International Journal of Sciences: Basic and Applied Research (IJSBAR)

ISSN 2307-4531
(Print & Online)

http://gssrr.org/index.php?journal=JournalOfBasicAndApplied

Investigating the Impact of Different Reservoir Property Modeling Algorithms and Their Associated Uncertainties on Volume Estimation (Gullfaks Field, North Sea)

Benedict Aduomahor[a*], Onyekachi Ibezim[b]

[a]Shell Center of Excellence in Geosciences and Petroleum Engineering, Benin, Nigeria
[b]Department of Earth and Atmospheric Science, University of Manchester, United Kingdom
[a]Email: bennymarose@gmail.com
[b]Email: ibezimonyekachi@gmail.com

Abstract

Reporting reliable results for hydrocarbon volume estimation is important for both economic analyses and making key decisions in reservoir management and development. Adequate facies and petrophysical modeling of static reservoir properties are key inputs for the derivation of a robust static reservoir model from which static volume is computed and inherent uncertainties are quantified. However, the choice of geostatistical algorithm for building the model depend on development and production maturity, degree of reservoir heterogeneity and the type, quality and amount of data. This study therefore aims at investigating the impact of the combination of stochastic and deterministic methods of property modeling on volume estimation and also perform uncertainty and sensitivity analyses to quantify uncertainties so as to aid exploration and production decision making process. Facies model were simulated/generated using both stochastic and deterministic algorithms. The resultant facies model formed an input for the petrophysical modeling process also using both stochastic and deterministic algorithms. For each combination, hydrocarbon pore volume was computed. Monte Carlo Simulation method was used to perform the uncertainty analysis where the low case (P10), mid case (P50) and high case (P90) was outputted. The results show that a combination of Sequential Indicator Simulation (facies) with Sequential Gaussian Simulation (petrophysical) captured a large range of hydrocarbon pore volume for the twenty equiprobable realizations simulated while the combination of Truncated Gaussian Simulation with trend and Gaussian Random Function Simulation gave a limited range.

----

* Corresponding author.

A combination of the deterministic algorithm gave a single estimated and more pessimistic volume. Uncertainty analysis indicated that the facies modeling process and the combination of SIS_SGS algorithm have a higher impact on volumetrics.

Keywords: Gullfaks Field; Volume estimation; Modeling algorithm; Facies/Petrophysical model; Uncertainty/sensitivity analysis.

1. Introduction

1.1 Preamble

Hydrocarbon Volume Estimation is an essential task that must be completed as accurately as possible by any company in the Exploration and Production Industry. It involves a quantitative measurement of the economically recoverable hydrocarbon(s) in a field, area or region. At every stage of hydrocarbon life cycle, reserve volume estimation is key.

Estimating hydrocarbon reserves is a complex process that involves integration of geological, geophysical and engineering data. Although increasing data density almost always results in a concomitant increase in accuracy of estimation, volume estimation still remains a technically uncertain task due mainly to the heterogeneity and dynamism of the earth and earth processes respectively. Uncertainties involved in hydrocarbon volume estimation are elucidated below;

The first level of uncertainty is associated with one-dimensional data such as porosity, hydrocarbon/water saturation and net-to-gross at or near the well bore. The second level of uncertainty arises when one dimensional reservoir properties are extrapolated into two or three dimensions. Such properties as Gross Rock Volume (GRV) are uncertain due to the inherent data uncertainties and assumptions giving every reservoir model a more apt description as a simplified representation of the complex geological/rock/fluid system obtainable beneath the earth surface. The third level of technical uncertainty is associated with the volume estimation process itself. Shortcomings in estimation procedures and algorithms literally compound imperfections in the reservoir model.

Using the Gullfaks Field in the Northern North Sea rift system as a case study, the project shows how different combinations of property modeling algorithms capture uncertainties in static volume estimation, thereby making recommendations on the most appropriate geoststistical algorithms combination suitable for volumetrics at the different phases of hydrocarbon asset life. Uncertainty and sensitivity analyses were also quantified.

1.2 Problem Statement

The Gullfaks Field is an intensely deformed area, the deformation is so intense it was described as the most complex area so far developed in Norwegian waters [[5]]Using fault patterns and geometry and their associated bedding geometry, [[1]]divided the field into two structurally distinct sub-areas; a major domino area and an eastern horst complex. In between both areas, they identified an accommodation zone. Notable in the Gullfaks Field however is that its structural and stratigraphic complexity is only matched by the prolific nature of its reservoirs (initial recoverable reserves of 2.1 billion barrels, $330*10^6 m^3$).

Geostatistical studies of the stratigraphic sequences are requisite tools in making fair predictions of the reservoir properties away from well control points and thereby aiding the exploitation of the huge potential of the reservoirs. In this integrated project, a reservoir model was estimated using various combinations of property modeling algorithms for discrete (facies) and continuous (petrophysical) properties. Uncertainties associated with these algorithms as well as the sensitivity of some input data which could aid accuracy of the computed volume were also estimated.

1.3 Study area

The Gullfaks giant oil field lies within (**Error! Reference source not found.**)the Norwegian license PL 050 in block 34/10 at 61^0N and2^0E in the Norwegian sector of the North Sea ([4]). The Gullfaks Field was discovered in 1978 and was set on production in1986. It is one of the largest oil producing fields in Norway.

The Gullfaks field covers an area of 51km^2 with water depths ranging from 135 to 220m. It is located in the central part of the East Shetland Basin on the northern North Sea Graben and represents the shallowest structural element in the Tampen spur, bounded to the east by the East Shetland platform and to the west by the Viking graben [[5]]. The Gullfaks contains reservoirs in the Brent Group, Cook formation, Statfjord Formation and Lunde Formation. The Brent Group contains about 73% of oil in place with moderate to very good reservoir properties. The large number of faults in the area has led to differences in lithology with each formation resulting in a reservoir with complex geology

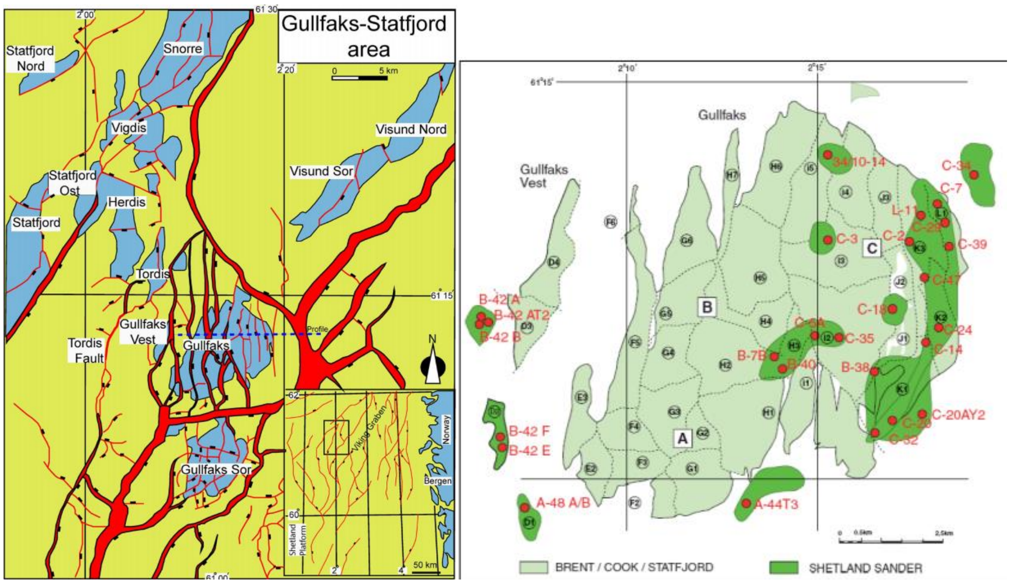

Figure I: Location of the Gullfaks field and map of segments in the Gullfaks field

1.4 Geology of the Area

The Gullfaks Field is characterized by two structurally contrasting compartments; a western domino system with typical domino-style fault block geometry and a deeply eroded western horst complex of elevated sub-horizontal layers and steep fault. Between these two zones is a modified accommodation zone (Graben System), identified as a modified fold structure ([1]). The domino area is the main area of the Gullfaks Field. The deformation in this part of the field has resulted in a series of generally N-S-trending faults. These faults (main faults) have displacements of 50-500m. Dips here are unusually low (25-30^0 to the east) whereas the sedimentary strata dip gently, typically about 15^0 to the west. Also, in this area, there are minor faults with throws less than 50m. These faults have an overall E-W trend. The

Eastern Horst Complex has faults steeper than is obtainable in the domino area. Dips of about 60-70^0 are common and both E and W dipping faults occur. The main faults here (more planar than in the domino area) are N-S trending. Jurassic sediments seen clearly (good reflectors) in the main part of Gullfaks are eroded here. This accounts for the poor sedimentation in the eastern portion of the Gullfaks Field. In terms of stratigraphy, the producing reservoirs of interest in the Gullfaks Field are the delta Sandstones of the Middle Jurassic Brent Group (most important), the shallow-marine Lower Jurassic Cook Formation and the fluvial-channel and delta-plain Lower Jurrassic Statfjord Formation. The Brent Group is made up of five Formations from the base to the top is thus; Broom, Rannoch, Etive, Nesss and Tarbert. Often times, the Brent Deltaic wave system is interpreted to be of fluvial-wave interaction. The Brent Group is of mainly Bajocian-Early Bathonian (Broom Formation is Aalenian in age) age forms the upper and main part of the reservoirs. It is sub-divided into the Broom (8-12m), Rannoch (50-90m), Etive (15-40m), Ness (85-110m) and Tarbert (75-105m) Formations, all deposited in a deltaic environment. A broad lithological sub-division can be made between Shaly Ness Formation and sandy intervals below and above [[1]].

