Modern seismic reprocessing to cope the demands of geothermal projects

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ABSTRACT

While seismic imaging is standard in the exploration of oil and gas fields, its significance is growing as the basis for success of geothermal projects. Standard seismic processing strategies work for areas with simple geology, but do not lead to satisfactory results in complex geologic settings. As geothermal projects regularly face such complexity (e.g. the fault systems of the Rhine Graben), the applied standard and often outdated seismic processing techniques do not provide sufficient subsurface imaging. Experience from numerous projects in highly complex geologic settings shows that five key steps are crucial to overcome these difficulties: 1. Near surface velocity model and basic statics solution, 2. surface wave suppression, 3. increase in signal-to-noise ratio and data regularization, 4. stacking/migration velocities and residual statics and 5. sophisticated imaging e.g. the Reverse Time Migration and interval velocity model. In this paper, we will present examples and further information on these key steps.

Keywords: Seismic Processing, Imaging of Faults, Reverse Time Migration, Full Waveform Inversion

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INTRODUCTION

To implement successful geothermal projects, a careful drill path planning is mandatory. Drill path, drill location and target depth are planned based on a seismic image. Thus, the success of the entire geothermal project depends on the accuracy of this seismic image [1, 2]. Therefore, seismic is a small but very crucial step in the success of a geothermal project. The complexity of geologic settings, (e.g. steep dips, faults) and problems due to the proximity to civilization (strong ambient noise, limited frequency content, data gaps) of various geothermal locations require enhanced processing strategies for a convincing and veritable image on which the geologic model is based [3, 4, 5, 6]. Insufficiencies resulting from outdated or inappropriate processing strategies include the loss of amplitude conservation, resolution, reflection continuity and frequency content. In addition, a poor resolution of near-surface velocity variations worsens the image significantly even in deeper parts [7]. Due to smooth travel time requirements, ray-based depth migration techniques such as Kirchhoff or Beam are inadequate for the complex velocity models involved in these areas. This may lead to a horizontally shifted location of faults in the range of tens to hundreds of meters [8]. Considering drill path and target depth planning, these are uncertainties that threaten the success of the entire geothermal project. All these shortcomings cause problems and costs that enhanced seismic data processing could avoid [1]. Experience from projects from the oil and gas industry, nuclear waste deposits and geothermal projects led to the development of advanced technologies, methods and strategies, which will be described in more detail in this paper.

METHOD

1. Near surface velocity model and basic statics solution

The first step to successful imaging is the near surface velocity model and the associated basic statics solution. Directly below surface, small geologic structures like infills or quaternary bodies and outcropping or eroded layers can cause a higher variety of velocities compared to deeper laying layers. When the seismic wave travels through these small structures, a misfit in travel time results, which is even twice in the data as the seismic wave travels downwards and upwards through these anomalous velocity zones. The basic statics corrections are meant to remove

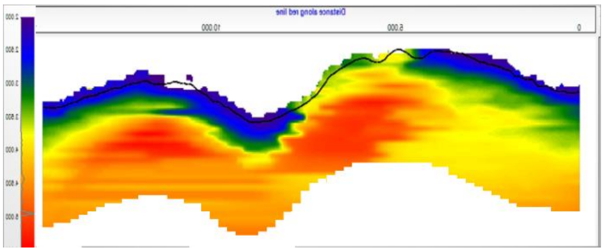

Figure 1: Velocity model from the first break tomography calculated with constant node spacing.

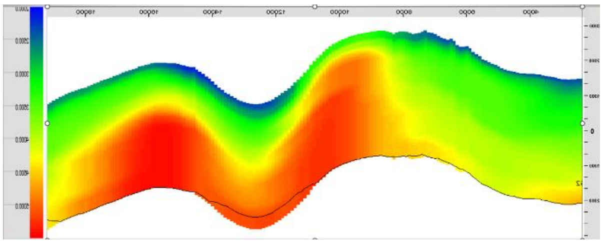

Figure 2: Velocity model from the first break tomography calculated with variable node spacing.

