Stepping towards more accurate reservoir characterization

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Abstract

The seismic reservoir characterization of today is more sophisticated and comprehensive. Modern seismic data acquisition, processing, and imaging, with long offset, wide azimuth data is yielding higher resolution, and even with conventional workflows leads to improved quantitative interpretation. Conventional workflows can be improved upon by bringing in changes which can result in value addition to achieve the desired objectives. Example changes could be bringing in appropriate poststack processing steps for preconditioning noisy prestack seismic data from areas with high-velocity near surface geological formations which impact the quality of seismic data, enhancing the bandwidth of the seismic data for improvement of resolution, the use of a calibrated well-driven velocity field in place of the velocity field obtained from seismic data processing, generating more accurate low-frequency impedance models for prestack simultaneous impedance inversion using multiattribute analysis, and even using different facies trends for inversion of seismic data for multi-level pay formation as in the Permian Basin.

Successful implementation of such workflows could result in more accurate three-dimensional reservoir characterization, and reservoir heterogeneity. In such cases reservoir properties estimated from seismic data in the form of lithology and petrophysical properties are found to be more realistic. Additionally, utilization of machine learning workflows can contribute to an improved level of understanding of the reservoir in terms of lithofacies and the overall heterogeneity. Application of advanced visualization tools can aid such understanding.

In our discussion here we focus on some of the aspects pertaining to impedance inversion of seismic data, as it forms an important steppingstone to the determination of various reservoir properties and thus its characterization. We also include an example on unclassified seismic facies classification with the use of generative topographic mapping method.

Keywords: reservoir, characterization, attributes, impedance inversion, frequency bandwidth

Preconditioning noisy data with poststack processing steps

For prestack data analysis, such as extraction of AVO attributes (intercept/gradient analysis) or simultaneous impedance inversion, the input seismic data must be preconditioned in an amplitude-preserving manner. Usually, these steps are generating partial stacks (that tone down the random noise), bandpass filtering (which gets rid of any high/low frequencies in the data), more random noise removal (algorithms such as tau-p or FXY or workflows using structure-oriented filtering), trim statics (for perfectly flattening the NMO-corrected reflection events in the gathers) and muting (that zeroes out the amplitudes of reflections beyond a certain offset/angle chosen as the limit of useful reflection signal). This sequence works in most cases.

Sometimes, high velocity near-surface formations have a significant effect on the quality of the seismic data below, e.g., in seismic data acquired in the Delaware Basin, Texas, US. Quite often it is observed that the P-
reflectivity or S-reflectivity data extracted from AVO analysis appear to be noisier than the final migrated data obtained with the conventional processing stream, which may comprise of processes that are not all amplitude-friendly. This observation suggests exploring if one or more poststack processing steps could be used for preconditioning of prestack seismic data prior to putting it through simultaneous impedance inversion for example.

A typical poststack processing sequence that can be used on prestack time-migrated stacked seismic data may include various steps, beginning with FX deconvolution, multiband CDP-consistent scaling, Q-compensation, deconvolution, bandpass filtering, and some more noise removal using a nonlinear adaptive process. These different processes are applied with specific objectives in mind. Beginning with attenuation of random noise using FX deconvolution, application of a multiband CDP-consistent scaling would balance the frequency and amplitude laterally. In such a process the stacked seismic data are decomposed into two or more frequency bands and the scalars are computed from the RMS amplitudes of each of the individual frequency bands of the stacked data. The computed data are stacked on the individual bands and summed back to get the final scaled data. Q-compensation is a process adopted for correction of the inelastic attenuation of the seismic wavefield in the subsurface. An amplitude-only Q-compensation is usually applied. The values of the inelastic attenuation are quantified in terms of the quality factor, Q, which can be determined from the seismic data or VSP data. In case such a computation proves to be cumbersome or challenging, a constant Q value is applied that is considered appropriate for the interval of interest.