1.5 Petroleum Potential of the Area

The North Sea is a marginal sea of the Atlantic Ocean with its location depicted in (Figure I). It is one of the most prolific petroleum basins in the world and contains majority of the UK's fields and discoveries. The oil and gas accumulations occur in a variety of structural settings and within reservoir rocks of several of ages, but almost all originated from shales that were deposited during a relatively brief stratigraphic interval encompassing Late Jurassic to earliest Cretaceous time [[10]]. Ranked as a giant by world standards, Gullfaks is one of the largest discoveries on the north-west European continental shelf.

2. Materials and Methods

This paper is an integrated project that takes into account inputs from key subsurface disciplines; Geology, Geophysics and Petrophysics/Petroleum Engineering. A succinct disambiguation of the methodology is given below.

- Data loading and QC
- Build a robust stratigraphic framework
- Seismic interpretation (horizons, faults)
- Generate synthetics and maps (isochore, facies, reservoir, depth and time structure maps, attributes map)
- Create a 3D structural grid model of the Gullfaks field using stochastic and deterministic algorithm
- Populating 3D facies models generated with petrophysical properties using
- Compute volumes for every chosen algorithm
- Run uncertainty analysis using Monte Carlo simulation.

A generalized workflow (Figure II), colour-coded (Blue-Geophysics, Green-Geology, Purple-Petrophysics/Petroleum Engineering, Orange-Multidiscipline) to indicate input from specific disciplines is shown below;

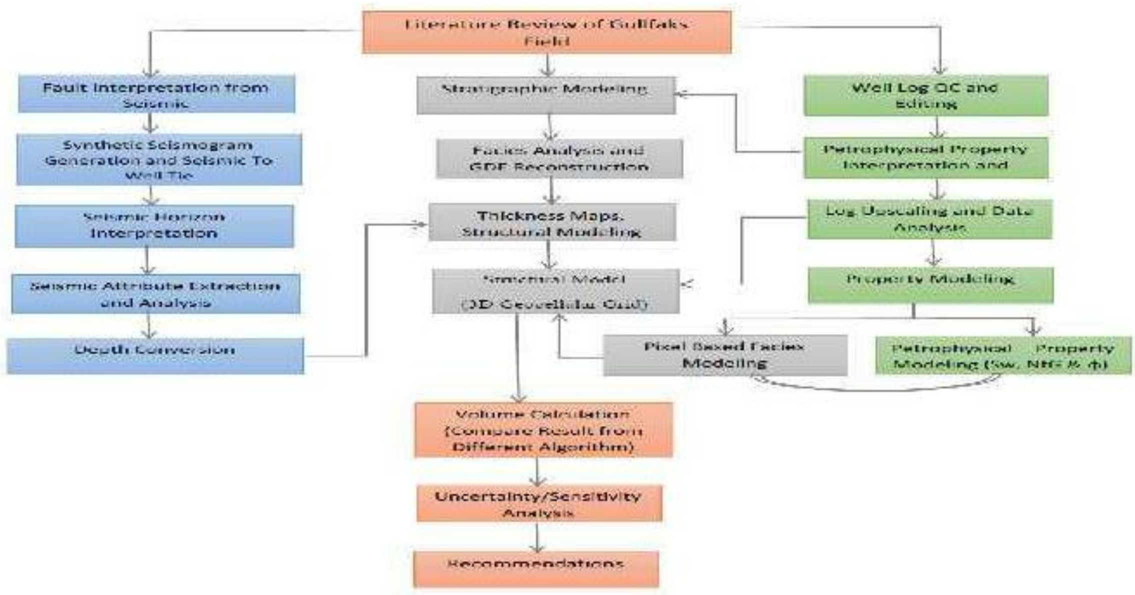

Figure II: Generalized Project workflow

The data used for this project are; Gullfaks 3D Seismic data, Checkshot data and well log data from 13 wells. The tools used are PETREL 2014 and TECHLOG 2014. (*All data provided by Software Integrated Solution*

(SIS) Schlumberger NGA).

2.1 Stratigraphic Modeling

This segment was geared towards building the framework of the stratigraphy of the field. Facies analysis here involved studying the reservoir using well data and other available data to build a contextual knowledge of the middle Jurassic Brent group (mainly Etive, Ness and Tarbert Formations) as seen in the wells. In this segment, a robust understanding of the stratigraphy of the field was built by establishing the strike and dip of the field, lithologic identification, robust well log correlation, lithologic thickness maps and establishment of environment of deposition and gross depositional environment. Three reservoirs from the shallowest; Etive, Ness and Tarbert were identified in the wells and correlated

2.2 Seismic Interpretation

Seismic Interpretation is the extraction of subsurface geologic information from seismic data. Structural and stratigraphic information are key areas of focus during this process. Faults and horizons which are basic input for a robust structural model are the product of this process. Quintessential steps/sub-processes followed here include; synthetic seismogram generation and well to seismic tie, fault interpretation, horizon interpretation, depth conversion and seismic attribute extraction and analyses.

2.3 Structural Modeling

Structural Modeling involves creation of a digital model of a reservoir. In the process, we sought to imitate the architecture and structuration of the reservoir, therefore 'bringing the subsurface closer'. Structural Modeling is the center-piece of the project as it is the model we built here that we later populated with properties (discrete and continuous) so as to make volume estimation possible. For this model, we used the Structural **Framework** Process (Figure III). The creation of a model using Structural. Framework Process can be closely linked to seismic interpretation, allowing models to be built on the fly in a "Modeling While Interpreting" workflow. The objective here is to facilitate the creation of structurally correct. Interpretation. The Structural Framework Process is a novel process in PETREL. It builds the 3D model in such a way that the volume of interest is shaped as a cube. The structural gridding process is the process that converts the reservoir framework into a 3D geocellular mode. The procedures are shown below.

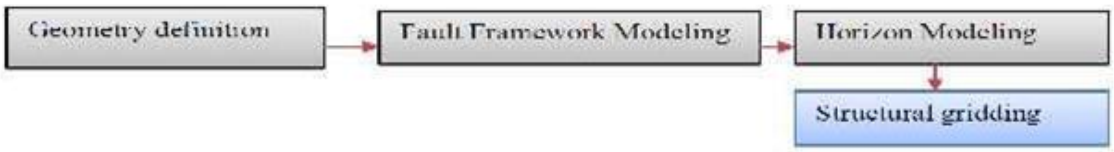

Figure III: Structural Modeling Workflow

2.4 3-D Property Modeling

This is the process of filling cells of the 3D grid with discrete and or continuous properties. The goal is to use all geological information available to build a realistic property model. The ultimate reason for building a reservoir model is to maximize the value of data by incorporating all available information into a quantitative digital representation. The objective of Property Modeling is to enable you to distribute properties between the available wells while preserving the realistic reservoir heterogeneity and matching the well data. Efficient exploitation of reserves requires a more sophisticated approach to account for tectonics, complex sedimentary and diagenetic processes that have formed reservoirs. Reservoirs are heterogeneous units occurring at every scale and the need for accurate characterization is essential for economic planning. Statistical models offers insight into the level of uncertainty and heterogeneities through multiple realizations of static models. Reservoir models for this study are defined in two major scales:

a) Large scale structures definition of the geology through the use of structural interpretation from seismic and well log information. This aims to recognize depositional units, define the geometry relationship, and interpolate intelligently between wells.
b) Use geostatistical techniques to define small scale structures. This is to define the heterogeneities within each depositional unit earlier defined and to provide missing information away from well control points.