the impact of vertical and lateral variations in the near surface velocity and compensate for the difference in seismic travel time caused by such variations. In settings with topography and/or highly variable subsurface velocities, standard refraction or elevation statics fail to provide accurate results as they suggest structures in time domain which are due to velocity variations. Here, tomographic approaches are key to remove shallow subsurface velocity effects. A standard first break tomography is based on a regular grid of nodes which are then updated by an inversion process based on first break pick times. A better approach is a variable node spacing tomography. Here, the grid for calculation starts at topography and has smaller distances between nodes close to the surface and a wider spacing with increasing depth. This way, small-scale velocity changes close to the surface can be included in contrast to a regular constant grid size. The result is a high-resolution velocity model in depth domain below surface. Figure 1 shows the result of a first break tomography calculated with a constant node spacing of 50 m. Figure 2 displays the tomography result for the same section calculated with a variable node spacing of 10 m at the surface increasing to 100 m at the bottom of the model in ~2 km depth. Its lateral node spacing is constant with 50 m. While the velocity model with the standard approach implies blocky structures, the variable node spacing tomography results in a smoother velocity field. Both models pick up the deeper high velocity zone correctly. In the shallow part, the velocity model from variable node spacing tomography is much more detailed and shows less thickness of the low velocity zone. The tomography result is used to calculate a static solution. Figure 3 and Figure 4 show the effects of the static solution on the seismic stack. Even for the deeper part the visibility and continuity of reflectors are improved with the static solution from the variable node spacing tomography in Figure 4 compared to the standard solution in Figure 3.

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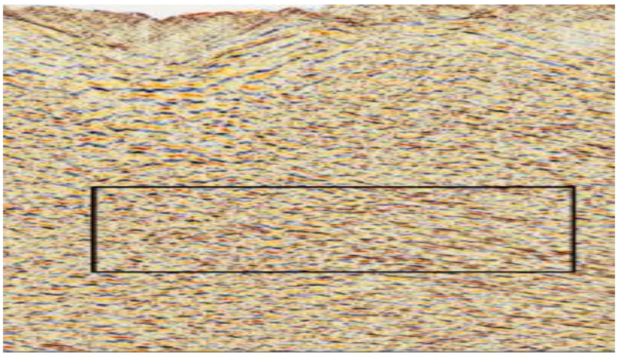

Figure 3: Seismic stack with static solution from a constant node spacing tomography.

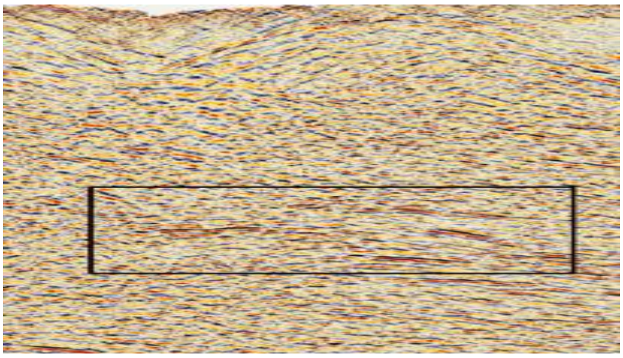

Figure 4: Seismic stack with static solution from a variable node spacing tomography.

2. Noise model and adaptive subtraction

One aim of processing is to "denoise" the seismic data, which means to reduce the noise and thereby amplify the primary signal. The surface wave exhibits high amplitude levels and overlays the primary reflection signal in the shot cone completely (Figure 5). Therefore, its suppression is an important part of the denoise process. To eliminate this noise, the surface wave can be modelled and subtracted from the input data. Here, a simple subtraction of the model delivers reasonable results at a first glance: Figure 5 shows the input shot gather with the noise of the surface wave, the shot gather after standard subtraction is plotted in Figure and in Figure after adaptive subtraction. With both methods the noise in the shot cone is eliminated and the results look very similar. Nevertheless, if we look at the frequency spectrum in Figure 6 the difference between both methods is clearly visible. A significant portion of the intensity of low frequencies are missing after standard subtraction. These are preserved with the adaptive subtraction. Here, the surface wave model will be adapted to the input data regarding frequency content, amplitude, and phase prior to subtraction. Hence, the low frequency content is preserved and enables broadband processing. This is also of great importance for later steps like the Full Waveform Inversion (FWI), which needs low frequencies for a stable inversion. Figure 7 and Figure 8 show the difference between the result after subtraction and the input data. One can observe that standard subtraction (Figure 7) also removes primary energy, which is reduced with adaptive subtraction (Figure 8).