A long time-window deconvolution can also be applied to the data with appropriate parameters, which tends to compress the embedded wavelet in the data, and thus enhance their frequency content. This step is usually followed by bandpass filtering, usually applied to remove unwanted frequencies that may have been generated in the deconvolution application. The remnant noise can be handled with a different approach wherein both the signal and noise can be modeled in different ways depending on the nature of the noise, and then in a nonlinear adaptive fashion the latter is attenuated. Such a workflow can be more effective than a singular FX deconvolution process. That all the above-stated processes are amplitude-friendly can be checked by carrying out gradient analysis on data before and after the analysis.

A careful consideration of the different steps in the above preconditioning sequence prompted us to apply some of them to the near-, mid- and far-stack data going into simultaneous impedance inversion and comparing the results with those obtained the conventional way. Four angle stacks were created for a seismic data volume from Delaware Basin by dividing the complete angle of incidence range from 0 to 32°, with the near-angle stack (0-8°), mid1-angle stack (8-16°), mid2-angle stack (16-24), and far-angle stack (24-32°). Figures 1 illustrates the advantage of following through on this processing sequence application. Notice the far-angle stack is subjected to many of the processing steps mentioned above, and a comparison is shown with the conventional processing application. The overall signal-to-noise ratio is seen to be enhanced and stronger reflections are seen coming through after application of the proposed poststack processing steps. Similar reflection quality enhancement is seen on mid1 and mid2 angle stacks, but not shown here due to space constraints. To ensure that these processing steps have preserved true-amplitude information, gradient analysis was carried out on various reflection events selected at random from the near-, mid1-, mid2- and far-angle stack traces, and found to be satisfactory. The amplitude trend after the proposed preconditioning shows a similar variation as seen obtained using the conventional processing flow.
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Figure 1: An arbitrary line passing though the far-angle stacked volume that used the (a) conventional preconditioning, and (b) preconditioning with application of some post-stack processing steps. Notice the overall enhancement in the signal-to-noise ratio and the emergence of stronger reflections through the remnant ambient noise. *(After Sharma and Chopra, 2019)*

Figure 2: An arbitrary line passing though the P-impedance volume that used the (a) conventional preconditioning, and (b) preconditioning with application of some post-stack processing steps. Notice the overall enhancement in the signal-to-noise ratio and the emergence of stronger reflections through the remnant ambient noise. At the location of the pink arrow in (a) the well data does not show high impedance as seen on the seismic impedance section. A much better match is seen in (b). *(After Sharma and Chopra, 2019)*
In Figure 2 we show a similar comparison of P-impedance sections using the proposed workflow and the conventional one. Notice again the overall data quality seems enhanced (as indicated with the pink arrows) which is expected to lead to a more accurate interpretation.

**Frequency bandwidth extension**

Sometimes the target zones are thin, and the bandwidth of the available seismic data is just not sufficient to resolve them. Any reservoir characterization exercise may not come about successfully. In such cases, the input data could be frequency enhanced.

We put the input seismic data through a bandwidth extension process and derive the reflectivity volume. In principle, once the reflectivity volume is derived from the seismic data, it is possible to filter it back to a frequency bandwidth higher than the input seismic data. But there are some seismic interpreters in our industry who are not comfortable with the idea of enhancing the bandwidth of the data beyond the recorded frequencies. Keeping that in mind here we filter the derived reflectivity volume to the same bandwidth as the input seismic data, i.e., 5-10-50-60 Hz. The seismic section equivalent to the section shown in Figure 3a is shown in Figure 3b. Notice the improvement in the resolution detail, which is also seen on the frequency spectrum shown in the inset. The amplitudes of the frequencies beyond 25 Hz have been enhanced so that the spectrum now looks flatter. The correlation with the impedance logs also looked much better.

