Reservoir characterization analysis in glacial reservoirs

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Abstract

This research aims to characterize reservoir properties by applying rock physics and AVO analysis followed by pre-stack inversion. Two approaches are investigated: One approach addresses the case in which there are wells and seismic data, and the other addresses cases where only seismic data are available. The former approach is achieved by using well-log cross-plots for rock physics modeling to determine the feasibility and pay zone through gas fluid substitution followed by AVO analysis. Pre-stack inversion is then used to predict porosity and gas saturation. In the second approach, a synthetic seismogram is generated and compared to the observed seismic trace at the location of interest by forward modeling P-wave interval velocity and density. The best-matching P-wave velocity and density are subsequently used to generate synthetic well logs at the same location. Pre-stack inversion is then performed on these synthetic wells to predict porosity and gas saturation. Property prediction is performed by a feasibility study and pay zone calculation using rock physics modeling of the nearest well to the seismic block. Finally, the results of this case are validated using real wells. This new approach of reservoir characterization using synthetic wells is applied on reservoir channels and yielded a fairly good porosity prediction but a less accurate prediction of gas saturation.

Keywords Inversion · AVO · Rock physics analysis · Fluids prediction · Porosity prediction

Introduction

Reflection seismic data play a major role in hydrocarbon exploration and field development. There have been advances in the oil industry to increase the rate of successful wells and increase hydrocarbon reserves. The identification of reservoir fluids is essential for interpreters to place their prospects at the maximum hydrocarbon accumulation trap in the reservoir. Hydrocarbon-filled reservoirs are characterized with lower acoustic impedance, as they have lower density and lower velocity than the surrounding water-filled rocks. There are different methods to characterize fluid properties in the reservoir, such as well logs, seismic modeling/inversion, amplitude variation with offset (AVO) inversion, and rock physics.

In forward seismic modeling, we apply a mathematical simulation on earth properties, such as P-wave velocity (Vp), S-wave velocity (Vs), and density (ρ) to generate synthetic seismic data. Density is measured by emitting gamma rays into the formation, which collides with the formation’s electrons. Gamma rays reach the detectors more in a low-density than in a high-density formation, as the higher the presence of electrons in the formation is, the higher the reduction of energy is, and the fewer the electrons captured by the detector are. Generally, the rock’s density is inversely proportional to the porosity. The sonic log measures the time it takes for a sound wave to travel through a formation. Porosity, lithology, and fluid content affect the travel time of the wave in a formation (Varhaug 2016).

Rock physics use simplified models of rocks to predict their behavior under various subsurface conditions, particularly how a rock property (e.g., P-wave velocity) changes as its pore fluid is changed. Gassmann equations are commonly used in calculating the elastic moduli of a porous rock, as its pore fluid is substituted partially or fully by another fluid.

In seismic inversion, seismic reflectivity data are converted into rock properties. Seismic inversion is classified according to the type of seismic data used: pre-stack
or post-stack data. Post-stack seismic inversion is used for acoustic impedance, which is $P$-wave velocity multiplied by density. Pre-stack seismic inversion is used for acoustic impedance, velocity ratio ($V_p/V_p$), and density (Altowairqi 2015). Log data have to be conditioned and verified before they are utilized. To perform an acoustic impedance inversion modeling, an earth model is estimated by using formation depths, velocities, and thicknesses derived from well-log data. This model is convolved with a wavelet estimated from the seismic data to generate a synthetic seismic data. Inversion takes place by iterating between the synthetic forward model and the real seismic data to obtain the best-fit model. Seismic data are band-limited due to practical limitations of the seismic source. Therefore, low-frequency models are generated from well-log data to constrain the inversion and add frequencies beyond the seismic band (Kemper 2010). The combination of the relative acoustic impedance, derived from the seismic data, and the low frequency, derived from the well logs, generates an absolute acoustic impedance model. Absolute acoustic impedance is required to obtain reservoir properties such as velocity and density (Barclay 2008).

