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Converted Modes in Subsalt Seismic Exploration

by

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A Thesis Submitted
in Partial Fulfillment of the
Requirements for the Degree

Master of Arts

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Abstract

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Salt has unusual properties which complicate seismic exploration. A model study examines some problems encountered in subsalt amplitude analysis and demonstrates that traditional techniques for detecting hydrocarbons and overpressured sediments using amplitude and velocity analysis are severely limited subsalt. Strong mode conversions generated at salt-sediment interfaces intrinsically limit amplitude versus offset techniques by diverting a significant amount of energy away from P-wave reflections. Some of the information lost from P-wave reflections is recouped by examining mode converted reflection amplitudes. Mode conversions are sensitive to different rock properties than P-waves, and those generated at the base of salt bodies are easily identified using acoustic and elastic modeling comparisons. Models demonstrate the use of base of salt converted mode amplitudes to gauge the strength of P-wave reflections for hydrocarbon discrimination. Further, mode converted amplitudes are used in conjunction with P-wave amplitudes from base of salt to detect overpressuring directly beneath salt.
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Chapter 1

Introduction

Subsalt primary wave data are contaminated by multiples and mode conversions and suffer from poor illumination, raypath distortion and mispositioned events. There are numerous processing techniques to remove artifacts and apply corrections, but the low signal-to-noise of subsalt data may render these useless. Mode conversions, which typically appear strongest where primary wave reflections are weakest in this low signal-to-noise environment, may be considered as signal rather than noise. Doing so offers an additional source of information about subsalt reflections to supplement P-wave data. To understand the complications encountered subsalt and the behavior of mode conversions and their effects on subsalt data, a series of model studies and data comparisons are presented. Simple models are used to understand factors affecting subsalt signal and the behavior of mode conversions. Analysis of the appearance and amplitude of mode conversions is used to assess whether they have value in interpretation and predicting rock properties.

1.1 Salt distribution and tectonics in the Gulf of Mexico

Salt is abundant in many areas of the world including the Gulf of Mexico, Western Africa, the north German plain, western Iran, southwestern Soviet Union and the Canadian Arctic (Twiss and Moores, 1992). In these areas, salt has had a profound influence on the geology. Salt has been the primary tectonic agent in the Gulf of Mexico since the onset of the Cenozoic. Under the weight of increasing clastic depositional loads, salt has migrated vertically and basinward in the Gulf. This movement has resulted in the formation of complex salt structures and the deformation of sur-
rounding sediments. These sediments are folded and faulted to accommodate the advance and withdrawal of salt.

Salt was deposited in the Gulf during the mid-Jurassic (Worrall and Snelson, 1989). Deposition of the salt was controlled by rift-generated topography that had not yet been buried. Salt was thin over the crests of horst blocks and thick in the grabens. During the Late Jurassic, salt deposition subsided and terriginous clastics were loaded on top of the incompressible salt. Under the stress of increased lithostatic load, salt began to deform and migrate basinward. This movement was accompanied by substantial faulting and folding of surrounding sediments (Worrall and Snelson, 1989).

Salt deformation was initiated by the influx of deposits from shifting alluvial sources. The location of sediment depocenters and the nature of deposits affected the amount and type of salt movement. Shifting deltas preferentially distributed sediments over the salt depending on sea level and topography. Near the sediment depocenters, salt moved vertically, creating isolated structures such as diapirs and canopies. Further offshore, salt moved laterally and formed very broad, semicontinuous salt lobes in response to progradation of shelf edges over autochthonous salt. The Sigsbee salt nappe marks the southernmost extent of salt migration. This salt nappe progressively overrode abyssal plain sediments at its distal termination. Clastic sedimentation, primarily from the Mississippi River continues to play a major role in the deformation of salt and its basinward advance (Worrall and Snelson, 1989).

Salt deformation has been fundamental to the evolution of growth faults, fold belts, and sedimentation patterns in the Gulf (Wu et al., 1990). Seaward migration of salt resulted in updip extensional growth faulting on the shelf and upper slope. An equivalent amount of downdip contraction in the middle to lower slope occurred through shortening of salt canopies or development of fold and thrust belts (Peel
et al., 1995). Because the basement has not undergone contraction or extension during the Cenozoic, extension and contraction is thin-skinned, accommodated by large-scale salt displacement and flow beneath the continental slope. In addition to deforming surrounding sediments, salt movement has affected patterns of sedimentation. Vertical salt movement resulted in topographic highs and lows, which channeled sediments to particular areas.

1.2 Salt-related imaging and drilling complications

Salt complicates seismic imaging because its unusual properties violate many of the simplifying assumptions made in seismic acquisition and processing. These characteristics result in filtering effects which limit the amount of seismic energy recorded, artifacts which obscure reflections, and geometries which are difficult to illuminate and interpret.

Compared to typical Gulf of Mexico sands and shales, salt has unusually high seismic velocities. Primary and shear wave velocities may be two to three times higher than those of surrounding sediments. As a consequence, the P-wave critical angle at the top of salt is small, perhaps on the order of 20 degrees. This small critical angle limits the amount of seismic energy transmitted through the salt and the amount of energy reaching subsalt reflectors. Further, P-waves which do enter the salt are severely bent and follow longer raypaths. As the thickness of the salt body increases, these raypaths become even longer, and P-waves may reflect back to the surface at offsets greater than the length of the recording cable (Figure 1.1).

The velocity contrast between salt and clastic sediments is also responsible for strong reflections and efficient generation of multiples and converted modes. These phenomena further reduce the amount of P-wave energy transmitted to interfaces below the salt body. At a salt-sediment boundary, the sharp change in material
Salt Thickness

Figure 1.1 The thicker the salt body, the longer the cable required to record energy for the same incident angle. Also note that severe ray bending causes the downgoing wave to strike the base of salt at a large incidence angle. This is conducive to wave conversion.

properties creates a reflection much stronger than one from a typical shale-sandstone contact (Figure 1.2). As a consequence, a substantially smaller amount of energy is transmitted to layers below the salt. This effect is compounded if the wave travels through multiple salt-sediment interfaces. By the time a seismic signal has traveled through all the salt-sediment interfaces, it may be considerably weakened. The strong reflection created at salt-sediment interfaces may generate multiples which interfere with P-wave imaging and interpretation. Strong mode conversions are generated at salt-sediment interfaces and divert energy away from P-wave reflections. As shown in Figure 1.2, mode conversions appear strongest at intermediate incidence angles and may even be stronger than primary waves. Both multiples and mode conversions interfere constructively and destructively with P-wave reflections and may be improperly interpreted as P-wave events.

In addition to its anomalous velocities, salt deforms easily into complex geometries when stress is applied (Jenyon, 1986). Dipping salt interfaces cause incident waves to strike at large angles. These waves may convert to shear waves or travel beyond
Figure 1.2 A comparison of energy of transmitted and reflected waves generated at a shale-sand interface and a shale-salt interface from an incident P-wave. The first letter in the legend indicates the outgoing wave type, and the second letter indicates transmission or reflection. For shale over brine sand, most energy is transmitted as a P-wave, decreasing slightly with increasing angle until it goes to zero at the P-wave critical angle (72 degrees). Beyond this angle, energy is reflected primarily as a P-wave. Conversion to shear waves is negligible. For the shale-salt contact, P-wave transmission is much smaller and is cut off at a smaller critical angle (30 degrees). P-wave reflection is considerably larger, especially at smaller incidence angles. Mode conversion is significant. Between 30 and 60 degrees, transmitted and reflected shear waves are stronger than the reflected P-wave. Shale has a primary wave velocity \( V_p \) of 3050 m/s, shear wave velocity of 1240 m/s \( V_s \), and density \( \rho \) of 2.4 g/cc. For the brine sand, \( V_p = 3200 \) m/s, \( V_s = 1537 \) m/s, and \( \rho = 2.2 \) g/cc. Salt has \( V_p = 4481 \) m/s, \( V_s = 2530 \) m/s, and \( \rho = 2.14 \) g/cc.
the length of the recording cable (Figure 1.3). The shape of the salt body may cause uneven illumination of layers below the salt body. It may act as a lens to focus energy or disperse it causing seismic data to look bright in some places and washed out in others. Small-scale variations in the surfaces of the salt body scatter seismic energy so the seismic section is riddled with diffractions which must be removed using migration. Many of the shapes salt assumes are 3D in nature and out-of-plane reflections may require 3D acquisition and processing.

In addition to the imaging complications salt creates, there are also risks associated with drilling through salt. Sediments with abnormally high pore fluid pressure may be encountered directly beneath salt bodies. Low permeability salt acts as a seal, potentially trapping pore fluids in the formations below it. When penetrated by a drill bit, the release of built-up fluid pressure may damage drilling equipment. Predrill pressure conditions are important in selecting drilling locations and mud weights. Traditional methods of detecting overpressure are inadequate where salt is involved. They depend upon a significant drop in compressional wave velocity to signal overpressured sediments. However, such a velocity inversion is common beneath salt bodies and may not be used to indicate overpressuring.

1.3 Mode conversions

Mode conversions are waves which travel partially as a P-wave and partially as an S-wave. They change wave type upon striking a boundary between rocks with different velocities and densities (Figure 1.4). This conversion occurs only at nonnormal incidence and varies as a function of the incidence angle reaching a maximum after the critical angle of the incident wave. The efficiency of conversion also depends on the ratios of the properties of the two media, namely primary wave velocity ($V_p$), shear wave velocity ($V_s$), and density ($\rho$). Physical modeling experiments (Purnell,
Flat layer: Ray traveling vertically is recorded at zero offset. Ray at offset is recorded at an equal offset.

Dipping layer: ray travelling vertically down strikes dipping layer at an angle equal to the dip angle $e$. The ray is recorded at an offset from the shot.

Dipping layer: The effect of dip is to rotate the range of incidence angles. Only rays traveling at an angle of $90 - e$ will strike the dipping interface at normal incidence. For a ray striking the interface at a large angle, the reflected ray may convert to a shear wave or may travel beyond the range of the recording line before it reaches the surface.

**Figure 1.3** The effect of dip on incidence angle is conducive to the generation of mode conversions.
1992; Tatham et al., 1983) show that conversion from P- to S-waves is particularly efficient in the case of high velocity zones such as salt, basalt, and carbonates. In such situations the shear velocity in the high velocity zone is similar to the P-wave velocity in adjacent rocks. Salt is particularly conducive to the generation of mode conversions not only because it is a high velocity layer, but also because it often assumes complex shapes. Dipping interfaces allow waves to strike at larger incidence angles where conversion is even more efficient.

**Figure 1.4** Wave conversion at two interfaces. A P-wave incident at the top of salt interface generates reflected P- and S-waves and refracted P- and S-waves. Each of the transmitted waves generates additional reflected and refracted P- and S-waves. Because the salt has much higher velocity than surrounding sediments, the transmitted P-wave at top of salt experiences severe ray bending. In contrast, the shear velocity of the salt is similar to the P-wave velocity of the overlying sediments. As a consequence, the transmitted shear wave does not bend as much and is particularly strong in this case.
Mode conversions are recognized on prestack gathers on the basis of several distinct characteristics. Because they travel at a slower shear velocity for part of their path, converted modes appear as nonhyperbolic events at a later arrival time than the corresponding P-wave reflection (Figure 1.5). They are strongest at intermediate incidence angles and die out at very large angles. NMO correction using primary wave velocities overcorrects these events, and theoretically they should not survive stacking. Ogilvie and Purnell (1996) showed converted modes may survive stacking and pose problems with imaging and interpretation. Mode conversions obscure reflections from primary waves, and if not correctly identified prior to stacking, they are indistinguishable from primary wave events and may be erroneously interpreted.

Although mode conversions pose challenges to conventional processing and interpretation of seismic data, previous studies have demonstrated their use in areas where P-wave imaging is poor. Offshore western Florida where a hard water bottom limited P-wave penetration, Tatham and Goolsbee (1984) separated strong mode converted events using tau-p processing. P- and S-wave sections showed good correlation and the S-wave data substantiated stratigraphic interpretations. Purnell (1992) used converted modes to image a larger range of dips than was possible with P-wave data alone. Ogilvie and Purnell (1996) migrated data using shear wave velocities to verify a base of salt interpretation made from P-wave data. Their results showed that simple adaptation of P-wave processing and analysis techniques may be applied to converted mode data to obtain a better picture of subsurface structure. These examples demonstrate the imaging value of mode conversions. They appear precisely where P waves are weakest: at larger incidence angles and beneath interfaces with great impedance contrasts.

In addition to their use in imaging, some preliminary work utilized converted wave amplitudes for rock property information. Several studies (Ensley, 1984; Frasier and
Figure 1.5 A shot gather generated by elastic modeling of a single interface. The upper medium is salt ($V_p = 4481 \text{ m/s}$, $V_s = 2530 \text{ m/s}$, $\rho = 2.14$), and the lower medium is a gas sand ($V_p = 2440 \text{ m/s}$, $V_s = 1620 \text{ m/s}$, $\rho = 2.16$). At zero offset, the PP (P incident, P reflected) reflection arrives at 0.9 s and has hyperbolic moveout. The projected arrival time of the PS conversion is 1.2 s. It is nonhyperbolic in shape and is strongest at mid-offsets.
Winterstein, 1990; Robertson and Pritchett. 1985) have shown that shear waves and mode conversions are sensitive to lithologic variations. Used in conjunction with P-wave amplitude analysis, they may distinguish lithologic anomalies from hydrocarbon-related anomalies. In anticipation of future use of converted mode amplitude analysis, Donati and Martin (1998) derived an approximation for P-SV reflection coefficients following the work of Shuey (1985).

1.4 Modeling

The complexities associated with salt such as sharp velocity contrasts, steep dips, folds, faults, and 3D effects make standard processing techniques inadequate and require implementation of more specialized procedures such as migration. Seismic modeling is another tool which can provide additional information about subsurface structure and rock properties. Models are created to mimic various geologic conditions and understand the seismic response to these conditions. For example, models may be created to examine the effects of salt, gas saturation, and mode conversions. Some of the modeling presented in this thesis includes:

- 1D seismograms: These synthetics simulate the ideal earth response at normal incidence. They do not include effects such as transmission and spreading losses, multiples, and mode conversions. One dimensional synthetic seismograms are useful for identifying primary reflections and assessing the effect of amplitude-modifying effects in more complicated models.

- 3D flat layer synthetic shot gathers: These models calculate the 3D seismic response to a stack of homogeneous plane layers. They include effects such as spherical spreading, transmission losses, mode conversions, and multiples.
These models are useful for demonstrating the effects of non-geometric factors on seismic amplitudes.

- 2D models of seismic lines demonstrate the effects of geometry on amplitudes. Elastic 2D models include the effects of mode conversions while acoustic models do not. Comparison of these models is used to identify mode conversions.

- Zoeppritz models: The Zoeppritz models calculate the Zoeppritz reflection and transmission coefficients for P- and S-waves incident at a plane interface between homogeneous isotropic media. These models are used to study the amplitude variation with offset (AVO) of reflected waves.

1.5 Outline of thesis

This thesis covers three main topics related to subsalt mode conversions: determining the effects of mode conversions on subsalt amplitudes relative to other amplitude modifying phenomena, identifying base of salt mode conversions, and amplitude analysis of base of salt mode conversions for detecting hydrocarbons and overpressured sediments directly beneath salt.

The second chapter is a model and data study to assess the importance of various factors affecting subsalt signal. Well logs and seismic data from the Gulf of Mexico are modeled to separate the effects of various amplitude-modifying phenomena due to wave propagation effects, geologic effects, and processing. Particular attention is focused on mode conversions at salt interfaces and their effect on subsalt AVO analysis.

In chapter 3, models and partial stacks from a Gulf of Mexico data set are used to identify base of salt mode conversions and assess their strength relative to primary waves. Acoustic and elastic synthetic shot gathers are compared to locate mode
conversions in the field data. Further evidence of base of salt mode conversions is provided by partial stacks made at several offset ranges. These stacks show strong mode converted energy appearing at larger offsets and obscuring P-wave reflections.

