})$$

$$\gamma(\mathbf{h}) = 0.40 \cdot Sph_{ah=150,av=2.5}(\mathbf{h}) + 0.45 \cdot Sph_{ah=150,av=12.5}(\mathbf{h}) + 0.15 \cdot Sph_{ah=1500,av=25.0}(\mathbf{h})$$

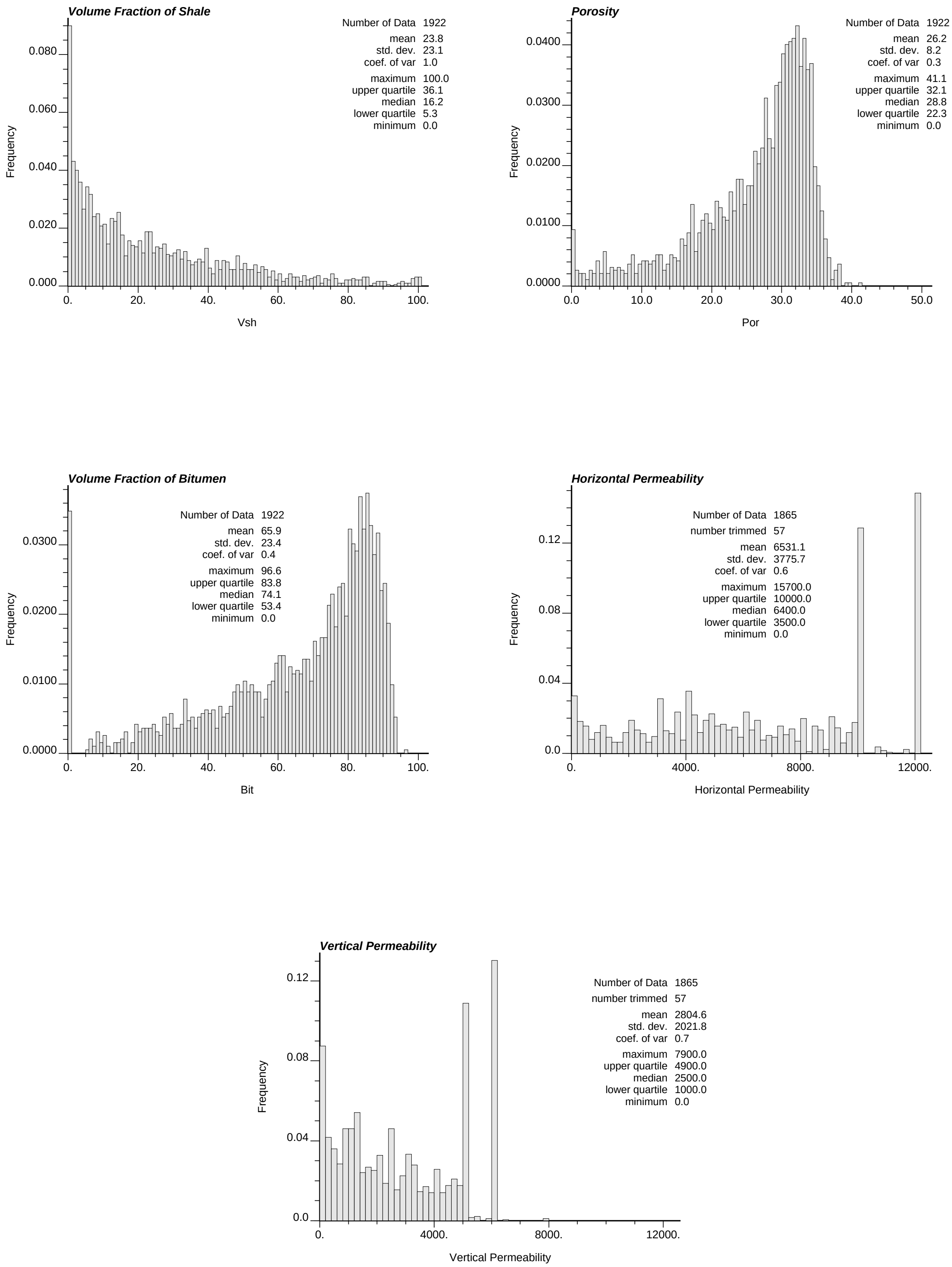

Figure 2: Histograms of the vshale, porosity, bitumen, horizontal permeability and vertical permeability.

