4. RESULTS

4.1. STATIC 3D RESERVOIR MODELLING

4.1.1. 3D Model Description

This model was built within an area of 8700.19 acres. This area covers a total 226 well, of which 221 wells were used into 3D model (see Figure 4-1).

It was incorporated seven zones in the model out of nine total zones identified for the sedimentological model. Those zones are defined as Carbonera C7. Being the top Carbonera C7 named as zone A and the bottom named as zone H. Those zones were selected as they are relevant production open zones in the well completions. Some wells mainly verticals are opened in more than one zone, but only two vertical wells (W-27 and W-158) are opened in four zones. The general opened zones with number of wells are shown in Figure 4-1 including vertical, horizontal, and deviated wells.

![Number of wells opened in different zones](image)

Figure 4-1. Relation between numbers of wells by perforated zones.

Figure 4-2 shows the 3D static model workflow applied in this study. The workflow starts with a quality control of reference elevation, coordinates, and directional surveys. Next step, is to validate and calculate basic well logs which comes from petrophysical model. Finally, well tops from sedimentological model are checked.

Once the structural surface is built with well tops, the isochore maps are created, and then a quality control of the surfaces is performed. When the quality control is finished, the data can be used into the static model to create the structural grid, zones, and layering. The well logs upscaling and data analysis are done during facies modelling and property modelling. Volumetric uncertainty and engineering calculations are the last steps during this process (see Figure 4-2).
3D lithofacies were built for three lithofacies, all under the same structural domain, but having different modelling distribution criteria through 3 geostatistical methods (Figure 4-3)

Figure 4-2. 3D static model workflow.

Figure 4-3. 3D geostatistical lithofacies modelling methods.

4.1.2. Structural Framework

This section explains how the structural framework was created using structural surfaces and well tops from vertical and horizontal wells.

General properties of the grid are shown in the following table (Table 1)
### Grid Properties

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of layers</td>
<td>141</td>
</tr>
<tr>
<td>Cells(nI<em>nJ</em>nK)</td>
<td>417<em>417</em>141</td>
</tr>
<tr>
<td>Total number of cells</td>
<td>24518349</td>
</tr>
<tr>
<td>Grid size IJK</td>
<td>20 mts<em>20 mts</em>1 ft</td>
</tr>
<tr>
<td>Length</td>
<td>6847 mts</td>
</tr>
<tr>
<td>Width</td>
<td>5171 mts</td>
</tr>
<tr>
<td>Gross Thickness (H)</td>
<td>141 ft</td>
</tr>
</tbody>
</table>

Table 1. General grid properties.

#### 4.1.2.1. Gridding and Horizons

This model does not use faults from seismic interpretation, as they do not represent compartmentalization into the reservoir in this specific area. Additionally, structural surfaces were built through wells tops and seismic information was not used. The stratigraphic top called zone A sets the upper limit and zone H sets the bottom limit in the model. The horizons belong to 8 structural surfaces created through the tops interpreted in the sedimentological model.

The grid size increment selected in I and J direction were 20*20. Normally models have a coarser grid cells but for this case, it was necessary to increase the lateral resolution to include horizontal wells details and heterogeneity which have a minimum length of 600 feet, therefore, this length is divided laterally into more than 6 cells.

#### 4.1.2.2. Zonation and Layering

The zones created for this model were seven according to the sedimentological model (see Figure 4-4).

Vertical layer resolution selected was 1 foot for all zones. It was selected 1 foot cell thickness to represent small laminations along the well (see Figure 4-5).

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1 Grid size units IJ directions are meters and k in feet.
According to the optimum layering, all zones were divided proportionally into 1 foot of thickness corresponding to the number of layers showed in the Table 2.

<table>
<thead>
<tr>
<th>Layer thickness (ft)</th>
<th>Average zone thickness (ft)</th>
<th>Average zone thickness (ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zone 1</td>
<td>1</td>
<td>17</td>
</tr>
<tr>
<td>Zone 2</td>
<td>1</td>
<td>19</td>
</tr>
<tr>
<td>Zone 3</td>
<td>1</td>
<td>23</td>
</tr>
<tr>
<td>Zone 4</td>
<td>1</td>
<td>15</td>
</tr>
<tr>
<td>Zone 5</td>
<td>1</td>
<td>24</td>
</tr>
<tr>
<td>Zone 6</td>
<td>1</td>
<td>23</td>
</tr>
<tr>
<td>Zone 7</td>
<td>1</td>
<td>20</td>
</tr>
<tr>
<td></td>
<td></td>
<td>141</td>
</tr>
</tbody>
</table>

Table 2. Number of layers by zones.

4.1.3. Lithofacies Curve Creation

Lithofacies curves consist mainly of 3 lithologies: sandstone, shale, and shaly sand. These lithofacies were defined through a normalized Gamma Ray (GRn) Cut-off from vertical and horizontal wells. It was found that the best sand and shale GRn cut-off are 55 API and 88 API respectively.

These values have the best representation of lithology according to porosity and permeability behavior, (see Figure 4-6).

Once the cutoff was found and using the environmental facies identified in the sedimentological model, it was established non reservoir lithology which is the shale, Next, it was created sand main channels (SMAC\(^2\) - correlated to cylindrical shape), sand minor channels (SMIC\(^3\) - fining upward), sands crevasse splay (SCS\(^4\) - coarse upward) and shaly sand for intermediate lithology as a retarding rock. In that case, the model has 5 facies in total.

\(^2\) SMAC: It is the abbreviation to refer to Sand belongs to main channels.
\(^3\) SMIC: It is the abbreviation to refer to Sand minor channels.
\(^4\) SCS: It is the abbreviation to refer to Sands crevasse splay.
Those initial lithofacies defined were checked through a porosity versus facies Crossplot to identify differences and similarities between them and simplify the number of facies to be used.

The Crossplot in Figure 4-7 shows that SMAC, SMIC and SCS have the same minimum and maximum porosity value, meaning that those facies can be merged in one lithofacies. The porosity’s behavior in each lithofacies was the same for permeability.

It was decided to work only with sand, shaly sand and shale which were renamed as reservoir, retarding and shale rock respectively, in order to represent lithofacies integrated with petrophysical properties.
4.1.3.1. Shale

It acts as a fluid flow barrier. Shale is the finest grain size lithofacies, it is a seal that contains water in its structure and it does not allow the flow of fluids through it. Its maximum porosity is 0.08 and permeability less than 1 mD which is the threshold with the retarding rock.

4.1.3.2. Retarding Rock

The concept of a Retarding Rock is introduced in this study as a rock that slows down the fluid movement and/or hydraulic pressure communication, notice that this concept links the geology and the reservoir engineering knowledge as a pure geological concept will name this rock as a shaly sand or sandy shale while a reservoir engineering concept will label this rock as a baffle.

The Retarding Rock has a wide spectrum of properties, because it shares a lithological transition with shales having low porosities around 0.04 and has transition with reservoir rock lithofacies with porosities 0.22 (see Figure 4-9). These lithofacies is composed of fine and very fine grain size and show how the accumulation of heavy oil is controlled by grain size.

From the author knowledge, this is the first study that document explicitly the link of geological and engineering aspects of this kind of lithofacies. As one of this study objectives was to identify the facies impact on the oil rate, it was found that this lithofacies plays an important role in the fluid mobility specially with high resolution grids as it covers a wide range of porosities having an average facies proportion of 25% approximately (see Figure 4-13).

One can think of this lithofacies as a transition rock from the shale (that does not allow any fluid flow) to a reservoir rock (that has the best flow capacity properties). In reservoir engineering, this kind of rocks belongs to those named as baffles, in this study, it was properly identified and characterized those baffles labeled as retarding rock.

Retarding rocks does not present oil stain even having good porosities up to 18% and permeabilities up to 10 mD because its fine and very fine grain size do restrict the flow of heavy oil. The main proportion of this rock belongs to rock type 5 and part of rock 6.

4.1.3.3. Reservoir Rock

Reservoir rock is the best quality lithofacies rock, it has an average porosity of 0.22, it consists of coarse (sandstones and conglomerates) and fine grain size. Based on the oil characteristics present in this field, part of this lithofacies let oil flow (porosities up to 0.23 and permeabilities up to 600 mD) (see Figure 4-9). Reservoir rock is a potential rock that can storage hydrocarbons. The Shale acts as a hydraulic seal.

Figure 4-8 shows two wells with the basic set of logs (Gamma ray, and resistivity) in the first two tracks, next to them electrofacies, and lithofacies curves, in the last tracks porosity and

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5 During dynamic reservoir simulation stage, it is common to include barriers and baffles to match reservoir pressure depletion with time and production. Baffles can be structural or sedimentological, in this study the retarding rock lithofacies belongs to a sedimentological baffle.
permeability logs. This image also shows the relationship between curves in sandy zones porosity and permeability deflecting towards high values. In the facies set, it is highlighted in magenta is the track that will be used for modeled lithofacies.

Figure 4-8. Example of initial lithofacies and simplified lithofacies.

The validation of lithofacies curve results was done through a permeability versus porosity Crossplot filtered by lithofacies (see Figure 4-9). The following graph shows a relationship between petrophysical properties and lithofacies. The lithofacies classified as reservoir rock reveals porosities up to 0.20 and non-reservoir lithofacies (Shale and retarding rock) have lower porosities. Reservoir lithofacies up to 0.23 porosity and 600 mD is the rock with best oil flow capacity and storability (zone green in the Figure 4-9).

Figure 4-9. Crossplot permeability versus porosity versus lithofacies.
4.1.4. Well Log Upscaling

Well log upscaling was generated for all logs that were going to be modeled such as: Lithofacies, shale volume (Vsh), porosity (PHIE), and, permeability (K).

Lithofacies logs as discrete variable were upscaled by “most of” method which upscales facies using percentage of occurrence of the facie in each cell and it uses the cell volume. This method selects the facies with highest proportion represented into the well log, so it fills the grid cells with the facies identified in the log.

Continuous variables (porosity, permeability and volume of shale) were upscaled by arithmetic average method, because it had the best representation of the input model data.

Additionally, the conditioner used to upscale facies is named as “simple”, which is an averaging method. This method does the average according to cells that touch the well trajectory. It was selected because it does not affect the upscaling in horizontal and deviated wells. Volume of shale, porosity and permeability used neighbor cell as all input wells are vertical.