A notable step to achieving a robust property model is **scale up well log process** (well log upscaling). This step involves averaging of well log data into 3D grid cells. Well logs needed for the modeling process are upscaled into the 3D grid to assign values to cells that are penetrated by the wells. Upscaling shown in (Figure IV) is done because the grid cells can only be assigned a single value hence the upscaling of the well logs (lower sampling rate) into the 3D grid cells (larger sampling rate).

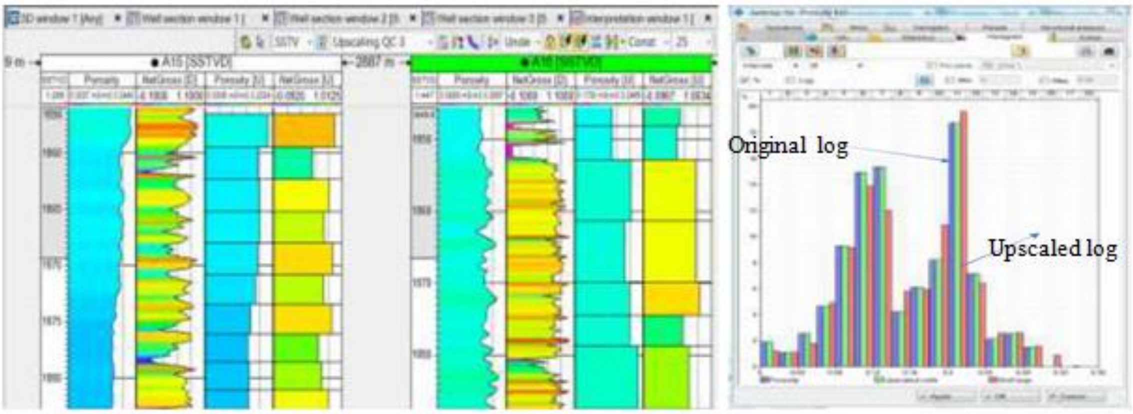

Figure IV: Upscaled porosity and net-to-gross logs on two wells. Histogram serves as QC for accurate upscaling

It is noteworthy to point out at this juncture that paucity of data for this project meant that some key logs required for petrophysical modeling such as water saturation logs and net-to-gross logs were generated using **Artificial Neural Network (ANN).** For the few wells that possessed the required log suites, ANN was still done as a way to Quality Check the derived logs for the wells without the requisite logs. Geostatistical techniques employed to demystify reservoir complexity are broadly divided into stochastic and deterministic methods. Deterministic techniques are relatively faster to run and used when dense data are available (many wells, seismic + wells). It yields a single estimated result i.e. a realization and this makes it difficult to understand the degree of uncertainty in the model [[9]]. Stochastic techniques are used when sparse data are present yielding hypothetical results based on the input data. They generate multiple realizations which help in understanding the degree of uncertainty in the model. Stochastic techniques also honor data variability [[9]]. Below is a (Table I) of the Stochastic and Deterministic algorithms used for both the facies (discrete) and petrophysical (continuous) properties.

Table I: one-stop view of the methodology and algorithms employed for property modeling in this paper

Geostatistical Method	**Facies Modeling Algorithms**	**Petrophysical Modeling Algorithms**
Stochastic Method	Sequential Indicator Simulation (SIS)	Sequential Gaussian Simulation (SGS)
	Truncated Gaussian Simulation (TGS) with trend	Gaussian Random Function Simulation (GRFS)
Deterministic Method	Indicator Kriging	Co-Kriging

2.5 Uncertainty/Sensitivity Analysis

Monte Carlo simulation as a process was used to run the model numerous times with a random selection from the input distributions for each variable ([2]). The results of these numerous scenarios gave a "most likely" case, along with a statistical distribution to understand the risk or uncertainty involved. Monte Carlo. simulation is an alternative to both single-point (deterministic) estimation and the scenario approach that presents worst-case, most-likely, and best-case scenarios. A full Monte Carlo run (”combined run”) was sampled for each loop, one value for each of the distributions and volumes were computed. When this was done N times, then a final volume distribution emerged. To investigate the relative influence of each of the uncertain variables, the sensitivity run was chosen. A sensitivity plot shows the influence of each of the uncertain parameters, comparing the relative influence of each of the parameters on modeling and volumetrics ([3]).

3. Results

3.1 Well Log Correlation and Sequence Stratigraphy

Three reservoirs (Etive, Ness and Tarbert) reservoirs all belonging to the Brent Group were from the logs and these were correlated lithologically across both strike (NE-SW) and dip (NW-SE) directions. Using an integration of sequence stratigraphy, structural stratigraphic framework and the interpretation of log motifs (stacking patterns of facies) within and the across field and previous literature, depositional environments were delineated for the rock units. Well B9 (shown below) was the type well from whence correlation was carried across the field. Dominant environments of deposition are; Upper Shoreface-Red, Mouthbar Complex-Light blue, Marine-Green, Shallow Marine-pink, Overbank Deposits-Orange and Distributary Channels-Cyan.Without enough data, Sequence Stratigraphic correlation based mainly on a proposed biostratigraphic chat of the Brent Group [1] was also done (Figure V).

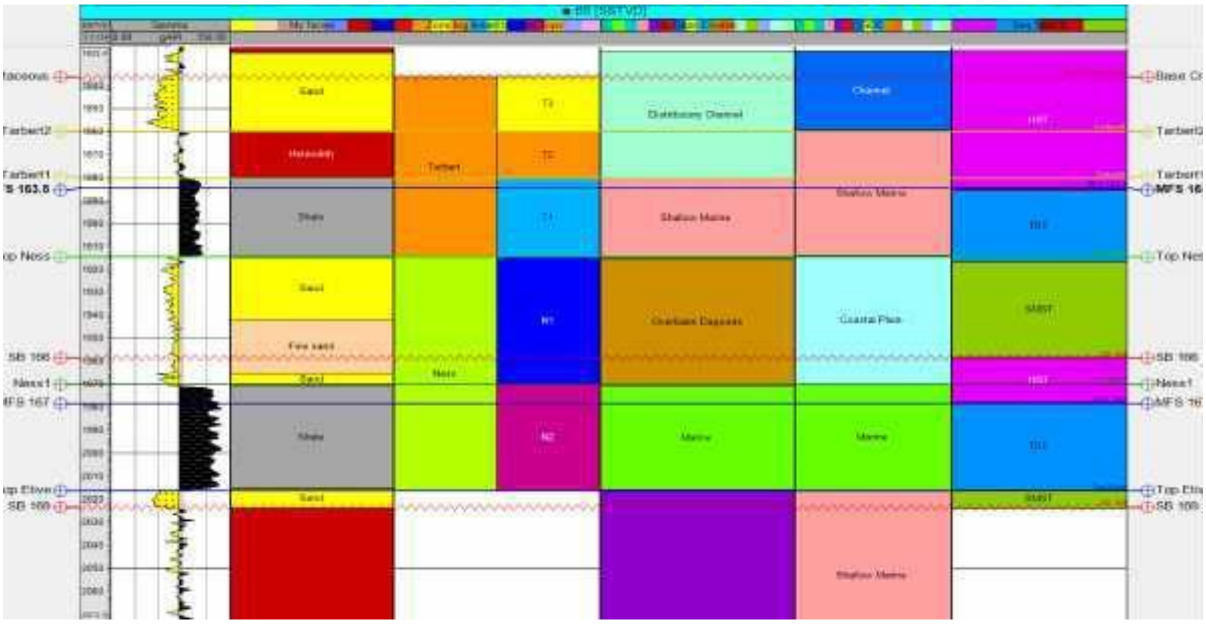

Figure V: Well B9 showing (from first track) Gamma ray log, lithologic units, Formations, Zones, Environment, of Deposition, Gross Depositional Environment and Well log sequence stratigraphy

3.2 Seismic Interpretation

The needed faults and horizons needed to build a structural model were derived from seismic through this process. These horizons already identified as reservoirs in the well logs were identifiable on the 3D seismic data owing to a robust and good tie gotten from the domain reconciliation process, well-to-seismic tie carried out. The well to seismic tie is shown below in (Figure VI)