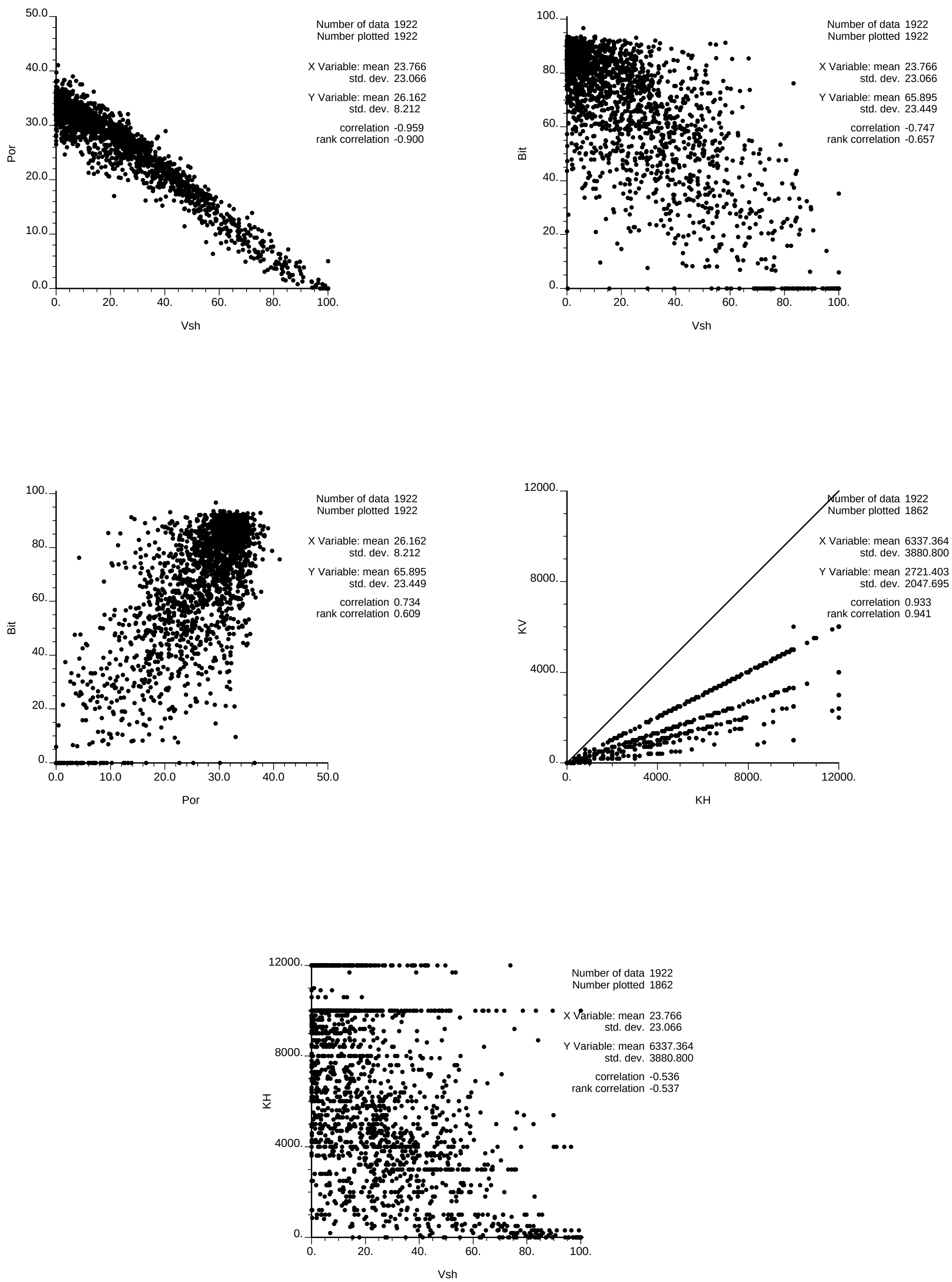

Figure 3: Scatterplots of porosity versus vshale, bitumen versus vshale, and bitumen versus porosity, horizontal versus vertical permeability, and horizontal permeability versus the volume fraction of shale.