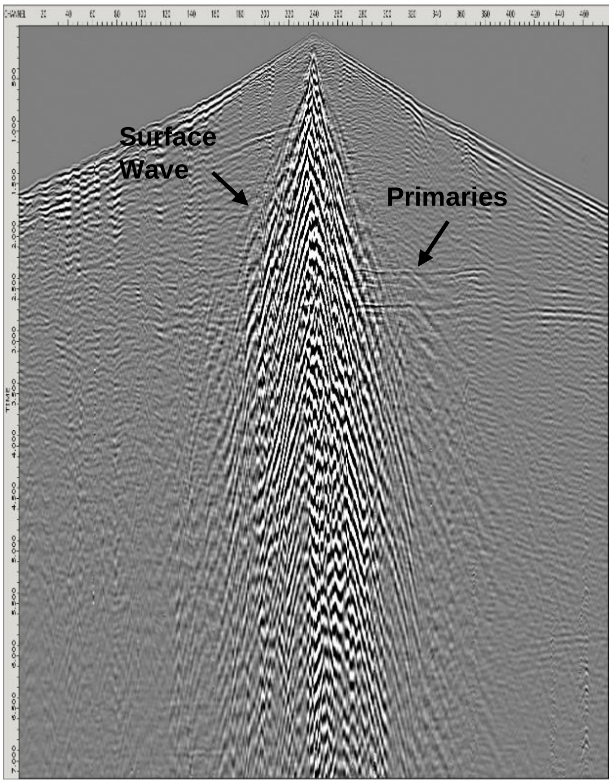

Figure 5: Shot gather before surface wave subtraction. Its noise is visible in the shot cone.

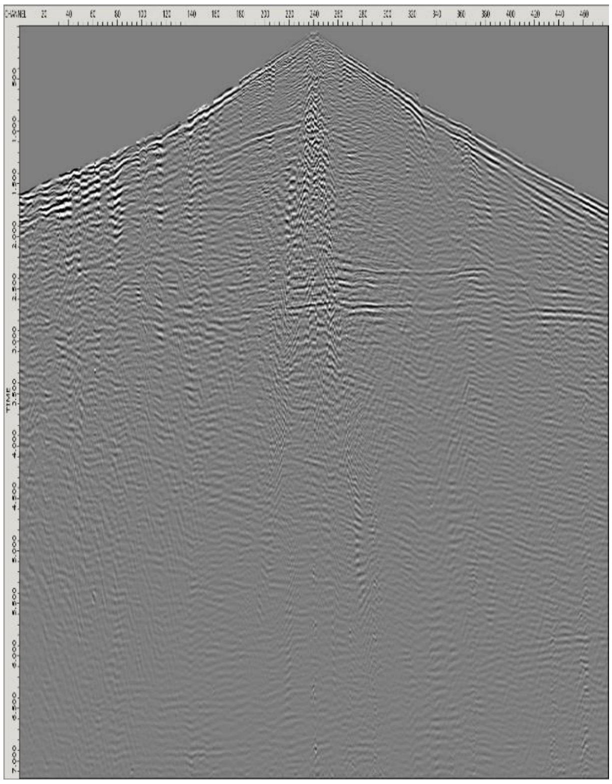

Figure 7: Shot gather after adaptive subtraction of the noise model.

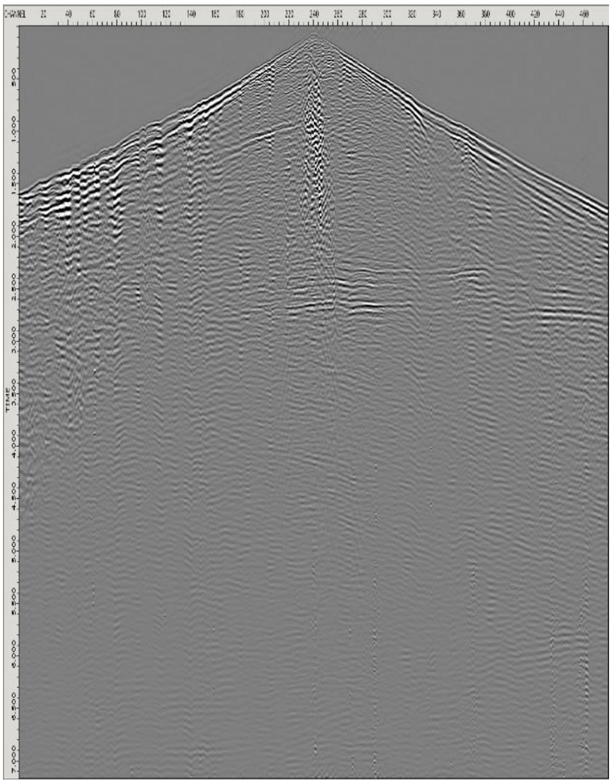

Figure 6: Shot gather after standard subtraction.