Amplitude variation with offset (AVO) analysis is a technique used for hydrocarbon identification by analyzing seismic reflection amplitude anomalies. Zoeppritz equations are used to derive the amplitudes of a reflected $P$-wave as a function of incidence angle. These equations are too complicated to be used for explaining the relationship between amplitudes and the physical parameters. There have been several approximations of Zoeppritz equations over the years. Bortfeld (1961) emphasized the fluid and rigidity terms, which helped in interpreting fluid-substitution problems. Aki and Richards (1980) emphasized $P$-wave and $S$-wave velocities and densities. Shuey (1985) modified these equations to include Poisson’s ratio and found a relationship between angle stacks and rock properties. Shuey’s approximation is given by

$$ R(i) = A + B \sin^2 i + C(\tan^2 i - \sin^2 i) $$

$$ A = \Delta V_P/2V_P + \Delta \rho/2\rho $$

$$ B = \Delta V_P/2V_P - 4V_S^2/V_P^2(\Delta \rho/2\rho + \Delta V_S/2V_S) $$

$$ C = \Delta V_P/2V_P $$

where $R(i)$ is the reflection coefficient of a reflected $P$-wave due to an incident $P$-wave; $i$ is the average of incidence and transmission angles across the interface; $V_P$ is the average of $P$-wave velocities across the interface; $V_S$ is the average of $S$-wave velocities across the interface; and $\rho$ is the average of densities across the interface.

The first term, $A$, in Shuey’s equation is the normal-incidence reflectivity that dominates at small incidence angles (0–15°), the second term, $B$, dominates at intermediate incidence angles (15–30°), and the third term, $C$, dominates at large incidence angles (30–45°). The third term, $C$, is usually insignificant as most incidence angles are below 30° (Feng and Bancroft 2006). Gas sand reflections have been divided into four classes based on their AVO characteristics. The intercept and gradient are plotted to view different trends of elastic properties and determine these classes (Rutherford and Williams 1989).

A main challenge of targeting glacial channels in 3D seismic blocks in the study area is to characterize the reservoir fluid type. The main cause is the difficulty in performing pre-stack inversion due to the lack of well control in these blocks and the poor quality of the pre-stack gathers. In this study, a new approach is investigated to characterize reservoir properties, by using synthetic wells, in these glacial reservoir channels from seismic data. Reservoir properties are predicted from a pre-stack inversion model that utilizes rock physics and AVO models. Two approaches are investigated: One approach addresses the case in which there are wells and seismic data, while the other approach addresses the case where only seismic data are available. The results of the two approaches are then compared.

This paper starts with a brief overview of the study area highlighting its main exploration challenges. This section is followed by a description of the main methodologies and proposed workflows. An application of the workflows is illustrated subsequently in Results section. Finally, we conclude with a summary and a brief discussion of the accuracy for the proposed workflows in Conclusion section.

**Study area**

Paleozoic rocks are exposed along the eastern margin of the Arabian Shield in addition to northwestern and central Arabia. Central Arabia went through a series of epeirogenic movements associated with global tectonic events. The three main regional tectonic episodes were Taconic, Acadian, and Hercynian movements. Middle Ordovician and Upper Silurian unconformities are a result of these epeirogenic phases (Laboun 2009).

During the Middle Ordovician, sediments were deposited in stable marginal shelf conditions as a result of tectonic quiescence (Senlap and Al-Duaiji 2001). The area went through an uplift and tilt following deposition during the late Ordovician. Lower Ordovician and Middle Ordovician formations were exposed and eroded. Upper Ordovician glaciation affected the Arabian Plate that was sitting on the margin of the Gondwana supercontinent during the Upper Ordovician, which resulted in the deposition of glacial sandstone.
formation, which is the target in this study area, across the Arabian Plate. In the outcrop, the Upper Ordovician glacial sandstone formation is a confined underfilled valley with very fine to conglomeratic sand-dominated glaciogenic deposits. In the subsurface, deposits are unconfined over-filled valleys with glaciomarine sandstones.