$$\gamma(\mathbf{h}) = 0.400 \cdot Sph_{ah=200,av=2.0}(\mathbf{h}) + 0.425 \cdot Sph_{ah=400,av=9.0}(\mathbf{h}) + 0.175 \cdot Sph_{ah=3500,av=15.0}(\mathbf{h})$$

where "Sph" refers to the classical spherical variogram function of geostatistics, ah is the horizontal range, and av is the vertical range.

Geostatistical simulation may be used to construct numerical geological models at arbitrary resolution; however, it is not possible nor optimal to simulate at the scale of the corehole data. After a sensitivity study, a 50 by 50 by 1 m grid resolution was chosen. A finer resolution was not chosen because (1) the details would not be passed into flow simulation, and (2) the disk storage required for multiple realizations would be excessive. A coarser resolution would result in important geologic detail being lost. The numerical models have 210,000 cells.

Sequential Gaussian simulation (the `sgsim` program from GSLIB) was used for the geostatistical simulation. Vshale is simulated first, then porosity is simulated with the correct correlation with vshale, then bitumen is simulated with the correct correlation to vshale, then horizontal permeability with the correct correlation to vshale, and finally vertical permeability with the correct correlation to horizontal permeability. 101 realizations were constructed.

Ranking Geostatistical Realizations

The realizations are ranked at different scales, that is, the 101 realizations are ranked *globally* according to the "quality" of the realizations and the realizations are ranked *locally* near each candidate well pair. After some experimentation, the final ranking measure is the volume of sand. For global ranking, it is the total volume of sand in the entire model. For local ranking, we use the volume of sand within a restricted volume. The local ranking, of course, is different from the global ranking; however, this local ranking is more appropriate for choosing local models for flow modeling.

Flow Results

Twelve flow simulation cases were considered that correspond to four well pair locations (scenarios) and three geostatistical models (low- side, median, and high-side). The scenarios range from very good (number 1) to marginal (number 3) and span the geostatistical uncertainty at each of the four locations.

Flow simulation provides oil rate, steam-oil-ratio (SOR), and the time variation of all other variables. The critical variables are the stabilized production *rate* and the cumulative *SOR*. There is an excellent correlation between Rate and SOR, see Figure 5. The SOR decreases as the Rate increases.

The geological ranking index is the volume of sand within the nominal drainage volume of each well pair. Figure 6 shows the relation between the flow responses and the geological ranking index. There is an excellent correlation in both cases.

The relation indicated by 12 points must be filled-in for subsequent uncertainty analysis. Synthetic data are generated to follow the relations indicated in Figure 6. The results are shown on Figure 7 where the results of Figure 6 are reproduced with additional data points following the general trend.