Well log upscaling was performed to reproduce the input of log facies to build a representative model. The well log upscaling was executed in each well and their quality control was done through a histogram comparing raw data and upscaled data. Figure 4-10 shows the match between upscaled lithofacies, Vshale, porosity and permeability logs vs raw data of these logs with a maximum difference identified of 2%.

The horizontal wells upscale depended mainly on the areal cells size more than layering definition. This model has a good representation because it has a small cell size (20 meters*20 meters).

The averages are done using the facies, meaning that property averages are associated to the facies in the upscaling process.

![Figure 4-10. Well logs vs upscaled logs lithofacies, Vshale, porosity and permeability histogram.](image-url)
4.1.5. Data Analysis

4.1.5.1. Vertical Proportion Curves

The Vertical proportion curves (VPC) step is only performed to lithofacies variable because it is the only discrete variable to model. Data analysis process allows to perform a quality control of raw log data and upscaled data, before performing facies and petrophysical modelling.

These proportion curves depend on the vertical detail and the number of wells involved in each zone. VPC for all model are the same because they are under equal number of layers and wells except for the hierarchy geomorphologic model (HGM) as this model is controlled by the number of wells that belong to a grouped facies region.

Specifically, to hierarchy geomorphologic SIS model is divided in two regions, one of them grouped the electrofacies such as cylindric, coarsing upwards and finning upwards which represent facies channels and crevasse splay. Floodplain region was associated to serrated electrofacies.

Zone 4, 5 and 6 are the sandiest zones, which are proportions of more reservoir rock potential according to these curves.

In the Appendix A1 and A2, it is presented vertical proportion curves for each zone modeled, and the regions mentioned are graphically showed.

4.1.5.2. Variograms

• General Aspects

Some variogram maps were built to identify the anisotropy direction before building all variograms. These maps were done to compare channels directions obtained in the electrofacies model.

Through anisotropy maps helps to identify and find the best correlation of the major and minor range and preferential directions. (see Figure 4-11).

The variograms were matched with an exponential model, due to the complexity of the sedimentological feature and it represents a high variation of rock quality and petrophysical properties.

The azimuth used as a reference to build the variograms was the main or preferential channels direction given by the Ecopetrol’s sedimentological study. Anisotropy maps were used for the last 3 zones (zone 5 to zone 7) which do not have sedimentological maps (Table 3).
Variograms were built in three directions vertical, minor, and major by zone and lithofacies. It was modeled in total 261 variograms in these directions. These variograms are shown in Appendix B1 and B2. Four lithofacies methods were completely depended on the variograms except for Multiple Point simulation which is tied to training images.
Lag distance and search radius: The average distance of all wells is 668 meters. The lags distance used was controlled by the mean distance between wells according to well spacing which intercept each zone. The minimum distance used was 200 meters and maximum 798 meters. For vertical variograms lag distance selected was 1 foot according to the layering thickness and the search radius was controlled by the half zone thickness (see Table 4). The search radius was a half distance of the large direction, the minimum distance was 2700 meters with and a maximum of 4270 meters.

<table>
<thead>
<tr>
<th>Vertical Variogram</th>
<th>Zone 1</th>
<th>Zone 2</th>
<th>Zone 3</th>
<th>Zone 4</th>
<th>Zone 5</th>
<th>Zone 6</th>
<th>Zone 7</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zone Thickness, H (ft)</td>
<td>17</td>
<td>19</td>
<td>23</td>
<td>15</td>
<td>24</td>
<td>23</td>
<td>20</td>
</tr>
<tr>
<td>Search radius (ft)</td>
<td>10</td>
<td>11</td>
<td>12</td>
<td>8</td>
<td>13</td>
<td>13</td>
<td>10</td>
</tr>
</tbody>
</table>

Table 4. Vertical variogram search radius vs zone thickness.

Sill and Nugget: All variograms were adjusted mainly in their first point until reaching the sill and by defining the presence or not of nugget effect.

The highest nugget found was 0.0638 which belongs to zone 3 facie retarding rock, meaning this zone has the most facies discontinuities. The semivariance is reduced in smallest values because the samples are more correlated, indicating samples are dependent between each other.

Nugget and sill indicate the random aspect of the data. According to the variograms calculated in this study the nugget effect found it in most cases were zero or close to zero. The sill found was greater than 0.9, and it was reached at 81% (Appendix B1 and B2). In the case where the sill was less than 1, it means that value is the variability within the layers and the remaining part to reach 1 is the variability between layers (see Appendix B1 and B2, also see Table 5 and Table 6).

Range: The range shows the spatial data variability. For SIS Variograms, in the major direction for reservoir lithofacies the average range was 1042 meters, in the minor direction 725 meters and vertical 10.49 feet. SIS Hierarchy geomorphologic method trend modelling by region showed an average in the major direction of 712 meters for reservoir rock lithofacies region 1 and 2 (see Table 5 and Table 6). These ranges can give an idea of the extension of the bodies (channels) in the AOI.

<table>
<thead>
<tr>
<th>SIS Using facies tendency preferential direction</th>
<th>Code</th>
<th>Lithofacies</th>
<th>Range major direction (m)</th>
<th>Range minor direction (m)</th>
<th>Range vertical direction (ft)</th>
<th>Sill</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>0</td>
<td>Shale</td>
<td>1057</td>
<td>870</td>
<td>7.9</td>
<td>0.97</td>
</tr>
<tr>
<td></td>
<td>1</td>
<td>Reservoir rock</td>
<td>1042</td>
<td>725</td>
<td>10.49</td>
<td>0.98</td>
</tr>
<tr>
<td></td>
<td>2</td>
<td>Retarding rock</td>
<td>904</td>
<td>667</td>
<td>4.6</td>
<td>0.98</td>
</tr>
</tbody>
</table>

Table 5. Results of variograms used to model facies through SIS using facies tendency preferential direction modelling
The range of data correlation depends on direction and distance. The vertical range correlation is less than the horizontal range. Walther’s Law, which is a principle of sedimentary geology, it supports the horizontal variability found in the vertical direction; just at different length scales.

Some variograms have zonal anisotropy for example zone 1 region 2 (see Appendix B2). It is common to find geometric anisotropy in the horizontal direction. In the vertical direction of Shale lithofacies, it is possible to see geological trends in large distances (see Appendix B2. for example, Zone 1, 2, 3 region 1) indicating grain size or facial variation in the rock. It is identified in the variogram when the sill increases beyond the semi-variance to large distance (Appendix B2).

4.1.6. Data Distribution

First, it is assigned the data distribution to each zone and petrophysical parameter to be modeled. Then, the petrophysical properties are modeled using the same facies variograms. In the distribution data step, the data is transformed into a normal distribution. The distribution selected was standard, where the minimum and maximum value from the data is taken by lithology and zone, and the distribution was based on the upscaled data.

4.1.7. 3D Lithofacies Modelling

The area of study is covered by a transitional a fluvial depositional system, which have some modelling challenges to capture their heterogeneity. This system has an impact on the rock properties which ultimately impacts the flow of fluids in the reservoir.

The result of the variograms were one of the main inputs for facies modelling as well as VPC for modelling through SIS techniques. This information integrates the data obtained from sedimentological maps such as preferential bodies’ direction.
It was used 3 different geostatistical methods SISM, MPS and TGS to represent the facies distribution uncertainty. Also, these techniques were selected according to the data available for facies modelling.

Shale volume, porosity and permeability were modeled from logs provided by Ecopetrol’s petrophysical model, other properties such as rock type, net to gross, and water saturation were calculated cell by cell into the model according to algorithms, correlations and functions defined by the petrophysical model.

The following is the proposed workflow in this study to generate probabilistic scenarios required to identify the impact of facies areal and vertical distribution in the oil rate (Figure 4-12):

1. The first lithofacies model and petrophysical model built was called training model. This model was used to control the training properties model in order to calculate de STOIIP. This volumetric training case was used to perform 300 realization modifying the seed as an uncertainty variable to obtain the base case model. This base case was built using the seed belonging to the P50 percentile of training case.

2. Base case seed uncertainty was used to reproduce the lithofacies and properties model to do a new 300 realizations to select the most representative percentiles (P10, P35, P50, P75 and P90) in order to build a new model for each of them and represent them as static model uncertainty scenarios.

3. Like training model, the base case lithofacies model controlled the properties model such as porosity, permeability, and shale volume. Using these models, it was calculated the net to gross, rock types, and water saturation. As these impacts the variables to calculate the original oil in place volume (STOIIP) for the probabilistic scenarios.

4. The process previously described were used in all the methods and this procedure was applied to reduce the uncertainty to model the best facies approach.
4.1.7.1. Sequential Indicator Simulation (SIS)

**Electro-Facies Tendency Using Only Preferential Direction Trends.**

Sequential indicator simulation modelling technique is very detailed to capture the heterogeneity. It uses variograms built with the preferential direction channels obtained with the electrofacies model provided by the Ecopetrol sedimentological study. This model does not have any background or secondary attribute, because the seismic data was not available in depth to be used, then the electrofacies maps will be used in another SIS model scenario which will be explained later.

SIS facies model method takes a simulated value in each location of probability data distribution, which is calculated from sampled data. The algorithm starts randomly from one point and it sequentially advances through the grid modeled. During the interpolation each point search other points in the neighborhood defined by the variogram.

Ordinary kriging was used, as the mean calculated by areas works better than global mean. It is supported on the high density of the data used in the interpolation, the stationarity which was less evident in some sectors of the model and high heterogeneity.

During the modelling stage, it was identified the seed and variograms in unsampled areas are high impact variables. Seed defines the starting point for the algorithm to populate the grid, it has 32000 possible positions to initiate the sequential simulation. Variogram establish the spatial correlation among the data according to the bodies direction.
Figure 4-13 shows modeled lithofacies, upscaled and well logs histograms for all percentiles. Non-reservoir rocks (Shale code 0 and retarding rock code 2), have around 5% difference. Reservoir rock is statistically well represented by the lithofacies model. All percentiles models have similar lithofacies distribution.

In Appendix C1 are displayed P50 percentile model. It shows an example of lithofacies distribution according to electrofacies maps for zones 1 to 4 and anisotropy maps for zones 5 to 7. The grids showed belongs to layers where it is easy to observe the bodies direction, in order to check its correlation with electrofacies maps.