The Upper Ordovician deformed unit (Melvin 2015) was also deposited along with an Upper Ordovician glacial sandstone formation as a result of sea level fall and glaciation. The Upper Ordovician deformed unit is composed of a repetition of tillite, boulder-clay, and fine-grained micaceous sandstone lithofacies. The Upper Ordovician glacial sandstone formation ranges from fine- to coarse-grained through cross-bedded fining upward sandstone. The glaciation events subdivide the Cambrian-Ordovician-Silurian succession into three depositional cycles: the pre-glaciation cycle (Lower and Middle Ordovician formations), the syn-glaciation cycle (Upper Ordovician Formation), and the post-glaciation cycle (Uppermost Ordovician and Lower Silurian units).

The Upper Ordovician glacial sandstone formation is believed to be deposited in a range of fluvio-glacial and glaciomarine environments. Palynological data from core analysis in the study area indicate glaciomarine conditions where sub-glacial erosion of tunnel valleys fed glacial outwash fans that were developed during ice maxima low-stand phases separated by extended narrow channels (Craigie et al. 2016). The Uppermost Ordovician post-glacial unit unconformity of the fluvial and shallow marine and isostatic rebound caused regional instability. Uppermost Ordovician post-glacial unit sedimentation was deposited above the unconformity as a result of differential unloading and fault reactivation. In this area, the Uppermost Ordovician post-glacial unit is shallow marine and dominated by tidal features. The Lower Silurian unit overlies the Uppermost Ordovician post-glacial unit. As the eustatic sea level rose on the Gondwanan ice sheet during the Lower Silurian, the glacial margin was flooded, and Lower Silurian unit sediments were deposited. The Lower Silurian unit acts as both the source and a seal for the Upper Ordovician formation. It is characterized by a gray to black color, organic, rich mudstones, and claystones.

**Methodology**

This research is based on two approaches. The first approach uses well-log data for rock physics modeling and AVO analysis in the feasibility study stage. A pre-stack inversion model is then generated in order to predict properties such as porosity and gas saturation zones. The second approach assumes that there are no drilled wells in the seismic block and predicts porosity and gas saturation at planned well locations. At each one of the planned well locations, synthetic P-wave velocity and density logs are generated by forward modeling. These synthetic logs are then convolved with a wavelet to create a synthetic seismogram that matches the seismic response. These models are iterated to obtain the best-fit match between the synthetic seismic and the real seismic responses. A pre-stack inversion model is then generated based on these synthetic wells. Property prediction is achieved by a feasibility study and pay zone calculation using rock physics modeling of the nearest well to the seismic block, which is about 60 km away from the block in our study area. The workflow of the pre-stack inversion for the first approach is indicated in Fig. 1.

The 3D seismic volume used in this study covers an area of approximately 3400 km². Interpretation was achieved on post-stack data. Inversion was run on five angle stacks, which go from 0° to 50° at an increment of 10°. Measured and calculated logs from six drilled wells,
including sonic data, density, and their mineral content, are used in this study. Five of those wells are located in the seismic block. Five horizons are picked on seismic data ranging from shallow to deep (Fig. 2). They are used in building the low-frequency model to constrain the inversion.

After horizon picking, seismic data are flattened at top target (H3) and spectral decomposition attributes are generated at 15, 20, and 25 Hz. These frequencies were selected because they display the clearest channels’ geometries compared with other frequencies. These three attributes are blended together to form a red-green-blue (RGB) color-blended map, where each color corresponds to a specific frequency range. This RGB color-blended map is used to view the channel geometry, and the channel polygons are drawn from this attribute map (Fig. 3).

Results

Approach 1-inversion using real wells

Rock physics modeling

The first step for an inversion feasibility study is to cross-plot acoustic impedance and porosity logs to find the relationship between them. Cross-plotting acoustic impedance and porosity logs for all wells used in this
study at the target formation, color-coded with water saturation log, show an inverse relationship between acoustic impedance and porosity with a correlation factor of 80% (Fig. 4).