With evidence for strong base of salt mode conversions and a technique to identify them, chapters 4 and 5 focus on amplitude analysis of base of salt mode conversions for hydrocarbon and overpressure detection. Zoeppritz coefficients demonstrate the problems encountered in detecting hydrocarbons at base of salt using only P-wave data. Amplitudes of base of salt mode conversions are analyzed to determine whether they may contribute to hydrocarbon detection. In chapter 5, an alternative method of detecting overpressure is developed which may be applied directly to the base of salt. Zoeppritz coefficients and stacked synthetic seismic sections demonstrate how mode converted base of salt amplitudes may be used to signal overpressuring and distinguish it from other amplitude anomalies not due to overpressuring.
Chapter 2

Problems in subsalt P-wave amplitude analysis

2.1 Introduction

Reflection coefficients vary as a function of offset due to changes in elastic parameters across an interface. The basis of AVO (amplitude variation with offset) analysis is to utilize these variations to characterize fluid and lithologic conditions. However, there are a multitude of factors which alter reflection amplitudes and are unrelated to changes in rock properties and pore fluid. These are grouped into data acquisition, processing, geologic and wave propagation effects. Data acquisition effects include source directivity, source and receiver arrays, and source and receiver coupling. Processing-related amplitude distortions may be caused by improper selection of parameters and processing sequences. Techniques such as scaling, NMO, and filtering may cause unwanted alterations of amplitudes. Geologic effects are the result of dipping and curved reflectors as well as tuning caused by thin layering. Wave propagation effects are a consequence of overlying geologic conditions. They include spreading losses, transmission losses, interbed and surface multiples, mode conversions, and inelastic attenuation. Many of these geologic and wave propagation effects are magnified when salt is present. Due to salt's complex geometry and high velocity, they may imprint particularly severe amplitude variations on subsalt data. Poor imaging conditions below salt may necessitate additional processing routines to increase signal-to-noise potentially at the cost of imprinting even more amplitude variations. The magnitude and complex nature of amplitude distortions due to processing, geo-
logic, and wave propagation effects in the presence of salt call into question the ability to extract lithologic and pore fluid information from subsalt amplitudes.

A modeling study based on well log and seismic data from the Gulf of Mexico is presented which examines processing, geologic, and wave propagation effects on subsalt amplitudes and the limitations they impose on amplitude analysis techniques. Zero offset synthetic amplitudes derived from well log data are compared with amplitudes from more complex models and seismic field data to assess the consequence of various amplitude-modifying phenomena. Particular attention is focused on the role of mode conversions, salt geometry, and scaling and migration techniques in altering the AVO response of gas and brine sands to the point where they are indistinguishable from each other. Results of this study explain the failure of subsalt amplitude analysis in the following case history, suggest limitations on the application of amplitude analysis techniques such as AVO, and recommend procedures to remove unwanted amplitude-modifying phenomena.

2.2 Previous work on amplitude distortions and subsalt amplitude analysis

Several studies have examined amplitude distortions due to processing, geology, and wave propagation effects on amplitudes and the implications for AVO analysis. Allen and Peddy (1993) detail several case histories of failed AVO prospecting due to amplitude anomalies caused by processing, thin bed tuning, source and receiver array effects, and 3D geometric effects. Martinez (1993) quantified wave propagation effects on the extraction of AVO parameters. Using elastic synthetics, he examined multiples, converted modes, spreading losses, and attenuation in a sequence of alternating sands and shales. Even in the absence of salt, mode conversions and multiples
imprinted large and complex amplitude variations which altered the AVO response. Ramos (1998) concentrated on processing bias in AVO analysis. He evaluated several processing sequences which included radon demultiple, spectral whitening, and various amplitude scaling procedures. The order in which these processes were applied altered the signal-to-noise and relative amplitudes of the data to different degrees. Martinez (1993) and Ramos (1998) restricted their studies to areas without salt and did not consider the aggravated effects of salt-related multiples, mode conversions, geometric complexities, and poor signal-to-noise.

Advances in subsalt exploration have generated a need to understand the severity of wave propagation and processing effects in the presence of salt. In addition, complex salt bodies require an understanding of geometric effects on subsalt illumination. Recent developments in depth imaging (Ratcliff and Weber, 1997; Ratcliff et al., 1995) and acquisition design (Cramer et al., 1995) increased signal-to-noise of subsalt data to the point where subsalt reflections could be interpreted. With high quality subsalt data available, efforts are being made to extend amplitude analysis techniques to subsalt data. Lindsay and Ratcliff (1996) noted variations in subsalt reflection amplitudes which mimic the response of a gas sand with a class 3 AVO anomaly. Due to the complications associated with salt, it was not possible to determine whether these amplitudes were indicative of pore fluids or the result of salt-related wave propagation and geometric effects. Lindsay and Ratcliff (1996) and later Muerdter et al. (1996; 1997) examined part of the problem: the geometric effects of complex salt structure. They used 3D ray trace models to examine the distortion of raypaths and illumination patterns below salt. Fold coverage maps showed that the shape of the overlying salt, particularly at the edges, caused large amplitude variations unrelated to the rock properties. Future work includes correcting subsalt data for uneven illu-
mination and examining processing-induced distortions and wave propagation effects such as multiples, spreading losses, and attenuation.

This study continues the work of previous authors by considering processing, wave propagation, and geometric effects on subsalt amplitudes. Elastic modeling is used to evaluate amplitude distortions and particular attention is addressed to the effect of mode conversions on AVO response.

2.3 Failure of subsalt amplitude analysis

A data set from the Gulf of Mexico is presented with examples of successful and unsuccessful subsalt amplitude analysis. The inability to distinguish brine sands from gas sands on the basis of amplitudes highlighted the need to better understand factors influencing subsalt amplitudes.

While it was possible to distinguish extra salt (outside of salt) gas sands from brine sands in the field area on the basis of high amplitude anomalies, extension of this technique to subsalt sands was not as successful, as illustrated by the amplitude map shown in Figure 2.1. This map is a color-coded display of seismic amplitudes from a subsalt sand horizon picked on 3D depth migrated seismic data. With the assumption that high amplitudes (in red) indicated hydrocarbons and low amplitudes (in blue) were from brine-saturated sands, wells C and D were drilled on high amplitude anomalies of similar magnitude. Only well C encountered gas while well D penetrated a thick brine-filled sand. In this case, subsalt amplitudes displayed on the amplitude map were not reliable indicators of pore fluids, and traditional amplitude analysis techniques failed to distinguish gas sands from brine sands.

There are many factors which may have caused brine sands to have as strong an amplitude as gas sands. Mode conversions, multiples, geometric effects, and amplitude-modifying processing techniques are potential culprits. A model study
was conducted to determine which of these factors contributed to the failure of subsalt amplitude analysis and limit the applicability of amplitude analysis techniques to subsalt prospecting in general.

Figure 2.1 Seismic amplitude map of subsalt horizon 3 (see Table 2.1) constructed from 3D depth migrated data. This horizon intersects the stem of a canopy salt structure (upper left). High amplitudes are shown in red and were assumed to indicate hydrocarbons while low amplitudes in blue were assumed to be brine sands. Wells C and D were drilled on high amplitudes, but only well C encountered gas. In this case, subsalt amplitudes were not accurate indicators of pore fluid, and it is likely there are several factors modifying these amplitudes which are unrelated to rock properties.

2.4 Data

Data used in this study are listed in Table 2.1. Data quality and coverage are high, and a variety of geologic conditions are sampled. The seismic data have high signal-
to-noise, and the salt structures encountered have relatively simple geometries which do not severely limit imaging. With the exception of well B, all wells tie directly to the seismic data for calibration purposes. This is especially important for relating amplitudes on the seismic data with lithologies and pore fluids identified on the well logs. Seismic data coverage allow for comparisons of brine sands and gas sands outside of and underneath salt. These comparisons form the basis of the modeling study to understand how salt affects seismic amplitudes.

2.5 Method

Several types of modeling programs were used to examine the seismic response under increasingly complex earth conditions. A zero offset modeling program created synthetic seismograms using well log data and seismic velocity models. Using the same input, multi-offset synthetics were created using a 3D flat layer modeling code. Two-dimensional effects were included in 2D elastic wave equation modeling code to simulate an entire seismic line. By incrementing the complexity of each model, it

<table>
<thead>
<tr>
<th>Well</th>
<th>Location</th>
<th>Sand horizon(s)</th>
<th>Pore fluid</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>subsalt</td>
<td>1,2</td>
<td>gas</td>
</tr>
<tr>
<td>B</td>
<td>extra salt</td>
<td>3</td>
<td>brine</td>
</tr>
<tr>
<td>C</td>
<td>subsalt</td>
<td>1,3</td>
<td>gas</td>
</tr>
<tr>
<td>D</td>
<td>subsalt</td>
<td>3</td>
<td>brine</td>
</tr>
<tr>
<td>E</td>
<td>extra salt</td>
<td>2</td>
<td>brine</td>
</tr>
</tbody>
</table>

Table 2.1 A list of the wells and sand horizons they penetrated. In the following text, sand horizons are referred to by a number which designates the horizon and a letter which designates the well.
was possible to understand the effects of certain amplitude-modifying phenomena in isolation (Table 2.2).

The synthetics were generated for various geologic settings based on well log and seismic data to study the amplitude response to gas and brine sands in subsalt and extra salt environments. Control models were created at each well location to compare amplitude responses after substituting pore fluids and salt for sediment (or vice versa).

2.5.1 Creating input earth models for 1D and 3D flat layer modeling code

The earth models for 1D and 3D flat layer modeling programs consisted of several hundred isotropic and homogeneous layers with P-wave velocity ($V_p$), S-wave velocity ($V_s$), density ($\rho$), and layer thicknesses extracted from well logs. The logs were block averaged at 12 m increments to reduce the number of layers to only those showing large fluctuations in the P-wave acoustic impedance. In addition to $V_p$, $V_s$, $\rho$, and thickness, the 3D flat layer modeling code required values for P-wave and S-wave attenuation. Attenuation was assumed constant to simplify the modeling.

Data from well logs alone were insufficient for modeling because logging typically started beneath the salt canopy at depths of 2438 to 2743 m. In order to include the effects of water bottom multiples, salt-related multiples, and mode conversions in the 3D flat layer modeling, it was necessary to extend the earth models to sea level. This upper portion was constructed from the velocity model used to depth migrate the seismic data. The trace from the seismic compressional velocity model at the well location was extracted and merged with the $V_p$ log. The extracted trace was converted to $\rho$ and $V_s$ using trend curves empirically derived for the area (see Appendix A). These upper portions were appended to the top of the density and shear logs. An example of the complete $V_p$, $V_s$, and $\rho$ earth models for well A appears in Figure 2.2. From the surface to the water bottom (1326 m), the models have
<table>
<thead>
<tr>
<th>Model/Data</th>
<th>Amplitude-modifying effect</th>
</tr>
</thead>
<tbody>
<tr>
<td>1D</td>
<td>ideal zero offset amplitudes</td>
</tr>
<tr>
<td>3D flat layer</td>
<td>transmission losses, spherical spreading losses, mode conversions, multiples, attenuation, some processing techniques</td>
</tr>
<tr>
<td>2D</td>
<td>all of the factors included by the 3D flat layer models plus geometric effects such as scattering, raypath bending, focusing</td>
</tr>
<tr>
<td>3D seismic data</td>
<td>all of the factors included by the 2D models plus 3D effects, thin bed tuning, random noise, anisotropy, source and receiver effects</td>
</tr>
</tbody>
</table>

Table 2.2  As models become increasingly complex, there are more factors to account for in understanding amplitude behavior.

constant values for water. Below water bottom, values gradually increase following a trend from the depth migration velocity model. This trend is interrupted between 1722 m and 2652 m by a salt body with constant $V_p$, $V_s$, and $\rho$. The logged interval extends from 2987 m to 4413 m.

In order to create several control versions of the earth model shown in Figure 2.2 for comparison, salt was replaced with a smoothly increasing sediment trend and gas sands were replaced with brine sands. Fluids were substituted using $V_p$, $V_s$, and $\rho$ values from brine or gas sands at equivalent depths from neighboring logs. These substitutions result in four synthetics with different sands of interest: subsalt gas sand, subsalt brine sand, extra salt gas sand, and extra salt brine sand. The various substitutions were made for all of the wells although only a few comparisons are presented in the following text.
Figure 2.2 $V_p$, $V_s$, and $\rho$ models from well A after blocking and correlation. The upper portion of these models is constructed from the depth migration velocity model. The lower portion is the logged interval. After blocking, the number of layers in the logged interval is reduced to several hundred. The zero offset synthetic generated from the P-wave acoustic impedance is the trace on the left. It was correlated with the seismic trace extracted at the well location, shown on the right. After correlation the major events, water bottom, top of salt, base of salt, and high impedance sands, line up on both traces at equivalent depths.
2.5.2 1D Modeling

A 1D synthetic seismogram was created with the algorithm described in the AVO User's Guide (Russell and Hampson, 1994). A reflectivity series was generated from \( V_p \) and \( \rho \) earth models. This was convolved with a wavelet whose phase and frequency were matched to that of the seismic data in the zone of interest. Time shifts between the seismic data and the synthetic were minimized by slightly adjusting the value of the \( V_p \) log. An example of the zero offset synthetic appears in Figure 2.2.

The synthetic represents the ideal earth response:

- raypaths are assumed vertical,
- layering is horizontal,
- each layer is characterized by \( V_p \), \( \rho \), and thickness,
- the wavelet is time-invariant so its frequency does not decay with depth,
- all amplitude modifying factors other than those involving the reflection coefficients are ignored.

Comparisons between the 1D synthetic seismogram and more complicated synthetics and seismic data were made to identify primary reflections, assess processing techniques, and evaluate the effects of mode conversions.

2.5.3 3D flat layer modeling

Synthetic shot gathers were created with a modeling code documented in Subhashis and Frazer(1990). The algorithm computes the 3D seismic response for a stack of homogeneous plane layers iteratively by successive inclusion of deeper layers. A point source was specified with receivers placed according to acquisition parameters for field data.
The 3D flat layer models include several amplitude-modifying effects not accounted for in the 1D synthetics. Offsets are not limited to zero, and arrival times, wave shape, and amplitudes vary with offset. Further, layers are characterized not only by $V_p$, $\rho$, and thickness but also by $V_s$, $Q_p$ (P-wave attenuation), and $Q_s$ (shear wave attenuation). Reflection amplitudes are influenced by mode conversions, surface and interbed multiples, spherical spreading losses, and diffractions. Processing applied to the 3D flat layer synthetics to compensate for spreading losses and remove multiples was evaluated by comparison with 1D models. In addition, the AVO trends of subsalt and extra salt reflections were measured to evaluate the effect salt-related multiples and mode conversions.

2.5.4 2D Elastic Modeling

The 2D pseudospectral wave equation modeling program used to create synthetic elastic sections is based on the method described in Kosloff and Baysal (1990). Details of its implementation are found in Strahilevitz (1996). A numerical grid is used to calculate the spatial derivatives in the wave equation by fast Fourier transforms. Time derivatives are calculated by second order differencing. This program provides accurate amplitudes with fewer gridpoints than required by finite difference modeling codes.

To run this code, it was necessary to specify a grid, source term, and material parameters associated with a 2D structural model. The grid and source term were selected to mimic acquisition parameters of the field data. The structural model was constructed from an interpretation of a prestack depth migrated line intersecting well A. Material parameters $V_p$, $V_s$, and $\rho$ were assigned to different layers in the model based on well log information and seismic velocity analysis. In particular, sand horizons 1A and 2A were assigned values based on information from well A.
The modeling code generated multiple shot gathers across the entire structural model. These shot gathers were sorted to CMP gathers, processed and stacked to produce a seismic section.

Of the models used in this study, the 2D elastic synthetic section is the most realistic duplication of the seismic field data. The modeling code accounts for transmission losses, interbed and surface multiples, mode conversions, and spreading losses. Because it allows for lateral and vertical variations in structure and velocity, amplitudes in the 2D elastic synthetic are subject to geometric effects due to dip and reflector curvature. Amplitudes of subsalt horizons were examined to determine the effects of uneven illumination, complex salt geometry, and different migration algorithms.