Seed parameter showed a big impact on the lithofacies distribution between percentiles meaning that this variable is an important one to be checked during the modelling stage (see Figure 4-14). When the results between lithofacies are visually compared, it is easy to find differences among them, for example Figure 4-14 shows the grid results of the percentiles modeled with SIS method. These grids show the layer 19 which belongs to zone 2, and it is possible to observe how the sand bodies’ connectivity changes among models. This layer corresponds to an open production zone in the PBU’s W-91 well and also zone 2 which is one of the most common zone open in the wells.

In general, the proportion of reservoir rock or sandstones (yellow) looks similar, but it changes in some specific sectors. The distribution changes depending on the seed applied or the percentile modeled. All models are using the same variogram data but different seed. That result shows the seed impact in the facies distribution modelling which also have an impact on the properties distribution as well (See Figure 4-28).
Hierarchical Geomorphologic from Electrofacies Maps as a hard data.

The main goal of this model is to incorporate the electrofacies maps and restrict the modelling to them by trend modelling. To accomplish this task, first it was necessary to create an electrofacies regions to limit the variograms to specific depositional electrofacial characteristics. These electrofacies regions were grouped in two regions:

- **Region 1** contains structures such as block (main channels), coarsening upward (crevasse splay), and finning upward (minor channel), They were grouped in this way because all this bodies have potential to store oil in their best rock type (Figure 4-15).

- **Region 2** belongs to a serrated electrofacies (floodplain-tidal flat), it is the shaly facies and it is not a competent rock to contain oil (see Figure 4-15).
These regions limited the horizontal variograms, because each variogram is now assigned to the new region

Zones 5, 6 and 7 do not use a region division because they do not have an electro-facial model, then it was used the boundary of the model as the other methods.

Based on variograms and vertical proportion curves by region, zones and lithofacies were used to apply the trend modelling workflow, as a result of this, it was obtained a probability cube by lithofacies for all zones (see Appendix D1). This procedure does not need to be under seed dependency.

According to the statistics results presented in Table 7, the mean of reservoir rock probability is higher than the other two lithofacies. In addition, the dispersion of this lithofacies is higher as well compared to the other lithofacies based on the variance value.
The previous statistics about probability applies to SIS techniques which are covered by the same data wells.

The probability cubes are used to the model lithofacies training case and other cases (base case and the percentiles) as well. They control lithofacies proportions in each zone while variograms control the areal correlation.

Appendix D2 shows the P50 case as a representative example of the uncertainty scenario of lithofacies result.

Figure 4-16 shows the histograms for modeled lithofacies, upscaled and well logs for all percentiles modeled (see Figure 4-16). The differences between upscaled and modeled data are greater than 5%, indicating underestimation for lithofacies 1 and overestimation in lithofacies 0. Based on the histogram information all models are quite similar, statistically their maximum difference is 0.7 among models.

The difference among all percentiles is related to the distribution of the sand bodies and shales, both used different seed with same variography model, this shows the seed impact on lithofacies distribution in the model. Despite the small variation presented in the general lithofacies proportion

<table>
<thead>
<tr>
<th>Probability cube</th>
<th>Mean</th>
<th>Standard deviation</th>
<th>Variance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shale</td>
<td>0.2060</td>
<td>0.1901</td>
<td>0.0362</td>
</tr>
<tr>
<td>Reservoir rock</td>
<td>0.5431</td>
<td>0.2715</td>
<td>0.0737</td>
</tr>
<tr>
<td>Retarding rock</td>
<td>0.2509</td>
<td>0.2105</td>
<td>0.0443</td>
</tr>
</tbody>
</table>

Table 7. Summary of probability cubes by lithofacies results.
shown in the histogram among the percentiles, the visual inspection highlights important dissimilarities between them (see Figure 4-17).

<table>
<thead>
<tr>
<th>Zone 2 layer 19</th>
<th>SIS Hierarchy P10</th>
<th>SIS Hierarchy P35</th>
<th>SIS Hierarchy P50</th>
</tr>
</thead>
<tbody>
<tr>
<td><img src="image1.png" alt="Image" /></td>
<td><img src="image2.png" alt="Image" /></td>
<td><img src="image3.png" alt="Image" /></td>
<td><img src="image4.png" alt="Image" /></td>
</tr>
</tbody>
</table>

Figure 4-17. SIS Hierarchy geomorphologic lithofacies Example, for all percentiles modeled in zone 2 layer 19.

4.1.7.2. Truncated Gaussian Simulation (TGS)

Truncated gaussian simulation modelling, it is widely known technique that works very well in transitional environments, some zones in this study were identified as transitional influence, mainly zone 1; nevertheless, all zones were modeled under this method.

The lithofacies proportion were organized from lower to high lithofacies proportion percentage. In that context lithofacies are prioritized to be modeled. Each zone has different lithofacies order based on their proportionality.

This technique uses the same sequential indicator simulation variograms parameters, and the seed was modified following the procedure described in other methods.

TGS P10 has the highest shale proportion (17.3%) and the lowest reservoir rock (57.3%) proportion modeled, compared to other percentiles. Retarding rock honored the upscaled cells and well logs proportions in all percentiles (see Figure 4-18).

The result of this technique showed variation on the lithofacies distribution in all percentiles (Figure 4-19), been a common fact in all modelling methods. The contact between lithofacies depend on the
priority given to them. In general, in the Figure 4-19 is common to find reservoir – retarding rock contacts than shale – reservoir rock, indeed retarding rock looks such as background lithofacies

Figure 4-18. Histogram lithofacies model by Truncated Gaussian Simulation (TGS).

<table>
<thead>
<tr>
<th>Zone 2 layer 19</th>
</tr>
</thead>
<tbody>
<tr>
<td>TGS P10</td>
</tr>
<tr>
<td><img src="image" alt="TGS P10" /></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>TGS P75</th>
<th>TGS P90</th>
</tr>
</thead>
<tbody>
<tr>
<td><img src="image" alt="TGS P75" /></td>
<td><img src="image" alt="TGS P90" /></td>
</tr>
</tbody>
</table>

LEGEND
- Shale (Non Reservoir)
- Reservoir rock
- Retarding rock (Non Reservoir)

Figure 4-19. Example of lithofacies model by TGS, layer 19 zone 2.
4.1.7.3. Multiple Point Simulation (MPS)

While SIS and TGS modelling techniques use variograms (two points statistic) to populate 3D models, the Multiple Point Simulation modelling technique uses images:

According to the depositional environment, it was selected one satellite image (see Figure 4-20) and the electrofacies maps that represent the reservoir’s zones. Those images were used as training images. These images were processed in Petrel by converting them into a continuous map, then the image in this step is represented by values from 0 to 1.

<table>
<thead>
<tr>
<th>Depositional System</th>
<th>Image Selected</th>
<th>Name</th>
<th>Coordinates</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wave Dominated Estuary</td>
<td>Willpa Bay</td>
<td>46°40’23.79”N 123°58’57.30”O</td>
<td>Sentinel Image <a href="http://marinespecies.org/introduced/wiki/Morphology_of_estuaries">http://marinespecies.org/introduced/wiki/Morphology_of_estuaries</a></td>
<td></td>
</tr>
<tr>
<td>Fluvial Tidal Influence</td>
<td>Columbia River Estuary</td>
<td>46°13’45.81”N 123°33’11.82”O</td>
<td>Google earth <a href="http://marinespecies.org/introduced/wiki/Morphology_of_estuaries">http://marinespecies.org/introduced/wiki/Morphology_of_estuaries</a></td>
<td></td>
</tr>
<tr>
<td>Meandering River</td>
<td>Chulym River</td>
<td>57° 7’45.86”N 87°29’31.11”E</td>
<td>Google earth</td>
<td></td>
</tr>
<tr>
<td>Braided River</td>
<td>Yukon River</td>
<td>62°58’29.88”N 164°13’39.87”O</td>
<td>Google earth</td>
<td></td>
</tr>
<tr>
<td>Braided River</td>
<td>Lenna River</td>
<td>72°29’40.66”N 127°12’53.14”E</td>
<td><a href="https://earthobservatory.nasa.gov/images/7343/lena-river-delta-russia">https://earthobservatory.nasa.gov/images/7343/lena-river-delta-russia</a></td>
<td></td>
</tr>
</tbody>
</table>

Figure 4-20. General information about images selected to control the lithofacies model.

These images are incorporated into a preliminary 3D grid and converted in a discrete variable tied to lithofacies codes (Lithofacies 0, 1 and 2). After that, this grid image is edited in order to keep the upscaled lithofacies proportion and correct some unidentified codes. The lithofacies proportion that the grid integrate from the image must be compared to the upscaled cells, it must have a maximum difference of 10%.

The images used had different levels of stationarity then, the search mask and the number of informed nodes used must have a high search radio. As these images lead to incorrect statistics, they were edited
to preserve the proportion needed in each zone for modelling purposes. In the training process it was necessary to have many iterations to get the most representative image (Figure 4-21).

Training images were created by multiple realizations by modifying the search mask parameters to select the best illustration of the zones to be modeled. One pattern when this image is obtained is created and it is used to control the lithofacies model. The difficulty applying this method was reproducing the training image with similar features as the original one. Figure 4-21 depicts the process and results of multiple point simulation.

<table>
<thead>
<tr>
<th>Zone 1</th>
<th>Zone 2</th>
<th>Zone 3</th>
<th>Zone 4</th>
<th>Zone 5 and 6</th>
<th>Zone 7</th>
</tr>
</thead>
<tbody>
<tr>
<td>Willapa Bay, Southwest Pacific Coast USA. Wave dominated estuary</td>
<td>Columbia River Estuary, Oregon. Fluvial tidal influence</td>
<td>Chulym River, Russia. Meandering river</td>
<td>Lena River, Russia. Braided river depositional system</td>
<td>Yukon River, Alaska. Braided river depositional system</td>
<td>Lena River, Russia. Braided river depositional system</td>
</tr>
<tr>
<td>Processed petrel image</td>
<td>Processed petrel image into continuous values</td>
<td>Image converted into the grid as a discrete lithofacies log (lithofacies codes 0, 1, 2). Interpreted to honor lithofacies proportion</td>
<td>Trained image based on discrete converted image</td>
<td>Trained image based on discrete converted image</td>
<td>Trained image based on discrete converted image</td>
</tr>
<tr>
<td>Image converted into the grid</td>
<td>Trained image</td>
<td>Trained image</td>
<td>Trained image</td>
<td>Trained image</td>
<td>Trained image</td>
</tr>
<tr>
<td>Lithofacies final model layer</td>
<td>Zona 1 Layer 16</td>
<td>Zona 3 Layer 48</td>
<td>Zona 4 Layer 61</td>
<td>Zona 3 Layer 90</td>
<td>Zona 7 Layer 134</td>
</tr>
</tbody>
</table>

Figure 4-21. Process and results multiple point simulation and some examples.
The percentiles modeled are quite similar among them with a maximum difference of 8% between upscaled logs and modeled for lithofacie code 0 (shale) and other lithofacies are below 4% (Figure 4-22).

