Seismic Determination of Reservoir Heterogeneity: Application to the Characterization of Heavy Oil Reservoirs

Annual Report


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Abstract

The objective of the project was to examine how seismic and geologic data can be used to improve characterization of small-scale heterogeneity and their parameterization in reservoir models. The study focused on West Coalinga Field in California.

The project initially attempted to build reservoir models based on different geologic and geophysical data independently using different tools, then to compare the results, and ultimately to integrate them all. We learned, however, that this strategy was impractical. The different data and tools need to be integrated from the beginning because they are all interrelated. This report describes a new approach to geostatistical modeling and presents an integration of geology and geophysics to explain the formation of the complex Coalinga reservoir.
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Chapter 1

Introduction

The objective of the project was to examine how seismic data can be used to parameterize models of small-scale reservoir heterogeneity. Although these heterogeneities may not be resolved individually (deterministically) using seismic data, one can at least attempt to estimate their statistical properties from seismic data. Initially we planned to derive geological and geophysical heterogeneity models in an independent manner to allow comparison, but we came concluded that no single approach alone will suffice for the Coalinga field. Instead, geological and geophysical models need to be integrated early to succeed in complex environments.

Reservoir characterization is an essential step in delineation, development, and produc-
tion of hydrocarbon reserves. Our test area, the giant Coalinga field in California’s San Joaquin Valley, is a good example. Large-scale steam-flood projects have been utilized for many years in order to enhance recovery of heavier oil. Steam-floods are costly to operate due to the necessary infrastructure and their energy consumption. Optimally, injected steam would spread evenly from the injection point and push the oil toward the producer wells. In reality, the steam patterns are very complex. Reservoir characterization provides an improved understanding of the reservoir and the movement of steam, which will help to increase the profitability by reducing steam injection which decreases the environmental impact of steam injection. Reservoir heterogeneity affects not only the steam flood, but also the production. The Coalinga reservoirs are strongly compartmentalized which is aggravated by the high oil viscosity. Reservoir characterization helps siting infill wells to produce bypassed oil to increase ultimate recovery.

Knowing the details of the reservoir allows simulation of different injection or production scenarios. The problem, however, is to build an accurate and suitable reservoir model that includes small-scale heterogeneity. Locally, boreholes yield an excellent description of the vertical heterogeneity at different spatial scales ranging from centimeters to hundreds of meters. Most of the time, the lateral heterogeneity cannot be derived from well data because of the large distances between wells. The most abundant data are seismic data, but their resolution is only on the order of tens of meters which is typically insufficient to resolve geological heterogeneities. Features smaller than a seismic quarter wavelength cannot be resolved with certainty. Yet the geology exhibits many small-scale features which may have a pronounced effect on the reservoir. For example, a clay drape is invisible on the seismic data but poses an impenetrable barrier to steam and oil. By combining seismic and well data, a deterministic framework is traditionally constructed which contains the major stratigraphic features. Small-scale features are filled in using statistical methods conditioned to well data and outcrops. The parameters for the fill-in process are often provided by measurements of analogous outcropping formations, analogous mature reservoirs with a dense well spacing,
horizontal wells, pressure and production tests, or simply by accepting the default parameters of the modeling packet.

The objective of the project was to examine how seismic and geologic data can be used to describe small-scale heterogeneity and parameterize the reservoir models. Although these heterogeneities cannot be resolved individually (deterministically) using seismic data, we attempted to estimate their statistics from seismic data. The Coalinga field contains more than 2000 wells which provide the unusual luxury that even small-scale heterogeneity can be characterized with well data. The site allows construction of reservoir models from either seismic data or wireline logs and outcrops. Since these data are independent, the models could be compared and validated against each other. No single heterogeneity model, however, can characterize the heterogeneity of Coalinga field. Instead, geologic and geophysical heterogeneity models need to be integrated early.
1.1 Executive Summary

The objective of the project is to examine how seismic data can be used to improve characterization of small-scale heterogeneity and their parameterization in reservoir models. During the fourth and final year, we applied the inversion algorithm for the parameters of object-based reservoir models to seismic and wireline data from Coalinga field. We also continued interpretation of the seismic poststack data and their integration with regional and local geological data.