Figure 6: Spectrum after standard subtraction (red) and adaptive subtraction (green, dashed). Note that part of the low frequency content is missing after standard subtraction.

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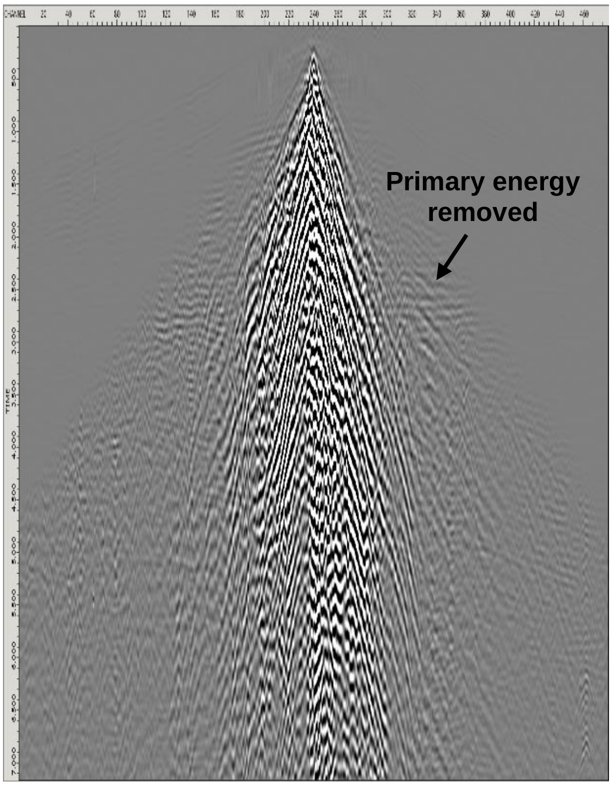

Figure 7: Difference between input data and result after standard subtraction.

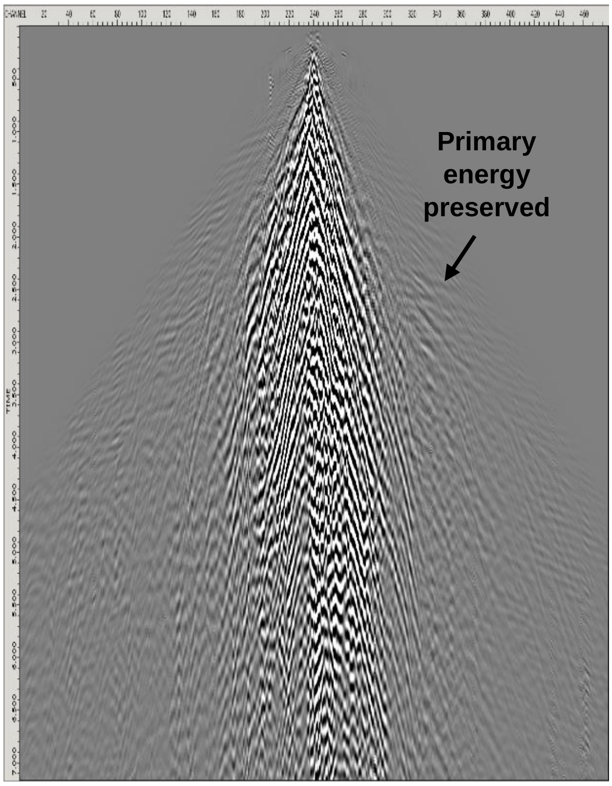

Figure 8: Difference between input data and result after adaptive subtraction.

3. Common Reflection Surface (CRS)

The first approaches to stack a seismic section included only the common mid-point (CMP) location. The underlaying normal moveout (NMO) model assumed just flat layers in the subsurface [9]. This model was extended to include the dip component by dip moveout (DMO) processing [10]. In addition to dip and depth, CRS analyses the curvature of subsurface reflection elements [11]. These wavefront attributes are even accurate for complex media and useable for applications such as data regularization, interpolation, or diffraction processing [12]. The CRS stacking operator is not limited by a surface bin cell anymore but includes the energy from the entire Fresnel zone. Hence, if a reflector element is illuminated by the seismic acquisition, CRS processing will probably be able to collect such energy [11]. The CRS algorithm improves the data quality significantly, especially in areas with a low signal-to-noise ratio [13]. Furthermore, CRS can be used for data regularization, which influences the migration result considerably. Irregularities in receiver/shot locations result in an irregular fold of coverage and data gaps, which likely lead to migration artefacts. CRS processing along with 5D interpolation are