![MPS Percentiles](image)

Figure 4-22. Histogram lithofacies model by Multiple point Simulation (MPS).

Figure 4-23 and Figure 4-24 show the results of MPS technique for percentiles P10, P50 and P90 percentiles for each zone at one representative layer. All the results showed here depict features related to the depositional environment associated to each zone where it is possible to identify channels direction. Nevertheless, in braided representation (zone4-5-6) it is quite hard to stablish the preferential direction of the bodies because they are interlaced each other.
Figure 4-23. 3D Facies distribution zones 1, 2, 3, and 4 by MPS percentiles P10, P50 and P90.
### 4.1.8. 3D Petrophysical Modelling

3D Petrophysical properties model was controlled by the lithofacies models previously described, these lithofacies defines from their curve’s creation has been attached to properties. Those lithofacies try to differentiate characteristics which controls the oil accumulation.

#### 4.1.8.1. Porosity and Permeability

Porosity and permeability are the most important petrophysical variables in hydrocarbon reservoir evaluation. First, it represents the pore space available for fluids storage and second variable describes the flow capacity.

Both models use the same variogram and seed applied in lithofacies modelling, because the idea is to guide the properties to keep the preferential direction defined in the lithofacies model.
In the initial part of the process, before building the lithofacies model these variables were compared to verify the link between them (as was shown in the Figure 4-9).

These properties were modeled under sequential gaussian simulation (SGS). Additionally, permeability used collocated algorithm effective to keep the relationship between these variables, constraining it to the previously created porosity model.

The following tables show the porosity and permeability statistics for modeled P50 lithofacies methods and upscaled log porosity and permeability. Porosity deviation from upscaled mean is maximum 0.0233 and minimum 0.0030 (Table 8).

<table>
<thead>
<tr>
<th>Lithofacies Modelling Methods</th>
<th>Modeled P50</th>
<th>Upscaled Logs</th>
</tr>
</thead>
<tbody>
<tr>
<td>SIS</td>
<td>0.01 - 0.35</td>
<td>0.01 - 0.35</td>
</tr>
<tr>
<td>Hierarchy Geomorphologic</td>
<td>0.01 - 0.35</td>
<td>0.01 - 0.35</td>
</tr>
<tr>
<td>TGS</td>
<td>0.01 - 0.35</td>
<td>0.01 - 0.35</td>
</tr>
<tr>
<td>MPS</td>
<td>0.01 - 0.35</td>
<td>0.01 - 0.35</td>
</tr>
</tbody>
</table>

Table 8. Statistic report of porosity for modeled and upscaled logs.

Porosity presents a bimodal distribution (see Figure 4-25). It has two peaks, one towards low values and the other one towards high porosities. Although the data reported in the Table 8 are global it does not discretize the two groups observed in this histogram.

Permeability is skewed to left. It is a positively skewed distribution, log normal distributed (Figure 4-26). The maximum value of this variable is 40133 and minimum 0.0001. All means between percentiles even compared to upscaled logs are at 100 - 200 mD of difference (Table 9).

<table>
<thead>
<tr>
<th>Lithofacies Modelling Methods</th>
<th>Modeled P50</th>
<th>Upscaled Logs</th>
</tr>
</thead>
<tbody>
<tr>
<td>SIS</td>
<td>0.001 - 40133</td>
<td>0.001 - 40133</td>
</tr>
<tr>
<td>Hierarchy Geomorphologic</td>
<td>0.001 - 40133</td>
<td>0.001 - 40133</td>
</tr>
<tr>
<td>TGS</td>
<td>0.001 - 40133</td>
<td>0.001 - 40133</td>
</tr>
<tr>
<td>MPS</td>
<td>0.001 - 40133</td>
<td>0.001 - 40133</td>
</tr>
</tbody>
</table>

Table 9. Statistic report of permeability for modeled and upscaled logs.
Figure 4-25. Porosity histograms.

Figure 4-26. Permeability histograms.
Figure 4-27 is a typical crossplot porosity versus permeability filtered by lithofacies for P50 case representing all lithofacies models, this graph represents the linear relationship between porosity and permeability, in addition it depicts the transition between shale - retarding rock and retarding rock – reservoir rock lithofacies.

In general retarding rock has porosities from 0.04 to 0.23 and permeability from 0.056 and 304.8 mD. Shale’s porosity is between 0.01 and 0.085 and 0.001 to 2.2 mD of permeability. Reservoir rock has 0.18 as a minimum and 0.35 as the maximum porosity value, now permeability range starts in 8 mD and end in 40133 mD.

The results of properties model using lithofacies modeled by different geostatistical facies model methods can be visualized in Figure 4-28. Properties are completely controlled by lithofacies direction and the correlation between then is clear and easy to find. The sand bodies depicted in those grids at layer 19 through different percentiles reveal how each property model depends on how lithofacies are distributed areally. Percentiles model are changing laterally because of the seed impact on properties (see Appendix E).
Figure 4-28. Example of lithofacies influence on porosity and permeability distribution, zone 2 layer 19 for all lithofacies model percentile P50.
4.1.8.2. Net to Gross

Net to Gross (NTG) variable was calculated as 1 minus normalized shale volume, this guarantees that the range of the values were between 0 to 1. The NTG grid represents the sand proportion presented in the gross thickness.

Net to gross calculation was modeled in each uncertainty scenario modeled. Appendix E shows the results of shale volume and net to gross P10, P50 and P90 percentiles selected layer by zone.

The histogram presented in Figure 4-29 shows that most of the data is concentrated in net to gross 1, almost 35% of the data are concentrated in that value and shale volume values from 0 to 0.2, indicating an important proportion of sand in the model.

Net to gross is used to calculated net thickness which is then linked to the flow capacity coming from PBU results.
The areal distribution of net to gross and volume of shale are well controlled by lithofacies as well (see Figure 4-30). All percentiles models depicted in this figure preserve the bodies geometry.

Figure 4-30. Example of lithofacies influence on net to gross distribution, zone 2 layer 19 all lithofacies methods modeled percentile P50.

<table>
<thead>
<tr>
<th>Lithofacies</th>
<th>Shale Volume</th>
<th>Net to gross</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sequential indicator Simulation</td>
<td></td>
<td></td>
</tr>
<tr>
<td>SIS Hierarchy Geomorphologic</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Truncated Gaussian Simulation</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Multiple Point Simulation</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

LEGEND
- Shale
- Reservoir rock
- Retardig rock

1 0.5 0
4.1.8.3. Rock Type Model

Rock types were calculated cell by cell into the 3D grid. The pore throat radius function implemented uses Pitman R50 equation. This function depends on porosity and permeability. It was selected the rock types based on R50 cut off calculation. The best rocks are (1, 2, 3, 4, and 5) and they have a R50 ≥ 29 mm to 4 mm.

Figure 4-31 is an example of the crossplot porosity versus permeability classified by rock types, where the rock types 1 to 5 are the reservoir having permeability up to 500 mD and porosities higher than 0.19. All models has a graph like this with the same behavior.

![Crossplot Porosity and Permeability SIS facies model](image)

Figure 4-31. Porosity and permeability crossplot - SIS facies model.

Figure 4-32 shows the lithofacies modeled with all lithofacies methods and the rock type model for P50 percentiles (see Appendix E all methods by P10, P50 and P90). It is possible to observe how the lithofacies has a complete control on properties distribution. In a sampled location, it follows the hard data and the unsampled zones, it takes the geometry from the lithofacies model. Where yellow color is reservoir rock in lithofacies that is mainly associated to rock type 1, 2, 3, 4 and 5 which have the best rock properties (high porosity and permeability). Retarding rock is the light brown in the lithofacies grid which can be correlated mainly with rock type 6.
Figure 4-32. Example of lithofacies influence on rock type distribution, zone 2 layer 19 all lithofacies modeled percentile P50.
4.1.8.4. 3D Water Saturation Model

The Free Water Level (FWL) defined for this field is tilted, based on hydrodynamic studies and wells information. The FWL was built from the tops defined in the vertical wells.

This water saturation model started by building a height grid using the FWL surface, then it was used to calculate a capillary pressure grid. Base on capillary pressure curves and using the J function methodology, it was defined the water saturation by rock type. This water saturation model used a J function correlation for each rock type.

All static models use the same capillary pressure grid, because it does use the oil and water densities. J function needs to be re-calculated for every static model as it has a porosity and permeability input which are varying depending on the facies model used.

Figure 4-33 is an example of water saturation model cross section view for two model lithofacies methods percentile P50. Water saturation hierarchy geomorphologic lithofacies model are more saturated by water in the potential upper oil zone, which means an increment of shaly rocks with low properties (bad quality rocks - RT6 or 7 mostly).

![Water saturation P50 SIS hierarchy lithofacies model](image)

Figure 4-33. 3D water saturation distribution NWW-SE direction.

Not necessarily reservoir rock can be saturated with oil, in other words, this rock can have high water saturation too. The sand bodies with 100% water saturation can be recognized grid (see Figure 4-34 and Appendix E).
Figure 4-34. Example of lithofacies influence on water saturation distribution, zone 2 layer 19 all lithofacies methods modeled percentile P50.
4.1.9. Volumetric Calculation

Before running any uncertainty realization, it was necessary to calculate the stock tank oil-initially-in-place (STOIIP) for every case which is going to be used as a base or reference in the Monte Carlo process.

