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ESTIMATION OF LOG PROPERTIES USING SEISMIC ATTRIBUTES

QUAID-I-AZAM UNIVERSITY
ISLAMABAD

By

ABDUL MALIK
M.Sc. GEOPHYSICS
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In the name of Allah,
The most Beneficent, the most Merciful.

I found Whose Favors always with me,

Only the mistakes have been mine.

Certificate

This dissertation by ABDUL MALIK is accepted in its present form by the Department of Earth Sciences, Quaid-e-Azam University, Islamabad as satisfying the thesis requirement for the award of M.Sc degree in Geophysics.

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Dedicated to

Hazrat Muhammad (PBUH)

CONTENTS

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Abdul Malik

Abstract

A systematic reservoir property mapping work flow is descried that integrates logs and seismic data using neural network base techniques. Seismic attributes are extracted and analyzed both qualitatively and quantitatively for being the best descriptive reservoir properties. The relationship between the the petrophysical property obtained through logs and seismic attributes is determined by using various iterations for quality matrix and calibration function. This relationship is further put in next to mapping of reservoir mapping guided by seismic attributes.

This Geostatistical approaches is applied to Aurora Greek data acquired in North Sea acquired by the "Schlumberger".

CHAPTER # 1

INTRODUCTION TO THE PROJECT

Introduction to Project

Most of the productive reservoirs area discovered throughout the world in the structures located in offshore. In this particular, the given data set also belongs to same geologic system. However, the information pertaining to the data set is brief, i.e., as follows;

1.1: Data Inventory and Description

Project data is based upon real data that was collected from Schlumberger SiS. It comprises interpretation of potential horizons and faults over the prospect area based upon a 3d seismic surveys as shown in figure 1. The least information on interpretation of horizons in terms of time-picks on seismic is available, i.e., shown in figure 2. Besides, all the stratigraphic and geologic information is obscured.

1.2: Surveys Information

Project has a 3d survey located as under:

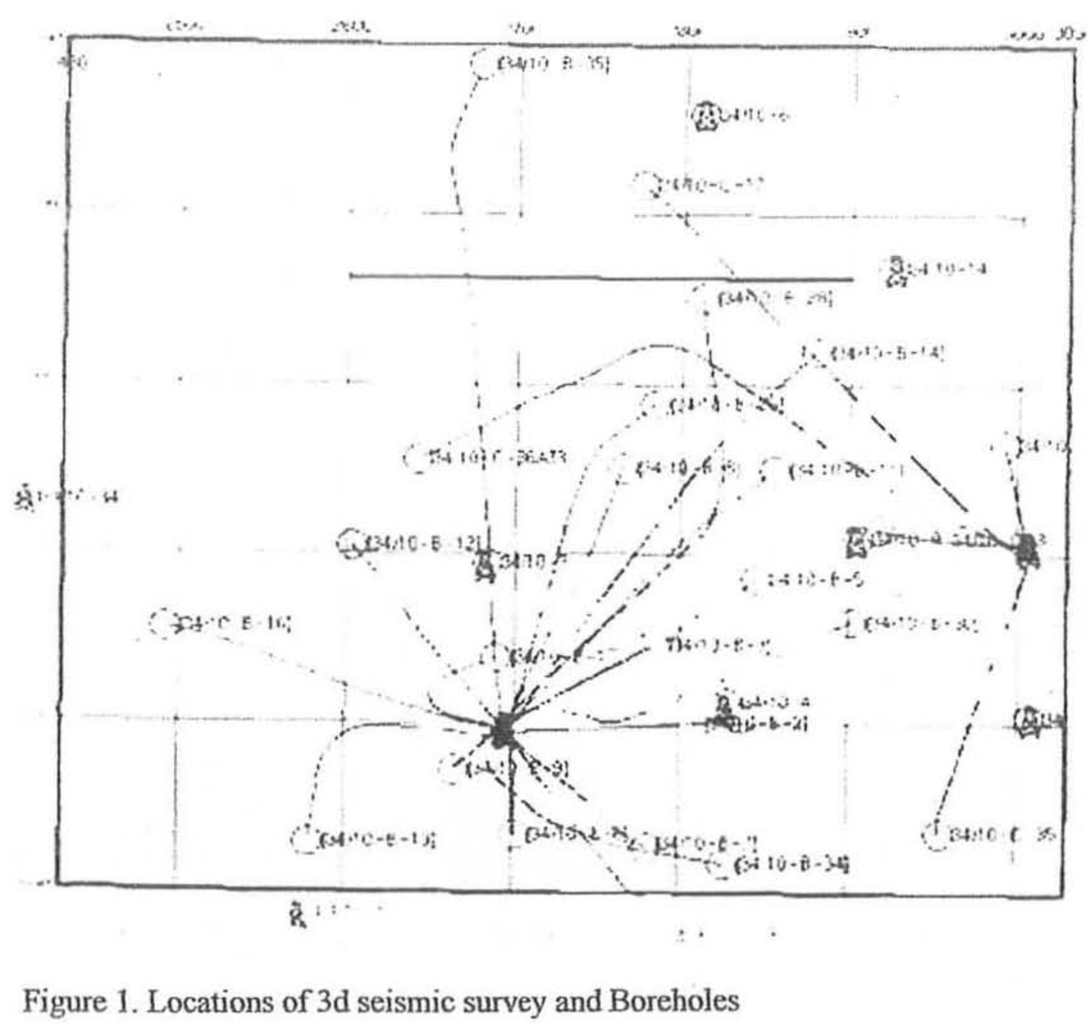


Figure 1. Locations of 3d seismic survey and Boreholes

As the major technologic target of the area is the mapping of porosity of the reservoir. Special softwares have been used to compute the petrophysical properties through available Open hole logs. As it goes further, Seismic Attributes have been calculated over the 3d seismic within the reservoir bounded by NESS and RANNOCH horizons.

1.3 Interpretation Information

Whereas, interpretation along the seismic horizons is given in table.

Layer Name	Borehole Name	Top Marker	Top MD (m)	Top TVD (m)	Bottom Marker	Bottom MD (m)	Bottom TVD (m)	Gross Porosity TVD (m3/m3)
NESS	34/10-1	NESS	1781.72	1781.61	RANNOCH	1872.2	1872.08	0.255172
NESS	34/10-14	NESS	1907.91	1907.85	RANNOCH	2002.7	2002.63	0.264726
NESS	34/10-3	NESS	1904.53	1904.53	RANNOCH	2002.4	2002.4	0.262439
NESS	34/10-34	NESS	2081.5	2081.4	RANNOCH	2188.3	2188.16	0.250053
NESS	34/10-5	NESS	1970.3	1970.25	RANNOCH	2070.3	2070.2	0.276039
NESS	34/10-6	NESS	2105.67	2105.59	RANNOCH	2197.3	2197.22	0.267406
NESS	34/10-8	NESS	1868	1867.9	RANNOCH	2006.8	2006.63	0.257392
NESS	34/10-9	NESS	1832.88	1832.77	RANNOCH	1868.2	1868.07	0.279949
NESS	34/10-B-11	NESS	3232.5	1902.16	RANNOCH	3263.04	1917.36	0.251883
NESS	34/10-B-12	NESS	2803	2122.02	RANNOCH	2931	2234.31	0.205395
NESS	34/10-B-13	NESS	3023.83	2036.46	RANNOCH	3185.33	2141.49	0.245255
NESS	34/10-B-14	NESS	3696.66	1929	RANNOCH	3933.95	1998.64	0.250703
NESS	34/10-B-16	NESS	3461.77	2223.47	RANNOCH	3792.43	2404.3	0.170451
NESS	34/10-B-17	NESS	2367.07	1977.86	RANNOCH	2537.77	2032.76	0.226013
NESS	34/10-B-2	NESS	2476.41	1906.45	RANNOCH	2561	1940.98	0.267401
NESS	34/10-B-26	NESS	3568.7	2095.73	RANNOCH	3725	2187.59	0.194907
NESS	34/10-B-3	NESS	2327.5	2021.65	RANNOCH	2460.5	2105.94	0.216274
NESS	34/10-B-30	NESS	2524.81	1863.57	RANNOCH	2862.21	1868.18	0.257375
NESS	34/10-B-34	NESS	2482.82	1899.27	RANNOCH	2876.71	1913.16	0.251406
NESS	34/10-B-35	NESS	5407.96	2167.4	RANNOCH	5672.25	2250.66	0.204784
NESS	34/10-B-4	NESS	2504.5	1848.23	RANNOCH	2540	1866.3	0.291369
NESS	34/10-B-5	NESS	2865	1878.75	RANNOCH	2931	1911.51	0.288768
NESS	34/10-B-6	NESS	2161.5	1966.30	RANNOCH	2242.5	2036.71	0.244517
NESS	34/10-B-8	NESS	2767	2058.5	RANNOCH	2964.5	2145.92	0.241607
NESS	34/10-B-9	NESS	2090.5	1984.35	RANNOCH	2200.5	2104.59	0.232384

Figure 2 Seismic interpretation horizons and Geological Markers

1.4: Faults Interpretation

Fault interpretation is also given and briefly included here just as being part of the salt regime. Also, these faults are of prime importance in making of traps for potential reservoirs.

1.5: Objective Oriented Reservoir Description

Sand is in the NESS and RANNOCH are very thin – but due to expensive normal faulting total reservoir is divided in pockets but over all this interval is potentially promising. Known reservoir Porosities at well locations serve pivotal position by being consistent across the area. For further development of field it's essential to know the porosity through out the surveys area to have more production wells drilled with confidence. (Walls, Taner, Guidish, Taylor, Dumas and Derzhi, 1999)

1.6: Information provided Vs Goal and Way Forward

All the provided data mainly emphasizes the structurally interpreted reservoir and so forth wells drilled with considerable production. Since the reservoir exists in highly faulted regime so if reservoir characteristics are to be known with more confidence, we can employ some geostatistical technique which could take a seismic property and real measured control from the well and establish a relationship which could be further propagated over the area to know the property in with precision.