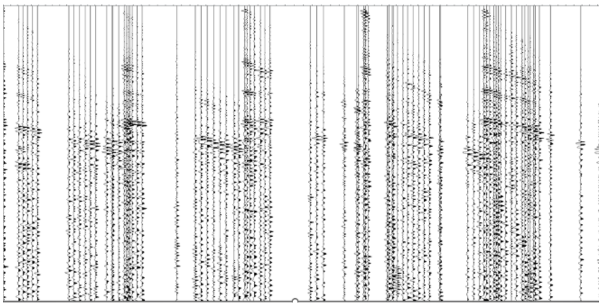

Figure 9: CMP gather before CRS.

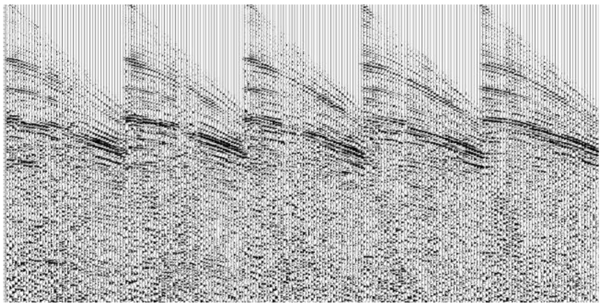

Figure 13: With CRS regularized Gather.

modern regularization techniques with CRS even working in areas where 5D often fails such as low signal-to-noise ratio, low fold of coverage and steep dips. An irregular acquisition layout is a common problem for geothermal projects. These projects are typically close to civilization. Infrastructure, buildings and no permit zones, e.g. nature conservation areas, prevent a regular acquisition layout. Figure 9 shows CMP gather with an irregular trace spacing and missing traces in many offset classes. After CRS prestack data regularization, the bin gathers are properly filled and show an improved signal-to-noise ratio (Figure 13). The irregularities without CRS will affect the prestack time migration significantly and lead to a poor seismic image (Figure 12). In contrast, CRS improves the prestack time migration especially for areas with data gaps (Figure 10). With greater depth, reflectors become visible that are overlain by noise without CRS.

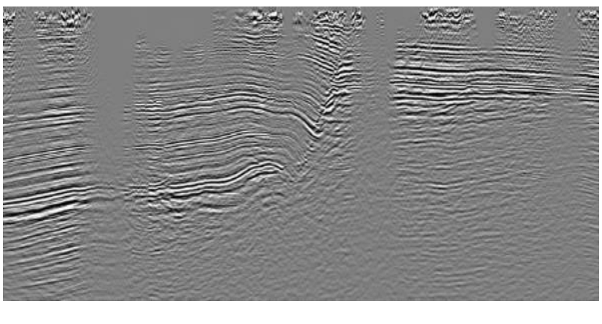

Figure 12: Prestack Time Migration result without CRS.

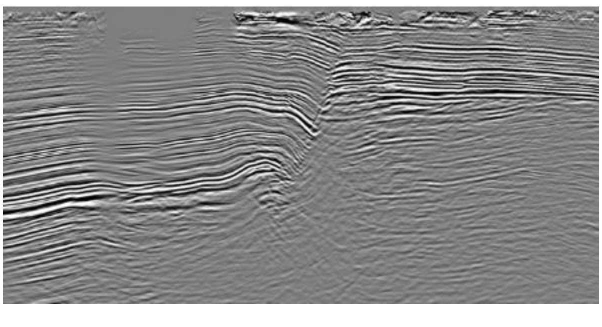

Figure 10: Prestack time migration result after CRS application.

