Seismic Reservoir Characterization Using Model Based Post-stack Seismic Inversion: In Case of Fenchuganj Gas Field, Bangladesh

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In the study, model based post-stack inversion technique was used to create pseudo logs at each seismic trace at the well location to constitute high resolution acoustic inverted impedance models. Interpretation of GR log, SP log, Caliper log, and seven sand bodies were marked as reservoir zones in well FG #X, which were identified as a hydrocarbon bearing reservoir. All of predicted gases bearing zones in the well FG #X show the low acoustic impedance (AI) values in inverted section analogous with the calculated AI value of logging data. The impedance value in an inverted section during 1660-1980 ms represents an image of the alteration of thin sand and a thick shale layer of Upper Bhubon formation. By observing the relatively lower AI values in the inverted section three locations have marked as additional well locations (PW 1, PW 2 and PW 3), which are more prospective for optimizing the gas recovery from this field.

Keywords
Surma Basin, Wavelet, Reservoir, Seismic trace, Post-stack inversion, Acoustic impedance

1. Introduction

Reservoir characterization plays an essential role in the prediction of the reservoir properties as well into the economic potential of the field. A detailed study of the static behavior of a producing hydrocarbon reservoir is essential for the development planning of the reservoir and to reduce risk and uncertainty in choosing new drilling locations. Perception of reservoir characterization requires integrated analysis and understanding of the available data, such as seismic data and well log data.

In any seismic reservoir characterization studies, the first step towards a successful hydrocarbon discovery is the mastering of a good subsurface image of seismic data. The reflected seismic wave amplitudes are functions of acoustic/elastic impedances, which project a contrast (reflection coefficient) between the lithology above and below a reflecting boundary. Seismic data is the output of a convolution operation between the earth reflectivity and a source wavelet. The convolution operation produces a band-limited trace, the bandwidth of which is determined by the seismic wavelet. Also, due to the band limited nature of the seismic data, lack of low frequencies prevent the transformed impedance trace from gaining the basic impedances or velocity structure, which is crucial to making a geological interpretation. An attempt to recover this resolution is usually made by obtaining the reflectivity through a deconvolution operation, which is an inverse problem.

Seismic inversion is the process of extracting information about elastic rock properties from seismic data based on the travel-time, amplitude, and phase information contained within a seismogram. It is an optimal way to get a better subsurface image. Commercially, different seismic inversion methods are used to map the detailed reservoir properties such as lithology and fluid properties. In this research work, model based post-stack seismic inversion analysis is used to identify the gas bearing potential zones and possible well locations for further development of the Fenchuganj gas field. Only a small part of full reservoir and modified coordinates were studied due to data confidentiality. The Fenchuganj field has several pay zones and stratigraphy of the structure is consists alternate shale and sandstone in varying proportion. A conventional seismic interpretation technique is very uncertain in predicting rock physics. For this reason, this study intends to reduce the uncertainty to a delineation.
tion of hydrocarbon bearing distribution prediction.

2. Geology and Stratigraphy

The study area is under the Fenchuganj structure which is situated in the transition zone between the central Surma Basin and the folded belt in the east and is closest to the eastern margin of the central Surma Basin, which is separated in the north from the Kailashtila Anticline, in the east from the Harargaj Anticline, and in the south from Batchia Anticline (Fig. 1). In the Surma Basin (Sylhet Trough), it appears that the Fenchuganj structure is the third elevated structure, followed by the Chattak and the Atgram Anticline. This structure appears as a reversibly faulted asymmetrical anticline with a NNE-SSW trending axis. This fault is wider in the southern region, which becomes narrower towards north. It observed that the eastern flank of the anticline is steeply dipping than the western flank due to reverse fault.

Structural and combination traps of Miocene age occur along stratigraphic boundaries, in sandstone-filled channel deposits, and in sandstone beds sealed laterally by shale-filled channels; these comprise major traps in the eastern part of the basin. In general, these sedimentary strata have been folded into several large-scale anticlines that are unfaulted or slight to moderate fault in the western and central parts of the basin.

