Chapter 8

Automated seismic interpretation

The trade with petroleum is of considerable importance for the world economy and exploration and production of petroleum is a large business. Most petroleum resources are buried under the surface of the earth. Imaging properties of the subsurface is consequently a major task in petroleum exploration. Seismic analysis is one of the principal tools for mapping the subsurface properties.

In this chapter, solutions to two major problems in petroleum exploration, fault and stratigraphic boundary pattern recognition, will be proposed. In contrast to the previous chapters of this dissertation, the application is no longer texture analysis. However, parts of the approaches are related to texture approaches.

In Section 8.1, an introduction to petroleum exploration with reflection seismics will be given. In Sections 8.2 and 8.3, solutions to the problems of fault and stratigraphic boundary interpretation are proposed and discussed. Finally, in Section 8.4, the chapter is summarized.

8.1 Introduction to petroleum exploration with seismic

Denham [27] gives the following introduction to seismic reflection exploration: "Seismic reflection exploration – the study of the earth using sound waves reflected from beneath the surface – is the dominant method in exploration geophysics. [...] Exploration geophysics is merely a tool we use to look at the geology of a part of the earth we can neither sample nor visit in person. The geological understanding which we build using geophysics and other geological tools is itself only a tool used to detect a probable oil or gas field. Seismic interpretation is the interface between the exact [...] and inexact [...]. The earth is so complex that we never have a complete picture." In this section, a brief introduction to geology, petroleum exploration, seismic signals, and seismic signal processing will be given. For more extensive coverage of geology and seismics, several books and articles are available, e.g., [27, 54, 57, 119].

8.1.1 Geophysical background

Practically all occurrences of known oil and gas are in sedimentary rock. A sedimentary rock is formed by the accumulation, diagenesis, and solidification of organic material, mud, silt, sand, and other clastic materials. As new material is sedimented atop, pressure increase forms sedimentary rock bodies.

Provided adequate temperature, organic sediments starts forming oil and gas. These sedimentary layers are denoted *source rock*. The oil and gas may flow through permeable media. Since the density of petroleum is less than the density of water, it will be replaced by water if it is allowed to escape. If no sealing cap is present, it will escape to the surface of the earth. However, if there is a combination of a sealing cap and a porous medium, the petroleum may be trapped and accumulate in a *reservoir*. The quest for oil and gas is the search for such reservoirs in the ground. Typical porous media are sandstone and limestone while the most common caps are non-permeable sedimentary layers, e.g., shale, and structural seals, stemming from faults generated by tectonic or deformation forces.

Permeability is also a necessity for successful production, since reservoirs are produced by a few wells draining a very large volume (a petroleum reservoir may be several kilometers in extent). Some sediments are in nature permeable, but permeability may also stem from breaks in a sealing cap.

The focus of this chapter will be on automatic identification of *faults* and *stratigraphic* properties important for the flow (permeability) and sealing of petroleum. However, before the attention is focused on these problems, an introduction to seismic signals, signal gathering, preprocessing, and inversion will be given.

8.1.2 Seismic surveying

Seismic surveying is one of the major techniques used for constructing an image of the subsurface for the detection of oil and gas reservoirs. In a seismic survey, a source is emitting sound waves through the (sedimentary) layers of the earth. Any interface between layers of rock with different speeds of sound and densities will reflect some of the incoming sound pulse back to the surface. The sound source may be a dynamite explosion, a pneumatic air gun, a massive vibrating object, or similar. The recorders are typically geophones, measuring vibration in the earth, or hydrophones, measuring sound pulses in water. An illustration of a sea survey configuration with boat, sound source, and receivers is shown in Figure 8.1. Reflections with long reflection times (typically up to a few seconds) basically correspond to deep interfaces (up to a few thousand meters) or large reflection angles. The maximum resolution of the recorded seismic signal is in the range of beteween a meter and a tenth of a meter.

Traditionally, seismic surveys gave two-dimensional cross sections of the earth. However, most seismic surveys today provide three-dimensional mappings of the earth, e.g. by closely spaced two-dimensional cross sections. This provides for improved noise removal and a better understanding of the sediments. Another recent trend is 4D seismic, where multiple seismic surveys are conducted over time (fourth dimension) in order to monitor and map the drainage of the reservoirs.