2.5.5 Processing

Processing was applied to 3D flat layer and 2D elastic synthetics so stacked amplitudes could be compared with the amplitudes of 1D synthetics and migrated field data. The purpose of these comparisons was two-fold: to observe the geologic and wave propagation effects on amplitudes and to evaluate processing techniques which correct for some of these phenomena. Attempts were made to mimic processing applied to the field data. Elements of the prestack processing flow are shown in Figure 2.3. With the exception of inner and outer mutes which were used in place of a trace weighting function, the processing of synthetics and field data was the same. Various gas and brine sand reflections on 3D flat layer synthetic shot gathers were analyzed for AVO. Stacking, migration, and post-stack processing is illustrated in Figure 2.4. Stacked and migrated amplitudes from synthetics and field data were compared with each other.

Processing modules shown in Figures 2.3-2.4 are described in detail below.
Prestack Processing Flow

3D flat layer synthetic, 2D elastic synthetic, field data

![Diagram of prestack processing flow]

**Figure 2.3** Prestack processing applied to 3D flat layer models, 2D elastic models, and data.
Post stack Processing Flow

Figure 2.4 Post stack processing applied to 3D flat layer models, 2D elastic models, and data.

- spherical divergence correction: compensated for amplitude loss due to wavefront spreading using a $1/tu^2$ correction where $t$ is travel time and $u$ is velocity.

- bandpass filter: a Butterworth filter using frequency-slope values of 6-18-40-45 removed low and high frequency noise.

- normal moveout correction: corrected for the variation of reflector arrival time because of variation in offset (Sheriff, 1991). Three-dimensional flat layer synthetics were corrected using the exact $V_p$ model constructed from the merged sonic log and seismic velocity model. This depth-interval velocity model was converted to time-RMS velocity prior to applying NMO.

- radon filter: suppressed water bottom and interbed multiples. The multiples were modeled using a parabolic radon transform and subtracted from the data.
First, a mute was applied to cut out first break refractions and NMO stretch. NMO flattened primaries while multiples were undercorrected. When transformed to time-moveout space, multiples, having negative moveout, were well separated from primaries. A mute was picked to remove to multiples. This radon filter was applied in a second pass to subtract multiple energy.

- time and space variant filter: cut out high frequency noise. The bandwidth of the filter was varied to accommodate the loss of high frequencies with increasing distance from the source.

- trace weighting: an offset dependent bell-shaped function which downweighted near and far offset traces to suppress multiple and mode converted energy.

- inner mute: removed near traces which were dominated by multiple energy in synthetics only.

- outer mute: cut out zones with severe NMO stretch and removed mode conversions which appeared at far offsets. Inner and outer mutes were used on synthetics in place of a trace weighting function.

- stack: 3D flat layer synthetic shot gathers were stacked so they could be compared with depth migrated 2D elastic synthetic sections and 3D depth migrated field data.

- match filter: matched the phase and amplitude characteristics of 3D flat layer synthetics to those of zero offset synthetics so that reflectors could be easily identified.

- trace equalization: scaled 3D flat layer synthetics so they could be compared against each other. The scalar was computed by finding the RMS amplitude
along a time window centered around the horizon of interest. A new amplitude was calculated by dividing the old amplitude by the scalar.

- prestack depth migration: collapsed diffractions and repositioned dipping reflectors in 2D elastic synthetic. Maximum energy Kirchhoff and finite difference methods were applied to the 2D elastic synthetics and compared against each other. Three dimensional Kirchhoff prestack depth migration was applied to the field data.

- spectral whitening: applied to increase the bandwidth of the data. A bandpass filter was applied afterwards to remove high frequency noise which may have been boosted by the whitening (applied to field data only).

A diagram outlining some of the modeling and processing steps appears in Figure 2.5. Amplitudes of various synthetics were measured: 3D flat layer synthetics before and after stack, 2D elastic synthetics after Kirchhoff and finite difference migrations, 3D depth migrated field data before and after spectral whitening, and 1D synthetics.

2.6 Results

2.6.1 Effects of processing on amplitudes

Comparing 1D and 3D flat layer models

In order to evaluate the effects of the processing documented in Figures 2.3-2.4 on seismic amplitudes and noise removal, amplitudes from 1D synthetics were compared with stacked amplitudes from 3D flat layer synthetics for various subsalt sands.

Overall, amplitudes from 1D and 3D flat layer synthetics are relatively similar (Figure 2.6). Except for sand 2A, amplitudes differ only by 6 to 15 percent. These
Figure 2.5  Construction of 1D and 3D flat layer models from well logs. $V_p$ and $\rho$ logs (upper right) were used to generate a reflectivity series. This was convolved with a wavelet extracted from the seismic data to create the zero offset synthetic. $V_p$, $V_s$, $\rho$, $Q_p$, and $Q_s$ curves comprised the input for 3D flat layer modeling code. This program generated a shot gather (upper left).

After processing, amplitudes were tracked above and below gathers for horizons highlighted in yellow to examine the AVO trend. The gather was stacked and amplitudes were compared with those from the zero offset synthetic and the seismic trace at the well location.
Figure 2.6  A comparison of amplitudes of sands from 1D synthetics (red) and the same horizons from stacked 3D flat layer synthetics (blue). Amplitudes from the 1D synthetics are a result of the material parameters. Amplitudes from the 3D flat layer synthetics were subjected to a number of modifying factors including: spherical spreading, multiples, mode conversions, and processing described in Figures 2.3-2.4. The magnitude of these factors can be ascertained by comparing amplitudes with the 1D synthetics.

similarities suggest the processing applied to the 3D flat layer synthetics was effective in removing noise and preserving amplitudes. Examination of the 3D flat layer gathers prior to stacking showed the majority of multiple energy was removed by the radon filter. Gathers were NMO corrected using the exact velocity models so errors were due only to the small angle limitation in the NMO module. The spherical divergence correction is responsible for some of the variations observed in Figure 2.6. Amplitudes were scaled to correct for decay due to wavefront spreading. The scalar was computed using a $1/tv^2$ correction, and velocity was assumed constant. As a consequence of
this approximation, shallower reflections such as sands 1A and 1C were gained too high because the constant velocity exceeded the RMS velocity of shallow reflections. Deeper reflections, 2A, 2E, 3C, 3D, were undercorrected because the constant velocity was lower than the velocity of sediments at these depths.

While an approximated spherical divergence correction is responsible for some of the amplitude variations between the 1D and 3D flat layer synthetics, mode conversions account for more erratic variations. Examination of the 3D flat layer gathers after processing and prior to stack showed the most obvious source of noise remaining after processing was due to mode conversions from the salt body. No attempt was made in the processing to remove these events and they imprinted significant amplitude variations. For example, sand 2A suffers a 35 percent reduction in amplitude after 3D flat layer modeling and processing. As observed in Figure 2.16, a strong mode conversion from the salt body interferes with the reflection from sand 2A. Mode conversions were also observed interfering with sands 1C, 3C, and 3D and probably contributed to the difference in amplitudes of the 1D and 3D flat layer synthetics. In contrast, extra salt sand 2E did not suffer from salt-related mode conversions and amplitudes from 1D and 3D flat layer models for this sand differ by only 6 percent.

Comparing 2D elastic models

To examine the effects of Kirchhoff prestack depth migration which was applied to the field data, a 2D elastic synthetic was migrated using a similar algorithm (Figure 2.7) and compared with the same section migrated with a finite difference algorithm (Figure 2.8). The two migrated sections were compared and amplitudes of sands 1A (red) and 2A (blue) were measured above both sections.

The finite difference migrated section provides a cleaner image of the model and more accurate amplitudes than the Kirchhoff migrated section. The finite difference
migration suffers from less numerical noise and handles lateral velocity variations well. In contrast, the Kirchhoff migration does not handle significant ray bending which occurs at the salt interfaces and dipping reflectors. This shortcoming is particularly evident in the amplitude tracks of sands 1A and 2A beneath the salt body. Compared to amplitudes measured on the finite difference migration, the amplitudes from the Kirchhoff migration are much more erratic. Oscillations are sharper and of greater magnitude. Differences in amplitude between the finite difference and Kirchhoff migration are attributed to the method of calculating the wavefield. The Kirchhoff migration approximates the wavefield as a ray whereas the finite difference migration computes the full wavefield.

**Seismic data comparison**

The effects of trace weighting and spectral whitening were evaluated by comparing field data and 3D flat layer synthetics.

Spectral whitening was applied after prestack depth migration to scale up high frequency reflections. A comparison of Figures 2.9-2.10, demonstrates that spectral whitening increases the high frequency content of the data, particularly below the salt body. Amplitudes selected from the field data before and after spectral whitening are displayed in Figure 2.11. All subsalt sand amplitudes increased after spectral whitening while the amplitude of the extra salt sand 2E decreased slightly. As illustrated by a comparison of spectra of subsalt and extra salt data (Figure 2.12), the amplitude spectra of extra salt data did not undergo as significant shaping as the subsalt data. To achieve the desired amplitude spectrum shown for the extra salt data, it was necessary to boost amplitudes up between 20 and 40 Hz and to cut out very high frequencies (above 70 Hz). In contrast, the amplitude spectrum of the subsalt data required scaling up frequencies between 5 and 40 Hz to counteract
Figure 2.7  Two-dimensional elastic synthetic based on seismic line through well A. This section was migrated using a maximum amplitude Kirchhoff migration algorithm. Amplitudes for sand 1A (red) and 2A (blue) are tracked above the synthetic. Beneath the salt, these amplitudes show strong oscillations related to the complex geometry of the salt body and the 1A and 2A reflectors. Also note numerical noise is quite high.
Figure 2.8  The same 2D elastic synthetic shown in Figure 2.7 but migrated with finite difference techniques. Amplitudes for sand 1A (red) and 2A (blue) are generally smoother than amplitudes tracked after Kirchhoff migration. Additionally, numerical noise is not as strong. Amplitude tracks terminate because it was not possible to pick coherent reflections beneath the steeply dipping salt flank.
Figure 2.9  Seismic line through well A after Kirchhoff prestack depth migration. High frequencies quickly degrade with depth.
Figure 2.10  The same seismic line shown in Figure 2.9 after Kirchhoff depth migration, spectral whitening, and bandpass filter. Spectral whitening compensated for the loss of high frequencies with depth. Base of salt and reflectors directly beneath the salt appear sharper after spectral whitening.
the linear drop in amplitudes with frequency. These amplitude spectra demonstrate that frequencies were significantly lower subsalt and scaling was necessary to boost amplitudes of higher frequency signal.

![Comparison of raw and spectrally whitened amplitudes](image)

**Figure 2.11** A comparison of raw amplitudes (green), directly after 3D prestack Kirchhoff depth migration, and the same amplitudes after spectral whitening and bandpass filtering (yellow). Spectral whitening increases all amplitudes with the exception of sand 2E.

To assess whether spectral whitening provided more realistic amplitudes, amplitudes from spectrally whitened data were compared with those from 3D flat layer synthetics (Figure 2.13). Spectral whitening generally improved the match between amplitudes from the field data and the synthetics.

In spite of the improvements with spectral whitening there are still variations between amplitudes from the field data and synthetics, some of which may be attributed to processing effects. Among the more noticeable variations is the difference between sand 1A after 3D flat layer modeling and after spectral whitening. The ratio of these
Figure 2.12 The effects of spectral whitening on extra salt and subsalt amplitude spectra. Amplitude spectra of extra salt data before and after spectral whitening is shown in the top two figures. Amplitude spectra for subsalt data at an equivalent depth before and after spectral whitening are shown below. Extra salt amplitudes did not require as much shaping as subsalt amplitudes whose spectrum shows an almost linear drop with frequency.
amplitudes is 0.77. In contrast, the same ratio for sand 2A, also from well A, is close to 1. Prestack depth migrated gathers corresponding to well A were examined for a clue to this difference. It was observed that a trace weighting function was applied only to a portion of the gathers. As shown in Figure 2.14, trace weighting was applied below 3353 m (11,000 ft) which included sand 2A but not sand 1A. Trace weighting effectively lowered amplitudes of 2A so they were similar to amplitudes from the 3D flat layer model. However, because trace weighting was not applied to sand 1A, amplitudes on the field data appeared much larger than on the 3D flat layer models.

In addition to improper application of the trace weighting function, differences in amplitude may be due to geologic effects. One hundred twenty meters away from the well location, amplitudes between horizon 1 and horizon 2 appear more balanced. Changes in lithology may cause horizon 1 to be anomalously high in comparison to horizon 2 coincidentally at the well location.

2.6.2 Effects of salt on amplitudes

Wave propagation effects: gas sand/brine sand comparisons

To examine the effects of salt on AVO and stacked amplitudes and address implications for discriminating gas sands from brine sands subsalt, 3D flat layer models were examined pre- and post-stack.

The effect of salt on a brine sand is investigated in Figure 2.15. Log and seismic information were used to create the 3D flat layer model without salt. By inserting a salt body in the upper portion of the earth model, a gather with salt was generated for comparison. These synthetic gathers were processed according to the flow in Figure 2.3. Trough and peak amplitudes measured across the brine sand B3 are plotted above the gathers in Figure 2.15. There are several important differences to note between the amplitudes of the subsalt and extra salt brine sands:
Figure 2.13  A comparison of amplitudes from spectrally whitened depth migrated seismic data (yellow) and 3D flat layer models (blue). Differences in amplitudes may be due to additional processing techniques applied to the whitened field data and 3D geometric effects. Amplitudes for sand 1A are particularly high after spectral whitening as compared to sand 2A. These differences for sands in the same well are attributed to the improper application of a trace weighting function.

- lower signal-to-noise of the subsalt gather is measured by the amplitude tracks for sand B3. Amplitudes tracks for the brine sand are three times lower in the gather with salt than the gather without salt;

- the amplitude trend plotted for the subsalt brine sand displays the effect of mode conversions. A particularly strong mode conversion is observed intersecting sand B3 at mid-offsets. Where mode conversions intersect the brine sand, amplitudes oscillate, showing both constructive and destructive interference.
Prestack Depth Migrated Gathers

Figure 2.14  Prestack depth migrated field gathers showing trace weighting application. Trace weighting applies a bell shaped weighting function with offset. This downweights near and far offsets, effectively lowering the overall stacked amplitude. The onset of the trace weighting function in these field gathers is indicated by reflections which increase at mid-offsets and decrease at far offsets. Sand 2A was altered by the trace weighting function, but sand 1A was not. Therefore, 1A amplitudes are particularly high relative to 2A amplitudes.
Subsalt and extra salt brine sand comparison

Figure 2.15  This figure shows the original $V_p$ earth model used to construct the 3D flat layer gather without salt on the left. This earth model was modified by replacing a portion of the smoothly increasing sediment trend with a 914 m thick salt body. The 3D flat layer gather on the right shows the effects of the salt body. Note the earlier arrival times of subsalt reflections due to high salt velocity. The processing documented in Figure 2.3 was applied to both gathers. Strong salt-related mode conversions were not removed in the processing, and are observed below 3500 m crossing flat reflectors at mid-offsets. Trough and peak amplitudes for brine sand B3 are plotted above the gathers. Amplitudes in the gather with salt are approximately three times lower. In addition, the effects of mode conversions can be observed as strong oscillations in the amplitude tracks of the subsalt brine sand.
To demonstrate the effect of salt on gas sands, a similar comparison was made using 3D flat layer models of well A (Figure 2.16). The original P-wave velocity earth model used to construct the gather with salt is shown on the right. In contrast to the previous example, salt was replaced with a smoothly increasing sediment velocity trend. The extra salt synthetic gather is displayed on the left. Trough and peak amplitudes of gas sands 1 and 2 are plotted above and below the gathers respectively. Both observations for the brine sand comparison are valid for the gas sand comparison. Again, subsalt amplitudes of the gas sands are approximately three times lower than extra salt amplitudes. Strong mode conversions are evident in the gather with salt and intersect both gas sands causing amplitude trends to oscillate.

While interference effects due to mode conversions and low signal-to-noise hamper AVO analysis beneath salt, there is a more damaging effect which counteracts the AVO trend for gas sands. As shown in Figure 2.16, gas sand 1A shows an increase in amplitude with offset. This anomalous trend (designated as a class 2 AVO anomaly, see Appendix B) is typically used to identify gas sands. In the presence of salt, this trend is reversed, and the amplitude decreases with offset. This is another effect of strong salt-related mode conversions (Davis, pers. comm.). At larger offsets, an increasing amount of energy is diverted from the P-wave to mode conversions, enough to counteract the AVO trend of the gas sand.