The Surma Basin contains a great thickness of Tertiary sedimentary strata. This basin contains as much as 20 km of sediments consisting of deltaic, estuarine, shallow-marine sandstones, siltstones, and shales that contain abundant plant-derived organic materials. The variety of sedimentary facies of the Surma Basin indicates a range of depositional environment during Neogene time. These strata generally contain about 0.5 to 3% total organic carbon (TOC) although in places the content of organic matter may range up to 10.5%. Thermal maturation is sufficient to generate natural gas and liquids throughout much of the area.

The Fenchuganj gas field’s geology is similar to that of other fields situated in Surma Basin. The stratigraphy sediments of Fenchuganj structure consists alternate shale and sandstone in varying proportion of Oligocene to Recent age. The stratigraphic succession of the Fenchuganj gas field is based on geological data, seismic data, and well data with brief lithological description are given in Table 1. The reservoirs have been founded in the Miocene sediments, which are mainly composed of alternating gray to dark gray clay, very fine to medium grained sandstones and potential source rocks include shales and carbonaceous shales of Eocene, Oligocene, and Miocene age in the basin center and in the synclinal troughs between the fold trends.

3. Methodology

The seismic inversion method is basically a process of transforming seismic amplitude value to impedance value. This is done by deconvolution process which transforms seismic trace to earth reflectivity. Inversion is the subsurface modeling technique to produce a geologic structure using seismic data as input and well data as control. The post-stack seismic inversion methods use stacked (zero-offset) seismic data to produce images of the AI in depth or time. AI is one of rock-physics parameters, which is influenced by the type of lithology, porosity, fluid content, depth, pressure and temperature.

The fundamental concept of seismic exploration is to send a short time signal into the earth, which is then reflected back from a boundary between two units called reflector. The signals are transmitted through the earth as an elastic wave and brought back to the receiver subsurface information such as geological structure, lithology and fluid through travel time, reflection amplitude and phase variation. If we assume that the angle of incidence is zero and that the layers are flat, the Zoeppritz equations will simplify to the more manageable equation given by Eq. (1).

\[
\eta_i = \frac{Z_{i+1} - Z_i}{Z_{i+1} + Z_i}
\]  

Where \( \eta_i \) is the zero-offset P-wave reflection coefficient at the \( i \)-th interface of a stack of \( n \)-th layer, and \( Z_i = \rho_i \times V_i \) is the AI impedance of the \( i \)-th layer.

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The most severe drawback is that the effect of the band-limited wavelet is supposed to remove the low frequency component of the reflectivity and treat the trace as a set of reflection coefficients, which means that it can never plus some additive noise. Actually the recorded seismic trace is the convolution of the reflectivity with a band-limited seismic wavelet. The most severe drawback is that the effect of the band-limited wavelet is supposed to remove the low frequency component of the reflectivity and treat the trace as a set of reflection coefficients, which means that it can never plus some additive noise.

Equation (1) can be used as a simplified model for the reflections found on a stacked seismic section. Actually the recorded seismic trace is the convolution of the reflectivity with a band limited seismic wavelet plus some additive noise:

$$S_t = w_t * r_t + n_t$$  \( (2) \)

Where \( S_t \) is the seismic trace, \( w_t \) is the seismic wavelet, \( r_t \) is the reflectivity integrated from depth to time, * denoting convolution, and \( n_t \) is the noise component.

Lindseth was one of the first geophysicists to show that if we assume that the recorded seismic signal is as given in Eq. (1), it is possible to iteratively obtain the acoustic impedance in the next layer, \( Z_{t+1} \):

$$Z_{t+1} = Z_t \left[ \frac{1 + r_t}{1 - r_t} \right]$$  \( (3) \)

Applying of Eq. (3) to a seismic trace can effectively transform the seismic reflection data to P-impedance. The AI for the first layer needs to be estimated from a continuous layer above the target area. In this method, the impedance for the \( n \)-th layer can be calculated as follows:

$$Z_n = Z_1 * \prod \left( \frac{1 + r_t}{1 - r_t} \right)$$  \( (4) \)

This procedure, however, is not free from problems. The most severe drawback is that the effect of the band-limited wavelet is supposed to remove the low frequency component of the reflectivity and treat the trace as a set of reflection coefficients, which means that it can never be exactly recovered Eq. (2). Another prime concern is inversion involves removing noise component and proper scaling of seismic data. To assure a more realistic result the low-frequency component missing in the seismic is added the logging data with stacked seismic data. An update approach to inversion is a model based inversion in which an initial low frequency model is modified iteratively to give the best fit to seismic data. The main steps in the inversion procedure include the data preparation and data input into the software, calibration by tying well logs to the seismic data, estimation of the wavelet, generation of a low-resolution initial model, inversion analysis, and inversion. The specific software used in this research to perform model based inversion of stacked seismic data is H-R (Hampson-Russell) STRATA program by CGG Veritas at BAPEX interpretation laboratory under Geophysical Division.