Object-based reservoir models build realizations by emplacing geometric objects corresponding to channels, barriers, or sheet sands. Previously, we developed an algorithm to estimate the object parameters from seismic data and tested the algorithm with synthetic seismic data. Recently, we applied the inversion algorithm to Coalinga field to test its applicability with field data and found that the results are very encouraging. Using a very simple model of blocky heterogeneity, we were able to improve the optimal reservoir realization by 20% by estimation and optimization of the geometry parameters from seismic data.

We also finished mapping of the four Temblor unconformities on seismic data and used seismic volume visualization, geobody analysis, and seismic attributes to segment the reservoir into different sedimentary zones with different. We learned that the top and bottom portions are richer in sand than the middle while also exhibiting better connectivity. Finally, we were able to tie these observations to the regional stratigraphic and tectonic history which explains the complex reservoir with rapidly varying heterogeneity, furthers our insights, and ultimately allows integration of all our results.
1.2 Cumulative Bibliography

Theses and Dissertations


Publications


Presentations and Extended Abstracts


M. G. Imhof and W. C. Kempner, ‘Seismic Heterogeneity Cubes and Corresponding Equiprobable Simulations’, American Association of Petroleum Geologists Annual Convention, Salt
Lake City, 2003.


J. Piver, J. W. Castle, M. T. Poole, R. A. Hodges, and M. G. Imhof, ‘Integrating Geologic Models and Seismic Data to Characterize Interwell Heterogeneity of the Miocene Temblor Formation, Coalinga, California’, Geological Society of America Joint Annual Meeting of the South-Central Section (37th) and Southeastern Section (52nd), Memphis, 2003.


Chapter 2

Object-Based Stochastic Facies
Inversion

2.1 Introduction

Reservoir models are a necessary tool during the exploration, delineation, and exploitation of hydrocarbon reservoirs. Data quality and resolving power are often too limited to build a detailed, deterministic model where all heterogeneity was fully observed in the data. Instead, stochastic methods are used to fill in unresolved details at short scales (e.g. Dubrule, 1989; Haas and Dubrule, 1994). The stochastic nature of these models allows construction of different realizations which all have the same broad characteristics but differ in the details. These differences qualify and quantify the uncertainty and risk related to the incomplete knowledge and sparse data coverage. Such realizations may be generated by defining a model and specifying its parameters which encompass composition and internal structure of the reservoir.

Core and geophysical wireline data provide a detailed account of the lithologic composition of a reservoir and are capable of identifying small-scale heterogeneities at the well locations. These data are incapable of resolving features that deviate from the well path.
Their lateral extents, for example, are unresolved, and hence, log correlation and deterministic seismic interpretations are often used to interpolate between wells.

The seismic reflection interpretations provide a means of resolving lateral and vertical heterogeneity between wells, but are subject to a vertical resolution limit of $\frac{1}{4}$ wavelength and a lateral limit of one Fresnel zone ($\approx \sqrt{\text{depth} \cdot \text{wavelength}}$). Due to resolution limits of deterministic seismic interpretations, and the one dimensional nature of core and wireline data, conventional techniques of generating reservoir models rely on experience, geologic intuition, and modern environments or ancient outcrop analogs to further characterize a reservoir. For example, to characterize a reservoir exhibiting channelized features, intuition and analogs aid in defining the sinuosity of small-scale channels, width-to-depth ratios of associated facies, and how these associated facies are positioned spatially with respect to one another.

Object-based reservoir models build a realization by emplacing geologically meaningful geometric shapes representing channels, barriers, and other geologic objects using geometric and stochastic parameters such as distributions of thickness, sinuosity and/or aspect ratio. The purpose of the proposed object-based stochastic facies inversion is to reduce the dependence on geologic intuition and analogs when generating realizations of hydrocarbon reservoirs.

I outline a pilot study technique which estimates model parameters and their distributions and ranges from all available data, including plentiful seismic attributes. The inversion process begins with an initial reservoir realization, which is compared to observed data. Based on this comparison, a new set of parameters is chosen. The new set of parameters is used in the object-based reservoir simulation to generate a new realization, which is conditioned to the well logs. This iterative process continues until a single model with a user defined “acceptable” match between the realization and data is attained.