Usually, a matter of concern for seismic interpreters is about the preservation of amplitude variation, both in the post-stack and the pre-stack seismic data. This is important for all AVO analysis work as well as impedance inversion performed on the seismic data. We picked up the pre-stack seismic data for a data volume from central Alberta, and after conditioning of the gathers, generated the near-, mid- and the far-angle stacks. This is the input required for simultaneous inversion. In Figure 4 we show the amplitude variation of the near-, mid- and far-angle traces for one such gather for two equivalent events, before and after spectral balancing. We notice that though there is a small change in the amplitude of the events after thin-bed reflectivity inversion, which is expected, the relative amplitude variation with angle is very similar.

Finally, simultaneous inversion was run on the pre-stack data after preconditioning and thin-bed reflectivity inversion run on angle stacks. The result of the impedance inversion in the form of P-impedance sections, before and after thin-bed reflectivity inversion are shown in Figure 5a and b. The overlaid impedance logs are shown as curves as well as coloured strip logs. Notice the mismatch indicated with the yellow arrow between the log and the inverted impedance values in Figure 5a, whereas it shows reasonably good match between the two in Figure 5b. Also, in the intervals indicated by the dashed blue braces to the right, many of the events are seen better well-defined and more focused in Figure 5b than Figure 5a.

We thus conclude from the above exercises that the varying frequency content in seismic data can pose problems while carrying out synthetic seismogram correlation to seismic data. The roll-offs that are seen on the frequency spectra of input seismic data can be flattened out with the application of an amplitude-friendly frequency balancing process. Such an application being a post-stack process but can be fruitfully run on the near-, mid- and far-offset stacks, which can then be put through simultaneous impedance inversion. The results of such exercises can lead to more accurate interpretations which obviously help the bottom-line.
Figure 3: Segment of a seismic section from the (a) input seismic data, and (b) input seismic data with thin-bed reflectivity inversion and filtered to the same bandwidth as the input seismic data. The frequency spectra in the insets show the bandwidth of the seismic data as 5-10-50-60 Hz, that of the filtered thin-bed reflectivity inversion is now seen as flatter. (After Chopra and Sharma, 2016)
Figure 4: The angle stack traces for a short time window, created for data before (a) and after spectral balancing, (b) are shown to the left, where the red and blue bars mark similar events. The amplitudes of these similar events are plotted as a function of angle to the right in (c). Notice that while there is a small change in the amplitude of the events after spectral balancing, the relative amplitude variation with angle is very similar. *(After Chopra and Sharma, 2016)*

Next, we discuss the generation of accurate low-frequency impedance models that can be used for impedance inversion.

**Construction of accurate low-frequency models for impedance inversion**

It is common knowledge that the low-frequency band (< 10Hz) of the frequency spectrum is missing in the seismic data, and consequently, the transformed impedance data also have this frequency band missing. This low-frequency band can be extracted from the impedance well log curves and added to the transformed impedance data, when their values, now called absolute values, match the values seen on the impedance log curves.

The low-frequency band we refer to here is first constructed in the form of a model, which may be 2D or 3D depending on whether the data being inverted is 2D or 3D. The low-frequency model is constructed such that the different subsurface interval impedance values are constrained by the horizons interpreted on the seismic data. This leads to more meaningful inverted impedance data. As we begin to use such inverted data, we realize we are in for surprises. For a 2D seismic profile passing through some wells, when the low-frequency trend extracted from a single well is used in the impedance inversion, the impedance section may
Figure 5: Segments of P-impedance sections generated using (a) the input seismic data, and (b) the data with thin-bed reflectivity inversion. The impedance log at the location of the well is shown as a curve, as a colour strip. Notice the yellow arrows indicating the mismatch between log and the inverted impedance in (a) and a much better match in (b). Also, the intervals indicated to the right with braces indicate the zones that show more well-defined events in terms of impedance in (b). (After Chopra and Sharma, 2016)

may not match the impedance logs at the other well locations. Similarly, if a single-well low-frequency trend is used for inverting a 3D seismic volume, we often run into a similar problem.