Analysis tools and techniques with considerably better resolution are available for

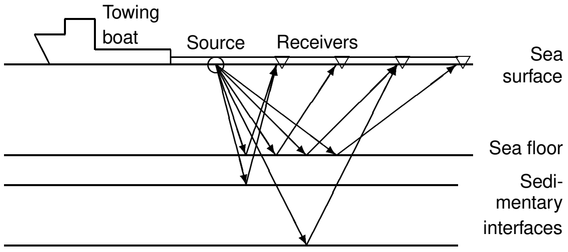


Figure 8.1: Principle of offshore seismic surveying.

wells. Some examples are sonic measurements, radioactive measurements, and core samples. However, wells are very costly to produce, typically in the range of ten million US dollars per well. Consequently, the number, and therefore the density, of wells is very low, especially during exploration. In practice, seismic and well measurements are the only applied techniques for imaging the subsurface in petroleum exploration.

8.1.3 Seismic processing

The processing steps leading up to an image of the sub-surface may be divided in two parts; 1) seismic processing for data enhancement and 2) seismic inversion. In this subsection, a few of the most important enhancement techniques are briefly reviewed. Inversion is treated briefly in the next subsection.

The ideal signal source would be a source emitting a Diracs delta pulse into the earth, i.e., a pulse with infinitesimal duration and infinite amplitude. However, this is not practically attainable and the submitted waveform is only approximating the Diracs delta pulse. Furthermore, the source is not 100% repeatable. To compensate for these problems, the recorded seismic reflection signals are deconvolved with the recorded source waveform.

The transmission medium, the earth, is a similar distortion source. Of particular interest is the fact that high frequencies are damped, resulting in blur and reduced resolution. This is particularly a problem for reflections with long travel times. To compensate for this problem, the seismic signal may be deconvolved with a modeled unit pulse response of the transmission medium.

Yet another problem with the data quality is the low signal to noise ratio of the signal due to several noise sources. If the noise is random and data independent, averaging multiple measurements of the same property will yield reduced noise. This is utilized in a technique denoted stacking, where multiple measurements from the same reflection point are averaged.

A multitude of other data quality improvement techniques with various tradeoffs also exist. A more complete presentation is given by Kearey [57].

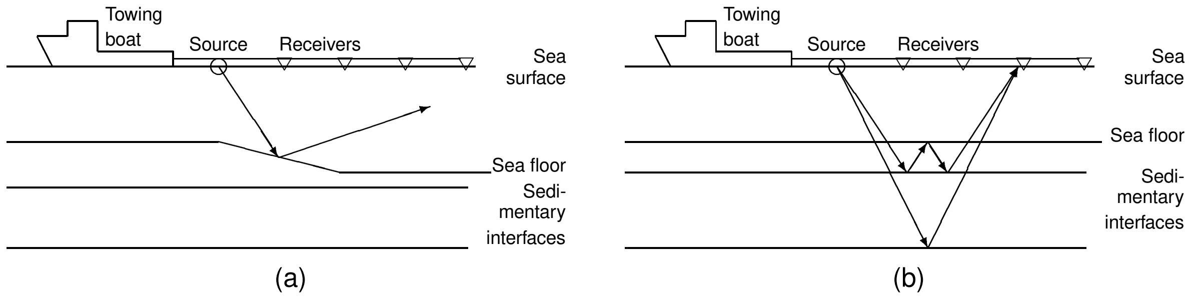


Figure 8.2: (a) Illustration of problem with dipping layers. (b) Multiple reflection paths yielding the same arrival time.

8.1.4 Seismic inversion

If the internal structure and physical properties of the earth were known, the magnitude of the recorded seismic measurement could be predicted accurately. However, in seismic data analysis, the problem is the converse, namely to deduce some aspects of the earth's internal structure on the basis of the measurements. This is a problem with a non-unique solution since many different geological configurations could produce the observed measurements.

The basic survey model, presented in Section 8.1.2, was developed with an assumption of horizontal reflectors. Since the angle of incidence is equal to the reflection angle, the reflection point is midway between the source and the receiver if the reflectors are horizontal. For dipping reflectors, however, this simple relation is no longer valid, see Figure 8.2(a), and without knowledge of the dip, the reflection point is unknown. The solution is to carefully examine the data to determine the most probable dip angles of the major reflectors and compensate for the dip by a process called *migration*.

Travel times and amplitudes are the only measured properties of the seismic signal. The travel time is a function of the sound velocity in the transmission medium and the length of the signal path. However, there are many possible paths from source to receiver having the same travel time. Of particular interest is multiples – reflections "bouncing" between multiple reflectors. An example sketch of multiple reflections is illustrated in Figure 8.2(b). The effect of multiple reflectors may be that the multiples from strong reflectors completely drown the information from weaker reflectors. In order to remove multiple reflections, the first arrivals are analyzed. Then a probable multiple reflection path is modeled and the modeled multiple response is subtracted from the measured seismic response.