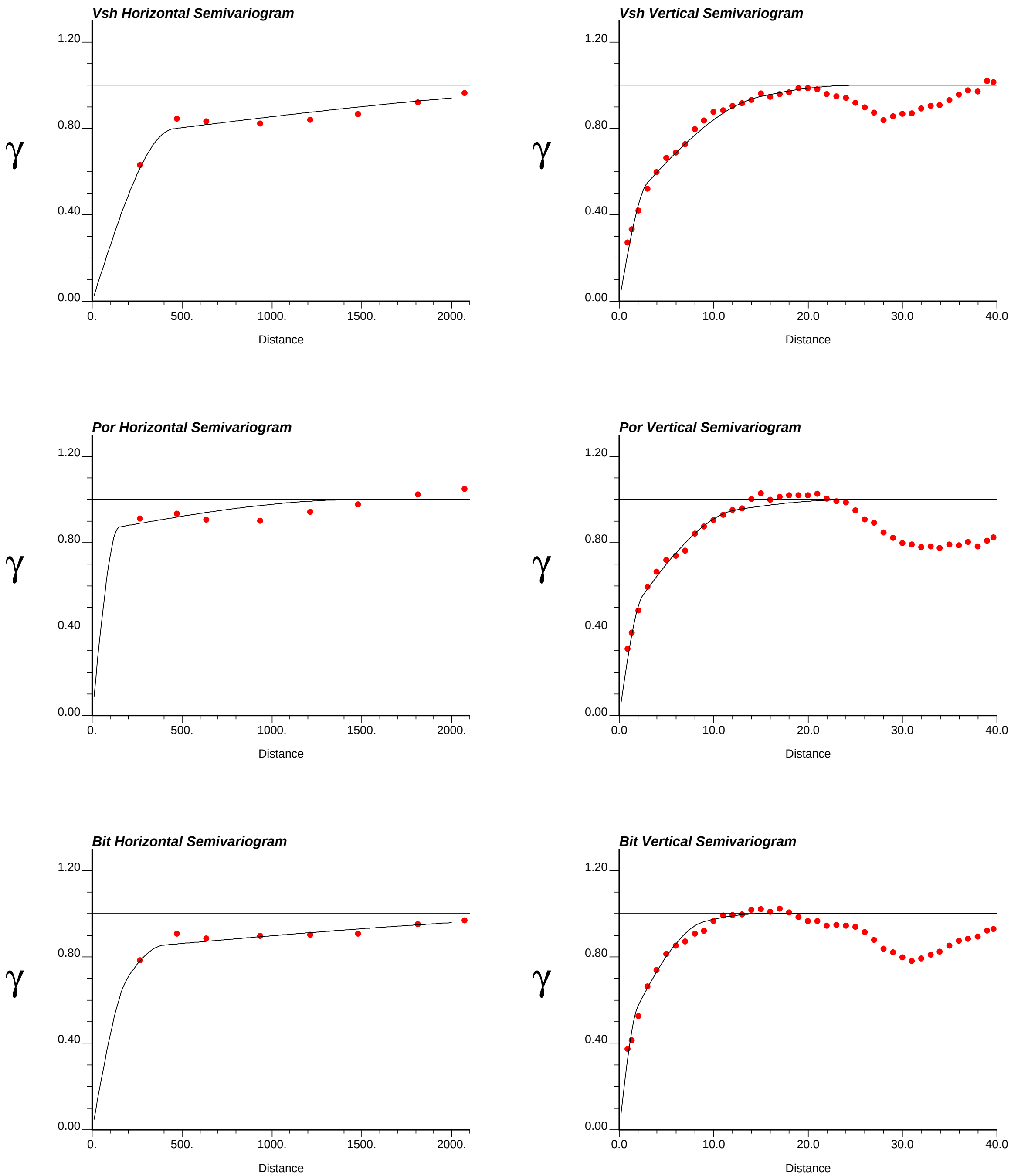

Figure 4: Horizontal and vertical variograms for vshale, porosity and bitumen.

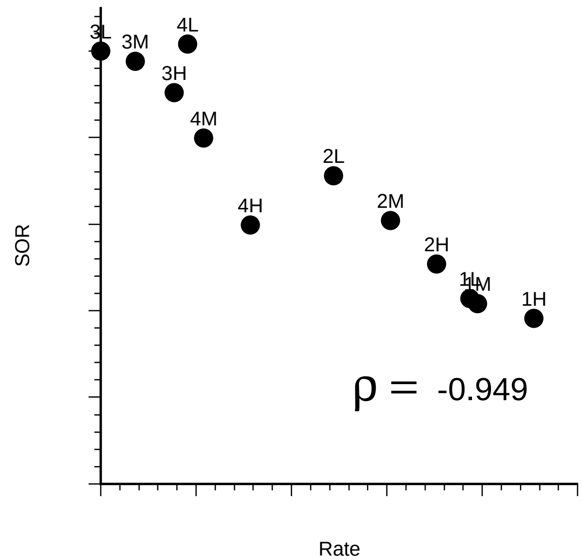

Figure 5: Cross plot between *rate* and the cumulative *SOR*. The four cases (1,2,3, and 4) are labelled together with the geostatistical ranking (L, M, H). Note the excellent correlation.