Another way to generate a low-frequency model is to make use a few wells for generating the low-frequency model for inclusion in the impedance inversion. Such a technique linearly interpolates the impedance data between the wells using weights calculated on the basis of inverse distance, and similarly extrapolates away from the well control. When quality checks are performed on the generated low-frequency models using this technique, often they are found to exhibit artifacts in the form of artificial tongues with anomalous impedance values, appearing more like bull’s eyes. Such patterns are not geological and do not generate meaningful impedance sections or volumes.
A new workflow for building a low-frequency model for impedance inversion which uses both the well log data as well as seismic data can be applied. Suitable attributes derived from seismic data, as well as the data from different wells are used to estimate a linear regression relationship. This relationship is then used to predict the low-frequency component for use in impedance inversion.

In our case here the objective of multi-attribute analysis is to find a relationship between the well log data and seismic data at the well locations. Once this relationship is obtained it will be used to predict a volume of the log property at each trace location of the seismic data. A simple way of doing this is to crossplot the two in the broad zone of interest. Where a cluster of points is usually seen. A best-fit or regression line is then drawn through the cluster of points, which represents the relationship between the two variables crossplotted. But in such cases in general, a large scatter of the points is noticed on the crossplots, which prevents us from using a single seismic attribute for predicting the target log property.

For improving upon the scatter of points on the crossplot, we try bringing in more attributes in our analysis and executing the multi-attribute regression analysis. In this analysis, the target log is modeled as a linear combination of several input attributes at each sample point. This modeling yields a series of linear equations, which are solved for obtaining a linear weighted-sum of the input seismic attributes in such a way that the error between the predicted and the target log is minimized in a least squares sense.

![Figure 6: Workflow for low-frequency model generation based on multi-attribute regression analysis.](image)

The proposed workflow (Figure 6) for generating low-frequency impedance model is superior to the existing methods of low-frequency impedance generation. The quality of the low-frequency impedance model used in the inversion has a pronounced effect on the final impedance result, and thus a superior low-frequency
impedance model when used in the inversion process yields a more accurate impedance inversion output. Our work on other such exercises corroborates this conclusion. We recommend this workflow for carrying out estimation of elastic parameters for quantitative interpretation of seismic data, especially when there is lateral variation of the impedance from well-to-well through the 3D volume.

Figure 7: P-impedance sections with the P-impedance logs overlain on it at a blind well, when (a) single-well, (b) multi-well based low-frequency model is used in impedance inversion. Notice the mismatch of the inverted impedance values with the measured log values in the highlighted zone in (a), whereas they match well in (b). (After Ray and Chopra, 2015)

Figure 7 shows a comparison of inverted impedance sections where a single-well low-frequency model was used in one (Figure 7a) and a multi-well low-frequency model was used in the other (Figure 7b). A clear mismatch of the inverted impedance values with the measured impedance values is seen in (a), whereas a good match is seen in (b). Should such erroneous low-frequency models be utilized in impedance inversion, the resulting rock physics parameters, or parameters such as TOC are computed therefrom will be in error. One such example we display in Figure 8, where a comparison from the generated TOC volumes is shown. The erroneous low-frequency impedance model yields low TOC values as indicated in the highlighted areas in (a), which should be high values as per the geochemical data available from wells in those areas (not marked). When an accurate low-frequency impedance model is used in impedance inversion and the subsequent TOC computation, higher values are seen in the highlighted zones as are expected.
Use of calibrated well-driven velocity field in AVO

Amplitude variation with offset or angle (AVO or AVA) has been widely used for discriminating hydrocarbons from brine-saturated rocks. Such analyses are based on Zoeppritz equations that describe the partitioning of energy at a rock interface into reflected and refracted energy components.