The discussion given here is not a complete analysis of all inversion techniques. Compensation techniques for problems as refractions, diffractions, etc. also exist, see [27, 54, 57, 119].

8.2 Fault identification

At a large scale, the initial sedimentation pattern was horizontal, but deformation by folding and faults, as illustrated in Figure 8.3, might make structural traps. These fold-

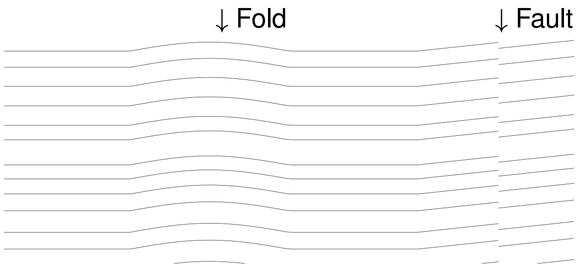


Figure 8.3: Illustration of principle behind two types of structural traps, fold and fault.

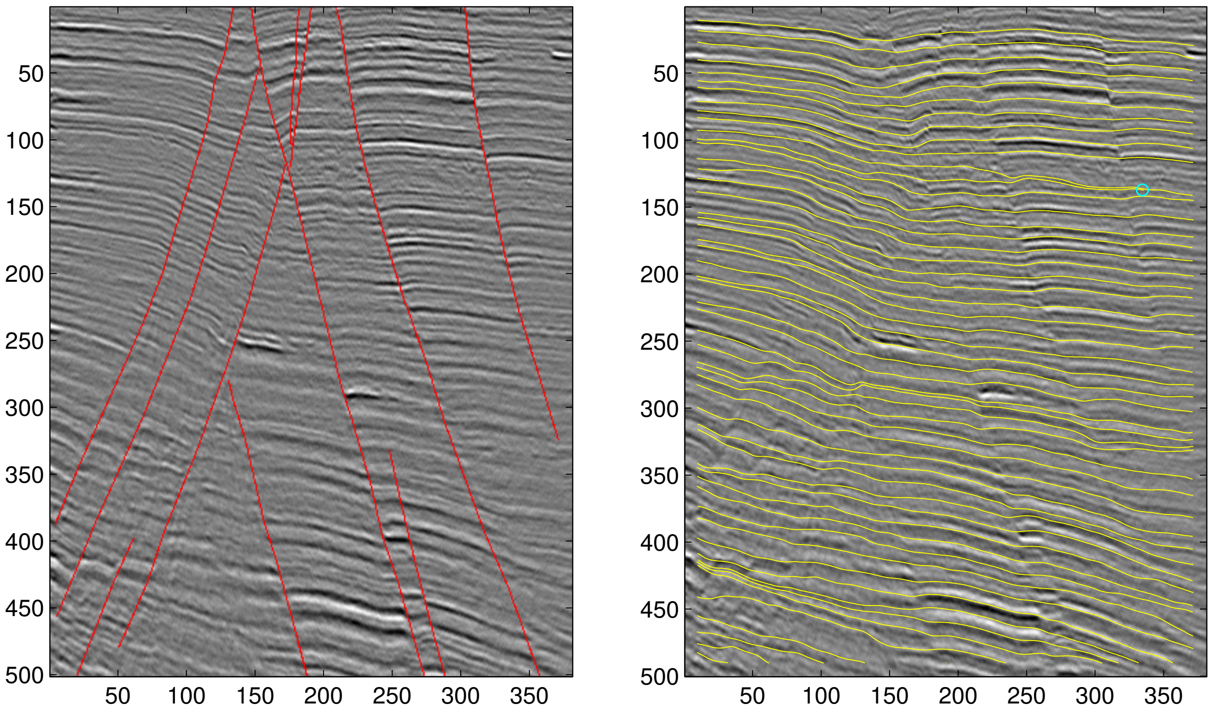
ings and faults are formed by tectonic forces, i.e., by movements from deep within the earth's crust (e.g. earthquakes), flow of salt or shale[1] from deeper layers, or differential compaction. A fault may generate a fluid channel through a sealing layer or seal a permeable layer and is therefore of significant importance in the quest for oil and gas. It will typically be represented by an abrupt change in the seismic response and may therefore be detected by methods for detection of abrupt changes. The final goal of fault analysis is an interpretation as shown in Figure 8.4(a).