The initial volumetric for training and base case models were deterministic and they were used to set the parameters to run the probabilistic scenarios for the first 300 realization. The same happens with the base case scenario which correspond to P50 training model percentile and it is used to set and run a new uncertainty process; see Table 10.

Table 10. Volumetric report of base cases percentile P50.

<table>
<thead>
<tr>
<th>Lithofacies Geostatistic Methods</th>
<th>Bulk Volume (10^6 Bbl)</th>
<th>Net Volumen (10^6 Bbl)</th>
<th>Pore Volumen (10^6 RB)</th>
<th>HPV (10^6 STB)</th>
<th>STOIIP (10^6 STB)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Using facies tendency preferential direction</td>
<td>6392</td>
<td>4217</td>
<td>1115</td>
<td>613</td>
<td>601</td>
</tr>
<tr>
<td>Hierarchy geomorphologic</td>
<td>6392</td>
<td>3818</td>
<td>974</td>
<td>525</td>
<td>514</td>
</tr>
<tr>
<td>Truncated Gaussian Simulation</td>
<td>6392</td>
<td>3913</td>
<td>996</td>
<td>534</td>
<td>523</td>
</tr>
<tr>
<td>Multiple Point Simulation</td>
<td>6392</td>
<td>3930</td>
<td>1026</td>
<td>571</td>
<td>560</td>
</tr>
</tbody>
</table>

Appendices F1 to F4 show the STOIIP distribution in the training case and the base case for all lithofacies method modeled. When all percentiles are contrasted into the same methods the difference numerically between training case and base case are negligible values. Among methods the STOIIP vary maximum 87 MMbbls (around 15%) and minimum is 41 MMbbls (Table 10).

4.1.10. Lithofacies Uncertainty Analysis

4.1.10.1. Selection of Uncertainty Parameter

In order to identify the sensitivity parameters, it was done a test to identify the most sensitive lithofacies distribution variable between variogram and seed. Variograms are well known to be a sensitive tool to evaluate the spatial correlation. Nevertheless, seed is another important parameter but it has been less studied.

The test consists in evaluating how the STOIIP is impacted by using the maximum and minimum seed value and maximum and minimum range in the major direction. Each input was used to build a four static models (see Figure 4-35) changing only the values presented in the Table 11.
Table 11. Parameters used in the sensibility evaluation.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Input Value</th>
<th>Result Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Variogram</td>
<td>Major Direction Range Minimum</td>
<td>900</td>
</tr>
<tr>
<td></td>
<td>Major Direction Range Maximum</td>
<td>2000</td>
</tr>
<tr>
<td>Seed</td>
<td>Maximum</td>
<td>32000</td>
</tr>
<tr>
<td></td>
<td>Minimum</td>
<td>100</td>
</tr>
</tbody>
</table>

Figure 4-35. Scenarios modeled to evaluate the sensitivity of major range and seed.

Figure 4-36 shows that the seed has a higher impact than major direction of variograms. Base on this analysis it was selected the seed as an uncertainty parameter for this study.
Geostatistical methods as Sequential Indicator Simulation (SIS), Truncated Gaussian Simulation (TGS), Multiple Point Simulation (MPS), and Gaussian Random Function (GRF) among others used a generator of random numbers which establish the order to populate the cells called seed.

The selection of the initial seed value for the training facies case model was obtained iterating to get the best response in the statistical reproduction of upscaled logs versus modeled result. This process was performed after the vertical curves proportion and variogram fitting step. If the seed is the same for all zones it will reproduce the same model.

4.1.10.2. Selection of Optimum Number of Realizations

It was generated 600 sensitivity cases per method and 28 static models in total including the initial oil rate calculations to study the impact that facies distribution on the oil rate in a stratigraphic and heavy oil field.

To identify the number of realizations, it was done a first test with 30 samples (30 realizations), according to the literature that is the minimum number recommended, but the distribution was poor, and apparently the number of samples were not representative (see Figure 4-37).

The minimum number of samples selected were 300 (seed sensibility was 300 samples - 300 realizations), because the uncertainty variable is only one. Nevertheless, it could be a greater number of samples to be closer to the mean and take a normal distribution based on the central limit theorem, but this number of realizations was enough to see the behavior of the seed. The number used was found by iterating to find a smaller number of realizations that generates the normal distribution.
In all techniques, it is created a training model as presented in 3D lithofacies and Petrophysical modelling section. The realizations were made under Monte-Carlo method changing seed as uncertainty variable. It was run 600 realization by facies method, in total they were 2400 realization.

4.2. ENGINEERING CALCULATION AND ANALYSIS

This section shows the workflow to stablish the oil relative permeability proposed correlation, pressure transient analysis of vertical wells, productivity index and oil rate production.

4.2.1. Oil Relative Permeability Proposed Correlation

The following proposed interpolated oil relative permeability for heavy oil was based on a combination of EOR (Coat’s et. al. (1980) and gas condensate (Heriot Watt University) relative permeability interpolation function. The interpolated relative permeability function uses a weighted factor $Y$, which for the case of gas condensate reservoirs depends on the adimensional capillary number while for EOR models depend on adimensional interfacial tension (IFT) weighted function.

$$k_{ro} = k_{ro,interpolated} = Y \cdot k_{ro,min} + (1 - Y) \cdot k_{ro,max} \quad \text{Equation 4-1}$$

Where $Y$ is the weight factor, $k_{ro}$ is the interpolated oil relative permeability, $k_{ro,min}$ is minimum or base oil relative permeability and $k_{ro,max}$ is maximum oil relative permeability. Minimum and Maximum oil relative permeabilities are function of other parameters different than saturation, like rate (velocity), IFT, viscosity, etc.

In this study it is proposed that the minimum or base relative permeability is obtained with the highest expected viscosity in the field which is 752 cp and the maximum oil relative permeability is obtained with the lowest expected oil viscosity which is 100 cp. Those are the extreme values of this field.
Several correlations have been proposed in the literature to capture the oil viscosity effect on heavy oil relative permeabilities like those presented by Menad et al., (2019). Here, in this study it was selected the dimensionless oil viscosity factor for weighted factor $Y$.

The weighting factor $Y$ is related to oil viscosity as it is very well known that this is one of the main parameters that impacts the fluid flow in heavy oil reservoirs, the proposed expression is as follows:

$$Y = \left( \frac{\mu_o}{\mu_{o,base}} \right)^{m_o} \quad \text{Equation 4-2}$$

Where $\mu_o$ is the oil viscosity (for example the oil viscosity expected in a grid cell or a well), and $\mu_{o,base}$ is the base oil viscosity (this is the highest viscosity expected, for this case, it was 752 cp). $m_o$ is a factor used to tune the interpolated oil relative permeability either to laboratory experiments or field oil production data as will be shown in Figure 4-40.

By knowing from literature review that oil viscosity is the second most important parameters after water saturation that impact the oil relative permeabilities then, Equation 4-3 was considered to be a good approximation to link laboratory data available with field production data.

The following figure shows the conceptual model of the expected behavior of base (or minimum), maximum and interpolated oil relative permeabilities.

![Figure 4.38. Conceptual interpolated oil relative permeability.](image)

Based on relative permeabilities end points, it was generated the end point correlations with oil viscosities as it is shown in the figures bellow (Figure 4-39). For rock types where the information was not available it was interpolated or extrapolated their expected behavior based on the closest rock types.
4.2.2. Oil Rate Match per Well Using the Proposed Heavy Oil Relative Permeability

The following graph (Figure 4-40) shows a sequence of tests to match the estimated oil rate per well at different \( m_o \) values. As shown in Equation 5-2, \( m_o \) affects the degree of interpolation of the final oil relative permeability.

- When \( m_o \) is very low (\( m_o = 0.01 \)) the interpolated oil relative permeability (kro int) is the same as the base (minimum) oil relative permeability (kro base). In other words, if the lowest oil relative permeability is used, the initial oil rate estimation is very low and will not match observed field data.

- Once \( m_o \) is increased (\( m_o = 0.5 \)), the interpolated oil relative permeability increases (kro int) and the oil rate begins to increase, but still, it does not match the observed data.

- Finally, until several iterations to minimize the error between the observed and calculated oil rate by changing \( m_o \) (\( m_o = 1.56 \)), it is possible to obtain the final interpolated oil relative permeability that allows to have the closest match of the oil rate.

This specific section shows the approach proposed in this work to match the complex oil relative permeabilities in a heavy oil reservoir presented in section 1.4.2. and analytical the link between all geological work explained in section 4.1 and reservoir engineering models without running a dynamic reservoir simulation model.

This specific step is quite important as it impacts the productivity index (PI) calculation per grid cell. This step guarantees that the sweet spots inferred using the PI are not underestimated by using the base relative permeability.
4.2.3. Pressure Transient Analysis of Vertical Wells.

Pressure Transient Analysis techniques can be performed for any kind of well geometry but the desired test to be use is a pressure build up (PBU) from vertical wells. One of the main reasons is that it minimizes the assumptions in the interpretation stage such as true stratigraphic thickness, flow geometry and skin characterization, and minimize possible induced instability errors compared with a draw down test.

In this study it was available only one PBU which was used as a quality control for the static model. Variables that were checked using the PBU were Kh, Skin and PI.
The following table shows the main parameters for PBU analysis.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>ID</th>
<th>Value</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity</td>
<td>∅</td>
<td>0.31</td>
<td>Fraction</td>
</tr>
<tr>
<td>Total Compressibility</td>
<td>Ct</td>
<td>3x10^{-6}</td>
<td>psi^{-1}</td>
</tr>
<tr>
<td>Derivative Value</td>
<td>Derivative</td>
<td>126</td>
<td>psi</td>
</tr>
<tr>
<td>Reservoir Pressure</td>
<td>Pres</td>
<td>1005.5</td>
<td>psia</td>
</tr>
<tr>
<td>Bottom Hole Pressure</td>
<td>Pwf</td>
<td>25</td>
<td>Psia</td>
</tr>
<tr>
<td>Wellbore Radius</td>
<td>rw</td>
<td>0.578</td>
<td>ft</td>
</tr>
<tr>
<td>Production Time</td>
<td>tp</td>
<td>1476</td>
<td>hr</td>
</tr>
<tr>
<td></td>
<td>Δt</td>
<td>6</td>
<td>hr</td>
</tr>
</tbody>
</table>

Table 12. PBU main parameters.