In actual practice, NMO-corrected prestack seismic data are conditioned for enhancing the signal-to-noise ratio and thereafter put through amplitude-variation-with angle (AVA) analysis. As all mathematical formulation for AVA analysis is carried out in the angle of incidence domain, a significant step in the AVA workflow is to transform conditioned NMO-corrected seismic offset gathers to angle gathers. For doing this, practitioners have two options that they could explore. One of them is to make use of the seismic velocity field obtained from processing of the seismic data, and the other is the well-driven velocity field generated using the sonic log curves. Generally, seismic stacking velocities exhibit an increasing velocity trend, which is quite evident when overlaid on the offset gathers for quality control purposes as shown in Figure 9a. Even when they do show variation at strong impedance contrast geologic markers, the vertical and lateral variations may not be smooth. Segments of sections from the seismic as well as well-driven interval field are also shown in Figure 9a and b, with a sonic log curve (filtered to seismic bandwidth) overlaid on them. Notice on the seismic interval velocity section the variation in velocity, both laterally and vertically is not smooth, as no significant geologic changes are expected. The well-driven velocity field looks more reasonable in terms of interval consistency and correlation, and so appears to be more authentic. Such a more realistic interval velocity field when used in the AVA analysis exhibits significant differences in the gradient attribute. Besides, the angle range computation may be different in the two cases as indicated with the two white block arrows in Figure 9a and b.
As stated above, intercept and gradient attributes can be computed using Shuey’s approximation to Zoeppritz equations. As the intercept attribute is a function of just the impedance contrast at zero offset, no appreciable differences are seen on the intercept sections. However, as the gradient attribute is a function of the P-wave velocity, S-wave velocity, and density, which in turn are a function of the various rock-fluid properties, significant differences may be seen between the gradient attribute computed using the seismic velocity field and the well-driven velocity field. In Figure 10a and b we exhibit such a comparison, for data from central Alberta, Canada.

The interpretation of the intercept and gradient attributes is usually carried out by judiciously selecting the data covering the zone of interest from the two attributes and display them in crossplot space.
actually confirmed by generating a modeled gather for one well, crossplotting the intercept and gradient, where a striking resemblance was seen between the two.

![Impedance inversion with different facies trends](image)

**Figure 10:** An arbitrary line passing through different wells extracted from the AVO gradient volume generated when (a) seismic velocity, (b) well-driven velocity was used in the analysis. The seismic data are from central Alberta, Canada. *(Data courtesy, TGS, Canada) (After Sharma and Chopra, 2019)*

**Impedance inversion with different facies trends**

The output attributes from prestack simultaneous impedance inversion are P-impedance, S-impedance, and density (if the angle of incidence range extends beyond 40 degrees). The inversion process begins with the low-frequency model, which is used to generate synthetic traces for the input partial stack. Zoeppritz equations or their approximations are used to estimate the band-limited elastic reflectivities. These model impedance values are then iteratively tweaked in such a manner that the mismatch between the modeled angle gather and the real angle gather is minimized in a least squares sense. One of the fundamental assumptions made within the simultaneous inversion workflow is the linearization between \( \ln(I_P) \) and \( \ln(I_S) \) as well as \( \ln(I_P) \) and \( \ln(\text{Rho}) \). Such workflows work well for a continuous impedance inversion carried out over a time window, over which the above-mentioned linearity holds.
Quite often, especially when dealing with complex geology, the simultaneous inversion workflow outlined above may not be directly applicable. We cite here an example from the Delaware Basin, Texas, USA.

Figure 11: (a) The stratigraphic column of the Delaware Basin focused on the Bone Spring and Wolfcamp intervals and its correlation with seismic data. (b) Lithological trend analysis in terms of crossplots to be used in impedance inversion in different litho-intervals within Bell Canyon and Mississippian markers. The different litho-trends have been overlaid on the one crossplot with blue line for the Bell Canyon to Bone Spring interval, green for the Bone Spring to Top Wolfcamp interval, and purple line for the Top Wolfcamp to Mississippian interval. (Data courtesy: TGS, Houston) (After Sharma and Chopra, 2019c)