The inversion is highly nonlinear, and hence, convergence cannot be taken for granted and may be excruciatingly slow. We also have to emphasize that this contribution is only a first
outline of such a procedure. Many questions remain unresolved and will need to be resolved later. For example, which seismic attributes should be used: amplitudes, impedance, or something else? Should seismic attributes be used for both the conditioning of realizations and the improvement of parameters? We believe, however, that the outlined quantitative approach to the definition of these parameters will generate reservoir models with improved realism and increased correlation between predicted and recorded production histories.

2.2 Process

Our technique for generating a reservoir realization is contained in two loops as depicted in the schematic diagram shown on Figure 2.1. In the outer loop (shown in blue), we optimize the set of model parameters. In the inner loop (shown in red), we optimize the realization for a given set of parameters. In fact, we are searching for the set of random numbers which yields the stochastic model realization most compatible with the constraining wireline and seismic data!

The inner loop consists of generating an object based realization. For simplicity, we use the industry standard RMS composite facies module by Roxar (2002), although competing or homegrown software modules would perform equally well. The objects are distributed in accordance to specified volumetric proportions, statistical distributions for the parameters, and placement rules which govern clustering. The generated models honor a set of interval facies logs. They are also constrained by external seismic attributes. The volumetric proportion of the facies are simply estimated by the linear footage of the facies present in the logs. Placement rules are suggested by the environment and the geologic interpretation of the geometric shapes. The software module simply adds objects into the volume. Location, orientation, and other geometric parameters are drawn from the specified distributions. A placed object which is incompatible with the wireline or seismic constraints is simply removed again. The module tries adding objects until the specified volumetric proportions are
Figure 2.1: Schematic depicting the object-based stochastic facies inversion depicting the inner (red) and outer (blue) loops
satisfied within some predefined tolerance interval. Once completed, the process advances to the outer loop with the single realization that passed these criteria. Because the module tries to condition its realizations perfectly to the wells, a portion of all available wells are excluded from use in the inner loop for exclusive use in the outer loop.

The outer loop optimizes the geometrical parameters such as aspect ratios and orientations of the included geologic objects. The optimization of these parameters is achieved via a simulated annealing (SA) guided search technique to nonlinear inversion. The inversion model space \( m_{rs} \) is populated with the statistical parameters necessary to generate a reservoir realization,

\[
m = \begin{bmatrix}
m_{1,1} & m_{2,1} & \cdots & m_{R-1,1} & m_{R,1} \\
m_{1,2} & m_{2,2} & \cdots & m_{R-1,2} & m_{R,2} \\
& & \ddots & & \\
m_{1,S-1} & m_{2,S-1} & \cdots & m_{R-1,S-1} & m_{R,S} \\
m_{1,S} & m_{2,S} & \cdots & m_{R-1,S} & m_{R,S}
\end{bmatrix}
\]

modified from Sen and Stoffa (1991), where each row (1 through \( S \)) corresponds to a particular statistical parameter and each column (1 through \( R \)) corresponds to a possible value that the respective parameter can attain. For instance, \( m_{1,R,1} \) may correspond to \( R \) possible values for mean channel width, \( m_{1,R,2} \) may correspond to the \( R \) possible standard deviations associated with that mean channel width, etc.

After the initial model was chosen \( m_{1,1} \) and a realization generated, cores are extracted from the realization \( C_s \) at the location of the omitted interval facies logs \( C_o \). This ensemble of omitted logs serves as the observed data to calculate the objective function. The binary objective function \( E \) is evaluated such that if \( C_o(x, y, z) = C_s(x, y, z) \) then \( e = e + 1 \), however if \( C_o(x, y, z) \neq C_s(x, y, z) \) then \( e = e + 0 \) and \( E = \frac{e}{z_{total}} \).

This process repeats for all \( R \) values of the current parameter, maintaining constant
values for $m_{1,2\rightarrow S}$. A probability distribution $P$

\begin{equation}
P(m_{rs}) = \frac{\exp\left(\frac{E(m_{rs})}{T}\right)}{\sum_{r=1}^{R} \exp\left(\frac{E(m_{rs})}{T}\right)} \quad \text{where} \quad T = T_0 \times 0.99^i \tag{2.2}
\end{equation}

is evaluated (Sen and Stoffa, 1991), which calculates the likelihood that any one of the $R$ values of the current parameter is correct based on the energy function $E$.