The derivative showed in Figure 4-41 is quite complex, the signature of the derivative has the expected constant pressure support boundary, but as the skin is lower than 0 it was masked by the radial flow refers to ¡Error! No se encuentra el origen de la referencia. (section 1.5). Additionally, this specific well suggests fluid redistribution in the wellbore and a multilayer behavior. Due to this complex fluid dynamics, it was necessary to perform the pressure transient analysis using a numerical approach rather than the analytical method.

The following set of graphs (Figure 4-41) shows the multilayer approach used to reproduce as close as possible the signature of the derivative. It was used the Kh of the 2 layers obtained from the base static model and the oil relative permeability from Figure 4-40 to perform the numerical PBU analysis. This proves that with the Kh from the static model and by using the interpolated oil relative permeabilities is it possible to reproduce the late time region.

Figure 4-41. Multilayer behavior W-091.
Figure 4.42 shows the Kh values of the 2 layers in the static model in well W-091 compared with the values used in the Pressure transient Analysis.

It is important to highlight that comparing the Kh from PBU with Static models is a very important step while building the static model. If both Kh are not the same it will strongly affect the prediction of fluid flow in the porous media. This is not a trivial task and full integration of petrophysical data and reservoir engineering data will guarantee to reduce the uncertainty in the permeability of the static model.

In this specific case, only one PBU was available but it was good enough to have a coherent static model which also affect the match the oil relative permeabilities.

4.2.4. Initial Oil Rate in 3D Static Model Grid.

This is a unique step in the static model workflow proposed in this study. The aim of this step is to guarantee a smooth transition between static and dynamic model. After building the static model and calibrating the oil relative with the proposed interpolated oil relative permeability correlation (see Section 4.2.1) it was calculated reservoir engineering parameters such PI, Oil Rate for hypothetical wells that could cross every grid cell of the static model.
The advantages of this workflow are:

1. It is a tool that a geologist and reservoir engineer can use as quality control of static model output such as permeability and water saturation. This helps a smooth transition from static to dynamic models.

2. Heavy oil relative permeabilities are not only function of saturation but also of oil viscosity. Commercial reservoir simulators commonly use oil relative permeability that are only function of water saturation, therefore the workflow can be used to identify the best relative permeability that fits most of the data avoiding long iterations with the dynamic model.

3. With this workflow it is possible to generate multiple oil rate across all the reservoir helping to properly quantify production uncertainty.

The following steps were done to calculate the oil relative permeability in the 3D statis model:

- First, each end point of relative permeability (Kro, Swirr, Sor, Kro@Swi) and Corey exponents by rock type were incorporated into the 3D model.
- The next step is to include in the static model, the correlations found for the end points at different viscosities, and the oil relative permeability using the Corey function. In this step every grid cell has the minimum and maximum oil relative permeability (see Figure 4-44) used to calculate the interpolated oil relative permeability (Kroint) at different oil viscosities.
- Finally, by using the weighted function Y to calculate the 3D interpolated oil relative permeability it is possible to estimate the final kro per each grid cell as every cell has different water saturation, permeability, and oil viscosities. The process is explained in the Figure 4-45.
- Once these maximum and minimum endpoints and Corey exponents are obtained into the 3D model, the interpolated oil relative permeability is calculated which will be used in the 3D oil rate calculation step.

Notice that the workflow proposed in this study is for a heavy oil reservoir but it can be easily extrapolated to black oil, volatile oil fields, also gas and gas condensate fields by just using the right rate equation from reservoir engineering.
The previous calculation was done only for the percentiles selected in order to see the differences between them and among other modelling techniques.

Figure 4-44 shows the areal distribution impact of the facies by different models on the minimum, maximum and interpolated oil relative permeability for percentile P50 layer 19 zone 2.

<table>
<thead>
<tr>
<th>Kromin</th>
<th>Kromax</th>
<th>kroint</th>
</tr>
</thead>
<tbody>
<tr>
<td><img src="image1.png" alt="Kromin SIS P50" /></td>
<td><img src="image2.png" alt="Kromax SIS P50" /></td>
<td><img src="image3.png" alt="kroint SIS P50" /></td>
</tr>
<tr>
<td><img src="image4.png" alt="Kromin SIS Hierarchy Geomorphologic P50" /></td>
<td><img src="image5.png" alt="Kromax SIS Hierarchy Geomorphologic P50" /></td>
<td><img src="image6.png" alt="kroint SIS Hierarchy Geomorphologic P50" /></td>
</tr>
<tr>
<td><img src="image7.png" alt="Kromin TGS P50" /></td>
<td><img src="image8.png" alt="Kromax TGS P50" /></td>
<td><img src="image9.png" alt="kroint TGS P50" /></td>
</tr>
<tr>
<td><img src="image10.png" alt="Kromin MPS P50" /></td>
<td><img src="image11.png" alt="Kromax MPS P50" /></td>
<td><img src="image12.png" alt="kroint MPS P50" /></td>
</tr>
</tbody>
</table>

Figure 4-44. Minimum, maximum, and interpolated oil relative permeability calculated into the 3D grid (Zone2, Layer 19).
Following equation 4-3 and Figure 4-45 shows a representation of how the interpolated oil relative permeability was done using 3D static model.

\[ \text{Kroint} = \left( \frac{\mu_o}{\mu_{o,b}} \right)^{m_o} \cdot K_{ro,min} + \left( 1 - \left( \frac{\mu_o}{\mu_{o,b}} \right)^{m_o} \right) \cdot K_{ro,max} \]

\[ Y = \left( \frac{\mu_o}{\mu_{o,b}} \right)^{m_o} \]  

**Equation 4-3**

Figure 4-45. Calculation of interpolated oil relative permeability into the 3D grid (Zone2, Layer 19).

After obtaining the interpolated oil relative permeability for each grid cell in the static model. Equation 4-4 and Figure 4-46 shows an example of how the oil rates was calculated for each grid cells assuming that a hypothetical vertical well crosses a cell.

\[ q_o = 0.007082 \times \frac{k \cdot h \cdot \text{Kroint}}{\mu_o \cdot B_o} \times \frac{(P_{res} - P_{wf})}{\ln \left( \frac{r_e}{r_w} \right) + s - 0.75} \]  

**Equation 4-4**

Figure 4-46. 3D initial oil rate Calculation (zone 2, layer 19).
5. DISCUSSION

The main objective of this project is to study the impact of sedimentary facies distribution on heavy oil production rate in a Llanos Basin field by using multiple facies realizations and calculating the initial oil rate into the static model grid.

5.1. FACIES MODEL DISTRIBUTION PREDICTABILITY

The facies distribution models made probabilistically through different methods showed the important variation in unsampled areas among the methods and percentiles. Seed parameter generated those changes in distribution while preserving the proportionality from upscaled logs. In other words, the modeled predictability will be the percentage reproduced by lithofacies based on the upscaled log lithofacies, for example in the lithofacies modelling section 4.1.7 the proportion showed through the histograms for lithofacies in the upscaled wells were 11.6% Shale (code 0), 64.8% reservoir rock (code 1) and 23.6% retarding rock (code 2) and percentage value obtained from different models, those proportions are always achieved by all lithofacies predictions and models.

Another way to evaluate predictability is through a blind test. Blind tests are a simulation run used as a validation technique. It consists of leaving out all information related to some selected wells, then the data that belongs to these wells are not used during the modelling process. At the end, the lithofacies and petrophysical modeled data is compared to the wells logs in order to validate and identify the results.

The static models have 221 wells while the blind test modes have 215 wells. The wells selected to be removed were the vertical wells (W-28, W-91, W-117, W119, W316 and W-568) which had the best match oil rate, are spread across all the field, have different facies distributions, and covers all the production range. This sensitivity was done for all lithofacies methods.

P50 percentile was selected to test the predictability of the lithofacies distribution model, and it will be a reference model to compare the results obtained areally and the lithofacies wells logs and upscaled logs will be the reference as well for local analysis.

5.1.1. Blind Test

5.1.1.1. Electro-facies Tendency Using Only Preferential Direction Trends - SIS

The procedure to build this model was the same described it in the Section 4.1.7, the only difference between them is the number of wells used. The seed used was 15244 and it corresponds to percentile P50. This method reproduced over 56% of the well’s column in only three wells (W28, W316, and W119) the other three are under 56% of accuracy.

Figure 5-1 represent P50 lithofacies distribution using all wells and eliminating 6 of them. In general, the models look quite similar except in some areas of the model, it is due to the variogram which was adjusted to the new sampled population, nevertheless they did not change substantially, it modified the distribution in small areas in the south, east center and north-west.

Blind test is known as well as leave-out
In unsampled zones where the wells were removed in the location of W-117, W028, W119, the blind test model are not representing the well data represented in layer 19 zone 2. This kind of unpredictability in these areas is associated to the neighbor's information which shows the local heterogeneity, (Figure 5-2a, b, and c).

Base on that when the wells are removed the blind test model tends to increase shales in the removed wells location, it is possible to infer that these wells are in high heterogeneous areas, this it is why the remaining wells which are controlling the blind model are not predicting the location unsampled because they are having internal lithological variation to populate the area (Figure 5-1).

The areas where these wells were left out continued having important density of information around from horizontal wells which are in the same cluster this argument support the idea about local heterogeneity.

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Following well intersections show graphically each blind test well. Figure 5-2 shows the original SIS model with all the wells (graphs to the right) and the blind test models showed to the left, the wells show the lithofacies column from the log for comparative purposes. The open zones to flow are predicted under SIS model with some exceptions in W-091 and W-028.

**Figure 5-2.** Well intersection to represent the blind wells model SIS P50.

### 5.1.1.2. Hierarchy Geomorphologic Blind Test Model Removing 6 Vertical Wells.

The percentile P50 represented through this model is 19959, it corresponds to the seed used in the SIS hierarchy model with all wells. The blind test model reproduces with accuracy 66% of the wells, where 4 wells are represented over 60% (W028, W091, W316 and W119) and other 2 wells are between 40% - 50% (see Figure 5-9). In this model the variograms were adjusted according to the well information remained in the model. Base on Figure 5-1, the modification in the variogram had an impact on the bodies extension. The variograms used in the blind test has more connectivity than the model with all wells in the north west part of the modeled area, this result is due to the variography response. In this model is also evident the local heterogeneity present in the W-117 and W-091 area (Figure 5-3 dotted magenta box).
When the lithofacies model is compared to well log lithofacies curves belonging to these wells, it is possible to observe the vertical similarities and differences between them. In Figure 5-4, it is shown well log curve for all wells removed from the model (graphs to the right) versus the Hierarchy Geomorphologic SIS model predicted (graphs to the left) with all wells. It is possible to identify a similar response in some wells like W091 and W-119 (Figure 5-4a and b). Thinner intervals were not represented in blind models in general because their lateral extension in limited and they can only exist in the removed wells, but large thicknesses can be reproduced because laterally may be more extent.