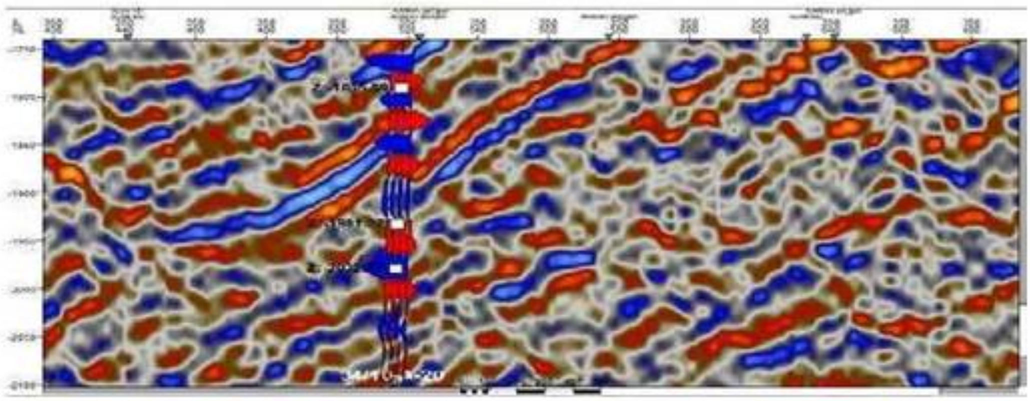

Figure VI: Well 34/10-A-20 seismic to well tie

3.3 Structural Modeling

Three horizons and twenty-one faults were interpreted on the seismic were used to build a robust reservoir model. It should be noted however that beyond this point, only the shallowest reservoir (Tarbert reservoir) was used and volume estimation, uncertainty analysis and sensitivity analysis all considered this reservoir alone. The model (Figure VII) it should be noted is an “empty” 3D geocellular model until property modeling process is used to populate its cells.

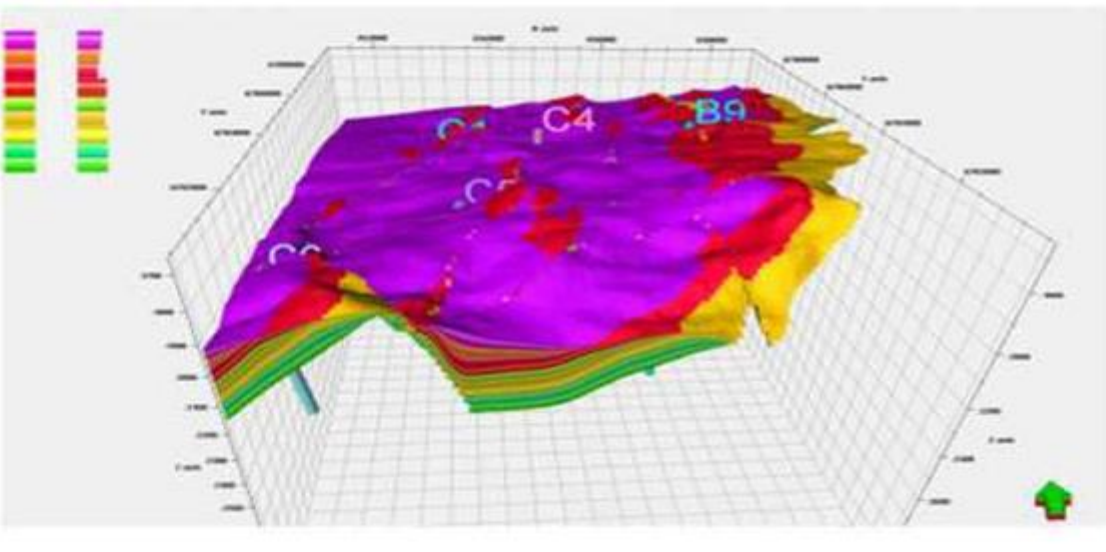

Figure VII: Structural Model of the Gullfaks Field

3.4 Property Modeling

Property modeling in this project was done rather iteratively in this project using various algorithms and algorithms combination to generate volumes of hydrocarbons. The chart below (Figure VIII) summarises the different combinations (Facies modeling algorithms and Petrophysical Modeling algorithms) of the different algorithms as used in this project.

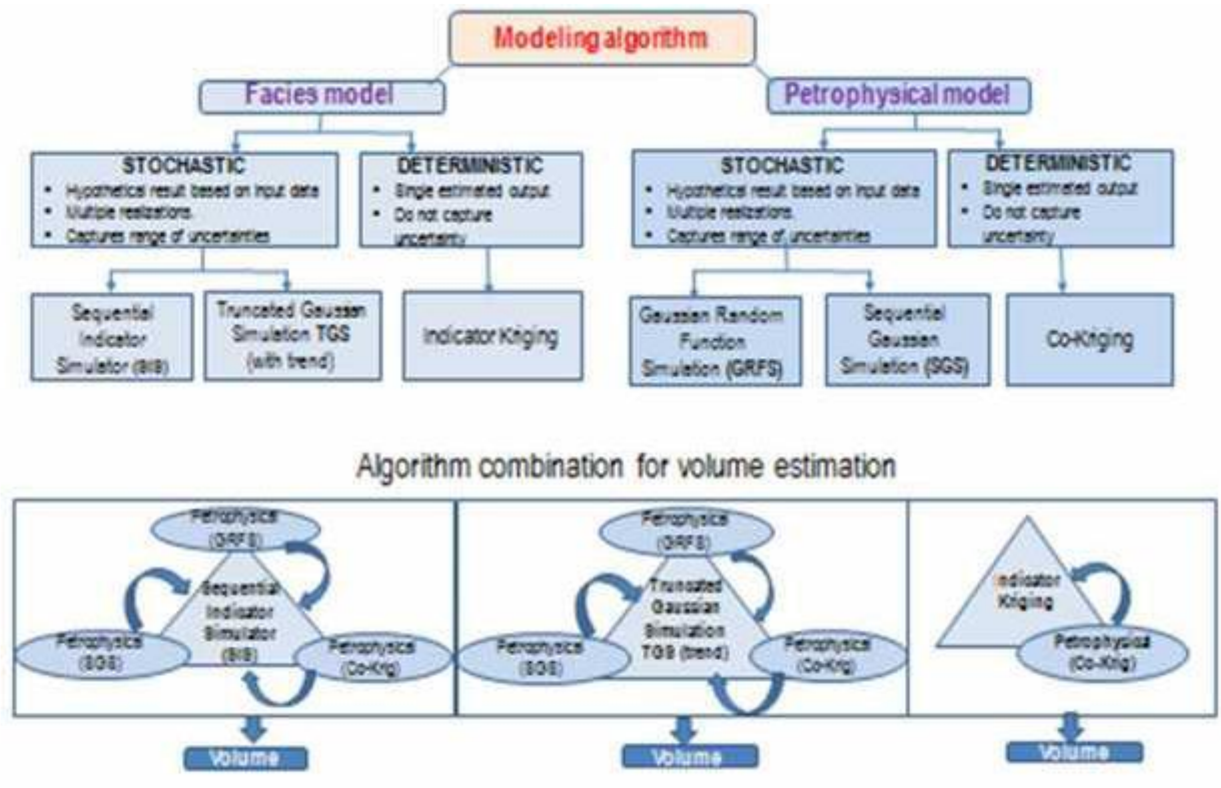

Figure VIII: Property modeling for this project at a glance

Three realizations were derived in this project for all the stochastic algorithms used in the Facies Modeling portion of the property modeling. The deterministic algorithms though produce a single result. For the stochastic facies model, three realizations were derived but only one of the realizations (Figure IX) was used as an input into the petrophysical modeling process. In the pertopysical modeling stage, net-to-gross, porosity and water saturation models were all generated as a prerequisite to volume computation. The outputted grids of the Facies Modeling process were used as inputs to the Petrophysical Modeling process are seen below

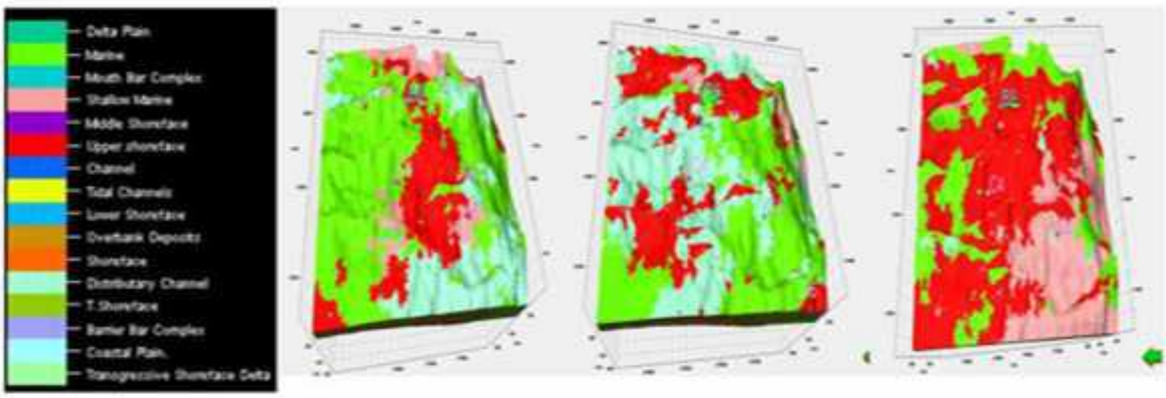

Figure IX: (L-R); SIS Realizations 1, 2 and 3.