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4. Stacking velocity analysis, residual statics, and migration velocity analysis

Stacking velocity analysis, residual statics, and migration velocity analysis benefit from all previously described steps with a proper basic static, enhanced denoising and an improved signal-to-noise ratio. In Figure 11 an uncorrected CMP gather (left), the semblance (middle) and the normal moveout (NMO) corrected CMP gather (right) are displayed. Reflections are hyperbolic in the uncorrected gather. They become flat, when the correct NMO velocity is applied. For the correct NMO, the semblance is maximum because the seismic wavelet of NMO corrected adjacent traces is similar (have their peaks/troughs at the same time). Due to high noise levels, the semblance of the CMP gathers shows no clear trend. In Figure 12 the same gather is displayed with CRS processing applied. Here the CRS gather shows a much better data quality and allows for a more reliable identification of reflection signal. Hence, the semblance is better focused and a clear velocity trend becomes visible. An additional step to improve the stacking velocity are constant velocity stacks. The entire section is stacked multiple times with one constant velocity (e.g., with velocities from 1,5 to 5 km/s with an increment of 0,1 km/s). This provides a quality control as all real structures visible in these stacks must be present in the final result. Migration velocity analysis in time domain can be performed likewise. The velocity can be picked with the uncorrected and corrected Common Image Gather and their semblance as well as with constant velocity migrations. For the migration velocity in time domain also percentage velocity variations (of the stacking or preliminary migration velocities) can be calculated. The percentages for which the Common Image Gather show flat events are picked and multiplied with the input velocity field.

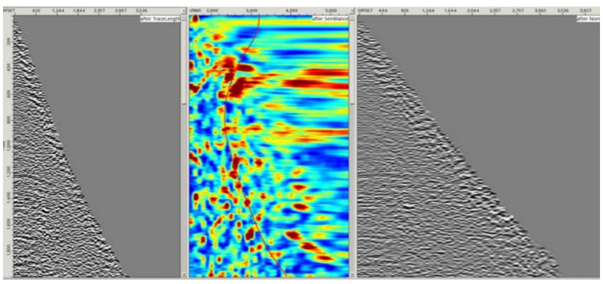

Figure 11: Uncorrected CMP gather (left), semblance (middle) and NMO corrected gather (right).

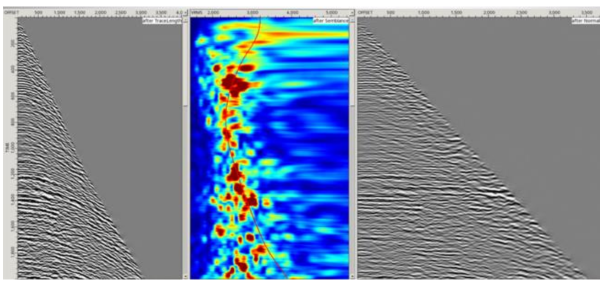

Figure 12: Uncorrected CRS gather (left), semblance (middle) and NMO corrected CRS gather (right).

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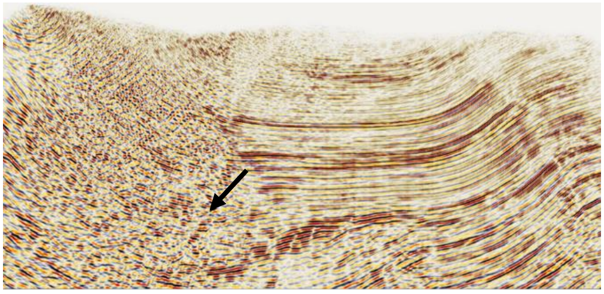

Figure 13: Result of Kirchhoff Depth Migration with CRS applied.

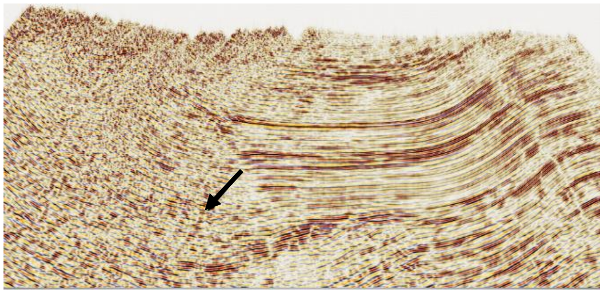

Figure 14: Result of the RTM with CRS applied.

5. Reverse Time Migration (RTM) and Full Waveform Inversion (FWI)

Correct positioning of geologic structures is mandatory in seismic depth imaging. As ray-based depth migration techniques, which are standard in processing, fail to solve travel times correctly for complex velocity models, the usage of the RTM is favored. By solving the acoustic wave equation, the RTM realistically simulates the propagation of waves through the subsurface. This way, the algorithm can account for any complexity in the velocity model [8]. The seismic image calculated with a Kirchhoff Depth Migration (Figure 13) can be compared to the result of the RTM in Figure 14. For the sedimentary structures both migration algorithms provide reasonable results. But the RTM yields a much clearer image for the complex geology on the left side of the section. The data continuity and visibility of reflectors is increased significantly in the questionable area. Moreover, the fault (marked with an arrow in Figure 13 and Figure 14) has moved by about 200 m to its actual location. The correct positioning of faults is of great importance e.g. for the planning of the drill site and drill path.