W-117 has a big sand package in the opened zone and it was not represented by the blind model (Figure 5-4a), checking their neighborhood it was found that this sand was only present in this well, the nearest wells had retarding rock predominantly and small sand laminates.
5.1.1.3. Truncated Gaussian Simulation Blind Test Model Removing 6 Vertical Wells.

For comparative purposes the layer selected is the same of all the methods, even if the accuracy of this model is 66% for this specific layer, the Figure 5-5 shows a higher degree of correlation between the model with all the wells and the blind test.

In the direction of wells W117 and W-091 and the surroundings of W028 the blind test model is pessimistic (low amount of reservoir rock) compared to all wells model (see the first and the last well intersection showed in the Figure 5-6a and c) in other cases it looks optimistic adding more sands intervals.
Figure 5-5. Lithofacies model layer 19 zone 2, TGS all wells and blind test P50.

Figure 5-6. Well intersection Comparing well lithofacies log and lithofacies model predicted TGS P50.
5.1.1.4. Multiple Point Blind Test Model Removing 6 Vertical Wells

Blind multiple point simulation in Figure 5-7 shows a completely different distribution in unsampled areas. The layer represented in this figure is quite patterned and shows several small laminations in the vertical column (see Figure 5-8).

<table>
<thead>
<tr>
<th>MPS Model Zone 2 layer 19</th>
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<tbody>
<tr>
<td></td>
</tr>
<tr>
<td>P50 all wells</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>Shale (Non Reservoir)</td>
</tr>
<tr>
<td>Reservoir rock</td>
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</tbody>
</table>

Figure 5-7. Lithofacies model layer 19 zone 2, MPS all wells and blind test P50.

Figure 5-8 shows a vertical direction of MPS method, it shows many intercalations in the vertical column in blind test and all wells models. Although around the blind test wells, shows continuity in the sand bodies. This method reproduces only two wells over 50% to 60% and four wells under 50%.
5.1.2. Predictability among Modelling Techniques

Once the lithofacies were generated through all methods, the percentile P50 was selected to build a blind test model of all lithofacies methods. This trial is used to evaluate the predictability of those lithofacies model in unsampled areas, which will be proved with the removed wells.

The percentile P50 in lithofacies modeled methods have different seeds. The goal of this sensitivity is only to evaluate the model by removing the wells keeping other variables equal to the original model. Figure 5-9 shows the histogram which depicts the predictability accuracy of the blind test models comparing to the well lithofacies curves for the 6 removed wells against the synthetic modeled curve created. The highest accuracy was found with SIS hierarchy model, this method predicted two wells.

8 Accuracy:”In measurement of a set, accuracy is closeness of the measurements to a specific value, while precision is the closeness of the measurements to each other”. 
over 70% and two over 60% accurately. In general, it is the most accurate method in this study. Their accuracy is because it uses the sedimentological maps as a second variable which controls directly the lithofacies model.

Other methods obtained diverse results, however they have at least one well predicted with accuracy over 60%. W-119 was the well better represented by the all methods except for MPS method. W-316 was quite similar predicted through all methods, because it is located in a homogeneous area with a good well data information in the neighborhood.

Although the reservoir seems homogeneous globally, when it is evaluated locally the modeled area it is found heterogenous areas, and that zones corresponds with unpredicted wells.

The predictability including a precision ±1 foot of the lithofacies is showed in Figure 5-10. One can understand that the accuracy is how the model was able to reproduce exactly the lithofacies while the precision is how the model was able to predict the lithofacies with an error of 1 foot above or below the “real” value. Notice how the predictability of the model increases from 4% in some cases up to more than 20% in some cases, for example MPS has an important precision percentage in ±1 foot, it might be due to the cyclicity present in this method along the model in vertical and lateral direction (Figure 5-8).

![Facies Percentage Predictability - P50 - Accuracy](image)

**Figure 5-9.** Accuracy among wells for lithofacies distribution methods P50.

![Facies Percentage Predictability - P50 - ±1 foot Precision](image)

**Figure 5-10.** Precision among wells for lithofacies distribution methods P50.
5.2. FACIES DISTRIBUTION IMPACT ON INITIAL OIL RATE IN A HEAVY OIL RESERVOIR

In this section it will be shown the quantification of facies distribution impact on the initial oil rate production.

5.2.1. Facies distribution impact on the initial oil rate in the AOI.

Lithofacies distribution variation along the area modeled is affected by changes of seed as was previously demonstrated (see Section 4.1.7 and 5.1), then properties distribution varies as well and at the end there is an impact in the initial oil rate grid.

Figure 5-11 shows the differences among the lithofacies models at the percentile P50 and these changes are identified in the oil rate grid. Null initial oil rate is represented by magenta color in this figure and it is mainly associated to shale, retarding rock and in some cases thin lamination of reservoir rock intercalated with shales and retarding rock, they are filled by water. Sampled points preserve the same lithofacies in those locations in all models because they are hard data, the evident changes are in unsampled areas. Above 10 bls/d the initial oil rate grid shows green colors and they are distributed according to lithofacies grid.

The oil rate is directly associated to sandy lithofacies with some restriction on porosity and permeability due to the oil viscosity. Those sands over 0.23 porosity and 600 mD of permeability allow easily the flow of this heavy oil through their porous media. Oil production is impaired in porosities and permeabilities up to 0.19 and 90 mD. The reservoir rock represented in the lithofacies model has fine sands with less textural maturity than the rocks which allow some flow of heavy oil.

The facies in each scenario has new properties therefore oil rate production distribution. It means the impact is variable and depends on the lithofacies distribution.

![Figure 5-11. Lithofacies distribution and oil rate grid at layer 19 zone 2.](image-url)
The blind test wells is one way to study the lithofacies distribution in unsampled areas and quantify their impact in oil rate production compared to the observed data.

Using the blind test, it was calculated the initial oil rate for all 6 blind test wells and compared with the observed initial oil production (opened/perforated zones) for each lithofacies modeled methods. Figure 5-12 shows the oil rate obtained by each method.

- Wells with low oil rates like W-117, W-028, W-316 have a strong correlation with the values calculated with SIS and SIS-Hierarchy methods.

- None of the methods can fully represent W-568 well. Some lithofacies are exclusively found in this well, that it is why the blind model cannot represent the well as it is biased mainly on the information coming from horizontal offset wells which are part of the same cluster area, (see Figure 5-13).

- W-091 reference well is represented by SIS hierarchy method (see Figure 5-14). This well is located in highly heterogeneous region and also it is located in a limit of transition lithofacies zone. In this well, it is difficult to predict the sand positioned in the upper part of the reservoir, because the closest wells (W-890H) are showing bad quality rocks (shaly and retarding rocks).

Figure 5-12. Predicted initial oil rate with the blind test model by wells and lithofacies method.
Figure 5-13. Well intersection in the well W-568 SW-NE direction.
Sedimentary Facies distribution Impact on Heavy Oil Production in a Llanos Basin field, Eastern Colombia

Figure 5-14. Well intersection in the well W-091 SW-NE direction.

W-119 Well is located in a well-informed data area, almost homogeneous according to the horizontal wells located in there. Horizontal wells information controlled the blind test model in sampled location. Figure 5-15 shows the lithofacies information in the closest wells to W-119 and it depicts SIS and SIS hierarchy methods which are the best lithofacies methods predicted.
Figure 5-15. Well intersection along the closest wells to the W-119.

Figure 5-16 shows the relationship between the facies predictability – accuracy and precision of P50 case and the initial oil production predictability (Figure 5-16a) and potential oil production predictability (Figure 5-16b) where every point in the graph is related to one of the blind test wells selected.

In general terms, it is observed that it is highly difficult for all the methods to exactly predict the initial oil rate, meaning P50 cases cannot exactly predict the exact amount of sand and rock types per well and per perforated interval. In other words, one can imagine that in the unknown location
a deterministic approach of opening/perforating a selected interval will not fully capture the uncertainty, as the opened interval might have too much sand or shale.

A better correlation of the calculated potential oil rate predictability and the facies predictability increases instead of using initial oil rate. The reason for this is that lithofacies model proportions and their distribution changing seed parameter are kept in all the models. It was found that this is a better way to evaluate the relationship between the oil rate and the facies prediction.

The potential oil rate predictability graph supports the use of sweet spots analysis and as it is not biased by any perforated intervals.

In this study, it is considered that any predictability above 60% is a good approach because even with the heterogeneity that every well has, it is possible to predict its oil range with an acceptable uncertainty. SIS Hierarchy method showed the best predictability correlation with the potential oil rate, meaning that a secondary variable to guide geostatistical models play an important role to increase static model reliability.

Figure 5-16c, represents the centralization of P50 respect P10 and P90, hierarchy model was properly centralized in the high predictability quadrant showing that P10 and P90 facies and potential oil rate are around these values. This proves that the uncertainty workflow proposed in this study was a fundamental step to centralize P50 models in the higher predictability quadrant.

![Figure 5-16. Relationship of facies predictability and oil production predictability.](image-url)
5.2.2. Retarding Rock

Rocks located in the transition between reservoir rock and retarding rock have porosities from 0.18 to 0.22 and permeabilities from 8 to 300 mD. Using the reference values reported in the Figure 5-17 the oil rate was tested changing viscosities and pressure in the transition zone between retarding rock and reservoir.

Figure 5-17 shows how the oil viscosity impacts the oil production rate with different drawdown pressure, a drawdown of 315 psia (near wellbore) has higher oil rate compared to the result using only 1 psia of pressure difference (in the reservoir) at the same viscosity condition.

The result of the retarding rock is evident in these graphs, the oil rate is very low even with low oil viscosity and increase in the oil relative permeability.