The Hydrocarbon pore volume of the Tarbert reservoir was generated using realization 3. The TGS with trend algorithm was built based on a conceptual mode of the subsurface. The Tarbert reservoir which was deposited during a relative sea level rise (transgressive events) where in the upper Brent deltaic sequence retreated southwards [**Error! Reference source not found.**].

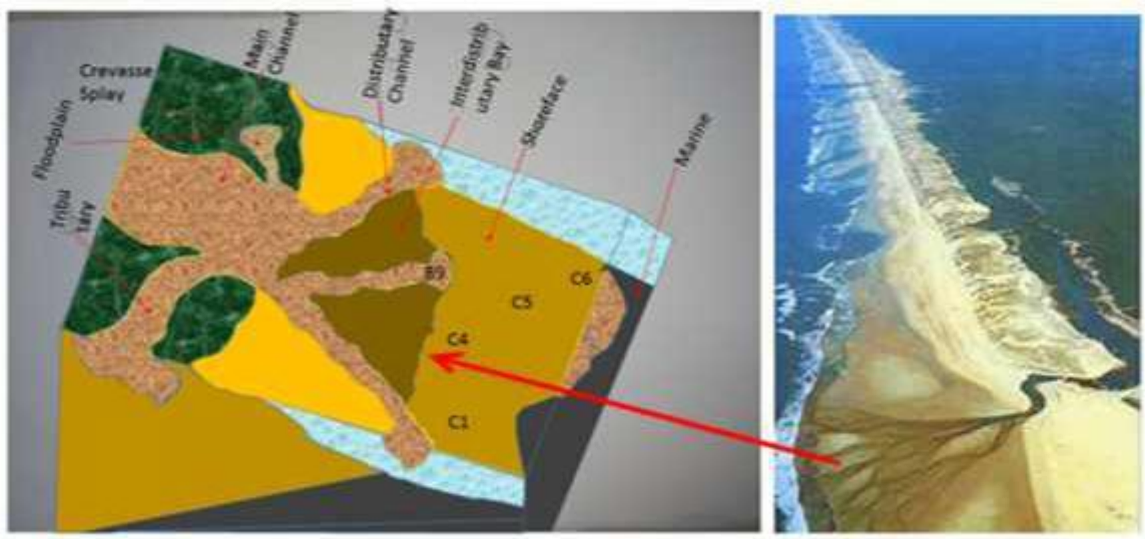

Figure X: Conceptual model of the upper Brent sequence and a picture of a possible surface equivalent

With the TGS with trend algorithm, the model below was built and three realizations were gotten;

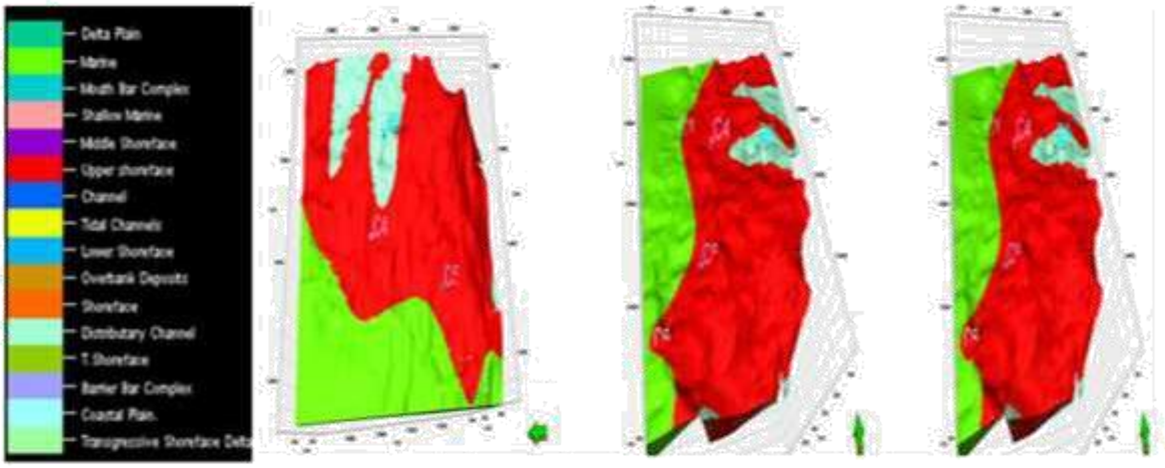

Figure XI: Realizations 1, 2 and 3 from TGS with trend algorithm

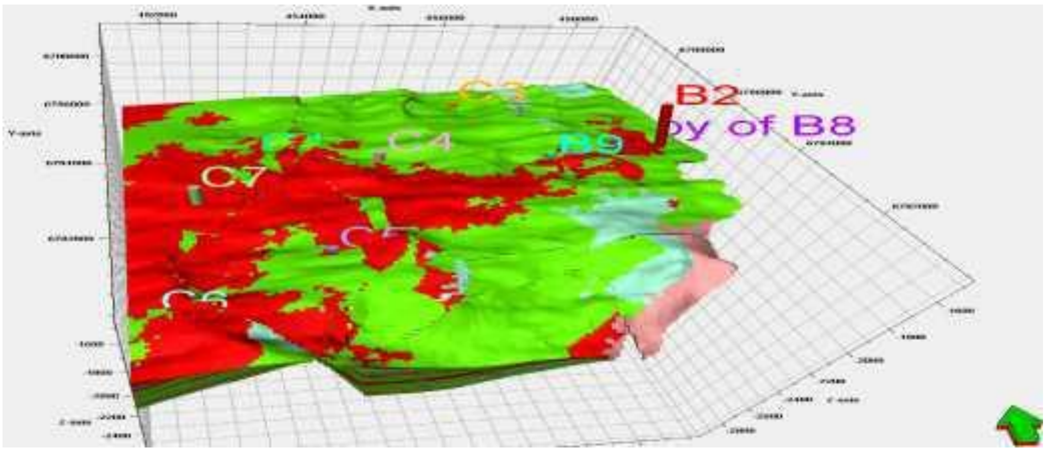

Figure XII: Facies model using Indicator Kriging

The porosity, net to gross and water saturation model of the Tarbert reservoir were simulated using facies model generated from the SIS, TGS with trend and Indicator Kriging algorithm respectively as input. This gave a prepared platform for which volume estimation was done. The output of the petrophysical model simulation is displayed below.

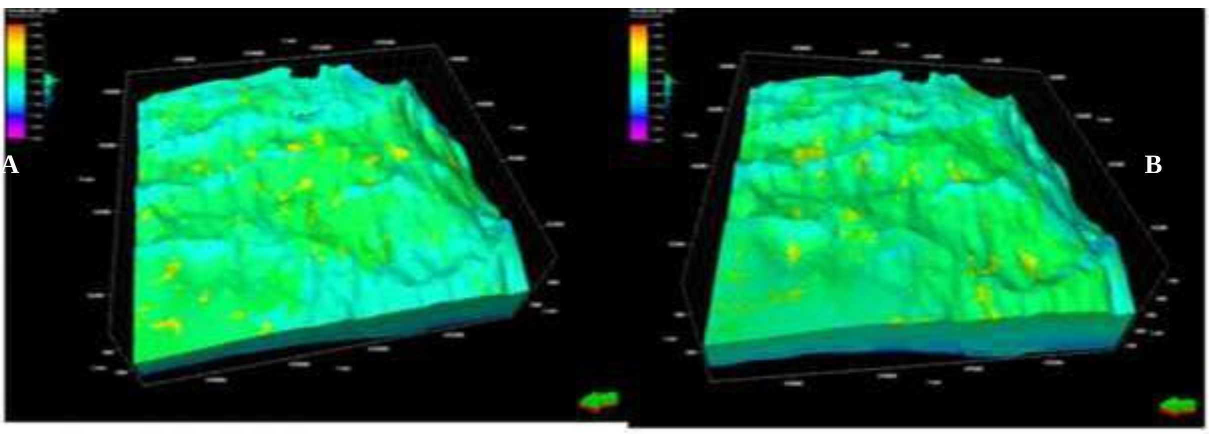

Figure XIII: porosity model using A) SGS algorithm and B) GRFS algorithm on SIS facies model