A new value for the current parameter is retained based on this probability distribution and the process continues to the next parameter, maintaining constant values for parameters $m_{r,1}$ and $m_{1,3\rightarrow S}$. An iteration $i$ in the annealing process constitutes the completion of evaluating the $R^{th}$ value of the $S^{th}$ parameter, the temperature $T$ is lowered, and the cycle repeats until the user defined “acceptable” match between the observed and synthesized log data is attained. To establish a computationally efficient cooling process, experimental trials are often performed before selecting the initial temperature $T_0$.

### 2.3 Application to the Coalinga Heavy Oil Field

Our novel method of generating reservoir realizations is applied to ChevronTexaco’s Coalinga heavy oil field in the San Joaquin Valley of southwestern California, shown on Figure 2.2. The Coalinga field is a mature field with an abundance of wireline log data which makes this an ideal site to test our methodology. For this project, we used 106 wells spread over 3 square miles, shown in Figure 2.3, which allowed exclusion of a generous number of wells to be used solely for evaluation of the objective function $E$.

The Coalinga field has been producing oil from the Temblor formation since 1887 (Clark et al., 2001). Based on the characterization by Clark et al. (2001), the Temblor formation is an unconformity bounded reservoir and can be subdivided into three main depositional zones as shown on Figure 2.4. The basal zone is bounded at the base by a major erosional surface, Base Temblor, which is identified on seismic data by the truncated marine shales.
Figure 2.2: Location of the Coalinga oil field in southwestern California.

Figure 2.3: Map showing the location of the modeling and control wells, the seismic line shown in Figure 2.4, and the cross section through the realizations shown in Figure 2.6.
of the underlying Kreyenhagen formation. This section is largely estuarine facies consisting of tidal channel and stacked tidal channels deposits (Clark et al., 2001). The Buttonbed unconformity marks the transition from the estuarine deposits to tide and wave dominated shoreline facies. This middle section, primarily composed of prograding units of coarsening-upward sandstones (Clark et al., 2001), is in turn capped by the Valv unconformity. This unconformity defines the transition to subtidal dominated facies consisting of cemented, laterally continuous, coarsening-upward sandstones (Clark et al., 2001), which is bounded at the top by the Top Temblor.

Figure 2.4: Dominant stratigraphic intervals within the Temblor formation
Table 2.1: Parameters and ranges for the basal zone of the Temblor formation. The dominant laminated sand, silt, and shale group is used as background into which other lithologies are embedded.

<table>
<thead>
<tr>
<th>Lithofacies Group</th>
<th>Index Number</th>
<th>Volume Fraction</th>
<th>Mean Length (m)</th>
<th>Mean Width (m)</th>
<th>Mean Thickness (ms)</th>
<th>Orientation (°)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sand</td>
<td>1</td>
<td>0.085</td>
<td>36.5 – 91.4</td>
<td>36.5 – 91.4</td>
<td>3.0 – 8.5</td>
<td>0 – 90</td>
</tr>
<tr>
<td>Laminated Sand, Silt and Shale</td>
<td>2</td>
<td>0.497</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>Burrowed Clay</td>
<td>3</td>
<td>0.147</td>
<td>36.5 – 204.2</td>
<td>36.5 – 204.2</td>
<td>3.0 – 16.8</td>
<td>0 – 90</td>
</tr>
<tr>
<td>Burrowed Sand</td>
<td>4</td>
<td>0.196</td>
<td>36.5 – 204.2</td>
<td>36.5 – 204.2</td>
<td>3.0 – 16.8</td>
<td>0 – 90</td>
</tr>
<tr>
<td>Fossiliferous Sand and Clay</td>
<td>5</td>
<td>0.058</td>
<td>36.5 – 64.0</td>
<td>36.5 – 64.0</td>
<td>3.0 – 5.8</td>
<td>0 – 90</td>
</tr>
<tr>
<td>Limestone</td>
<td>6</td>
<td>0.015</td>
<td>36.5</td>
<td>36.5</td>
<td>3.0</td>
<td>0</td>
</tr>
<tr>
<td>Calcareous Cemented Sand</td>
<td>7</td>
<td>0.002</td>
<td>36.5</td>
<td>36.5</td>
<td>3.0</td>
<td>0</td>
</tr>
</tbody>
</table>

Currently, production is focused in the basal zone of the Temblor formation and is aided by steam injection. Based on the wireline log interpretations of Mize (2002) and Piver (2004), seven lithofacies types occur in this basal zone of the Temblor formation and are listed in Table 2.1.