3.1 Well to Seismic Tie

In well to seismic tie, a synthetic trace was generated to correlate with recorded seismic trace. Since the well logs are in depth domain while seismic data is in the time domain, a check shot data were applied before correlation to convert well data into time domain. This process generates a non-linear TWT (two-way time) reference in TVD (true vertical depth) that is used to convert linear depth logs to a linear time domain. The common practice to compute vertical two-way reflection time using the P-wave velocity log data \( v(Z) \) is as follows:

$$t_Z(Z) = t_0 + 2 \int_{z_0}^{Z} \frac{dz}{v(Z)}$$  \( (5) \)

Where, \( t_0 \) is the best estimate of vertical two-way time to depth \( z_0 \). \( t_Z(Z) \) is the two-way time, a sampled function of depth \( z \). Steps common to the most good tie processing are shown in the flow chart below. The resulting trace is displayed on the same vertical scale as is the seismic section for direct comparison.
parison. To improve the match with the seismic data, the synthetic seismic trace can be recomputed using different wavelets and filters. Through a trial-and-error process, the interpreter determines at what point the synthetic trace "best fits" the seismic data. Variations in the quality of the well log data can have a major impact on the final synthetic display. To get a more realistic synthetic trace quality control of data was done, especially in case of well log data.

3.2. Wavelet Extraction

A seismic wavelet is nothing but the source signature, which is required during the inversion process of seismic data. A good wavelet is the core of inversion. In frequency domain wavelet extraction consists determining the amplitude spectrum and phase spectrum. The amplitude spectrum is determined from the autocorrelation function of the data under the usual assumption of "random" (or "white") reflectivity. The phase spectrum is more difficult to determine. Wavelet can and do change from trace to trace and as a function of travel-time. So extraction process should be determining a large set of wavelets for each seismic section. A practical and useful solution is to extract a single average wavelet for the entire section. The wavelet extraction can be purely deterministic (using surface receivers and other means), purely statistical (from the seismic data alone) or using a well log data which is done by correlating the log and seismic data. The phase spectrum is not reliably calculated by statistical method and need to be supplied as a separate parameter by the user. In contrast to the statistical method, wavelet using well log extraction procedure gives more exact wavelet.

3.3. Initial Model

Initial model provides the low and high-frequency components missing from the seismic data, which were used to reduce the non-uniqueness of the solution. Low frequency cut-off point, several band-pass filters were applied to the seismic data to the best estimate of the missing frequency range. Use interpolation along the seismic horizons and between the well locations to obtain the initial AI model. The spatial interpolation method used in the H-R software utilizes inverse-distance weighting and works as follows. Denoting any attribute (for example, the impedance) at well number \( i \) as \( L_i \), the corresponding attribute \( L_{\text{out}} \) calculated at any location near the wells is given by the following equation:

\[
L_{\text{out}} = \sum L_i \ast W_i
\]

Where the weights are:

\[
W_i = \frac{d_{i}^{-2}}{\sum d_{i}^{-2}}
\]

And \( d_i \) is the distance between well \( i \) and the location of interest. Power \((-2)\) used in this weighting ensures that weights stay constant and equal 1 in the vicinity of each well.

3.4. Model Based Inversion

Model based inversion is an approach to inversion that avoids the problems of recursive inversion by iteratively changing a model to give a least-squares fit to the seismic data. The basis of all the inversion analysis is the input data. In the post-stack seismic inversion, stacked seismic volume and the well logs are including velocity and density log is required. Model based inversion is a recent approach to inversion, which is based on the convolution model Eq. (2). If the noise is uncorrelated with the seismic signal, we can solve the reflectivity satisfying this equation (Eq. (2)). This is a non-linear and band-limited equation, which can be solved iteratively. That solution is gradually improving the fit between synthetic traces and the observed seismic data. The solution attempts to simultaneously solve the best-fit reflectivity and minimize the differences between the observed and predicted seismic traces. In H-R software model based inversion product is computed as shown in the flow chart (Fig. 3).