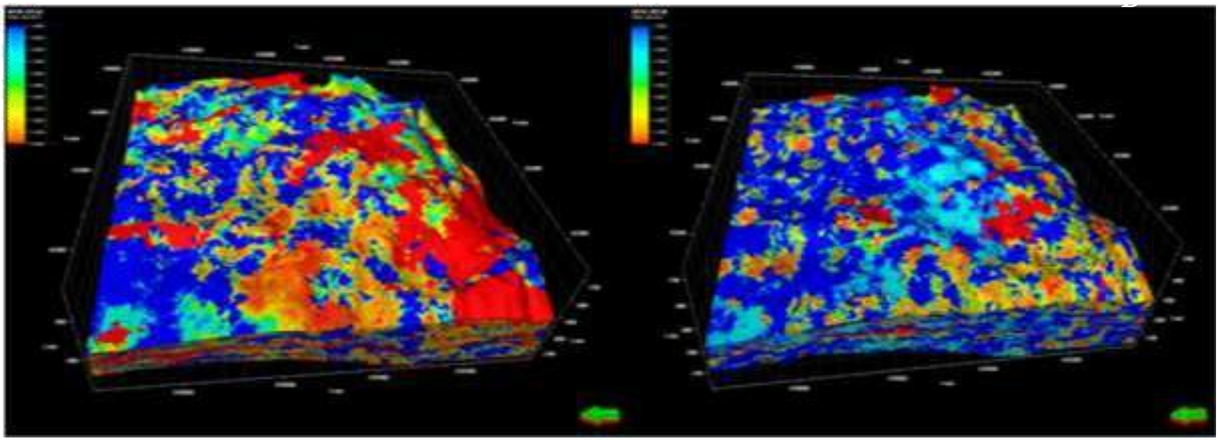

Figure XIV: Water saturation models using (a) SGS algorithm and (b) GRFS algorithm on SIS facies model

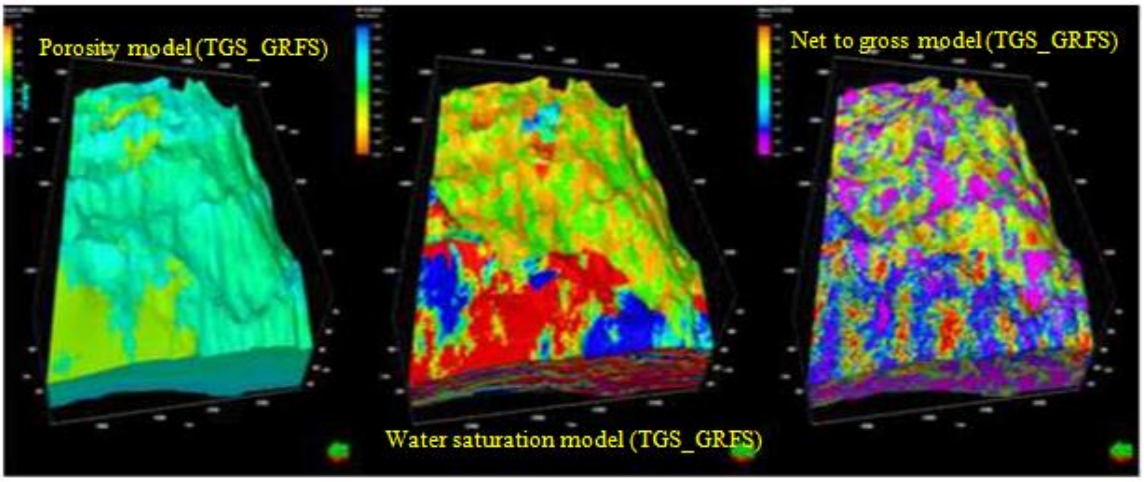

Figure XV: TGS_GRFS models

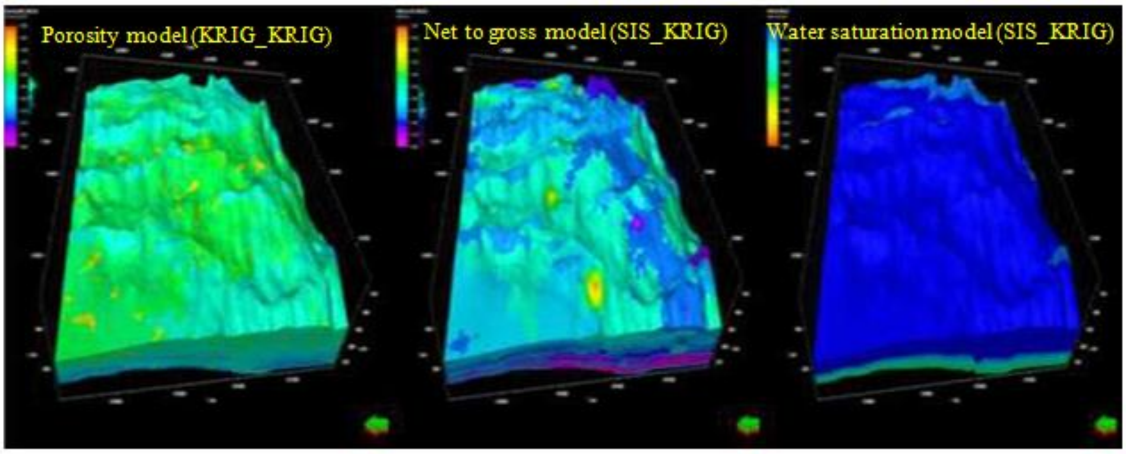

Figure XVI: Co-Kriging models

3.5 Volume Estimation

Hydrocarbon pore volume (HCPV) was computed for the unique combination of the facies and petrophysical modeling algorithm. The table below (Table II) summarizes the hydrocarbon pore volume derived for twenty realizations of the stochastic algorithm which are SIS and TGS with trend as well as the single outputted value of the deterministic algorithm.

Table II: Volumetric Output for each unique combination of property modeling algorithms

HYDROCARBON PORE VOLUME (HCPV) X10^6m3							
Realizations	SIS_KRIG	SIS_SGS	SIS_GRFS	TGS_KRIG	TGS_GRFS	TGS_SGS	KRIG_KRIG
1	40	35	70	36	42	36	37
2	36	89	54	40	38	73	0
3	37	78	68	37	44	74	0
4	37	65	61	35	34	69	0
5	40	36	35	37	36	40	0
6	38	91	67	39	41	44	0
7	39	71	81	41	49	46	0
8	36	89	51	40	54	64	0
9	43	101	60	37	40	45	0
10	40	75	37	39	47	66	0
11	37	53	70	39	36	58	0
12	39	67	59	40	50	74	0
13	38	80	69	37	64	70	0
14	39	103	66	38	56	51	0
15	42	88	70	39	65	71	0
16	41	79	58	38	44	53	0
17	36	58	68	36	62	52	0
18	40	65	65	42	69	36	0
19	40	42	71	37	46	43	0
20	36	36	66	39	49	37	0
RANGE	7	68	41	6	33	38	37

3.6 Uncertainty Analysis

A full Monte Carlo run (”combined run”) was sampled for each loop, one value for each of the distributions and volumes were computed. When this was done N times, a final volume distribution emerged.

The sensitivity plot shows the influence of each of the uncertain parameters, comparing the relative influence of each of the parameters on modeling and volumetrics. The result of the uncertainty analysis is as shown below using the histogram distribution and the tornado plot.