Figure 11a shows the stratigraphic column for the area. The Bone Spring formation has sequences of dark grey deep-marine shales interbedded with sands and black carbonates. While the sands were deposited as turbidites during low sea levels, the black bituminous-rich limestones were deposited in deep euxinic basinal environments. The Wolfcamp formation consists of dark shale and limestone with silt and sand zones. Both the Bone Spring and Wolfcamp are productive formations so are the Barnett, Mississippian and Woodford intervals. The extent of the broad zone of interest extends from the Bell Canyon (close to 800 ms) to Mississippian (close to 2800 ms), an overall interval of 2 seconds. Complicating this large time interval for inversion is the fact that it has varied lithology facies in the different subunits. The linearity between ln(I_P) and ln(I_S) as well as ln(I_P) and ln(Rho) could be in question, or different facies may exhibit different linear trends. In Figure 11b we exhibit a crossplot between ln(I_P) and ln(I_S) for the complete interval from Bell Canyon to...
Mississippian. We have overlaid the litho-trend lines from Bell Canyon to Bone Spring (blue line), Bone Spring top to top of Wolfcamp (green line), and top Wolfcamp to Mississippian (purple line). Notice all these facies trends are different, and thus carrying out simultaneous impedance inversion for the 2 seconds long interval with a single trend would not be advisable, to say the least. Consequently, we modified our simultaneous impedance inversion procedure. Instead of carrying out a single inversion run, we performed the inversion in three separate runs, each using its own litho-facies trend line as discussed above. The three inversion runs were then sutured together as a single impedance volume.

Figure 12: Inverted P-impedance section along the arbitrary line when (a) a single trend is used, (b) different trends are used in the inversion analysis. Significant differences can be noticed at the location of the different coloured arrows. (Data courtesy: TGS, Houston) (After Sharma and Chopra, 2019c)

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In Figure 12 we show equivalent arbitrary line sections passing through two wells, from the simultaneous impedance inversion run with a single trend (Figure 12a, generated for comparison only), and another with three different trends in separate zones and combined (Figure 12b). The impedance log curves for the two wells are overlaid on the sections in colour. Notice the difference in impedance values in the highlighted zones and at the location of the block arrows. Similar differences were seen on the S-impedance sections as well. Such differences can contribute significantly to the elastic properties which are derived from the P- and S-impedance volumes.

Various commercial impedance inversion software packages have been developed that talk of first deriving depth trends for individual facies in the zone of interest using rock physics analysis, which are then used for impedance inversion.

We firmly believe that our approach of using an accurate low-frequency model (based on the workflow we follow) as well as using the appropriate lithofacies trends in the simultaneous impedance inversion procedure can bring in accuracy in the desired results.

**Machine learning workflows contributing to a better understanding of reservoir**

Finally, we include here an example from the machine learning application for unsupervised facies classification for a geothermal sandstone reservoir in Denmark, where the determination of lateral variation in facies was the objective.

The target reservoir is a Triassic-Jurassic deep geothermal sandstone reservoir, north of Copenhagen, onshore Denmark. The data available for this study were a 2D seismic survey from 2013 (comprising five profiles with 3 km offset, designed for structural mapping, and outlining potential geothermal reservoirs), a local well (Karlebo-1A), and another well that penetrated the reservoir of interest.

![Seismic profile](image)

**Figure 13:** A seismic profile shown overlain by the main geological units with the projected location of the Karlebo-1A well. Yellow indicates the primary and secondary geothermal targets. *(Chopra et al., 2022)*

The geothermal interval is the sandstone-dominated Upper Triassic-Lower Jurassic Gassum Formation, which is being exploited for geothermal production and storage in Denmark. Figure 13 displays a seismic line with...
geologic interpretation with the Karlebo-1A well projection overlaid on it. The Lower Jurassic sandstone unit that overlies the Gassum Formation is a secondary geothermal target. Both these units lie at a depth of about 2 km below the ground level. Above the Lower Jurassic sandstone unit is the Fjerritslev Formation that is dominated by marine mudstones and shales, which is the regional caprock. The Lower Cretaceous sandstone unit sits on top of the Fjerritslev Formation, and in turn is overlaid by the high-velocity chalk formation that generates interfering multiples and converted waves, which makes processing of the seismic data challenging. Below the Gassum Formation are the impermeable mudstones of the Vinding, Oddesund, and other older formations. The observations from Karlebo-1A well indicate that while the Lower Jurassic reservoir unit is a homogeneous unit, the Gassum sandstone contains interlacing of thinly bedded shale. The reservoir temperature ranges between 50 and 65°C in the target interval.