Figure 5-17. Retarding Rock - Facies distribution impact on the initial oil rate production in a heavy oil field.

Figure 5-18, is an example of the distribution of the transition between retarding rock and reservoir rock in the surroundings of W-91, this transition belongs to a final part of rock type 6 and the beginnings of rock type 5.
5.3. SWEET SPOTS WITH DIFFERENT FACIES DISTRIBUTION MODELS

This section merges all the work done in this investigation; the sweet spots are the results of: 1) The uncertainty in facies distribution, 2) The proposed geological workflow step using Darcy law, 3) The proposed oil relative methodology that incorporates oil viscosity. It will be shown that missing one the previous steps will generate a bias in the uncertainty.

5.3.1. Geological Approach

From a geological perspective, potential areas are displayed through hydrocarbon pore volume (HCPV) maps. As it was found that the interpolated oil relative permeability (kro,int) methodology helps to calibrate the productivity index and the PI of the wells, the geological approach in this study also incorporates those findings.

Sweet spots also known as heat maps are obtained by multiplying porosity, net thickness (storage capacity), oil saturation, permeability, and the interpolated oil relative permeability. It was observed that HCPV maps if used as a sweet spot parameter are more optimistic that a heat map. The reason is that the permeability and the kro incorporated in the heat map causes an impact in the hydrocarbon maps creating a reduction of oil potential areas while preserving only the highest oil column values, this comparison can be observed in Figure 5-19.

Base on the maps presented in the Figure 5-19, it was identified three prospective areas which are shared among the P50 lithofacies methods (stippled polygons Figure 5-19). The red polygon is the most clear and repetitive area found it among all models even in other percentiles. In this figure also

![Figure 5-18. Retarding rock (stratigraphic baffles)- Facies distribution impact on the oil rate production in a heavy oil field.](image-url)
is highlighted hierarchy geomorphologic SIS model which is the most predictable model according to the analysis previously presented in Figure 5-16.

<table>
<thead>
<tr>
<th>SIS P50 Maps P50</th>
<th>Hierarchy Geomorphologic SIS Maps P50</th>
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</thead>
<tbody>
<tr>
<td>HCPV Map</td>
<td>Heat Map with Kri</td>
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<td>Heat Map with Kri</td>
<td>Heat Map with Kri</td>
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Figure 5-19. Range of possible sweet spots with different facies distribution models, by using geological approach (heat maps with Kroint) and comparison among Hydrocarbon pore volume maps.

5.3.2. Engineering Approach

Figure 5-20 is a compilation of all the geological work and geostatistical uncertainty studies linked with the proposed heavy oil relative permeability and analytical reservoir engineering concepts. This figure shows the results of the workflows proposed in this study.

All percentiles modeled by all method suggest a potential area to the west of the AOI (see Figure 5-20). It is evident how the facies distribution modeled with different methods share some similar regions while there are other regions that all the models show different oil potentials. It is highlighted the Hierarchy model in the figure below as it showed the higher facies and oil predictability, therefore this model can be used as a reference to observe the changes in the sweet spots distribution with other methodologies. Also notice that all methodologies have a calibrated PI in the vertical wells.
5.3.3. **Sweet Spot Techniques Comparison**

The inclusion of the interpolated oil relative permeability impacts the results of the heat map and the productivity index maps filtering more interwell prospective areas. Figure 5-21 shows different scenarios with and without Kroint to highlight the impact of this variable in the sweet spot selection. These maps are the result of the integration of static, dynamic data and the proposed oil relative permeability which clearly shows their impact to identify prospective and potential oil regions. As reference, the map highlighted in red is the one that showed best facies and oil predictability from the uncertainty methodology proposed in this study which includes the modified geological workflow including the Darcy law and the interpolated oil relative permeability.
Finally, This AOI has been drilled in different periods of time from before 2011 to nowadays. Figure 5-22 shows how to use the sweet spots to identify the order of priority to drill wells, starting from the highest to lowest PI respect to average facies.
Figure 5-22. Crossplot average lithofacies versus initial oil rate production.
6. CONCLUSIONS

For the first objective, the following findings were found during the assessment of facies distribution predictability models:

1. The predictability assessment of different facies distribution models showed that the unsampled zones cannot predict the facies in a distance longer than 500 meters when a second attribute does not exist to control the model. When a second attribute is used as a background into the static model, it has more chances to be more predictable of facies and properties in an unknown location.

2. The SIS hierarchy model has the highest facies accuracy. This method predicts more than 70% of two wells and two over 60% accurately. This is because it uses the sedimentological maps as a second variable to directly control the lithofacies model.

3. Seed parameter allows studying areal lithofacies and properties distribution in unknown locations by using different starting points, in this way it is possible to evaluate its uncertainty through hundreds equiprobable models. These models can show the possible facies and properties results in unknown locations, varying their distributions and generating an impact in the oil rate distribution (Appendix G and I). Nevertheless, the seed changes along the models and it keeps the global proportion of lithofacies (it preserves the data input) and it presents variations in STOIIP in the order of 15% (Figure 4-13, Figure 4-17, Figure 4-18 and Figure 4-22).

4. In the selected blind areas, all the facies methods evaluated are not completely predictable, they can represent less than 80% of the lithofacies. It may happen because the high heterogeneity in the unsampled areas and the limitation in each method.

For the second objective in the analysis of facies distribution impact on the initial oil rate was possible to conclude:

1. The SIS Hierarchy was the best lithofacies method that connect lithofacies and oil rate predictability. It has an average precision of 70% (see Figure 5-16).

2. The best correlation identified between oil rate and lithofacies predictability was determined by potential oil rate rather than observed initial oil rate, because the global lithofacies proportions modeled are conserved throughout all static models.

3. One limitation in oil rate predictability is related to reservoir rocks located in the transition zone with retarding rocks, as this zone can have rock type six, which is mainly saturated with water. Reservoir rock lithofacies predictability is not necessarily consistent with oil rate predictability. One example of this is the upper interval opened in W-568 in SIS lithofacies method, it predicted reservoir rock in the well, however it could not reproduce the oil rate in that completed zone, it was obtained only water (Appendix J).

4. It was calculated areally the hypothetical initial oil rate for vertical wells in each grid cell and it was validated by using the initial oil rate reported for the vertical wells (see Figure 4-46, Figure 4-40, and Figure 5-11). This process is simple but powerful step to be added at the end of the static
model workflow as it helps to smooth the transition between static and dynamic models. In addition, this step might avoid unnecessary iterations when building the dynamic models because it can perform a quality control of important parameters such as \(K_h\), relative permeabilities and potential flow of the wells.

For the third objective, through the sweet spot assessment using different facies distribution models was identified the following conclusions:

1. Interpolated oil relative permeability produces an important filtering effect in the sweet spot calculation, highlighting the best oil prospective areas. It is because the interpolated \(K_{ro}\) only selects mobile oil, otherwise the analysis will assume that all oil column is flowing.

2. Geological approach is more optimistic than engineering. It is because the first one uses only static variables and second method integrates the whole workflow implemented in this research (it includes static and dynamic parameters). Through these approaches were possible to identify a sweet spot in the north western part of the area of interest (Figure 5-19 and Figure 5-20) - (Appendix H and I).

3. The priority of oil field development can be done by using a crossplot of oil rate versus average lithofacies (discretized only sand 1 and shale 0). This graph can help to identify the starting point in the highest oil rates and finish in the lowest rates.

This project has other relevant findings that can contribute to the reservoir modeling knowledge.

1. Oil relatives permeabilities are highly sensitive to oil viscosity changes in heavy oil. This study developed a correlation to define an interpolated oil relative permeability by using the laboratory relative permeability end points at different oil viscosities to correlate the information when the data was not available (Figure 4-38 and ¡Error! No se encuentra el origen de la referencia.). These oil relative permeabilities have an important impact on the initial oil rate quantification in the heavy oil system. The proposed oil relative correlation is a relevant component to match the initial oil rate of vertical wells (Figure 4-40).

2. In this study, it was found that Seed is more sensitive than variogram (Figure 4-36), it can be associated to the functionality of each variogram parameter adjusted based on certain geological features as width, length, and direction. Variograms have certain control parameters of the data selected; the seed is not a parameter that is tuned using geologic information rather than a numerical random number.

3. Uncertainty static workflow proposed incorporates a training and base model. They demonstrated the P50 percentile in the hierarchy model was properly centralized in the upper right high precision predictability quadrant showing that P10 and P90 Facies and potential oil rate are around these values.

4. Multiple point simulation for the transitional zones in this field does not work well, it creates unreal artefacts (non geologic trends). It happens mainly in zone 1 and zone 2, in contrast to fluvial zones which are well represented (Figure 4-23 and Figure 4-24). This method requires that the training image selected achieve: stationarity, repeatability, and proportionality to have a good
result in the modelling. The images selected for transitional zones did not cover all these requirements, although they preserved the proportionality in the upscaled logs.

5. Even if there are several horizontal wells covering a big area in the sector selected, its lack of complete set of logs; in these horizontal wells might be increased the uncertainty to model their properties (porosity, permeability, and water saturation), but in unsampled petrophysical properties, lithofacies predominate these zones conditioning the model to represent a property according to the lithofacies.

6. The incorporation of the initial oil rate calculation in the static model workflow and its calibration with observed data helped to understand how the model is preserving the well properties and the oil potential of the whole reservoir column.

RECOMMENDATIONS

- The impact of facies on the oil rate depends on proportion, distribution, and connectivity of sand that accumulates oil, and the fluid barriers such shale, which block or allows the water to flow. It was notice that small laminations with high water saturation might produce high water rates. Future studies can study the impact of those layers and their distribution.

- A baffle is a reservoir engineering concept that applies for those rocks that partially allow pressure communication between regions. In this study, it was properly characterized this kind of rocks as a retarding rock. Future reservoir simulation studies might use the retarding rock concept to identity the impact in oil recovery and water flow behavior.

- Probabilistic models are the best option to evaluate the reservoir potential because those scenarios give the wide number of possible alternatives in unsampled zones depending on the stratigraphic complexity.

- This project works with 1 foot of vertical resolution, it cannot reproduce small laminated intervals (thickness lower than 1 foot) at that scale. Future studies can increase the resolution of the grid to account for these small laminations and study the impact in the fluid flow.
REFERENCES