Therefore, with the available information, we have made use of live technique of petroleum industry to map property by guidance of seismic attribute by Geostatistical Methods.

Since the method of mapping employs geostatistical techniques in building a relation between logs based reservoir properties and seismic attributes so all such fundamental entities are discussed for a thorough background.

CHAPTER # 2

SIGNIFICANCE OF LOGS AND SEISMIC DATA

CHAPTER 2

SIGNIFICANCE OF LOGS AND SEISMIC DATA

2.1: INTRODUCTION:

A log is a recording of physical or chemical properties of the rocks and fluids versus depth penetrated by drilling the well. A log is defined as "A *record of measurements and observations made in the borehole*". Instruments used in the borehole measure the properties of rocks and operation of these instruments is called *well logging*. The strip chart, on which measurement made, is called *well log*. Interpretation can be done in terms of formation characteristics, lithology, resistivity, formation factor, bulk density, porosity and permeability, and hydrocarbons contents. Correlation of subsurface conditions can be done from one well to another with the help of logs (Keys & MacCary, 1976)

Open hole logs are created by remote sensing equipment lowered into a hole drilled with a rotary or percussion-drilling rig. Cased hole logs are run after the well is cased to assess the current state of the reservoir, to check the mechanical integrity of the casing, tubing, or cement, and to monitor fluid flow.

2.2: DIFFERENT KINDS OF LOG:

Most frequent recorded logs in hydrocarbon exploration are called open hole logs. The name open hole is applied because these logs are recorded in the uncased portion of the well bore. Open hole logs are created by remote sensing equipment lowered into a hole drilled with a rotary or percussion-drilling rig. Cased hole logs are run after the well is cased to assess the current state of the reservoir, to check the mechanical integrity of the casing, tubing, or cement, and to monitor fluid flow. The two primary parameters determined from well logs measurements are porosity, and the fraction of pore space filled with hydrocarbons. The parameters of log interpretation are determined both directly or inferred indirectly, and are measured by one of three general types of logs:

(1) Electrical

(2) Nuclear

(3) Acoustic or Sonic.

The names refer to the sources used to obtain the measurements. The different sources create records (logs), which contain one, or more curves related to some property in the rock surrounding the well bore.

USES OF WELL LOGGING:

Well logging is used to determine the Reservoirs parameters i.e. water saturation, porosity and permeability, Hydrocarbons detection, Lithology, Borehole conditions, Temperature gradient, Structural and Stratigraphic interpretation, Correlation with other wells.

2.3: *ROCK PROPERTIES AND THEIR EFFECT ON LOGGING:*

Rock properties or characteristics that affect logging measurements are:

2.3.1: Porosity: It is the percentage of void spaces to the total volume of rock. It is measured as a percent and has the symbol Ø. The amount of internal space or voids in a given volume of rock is measure of the amount of fluids a rock will hold. The amount of void space that is interconnected, and so able to transmit fluids, is called effective porosity. Isolated pores and pore volume occupied by adsorbed water are excluded from a definition of effective porosity.

2.3.2: Permeability: It is the property a rock has to transmit fluids. It is related to porosity but is not always dependent upon it. Permeability is controlled by the size of the connecting passages (pore throats or capillaries) between pores. It is measured in Darcies or milidarcies and is represented by the symbol K_a. The ability of a rock to transmit a single fluid when it is 100% saturated with that fluid is called *absolute permeability* while the *Effective permeability* refers to the presence of two fluids in a rock, and is the ability of the rock to transmit a fluid in the presence of another fluid when the two fluids are immiscible. *Relative permeability* is the ratio between effective permeability of fluid at partial saturation, and the permeability at 100% saturation (absolute permeability).

*2.3.3: **Water saturation:*** It is the percentage of pore volume in a rock, which is occupied by formation water. Water saturation is measured in percent and has the symbol S_w.

Water saturation represents an important log interpretation concept because you can determine the hydrocarbon saturation of a reservoir by subtracting water saturation from the value, one (where 1.0 = 100% water saturation). Irreducible water saturation or $S_{w\ irr}$ is the term used to describe the water saturation at which all the water is adsorbed on the grains in a rock, or is held in the capillaries by capillary pressure. At irreducible water saturation, water will not move, and the relative permeability to water equals zero.

*2.3.4: **Resistivity:*** It is the rock property on which the entire science of logging first developed. Resistance is the inherent property of all materials, regardless of their shape and size, to resist the flow of an electric current. Resistivity is the measurement of resistance; the reciprocal of resistivity is conductivity. In log interpretation, hydrocarbons, the rock, and freshwater all act as insulators and are, therefore, non-conductive and highly resistive to electric flow. The unit of measure used for the conductor is a cube of the formation one meter on each edge. The measured units are ohm-meter^2 / meter, and are called ohmmeters.

$$R = Ar/L$$

Where:

R = resistivity (ohm-meter)

r = resistance (ohms)

A = cross sectional area of substance being measured (meters^2):

L = length of substance being measured (meters)

Resistivity is a basic measurement of a reservoir's fluid saturation and is a function of porosity, type of fluid (i.e. hydrocarbons, salt or fresh water), and type of rock.

2.4: WELL LOGGING TECHNIQUES:

2.4.1: *SPONTANEOUS POTENTIAL LOGS:*

The spontaneous potential (SP) log is used to identify impermeable zones such as shale, and permeable zones such as sand. The SP is a record of direct current (DC) voltage differences between the naturally occurring potential of a moveable electrode in the well bore, and the potential of a fixed electrode located at the surface. It is measured in milli volts.

Uses:

SP log is used in detection of permeable beds, boundaries of hydrocarbon containing formations, formation water resistivity (R_w), the volume of shale in permeable strata.

2.4.2: *RESISTIVITY LOGS:*

Resistivity logs are electrical logs, which are used to determine hydrocarbon versus water-bearing zones, to indicate permeable zones, and determination of resistivity porosity.

USE OF RESISTIVITY LOGS:

The most significant use of resistivity logs is to determine hydrocarbon versus water-bearing zones. Because the rock's matrix or grains are non-conductive, the ability of the rock to transmit a current is almost entirely a function of water in the pores. The resistivity of rocks is depending upon (a) effective porosity. (b) Salinity of formation and the quantity of hydrocarbons contained in the pore spaces.

Hydrocarbons, like the rock's matrix, are non-conductive and therefore, as the hydrocarbon saturation of the pores increases, the rock's resistivity also increases and on other hand resistivity decrease by increase the effective porosity and salinity.

2.4.3: POROSITY LOGS

Porosity logs are following types;

❶Sonic log

❷Density log

❸Neutron log

❹Sonic Log

A Sonic log is a porosity log that measures interval transit time ($_{\Delta}t$) of a compressional sound wave traveling through one foot of formation. Interval transit time ($_{\Delta}t$) in microseconds per foot is the reciprocal of the velocity of a compressional sound wave in feet per second. Formula for converting velocity to transit or acoustic travel time is:

$$T=10^6/V$$

V= velocity in ft/sec

T= acoustic travel time in micro-sec/ft

2.4.4: DENSITY LOG:

The Density log is a porosity log that measures electron density of a formation.

USES:

It is used in Identifying evaporite minerals, in the detection gas-bearing zones, to determine hydrocarbon density and to evaluate shaly sand reservoirs and complex lithologies.

2.4.5: NEUTRON LOGS:

Neutron logs are porosity logs that measure the hydrogen ion concentration in a formation. In clean formations (i.e. shale-free) where the porosity is filled with water or oil, the neutron logs measures liquid-filled porosity. Whenever pores are filled with gas rather than oil or water, neutron porosity will be lowered. This occurs because there is less concentration of hydrogen in gas compared to oil or water. A lowering of neutron porosity by gas is called *gas effect.* With the help of Neutron log reading, we can distinguish between the fluid filled pore space and solid matrix in the potential hydrocarbon formation. Neutron log is very helpful delineating the gas zone as compare with other porosity logs.

2.4.6: *GAMMA RAY LOGS:*

Gamma ray logs measure natural radioactivity in formations and because of this measurement, they can be used for identifying lithologies and for correlating zones. Shale-free sandstones and carbonates have low concentrations of radioactive material, and give low gamma ray readings. As shale content increases, the gamma ray log response increases because of the concentration of radioactive material in shale. (Keys & MacCary, 1976).

USES OF GR LOGGING:

The gamma ray log is used for defining shaly beds when SP curve is rounded; it is also used for measuring volume of shale of the zones or beds and .for the correlation in cased holes.

2.5: LOG: KEY TO A RESERVOIR

Using logs following parameter of hydrocarbon bearing formation can be formation calculated altogether average porosity (Phi_{av}), average volume of shale (Vsh_{av}), average water saturation (Sw_{av}), net pay thickness (H), productive area (A).

2.6: SEISMIC DATA IN TERM OF SEISMIC ATTRIBUTES

All measured quantities obtained from seismic data are called '*Seismic Attributes*'. These include complex trace attributes, velocities, offset-varying attributes, bedding patterns, their continuity characteristics, etc. Historically these attributes have been used at various stages of processing and interpretation. The Computation and Interpretive use of Seismic Attribute Consortium investigates their quantitative use in the interpretation process.

Seismic attributes may be defined as "all the information obtained from seismic data, either by direct measurements or by logical or experience based reasoning." (Taner, 1998)

Seismic Attributes provide important additional information to the interpreter by enhancing the sensitivity of seismic data to specific structural, stratigraphic or reservoir features. In addition, seismic attributes are a required input to more sophisticated attribute based classification methods, such as Seismic Facies Analysis.