In this dataset, acoustic impedance inversion differentiates between porous and tight zones. However, it does not indicate the rock’s fluid type, as there is no relationship between acoustic impedance and water saturation. An attempt to determine the rocks’ fluid type is to cross-plot acoustic impedance and Vp/Vs logs color-coded with the water saturation log. The Vp/Vs log differentiates between gas and wet zones. Three rock types were classified from the acoustic impedance and Vp/Vs cross-plot: porous gas sandstone, porous water sandstone, and tight sandstone. Rock types are verified from this plot with the wells used. Well A is displayed as an example to view the porous gas sandstone zone that is detected on the well logs (Fig. 5).

The target formation frequency spectrum range is between 7 and 42 Hz. Well logs were filtered to 30 Hz, which is lower than the maximum frequency for the target formation. Rock types are verified when the gas zone is detected on the well logs in Well A (Fig. 6).

To define the pay zone, well logs were fluid-substituted twice: once to 100% gas and once to 100% water. Fluid substitution aims to estimate changes in elastic properties due to changes in pore fluids. Based on the cross-plot derived from fluid substitution, a boundary line equation, between the gas and the wet zones in the porous section, is calculated to define the pay zone (Fig. 7). In the low-mid porous section, there is an overlap between gas and water
facies, which makes it difficult to determine fluid types in this zone by the pre-stack inversion.

**AVO analysis**

The following step for a pre-stack inversion feasibility study is AVO analysis. This analysis is performed by comparing the AVO response, at the target formation on a well location, between the observed seismic responses, i.e., the seismic gathers and a synthetic seismic gather. The synthetic seismic response is generated by applying Shuey’s approximation of the Zoeppritz equation on P-wave velocity, S-wave velocity, and density. This AVO analysis comparison aims to check the seismic amplitude compliance with AVO. If the seismic AVO follows the same trend as the synthetic seismic AVO, the seismic data are suitable for pre-stack inversion. If there is a mismatch in the AVO trend, that will affect the quality of the pre-stack inversion results.

Well C is displayed as an example for the AVO analysis comparison between synthetic and observed seismic responses. A synthetic seismic gather is generated at the top of the gas zone (Fig. 8). AVO analysis is then run at the same zone on both the observed (blue) and synthetic seismic gathers (red) (Fig. 9). When comparing these two AVO curves, both curves decrease in the near offset. In the mid-offset when reaching an angle of 20°, the AVO curve of the observed seismic gather starts to increase, while it keeps decreasing in the synthetic seismic gather. This AVO mismatch in the mid-offset will affect the quality of the
pre-stack inversion results, especially the Vp/Vs volume, which is calculated mainly from the mid-offset.

AVO analysis is also used to highlight potential gas zones in the area. This is achieved by calculating the angle of the best-fit line in the gradient and intercept cross-plot window. Gradient and intercept are calculated from the trend line equation of the AVO curve of the synthetic seismic gather. The gas trend line angle is then plotted on the intercept and gradient cross-plot window that is calculated directly from the seismic AVO trend line.

In Well C, the intercept and gradient were calculated from the trend line equation of the AVO curve of the synthetic seismic gather, which falls on top of the gas zone displayed in Fig. 9. After plotting the intercept and gradient for the synthetic AVO curve, a best-fit line of the data is plotted. The angle of this trend line is calculated which is about 67° (Fig. 10). This gas trend angle will be plotted on the seismic intercept and gradient cross-plot window to highlight the gas area.

The gas trend line angle is also calculated in Well A to validate the gas trend angle that was calculated earlier in Well C. In Well A, a synthetic seismic gather is generated at the top of the porosity zone after well logs are fluid-substituted to 100% gas, since most of the in situ fluid content is water (Fig. 11). The AVO curve is displayed to calculate the intercept and gradient from the trend line equation (Fig. 12).

After plotting the intercept and gradient for the 100% gas AVO curve, a best-fit line of the data is plotted (Fig. 13). The angle of this trend line is calculated to be −67°, which is the same as the trend line angle of the gas zone in Well C.