Because the laminated sand, silt and shale are the dominant facies in this zone at 49.7%, they are treated as the background material, where the other facies types are emplaced during the reservoir modeling. The remaining six lithofacies are modeled as arbitrary rectangular prisms with the ranges of aspect ratios and orientations specified in Table 2.1. Due to the relatively rare occurrence of limestone and calcareous cemented sand (< 2%), the aspect ratios are kept constant and small to prevent instabilities in generating a realization. In addition, the standard deviations associated with these aspect ratios and orientations remained fixed at 20% their respective mean value.

For this example, we chose a seismo-facies volume as the seismic attribute to condition
the reservoir modeling. This volume is calculated by the multiple regression analysis tool in the Emerge module of the Hampson Russell (2000) software package. The Emerge module provides a means to predict a core or well attribute, in this case interval facies, at the seismic trace location from any combination and number of seismic attributes (e.g. Tanner, 1978). The step-wise process first determines the best single seismic attribute discriminator of the well attribute, then finds by trial-and-error the best pair of seismic attributes given that one of the pair is the best single seismic attribute, and then the best three, four, etc. In this case we chose the following eight seismic attributes to predict the interval facies logs at the seismic trace locations: LOG[impedance], integrated absolute amplitude, integrate, instantaneous response frequency, instantaneous dominate frequency, quadrature trace, perigram\(^2\), and instantaneous amplitude\(^{-1}\).

Due to time considerations, the inversion process was allowed to run for nine iterations (\(\approx 168\) hours continuous CPU time) and achieved a 51% match between the nine omitted interval facies logs \(C_o\) and the cores extracted from the final single realization \(C_s\). As depicted on the convergence plot shown on Figure 2.5, this represents a 19% improvement from the initial 32% match between the control logs and the cores extracted from the initial single realization. The statistical parameters used to generate this final realization are listed in Table 2.2.

Figure 2.6, shown as a function of traverse distance and two-way traveltime below the interpreted Buttonbed unconformity, depicts a cross-section through the initial and final realization intersecting three of the omitted control wells. The extracted and omitted interval facies logs from these well locations are enlarged and depicted in Figure 2.7. The match between the control logs and those extracted from the initial realization (Figures 2.7(a), 2.7(b) and 2.7(c)) is marginal at best, however after nine iterations the extracted logs (Figures 2.7(d), 2.7(e) and 2.7(f)) are strikingly similar to the control logs. These results merely emphasize the significance of a 19% improved correlation between the facies interpretations at the control points and synthesized data.
Table 2.2: Parameters used to generate a realization for the basal zone of the Temblor formation with 51% agreement between the control and extracted interval facies logs. The dominant laminated sand, silt, and shale group is used as background into which other lithologies are embedded.

<table>
<thead>
<tr>
<th>Lithofacies Group</th>
<th>Index Number</th>
<th>Mean Length (m)</th>
<th>Mean Width (m)</th>
<th>Mean Thickness (ms)</th>
<th>Orientation (°)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sand</td>
<td>1</td>
<td>36.5</td>
<td>36.5</td>
<td>8.5</td>
<td>30</td>
</tr>
<tr>
<td>Laminated Sand, Silt and Shale</td>
<td>2</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>Burrowed Clay</td>
<td>3</td>
<td>82.3</td>
<td>189.0</td>
<td>12.2</td>
<td>70</td>
</tr>
<tr>
<td>Burrowed Sand</td>
<td>4</td>
<td>51.8</td>
<td>189.0</td>
<td>3.0</td>
<td>90</td>
</tr>
<tr>
<td>Fossiliferous Sand and Clay</td>
<td>5</td>
<td>51.8</td>
<td>51.8</td>
<td>5.2</td>
<td>70</td>
</tr>
<tr>
<td>Limestone</td>
<td>6</td>
<td>36.5</td>
<td>36.5</td>
<td>3.0</td>
<td>0</td>
</tr>
<tr>
<td>Calcareous Cemented Sand</td>
<td>7</td>
<td>36.5</td>
<td>36.5</td>
<td>3.0</td>
<td>0</td>
</tr>
</tbody>
</table>
2.4 Discussion and Conclusions

The adaptation to conventional techniques of generating reservoir models consists of using a simulated annealing parameter optimization technique as a proxy to geologic intuition and analogs. The results of this study suggest that a more systematic and quantitative approach to defining the statistical model parameters necessary to generate reservoir models is possible and can improve the match between predicted models and observed data. The recovery of these parameters that define the composition and internal short-scale structure of a reservoir through this formulation aids in resolving inter-well and possibly inter-trace heterogeneity.