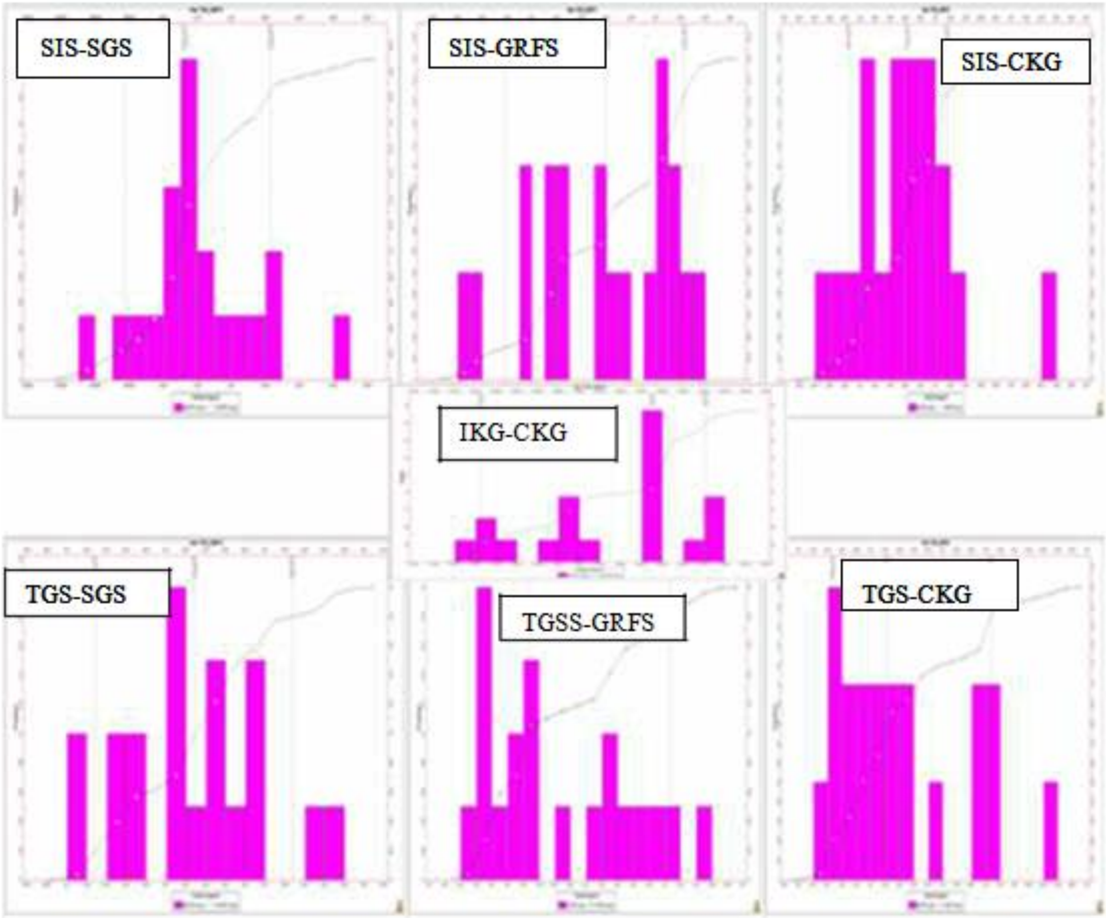

Figure XVII: Results for Uncertainty Analyses

Table III: Summarized result of P10, P50 and P90 ranking from uncertainty analysis

ALGORITHM COMBINATION	P10	P50	P90
SIS_KRIG	36	38	42
SIS_SGS	40	74	100
SIS_GRFS	39	65	70
TGS_KRIG	35	38	40
TGS_GRFS	36	46	63
TGS_SGS	38	64	73
KRIG_KRIG	37	37	37

3.7 Sensitivity Analysis

Sensitivity analysis was done in order to ascertain the relative impact of the different combined algorithm on hydrocarbon pore volume. The result is as seem in the tornado plot below.

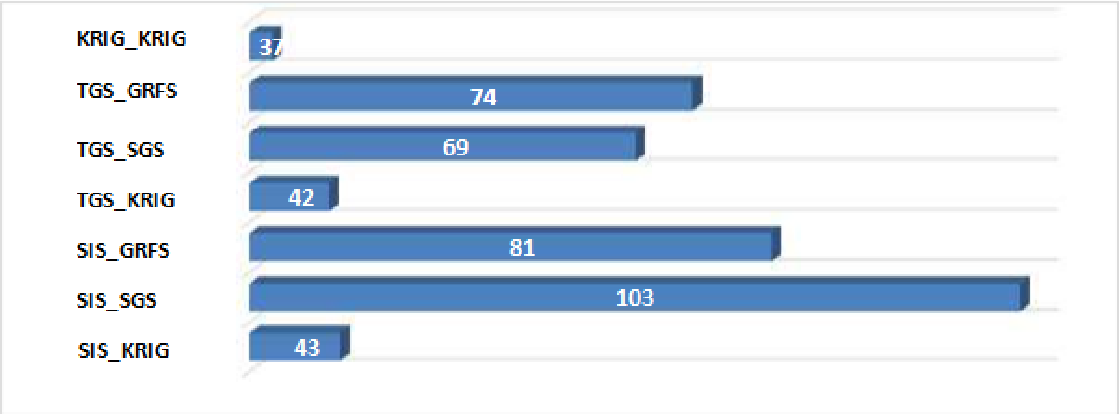

Figure XVIII: Tornado Plot of the range of volumes captured by the various modeling algorithm

Also, three (3) different processes were investigated with respect to their influence on HCPV oil. They are the make contact, facies modeling and petrophysical modeling process. The output is presented below:

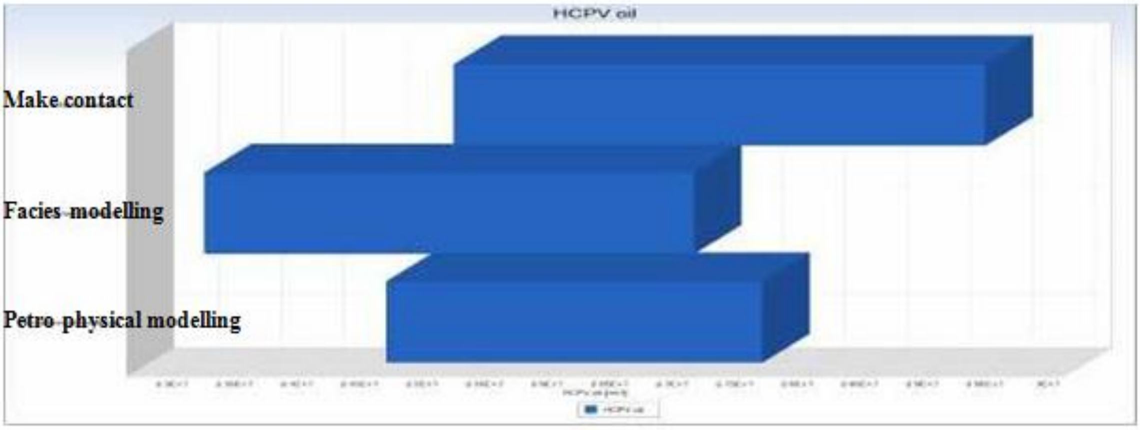

Figure XIX: Tornado Plot of the range of volumes captured by the various modeling process

4. Discussion

Sequential Indicator Simulation (SIS) is inherently a more 'uncertain' algorithm compared to the Truncated Gaussian Simulation with trend (TGS). This is due to the fact that it works on an undefined concept of environment of deposition while the TGS is more restrained, its data interpolation is constrained by the environment of deposition. This by extension means that the range of uncertainty derived from the combination of TGS with any petrophysical modeling algorithm is smaller than the range of an uncertainty derived from a combination of a SIS with any petrophysical modeling algorithm. The effect of the robust conceptual model constraining the TGS is also seen when looking at the equiprobable facies (realizations) produced by the TGS algorithm as the realizations have very subtle differences that are barely noticeable at first glance at the model. The environments of deposition i.e. Distributary Channel (blue), Upper Shoreface (red) and Marine (green) have very similar spatial relationship as opposed to what is obtainable in the SIS realizations. In the SIS realizations, the spatial relationship of the environments of deposition are markedly different. The extent of the environments and their boundaries are not as defined as in the case of TGS. Krigging gave a pessimistic value as the marine environment is a lot more abundant in the model produced. Marine environment is increased due to the smoothening effect associated with deterministic algorithms and this affects the facies reconstruction as the proportions of the most extended facies categories (marine) is increased. In petrophysical modeling, Sequential Gaussian Simulation (SGS) was noticed to compute rather slowly compared to Gaussian Random Function Simulation (GRFS). This is because it takes its time to do a sequential computation of the variables inputed and thereby capturing a wider range of uncertainty. This sequential approach is precisely the main difference between GRFS and SGS. GRFS computes randomly and faster thereby capturing a lower range of uncertainty. This explains why the combination of GRFS with any facies modeling algorithm has a lower range of uncertainty compared to a combination of SGS and the same algorithm. This is seen in the result (Table II) seen above. From the Monte Carlo Simulation volumes generated we see that the combination of SIS_SGS modeling algorithm gave the overall largest range of volumes capturing extreme values and the natural heterogeneity of the reservoir closely followed by the SIS_GRFS, next was the TGS_SGS and then the TGS_GRFS approach. While the kriging methods gives one single estimated volume, the principal goal of kriging is to produce the best result in term of local accuracy. The combination of SIS_SGS gave the largest range of uncertainty because both algorithms follow a sequential pattern. SIS uses upscaled cells as basis for fraction of facies types to be modeled. The variogram constrains the distribution and connectedness of each facies type. It is widely used to model facies with unclear or undefined shapes, or when few input data are available, like in this case study. For SGS, it uses a simple and mathematically stable algorithm it does not reproduce the input variance as accurately giving it flexibility, these combination helps to capture extreme values both maximum and minimum, but it is typically slower. They are both stochastic. The combination of TGS-GRFS gave a considerable large range of uncertainty because TGS with Trends is a fast modeling technique which is able to generate large scale geometries through construction of a close facies relationship, typically used to model unconstrained environment like transition between the different types of facies. While the GRFS is a novel Petrel developed algorithm for Gaussian Simulation, it is a non-sequential algorithm which is very fast. It accurately honors input data, input distribution, variograms and trends. They are both stochastic, which are good for accurate work in good timing. A combination of Indicator Kriging/ Co-kriging which are both deterministic algorithms gives the best locally accurate and smooth models this is done by interpolating well data. But it does not capture spatial variability it produces a single model and output a pessimistic volume which can be used for Field Development Planning (FDP). In wells where there are no important logs like resistivity log, Artificial Neural Network is proven as an option which can be safely used to generate logs with minimal error. For modeling porosity and net-to-gross, the SGS and GRFS is best suited, as stochastic simulations, the result made use of a random seed number and multiple representations are needed to gain an understanding of the uncertainty. It captures properly the range of uncertainty and property distribution across the 3D grid.