2.7: OVERVIEW OF CHARISMA ATTRIBUTES:

There a many seismic attributes used as to indicate specific reservoir parameters but in brief a few of attributes are described with their importance. (Brown, 1996)

2.7.1: Sample Level Attribute:

They provide pointer to areas that may contain hydrocarbon accumulation and are useful for horizon and fault interpretation. These are as under:

Seismic Amplitude:

These produce an amplitude map for the selected horizon, which helps in identification of bright spots, dim spots, and faults.

Quadratic Amplitude:

These are used together with the other seismic attributes to identify bright spots, dim spots, and faults.

Apparent polarity;

It is the sign of seismic trace (positive or negative) when the reflection strength has its maximum value. As apparent polarity is proportional to the acoustic impedance contrast, it may be useful as a bright spot indicator. Bright spot s associated with the gas accumulations may have lower acoustic impedance than the surrounding beds.

Instantaneous Phase:

It is the phase angle at any instant along the trace extracted from each sample at the picked horizon. It is used for the identification of subtle sedimentary and tectonic feature such as the Channels, downlaps, pitchouts, subtle faulting, offlap, onlap, or zones of thickening and thinning. (Dobrin, 1976)

Instantaneous frequency:

It is the first derivative of the instantaneous phase and the rate at which the complex trace changes. Rapid changes in instantaneous frequency can help us to identify feature such as pinch out edges of hydrocarbons and water contents

Reflection strength:

It is the description of wave-form shape. It is used to identifying the major lithological changes between adjacent rock layers such as unconformities, lithological identification of sub grouping, seismic sequence boundaries, gas accumulation and gross porosity changes are often more clearly visible when viewed as a function of reflection strength.

Cosine of phase:

Cosine of phase is the Cosine of phase. It is used in fault interpretation.

Response Phase:

It displays an attribute of the wave form measured at the reflection strength.high reflection strength is often associated with:

- Distinguishing a reflection from massive reflectors
- Major lithological changes between adjacent rocks layers
  - –Unconformities
  - –Lithological identification of sub-grouping

Seismic sequence boundaries

- Gas accumulation boundaries
- Gross porosity

First Derivative, Seismic amplitude:

It measured the slope of the tangent between the two nearest samples of the seismic amplitude at the picked horizon it is the quality check of the reflector and the interpretation. a constant value indicates a continuous reflector and that the interpretation only follows one reflector.

Second Derivative, Seismic amplitude:

It measured the slope of the tangent between the three nearest sample points of the horizon high value indicate that the trace has a rapid shift form peak ton trough (short Wavelength). Value near the zero of the second derivative (slope) indicate that the trace has a slow change from peak to trough (long wave length).

2.7.2: Volume-Based Attributes:

These calculate the attributes in each sample in an interval between a horizon an a sety time or between two horizons. These are separated into three different groups as under: Integrated attributes, heterogeneity attributes, and max/min attributes.

Integrated-Attributes:

It is volume-driven attribute that sums all amplitude values inside a volume.

Integrated-Seismic Amplitude:

Integrated-Seismic Amplitude helps us to identify bright spots, dim spots and faults.

Integrated- Apparent Polarity:

It indicates the sign of the reflection coefficient, such as lithology and unconformities. Its can also used a bright spot indicator.

Integrated-Instantaneous Frequency:

Rapid change of Instantaneous Frequency can help us to identify such features as pinchouts and edges of the hydrocarbons-water interfaces.

Integrated-Reflection Strength:

It is often associated with major lithological changes between adjacent rock layers like unconformities, lithological identification of sub-grouping, seismic sequence boundaries, gas accumulation, and gross porosity.

Integrated- Cosine of Phase:

It may help in structural delineation ,and also can used it together with the instantaneous Phase

Integrated-Magnitude Seismic Amplitude:

It calculate the sum of the absolute values of the amplitude along a seismic trace for a given volume of data and also demonstrate the changes in amplitude within an interval and can indicate changes in lithology over an interval. it is also helpful in bright spot analysis , texture analysis and locating thin beds. It can also be used to map direct hydrocarbon indicators in a zone.

Heterogeneity Attributes:

It calculates the amplitude values in each sample inside the defined volume and adds together the absolutes difference between the samples its important application is the detection of *shale* layers in *sand* bodied; a zone of high heterogeneity may be interpreted as having more shale than a low one. A trace which has a rapid change of amplitude will get high reflection heterogeneity values. (Schultz, Shuki, Hattori Corbett, 1994)

Heterogeneity-Seismic Amplitude:

It help in the detection of the shale layers in sand bodies

Heterogeneity- Instantaneous Phase:

It identifies sedimentary and tectonic features as:

- Channels
- Downlaps
- Pinchouts

Heterogeneity- Instantaneous Frequency:

It helps to identify variations such as pinchouts and edges of hydrocarbons, water contents

It is the measure of the reflectivity with in a time/depth window. Maximum amplitude is another measure of reflectivity with in a time window. We use this attribute to map strongest direct hydrocarbon indicator in a zone.

Maximum Value- Instantaneous Frequency:

It is the measure of the reflectivity with in a time/depth window. We use this attribute to map strongest direct hydrocarbon indicator in a zone.

Maximum Value- Reflection Strength:

It is measure of the reflectivity with in a time/depth window. We use this attribute to map strongest direct hydrocarbon indicator in a zone.

RMS- Seismic Amplitude:

It computes the square root the integral of the squared amplitude, divided by the number of the samples. It is measure of the reflectivity with in a time/depth window. We use this attribute to map strongest direct hydrocarbon indicator in a zone.(Taner & Sherif, 1977)

2.8: USE OF SEISMIC DATA:

Seismic methods are also useful in ground water searches and in civil engineering especially to measure the depth of bed rock in connection with the construction of large buildings, dams, highways and harbour surveys. Seismic techniques have found little applications in direct exploration for minerals because they do not produce good definition where interfaces between different rock types are highly irregular. However they are use full in locating features such as buried channels in which heavy minerals may be accumulated. Seismic attributes can be used in seismic interpretation. As seismic data quality improves, interpretation of seismic attributes becomes more reliable. Seismic attributes reveal information that often cannot be detected in conventional seismic displays. The attributes can be used for both quantitative and qualitative interpretation of any zone of interest.

2.9: COMPLEMENTING SEISMIC BY LOG DATA:

When the interpreter comes to establish a relationship between seismic section and borehole section he faces the problems of making a direct correlation between pattern of reflectors which are scaled vertically in terms of two way reflection time and the realities of subsurface geology as determined by the lithological logging of rock chipping and the core obtained from borehole. The geologist's lithological log is of prime importance in that it provides the basis for identification of reflectors in terms of boundaries between rocks of different type. Other geological work on the cores and chipping aims to establish the age and stratigraphy of geological section and the presented results of exploration drilling normally include a litho-stratigraphic log(rocks describes in terms of lithology) as well as a chrono-stratigraphic scale (the rock units subdivided according to age)

It is standard industry practice that at various stages during the drilling of a well and upon reaching the total depth (referred to on log as TD) geophysical logging tests are made with a variety of instruments. These are lowered to the bottom of the well, as drill at the time of logging, on a wire line which is usually a multi-core electrical cable on which the logging tool can be suspended. The loggings are then drawn upwards through the borehole, measurements of various parameters being made either continuously or by tests at selected horizon. The processed results of these geophysical tests provide data which allow identification of the inter-relationship between the seismic section time scale and the borehole section depth scale and thereby direct correlation between reflector pattern and stratigraphy. These measurements also provide data on the physical properties of the rocks penetrated by the borehole and such data important to a geological understanding of the variation in reflector pattern which can be seen in seismic section throughout an exploration province. As for as the seismic interpreter is concerned, the geophysical logging methods of most value to him are gamma-ray logging, compensated sonic logging and well velocity survey. The result of these are most usefully combined to provide a synthetic seismogram which is a process which aims to produce from the borehole physical data a computed seismic section display which should compare well with an actual seismic section surveyed through the well site.

2.10: RELATION BETWEEN SEISMIC SECTION AND LOG

The comparison between a seismic section (in two way time) and an acoustic log (interval transit time versus depth) leads to question about the relations between the two types of data and the possible combination of their corresponding data sets.

2.10.1: Acoustic log in relating logs and seismic data:

The acoustic log provides an obvious link between geophysics, seismic and well logging data. Although covering different frequency bands (acoustic log: in order of 10 kHz; seismic: ranging from about 10 to 100 Hz), the two techniques are based on the same laws of wave propagation but with different methodology. Under a certain number of conditions the seismic measurements collected at these different frequencies can be compared and used to improve knowledge of reservoir characterization. Acoustic log has a different vertical and lateral range of investigation compared with seismic surveys (surface or borehole).

It has a good vertical resolution –of the order of tens of centimeters –but is limited to the immediate vicinity of the borehole .By contrast, seismic profiling allows a more extensive spatial image, but the vertical resolution in no better than about ten meters.

Although the depth to time conversion of well log data is carried out using the acoustic velocities of formations obtained from acoustic logs(sonic logs), this method is insufficient to provide an effective comparison between seismic and logging surveys, thus it is thus necessary to perform a sonic calibration for the depth-time conversion.

The sonic log calibration involves establishing a time-depth relation consistent with the seismic survey yielding the same vertical resolution provided by the sonic logs. In other words, the sonic log measurements are recalculated to be compatible with the variation in fluids and litho logical composition, so the integrated travel time between two depth readings can be matched with the corresponding data from the well velocity surveys.

A well velocity (or check shot) survey is carried out by measuring the travel time of heads waves emitted from a surface shot by means of a geophone or an hydrophone placed at various depth in a well.

Check shot surveys are the predecessors of vertical seismic profile. Vertical seismic profiles (VSP) may. use more sophisticated tools to records the entire seismic wave train generated by the surface source and transmitted though the earth filter downward. A VSP survey is usually recorded at a much higher density of depth points but may not cover the entire well bore.