Unsupervised learning provides a means to determine if the seismic response can be related to flow units or rock types that can be calibrated with additional well control, but for which we do not understand the underlying petrophysical or geological theoretical support. Still seismic interpreters face a perpetual challenge of extracting heterogeneous seismic facies on different generated attributes. The common analysis tools include corendering, crossplotting and visualization, which can help to an extent in terms of simultaneous display of the input attributes.

Figure 14: Section display for the seismic profile from co-rendered GTM1 and GTM-2 using a 2D colour bar. Multiplexed colour bar shown in the above display. This display exhibits the best spatial resolution in all four intervals 1 to 4 compared with all the other methods discussed in this exercise. (Chopra et al., 2022)
Generative Topographic Mapping

Though the Kohonen self-organizing mapping (SOM) method is a popular unsupervised facies classification method, easy to implement, is computationally inexpensive, it does have limitations. First, there is no theoretical basis for the selection of parameters such as training radius, neighbourhood function, and learning radius, as all these are data dependent. Secondly, no cost function is defined in the method that could be iteratively minimized indicating convergence during the training process. Finally, as a measure of confidence in the final clustering results, no probability density is defined. Thus, an alternative approach to the Kohonen SOM method, called *generative topographic mapping* (GTM), which overcomes the above-stated limitations. It is a nonlinear dimension reduction technique that provides a probabilistic representation of the data vectors in latent space.

Thus, as the above description suggests, the GTM methods projects data from a higher dimensional space (8D when 8 attributes are used as input) to a lower dimensional space, which may be a 2D deformed surface. Once projected on to this plane, the data can be clustered in that space, corendered with RGB or crossplotted using a 2D colour bar.

In Figure 14 we show a section display for seismic line for the GTM-1 and GTM-2 crossplotted together using a 2D colour bar as shown to the lower right. This display exhibits the best spatial resolution in all four intervals 1 to 4 compared with all the other methods discussed in this exercise. The individual-coloured patches or facies are crisper and could lead to more accurate interpretations.

**Conclusions**

We have described a few different workflows here which when implemented on prestack/poststack seismic data bring in more accurate reservoir characterization. It is important to realize that incremental value additions through such workflows can build up and yield the rewards by way of successful drilling. Needless to mention, the minimum data (well logs, core calibration, petrophysical information) should be available so that geoscientists don’t need to cut corners and compromise on the results.

**References**


Satinder Chopra has 37 years of experience as a geophysicist specializing in processing, reprocessing, special processing, and interactive interpretation of seismic data. He has rich experience in processing various types of data such as vertical seismic profiling, well-log data, seismic data, etc., as well as excellent communication skills, as evidenced by the many presentations and talks delivered and books, reports, and papers he has written. He has been the 2010–2011 CSEG Distinguished Lecturer, the 2011–2012 AAPG/SEG Distinguished Lecturer, and the 2014–2015 EAGE e-Distinguished Lecturer. He has published eight books and more than 500 papers and abstracts and likes to make presentations at any beckoning opportunity. His work and presentations have won several awards, the most notable ones being the 2021 Roy O. Lindseth CSEG Medal Award (2021), AAPG Distinguished Service Award (2019), EAGE Honorary Membership (2017), CSEG Honorary Membership (2014) and Meritorious Service (2005) Awards, 2014 APEGA Frank Spragins Award, the 2010 AAPG George Matson Award, and the 2013 AAPG Jules Braunstein Award, SEG Best Poster Awards (2007, 2014), CSEG Best Luncheon Talk Award (2007), and several others. His research interests focus on techniques that are aimed at the characterization of reservoirs. He is a member of SEG, CSEG, CSPG, EAGE, AAPG, and the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

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