Figure 2.17 illustrates the dilemma strong mode conversions and low signal-to-noise create when distinguishing gas sands from brine sands on the basis of AVO. Extra salt, a gas sand is easily distinguished from a brine sand. The amplitude of the gas sand is twice as strong as the brine sand at zero offset. Its amplitude increases sharply with offset. In contrast, the brine sand shows only a slight increase in amplitude with offset. Subsalt gas and brine sands are virtually indistinguishable under the same criteria. At zero offset, the gas sand has only slightly higher amplitude. Its
Subsalt and extra salt gas sand comparison

Figure 2.16  This figure shows the original $V_p$ earth model which was used to construct the 3D flat layer gather salt on the right. This earth model was modified by replacing the salt body with a smoothly increasing sediment trend. Note the depths of top and base of salt for this example are the same as the previous example. Again, the gather with salt shows strong mode conversions which interfere with gas sands 1 and 2. Trough and peak amplitudes for gas sand 1 are plotted above the gathers, and amplitudes for gas sand 2 are plotted below the gathers. Amplitudes in the gather with salt are approximately three times lower and mode conversions imprint large oscillations in the amplitude tracks of the subsalt gas sands.
amplitude now decreases with offset and the rate of decrease is almost identical to that of the brine sand.

**AVO Response**

![Graph showing AVO response](image)

**Figure 2.17** Amplitudes at near and far offsets for four types of sand: extra salt gas sand, extra salt brine sand, subsalt gas sand, and subsalt brine sand. Extra salt gas sands and brine sands differ in terms of zero offset reflection strength and AVO trend. Underneath salt, these same sands are virtually indistinguishable using the same criteria.

To determine whether it is possible to distinguish gas sands from brine sands on stacked data, amplitudes of sands shown in Figure 2.17 were stacked and are compared in Figure 2.18. Extra salt, the gas sand is 2.2 times higher than the brine sand. In the subsalt case, both gas and brine sand amplitudes drop and the gas sand is only 1.5 times larger than the brine sand. Not only is this a smaller difference to detect, but overall amplitudes are three times lower subsalt so variations appear more subtle.
Comparison of extra salt and subsalt amplitudes

Figure 2.18  Stacked amplitudes for subsalt and extra salt brine and gas sands. Subsalt sands are two to three times lower in amplitude. While the gas and brine sands are easily distinguished extra salt, the difference between subsalt brine and gas sands is not as obvious.

Geometric effects: 2D elastic synthetics

The effects of salt geometry on the amplitudes of sands 1A and 2A were examined using the 2D elastic synthetic after finite difference migration (Figure 2.19). Variations in the amplitudes of sands 1A and 2A were used to gauge geometric effects due to the salt body and reflector faulting. Outside of salt (CDPs 6200-6400), amplitude tracks for sands 1A and 2A were smooth and almost equivalent. Closer to the salt edge (CDPs 6000-6200), amplitudes decreased because the edge of the salt body focuses
energy away from that area. Beneath the salt body, there was a sharp drop in amplitude equivalent to the three-fold decrease observed on the 3D flat layer synthetics. Amplitude tracks for horizons 1A and 2A oscillate erratically and diverge. These oscillations are due to the complicated curvature of the base of salt and faulting of both 1A and 2A. Divergence between the amplitude tracks of the two horizons indicated that horizons are being illuminated differently. While illumination of 1A is affected by the salt geometry and its own structure, sand 2A is affected by both these factors plus its own structure as well.

2.7 Discussion

Processing techniques were evaluated for their ability to increase signal-to-noise while preserving amplitudes. Most of them performed well at both tasks. Radon filters, mutes, and bandpass filters effectively removed different sources of noise without significantly altering reflection amplitudes.

Minor amplitude variations were introduced by processing techniques which used approximations. A spherical divergence correction using a constant velocity increased amplitudes of shallow reflections too much while not boosting amplitudes of deeper reflections enough. Kirchhoff migration, which approximates the seismic wavefield by a ray, has difficulty imaging in areas of steep dip and sharp velocity contrast. It was shown that finite difference migration provides more realistic amplitudes.

Other processing-related distortions were due to inconsistent implementation. A trace weighting function applied below a certain depth downweighted reflections. In comparison to these reflections, shallow reflections without trace weighting appeared deceivingly high.

Processing neglected mode conversions which were generated at salt interfaces and interfered constructively and destructively with P-wave reflections. They produced
Figure 2.19  Two-dimensional elastic synthetic after finite difference migration. Amplitudes of gas sands 1 and 2 are tracked in red and blue respectively above the section. Notice the drop in amplitudes when these horizons are subsalt. Also, complexities in the base of salt imprint complicated oscillations in amplitudes.
erratic oscillations in amplitude measurements at mid-offsets. A procedure to remove mode converted energy would have been helpful in boosting the low signal-to-noise of subsalt reflections.

Most processing-related distortions were minor compared with wave propagation effects. Strong reflections and mode conversions at salt interfaces account for a three-fold drop in subsalt amplitudes as compared with extra salt amplitudes. This decrease in P-wave signal below salt, combined with interference effects from mode conversions lower signal-to-noise of subsalt data. While the ability to distinguish gas sands from brine sands is already diminished in this environment, mode conversions severely limit hydrocarbon detection by AVO analysis. Mode conversions actually counteract the AVO trend of a class 2 anomaly subsalt. Detection of hydrocarbons on stacked data is also impeded as the difference in amplitude between gas sands and brine sands becomes smaller.

On top of mode conversions, geometric effects imprint large and erratic amplitude variations which depend on the shape of the salt body, the dip of overlying reflectors and the dip of the reflector being analyzed. Uneven illumination could be corrected for by calculating fold coverage maps and scaling amplitudes according to illumination patterns. In the example presented here, the salt body was relatively simple so that most geometric effects will be worse than those presented. Use of finite difference migration techniques is desirable to handle complex geometries.

Given lower signal-to-noise, strong mode conversions, and complex geometric effects, it is not surprising that amplitude analysis failed to discriminate hydrocarbons from brine sands on the basis of the stacked amplitude map shown in Figure 2.1. It is likely that wave propagation and geologic effects altered the amplitudes displayed on this map in such a manner that brine sands appeared to have amplitudes as high as gas sands. However, it is also possible that in spite of the multitude of factors
altering amplitudes, there is still some information about the pore fluids which can be extracted from this data. A closer examination of the amplitude map (Figure 2.1) shows that amplitudes at well C are slightly higher than those at well D. Perhaps this small difference is due to the presence of gas at well C and brine at well D. Until corrections are applied for mode conversions and geometric effects and finite difference migration can be routinely applied, such subtle stacked amplitude variations may form the basis of hydrocarbon detection subsalt.

2.8 Limitations of study

There are several other factors affecting amplitudes which were not addressed. These include acquisition effects, some processing techniques and sequences, thin layer tuning, anisotropy, and inelastic attenuation. Three-dimensional geometric effects were only examined indirectly through comparisons of field data and synthetics. A more comprehensive understanding of geometric effects would require the construction of 3D models. In addition to amplitude variations, salt caused observable changes in waveform and frequency content which were not examined. Another attempt to use AVO analysis subsalt to detect a gas sand with a class 3 AVO anomaly may have more promising results than detection of a class 2 AVO anomaly.
Chapter 3

Identification and significance of base of salt converted mode reflections

3.1 Introduction

As shown in chapter 2, salt-related mode conversions are large enough in amplitude to distort the AVO trends of gas sands. Mode conversions generated at the base of salt may be particularly strong. Not only is it important to be aware of their presence in subsalt data and to adapt processing accordingly, but also to understand how they may be utilized for imaging and rock property information. In this chapter, acoustic and elastic synthetic shot gathers based on 2D seismic data from the Gulf of Mexico are compared with field gathers to identify base of salt mode converted reflections. Their presence is verified by examining partial stacks created at various offsets. At certain offset ranges and beneath dipping interfaces, base of salt mode conversions are strong and continuous. Often these conditions coincide with and may be the cause of weakened P-wave reflections. While base of salt mode conversions may pose obstacles to imaging subsalt P-wave reflections, once identified, they may be used to verify P-wave interpretation of base of salt and possibly to directly image the base of salt. Additionally, it may be possible to extract information about rock properties by analyzing the amplitudes of base of salt mode conversions. This application is explored in Chapters 4 and 5.
3.2 Previous work

A considerable amount of work involving mode conversions has included the separation of mode converted reflections from primary reflections (Tatham and Goolsbee, 1984; Robertson and Pritchett, 1985; Frasier and Winterstein, 1990). Converted mode sections were used to verify interpretations made on the P-wave section. Rather than creating separate P and converted mode sections, Ogilvie and Purnell (1996) identified base of salt mode conversions directly on P-wave data. They showed several examples of mode conversions in Gulf of Mexico data sets which were strong enough to appear on sections processed for P-waves. For a one data set, they used elastic models to identify mode conversions from the base of salt. In addition to pointing out the problems these events create for interpreters, they also demonstrated that mode conversions can be used to directly image the base of salt. Kessinger and Ramaswamy (1996) discuss the adaptation of migration programs to use base of salt mode conversions for imaging. They present several comparisons of migrations with primary and mode converted data for imaging a steeply dipping base of salt reflection. Purnell (1992) also presented several examples from physical modeling experiments demonstrating the strength of mode conversions and their use in imaging when P-wave reflections are weak. The work presented in this chapter follows the work reported by Ogilvie and Purnell (1996). Partial stacks as well as elastic models are used to identify base of salt mode conversions and to evaluate their strength relative to P-wave data. Strong base of salt mode conversions have potential value for imaging and amplitude analysis.
3.3 Data

The 2D seismic data presented in this chapter were collected in the Green Canyon region of the Gulf of Mexico. The line traverses a relatively simple tabular salt body. The base of the salt body is flat and well imaged. The top of the salt structure is more complicated. Unmigrated stacks showed several diffractions which are probably due to small-scale rugosity. In addition, the top of the salt body dips gently to accommodate a shallow basin.

The data were acquired using a two ship acquisition scheme which allowed for the collection of 12 km offsets (Figure 3.1). Strong salt-related mode conversions appeared at these large offsets.

3.4 Method

Partial stacks and acoustic and elastic synthetic shot gathers were created to identify base of salt mode conversions and characterize their behavior. Partial stacks were generated at various offsets to examine the variation of P-wave and converted mode reflections. Acoustic and elastic synthetics were generated using the wave equation modeling code described in Chapter 2. These synthetic shot gathers were compared with field data to identify mode conversions.

3.4.1 Prestack processing

Prior to creating partial stacks and models, data were processed and migrated to reveal the structure of the salt body. Prestack processing included the application of a bandpass filter to remove low and high frequency noise, an inner mute to cut out multiple energy, an outer mute which limited offsets to 10.3 km, a spherical divergence correction to account for spreading losses, and deconvolution to flatten
Two ship acquisition

Ship 1 fires and ship 2 records data for offsets 6 – 12 km.

Ship 2 shoots and records data for offsets 0 – 6 km.

Alternate shooting by ships 1 and 2 achieves 12 km total aperture with 37.5 m shot spacing.

Figure 3.1 Acquisition of shot gathers with 12 km of offset using two ships.
the frequency spectrum. Semblance analysis was used to determine the velocities of major reflections approximately every 625 m. Prestack gathers were NMO corrected using these velocities.

### 3.4.2 Partial stacks

Partial stacks were generated from these gathers by summing together traces within an offset range of 450 m. The CDP gathers were sorted to offset to create partial stacks every 450 m. These stacks have the advantage of increased signal-to-noise because traces are summed. However, by stacking over a small offset range, they preserve reflections which may be destroyed by a full stack using all offsets. Several partial stacks were examined for evidence of mode conversions at intermediate to large offsets.

### 3.4.3 Velocity model building and depth migration

A full stack was also created from the NMO corrected CDP gathers. The initial migration velocity model was created by interpreting four major events on the stacked section: the water bottom, a shallow sediment reflector, top of salt, and base of salt. Interval velocities were assigned to horizons based on RMS velocities from the semblance analysis. The CDP gathers were muted at 6 km and prestack depth migrated using a Kirchhoff migration algorithm. The velocity model was updated using focusing analysis and the data were remigrated using the new velocity model. The migration collapsed diffractions at the top of salt and repositioned dipping sedimentary and salt reflectors. The final velocity model and migrated section are displayed in Figure 3.2.
Figure 3.2  Green Canyon data after Kirchhoff prestack depth migration with velocity model superimposed. The velocity model consists of four primary events with gradational boundaries: the water bottom (1200 m), shallow sediment reflection (2100-2600 m), top of salt (3400-4500 m), and the base of salt (7000 m). Velocities derived from semblance analysis were updated using focusing panels after depth migration.
3.4.4 Acoustic and elastic modeling

The velocity model used for depth migration was modified for input to the modeling code. The dimensions of the grid and the time sampling were based on parameters used to acquire the field data. Gradational boundaries between horizons were sharpened with the exception of the shallow sediment-sediment interface. This boundary was smoothed even further so that it would not create a reflection in the synthetics and thereby further complicate analysis of the synthetics. Extra traces were appended to either side of the model and extra samples were added to the base of the model as boundaries to attenuate waves before they reached the edges of the model. The $V_p$ model was converted to $V_s$ using Castagna's mudrock equation (Castagna et al., 1985), an empirical relationship between $V_p$ and $V_s$ for water saturated mudrocks:

$$V_s = \frac{(V_p - 1.36)}{1.16}$$  \hspace{1cm} (3.1)

The $\rho$ model was similarly created by converting the $V_p$ model to $\rho$ using Gardner's relationship for Gulf Coast sediments (Gardner et al., 1974):

$$\rho(g/cm^3) = 0.31V_p^{1/4}(m/s)$$  \hspace{1cm} (3.2)

The $V_p$ and $\rho$ models comprised the input for the acoustic modeling code while the elastic modeling required the $V_s$ model in addition to the $V_p$ and $\rho$ models. The shot location was selected based on the location of shot 90 from the field data (Figure 3.3) which showed evidence of mode conversions at far offsets. The acoustic and elastic shot gathers generated by the modeling code were compared with shot gather 90 (Figure 3.3) from the field to identify base of salt mode conversions.

Comparisons between the synthetics and field data were complicated by factors not accounted for in the modeling. While the synthetics include effects such as transmission losses, spreading, mode conversions, multiples, and 2D geometric effects, they
do not include the effects of noise, 3D geometric effects, and anisotropy. In particular
the effects of anisotropy on mode conversions may be quite severe as pointed out by
Alford (1986).

3.5 Results and Discussion

3.5.1 Acoustic and elastic model comparisons to identify base of salt
mode conversions

The acoustic synthetic shot gather is shown in Figure 3.4. Reflections appearing in
this shot gather are generated only from changes in the P-wave impedance. Three
reflections appear corresponding to the water bottom (1.57 s), top of salt (4.1 s), and
base of salt (5.2 s) interfaces in the input model. The zero offset arrival time and
moveout of these three events correspond to the equivalent reflections on the field
shot gather in Figure 3.3.

In contrast to the acoustic synthetic shot gather, reflections in the elastic synthetic
shot gather are due to changes in $V_s$ as well as changes in $V_p$ and $\rho$ (Figure 3.5). In
this gather, the same water bottom and salt-related reflections appear with identical
moveout and arrival times. However, there are two additional events beneath the
base of salt which do not appear on the acoustic synthetic gather. These events are
attributed to conversion of P-wave energy to S-wave energy at the base of salt. These
mode conversions have distinct characteristics which differentiate them from P-wave
reflections:

- Amplitudes are negligible at offsets less than 2000 m. They are strongest be-
tween 2 and 7 km offset.

- Moveout is steeper, appropriate for lower velocity waves.
Figure 3.3  Shot gather 90 from the Green Canyon data set. Acoustic and elastic synthetic shot gathers were created to mimic this gather.
Figure 3.4 Acoustic synthetic shot gather. Reflections for the water bottom (WB), top of salt (TOS), and base of salt (BOS) are due only to changes in the acoustic impedance. Note that structural effects cause the base of salt reflection to have nonhyperbolic moveout.
• Arrival times of mode conversions are later than their P-wave counterparts.