A line across the seismic angle stacks within the target window was fitted to calculate the intercept and the gradient from Shuey’s two-term approximation of Zoeppritz equations:

\[
R(i) = A + B \sin^2 i
\]  

The intercept and gradient from the seismic responses are plotted in Fig. 14. On this plot, the gas trend line angle that was calculated in Wells A and C is plotted. The potential gas area falls at an angle that is lower than the gas trend angle, and it is highlighted on the cross-plot.

The highlighted potential gas area in Fig. 14 is displayed on the target formation surface in Fig. 15. Channels polygons that were drawn from the spectral decomposition attribute are also displayed on the map. There is noise in the map, especially at the top right corner, which is probably due to edge effects. Due to noise in the seismic data, this map is to be used only as guidance for gas exploration.

**Wavelet extraction and the well to seismic tie**

An important step in building the inversion model is wavelet extraction. The wavelet suitability in running the inversion is measured by its predictability percentage, which measures the similarity or repeatability between the observed and synthetic seismic traces generated using this wavelet. Different kinds of wavelets have been tested on inversion, such as different multi-well deterministic wavelets, wavelet extraction from filtered seismic data, phase-shifted wavelets to correct for an inconsistent phase within the seismic data, and statistical wavelets that are extracted from the seismic data alone without the use of well logs. The wavelets that
are used for the pre-stack inversion are deterministic multi-well wavelets. They were selected for providing the highest predictability percentage.

For example, Fig. 16 shows that Well A ties closely to the observed seismic trace at the base of the target formation but generates a slight miss-tie at its top. The wavelet that is used in this well tie is used in the pre-stack inversion generation and yielded a predictability percentage of 66%.

**Pre-stack inversion model**

Observed seismic data are generally band-limited and lack low frequencies. Seismic data only show relative changes in
the values of rock properties. To obtain the absolute values, a low-frequency model needs to be added to the seismic data to make up for the missing low frequencies. The low-frequency model is built from the well logs and added to the seismic data for interpolation. It also needs horizon input to constrain the model. For pre-stack inversion, low-frequency models are needed for inverting acoustic impedance, density, and Vp/Vs. Figure 17 shows an example of a low-frequency model for acoustic impedance built from 0 to 8 Hz. The layering between horizons is very clear.

The three low-frequency models that were created for AI, density, and Vp/Vs are convolved with multi-well wavelets, generated from the five angle stacks, to generate the pre-stack inversion model. The inversion method being used is a model-driven inversion, where Aki and Richards approximations of the Zoeppritz equations are used to find a relationship between P-wave reflectivity and the angle of incidence (Ma 2002).

Well A is displayed as an example in Fig. 18 to compare the acoustic impedance inversion to acoustic impedance log that is filtered to 40 Hz, which is seismic frequency. On the right track, acoustic impedance volume was converted to a log (blue) using the time depth relationship of Well A to compare it to the actual acoustic impedance log (black). Both curves follow the same trend at the top target. In the deeper part, there is a miss-tie that is due to phase inconsistency in the seismic data. The Vp/Vs inversion in Fig. 19 is not tying well to the 40 Hz-filtered log due to the AVO mismatch that is displayed earlier in Fig. 9 between the observed and synthetic seismic responses.

Properties prediction

Porosity was estimated using the direct linear relationship method between acoustic impedance and porosity from all the well logs at the target formation level that is displayed in Fig. 4. Gas-saturated volume was estimated using the pay zone equation derived from rock physics modeling (Fig. 7). Well A is displayed as an example to compare the predicted porosity and gas saturation (blue) to the actual porosity and gas saturation logs (black) that are filtered to 40 Hz (Fig. 20). Predicted porosity and gas saturation volumes were converted to well logs using the time-depth relationship of Well A to compare them to the actual logs.