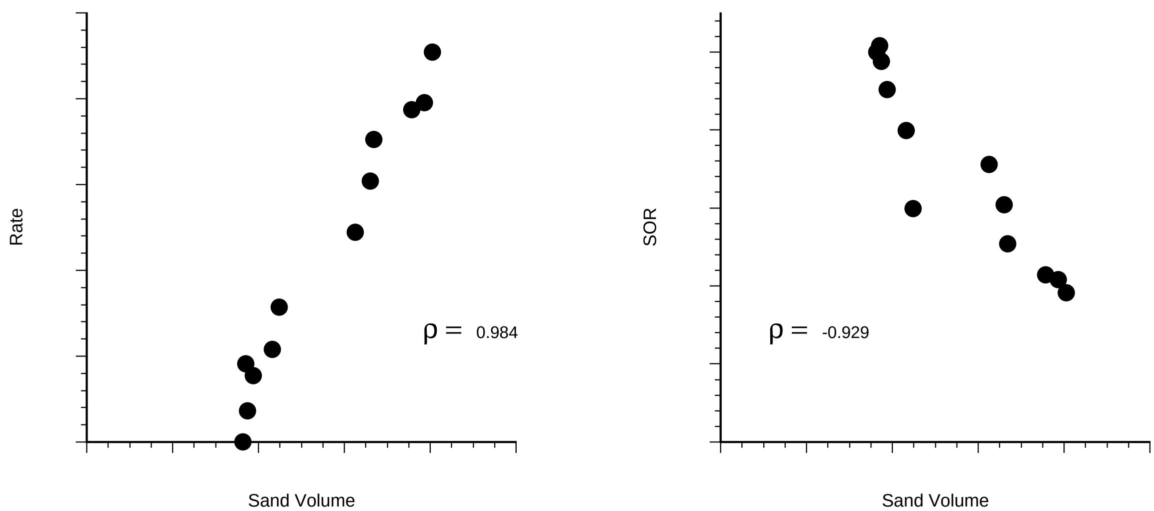

Figure 6: Relation of flow results for the twelve cases to the sand volume.