A high level of precision is required for the comparison of seismic and well logging datasets, particularly in the context of reservoir studies. Therefore, it is necessary to apply preliminary correction procedure before calibration of the sonic log to the check shot results or to well velocity survey.

The interval travel times obtained from the check shots survey and the sonic log are compared. The sonic log is then adjusted or calibrated according to well defined rules to match the check shot interval transit time.

Once the calibration has been carried out and a corrected time-depth relation established, it is possible to compare the well (logs) with surface seismic data. One technique employed for this purpose is the creation of synthetic seismogram using density and acoustic velocity logs. Bulk density and acoustic velocity logs are used to create an acoustic impedance log. After depth –time conversion, the reflection coefficient derived from the

Acoustic impedance log are then convolved with an appropriate wavelet to produce the synthetic section (often referred to as seismogram).

Seismic data obtained from the vertical seismic profile (VSP) with or without source offset, are processed to provide seismogram at seismic frequencies that are directly compare able with synthetic sections and the surface seismic section. Even though these data have a poorer vertical resolution compared with well logging and a restricted frequency range, they can be used to adjust profiles obtained from seismic reflection surveys carried out at the surface. In addition, borehole seismic surveys can be used for defining appropriate operators for stratigraphic deconvolution and converting seismic sections to acoustic impedance sections or logs.

The combination of bore hole seismic surveying with well logging techniques (see fig 2) enables a considerable improvement in the study of reservoir. In some cases, the seismic and down hole logging datasets may appear inconsistent with each other. In the present study, an attempt is made to explain the various reasons for the observed discrepancies between these two approaches.

2.11: IMPORTANCE AND CALCULATIONS FOR RESERVOIR STUDY:

The main goal of this study is to estimate porosity, water saturation, and volume of silt using several seismic attributes and then arrive at getting one conclusion based on the quantitative and qualitative analyses. In the quantitative analysis, nine seismic attributes are used to estimate the reservoir properties. These attributes are calculated and averaged over the zone of interest, from Base to Unconformity compared to the log derived reservoir properties from wells. *Multi-variant regression* is used to approximate a linear transformation between seismic attributes and reservoir properties. Then transformation is applied to the whole seismic data. In the qualitative analysis, spectral attributes are studied in addition to the nine seismic attributes. Attributes are related to the reservoir properties qualitatively. Both the quantitative and qualitative interpretation is in agreement. I preserved two wells for validation purposes. The estimated reservoir properties of these two wells using Multi- seismic-attributes approach are in agreement with the well driven reservoir properties. The multi-seismic -attributes driven reservoir properties method was compared to the single attribute method and to a method utilizing simple kriging of well information.

The need to improve reservoir characterization in order to optimize hydrocarbon extraction has led to the development of special techniques and increased collaboration of aspects in many different fields, i.e. geology, geophysics, logging and production engineering. The different type of information contributed by each of these approaches is complementary. (Chen & Sidney, 1997)

CHAPTER # 3

GEOSTATISTICAL METHOD FOR MAPPING A RESERVOIR

CHAPTER 3

GEOSTATISTICAL METHODS FOR MAPPING A RESERVOIR:

3.1 Introduction

Using Geostatistical techniques mapping of petrophysical properties can be explained with confidence. This explanation description can be qualitative or quantitative. Some of the important points are as under:

1. All the data are not available at the same time. As exploration and delineation of the reservoir continues additional data become available.

2. The quality of data collected from various sources may be different. Hence the uncertainty associated with the data is different as is the user's confidence level in the data reflected by the weights assigned to the data by him.

3. Data may be collected over different scales. For instance, quantities from log measurements typically reflect reservoir properties averaged around a distance of 5-10 feet around the measurement location. Quantities derived from a welltest typically average over a much larger distance around the measurement location. So in using the data the difference in scales has to be incorporated.

4. Some of the interpretation may be qualitative. For instance, the facies maps generated by a geologist to a large extent are influenced by his intimate knowledge of the area and it's depositional history.

The fundamental drawback in reservoir description oriented towards the goal of matching historical field performance lies in the fact that there are multiple reservoir descriptions possible which honor well location data (also termed as hard data) that could match the history. Hence reservoir simulation, by its very nature, falls in the realm of classic inverse problems wherein multiple permutations and combinations of input data could yield the same result. It cannot be assumed that once the historical performance is matched the reservoir model, which was used to arrive at the result, is untouchable. It should be appreciated that any forecasting or future performance estimation done with the aid of this model also carries a reflection of the uncertainty in the reservoir description itself. This is perhaps the essence of geostatistical methods since it is the one technique that gives the engineer a quantitative measure of uncertainty in the estimation of a particular variable.

3.2 Basic Statistical principles

3.2.1 Frequency distribution:

To construct a frequency distribution the data is divided into a number of intervals called class intervals. The number of measurements falling within a particular class is termed as class frequency fj. The class frequency normalized over the total number of samples is called relative frequency.

1 Mean:

The mean represents the summation normalized over the number of samples. It tries to capture the central tendency in a sample. Mathematically it can be written as

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} x_i$$

2 Meadian:

Another measure of central tendency is the median. It is the sample point in a dataset, which represents 50% probability. In other words, if one arranged all the sample points in an ascending order the sample that falls right in the middle represents the median and is calculated by

$$\tilde{x} = \frac{x_{n+1}}{2}, for\ n \quad odd$$

$$\tilde{x} = \frac{x_{n/2} + x_{n/2+1}}{2}, for\ n \quad even$$

3 Mode:

It is the observation that occurs most frequently in the sample. It is obvious that the mean, median and the mode will be coincidental if the distribution is symmetric. If the distribution is skewed the three central tendencies will be different. If the distribution is positively skewed we observed that Mode <Median <Mean. If the distribution is negatively skewed then we observed that

Mode >Median >Mean.

Extremes, **percentile:**

The minimum and maximum among the sample values may be useful to examine the variation in the data. Percentile values represent sample values, which are greater than a certain percentage of the sample values. For instance the 10% percentile value represent the observation that is greater than 10% of the total number of sample points.

4 Variance:

It simply represents the spread of the data. Mathematically we can calculate variance as,

$$S^2 = \frac{\sum_{i=0}^{i=n} x_i^2 - n\bar{x}^2}{n-1}$$

Where S2 is the sample variance, x is the mean and n is the total number of Samples. The square root of s is called standard Deviation.

5 Coefficient of Variation:

It is the ratio of the standard deviation to the sample mean. Mathematically it is defined as

$$CV = \frac{S}{\bar{X}}$$

It is a dimensionless quantity and is intended to provide a measure of the spread of the sample. By comparing the coefficients of variation in two data sets one can infer as to how much the data is centered around the mean or separated from the mean.

6 Range:

The range is another measure of the spread. The simplest definition of range is

$$R = Xmax - Xmin.$$

Xmax represents the maximum value and Xmin represents the minimum value and so on. The range can also be determined between successive quartile values. For Instance range can be defined as R = XsO-X25.

7 Sample Declustering :

Sample declustering is one of the simplest ways to eliminate the effect of biased sampling. For instance typically in a field wells are concentrated in places areas where there are oil shows as opposed to being uniformly spaced. High porosity in such areas may bias porosity computations away from those wells. Typically the whole area is divided into several sub-ręgions and the weight is calculated as an inverse of the number of points in that sub-region. The idea is logical since greater the number of data points within an area lesser the weight assigned to it and hence lesser it's impact on computations. For example if the point Xi falls within a subarea A where nA is the number of sample points then

$$wA = \frac{1}{nA}$$

8 Bivariate statistics:

A conditional distribution is the distribution of one particular variable, which is conditional upon the distribution of another variable. For instance if we consider porosity and permeability we can envisage different porosity classes and plot the permeability distribution of only those points belonging to a particular porosity class.

9 Covariance:

Covariance is the measure of relationship between two variables x and y. If and yare positively related (i.e. as x increases, y increases) covariance is covariance will exhibit a negative value. Extending that logic if x and y are not related covariance will exhibit a value close to zero. Mathematically it is defined as

$$c(x,y) = 1/n\sum_{i=1}^{i=n} x\,i\,yi - 1/n\sum_{i=1}^{i=n} x\,i\,yi$$

Similar to variance covariance is defined in units depending on the units of and y. Similar to regression coefficient in univariate statistics we can define correlation coefficient between 2 variables as follows:

$$r(x,y) = \frac{C(x,y)}{SxSy}$$

where r(x,y) is the correlation coefficient and Sx and Sy are the respective standard deviations of the variables x,y respectively.

10 Linear Regression:

The simplest equation is the y = mx + b. It can be mathematically shown that the best fits is obtained when

$$m = \frac{c(x,y)}{Sx^{2}},\ b = \bar{Y} - m\bar{x}$$

where c(x,y) is the covariance between x and y, s/ is the variance of variable x,

y and x are the respective means of the variables x and y. The goodness of fit is

indicated by the correlation coefficient between the 2 variables.