4. Result and Discussion

Using P-wave curve and density log with VSP (Vertical Seismic Profiling) data for well seismic tie shows that the log curves and check-shot surveys of study well were inserted which are corresponding to well locations. In this paper, log data and check-shot survey of well FG #X and post-stack seismic section FGS #A shown in Fig. 4 are used to evaluate the potential for middle to deep zone in the study area. The post-stack seismic section illustrates a typical cross section of an anticline (Fig. 4). As we know, the well log is the fundamental method
to reflect the subsurface condition by using physical properties of rocks which are the key parameters of the reservoir characterization. However, a potential hydrocarbon bearing zone can be identified by having low to medium value of the gamma ray response\textsuperscript{28)}, very negative spontaneous potential (SP) log reading, with high resistivity, higher value of neutron porosity, lower density than the same lithology that surrounds the reservoir, and decrease of sonic velocity response\textsuperscript{25}).

Using GR log, SP log and Caliper log, seven sand bodies zone (A, B, C, D, E, F and G) marked as reservoir zones were interpreted with high hydrocarbon bearing potential (Fig. 6) at well FG #X. The depth of the estimated zones and their lithological properties based on log data are shown in Tables 2 and 3. Zones B and C have relatively thin reservoir sand with average density about 2.3 (g/cm\(^3\)); and AI value is almost 21,100-22,900 (ft/s) (g/cm\(^3\)). Besides zones D and E are the thickest potential gas bearing zones with low average density and AI value (Tables 2 and 3).

The well to seismic tie has long been considered an art for geophysical interpreters\textsuperscript{24}). The synthetic trace is created to correlate with the recorded seismic trace and extract a suitable wavelet for inversion. As we have mentioned in section 3.2, the wavelet derives either directly from the seismic data or is computed with the aid of available well data. The synthetic seismic can be compared with the seismic trace physically measured at the well to improve the picking of seismic horizons and to improve the accuracy and resolution of formations of interest\textsuperscript{25}). At first, we estimated a statistical wavelet, but this wavelet gives a poor correlation coefficient that is below 0.60. Consequently, a full wavelet is estimated using well log and seismic data shown in Fig. 5. This wavelet includes an estimation of the phase obtained by matching the real and synthetic phase spectra at the well location. The length of extracting wavelet is 150 ms with 20 ms taper length and the phase of extraction is set to be a constant phase. The synthetic trace using full wavelet is represented in Fig. 6. The synthetic traces using full wavelet, gives

Table 2 Interpreted Lithology of the Fenchuganj Gas Field at Well FG #X Based on Log Data

| Estimated depth in meter | Lithology | Remark |
|--------------------------|-----------|--------|
| 1300-1350                | Shale     |        |
| 1350-1375                | Sand      | Zone A |
| 1375-1655                | Shale     |        |
| 1655-1680                | Sand      | Zone B |
| 1680-1693                | Shale     |        |
| 1693-1705                | Sand      | Zone C |
| 1705-1815                | Shale     |        |
| 1815-1850                | Sand      | Zone D |
| 1850-2020                | Shale     |        |
| 2020-2080                | Sand      | Zone E |
| 2080-2148                | Shale     |        |
| 2148-2154                | Sand      | Zone F |
| 2154-2206                | Shale     |        |
| 2206-2260                | Sand      | Zone G |
| 2260-2511                | Shale     |        |
| 2511-2526                | Sand      |        |
| 2526-2612                | Shale     |        |
| 2612-2627                | Sand      |        |