A technique for fault analysis was presented by Alam and Caragounis [3], where the seismic horizons were auto-traced and faults identified by discontinuities in the extracted horizons. However, by experience, auto-traced horizons are not very reliable. Consequently, the fault detection may be biased by errors in the horizon identification. Bahorich and Farmer [7] recently presented a patented [8] technique for fault feature extraction (highlighting) by local coherence analysis. The coherence method is based on the idea that two adjacent traces[2] separated by a fault are poorly correlated, using attributes from the cross correlation as fault features. However, the windowing in the cross correlation causes a smeared response. A third approach to fault enhancement has been presented by Schwab et al. [117], in where an optimized horizontal linear prediction error filter is applied to the seismic. This filter will yield high amplitude at discontinuities, e.g. faults. Techniques for adapting the predictor to the underlying orientation of the seismic reflectors have not been presented, thus making it very sensitive to varying dip of the reflectors.

A fault feature extraction technique based on the orientation estimate is developed and tested in Subsection 8.2.1. A technique for transforming the fault features into a fault interpretation is required and a discussion of methods is given in Section 8.2.2.

[1]Salt is heavier but less compressible than most other sedimentary materials. As pressure increases, other materials are compressed more than the salt and their densities increase. This make them heavier than salt and the salt starts to prograde towards the surface. A similar situation may occur with water filled porous shale or clay where the water is not allowed to escape during the pressure increase.

[2]A trace is the term used for one column of seismic samples in the seismic volume, i.e., a vertical one-dimensional signal.



(a) (b)

Figure 8.4: (a) Example seismic cross section with manual fault interpretation. (b) Illustration of the local orientation the cross section.

8.2.1 Fault feature extraction

If a fault intersects a strong seismic reflector, the reflector typically becomes discontinuous and is characterized by an abrupt change in the seismic signal. A convolution mask (filter) like

$$\begin{bmatrix} -1 & 0 & 1 \\ -1 & 0 & 1 \\ -1 & 0 & 1 \end{bmatrix} \tag{8.1}$$

will intuitively enhance abrupt changes in seismic sections, while suppress smooth regions (the average is zero) horizontally. This filter, known as the Prewitt [48] filter, is often used for enhancement of vertical edges in image processing. A similar version exists for enhancement of horizontal edges. An alternative filter is the Sobel [48] filter,

$$\begin{bmatrix} -1 & 0 & 1 \\ -2 & 0 & 2 \\ -1 & 0 & 1 \end{bmatrix}. \tag{8.2}$$

Both masks perform approximate partial derivative estimation.

An edge in image processing is the transition from a bright region to a dark region, or vice versa. For any such vertical edge, any of these masks will have either a large positive or a large negative value. For a fault, on the other hand, the arrangement of bright and dark samples is more complex and the response may change from large positive to large negative in a small neighborhood. However, compared to non-faulted regions, the *magnitude* of the response is overall large.

As we can see from the seismic section of Figure 8.4(a), we do not always have vertical fault planes intersecting horizontal seismic reflection patterns. Since the reflectors have similar characteristics as edges, any edge enhancement mask having some component perpendicular to the reflectors will also enhance the *reflectors*. Hence, to enhance faults and not reflectors, the edge enhancement mask must be tuned to be parallel to the reflection layers. The layer orientation may be estimated using the same technique as proposed by Kass and Wittkin [56] and improved by Rao and Schunck [113]. This approach basically used vertical and horizontal partial derivative of Gaussian filters for orientation estimation, followed by directional smoothing. An illustration of the estimated directionality of the seismic section in Figure 8.4(a) is shown in Figure 8.4(b).