Among all the four methods used for water saturation, only the Co-Kriging algorithm honours data 100% at well point, input distributions, variograms, and trends, it is able to estimate a large amount of points through a combination of multi-threading and smart neighbourhood searching, it uses the closest input point for each unsampled location which makes it very useful for modeling continuous property like water saturation. The Collocated Co-Kriging gave a better separation of the reservoir fluid into the water zone and hydrocarbon zone and they also gave better prediction of water saturation at the lower part of the reservoir.

5. Conclusion

Reserve Estimation is a vital part of Exploration and Production Business decision making. Acting as a 'spring-board' for E&P key business decision, it encapsulates the portfolio of any E&P company and hence, the importance of correctly estimating volumes of reserves cannot be over-emphasized. Be that as it may, volume estimation remains a very 'uncertain task' due to the heterogeneity of earth processes. To compute this volume, various algorithms, underpinned by geoscientific and engineering practices have been developed over time to reduce the possible errors associated with hydrocarbon volume estimation. Unique combinations of both the facies and petrophysical modeling algorithm have been used to build various realizations of static models and volumes were computed, which were subjected to Monte Carlo Simulation giving us a range of volume for each unique combination, then P10, P50, P90 can be identified and used for Field Development Plan (FDP). This was used to capture the range of uncertainties in the models. Different combinations which includes Sequential Indicator Simulation (SIS) combined with Sequential Gaussian Simulation (SGS) / Gaussian Random Function Simulation(GRFS)/ Kriging, Truncated Gaussian Simulation with Trend (TGS) combined with Sequential Gaussian Simulation/ Gaussian Random Function Simulation(GRFS)/ Kriging, and Indicator Kriging combined with kriging/ Co-Kriging making using the Gullfaks Field as case-study. The results of the combinations are seen in table 2 and a sensitivity analysis plotted in a tornado chat in (Figure XVIII) was used was used to show the range of uncertainties captured by each combination of algorithms. The second tornado (Figure XIX) shows how the processes involved in volume estimation affect the estimated volume. This it should be noted only shows how the make contact, facies modeling and petrophysical modeling affects volumetrics (quantity of hydrocarbon) but not the range of uncertainties associated with each combination of algorithms. The result as seen in (Figure XIX) shows that the make contact process have more impact on HCPV relative to the facies and petrophysical modeling process. This can be attributed largely to the absence of capillary pressure data which is requisite for building a saturation height model and defining accurate depth pressure profile for which fluid contact can be established with high degree of certainty and accuracy. Key recommendations are stated below and captures the uniqueness and relevance of this study which is aimed at aiding key management decisions in the E and P industry amidst the presence of uncertainties which arise from data quality and interpretation, structural and stratigraphic models, multiple realizations from stochastic algorithm choice and its parameters all of which introduce high technical uncertainties on volume estimation. Today, many E&P companies are riding high up, in affluence and influence far above many other companies in various other industries. They did not get there by hoisting themselves up on an elevator, neither did they defy gravity to get to where they are, they are simply riding on the backs of their reserves, a run way for them to soar far above the chasing pack hence, Volume Estimation is serious business!.

5.1 Recommendations

Throughout the various stages of hydrocarbon life cycle it is recommended to use an appropriate combination of algorithms. The recommendations below are based on the result of the study. At the exploration stage, a combination of SIS-SGS is preferred because of the paucity of data at that phase and it also offers the ability to capture all possible range of uncertainties (realizations from the available data). This is confirmed from the wide range of volume outputted for this combination as evidence in (Table II). Both algorithms are computed sequentially. For this combination, SIS variogram constrains the distribution and connectedness of each facies type and it is widely used to model facies with unclear or undefined shape. SGS is a simple and mathematically stable algorithm it does not reproduce the input variance as accurately thereby giving it flexibility. This combination helps to capture extreme values both maximum and minimum, but it is typically slower. At the Appraisal stage when more data are coming in and the conceptual model can be defined, it is preferred to use the combination of TGS-GRFS. This combination gave a considerable large range of uncertainty because TGS follows a suitable conceptual model which at the appraisal stage must have been understood due to a denser collection of data which then inherently reduces some of the uncertainties posed in the exploration phase. This project for example was done with TGS with trend because the environment of deposition was understood to be retrogradational (transgressive) environment. GRFS on the other hand is a non-sequential algorithm which accurately honors input data, input distribution, variograms and trends. At the development stage where there is expected to be a data abundance, the combination of both deterministic algorithm, kriging-kriging is preferred because it gives the most accurate and smooth local estimate and whose function has a unique solution and does not attempt to represent the actual variability of the studied attribute (variability it should be noted comes from the variograms, trends, input distribution and probability). The smoothing property of this interpolation algorithm replaces local detail with a good average value. It is also point specific, does not capture spatial variability, produces a single model and output a pessimistic volume which can be used for field development planning (FDP). Generally, in order to capture heterogeneity and range of uncertainties in the data available the stochastic methods or algorithms are recommended.

References

[1]. Yielding, G., Overland, J. A., & Byberg, G., (1999) Characterization of fault zones for reservoir modelling: an example from the Gullfaks Field, northern North Sea. Bull AAPG 83:925–951Fossen, H, and Hesthammer, J, “Structural Geology of the Gullfaks Field, Northern North Sea”. Special Publication-Geological Society of London, 231-262, 2001

[2]. Francis J.T and Martin R.H.E “Uncertainty Estimation in Volumetrics for Supporting E & P Decision Making” (Netherland Institute of Applied Geoscience, Delft), 2011.

[3]. Geoff .B.M., “Stochastic Simulation and Reservoir Modeling Workflow” (C&PE 940), 2005b

[4]. https://en.m.wikipedia.org/wiki/Gullfaks_oil_field

[5]. Petterson, O., Storli, A., Ljosland, E. & Massie, I., “The Gullfaks Field: Geology and Reservoir Development. North Sea Oil and Gas Reservoirs - H. Norwegian Institute of Technology. Graham & Trotman, London, 67-90, 1990.

[6]. Schlumberger Petrel Manuals; Property modelling 2013, Petrel Geology 2014, Petrel Geophysics

2013, Velocity modeling 2011 and Structural Modeling 2012

[7]. Shepherd, M., “Geostatistical Methods”, in M. Shepherd, Oil field production geology: AAPG Memoir 91, p. 159-174, 2009.

[8]. Steel, R. J. and Ryseth, A. "The Triassic early Jurassic succession in the Northern North Sea: Megasequence Stratigraphy and Intra-Triassic Tectonics”. In: Tectonic-Events Responsible for Britain's Oil and Gas Reserves (Eds R. F. Hardman and J. Brooks). Spec. Publ. Geol. Soc. London **55**: p139–168, 1990.

[9]. Udeze C., “Modeling Petrophysical Property Variations in Reservoir Sand Bodies Using Artificial Neural Net and Object Based Techniques; Gullfaks Field, North Sea. Society of Petroleum Engineers, SPE NAICE 2015

[10]. USGS Bulletin 2202-C, Kimmeridgian Shales Total Petroleum System of the North Sea Graben Province