11 Probability and laws of probability :

Probability better let us consider the experiment of rolling a dice. The list of all possible outcomes can be written as

$S = \{1, 2,3,4,5,6\}$

This is called the sample space for the experiment. If we consider an event consisting of all even numbered outcomes the event would be EventE1 = {2,4,6}. Hence the probability of event E is 3/6 = 0.5. If we consider another event consisting of all outcomes less than 4 we can write event E2 = {1 ,2,3}. The intersection of the two events is (E1 ∩ E2) = {2} and the union of the 2 events (E1 u E2) = {1 ,2,3,4,6}. We can extend the logic to say that probability of the union and intersection of events E1, E2

P(E1 (J E2) = 1/6 and P(E1 u E2) = 5/6

12 Conditional probability :

It is the probability of an event occurring given that a related event has already occurred. For example if one rolls a pair of dice the total number of possible outcomes is 36. If we are trying out the probability of having a sum total of two from both the dice given that one dice has already shown 1 it would be equal to the probability of finding 1 on the other die yet to be thrown. This is equal to 1/6. Mathematically it is

$$P(A I B) = \frac{P(AnB)}{P(B)}$$

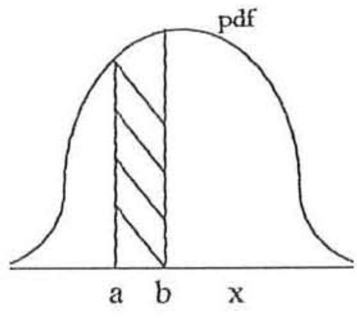
13 Probability density function (pdt) :

It is very closely related to the frequency distribution function. For a continuous variable the probability density function f(x) can be defined as

$$P[a <= X <= b) = \int_{a}^{b} f(x)dx$$

where $\int f(x)dx=1$

Graphically this is shown as follows and is basically the area under the probability curve between a and b as indicated by the shaded area



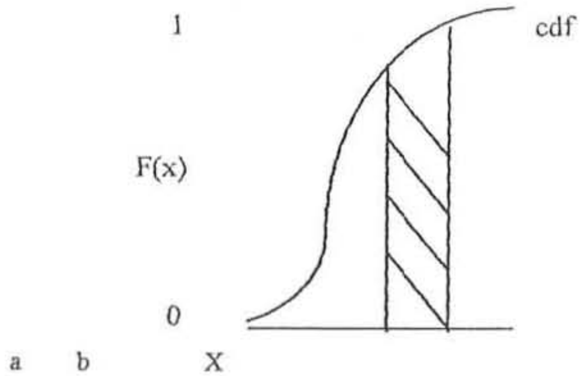
14 Cumulative distribution function:

It is denoted by F(x) and is mathematically defined as

$$F(a) = p[X <=_{29} a] = \int_{-\infty}^{a} f(x)dx$$

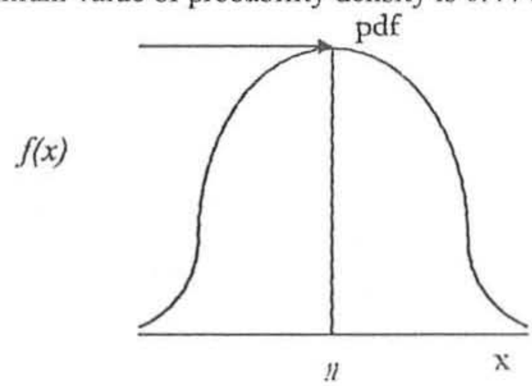
To calculate the probability of X lying between a and b the probability is as follows and is graphically highlighted in the cdf figure.

$$pea < X <= b) = p[X <= b]- p[X <= a] = F(b)-F(a)$$



15 Normal distribution:

The normal distribution is the most widely known distribution and is represented by the following equation. The mean of the distribution is *f.1* and the variance is *a2*. It maximum value of probability density is 0.4 / *a* and occurs at μ



The picture represents the pdf for a normal distribution wherein the maximum probable value, which occurs at the mean of the distribution, is highlighted.

CHAPTER # 4

VARIOGRAM MODELING AND RELATED THEORY

CHAPTER 4

VARIOGRAM MODELING AND RELATED THEORY

4.1 Stationarity and Covariance

4.1.1 Assumption of stationarity

In subjective terms it simply means that based on the information available from the sample we can infer details about the population. For instance in a Particular school in a big city 40% of the children going to grade ten may be girls. If we can infer that out of all grade ten children going to several schools in the city 40% of them are girls the population is said to be behave in a manner that satisfies the first order of stationarity.

In the context of a reservoir it simply means that if we divide the area of Interest into small sub areas and calculate the means of the points within those sub areas the means are approximately constant. In other words we could in Principle consider one sub area, calculate the mean, and infer the mean of the whole area or the population based on it. Mathematically this can be written as

$$E[X(u)] = E[X(u+ h)]$$

In other words the expected value of the variable u which is the mean at location u is same as the expected value of variable u lag distance h away. The second order of stationarity states that a function of two random variables located h distance apart is independent of the location. Mathematically it can be written as

$$C[X(U1),X(1 + h)] = C[X(U2),X(U2 + h)]$$

In other words the covariance is only a function of the distance h and is independent of the values that the variable u can take. We can also define other functions that capture the spatial relationship as a function of lag distance hand that is the variogram.

4.1.2 Variogram

The variogram is the most commonly used technique in geostatistics literature to describe a spatial relationship. Mathematically it is defined as

$$y(h) = \frac{1}{2} Var[X(u) - X(u+h)] = \frac{1}{2n(h)} \sum_{i=1}^{n(h)} [X(Ui) - X(Ui+h)]^2$$

It is essentially half the variance between two values located h distance apart. It is obvious that at zero lag distance the variogram value would be zero. In other words, the closer the values are spatially the stronger the relationship. The greater the distance the weaker the correlation between the values. This translates to smaller variogram values at shorter distances and larger variogram values at greater distances.

4.1.3 Example:

The following table is given to compute the variogram at 1 feet lag, 2 feet lag and 3 feet lag.

Depth	*Porosity(%)*
2000	8
2001	10
2002	7
2003	6
2004	11
2005	12
2006	5

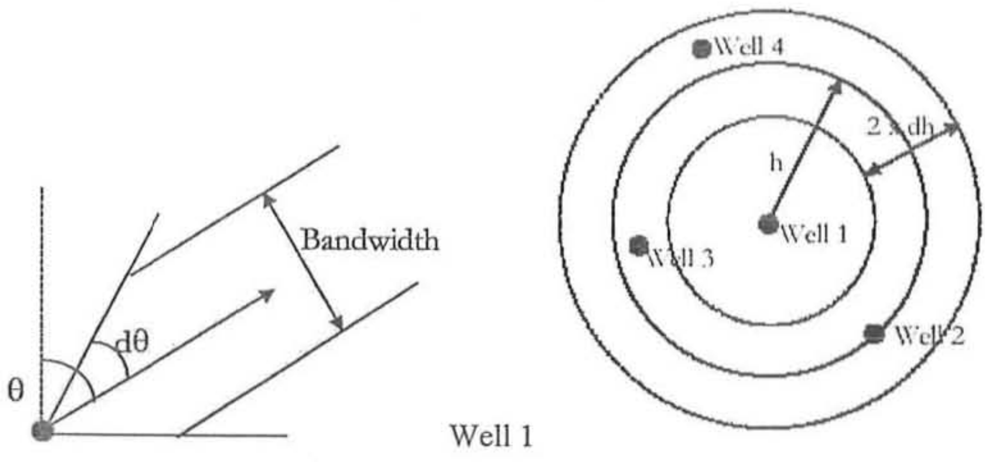
The variogram value at 1 feet can be calculated by taking all pairs of Porosity values separated by 2 feet.

The variogram value at 3 feet can be calculated by taking all pairs of porosity values separated by 3 feet the relationship between the variogram and covariance can be expressed as

$$Y(h) = C(O) - C(h)$$

where all the C terms represent covariances at respective lag distances. The covariance at zero lag distance is essentially the variance in the variable itself.

Concepts of lag, tolerance and bandwidth:



When we compute the variogram value at a certain lag distance we calculate the average squared difference for all pairs of values separated by a lag distance h. For this to be truly representative we need to ensure sufficient pairs exist at each lag distance. Hence to estimate a variogram value at a lag distance of h we include all pairs that lie within (h+dh) or (h-dh). This increases the stability of the structure in the variogram. The same logic can be extended for directions. So, instead of looking in one particular direction we define an angle tolerance and include all pairs that lie within the sector () + *d* () and () - *d* (). IT should be noted that if the angle tolerance is unchecked with increasing lag distance the sector becomes wider and wider. Hence we define a bandwidth that ensures that once a certain maximum width is reached it is maintained further away.

4.2 Transforms of variables:

4.2.1 Need for transforms

The variogram represents the average of the squared differences of variable pair values at a certain lag distance. Since it uses the square of differences, large differences between a particular pair are magnified. Such pairs can have a significant impact on the overall variogram value at a certain lag distance and resultin instability in the structure of the variogram.

Log transform

It is simply the natural logarithm of the value. It is typically used in the case of analyzing permeabiliy data. The order of magnitude variations present in the permeability data are translated into the integral part of the log of the value.

Power Transform

It is a more generalized case of the log transform. It is the value raised to a fractional power. The log transform is simply a more extreme case since it the value raised to a power of 0.1. Power transforms are typically used on seismic attributes and permeability which exhibit inherently high variance. Power transforms should be used with caution when a certain variable exhibits both positive and negative values.

Rank transform

Instead of computing the variogram based on the actual values we could rank any given data set and normalize the rank over the number of samples in the dataset ensuring that the transformed variables always takes values between 0and 1

Indicator transform

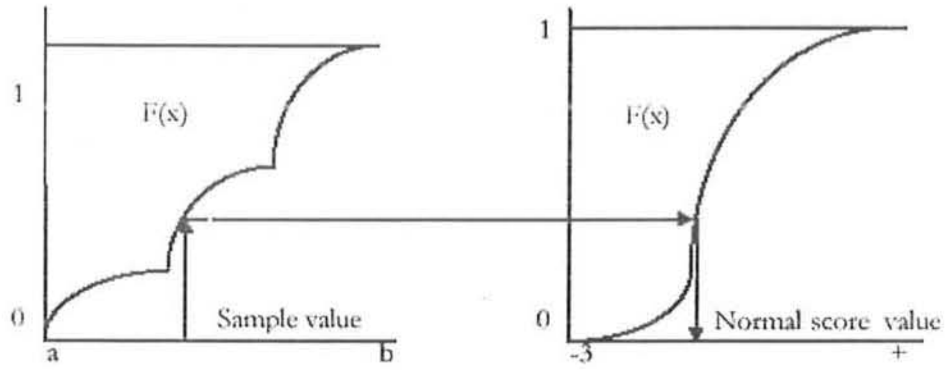
It allows the transformation of a continuous variable into a discrete variable. If a certain threshold Xt is defined the indicator transform can be written as

$I(u,Xt) = 1, X(u) <= Xt$ $\qquad$ $I(u,Xt) = 0, X(u) > Xt$

Typically the 25%, 50% and 75% values are used as thresholds. It is evident from the above definition that indicator values are always either 1 or o.