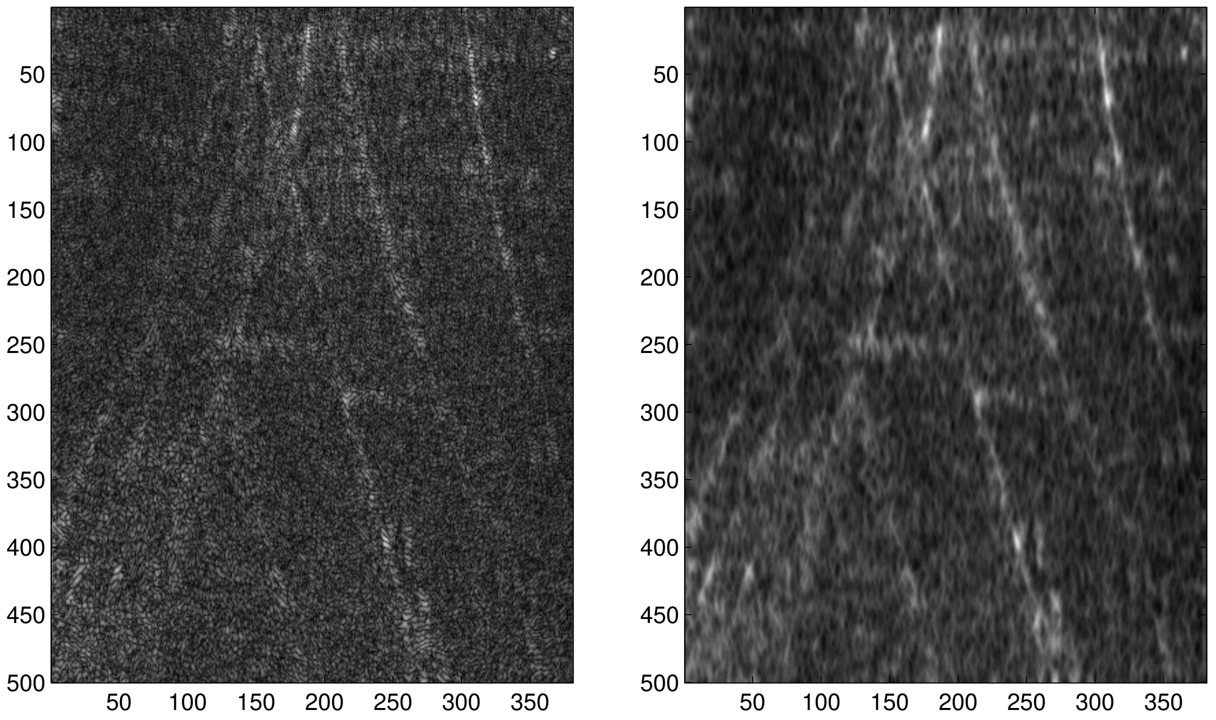
Rotating a discrete filter mask by an arbitrary angle is not straightforward. To accomplish the rotation, a linearly interpolated continuous representation may be modeled, rotated, and re-sampled. One local orientation value is estimated for each pixel and the edge mask should be tuned accordingly. That is, the edge mask should adapt to the local orientation. However, the generation of a new mask for each pixel is computationally complex. A faster approach is to generate a set of masks for a range of orientations offline, store them in a look-up table, and apply the mask tuned to the closest orientation. However, an even more computationally efficient approach is to use a separable edge filter. In a separable implementation, the edge mask tuned to the angle θ may be given by $\cos(\theta)h_0 + \sin(\theta)h_{\frac{\pi}{2}}$, where h_α is the edge mask tuned to the angle α. By this approach, only two separable filters are necessary in the feature extraction stage.

All of these approaches were evaluated, with only insignificant differences in feature quality. A result from the separable approach is illustrated in Figure 8.5(a). The perceived quality or clarity of the extracted features can be improved by some kind of smoothing of the features. Figure 8.5(b) shows the image of Figure 8.5(a) smoothed by a two-dimensional Gaussian low-pass filter with $\sigma_s = 3$ along the fault direction and $\sigma_s = 0.5$ perpendicular.

Any of the images of Figure 8.5 are highlighting the faults significantly better than the original seismic image. Hence, they may aid manual fault identification, which is a major and difficult task. Furthermore, as we will see in the next subsection, the features may also be used for automatic or semi-automatic fault identification.

Some other approaches to fault feature extraction have also been attempted, with less success. Approaches using appropriately tuned Gabor filters, Section 2.2.3, other band-pass filters derived from the QMF banks of Section 3.2, the optimal texture filters[3] of Section 5.3, and the phase difference highlighting technique by Bovik et al. [13] have been attempted. However, all the results were worse than the results with the edge enhancement filters. Some of the experiments are reported in [98]. Application of edge

[3]With optimal texture filters, the fault was modeled as an instantaneous texture.



(a) (b)

Figure 8.5: (a) Orientation adaptive *separable* Sobel mask response magnitude for the seismic cross section of Figure 8.4 and (b) a directionally smoothed version.

enhancement techniques without strong orientation properties, like the Laplacian [48] and SUSAN [121], have also been evaluated. However, due to strong edge characteristics of the seismic *reflectors*, all applied non-oriented techniques tended to emphasize the reflectors much more than the faults.

8.2.2 Fault surface identification from the extracted features

In order to have an automatic fault identification system, some approach for converting the fault features into fault surfaces in 3D or fault lines in 2D is needed. The ideal situation is to have a fully automatic system, transforming the fault features into fault surfaces with no user interaction. If it is assumed that the faults may be represented as lines of linked straight segments in 2D cross-sections, the Hough transform [39, 45] may be used to detect the segments. A significant effort was done to utilize the Hough transform technique for this approach, using the technique from [10]. The best result was as shown in Figure 8.6(a). For implementational reasons, the image was divided into overlapping blocks, and one line segment detected per block. This causes some false detections that may easily be removed. However, we still see that multiple faults or fault segments are missed by the approach.