Data source: Geology Div., Bangladesh Petroleum Exploration and Production Co., Ltd., Dhaka.
a high correlation level with composite trace where the current correlation coefficient is 0.905. Parameter analysis window in Fig. 6 shows that the time lag is 1 ms and correlation will be slightly improved by the suggested time shift. We applied the time shift to get the best fit match with the composite trace. On the basis of correlation, a new log called P-wave corrected log (using the H-R STRATA software) which is used in the building of the initial mode. However, due to band limited nature of the seismic data, the lowest and the highest frequencies were missed. Lower frequencies are the most critical to rock properties, because it leads to determining fluid, porosity, and all other reservoir properties. To make unique solution low frequency model is needed to supply the low frequency component missing from the seismic trace data in the inversion. The initial model was built by interpolating the AI from targeted well location. The density and sonic logs in the well permit calculation of the AI response. The converted acoustic impedance logs were filtered via a 10/15 Hz high-cut filter to create an initial AI model for the inversion shown in Fig. 7. This is important because we expect only the low-frequency component of the model to supply the low frequencies missing from the stacked seismic data.

The Inversion QC (quality control) analysis performed on selected well location means testing a range of inversion parameters quickly and comparing different parameters before performing the actual inversion. The total inversion was performed using both the QC.
analysis determined that the default inversion parameters are satisfactory, and that STRATA calculates a single global scale, which optimizes the fit between the inversion traces and the actual logs at the well location. In case the parameter analysis is satisfactory, the inversion results were applied to the whole seismic volume. The inversion analysis result at the well location compared to the original log at well FG #X shown in Fig. 8. The inverted impedance was comparable to the impedance from the log in the time between 900 to 2000 ms. The original well log used in inversion ended at the time level 900 ms and below 2000 ms in Fig. 8; the inverted impedance (high spiking curve in first panel) is quite different from the log impedance (low spiking curve in first panel). Measured error was estimated between the original AI and inverted AI result is 4173.83 (ft/s) (g/cm³). The second panel shows the synthetic traces (left) calculated from this inversion result compared with the input seismic traces (right). A visual comparison of real seismic data and inverted synthetic trace in well location shows a good correlation coefficient of 0.910788 (Fig. 8). The analysis of the inversion product has proved that the result is consistent with the actual gas presence observed in the existing well in study area. 

A cross section of the Model Based Post-stack inversion result is shown in Fig. 9 by applying the same parameters throughout the entire volume. The trace data in the model is the synthetic trace computed during well correlation. Inversion product (Fig. 9) has provided clear subsurface image and vertical variations of formation. The discontinuous color attributes at right side of the inversion result indicate presence of a fault zone. Interpreted reservoir zones through logging are

![Inversion QC Analysis Window](image)

Fig. 8 Inversion QC Analysis Window

![Model Based Post-stack Seismic Inverted Section](image)

Fig. 9 Model Based Post-stack Seismic Inverted Section

PW 1, PW 2 and PW 3 are prospect wells (vertical straight line) and zones marked by circles with the low impedance value are the predicted potential zones. The acoustic impedance values are represented by a color scale: the impedance increases from 16,592 to 33,263 (ft/s) (g/cm³) as indicated by the variations of color intensity which changes upward from light to dark. The traces within the model are synthetic traces. Locations marked by horizontal line upon the P-wave curve are indicated the near well bore gas distribution zones interpreted by wire log data of well FG #X. Baffling impedance amplitudes at right portion of this section indicate the fault effected part (fractured zone) of the structure.

PW 1, PW 2 and PW 3 are prospect wells (vertical straight line) and zones marked by circles with the low impedance value are the predicted potential zones. The acoustic impedance values are represented by a color scale: the impedance increases from 16,592 to 33,263 (ft/s) (g/cm³) as indicated by the variations of color intensity which changes upward from light to dark. The traces within the model are synthetic traces. Locations marked by horizontal line upon the P-wave curve are indicated the near well bore gas distribution zones interpreted by wire log data of well FG #X. Baffling impedance amplitudes at right portion of this section indicate the fault effected part (fractured zone) of the structure.