It is possible to identify the particular raypath associated with mode converted reflections by projecting the zero offset arrival time of the reflection and calculating the delay in arrival time due to a portion of the raypath being traversed as a lower velocity shear wave. For example, the two-way travel time through the salt body for a P-wave is approximately 1 s. For a shear wave traveling at approximately half the P-wave velocity, the travel time through the salt will be doubled. This event should appear 1 s below the PP reflection from the base of salt, at 6.2 s. This corresponds approximately to the projected arrival time of the later mode converted event. This is the SS (S wave incident at base of salt, S wave reflected) reflection from the base of salt. The PS or equivalently the SP reflection from the base of salt appears 0.5 s after the PP reflection from base of salt at approximately 5.7 s.

A comparison of acoustic and elastic models reveals a difference in the AVO of the PP base of salt reflection. These amplitudes decay more rapidly with offset in the elastic model than in the acoustic model. This is due to increased conversion to shear waves at larger offsets.

By comparing the elastic synthetic with the field gather, it is possible to identify mode conversions in the field data based on AVO, moveout and projected zero offset arrival time. The PS/SP mode conversion from base of salt is shown in Figure 3.6. This mode conversion was identified by characteristics similar to those of the mode conversion appearing on the elastic synthetic: strong amplitudes between 3700-8000 m and a projected zero offset arrival time of 5.7 s. The moveout of the event appearing in the field data is steeper, also characteristic of mode conversions.

The SS reflection is not as easy to identify in the field gather. While there are some high amplitude events which appear at the same offset range and have similar moveout as the event shown in the elastic synthetic, it is difficult to identify one event
Figure 3.5  Elastic synthetic shot gather. Reflections for the water bottom, top of salt, and base of salt are due to changes in $V_p$, $V_s$, and $\rho$. Two events appearing below the PP base of salt are the PS/SP and SS mode converted reflections from the base of salt.
in particular as the base of salt SS reflection. The signal-to-noise of the field data at this depth (approximately 9-10 km) is too poor and continuous reflections cannot be identified. The approximate location of the SS reflection from base of salt is shown in Figure 3.6.

3.5.2 Partial stacks

The presence of mode conversions outlined in Figure 3.6 is verified by examining partial stacks constructed at various offsets. These sections demonstrate that different offsets are dominated by different types of signal. Near offsets contain primarily P-wave reflections. At larger offsets, mode conversions begin to appear. At the largest offsets examined, P-wave signal is very weak and mode conversions are the only coherent form of energy observed. Partial stacks at 2500 m, 4300 m, 5650 m and 7000 m are described below:

- partial stack at 2500 m (Figure 3.7): The top of salt, which forms a shallow basin at the center of the section is composed of several diffractions. These diffractions indicate it has small-scale irregularities on its dipping surfaces. The base of salt, located just above 5.5 s, is flat and continuous. Subsalt reflections appear to dip down to the right.

- partial stack at 4300 m (Figure 3.8): While the top of salt reflection is slightly clearer in this stack than the previous one, the base of salt reflection is not as continuous. It is strong between CDPs 2230 and 2400, but is difficult to trace at larger CDPs. Directly below this dim spot is a reflection appearing at 6.25 s. This time corresponds to the arrival time at 4300 m offset of the base of salt PS/SP mode conversion appearing on the elastic synthetic and the field gather. This potential PS/SP mode conversion is also strong between CDPs
Figure 3.6  Green Canyon shot gather 90 with interpretations based on acoustic and elastic models. While it is possible to identify potential PS/SP base of salt reflections, it is more difficult to identify potential SS base of salt reflections. The line for the SS base of salt reflection points to the approximate location of this event.
3200-3500 and at a time of 6.3 s. Above it, the PP base of salt reflection is correspondingly weak. The dimming of the PP base of salt reflection and corresponding appearance of the PS/SP mode conversion may be a consequence of the geometry of the top of salt. The dip of the top of salt may favor the generation of mode conversions at the cost of the PP base of salt reflection.

- partial stack at 5650 m (Figure 3.9): The PP base of salt is noticeably weaker in this stack but is still visible between CDPs 2230-2500. This weakening of the base of salt reflection at larger offsets was also observed on the elastic synthetic gather. Because the weakening did not appear on the acoustic synthetic, it is probably due to increased conversion of primary wave energy to shear waves. As further verification, the PS/SP base of salt is stronger and more continuous than in the previous stack. It appears at times between 6.3 to 6.5 s which again correspond to the arrival times shown on the field gather for the PS/SP reflection at 5700 m offset. As was the case with the partial stack at 4300 m, it is not possible to see the dipping subsalt reflections.

- partial stack at 7000 m (Figure 3.10): The PP base of salt is barely visible at this offset. The PS/SP base of salt is strong and continuous at approximately 6.8 s which corresponds to the arrival time shown for the PS/SP reflection on the field gather. It is difficult to distinguish other coherent reflections on this low signal-to-noise data.

The partial stacks revealed several characteristics about the appearance and strength of mode conversions. It was possible to identify the base of salt PS/SP mode conversion which appeared strongest where the P-wave base of salt was weakest. This occurs not only at large offsets where P-wave signal-to-noise is low, but also at smaller offsets when structural conditions permit incident P-waves to
**Figure 3.7** A partial stack at 2500 m offset. Top of salt consists of several diffractions indicating an uneven surface. The base of salt, appearing at 5.5 s, is strong and continuous across the entire length of the section. Subsalt reflections appear to be dipping down to the right. Note that data is missing between CDPs 3100 and 3400.

strike at large angles. Given that mode converted base of salt reflections are strongest where P-waves are weakest, they may be useful for verifying an interpretation of PP base of salt. In data where the PP base of salt reflection is poor due to complex overlying structure, it is possible that strong mode conversions may be present. They may be used to corroborate or even determine the location of the PP base of salt reflection.

From examining stacks at different offsets, it was evident that different offset ranges contain different information about the subsurface. For example, the partial
Figure 3.8  A partial stack generated at 4300 m offset. Reflections appear at later arrival times in this stack than in the partial stack at 2500 m because of the larger offset. While the top of salt appears slightly clearer in this stack than the previous, the base of salt is much less continuous. In locations where the base of salt is weakest, the PS/SP mode converted base of salt appears strongest. Subsalt reflections apparent in the previous stack are no longer evident.

Stack at 2500 m showed a strong continuous base of salt reflection and dipping subsalt reflections. Partial stacks beyond this offset showed progressive deterioration of the PP base of salt reflection due to the conversion of incident P energy to S waves. Further, these mode conversions obscured subsalt reflections. The dipping reflectors apparent in the 2500 m partial stack were overprinted with a strong PS/SP base of salt mode conversion at larger offsets. The partial stacks suggest that including
Figure 3.9  Partial stack at 5650 m offset. Compared with previous partial stacks, the PP base of salt reflection is considerably weaker. The PS/SP base of salt is stronger and more continuous. Subsalt reflections are difficult to detect. However, it is possible that SS base of salt reflections are present.

offsets beyond 2500 m would destroy useful near-offset data by stacking in a strong converted mode.

3.6 Future work

Information from the partial stacks may be used to refine the offset aperture used to migrate the Green Canyon data (Figure 3.2). While 6 km offsets were used for this migration, the partial stacks suggested limiting the aperture to 2.5 km would improve
Figure 3.10 The PP base of salt is just barely visible while the PS/SP base of salt is strong and continuous.

imaging of subsalt reflectors. At larger offsets, P-wave energy deteriorated and mode conversions appeared below the salt body destroying subsalt structural information.

In addition to imaging base of salt with P-waves, another migration could be run to image the PS mode conversion observed in the partial stacks. This would verify the base of salt interpretation and may be used in more complicated situations where the PP base of salt is poorly imaged.
3.7 Conclusions

Due to the large impedance contrast at the base of salt, mode conversions are strong. They may be distinguished from P-wave reflections using acoustic and elastic modeling comparisons on the basis of several distinct characteristics. Additionally, it is possible to identify the raypath followed by a particular mode converted reflection by calculating the traveltimes of mode converted raypaths and matching them with the projected zero offset arrival times of mode conversions appearing in a shot gather.

Partial stacks showed that mode conversions are particularly strong where P-waves are weak: at large offsets and beneath dipping interfaces. As a consequence, base of salt mode conversions may be potentially useful for verifying PP base of salt interpretations and possibly for direct imaging of base of salt.

Given the depth and geometry of the Green Canyon salt body, it is likely that mode conversions associated with other salt bodies will be even stronger than those observed in this study. Most salt structures have much more complicated geometries in which both the top and base have severe dip. Such interfaces are more conducive to the generation of mode conversions. Further, the Green Canyon salt body is relatively deep (3 km to top of salt, 7 km to base of salt) and surrounded by sediments with higher velocities than shallower sediments. For a shallower salt body, the impedance contrast at its interfaces is likely to be greater and mode conversions stronger.
Chapter 4

Amplitude analysis of primaries and mode conversions at base of salt for hydrocarbon detection

4.1 Introduction

The detection of hydrocarbons at base of salt using conventional P-wave AVO analysis is severely limited due to the generation of strong mode conversions at intermediate incidence angles. Mode conversions divert energy away from the reflected P-wave and may mask the AVO effect of a gas sand. However, when used in conjunction with P-waves, mode conversions may contribute to the identification of pore fluids at base of salt. Unlike P-waves, mode conversions are relatively insensitive to changes in pore fluid. Thus, it is possible to use mode conversions to gauge the strength of P-wave reflections and assess whether they are strong enough to indicate hydrocarbons. Reflection coefficients versus incidence angle for base of salt reflections demonstrate the difficulty in using P-wave reflections for detecting hydrocarbons and how mode conversions may help in discriminating brine sands from gas sands.

4.2 Previous work

Stacked amplitude analysis of P-wave stacks in conjunction with SH-wave or PSV-wave stacks has been used in several cases to verify P-wave amplitude anomalies as hydrocarbon-related. Ensley (1984) processed and correlated P-wave and SH-wave data. He compared stacked sections and verified amplitude anomalies on P-wave sections as being hydrocarbon- or lithology-related. Robertson and Pritchett
(1985) also successfully used SH-wave data to determine the cause of a subtle P-wave amplitude anomaly. The increasing amount of multicomponent data available made this technique more applicable. Frasier and Winterstein (1990) noted that converted mode stacked sections from multicomponent data approximated shear wave sections. They used converted mode stacks to verify P-wave amplitude anomalies. Zaengle and Frasier (1993) also used multicomponent seismic data. They jointly interpreted PP and PSV sections to differentiate low porosity carbonate cemented sands from porous gas-bearing reservoirs on the basis of a bright spot appearing on the PSV section.

Previous work measuring the amplitude versus offset of mode conversions is not as common as stacked amplitude analysis. Garotta (1987) promoted AVO analysis of converted modes to verify P-wave AVO interpretations. He argued that comparison of P-wave and converted mode amplitudes provides additional information to confirm pore fluid type. A year later, Garotta and Granger (1988) demonstrated the ability to measure the AVO responses of P-waves and mode conversions on conventional P-wave data. However, they did not offer fluid or lithologic interpretations based on converted mode amplitude analyses.

Due to relatively poor shear wave and converted mode data, amplitude analysis has been limited to qualitative comparisons with P-wave data. However, improvements in data quality particularly with multicomponent seismic data suggest a more quantitative analysis of converted mode stacked reflections and AVO may be possible. In anticipation of this, several processing and amplitude analysis techniques have been devised specifically for mode converted data. Donati and Martin (1998) and Zheng (1991) derived approximations for PSV reflections coefficients based on traditional P-wave AVO analysis techniques. Miles and Gassaway (1989) discuss adaptation of processing techniques for converted modes such as common reflection point stacking and modified spherical divergence correction. Others have worked on new processing
techniques for mode conversions including prestack depth migration (D’Agosto et al., 1998) and amplitude-preserving Kirchhoff migration (Nicoletis et al., 1998).

4.3 Relationship between P-wave and S-wave amplitudes and rock properties

At an interface between rocks with different structure or makeup, amplitudes of P- and S-wave reflections generated at this interface contain information about the properties of the media on either side of the boundary. Properties of rocks, which are quantified by elastic moduli and density, change at an interface, modifying the propagation of P- and S-waves. Depending on the P-wave and S-wave velocities and density of the media, the amplitudes of the P and S reflections generated at this interface vary with incidence angle. Anomalous conditions, such as the presence of gas, may cause these reflections coefficients versus angle to vary in a distinctive, though nonunique manner. Traditionally, the variation of the P-wave reflection coefficient with offset has been used to detect hydrocarbons because of P-wave sensitivity to pore fluid compressibility. However, S-waves may also be used to aid in this detection. They are sensitive to lithologic changes. In combination with P-waves, they may be used to distinguish anomalous amplitude trends due to lithologic changes from those due to gas accumulations. This is particularly useful where amplitude information from P-waves may not be reliable. As shown in Chapter 2, such corroborative information is especially needed subsalt where P-wave reflection amplitudes are complicated by many factors which may overwhelm amplitude variations due to pore fluid content.

Properties of the rocks, such as lithology, pore fluids, porosity, clay content, and grain size determine how a rock reacts to small deformations such as the passage of a
seismic wave. This reaction may be quantified by a number of elastic constants such as:

- bulk modulus ($\kappa$) or incompressibility, the ratio of pressure to the dilatation it causes;

- shear modulus ($\mu$) or rigidity, a measure of resistance to shearing strain.

The relationship between these elastic constants, density, and the propagation velocities of P- and S-waves are given by the following equations:

$$ V_p = \sqrt{\frac{\kappa + 4\mu/3}{\rho}} \quad (4.1) $$

$$ V_s = \sqrt{\frac{\mu}{\rho}} \quad (4.2) $$

(Sheriff and Geldart, 1995). $V_p$ and $V_s$ depend on different combinations of $\kappa$ and $\mu$. The velocity of a shear wave does not depend on the bulk modulus. Therefore when the shear modulus is zero, as it is for liquids, $V_s$ is zero and shear waves do not propagate. Shear waves are more sensitive to changes in the shear modulus than P-waves and may provide information about the rigidity and porosity of the formation. The P-wave does propagate through liquids at a reduced velocity which depends on the density and incompressibility of the fluid. P- and S-waves rely upon density in the same manner but the density effect can often be ignored because phenomena which change density usually change $\kappa$ and $\mu$ more (Sheriff and Geldart, 1995). Table 4.1 shows the effect of various rock properties on elastic constants and $V_p$ and $V_s$.

Changes in $V_p$, $V_s$, and $\rho$ across an interface may be observed on seismic data as variations in reflection strength of P- and S-waves for a given incidence angle. For example, the presence of a small amount of gas in the pores of a rock produces an
<table>
<thead>
<tr>
<th>Rock properties</th>
<th>Elastic constants</th>
<th>Velocities</th>
</tr>
</thead>
<tbody>
<tr>
<td>high porosity, round and coarse grains, low density, clay, fluid saturation, increasing differential pressure</td>
<td>$\mu$ decreases</td>
<td>$V_p$ decreases, $V_s$ decreases</td>
</tr>
<tr>
<td>high porosity, low density, increasing differential pressure, fluid saturation, decreasing compressibility</td>
<td>$\kappa$ decreases</td>
<td>$V_p$ decreases</td>
</tr>
<tr>
<td>high porosity, fluid saturation</td>
<td>$\rho$ decreases</td>
<td>$V_p$ and $V_s$ increase</td>
</tr>
</tbody>
</table>

Table 4.1 Effect of rock properties on elastic constants and velocities

Anomalous effect on the reflection amplitudes of P-waves. Gas, unlike water, is highly compressible. Thus, when gas replaces water in the pores of a rock, the rock’s bulk modulus is significantly lowered. The density decreases slightly because of the lower density of the gas, and the shear modulus remains zero. According to equation 4.1, $V_p$ decreases rapidly for small gas saturations in spite of the small decrease in density (Figure 4.1). $V_s$ is only affected by the change in density upon replacing water with gas. It increases linearly with increasing gas saturation. The effects of gas on $V_p$ and $V_s$ cause Poisson’s ratio to decrease rapidly at even low levels of gas saturation. Poisson’s ratio for a gas sand is typically less than 0.2 while it ranges from 0.25 to 0.4 for brine sands and shales (Allen and Pedy, 1993). The drop in Poisson’s ratio changes the amplitudes of reflections from the top of a reservoir as a function of the angle at which the P-wave strikes the boundaries. Generally, the reflection coefficient becomes more negative with increasing offset for a shale over a gas sand. Rutherford and Williams (1989) have subdivided this behavior of gas sands into three categories which can be recognized on seismic gathers (see Appendix B).
Figure 4.1  With the introduction of a small amount of gas into the pore spaces of a rock, $V_p$ decreases rapidly while $V_s$ increases monotonically. The combination of these effects causes Poisson's ratio to drop sharply.