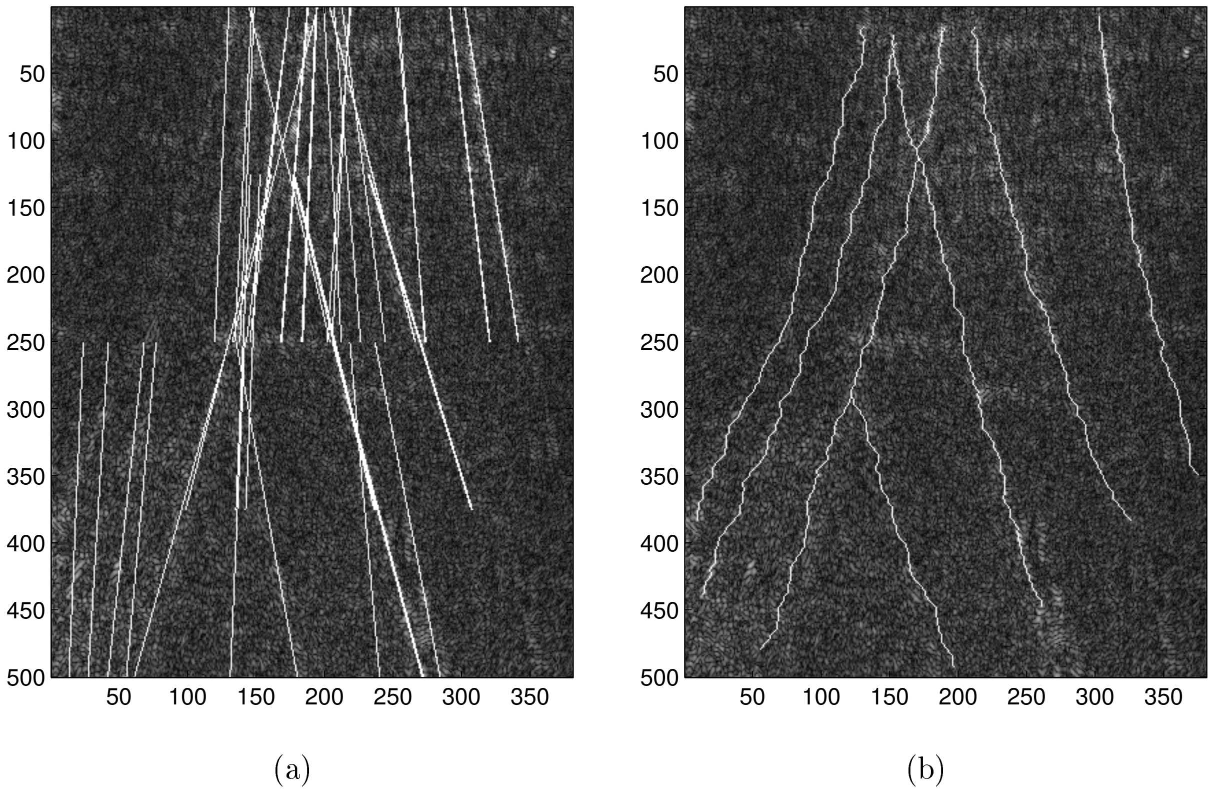
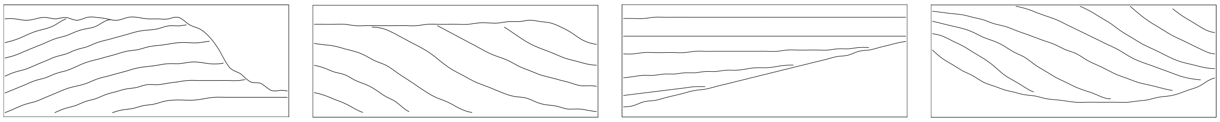


Figure 8.6: Interpreted faults from the image of Figure 8.5(a). (a) Fully automatic identification using the Hough transform. (b) Semi-automatic identification using minimum cost path.

A more successful alternative may be to do semi-automatic detection of the faults, i.e., detection requiring some user interaction. One way of converting the fault features into fault lines or fault surfaces is to let the user select seed points that the system uses for tracing the faults. Verwer et al. [134] suggest a technique for using linear programming to find a minimum cost path between two seed points. Results using this approach are shown in Figure 8.6(b). As we can see, all the major faults were traced successfully, although the lines are still somewhat jagged.