Predicted porosity, for all wells, showed a matching value of approximately 50% to the porosity log due to the seismic phase inconsistency that caused the miss-tie in the acoustic impedance inversion. Predicted gas saturation, for all wells, yielded a matching value of less than 20% to the gas saturation log due to the AVO mismatch that affected the quality of the Vp/Vs inversion.

Approach 2-synthetic well inversion

In this part, it is assumed that there are no drilled wells in this seismic block, and those identified wells on the map are planned wells. Whether the target is porous and gas saturated at these locations is unknown. A forward modeling technique is used to create synthetic logs at each of the planned wells’ locations. A pre-stack inversion model is then generated on these synthetic wells. Well F, which is about 60 km away from this block, is used for the rock physics modeling for the pay zone calculation and property
predictions. The workflow of the pre-stack inversion for Case 2 is indicated in Fig. 21.

**Synthetic well forward modeling**

At each of the planned wells’ locations, synthetic $P$-wave velocity and density logs are forward-modeled. The resulting reflection coefficient, from the synthetic log forward modeling, is convolved with a statistical wavelet that is extracted directly from the seismic response to create a synthetic seismogram that matches that seismic response. These synthetic forward-modeled logs are iterated to obtain the best-fit match between the synthetic seismic and observed seismic responses. All the synthetic forward-modeled logs of
$P$-wave velocity and density were within a 10% error when compared to the real well logs. Figure 22 shows an example of a synthetic seismic trace of Well A generated by forward modeling with the channel boundary drawn on the seismic section. $S$-wave velocity is estimated from $P$-wave velocity using a linear $V_p$–$V_s$ relationship in Well F with a correlation factor of 80% (Fig. 23).

**Rock physics modeling**

The rock physics feasibility study and pay zone calculation by rock physics modeling were performed on the nearest well to the seismic block, which is Well F. Cross-plotting acoustic impedance and porosity logs at the target formation, color-coded with a water saturation log, shows an inverse relationship between acoustic impedance and porosity with a correlation factor of 93% (Fig. 24).

Acoustic impedance inversion differentiates between porous and tight zones, but it does not indicate the rock’s fluid type. Acoustic impedance and $V_p$/$V_s$ logs color-coded with a water saturation log are cross-plotted to show the distribution of the data. Three rock conditions were identified from the acoustic impedance and $V_p$/$V_s$ cross-plot, which are porous gas sandstone, porous water sandstone, and tight sandstone (Fig. 25).
To define the pay zone, well logs were fluid-substituted twice: once to 100% gas and once to 100% water. Based on the cross-plot derived from fluid substitution, a boundary line equation, between the gas and the wet zones in the porous section, is calculated to define the pay zone (Fig. 26).

In the low-mid porous section, there is an overlap between gas and water facies, which makes it difficult to determine fluid types in this zone by the pre-stack inversion.

**Multi-well wavelet extraction**

A deterministic wavelet was extracted from each of the three synthetic channel wells, and they were combined together to form a multi-well wavelet. Figure 27 shows that Well A ties well to the seismic trace at the target formation. The wavelet used in this well tie is used in the pre-stack inversion generation and yielded a predictability percentage of 61%.

**Pre-stack inversion model**

Three low-frequency models were created for AI, density, and Vp/Vs from the five synthetic well logs. An example of a low-frequency model for acoustic impedance built from 0 to 8 Hz is shown in Fig. 28, where the layering between the top and base target horizons is clear. These low-frequency models were convolved with the five-angle-stack, multi-well deterministic wavelets, which were extracted from the synthetic wells, to generate the pre-stack inversion model.

Well A is displayed as an example in Fig. 29 to compare the synthetic acoustic impedance inversion to the acoustic impedance log that is filtered to 40 Hz, which is seismic frequency. Synthetic acoustic impedance inversion volume is converted to a log using the time–depth relationship of Well A. On the right track, synthetic acoustic impedance inversion log (green) is compared to the actual acoustic impedance log (black) and to the acoustic impedance inversion volume that
Fig. 21 Workflow of synthetic well inversion

was generated from Case 1. For comparison, the real well inversion (blue) is also shown in this track. Both inversion curves follow the same trend across the whole target formation. As discussed in Case 1, in the deeper part, there is a miss-tie between both inversion curves and the log, which is due to phase inconsistency in the seismic data. The correlation factor, for all wells used in the study, between the synthetic acoustic impedance inversion and the acoustic impedance inversion in the real well case is 81%.