4.4 Method

The Zoeppritz equations may be used to predict the amplitudes of reflected and transmitted waves. Reflection coefficients and energy for PP, PS, SS, and SP modes were calculated using the Zoeppritz equations to examine AVO trends for extra salt and subsalt hydrocarbons. The first set of models compare reflection coefficient trends for a shale over a brine sand and the same shale over a gas sand having a Class 3 AVO anomaly. This example corroborates findings presented in Chapter 2 and serves as a comparison for the subsalt example. The subsalt comparison includes the same brine and gas sands which are overlain by salt instead of shale. In this case, shear waves and mode conversions are particularly strong and are investigated for use in hydrocarbon detection.

4.4.1 Parameters for modeling

Velocities and densities for various lithologies simulated in the models are shown in Table 3.2. Gas sand and shale parameters were taken from Du and Spencer (1990). Values for salt were based on those used by Ogilvie and Purnell (1996). Values
for the brine sand were calculated by assuming a $V_s$ similar to that of the gas and calculating $V_p$ for a Poisson’s ratio of 0.35, appropriate for a brine sand (Allen and Peddy, 1993). Reflection coefficients were calculated from 0 to 45 degrees, assuming data for hydrocarbon exploration is collected within this range.

### 4.4.2 Zoeppritz program

A program was written to solve the exact Zoeppritz equations for partitioning of energy at an interface as a function of incidence angle, $V_p$, $V_s$, and density of each medium. Following a method described in Aki and Richards (1980), this program calculates reflection coefficients, transmission coefficients and relative energy for four waves simultaneously incident at a welded plane boundary between two elastic solids (Figure 4.2).

The Zoeppritz equations assume several simplifications about the media and wave motion. Waves are plane such that the disturbance, phase, and frequency are constant over all points in a plane perpendicular to the direction of wave propagation. Wave motion is in the plane of wave propagation so that only P- and SV-waves are considered. The half spaces on either side of the interface are homogeneous and isotropic and the boundary between them is plane and horizontal. Amplitudes cal-

<table>
<thead>
<tr>
<th>Material</th>
<th>$V_p$ (m/s)</th>
<th>$V_s$ (m/s)</th>
<th>$V_p/V_s$</th>
<th>$\sigma$</th>
<th>$\rho$ (g/cm³)</th>
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</thead>
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<tr>
<td>shale</td>
<td>3050</td>
<td>1240</td>
<td>2.45</td>
<td>0.40</td>
<td>2.4</td>
</tr>
<tr>
<td>brine sand</td>
<td>3200</td>
<td>1537</td>
<td>2.08</td>
<td>0.350</td>
<td>2.13</td>
</tr>
<tr>
<td>gas sand</td>
<td>2440</td>
<td>1620</td>
<td>1.50</td>
<td>0.100</td>
<td>2.16</td>
</tr>
<tr>
<td>salt</td>
<td>4481</td>
<td>2530</td>
<td>1.77</td>
<td>0.25</td>
<td>2.14</td>
</tr>
</tbody>
</table>

*Table 4.2* Velocities and densities for Zoeppritz models.
Figure 4.2 Solution of the Zoeppritz equations assumes four incident waves, P- and S-waves from above the interface and P- and S-waves from below the interface (not shown), are present simultaneously. Each incident wave produces four output waves which are designated in the diagram by three letters corresponding to incident wave type, outgoing wave type and whether the outgoing wave is transmitted (t) or reflected (r).

culated by the Zoeppritz equations differ from the seismic response measured in the field in several respects. Zoeppritz reflection coefficients do not include the effects of spherical wavefronts, wavelet interference due to layering, transmission losses, attenuation, divergence, and other phenomena. In addition, the Zoeppritz equations give the reflection coefficient in the direction of wave propagation whereas a geophone records the vertical component of the wavefield.

4.5 Results

4.5.1 Extra salt AVO analysis for hydrocarbon detection

Zoeppritz models were used to examine the effectiveness of P- and S-waves in discriminating gas sands from brine sands beneath shale and to serve as a comparison for extending AVO analysis subsalt.
The reflection coefficients and energy for the PP reflection from brine and gas sands beneath a shale are shown in Figure 4.3. The PP reflection coefficient for the brine sand is slightly negative and increases with increasing angle. The gas sand shows a class 3 AVO anomaly: a large negative reflection coefficient at normal incidence which increases with angle. It is distinguished from the brine sand on the basis of:

- a sharp increase in magnitude with angle. In this example, the PP reflection coefficient for the gas sand increases at a rate 3.5 times greater than that of the brine sand.
- a large normal incidence reflection coefficient. The PP reflection coefficient for the gas sand is 8.7 times larger than that of the brine sand at normal incidence.

While the brine sand also shows an increase in amplitude with angle, that increase is more likely to be overwhelmed by spreading losses, multiples, and other noise while the trend of the gas sand will survive these effects. Such a gas sand may appear on a CDP gather as a strong reflector with an anomalous increase in amplitude with offset.

The trends of the reflection coefficient curves are accentuated in the plot of PP reflection energy. The energy of the gas sand, summed from zero to 45 degrees is 30 times greater than that of the brine sand.

While P wave amplitude analysis is useful in selecting potential gas sands, it is not decisive. Other geologic conditions may lead to amplitude anomalies. For example, a clean (low clay content), highly porous sandstone under a shale may cause an increase in amplitude with offset similar to that caused by gas sands with less porosity. As a consequence, supplemental evidence from shear waves and mode conversions may be useful in determining the cause of P-wave amplitude anomalies.
Figure 4.3 PP reflection coefficients and energy for a brine sand and a gas sand beneath a shale. The reflection coefficient for the gas sand is distinct from the brine sand because of its greater magnitude at normal incidence and its dramatic increase in amplitude with incidence angle.

Figure 4.4 displays reflection coefficients and energy from SS, SP, and PS reflections for the same shale-brine sand and shale-gas sand contacts as shown in Figure 4.3. The reflection coefficients for the gas sands are generally slightly higher than those for the brine sands, but it is difficult to distinguish gas sands from brine sands either on the basis of AVO or normal incidence strength. This is verified in the energy plots which indicate that the SS reflection, which shows the greatest variation with pore fluid, is two times larger for the gas sand. Compared with the almost 9-fold increase observed in the PP reflection coefficient with gas sand, this variation is not significant enough to be useful in detecting hydrocarbons. Furthermore, it was assumed in the plots for the SS and SP modes that the shear wave source is comparable to that of the P-wave source. Without a shear wave source or a sharp impedance contrast
to generate strong shear waves, the SS and SP modes are likely to be very small in comparison with the PP mode.

As a consequence of these factors, the SS, SP, and PS modes would be barely visible on a seismic section and not directly useful as hydrocarbon indicators. In addition to low energy and insensitivity to pore fluid, reflection curves for SS and SP modes are complicated by critical angles which create spikes in the reflection coefficients and phase shifts. The occurrence of these critical angles dominates behavior of the reflection coefficients and interferes with the analysis of mode conversions for more subtle amplitude information concerning rock properties.

Although S waves are not useful for direct hydrocarbon detection, their insensitivity to hydrocarbons combined with their sensitivity to rigidity is useful in distinguishing gas-related P-wave amplitude anomalies from lithology-related anomalies. High amplitudes on P-wave data may be caused by lithologic variations unrelated to hydrocarbons. Shear waves and converted modes are sensitive to changes in the rigidity of a formation such as changes in lithology, porosity, and consolidation state. A bright spot on a PP section may be verified as gas-related by noting its absence on a converted wave section. As shown by the Zoeppritz models, gas does not create a strong reflection coefficient for shear waves. An amplitude anomaly which appears on both PP and PS sections is most likely related to changes in the rigidity of the formation such as lithology. In this manner, shear waves have been used in conjunction with PP AVO analyses to distinguish lithology-related amplitude anomalies from gas-related anomalies (see for example Ensley (1984)).

4.5.2 Subsalt AVO analysis for hydrocarbon detection

From the models examined previously, the PP reflection coefficient appears to be the most robust indicator of hydrocarbons at a shale-sand contact. However, as
Figure 4.4  Reflection coefficients and energy for the SS, SP, and PS modes generated at the interface between a shale and a brine sand and a shale and a gas sand. The reflection coefficients do not vary significantly depending on pore fluid type and are poor indicators compared with the PP reflection coefficient. The energy of the SS mode exhibits the greatest increase with the presence of gas. But compared with the increase in energy of the PP reflection coefficient it is insignificant.
shown in Chapter 2, the character of the PP reflection coefficient is severely altered in the presence of salt so that AVO analysis may no longer be useful in distinguishing hydrocarbons. Mode conversions are particularly strong at salt interfaces and are one of the main factors which alter AVO trends. Another set of Zoeppritz models are presented to evaluate the effects of mode conversions on a gas sand with a class 3 AVO anomaly and to determine whether they may be of use in distinguishing gas sands subsalt.

The reflection coefficients and energy for brine and gas sands at base of salt are compared in Figure 4.5. In this case, mode conversions are quite strong because of the sharp impedance contrast. In contrast to the example with shale overburden (Figure 4.3), the reflection coefficients for brine and gas sands are both decreasing in magnitude rather than increasing. Their rate of decrease is almost identical. Thus, the first criteria used previously to distinguish gas sands from brine sands is eliminated. In addition, the difference between normal incidence reflection strengths is reduced. The PP reflection coefficient for a gas sand is only two times greater than the PP reflection coefficient for a brine sand. In the extra salt case for the same sands, this difference was almost nine-fold. In terms of energy, the gas sand is only 5.6 times greater than the brine sand compared with 30 times greater in the extra salt case. The use of AVO analysis to distinguish gas sands from brine sands is severely limited in the case presented. It may be possible to distinguish gas and brine sands by comparing stacked amplitudes, but as shown in Chapter 2, the difference between a subsalt gas sand and a subsalt brine sand may not be great enough to distinguish the two on seismic data, particularly in the presence of spreading losses and noise.

Mode conversions do not appear to be directly useful in aiding detection of hydrocarbons at base of salt. An examination of mode conversions for pore fluid detection again is not promising (Figure 4.6). For all modes, the AVO trend for a gas sand and
Figure 4.5  PP reflection coefficients and energy for gas and brine sands at base of salt. Comparison with Figure 4.3 shows the effects of salt. Reflection coefficients and energy for gas and brine sands which increased with angle for shale overburden decrease with overlying salt. The rate of decrease of the reflection coefficients is almost identical making it difficult to distinguish gas from brine using AVO analysis.

A brine sand are quite similar. The energy difference between gas and brine sands is greatest for the SS mode, but energy for the gas sand is only 47 percent higher. This is another verification that shear modes (SS, SP, and PS) are not sensitive to changes in pore fluids. The small changes in reflection coefficients are due only to a decrease in density and a small increase in $V_s$ with gas.

However, it is possible to utilize mode conversions' insensitivity to pore fluid to aid in distinguishing gas. In particular, PS and SP modes may be used as normalizers because they change very little depending on pore fluid (Kessinger, pers. comm.). The PS and SP modes increase by 25 and 15 percent respectively for gas. In contrast, the PP mode increases by 5.6 times with gas saturation. To evaluate the relative strength of the PP mode, it may be compared with one of the mode conversions. Two comparisons are presented in Figure 4.7. The upper two plots show energy for
Figure 4.6  Reflection coefficients and energy for SS, SP, and PS modes for salt overlying gas and brine sands. Reflection coefficients for mode conversions generated at the base of salt are almost four times stronger than those generated at the base of shale. However, variations in reflection coefficients and energy depending on pore fluid type are small. Compared with the PP mode, these modes are not as useful for direct hydrocarbon detection.
PP and PS modes for brine and gas sands. The lower plots compare PP and SP modes for gas and brine sands. For a brine sand, the energy of the PP mode is half the energy of the SP mode. For a gas sand, the energy of the PP mode is 2.5 times the energy of the SP mode. Thus, it may be possible to evaluate the strength of the PP reflection by comparing it with the mode conversion. The strength of the PP reflection may then be associated with a particular pore fluid type. As similar comparison may be conducted using the SP mode. As with the PS comparison, the energy of the PP mode is slightly lower than the SP mode for a brine sand and several times higher than the SP mode for a gas sand.

4.6 Limitations

The conditions examined in this study are for the simple case of a single flat interface. Geometric effects and ray bending at top of salt were not considered. There is the additional complication of taking into account different raypaths when examining amplitudes from the PP and PS reflections. These raypaths may encounter different structural and geologic conditions so that their amplitudes may not be directly comparable. To account for the effects of geometry and top of salt, full-survey modeling as shown in Chapter 2 may be necessary. As shown in Figure 2.8, 2D elastic models can be used to identify amplitude variations due to geometry and migration algorithms. These effects may be compensated for so that amplitude variations due to fluid effects are uncovered.

4.7 Conclusions

Two examples were presented demonstrating the use and limitations of AVO analysis for hydrocarbon detection in subsalt and extra salt environments. Extra salt, a
Figure 4.7 A comparison of the energy of PP and mode converted reflections for brine and gas sands. For a brine sand, the strength of the PP and mode converted reflections are similar. In the case of a gas sand, the PP reflection energy is several times greater than that of the mode conversions. Because mode conversions do not vary in strength depending on pore fluid, they may serve as a gauge to compare PP reflection strengths against. Depending on the relationship of the PP reflection to the mode conversion, it is possible to infer whether gas is present.
class 3 gas sand was easy to distinguish from a brine sand on the basis of AVO and normal incidence reflection coefficient. Shear modes are usually very small extra salt, and their amplitudes do not vary in such a way as to indicate pore fluid type. As a consequence, PP reflection coefficients offer the best criteria for hydrocarbon detection extra salt.

In the subsalt environment, PP amplitude analysis is not as effective. The P-wave AVO trend for a gas sand at base of salt is reversed so that it increases with offset rather than decreases. The rate of this decrease is almost identical to that of a brine sand beneath salt. Further, the normal incidence reflection coefficient of the gas sand is only two times higher than the brine sand. These factors limit the use of P-wave amplitude analysis below salt as shown in Chapter 2. However, base of salt mode conversions are strong and may aid in detecting hydrocarbons directly beneath salt. Because they do not change amplitude depending on pore fluid, they may be used to gauge the strength of P-wave reflections from base of salt and assess whether P-wave reflections are strong enough to indicate hydrocarbons.
Chapter 5

Amplitude analysis of primaries and mode conversions at base of salt for overpressure detection

5.1 Introduction

As shown in chapter 4, mode conversions are relatively insensitive to changes in pore fluids. However, they are sensitive to changes in the rigidity of a formation such as porosity. This chapter examines the use of mode conversions to directly detect changes in porosity associated with overpressured pore fluids beneath a salt body. Overpressured sediments are frequently encountered below salt bodies in the Gulf of Mexico and have caused drilling problems and dangerous well blowouts. Detailed seismic velocity analysis has been employed since the 1960s to predict overpressured sediments prior to drilling by detection of P-wave velocity inversions. However, in the subsalt case this technique is not effective because inverted velocities are common at base of salt and not necessarily indicative of high pore pressures. An alternative method of predicting overpressure through seismic analysis is needed in this environment.

Amplitude analysis of both primary and converted mode reflections at base of salt may offer a more definitive means of identifying overpressure directly below the salt body. Differences in the sensitivity of P- and S-wave amplitudes may be utilized to constrain rock properties more accurately than depending only on P-wave amplitudes. In particular, S-waves depend more directly on shear modulus than P-waves and are sensitive to lithologic variations such as high porosity. Thus, overpressured sediments
which are accompanied by high porosity may be detected with anomalous S-wave amplitudes. Mode conversions have the potential to be especially useful for predicting overpressured conditions at base of salt because at this interface they are strong and easily identifiable based on their moveout and AVO (Ogilvie and Purnell, 1996). Using Zoeppritz and elastic wave equation models, examples are presented demonstrating the use of P-waves and mode conversions for overpressure prediction.