The first panel of this display shows an overlay of two impedance curves: the original impedance (low spiking curve) and the final inversion AI (high spiking curve) at the well FG #X. Time limit from 900 to 2000 ms with error calculation and the impedance misfit was minimized during the inversion (first panel). In second panel, the left wiggle seismic traces are generated from the inversion results while the real seismic data trace is shown in right and the correlation coefficient is 0.910788.
marked by the horizontal line on the inverted section above inserted P-wave curve. Lower impedance value takes place in sand zones, but the amount of lowering depends upon the fluid content of sand. In hydrocarbon bearing sand, lowering of impedance will be high if compared to that of water bearing sand\(^{23}\). All of predicted gas bearing zones in the log section of well FG #X show low impedance value in the inverted section (Fig. 9) with impedance value from 18,856 to 22,243 (ft/s) (g/cm\(^3\)). On the other hand, shale zones show high impedance from 27,519 to 33,152 (ft/s) (g/cm\(^3\)). The calculated value of acoustic impedance through log data at potential reservoir zones are almost same as that of the extracted from inverted section (Table 3). This acoustic impedance of rocks usually varies with different factors like depth, tectonic compression, burial history, inter-granular porosity, fracture porosity, cementation, and types of fluid and their saturation. The gas-filled unconsolidated highly porous sand at fairly shallow depths are seen in seismic sections as bright or dim spots (Fig. 9). These amplitudes or reflection anomalies were also appearing in AI inverted or impedance section as zones of low AI amplitude\(^{20}\).

AI values near 1100 ms and left side of the well location are almost 19,000-22,000 (ft/s) (g/cm\(^3\)). Again at left side of the well location (Fig. 9) and time about 1250 ms acoustic impedance range is about 21,500-23,000 (ft/s) (g/cm\(^3\)). In addition, at times around 1300 ms and 1430 ms, both sides of well, AI value are approximately 22,500-23,500 (ft/s) (g/cm\(^3\)) and 18,500-21,000 (ft/s) (g/cm\(^3\)), respectively. All of these low acoustic impedance zones are marked as potential reservoir zones with circles, indicative of channel sands of the Upper Bhuban formation of the Surma Group. On the other hand, at times near 1280, 1400 and 1600 ms of the inverted section with higher impedance values indicate the overlying shale layer (Fig. 9 and Table 3). AI magnitudes at these locations are nearly 27,100-32,250 (ft/s) (g/cm\(^3\)). The consecutive variations of the acoustic impedance values in inverted section at time 1660-1980 ms represent an image of the thin sand and thick shale layer alteration of Upper Bhuban formation. Through the observation of relatively lower impedance values in the inverted section three prospect well locations PW 1, PW 2 and PW 3 are estimated (proposed) and marked with vertical black lines. A fault zone is visible in the right part of the inverted section rather than the initial model (Fig. 7).

Further, we found that there was a notable difference between conventional and inverted seismic section. The result illustrates that inversion product combined with rock physics technique analysis could provide a better image to predict vertical section of a reservoir character distribution comparable to conventional seismic interpretation techniques (Fig. 10). However, due to lower resolution convention seismic section unable to produce such structure as clearly visible in inverted section which is almost similar to the log interpretation results. But in stacked seismic section, seismic attribute provides an image of the discontinuous formation distribution (Fig. 10). This promising result is a proof of concept that seismic inversion can be used as one of the tools to approach the hydrocarbon or reservoir distribution prediction.

5. Conclusion

By interpretation of GR log, SP log and Caliper log, seven sand bodies zone (A, B, C, D, E, F and G) were marked as reservoir zones in well FG #X which were identified as hydrocarbon bearing reservoir. The synthetic trace using full wavelet gives a high correlation level with composite trace where the current correlation coefficient is 0.905. The inversion analysis result at the well location compared to the original log at well FG #X provides a good correlation of 0.910788 between the inversion traces and the original logs. All of predicted gas bearing zones in the well FG #X show the low impedance values in inverted section and values
are about 18,856 to 22,243 (ft/s) (g/cm³). Also, the calculated AI value from logging data at potential zones are almost same as that of the extracted value from inverted section. Zones of low acoustic impedance at near times 1100, 1250, 1300 and 1430 ms, are marked (enclosed by circle) as potential zones of sand layer. On the other hand, at near times 1280, 1400 and 1600 ms are higher impedance zones indicating the overlaying shale layer. Furthermore, the impedance value in inverted section during time of 1660-1980 ms represents an image of the alteration of thin sand and a thick shale layer of Upper Bhuban formation. Observing the relatively lower impedance values in the inverted section estimated three prospect well locations (PW 1, PW 2 and PW 3), which are more prospective for optimizing the gas recovery from this field.

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