The major effort in manual fault identification is not the interpretation of a single seismic cross section, but the interpretation of hundreds of cross sections. Furthermore, it is reasonable to assume that the fault lines in neighboring sections are fairly close in position, shape, and orientation. Hence, another approach to semi-automatic identification is to use deformable template matching. This approach was taken by Østebø [82], but some further adjustments are required to make this approach robust enough.



(a) (b) (c) (d)

Figure 8.7: Some important stratigraphic boundaries: (a) Erosional truncation, upper boundary formed by erosion. (b) Toplap, upper boundary formed mainly as a result of non-deposition. (c) Onlap and (d) downlap, lower boundaries formed by sedimentation on initially inclined surfaces.

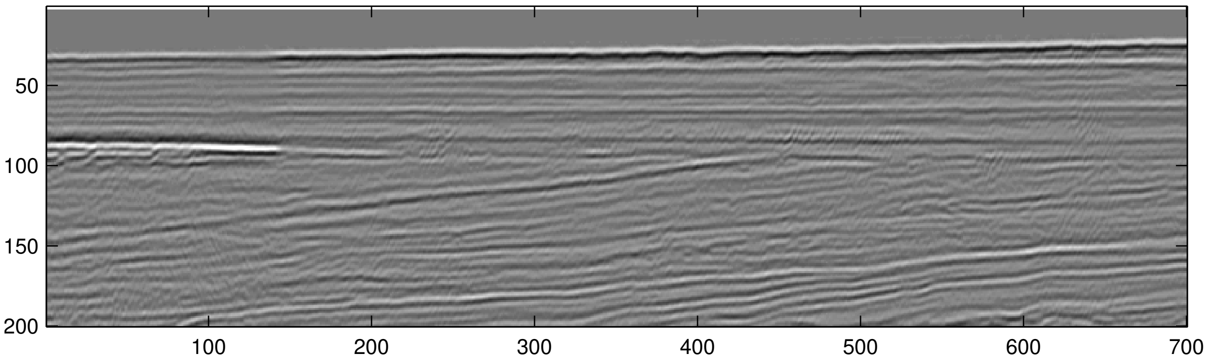
8.3 Stratigraphic boundary identification

Most oil and gas discovered has been found in structural or mainly structural traps [27] and the undiscovered potential in such traps is probably decreasing. Another kind of traps, stratigraphic traps, is now receiving increased attention. A stratum is "a tabular or sheet-like mass, or a single and distinct layer, or [...] sedimentary material [...], visually separable from other layers above and below by a discrete change in character [...] or by a sharp physical break in deposition, or by both." [72, 74]. Stratigraphic analysis [85] is the analysis of strata and their boundaries. The analysis of stratigraphic traps is generally more difficult than structural trap analysis. Hence, it may be expected that the proportion of undiscovered stratigraphically trapped reservoirs is larger than for structural trapped reservoirs.

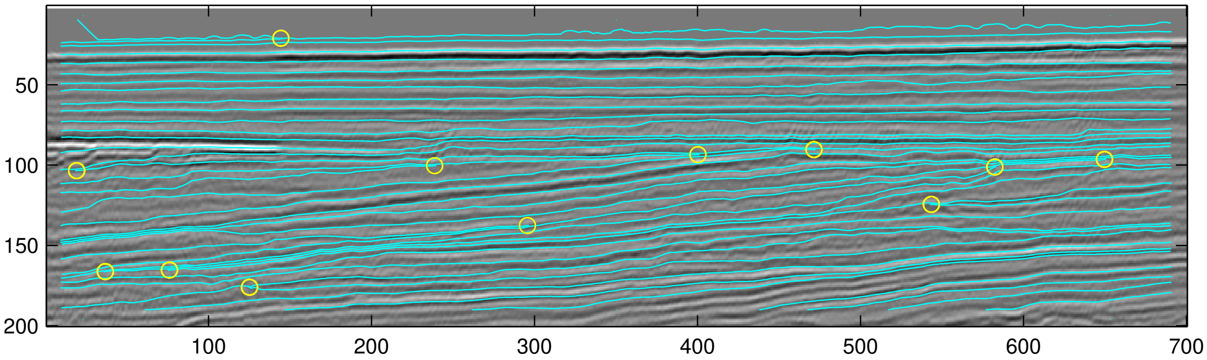
A stratigraphic trap occurs when the reservoir rock is surrounded by an impermeable seal and the depository layers did not have a horizontal structure. A river delta is a typical example of a non-horizontal deposition region. Crucial in the detection of stratigraphic traps is the identification of boundaries between different strata. An important class of boundaries are boundaries where one stratum *terminates* into another stratum [85, 75], see Figure 8.7. Seismic stratigraphic termination analysis is the analysis of termination patterns in the seismic signal. The straightforward approach to termination analysis is to do manual or automatic interpretation of all layers and analyze their terminations.