5.2 Previous work

Since the work of Pennebaker (1968) seismic methods of overpressure prediction have focused on the use of detailed seismic P-wave velocity analysis. The physical properties of overpressured sediments typically cause them to have a lower P-wave velocity than surrounding sediments so they may be identified as inversions on seismic velocity analyses. Building on the work of Pennebaker, later workers have refined this technique by incorporating nearby well data (Kan and Sicking, 1993; Keyser et al., 1991) and increasing the resolution of seismic velocity analyses (Aud, 1976; Reynolds, 1970). Application of the velocity analysis technique is limited in two important situations. It cannot detect overpressuring which is not accompanied by large changes in the elastic properties of the rocks. For example, when smectite transforms to illite, water is expelled into the pores, increasing fluid pressure. These high pressures typically do not cause detectable changes in the elastic properties of the rocks and therefore do not alter the P-wave velocity significantly. Best (1990) developed a prestack inversion technique to detect this type of overpressuring by simultaneously estimating $V_p$, $V_s$, and $\rho$ using near-offset reflectivity and AVO trends of P-wave reflections. The use of seismic velocity analysis is also limited because velocity inversions may be caused by lithologic effects other than overpressuring. For example, at the base of salt, there is typically a strong velocity inversion because of salt’s high velocities. It is not possible
to use seismic velocity analysis in this case to detect overpressuring which is common beneath salt bodies. Inversion of AVO data as described by Best (1990) and Pigott (1989) is an alternative method which does not rely solely on P-wave velocities.

Several authors indicated that $V_p/V_s$ may be used as a potential indicator of overpressuring. Tatham and McCormack (1991) mention that overpressured zones may have measurable $V_p/V_s$ anomalies. Khazanehdari (1998) predicts $V_p/V_s$ and Poisson's ratio are anomalously high for overpressured sediments. Laboratory measurements of $V_p$ and $V_s$ taken at increasing differential pressures confirm these statements (Domenico, 1977; Domenico, 1984). Domenico (1984) found that $V_s$ decreases more quickly than $V_p$ as differential pressure decreases, causing $V_p/V_s$ and Poisson's ratio to increase.

Given the effects of overpressuring on P- and S-wave velocities, seismic amplitudes may provide an indication of overpressuring prior to drilling. Dutta (1987) suggested that overpressuring may be accompanied by changes in seismic amplitudes. Paul (1990) correlated overpressured zones with abnormally high P-wave amplitudes. Shear wave and converted mode amplitudes should also be affected by overpressuring, perhaps to a greater extent than P-wave amplitudes given the change in $V_s$ relative to $V_p$.

5.3 Theory

Overpressured sediments may be characterized by anomalous elastic properties which alter the propagation of seismic waves. If these alterations are great enough, amplitude variations of P- and S-wave reflections may indicate overpressured conditions.

Through a mechanism such as rapid sedimentation and the presence of a low-permeability seal such as salt, some formations are able to maintain high fluid pressures as they are buried. Due to these high fluid pressures, the formation resists
compaction and is able to maintain a higher porosity than formations which are being compacted. High porosity formations are characterized by low rigidity (or shear modulus) and bulk modulus. P- and S-waves slow down as they travel through these high porosity sediments and their reflection amplitudes are altered. Thus, overpressuring may be predicted by the effect of high porosity on P and S reflection amplitudes.

5.3.1 Normally pressured sediments

As sediments are deposited in a marine environment, the pressures they are initially subjected to are minimal. The sediments are unconsolidated and have high porosity. Large pores are filled with fluid and intergrain contacts are few. Lacking shear strength, these water-saturated sediments behave like a fluid rather than a solid and have a very low shear modulus (low rigidity) compared with compacted formations (Hamilton, 1971). As a consequence of the low shear modulus, \( V_p \) and especially \( V_s \) are low (Figure 5.1). Thus \( V_p/V_s \) for shallow sediments is large.

As rocks are buried, they are subjected to stresses due to the gravitational loading of sediments and pore fluids. The total stress, or overburden pressure \( (P_o) \) is:

\[
P_o = P_d + P_f
\]

(5.1)

where

- \( P_d \) is the differential pressure or the portion of the overburden pressure supported by the rock matrix;

- and \( P_f \) is the pore fluid pressure (Dutta, 1987).

Normally, all of these pressures increase linearly with depth as shown in Figure 5.2.

With increasing burial depth, increases in differential pressure cause pores and cracks to close. Porosity decreases exponentially in the first 600-1000 m (Plumley,
Figure 5.1 $V_p$ and $V_s$ of shallow brine saturated sands versus differential pressure based on a data presented in Hamilton (1971). As differential pressure decreases with decreasing burial depth, $V_s$ decreases more rapidly than $V_p$. At 7000 KPa, $V_s$ is approximately 35 percent of $V_p$. At 70 KPa, $V_s$ is only 17 percent of $V_p$. 
1980). As fluids are expelled and the formation becomes more rigid, the bulk modulus and particularly the shear modulus increase. As a consequence, $V_p$ and especially $V_s$ increase. Once all of the pores are closed, which occurs approximately at a differential pressure of 15 MPa (Green and Wang, 1986), the elastic moduli respond weakly to additional increases in differential pressure. After porosity has substantially dropped, the rate of increase of $V_p$ and $V_s$ decreases. $V_p/V_s$ approaches a terminal value that depends on lithology and residual porosity (Tatham and McCormack, 1991).

![Diagram](image)

**Figure 5.2** Overburden pressure is the sum of pore fluid pressure and differential pressure. Under normal pressure conditions, pore fluid pressure increases linearly with depth and is equal to the hydrostatic gradient. If low permeability restricts the flow of pore fluids, pore fluid pressure exceeds the normal hydrostatic gradient. The fluid supports an increased portion of the overburden load thereby relieving stress on the rock matrix. Differential pressure, $P_D$, decreases.
5.3.2 Overpressured sediments

One type of overpressuring develops when deposition is rapid relative to the rate at which pore fluids are expelled. When this fluid-sediment mixture is capped by a low permeability seal such as salt, fluid flow is restricted. Under increasing burial pressure, the fluids are unable to migrate to lower pressure regimes. A portion of the overburden pressure which would normally be supported by the rock matrix is supported by the pore fluids and pore fluid pressure increases. High fluid pressures prevent intergrain contacts from adjusting to increased burial pressure, and the differential pressure decreases (Figure 5.2). The compaction process is slowed or interrupted.

The properties of overpressured sediments are similar to those of shallow sediments which have not been subjected to compaction. Overpressured sediments are characterized by high porosities more appropriate to shallow sediments (Plumley, 1980). They may even be unconsolidated and behave like viscous fluids (Sheriff and Geldart, 1995). Because high porosity lowers the shear modulus, \( V_p \) and \( V_s \) decrease (Figure 5.3). Like shallow sediments, overpressured zones are characterized by high \( V_p/V_s \).

Most traditional methods of overpressure prediction rely upon detecting an anomalous decrease in \( V_p \). However, Figures 5.1 and 5.3 suggest there is a significant drop in \( V_s \) which may be even greater than the drop in \( V_p \) for overpressured sediments. By combining information from both P- and S-waves, a more robust estimation of overpressure conditions is possible. One technique would involve measuring P- and S-wave traveltimes to the base of a potentially overpressured formation. This information may be used to extract \( V_p/V_s \). An anomalously high \( V_p/V_s \) may signal overpressuring. However, like traditional P-wave velocity analysis, it would be difficult to apply this technique at the base of salt, where a large velocity inversion is expected regardless of pressure conditions. Analysis of P- and
S-wave reflection amplitudes provides a more robust means of overpressure detection which may be used at the base of salt.

\[ \text{Figure 5.3} \] Based on lab measurements conducted by Toksoz (1976), there is a sharp decrease in \( V_p \) and \( V_s \) at low differential pressures. The relative decrease of \( V_s \) is greater than \( V_p \) causing \( V_p/V_s \) to increase for low differential pressures.

5.4 Method

Zoeppritz and 2D elastic wave equation models were used to test whether changes in \( V_p/V_s \) associated with an overpressured zone directly beneath salt show an anomalous AVO or stacked amplitude response which could be used to distinguish these sediments from normally pressured ones.

5.4.1 Zoeppritz models

The same Zoeppritz modeling code described in Chapter 4 was used to compare reflection coefficients and energy of PP, PS, SS, and SP modes for subsalt sands under various differential pressures.
5.4.2 Crossplots

Reflection coefficient curves created by the Zoeppritz modeling code were further analyzed by crossplotting AVO intercept (A) and gradient (B) values (Castagna et al., 1998). These values are from Shuey's two-term approximation to PP reflection coefficient (Shuey, 1985):

\[ R_{PP}(\theta) = A + B \sin^2(\theta) \]  \hspace{1cm} (5.2)

where \( R_{PP} \) is the PP reflection coefficient and \( \theta \) is the angle of incidence. \( A \) is the normal incidence reflection coefficient, and \( B \) is a measure of the offset-dependent reflectivity. Typically, \( A \)s and \( B \)s for brine saturated sandstones follow a well-defined background trend. Deviations from this trend may be attributed to hydrocarbons or lithologic effects.

Crossplotting was used to analyze a set of sands at various differential pressures. Intercept and gradient values were extracted after fitting PP reflection curves with a linear approximation to 25 degrees. \( A \) and \( B \) values from normally pressured sands were plotted to establish a background trend. Then \( A \) and \( B \) values extracted from overpressured sediments were plotted to determine whether they would appear as deviations to this trend. Intercept and gradient values were also extracted from PS, SP, and SS reflection coefficient curves because the gradient of these modes varied with differential pressure. These values were also crossplotted to determine whether overpressured sediments would appear as deviations from a trend of normally pressured sediments.

5.4.3 Elastic shot gathers

In order to examine the stacked response of PP, PS, SS, and SP base of salt reflections to different pressure conditions, elastic synthetic shot gathers were generated,
processed, and stacked. These synthetics include some of the effects not considered by the Zoeppritz models such as circular wavefronts and spreading losses.

The same wave equation elastic modeling program described in Chapter 2 was used for the overpressure study. Simple 2D $V_p$, $V_s$, and density earth models were created using a structure generator internal to the modeling code. In order to be comparable to the Zoeppritz models, these models were created with a single flat interface representing the base of salt. $V_p$, $V_s$, and density for the underlying sediments was varied according to the pressure regime being modeled. A sketch of the input $V_p$, $V_s$, and density models is shown in Figure 5.4. Rather than running a multi-shot survey, a single shot was fired and reproduced after stacking to simulate a stacked section. This was possible since the base of salt reflector was horizontal and velocities on either side were constant.

![Figure 5.4](image)

**Figure 5.4** Sketch of the input density and velocities models. The model was constructed using a structure generator internal to the modeling program by specifying locations of interfaces and assigning constant velocities and densities for the media. Absorbing boundaries on the sides and bottom of the model were necessary to attenuate energy bouncing back from the edges of the model. X marks location of the shot.
The synthetic gathers were processed to remove the effects of spherical divergence and NMO for primary, shear, and mode converted events. Mode conversions were NMO corrected using an average of the P-wave and S-wave velocities through the salt. The gathers were stacked and reproduced to simulate a stacked section. Stacks for PP, PS, SS, and SP base of salt reflections were compared for various pressure regimes.

5.5 Data

The input required for the Zoeppritz and elastic wave equation modeling programs were $V_p$, $V_s$, and density of sediments at various differential pressures. These values were obtained from published lab measurements, field measurements, and empirically-derived relations.

Several difficulties were encountered in collecting pressure-dependent velocity information. Shear wave velocities are often not recorded either in the field or in the lab. When they are recorded in the lab, accuracy decreases as the shear wave velocity decreases and extremely low shear velocities are not measurable (Domenico, 1984; Domenico, 1977). Several laboratory experiments recorded shear wave velocities, but both $V_p$ and $V_s$ were too high to represent realistic seismic velocities (Han et al., 1986; Domenico, 1984; Eberhart-Phillips et al., 1989; Christensen and Wang, 1985). Log measurements of shear wave velocities are also limited. Full-waveform sonic logs require S-wave velocities of the sediments to be greater than the P-wave velocity of the drilling mud, a qualification not satisfied by most Gulf of Mexico formations (Allen and Peddy, 1993). Further, logging information in highly overpressured sediments is difficult to obtain because of the hazards involved in drilling through such formations. Because shear wave velocities of overpressured sediments are expected to be quite low and there are practical limitations in recording such low shear wave velocities, the
lab-derived velocities selected for this study may represent a conservative estimate of the effects of overpressuring on S-wave and P-wave velocities.

Laboratory measurements from Domenico (1977) and VSP measurements from Lash (1980) were used to create two examples of overpressuring. The laboratory data provides measurements of $V_p$ and $V_s$ with differential pressures from 2.76 MPa to 34.5 MPa. The lowest differential pressure at which shear wave velocities were recorded was 6.90 MPa. Values at this pressure were used to represent overpressured sediments. Values for $V_p$ and $V_s$ measured at 34.5 MPa represented normally pressured sediments (Table 5.1) and were compared with the overpressured sediments.

Because field data relating velocities and differential pressures (particularly high differential pressures) were not available, it was necessary to use $V_p$ and $V_s$ measurements from normally pressured sediments and invoke two assumptions: 1. Multicomponent VSP data provides measurements of $V_p$ and $V_s$ of normally pressured sediments at depths from 3.0 m to 3300 m. Assuming these sediments had undergone normal compaction, depths were converted to differential pressures using a Gulf of Mexico average differential pressure gradient of 1.12 KPa/m (Plumley, 1980). 2. It was assumed that overpressured sediments at a given depth have $V_p$ and $V_s$ similar to that of shallower sediments. This was derived from an assumption presented by Plumley (1980). Based on these assumptions, values for $V_p$ and $V_s$ at shallow depths (approximately 400 m and 600 m) represented overpressured sediments. These were compared with values taken at a greater depth (2700 m) representing normally pressured sediments (Table 5.1).

Lab data and field data lacked density information so Gardner's rule (Eq. 3.2) was used to derive densities from P-wave velocities (Table 5.1).
<table>
<thead>
<tr>
<th>Material</th>
<th>Source</th>
<th>Pressure</th>
<th>$P_D$ (MPa)</th>
<th>$V_p$ (m/s)</th>
<th>$V_s$ (m/s)</th>
<th>$V_p/V_s$</th>
<th>$\rho$(g/cm$^3$)</th>
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</thead>
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<tr>
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<td>6.895</td>
<td>2028</td>
<td>640</td>
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<td>34.48</td>
<td>2232</td>
<td>952</td>
<td>2.35</td>
<td>2.13</td>
</tr>
<tr>
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<td>VSP</td>
<td>very high</td>
<td>3.448</td>
<td>1829</td>
<td>366</td>
<td>5.</td>
<td>2.02</td>
</tr>
<tr>
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<td>high</td>
<td>7.378</td>
<td>2073</td>
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<td>3.24</td>
<td>2.1</td>
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<tr>
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<td>VSP</td>
<td>normal</td>
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<td>2926</td>
<td>1280</td>
<td>2.28</td>
<td>2.28</td>
</tr>
<tr>
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<td>N/A</td>
<td>N/A</td>
<td>4481</td>
<td>2530</td>
<td>1.77</td>
<td>2.14</td>
</tr>
</tbody>
</table>

Table 5.1  Velocity and density values for overpressure zones were selected from lab data (Domenico, 1977) and approximated using shallow VSP data (Lash, 1980).

5.6 Results and Discussion

5.6.1 Zoeppritz models

Reflection coefficients and energy for the PP, PS, SP, and SS reflections from base of salt are presented in Figures 5.5- 5.6.

In Figure 5.5, the velocities and densities of the underlying sediments from the lab measurements were used to compare reflection coefficients and energy of normally and highly pressured sediments (34 and 7 MPa respectively). There are several observations of interest:

- For all modes, overpressed sediments always produce larger reflection coefficients. This is because the lower velocities of the overpressed sediments create a greater impedance contrast at the base of salt.