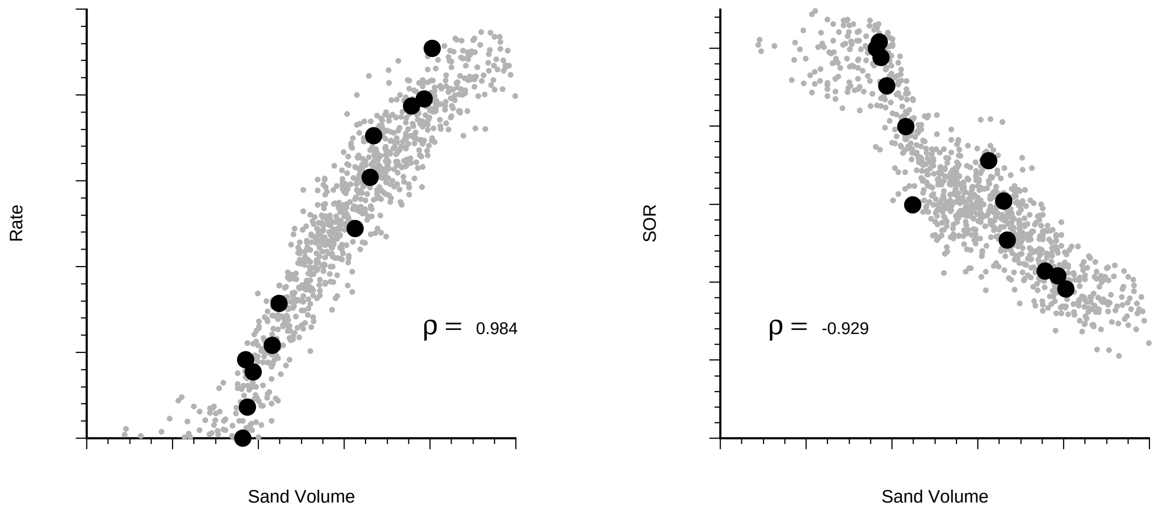

Figure 7: Relation of flow results for the twelve cases to the sand volume with filled-in synthetic values (1000 in each case). The need to *fill in* the cross plots with synthetic values is so that the production variable (rate or SOR) can be predicted for any sand volume, e.g., the sand volume at a location that has not been sampled.

Uncertainty in Well Productivity

Uncertainty in well production is linked to underlying geologic uncertainty, which is the variations in the geolgoic model that are permissible while remaining consistent with all available data. The differences in the 101 realizations quantify uncertainty. This geological uncertainty can be transformed to uncertainty in well productivity with the link between geologic uncertainty and production (Figure 7). One interesting chart that can be constructed is the uncertainty in cumulative production versus the number of well pairs. This would help to assess the number of well pairs to meet a certain production target. The sequencing of the well pairs must be determined before such a chart can be constructed. The ordering for this illustrative example is based on the choosing the best locations first.

Forty eight hypothetical non-overlapping well location configurations or scenarios are considered. Given the ordering, the geologic uncertainty at each location, and the relationship between the geologic ranking measure and production (Figure 7) we may derive the uncertainty in different flow responses versus the number of well pairs: Figure 8 shows the uncertainty in the average oil rate versus the number of well pairs. The exact numbers are not given; however, the concept is revealed. This uncertainty could be reduced by drilling additional coreholes.

Figure 9 shows the uncertainty in cumulative SOR for increasing number of well pairs. The increase in the SOR is due to the addition of well pairs locations of lesser quality, hence greater SOR. The uncertainty in SOR is remarkably wide *and* constant for increasing number of well pairs. Uncertainty will decrease as production comes on stream or with additional core holes to reduce geological variability.

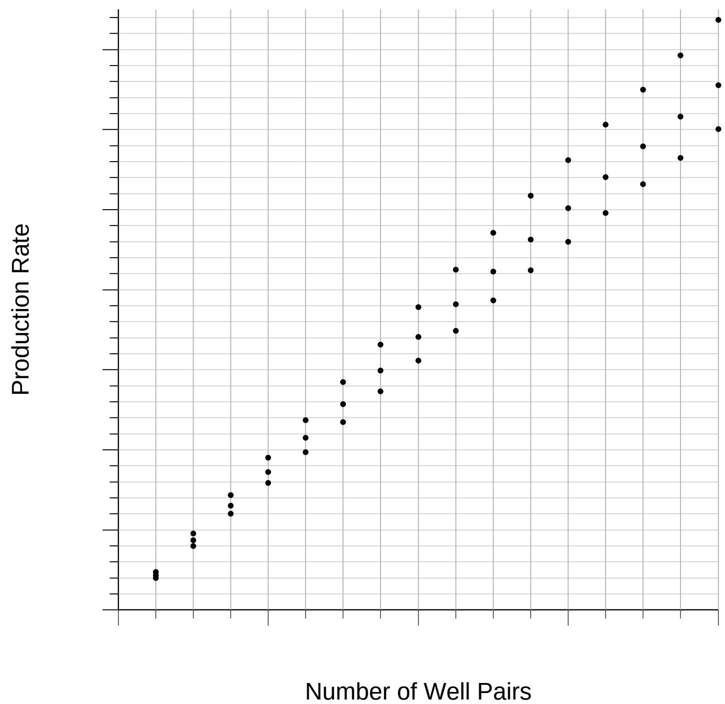

Figure 8: Cumulative production versus the number of well pairs. Note that the uncertainty increases with more well pairs and that the production does not increase linearly with the number of well pairs. This is due to the ordering of the well pairs, that is, the best locations are drilled first.