No explicit works on automated termination detection have been found, but implicit stratigraphic feature detection is reported with the coherence cube approach [7]. In this section, an approach to automated termination detection is proposed.

As with the fault feature extraction, the approach by Rao and Schunck [113] is utilized for orientation estimation. Given the local orientation estimate, *flow lines* following the local orientation are constructed. Starting at any position, the flow line is the curve through that position having the orientation of the local angle estimates in its path. The technique was applied to the image in Figure 8.8(a). In an illustrative experiment, flow lines sparsely covering the image were generated, Figure 8.8(b), and we can clearly see how the flow lines follow the orientation and indicate regions with terminations. A slightly different way of utilizing the method was applied in the experiments leading to Figure 8.8(c). In this experiment, the density of flow lines was increased significantly. When two flow lines (in this experiment; when two flow lines with seeds in the same column in the image)



(a)



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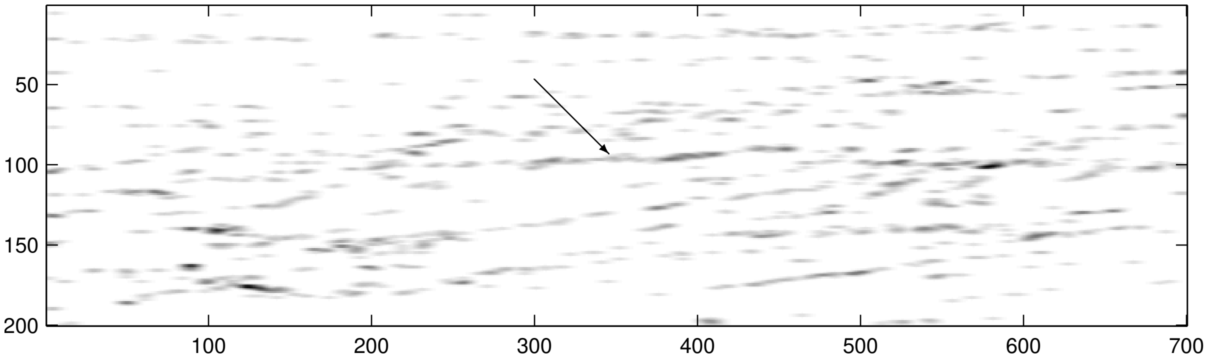

(c)

Figure 8.8: (a) Example seismic cross-section and (b) flow lines overlaid the seismic section, indicating the dominating local orientations. Terminating flow lines are marked by small circles. (c) Termination density, the arrow pinpoints an interface which is successfully highlighted by the technique.

converges to the same pixel position, that position is marked as a termination. For each termination, the value in an accumulator array with each cell corresponding to one pixel was increased by one and this accumulator array was smoothed and scaled appropriately for display. In this illustration, we can see the sequence boundaries of the different layers highlighted by black, e.g., around the pinpointed interface (about 100 samples from the top).

In the implementation used in the experiments, the step size in the flow line tracking was always one and the flow lines were represented as connections of line segments. The orientation of each line segment was taken to be the orientation in the sample position closest to the start of the line segment.

In summary, with the flow line technique proposed in this subsection, a solution to the problem of seismic stratigraphic termination detection is proposed. As we see, the technique is suited to the detection of terminating strata in the seismic images.

8.4 Summary

In this chapter, a review of the basic principles of geology, seismic data acquisition, and seismic data processing was given. Then the problem of fault identification was introduced. An approach to fault feature extraction using the edge enhancement filter masks tuned by the orientation of the seismic layers was proposed. It was shown that these features were powerful for fault highlighting. The fault analysis part was concluded with discussion and experiments on making a meaningful geometric description of the fault surface based on the extracted features.

Next, the problem of detection of terminating strata from seismic signals was introduced. A technique for termination detection based on local orientation estimates was suggested. In this approach, the local orientation was traced by flow lines. Flow line intersections correspond to terminating strata.

All the techniques for seismic analysis presented herein are founded on proven signal processing theory. No explicit use of horizon interpretation and other higher level seismic interpretation is made. This is expected to yield a system that degrades gracefully with the quality of the data and which is not biased by the interpretation.

For implementational reasons, all experiments, and therefore all discussion given in this chapter, have been made with the assumption that the input is a two-dimensional seismic cross section. Since the seismic data is inherently three-dimensional, this is a limitation to the power of the techniques. However, all techniques presented may readily be extended to three dimensions.