- The increase in reflection coefficients due to overpressuring is greater for the shear modes (SS, SP, and PS) than for the PP mode. The PP reflection coefficient is approximately 10 percent larger for overpressed sediments while
modes with at least one shear leg are 30 percent larger for overpressured sediments. Overpressuring causes a larger drop in \( V_p \) than in \( V_s \). The shear modes are more sensitive to this change than the PP mode.

- Reflection coefficient curves for normally and overpressured sediments follow similar trends. There are no distinct variations in the normal incidence intercepts or slope of reflection coefficient curves for overpressured sediments.

- The shear modes are as strong or stronger than the PP mode. The energy of the mode conversions are slightly larger than the PP mode. The normal incidence energy of the SS mode is approximately twice that of the PP mode.

In Figure 5.6, a similar set of Zoeppritz models were constructed using the velocities and densities from VSP data. For each mode, the energy and reflection coefficients for three cases are plotted: normal pressure, overpressure, and more extreme overpressure. Reflection coefficients and energy for the normally pressured sands in this example are lower than they are for the normally pressured sediments based on laboratory measurements. The magnitude of the reflection coefficients and energy for the overpressured sediments is similar to that of the overpressured sediments represented in the previous set of models while the highly overpressured sediments are approximately 50 percent higher.

The results calculated using the VSP data are consistent with those from the lab data. The difference between the normally pressured and highly overpressured sediments is quite large. This is because the drop in \( V_s \) for the overpressured sediments is greater. This large drop contributes to the increase in reflection coefficients with overpressuring for all modes. The PP, PS, and SP reflection coefficients are approximately 2.6 times larger than the corresponding reflection coefficients for the normally pressured sediments. The increase in the SS mode is the greatest. It increases 3.3
Figure 5.5  Reflection coefficients and energy for PP, PS, SP, and SS modes for salt over normally pressured sediments (dashed blue line) and overpressured sediments (solid red line). The velocities and densities are taken from lab measurements listed in Table 5.1.
times for overpressured sediments. These increases in reflection coefficients correspond to energies 6.5 times (for PP, PS, and SP modes) to 9 times (for SS mode) larger for overpressuring. As previously observed, there is no distinct change in the trends of any of the reflection coefficient curves. This suggests that AVO analysis may not be useful in detecting amplitude variations due to overpressuring.

5.6.2 Crossplots

To further test whether AVO analysis would be useful in distinguishing gas sands from brine sands, A and B values were extracted from reflection coefficient curves based on lab and field data and were crossplotted.

In Figure 5.7, intercept and gradient values extracted from reflection coefficient curves based on lab data are plotted. First, AB values for normally pressered samples (from 14 to 34 MPa) were plotted as asterisks to establish a background trend. For all modes, these AB values plotted along a straight line. Then, AB values from overpressured samples (7 to 10 MPa) were plotted as circles. Unfortunately, they do not appear on any of the crossplots as deviations from the trend established by the normally pressered sediments. They simply plot at one extremity of the trend.

Intercept and gradient values extracted from VSP data at various depths were crossplotted in Figure 5.8. These crossplots are very similar to those constructed from the lab measurements. Again, the normally pressered sediments form a straight line trend. The overpressured sediments appear at one extremity of these trends.

From these crossplots, it appears that AVO analysis would not be useful in distinguishing overpressured sediments from normally pressered sediments. Overpressured sediments do not appear on these plots as deviations from a trend established by normally pressered sediments.
Figure 5.6 Reflection coefficients and energy for PP, PS, SP, and SS modes for salt over normally pressured sediments (dashed blue line), overpressured sediments (dot-dash red line), and highly overpressured sediments (solid red line). The velocities and densities for these sediments are taken from VSP data listed in Table 5.1
Figure 5.7 Intercept (A) vs. gradient (B) for sands at differential pressures from 7 to 34 MPa. A and B values were extracted from reflection coefficient curves constructed from laboratory samples at 7 pressure levels. Normally pressured sediments (asterisks) plot along a straight line for all modes. Overpressured sediments (circles) plot at one extremity of this line. Since overpressured sediments do not appear as obvious deviations from the trend established by normally pressured sediments, it is unlikely that crossplotting and conventional AVO analysis would be useful in distinguishing overpressured sands from normally pressured sands.
Another more general conclusion reached by examining these crossplots is that AVO analysis of mode conversions (PS and SP modes) is severely limited. In contrast to the PP and SS modes which may vary in A (normal incidence reflection coefficient) and B (AVO gradient), the converted modes vary in only in B (Figure 5.9). This is because the normal incidence reflection coefficient for converted modes is always zero. As a consequence, one of the parameters used in AVO analysis to associate changes in reflection coefficients with rock properties is eliminated.

5.6.3 Elastic models

Although overpressuring may not be detectable through AVO analysis, it may be detectable on a stacked seismic section given that the reflection coefficients of the overpressured sediments are higher than the reflection coefficients of the normally pressured sediments. According to the Zoeppritz models, reflections from overpressured sediments are 2 to 3 times higher. To assess whether this increase would be obvious on a stacked seismic section, elastic models were created with a single interface: salt over normally pressured sediments, highly pressured sediments, and very highly pressured sediments. The values for these sediments were based on the VSP measurements listed in Table 5.1.

Stacked seismic sections for each mode are presented in Figures 5.10-5.13. The maximum trough amplitudes for the base of salt reflection are plotted above all traces. The variation of amplitudes depending on the type of sediments is consistent with the amplitude variations observed in the Zoeppritz models. Amplitudes of overpressured sediments are approximately 2 to 2.5 times higher than amplitudes of normally pressured sediments. The highly overpressured sediments have amplitudes 3 times higher than the normally pressured sediments. Thus, it is possible to distinguish overpres-
**Figure 5.8** Intercept (A) vs. gradient (B) for sands at various differential pressures. A and B values were extracted from reflection coefficient curves constructed using VSP measurements at 17 depths. Because normally (asterisks) and overpressured (circles) sediments plot along the same trend, it would be difficult to use AVO analysis to distinguish them.
Figure 5.9  The same AB values shown in Figure 5.7 at similar scales for all modes. Notice the mode conversions do not vary in A. This eliminates one of the parameters used in AVO analysis.
sured sediments from normally pressured sediments by comparing their amplitudes on a stacked seismic section.

![Diagram](image)

**Figure 5.10** Stacked PP base of salt reflection. Underlying the salt body are variously pressured sediments based on measurements from VSP data. The maximum trough amplitude of the reflection is plotted above the traces. The overpressured and highly overpressured sediments have amplitude 2 to 3 times higher than normally pressured sediments.

While a bright spot observed on a PP reflection from base of salt may be indicative of overpressuring, there are other conditions which may cause bright spots. For example, gas may cause a bright spot on the PP reflection. However, as shown in Chapter 4, the shear modes are relatively unaffected by the presence of gas and do not increase in amplitude. Therefore, in order to distinguish a bright spot on the PP base of salt reflection as hydrocarbon or pressure related, it is necessary to examine at least one of the shear mode reflections from base of salt (PS, SS, or SP). If one of the shear modes is bright, then the PP amplitude anomaly may be related to overpressuring. If one of the shear modes is dim, then the PP amplitude anomaly may be hydrocarbon related.
Figure 5.11  Stacked PS base of salt reflection. Underlying the salt body are variously pressured sediments based on measurements from VSP data. The maximum trough amplitude of the reflection is plotted above the traces. The overpressured and highly overpressured sediments have amplitude 2 to 3 times higher than normally pressured sediments.

5.7 Limitations

There are several limitations inherent to amplitude analysis and the sensitivity of seismic amplitudes to geologic conditions which affect the use of this technique to identify overpressured sediments.

As mentioned previously, amplitude analysis is nonunique. Although it is possible to associate overpressuring with certain amplitude responses, even with shear wave confirmation, there are other lithologic conditions which may cause the same amplitude response. The most likely factor which would produce similar amplitude responses on P- and S-wave reflections would be a change in lithology that would alter the porosity. Future work should examine what factors may cause similar responses.

Because porosity is the most significant physical change to signify overpressuring, an ability to detect overpressuring on seismic data requires that overpressured sediments preserved a substantial amount of their porosity. Differential pressures less than 15 MPa must not have been exceeded at any time during the burial of an overpressured formation. At higher differential pressures, the porosity has been
Figure 5.12 Stacked SS base of salt reflection. Underlying the salt body are variously pressured sediments based on measurements from VSP data. The maximum trough amplitude of the reflection is plotted above the traces. The overpressured and highly overpressured sediments have amplitude 2 to 3 times higher than normally pressured sediments.

substantially reduced so that changes in pressure conditions only weakly change the elastic properties of the formation.

There are mechanisms by which high fluid pressures can be generated at depth (clay transformation, for example) after porosity has already been substantially reduced by burial. Such overpressured zones would also be difficult to detect seismically (either through velocity or amplitude analysis) because they are not accompanied by changes in the properties of the rock matrix.

The elastic models constructed for this study are very simple and do not take into account the effects of geometry, overburden, gradational boundaries, anisotropy and tuning which alter amplitudes and may mask amplitude variations due to pressure conditions. Future work should test this technique under more complicated geologic conditions.
Figure 5.13  Stacked SP base of salt reflection. Underlying the salt body are variously pressured sediments based on measurements from VSP data. The maximum trough amplitude of the reflection is plotted above the traces. The overpressured and highly overpressured sediments have amplitude 2 to 3 times higher than normally pressured sediments.

5.8 Conclusions

From this modeling study, it was observed that converted mode amplitudes from base of salt are as strong as PP reflection amplitudes. They may be used in conjunction with PP amplitudes to detect overpressured zones and distinguish them from hydrocarbon traps. This technique may be applied directly to the base of salt reflection which was not possible using traditional P-wave velocity methods. This technique may also be applied to multicomponent data which records mode conversions at relatively small impedance contrasts. However, like amplitude analysis for hydrocarbon detection, the results are nonunique and bright spots on P- and S-wave sections may be indicative of lithologic anomalies other than overpressuring.
Chapter 6

Conclusions

This thesis examines factors complicating subsalt imaging and amplitude analysis, the effect of mode conversions on subsalt amplitudes and AVO analysis, and potential uses of base of salt mode conversions to characterize conditions at base of salt.

There are many factors affecting subsalt amplitudes unrelated to rock properties which make amplitude analysis for hydrocarbon detection difficult. These include wave propagation effects, geometric effects, and processing-related distortions.

Of these factors, processing related distortions are generally minor and avoidable. It is essential that processing techniques such as mutes, filters, and trace weighting functions be applied consistently to avoid introducing unwanted amplitude variations. Use of exact processing methods rather than approximations is desirable to preserve amplitudes as much as possible. For example, finite difference migration provides much more realistic amplitudes than Kirchhoff migration because the entire wavefield is migrated. Practical application of more exact methods which are also more computer-intensive is dictated by advances in computing power.

Wave propagation and geometric effects pose a much greater problem to subsalt amplitude analysis than processing distortions. These effects may be as large as amplitude variations due to changes in rock properties. Their complex variation depending on offset and location relative to the salt body make them difficult to correct for. Strong mode conversions generated at salt-sediment interfaces influence subsalt amplitudes in several particularly damaging ways:

- Along with strong reflections generated at salt-sediment interfaces, mode conversions account for a three-fold drop in subsalt amplitudes as compared with
extra salt amplitudes. Therefore, the signal-to-noise ratio of subsalt data is very low.

- Mode conversions interfere constructively and destructively with subsalt P-wave reflections producing erratic amplitude variations with offset. These imprinted oscillations make it difficult to accurately measure amplitudes of P-wave reflections with offset.

- The appearance of strong mode conversions at mid-offsets diverts energy away from P-wave reflections of gas sands. This effect is so great as to actually reverse the AVO trend of a gas sand with a class 2 or 3 AVO anomaly. As a consequence, the ability to distinguish gas sands from brine sands using AVO analysis is severely limited.

The effects of mode conversions as well as other wave propagation effects in the subsalt environment is so strong that both AVO analysis and stacked amplitude analysis may not be reliable methods for extracting information about rock properties. Even with application of processing techniques to compensate for some wave propagation and geometric effects, amplitude analysis techniques may depend on the identification of amplitude anomalies much more subtle than those found in extra salt environments.

While mode conversions create several complications in subsalt imaging and amplitude analysis, they may also be used in conjunction with P-wave reflections to characterize conditions at base of salt. Unlike P-waves, shear waves are insensitive to changes in pore fluid. Therefore, they may be used to gauge the strength of P-wave reflections from gas and brine saturated sands. Base of salt P-wave reflections which are several times stronger than base of salt mode converted reflections may indicate hydrocarbons while P-wave reflections approximately the same strength or smaller than mode conversions may not be large enough to be caused by hydrocarbons. Further,
because shear waves are sensitive to changes in porosity, they may be used with P-waves to predict overpressuring. Stacked base of salt P-wave and mode converted amplitudes are two to three times larger in the case of overpressuring. Analysis of stacked converted mode amplitudes provides the additional criteria necessary to distinguish a large P-wave amplitude anomaly as hydrocarbon or overpressure-related. The advantage of this technique is that it may be directly applied to the base of salt where conventional overpressure detection by P-wave velocity analysis is ineffective.

These techniques which depend upon amplitude analysis of base of salt mode conversions are possible with conventional P-wave data because base of salt mode conversions are as strong as or stronger than P-wave reflections at larger offsets. Further, mode conversions may be identified using acoustic and elastic model comparisons on the basis of distinct AVO, moveout and arrival times.

6.1 Future Work

Further work may be conducted to determine whether mode conversions may be identified on field data and used to characterize conditions at base of salt. A method incorporating some of the procedures documented in this thesis and full-survey modeling is proposed below:

1. select a seismic data set with a salt body and offsets long enough to include mode converted reflections from the salt body.

2. create 2D P-wave, S-wave, and density models based on a depth migrated section. From these models, generate acoustic and elastic synthetic sections. Compare these sections to identify base of salt mode conversions. Then determine whether mode conversions are present in the field data. It may be useful
to look at synthetic shot gathers and field shot gathers to identify particular mode conversions.

3. create partial stacks at various offsets to assess how strong base of salt mode conversions are relative to P-wave reflections.

4. create a series of 2D elastic models which simulate various conditions at base of salt. For example, sediment velocities and densities at base of salt may be varied to simulate brine sand, gas sand, and overpressured sediments.

5. compare the amplitudes of PP base of salt reflections among the various elastic synthetics and the data. Determine whether the P-wave amplitudes are high enough to be caused by hydrocarbons or overpressuring. The relative strength of the PP base of salt reflection may be evaluated by comparing it against the PS or SP base of salt reflections.

6. determine whether strong PP base of salt reflections are due to hydrocarbons or to overpressuring by examining the mode converted reflections. Relatively dim mode conversions may indicate hydrocarbons while strong mode conversions may indicate overpressuring.
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Appendix A

Trend Curves

Trend curves (Tim Summers, pers. comm.) to derive $V_s$ and $\rho$ from $V_p$ and depth (D):

$$V_s = 0.8214V_p - 3584.25 \quad (A.1)$$

$$\rho = 5.69 \times 10^{-5}D + 1.9084 \quad (A.2)$$
Appendix B

Classification of AVO anomalies

Seismic reflections from gas sands may produce several types of AVO responses. These responses are characterized by the normal incidence reflection coefficient and the contrast in Poisson's ratio at the reflector. Based on these two factors, Rutherford and Williams (1989) classified gas sand reflections into three groups:

- **Class 1**: The normal incidence reflection coefficient is strongly positive and shows strong amplitude decrease with offset. A phase change is possible at far offsets (Figure B.1).

- **Class 2**: The normal incidence reflection coefficient is slightly positive or negative. The AVO exhibits a large percentage change. If the normal incidence reflection coefficient is slightly positive, a phase change occurs.

- **Class 3**: The normal incidence reflection coefficient is large and negative. The reflection coefficient becomes more negative with increasing offset. Class 3 sands exhibit a large bright spot on stacked sections.

Each class may be associated with reflections from different types of sands. For example, class 3 sands are usually found in the marine environment while class 1 sands are generally found onshore.
Figure B.1 Diagram depicting the behavior of the three classes of gas sands.