Normal score transform

This transform allows a variable to be transformed into an equivalent normal(Gaussian) distribution. The cumulative distribution function can be constructed for any data set. For the normal distribution a pre-defined cumulative distribution function exists. Hence by simply looking up the cdf value corresponding to a particular sample in the dataset it's value in the transformed Gaussian space can be determined. The normal score transformed values typically have a mean of zero and a variance of one. The range of values is between -3 and +3. The procedure is schematically shown in the following figure.



Types of Variograms

The basic definition of the variogram assumes that the global mean is the same as the mean at individual lags or mathematically

$$\overline{x}_{-h} = \frac{1}{n(h)} \sum_{i=1}^{n(h)} x(u_i) = \overline{x}_{+h} = \frac{1}{n(h)} \sum_{i=1}^{n(h)} x(u_i + h) = global\_mean$$

The generalized equation of the variogram is called the semivariogram. The General relative variogram is a revised version of the same and is defined as

$$\gamma_{GR}(h) = \frac{\gamma(h)}{\bar{x}_h^{\,2}}$$

The normal variogram calculation is simply normalized over the lag mean at a particular distance, the intention being to eliminate the variations in the lag means. Similarly, the pair wise relative variogram is defined as

$$\gamma_{PR}(h) = \frac{1}{2n(h)} \frac{\left[x(u_i) - x(u_i + h)\right]^2}{\left[\frac{x(u_i) + x(u_i + h)}{2}\right]^2}$$

In this type each individual pair at a certain lag distance is normalized over the square of the pair mean.

Variogram modeling and requirements for modeling

Once we establish a spatial function purely as a function of distance the function can then be used to calculate values at unsampled locations provided we know the distances between the unsampled location and all the sample points. A variogram is an analytical equation that tries to capture to the best possible extent of the observed spatial trend in the data. The variogram value is zero at zero lag distance and increases with increasing lag distances. After a certain distance the variogram flattens out and reaches a constant value called "sill". The distance at which the sill is reached is termed as "range". Range can be thought of as the distance beyond which two sample points are completely uncorrelated.

Nugget effect model

The simplest model is the nugget effect model. It can be written as

$$\gamma(h) = 0 \quad \text{if } h = 0 \quad / \gamma(h) = C_0 \quad \text{if } h > 0$$

At a lag distance infinitesimally away from zero the sill of the model abruptly rises to a value of Co. The reason it occurs could be due to fact that the shortest distance at which we have available pairs is larger than the range or it could be a reflection of the uncertainty of measurement in the variable itself.

Spherical model:

$$\gamma_{Sph}(h) = C_0\left[\frac{3}{2}\left(\frac{h}{a}\right) - \frac{1}{2}\left(\frac{h}{a}\right)^3\right] for \quad h <= a \qquad \gamma_{Sph}(h) = C_0 \; for \quad h > a$$

The variogram model has been defined with arrange of "a" and a sill value of "Co". it can be easily seen that at lag h=a the value of the variogram becomes Co.

Exponential model

$$\gamma_{Exp}(h) = C_0\left[1 - \exp\left(\frac{-3h}{a}\right)\right] for \quad h >= 0$$

The variogram model is asymptotic in nature and hence never truly reaches the value of "Co" but essentially at h=a it reaches about O.95Co. For all practical purposes the distance "a" can be treated as the range.

Gaussian model

$$\gamma_{Gauss}(h) = C_0\left[1 - \exp\left(\frac{-3h^2}{a^2}\right)\right] for \quad h >= 0$$

The variogram model is also asymptotic in nature and hence never trulyThe variogram model is also asymptotic in nature and hence never truly practical purposes the distance "a" can be treated as the range.

Combination models:

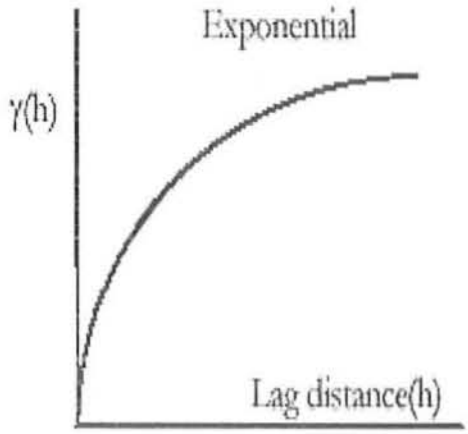
In certain cases one simple variogram model may not be able to capture the spatial trend observed in the data. In such cases combination models can be extremely helpful. For instance consider the following model which is *a* combination of the nugget, spherical and exponential models.

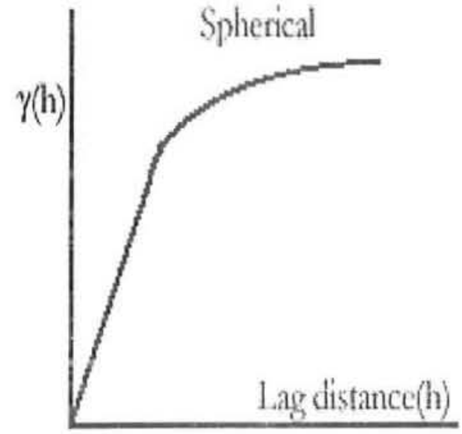
(h) = Co + *ClSphal(h)* + *CZExPaZ(h)*

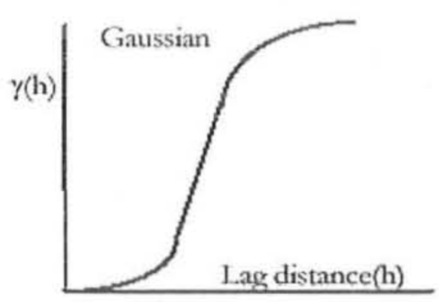
where the total sill value for the variogram Co+ C1+ C2 and the range for the spherical model is a1 and the range for the exponential model is a2

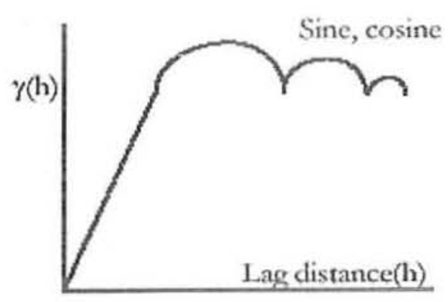
Sine and Cosine models:

This is very typical when variograms are computed in the vertical direction at a single well location. Geological processes often repeat in cycles and it's reflection can be seen as cyclical variograms.









Cross-variogram

The equation for the cross-variogram can be written as,

$$rc(h)=\frac{1}{2n(h)}\sum_{i=1}^{n(h)}[x(ui)-y\,(ui+h)]\,[y(ui)-y(ui+h)]$$

It can be seen that instead of squaring up the differences at any lag distance h we simply compute the product of differences at that lag between the primary variable x and the secondary variable y. It should be noted that unlike the standard variogram the cross-variogram need not be strictly positive. If two variables are negatively correlated (Le., as x increases, y decreases) then the cross-variogram will be negative.

Geometric anisotropy

Most typically spatial trends are analyzed along different search directions and the ranges in the different directions are analyzed. The direction with the largest range is termed as the direction of maximum continuity and the direction in which the shortest range is observed is termed as the direction of minimum continuity. To facilitate the mathematics generally the direction of maximum continuity is determined and the direction of minimum continuity is assumed to be perpendicular to it. Conceptually a variable may exhibit correlation over a larger distance in a certain direction owing to the presence of facies continuity in that direction (like a sand Chanel).

CHAPTER # 5

PROPERTY MAPPING TECHNIQUES

CHAPTER 5

PROPRTY MAPPING TECHNIQUES:

5.1 Kriging

5.1.1 Theory

Kriging uses a linear estimation technique to estimate a value at unsampled

locations. The value at the unsampled location is estimated as shown in the equation.

$$X^{*}(uO) = \sum_{i=l}^{n} LAiX(Ui)$$

where X*(uo) is the value at the unsampled location and X(Ui) is a sample point at neighboring location i and *Ai* is the weight assigned to the sample point. The assigning of weights depènd on the spatial relationship between the unsampled location and neighboring values. Kriging algorithms rely on the inversion of a matrix. The size of the matrix is governed by the number of samples chosen to estimate the value at a particular location. Too few samples may not a yield a reliable estimate at an unestimated location and too many samples increase the computational time. Hence an optimal balance must be struck between the two extremes.

5.1.2 Size and shape of search neighborhood

The search neighborhood defines the area consisting of all the sample points used in estimating an unsampled location. Conceptually, the minimum size should be dictated by the minimum number of sample points required for a reliable computation. The maximum size is difficult to ascertain. The maximum size can be set to be the range of the variogram, since sample points beyond the range of the variogram by definition would exert no influence on the unsampled location value.

If in two dimensions an isotropic variogram is used the search neighborhood will be perfectly circular. If an anisotropic model is used the search neighborhood will be elliptical. The logic is to have more sample points in the maximum direction of continuity and less sample points in the minimum direction of continuity.