In the previous section about the near surface velocity model and the basic statics solution, the importance of the correct near surface velocities was emphasized. As only few traces cover the upper ~150 ms (compare Figure 12), information about the velocity structures directly below the surface can hardly be retrieved by analyzing the gather during the standard velocity analysis. In addition to the velocity model from the first break tomography that is used for the basic static solution, the FWI is able to enhance the near surface velocity model significantly. The FWI is an iterative approach to find the best sub-surface model by minimizing the difference between the observed waveform and a calculated synthetic waveform in amplitude and phase in a dedicated frequency band. For a successful FWI calculation, the simulated waveform of the starting model needs to be less than half a wavelength apart from the wavelength of the observed data. Otherwise, artefacts are introduced into the velocity model by cycle-skipping, which means matching two different phases that do not belong to each other. To overcome the cycle skipping problem, the FWI requires low frequency data content. This way, the size of the wavelength is increased and the algorithm is stabilized [14]. Furthermore, with the velocity model derived from the first break tomography an initial model is available which is already close to the real sub-surface velocities. Figure 15 and Figure 16 illustrate the effect of the enhanced velocity model from the FWI on the seismic image. In the image calculated with the velocities without FWI (Figure 15) the velocities increase with depth. There are no clear geologic structures visible except for the dipping structure in the central part of the section. The velocities from the FWI follow the geologic structures and are higher than in the initial velocity model for the upper part of the section (Figure 16). By including the FWI velocities, a basin and faults are revealed that were not visible before.

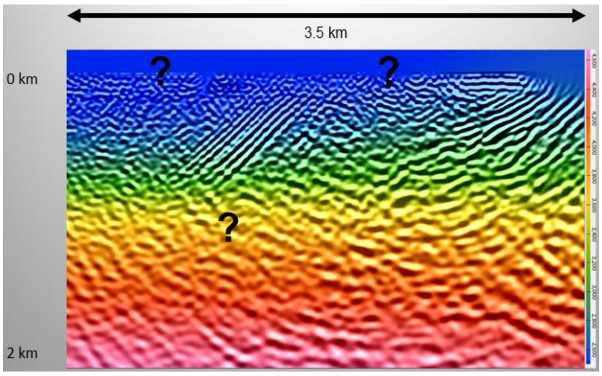

Figure 15: Depth migration result calculated with the velocity model from the tomography, which is displayed in the background.

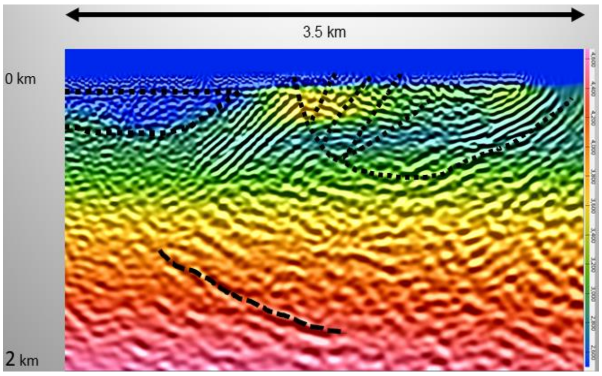

Figure 16: Depth migration result calculated with the velocity model from the FWI, which is displayed in the background.

CONCLUSION

Modern seismic reprocessing methods enable to solve difficulties that threaten the success of an entire geothermal project. Complex geologic settings with steep dips and faults can be imaged correctly by using CRS in combination with an RTM as a modern migration algorithm. These methods further profit from the correct near surface velocities calculated with a variable node spacing tomography in combination with an FWI.

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Typical problems of geothermal projects result from the proximity to civilization. These include strong ambient noise that can be reduced by enhanced denoising and CRS. Data gaps can be filled with CRS. The frequency content is preserved by methods like an adaptive subtraction that enables broadband processing. The resolution and reflection continuity are improved by all presented processing steps. Furthermore, the methods better preserve amplitudes enabling amplitude analysis for reservoir characterization. All these processing steps result in an enhanced seismic image that is crucial for the success of a geothermal project.

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