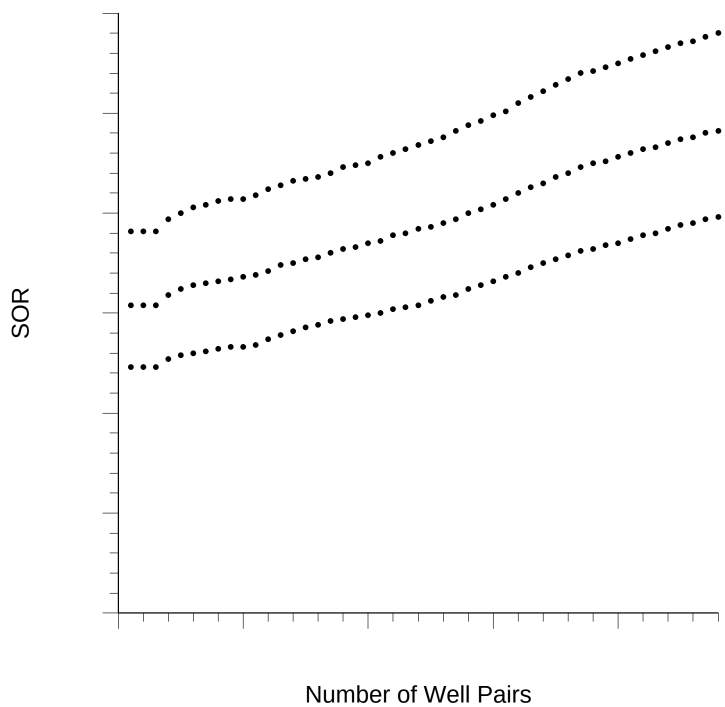

Figure 9: Average Cumulative SOR versus the number of well pairs. There are three dots for each number: the 5, 50, and 95 percentile, that is, the lowest production that could be expected, the median production expected, and the high side production. This chart relates to the *SOR* uncertainty. Note the increase in SOR for more well pairs, since lower productivity areas are produced later.

Locating Wells / Value of Information

It is possible to identify areas with the greatest geologic potential. These may be ordered to aid in selecting well locations. The ordering could be based on geological ranking since that geological ranking is highly correlated with actual well productivity as determined through the twelve flow simulations.

The *Value* of additional coreholes is that uncertainty will be reduced. A geostatistical simulation exercise could be used to address the reduction in geologic uncertainty due to additional coreholes. The cost of increasing the corehole density is easily quantified (number of additional coreholes multiplied by the cost of a corehole). The cost of uncertainty is, perhaps, drilling too many well pairs for the needed production or having to quickly establish new well pairs for greater production.

Future Work / Discussion

The results shown in this report are very encouraging: (1) flow response is linked to geological variations characterized by geostatistical techniques, (2) uncertainty is captured by the geostatistical methods, and (3) it is possible to reliably assess uncertainty in flow response due to geological variability.

There are two main aspects to the uncertainty in predicted production (1) geological uncertainty, and (2) uncertainty in production given a fixed geological model. We considered geological uncertainty. Additional geologic, engineering, and economic work could be conducted to quantify the value of additional data (coreholes and/or seismic). This would be of particular benefit in areas planned for future development.

One important contribution of the work presented here is the quantitative data to choose "the number of wells that will surely meet a specified production target." There may be excess capacity if a 5% low level is selected; however, that gives additional flexibility and the opportunity to debottleneck the plant. The probability and amount of additional flow capacity is also quantified by this study. The uncertainty is due to variations in the amount and spatial arrangement of shale. Additional coreholes would reduce this uncertainty and permit forecasting of future production with less uncertainty.

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