5.1.3 Cross-validation

Cross-validation is a procedure to gauge the amount of confidence we have in the estimates at unsampled locations. The most common method is the "leaving one out method". In this method one sample point is removed from the sample data at a time and the remaining sample points are then to calculate the value at that point as if this is an unsampled location. The value thus calculated is then compared with the known data value at that point. After repeating this sequence for all the points a cross-plot can be generated between the values at sample points and the corresponding estimated values treating them as unsampled locations.

After the cross-validation is finished we have two values at every location the true value and the estimated value. The estimation error can be written as

$$e(u_i) = x^*(u_i) - x(u_i)$$

In certain cases it may be observed that the error depends on the magnitude of the sample or in other words the error increases if the magnitude of the sample increases and vice versa. This type of behavior is known as "heteroscendasticity" of error variance. If the error is equally spread around zero and is independent of the magnitude of the sample this is termed as "homoscendasticity" of error variance. Ideally we should satisfy this behavior in practice.

5.1.4 Simple Kriging

The kriging algorithms use the "minimum variance unbiased estimation" technique to estimate values. In othe, words the weights should be computed ensuring that the estimated value is unbiased and the error variance is minimum

The condition of unbiasedness can be written as

$$X(uo) = ..10 + \sum_{i=1}^{n} LAiX(Ui)$$

wherein the covariance C matrix has to be inverted for solving the weights. If a sample point Uj is located very close to neighboring sample points Uj, then the covariance terms C(Uj,uj)would be large. This would result in lower weights being assigned to those points since the weight is inversely proportional to the "C" matrix. Conversely, stronger the spatial relationship between the unestimated value at Uo and the sample points at Uj larger the covariance value in matrix "c" and hence the weight assigned is correspondingly more. Hence conceptually we can see that the effect of clustering among the sample points is eliminated by assigning lower weights. It can also be seen that closer the location of the unestimated value to the sample points larger the influence of those sample points. Once the weights are calculated the error variance can be calculated as

$$\overset{2\ v}{\alpha E} = X(Yo, Yo) - \underset{\iota=\lambda}{\Lambda A\iota} X(Y\iota \ni Yo)$$

5.1.5 Ordinary kriging

Simple kriging requires that the mean be known but the true global mean is hardly ever known. The assumption of the first of stationarity may not be truly valid in the area being populated. Ordinary kriging procedure filters out the mean by enforcing a condition that all the weights sum upto unity.

If there is a trend present in the data the assumption of the first order of stationarity is negated. Hence such a trend has to be filtered out before performing the variogram computation and kriging. Ordinary kriging provides a means of filtering the linear trend in the three principal directions and trends in (xy) , (yz) or (xz).

3.1.6 Cokriging

Cokriging is a procedure for estimating one variable using other sampled variables.

The objective is to improve the estimate and reduce the uncertainty in the estimated values with the spatial information from other variables. Some typical examples are the estimation of permeability using porosity data and the estimation of porosity using seismic data. It should be noted that the fundamental assumption in the cokriging technique is that variables are linearly related to each other. The computational effort it takes to solve a cokriging system is more compared to simple or ordinary kriging since it uses more number of points and hence the matrix inversion is tedious. The variogram modeling effort is also comparatively more since it necessitates a variogram for the primary variable (variable we are trying to estimate and typically sparsely sampled), a variogram for the secondary variable (extensively sampled) and a cross-variogram that captures the spatial relationship of the primary variable against the secondary variable. The basic equation for an unestimated variable can be written as

$$* \quad nx \quad ny$$

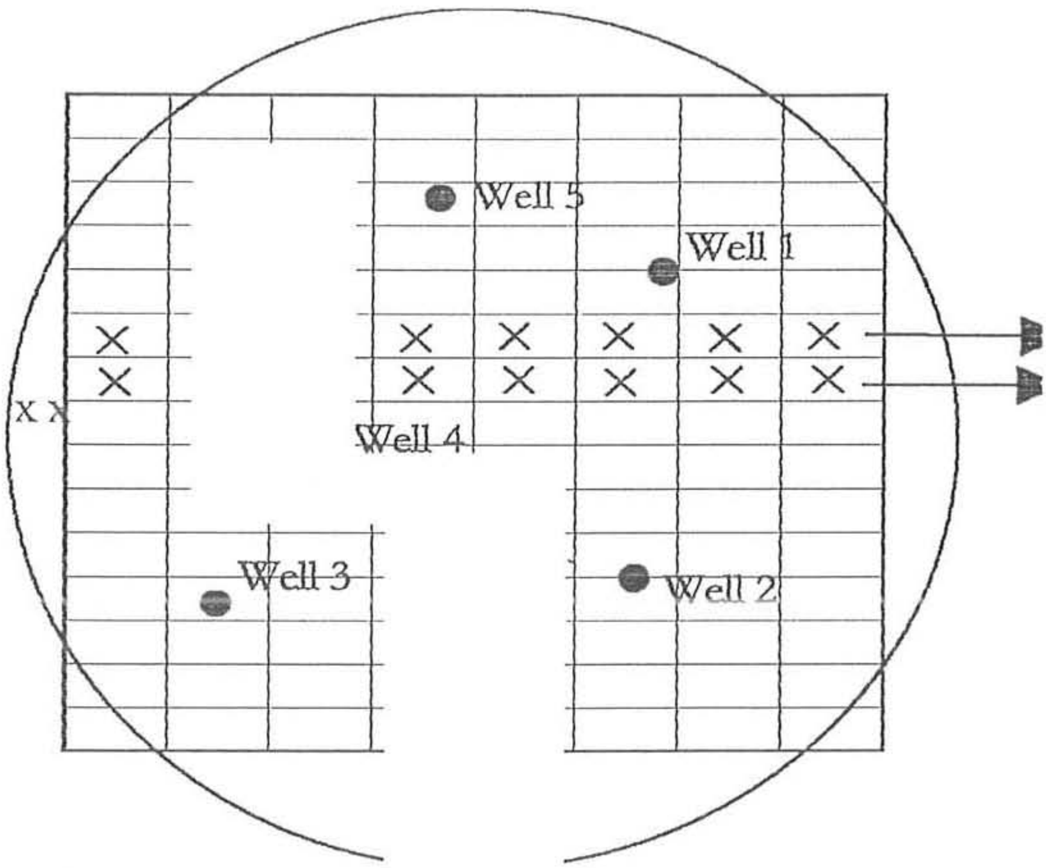
$$X\,(uo) = LAXiX(UXi) + LAYkY(UYk)$$

$$i{=}l \; k{=}l$$

where X is the primary variable and Y is the secondary variable, *A x, A yare* the weights assigned to the primary and secondary variable respectively.

5.1.7 Collocated cokriging

Cokriging can be performed when the primary variable and the secondary variable are both scattered over the area of interest. Collocated cokriging requires that a sample value of the secondary variable exist at each point where the primary variable is being estimated. Hence the most typical secondary variable used is a seismic attribute like acoustic impedance. The seismic grid definition is generally used as the guiding grid for the primary variable mapping. The primary advantage in using collocated cokriging is that the variogram modeling effort is considerably reduced. Given the condition of data sufficiency of the secondary variable it eliminates the need for modeling secondary variable variograms and cross-variograms.



Secondary variable needs to exist at all points the primary variable is compute

5.2 Conditional simulation

Conditional simulation provides a method by which instead of defining one estimate and the associated uncertainty at a particular location the uncertainty is characterized by multiple possibilities which are all equi-probable. Conditional simulation can simulate both continuous variables like porosity and permeability and also discrete variables like geological facies. The most commonly used techniques are the sequential gaussian simulation and the sequential indicator simulation.

5.2.1 Sequential Gaussian simulation

The steps to be followed are

1. Determine the global cumulative distribution functions (cdf) based on the observed values of any variable X.

2. Use this to perform normal score transform on the experimental to arrive at a set of transformed values that obey a Gaussian distribution.

3. Define a random path which visits each pixel or gridcell of the zone being simulated. Then start moving along this path, simulating the pixels as follows.

4. For a pixel to be simulated search for a specified number of neighboring Conditioning data points including both original data and previously simulated pixels as they come into existence.

5. Use conventional kriging on the above neighboring conditioning data constrained by the theoretical variogram to calculate the parameters necessary for the calculation of the Gaussian cdf at this pixel, that is the mean and the standard deviation for the cdf.

6. Pick a random number and derive a value at the pixel from the Gaussian cdf.

7. If all the pixels have not been simulated iterate on the above process till all of them are simulated.

8. If all the pixels have been simulated back transform the simulated Gaussian values

to the original variable,X.

9. This would complete one realization.

5.2.2 Sequential Indicator simulation

The steps to be followed are

1. Indicator simulation can be applied both on categorical and continuous variables. When using a continuous variable thresholds have to be applied on the variable to discretize it.
2. Estimate and model spatial relationships for each threshold in case of a continuous variable or each category in case of a discrete variable.
3. Set up a random path and visit each pixel in the zone being simulated. Then start moving along the random path simulating the pixels as follows
4. Use conventional kriging to come up with the probability values for each threshold or category. Construct a cdf based on these probability values at the pixel being simulated.
5. Use a random number generator to sample a value from the cdf thus established.
6. Once the cdf has been sampled transform this into ma unique threshold for a continuous variable or a unique category for a discrete variable.
7. Visit the next pixel in the random path and estimate indicator values for each threshold or category by using the sample values and the prior simulated values.
8. Once this process has been completed for all the pixels we essentially have one realization.
9. Different sets of realizations can be generated by using a different seed number feed in the algorithm.