In Fig. 30, the AVO mismatch between the observed and synthetic seismic responses is affecting the quality of both Vp/Vs inversions. The Vp/Vs synthetic inversion is not tying well with the real well Vp/Vs inversion. The correlation factor, for all wells used in the study, between these two inversions...
Porosity was estimated using the direct linear relationship between acoustic impedance and porosity from Well \( F \) at the target formation level that is displayed in Fig. 24. Gas-saturated volume was estimated using the pay zone equation derived from rock physics modeling in Well \( F \) (Fig. 26).

Well \( A \) is displayed as an example to compare the predicted porosity and gas saturation from the synthetic well inversion (green) to the actual porosity and gas saturation logs (black) that are filtered to 40 Hz, and predicted porosity and gas saturation based on the real well inversion case (Fig. 31).

Predicted porosity from synthetic wells yielded a matching value of approximately 80% to the predicted porosity from real well inversion. Predicted gas saturation from synthetic well inversion yielded a matching value of around 60% with respect to the predicted gas saturation from the real well inversion.

**Properties prediction**

Porosity was estimated using the direct linear relationship between acoustic impedance and porosity from Well \( F \) at the target formation level that is displayed in Fig. 24. Gas-saturated volume was estimated using the pay zone equation derived from rock physics modeling in Well \( F \) (Fig. 26).
Conclusion

This study was conducted to characterize reservoir properties in glacial channels from seismic data by applying a pre-stack inversion model. A second object was to test the ability of reservoir characterization by only using synthetic wells. Two cases were investigated: a case in which there are wells and seismic data and another case with only seismic data available. Porosity and gas saturation volumes were predicted for both cases from a pre-stack inversion model.

In the first case, the predicted porosity yielded fairly good results with a matching value of approximately 50% with respect to the porosity log due to the seismic phase inconsistency that caused the miss-tie in the acoustic impedance inversion. Predicted gas saturation gave a matching value of less than 20% to the gas saturation log due to the AVO mismatch that affected the quality of the Vp/Vs inversion.
In the second case, generating an inversion from synthetic wells yielded inversion results that were similar to the real well inversion because the synthetic modeled logs were within a 10% error from the real well logs. Predicted porosity yielded a matching value of approximately 80% with respect to the predicted porosity from the real well inversion. Predicted gas saturation from the synthetic well inversion yielded a matching value of around 60% with respect to the predicted gas saturation from the real well inversion. The fairly low matching in the gas saturation is due to the 10% error in the synthetic $P$-wave velocity and density and the 20% error in the synthetic $S$-wave velocity. Furthermore, the pay zone equations for the gas saturation predictions are different in the two cases, which also affected the matching percentage.

The study objective was only partially realized due to the low accuracy of the predicted gas saturation volumes generated from both inversion volumes. These volumes are not recommended to be used in future well planning. The seismic data used in this study were noisy and suffered from phase inconsistency. In addition, the processing workflow that was applied on the seismic data did not preserve the true amplitude, which contributed to the mismatch in the AVO response between synthetic and real seismic gathers at mid-offsets. We recommend reprocessing the pre-stack seismic data gathers to enhance the signal-to-noise ratio and use an AVO-friendly processing workflow.
Despite its limited applicability due to data quality, we believe that the two presented approaches are valuable to the community. They presented a better understanding of the roles of the seismic data quality, log responses, and multivariate analysis. The prediction was good for porosity and less for gas. In addition, porosity and gas predictions from the second approach were relatively close to those of the first approach despite the unavailability of wells within the seismic block, which is a common situation in exploration projects.

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**Declarations**

**Conflict of interest** The authors have no relevant financial or non-financial interests to disclose.

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