5.2.3 Other approaches

Some of the other approaches detailed in geostatistics literature are simulated annealing which performs a sequence of localized perturbations to find the global maximum/minimum in a pre-defined objective function. Also, sequential Cosimulation can be used which is basically an extended form of Cokriging. The idea is to capture the trends the secondary variable and enforce them while simulating the primary variable so that the imprint of the secondary variable is observed in the final co simulated result. (Issaaks & Srivastava, 1989)

CHAPTER # 6

METHODOLOGY AND RESULTS

CHAPTER 6

METHODOLOGY & RESULTS

6.1 Introduction:

Firstly, we have proposed a mechanism to identify appropriate seismic attributes that show good correlation with petrophysical properties (in particular formation) computed around the wells and correlations are used predict or work out a petrophysical property quantitatively over the project area. This has employed Neural Network calibration techniques that describe the correlation between a selected attributes and a calculated property. Mapping of petrophysical properties employed a variety of algorithms, which includes guided mapping, kriging, collocated cokriging, and conditional simulation.

Following will entail the whole workflow and accomplishment of the task in which research starts with seismic attribute extraction and ends with prediction and working out of petrophysical properties as described earlier:

6.2 WORKFLOW

This implies the steps involved to attain the objective from scratch, i.e., We have been given with a 3d seismic data over the project area and wells. All the wells contain log measurements which are used to compute petrophysical properties of the formation. Besides, volume based seismic attributes are calculated over the 3D survey and then correlation is established on a basis that to which attribute we have the best property correlation plus the consistency, proportionality and continuity of that relationship. Different iterations based on various algorithms are used and results are observed and finally a best relationship is found which can be taken as to be usable for advising petrophysical parameters of formation where no wells are drilled.

6.2.1 Seismic Attributes:

In the whole work cycle first important entity is Seismic Attributes which we have used to predict or indicate the physical properties but here we have used certain attributes for the correlation of specific rock properties.

6.2.2 Usage of Log Data:

As of prime importance, log data have been correlated with the Seismic Attributes and then calibration is done. These calibrated attributes indicate the petrophysical properties between the wells and used for the reservoir characterization.

6.2.3 Attribute Extraction and Calibration:

Seismic attributes are extracted around the intersection of each borehole to form an interpreted zone thus a pair of values is computed for each intersection .These pair of values indicate lithotype seismic attribute and log properties. In Calibration the Seismic Attributes have been analyzed against the reservoir properties, throughout the area of the formation then in some cases we find these resulting attributes are not matching with the measured properties exactly at the wells or known points. Which reflected not correspond to the expected statistical changes of the earth rock. For this purpose ,we made use of residual correlation application for improving results and we choose the consistent values (the borehole location), and then by calculating these residual correction and then after applying this residual correction best log to seismic correlation is achieved then petrophysics guided by seismic is explained.

6.3 In Put Data and Its Preparation:

We have used GeoFrame Log Property Mapping software to find relationship between the interpreted petrophysical properties and the extracted seismic attributes. These deduced relationships have guided to propagate of these properties over the reservoir area.

Particular kinds of data are used as input to LPM which are prepared and made as input as under:

WELL DATA

❶ Markers and formation top are marked interactively.

❷Surfaces by markers

❸Layers – difference between surfaces or formation tops

❹ Definition of Lithozones region

5. Logs curves as mentioned and described in the chapter 2.

SEISMIC INTERPRETATION

1. Seismic Horizons/Grids

Quality Matrix (Regression Coefficient)

	Gross_Porosity	Net_Pay_Porosity	Net _Pay_Thickness	Net_Pay_Water _Saturation	Net _Reservoir_Gross _Thickness_Ratio	Net_Reservoir _Porosity	Net _Reservoir_Water _Saturation
Integrated_Instantaneous_Frequency (AI - Grid)	[illegible]	24.1188	20.1066	[illegible]	44.2469	71.4652	27.9744
Integrated_Reflection_Strength (AJ - Grid)	71.3688	16.97	5.30824	46.8412	25.8751	[illegible]	78.7972
Integrated_Cosine_Of_Phase (AK - Grid)	43.6247	39.7231	20.1006	10.3866	61.8144	58.3962	77.6857
Max_Amplitude (AL - Grid)	[illegible]	8.41479	15.3434	74.2774	25.4336	[illegible]	62.9787
Reflection_Strength (AM - Grid)	[illegible]	21.3234	36.4681	64.7469	15.6875	[illegible]	74.7523
Integrated_Seismic_Amplitude (AG - Grid)	26.5912	36.0967	25.5268	3.62922	73.5268	49.2096	73.1192

Finally layers are calculated over the petrol physical properties are calculated.

Layer Name	Borehole Name	Top Marker	Top MD (m)	Top TVD (m)	Bottom Marker	Bottom MD (m)	Bottom TVD (m)	Gross Porosity TVD (m3/m3)
NESS	34/10-1	NESS	1781.72	1781.61	RANNOCH	1872.2	1872.08	0.295172
NESS	34/10-14	NESS	1907.91	1907.85	RANNOCH	2002.7	2002.63	0.284728
NESS	34/10-3	NESS	1904.53	1904.53	RANNOCH	2002.4	2002.4	0.262439
NESS	34/10-34	NESS	2081.5	2081.4	RANNOCH	2188.3	2188.16	0.250053
NESS	34/10-5	NESS	1970.3	1970.25	RANNOCH	2070.3	2070.2	0.276039
NESS	34/10-6	NESS	2105.67	2105.59	RANNOCH	2197.3	2197.22	0.267408
NESS	34/10-8	NESS	1868	1867.9	RANNOCH	2005.8	2005.63	0.257392
NESS	34/10-9	NESS	1832.88	1832.77	RANNOCH	1860.2	1860.07	0.279949
NESS	34/10-B-11	NESS	3232.5	1902.16	RANNOCH	3263.04	1917.36	0.251883
NESS	34/10-B-12	NESS	2803	2122.02	RANNOCH	2931	2234.31	0.205395
NESS	34/10-B-13	NESS	3023.83	2036.46	RANNOCH	3185.33	2141.49	0.245255
NESS	34/10-B-14	NESS	3696.66	1920	RANNOCH	3933.95	1999.84	0.258783
NESS	34/10-B-16	NESS	3461.77	2223.47	RANNOCH	3792.43	2404.9	0.170451
NESS	34/10-B-17	NESS	2367.07	1977.86	RANNOCH	2537.77	2032.78	0.226013
NESS	34/10-B-2	NESS	2476.41	1886.45	RANNOCH	2561	1940.98	0.267401
NESS	34/10-B-26	NESS	3568.7	2099.75	RANNOCH	3725	2187.59	0.194987
NESS	34/10-B-3	NESS	2327.5	2021.65	RANNOCH	2460.5	2109.94	0.216274
NESS	34/10-B-30	NESS	2524.81	1863.57	RANNOCH	2862.21	1868.18	0.257375
NESS	34/10-B-34	NESS	2482.82	1899.27	RANNOCH	2876.71	1913.16	0.251405
NESS	34/10-B-35	NESS	5407.96	2167.4	RANNOCH	5672.25	2250.66	0.204784
NESS	34/10-B-4	NESS	2504.5	1848.29	RANNOCH	2540	1866.9	0.291369
NESS	34/10-B-5	NESS	2865	1878.75	RANNOCH	2931	1911.51	0.288768
NESS	34/10-B-6	NESS	2161.5	1956.39	RANNOCH	2242.5	2036.71	0.244517
NESS	34/10-B-8	NESS	2767	2038.6	RANNOCH	2964.5	2145.92	0.241607
NESS	34/10-B-9	NESS	2090.5	1994.95	RANNOCH	2208.5	2104.59	0.232384

6.3.1 Extracting Seismic Attributes:

Using Charisma Seismic Attributes generator Volume based Seismic Attributes have been calculated by taking top and bottom of bottom of horizon same as to correspond the interval for measured petrophysical properties through Wellpix Lithozones. In the following table attributes are listed which have been computed for the purpose.

6.4 Data Analysis

Here in the first instance we have quantified the relationship between calculated petrophysical properties and then compute seismic attributes. The two main entities are separated as needful as first one is *Quality Matrix* and second is *Calibration Function*. Quality Matrix functionality given us opportunity to first specify a property to a measured seismic attribute and then examining whats could be results in terms of correlation function in next step. So here we have facility to edit such parameters which control the results indeed. This implies that quality matrix basically helps to gauge with precision that to which petrophysical property a attributes should be attached or related.

Through various iterations on reaching viable relationship between properties and attributes our initial data become ready to be calibrated through linear or nonlinear (neural network) calibration operation on the data. Thus, an equation is produced which permitted to relate property to attribute. In this way a pair of information consisting of property and attribute information based on mathematical relation is worked out for our next step.

6.5 Property Data Propagation and Mapping

After the data have been analyzed and Calibrated through the procedure as described earlier, next step is to grid and map the property based on relationship of Petrophysical property to Seismic Attribute which is essentially done through a specific method called

Guided Mapping. Because its simple method that used a seismic attribute to guide a property. Following are key steps that we have taken for the property grids as under;

Step # 1

As first step we apply the calibration function under the data analysis and an estimated grid is generated which just depicts the estimation applied over the data points after calibration.

Step # 2

For Calculating correction a values of residual scatter have been computed and this correction has sanctioned to calculate a correction to the estimated grid as computed step # 1.This has been done by value at each intersection point between the grid and a borehole, the gridded property value is compared to the actual property value measured in the borehole. An estimated correction is computed either in absolute (Residual) or relative (Ratio) value.

Step # 3

Correction Grid is computed by gridding the residual Scatter data found in previous step. In this step calculate Residual Grid area allows to compute a grid from the residual and this grid will be applied as a correction to Estimated grid in first step.

Step # 4

Now the difference between the estimated porosity grid and the residual porocity grid is resolved by applying the calculated correction to the Estimated Grid. This produces a final property grid that honors the value of the property known at the borehole. The property has now been populated out to the inter-borehole region of the interpretation work area. The final step in the guided mapping process is to estimate the confidence in the output.

REFERENCES