This improvement, however, comes at a high computational expense. One iteration requires evaluation of $R \times S$ forward models. For this study with $S = 16$ parameters and $R = 10$ possible values that each parameter can attain, one complete iteration typically required approximately 24 hrs of continuous CPU time on a SUN Blade 1000 workstation with a single 500 MHz processor. Different models, however, could be evaluated in parallel on a grid computer or parallel cluster which would reduce the required computer time linearly with the number of parallel evaluations. We did not have the necessary number of licenses for the object-based modeling software to explore this time saving strategy.

Figure 2.5: Depicts the convergence of the inversion (correlation verses iteration) from 32% to 51% in nine iterations based on nine control wells
Figure 2.6: Cross-section, through (a) the initial and (b) final realizations, intersecting three control wells.

I presented just a pilot implementation of our proposed modeling technique. Some changes may be warranted for future applications. For example, excluding a different set of boreholes to evaluate the outer loop (Figure 2.1) during every iteration which resembles jackknifing often used for statistical testing with limited data (e.g., Efron, 1982), may improve our confidence in the final realization. Also, we would like to use seismic data not only in the inner loop (Figure 2.1) as a constraint for the object-based model, but also in the outer loop to evaluate the objective function $E$. Currently, parameter optimization is performed with only a small amount of data. Seismic data volumes would have a dramatic impact on this optimization. The simulated annealing procedure was used in its discrete form where parameters can take only discrete values. There are continuous versions of simu-
lated annealing as well as other nonlinear inversion algorithms, such as the genetic algorithm (Stoffa and Sen, 1991) and neighborhood algorithm (Sambridge, 1999), which may improve performance. Lastly, the performance of the proposed scheme should be evaluated with
truly independent data instead of convergence or correlation criteria. One potential assessment would be to subject the reservoir models to flow simulations to compare predicted and recorded production histories.

There are also some unresolved research questions. The most pressing one is which seismic data to use in the inner and outer loops. For the inner loop, any seismic attribute could be used as a modeling constraint. Some attributes, however, may perform better while others may have a direct physical or petrophysical meaning. At present, it is not clear which attributes to select. For the use of seismic data in the outer loop, we have to transfer either the realizations, the seismic data, or both to one common quantity. For example, we could transform the realization to an impedance volume, and apply the convolutional model with an appropriate wavelet to obtain synthetic traces for comparison with the seismic amplitude data. Instead of directly comparing amplitudes, maybe one should compare seismic attributes of the synthetic and real data. As an alternative, we could invert the real seismic data into an acoustic impedance volume with the help of wireline data, and compare the resulting impedance volume estimate with the impedance of the model realization. And of course there may be other ways of comparing seismic data and model realizations.

Despite the obvious potential for improvements and the unresolved research questions, we believe that the outlined approach can eventually generate reservoir models with improved realism, better predictions and improved matches against control data, and better agreement between predicted and recorded production data.

2.5 Bibliography


Seismic Reservoir Characterization of Coalinga Oil Field

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Chapter 1

Introduction

Reservoir characterization and model building are necessary steps to develop an oil field and is a prerequisite (Mahapatra, et al. 2003a). Reservoir Characterization is the three-dimensional delineation of a reservoir, its structural framework, volume, heterogeneity, and distributions of rock and fluid properties, which allows maximizing production and minimizing costs, for example by optimizing well locations. Reservoir models are needed to evaluate risks and production scenarios. These models depend on fluid content, composition, and structure of the reservoir. Stratigraphic analysis coupled with detection of paleogeomorphic features like paleosol in highstand system tracts (HST), slumps and other mass transport complex features, channel-levee meandering features, etc. play significant roles in reservoir characterization.

Seismic reservoir characterization involves integration of geologic and seismic data. The resulting reservoir model is based on lithological parameters estimated from well cuttings, core, and wireline logs. Geoscientists utilize the well, seismic, and other relevant data to derive the most realistic model of the reservoir. But the interpretation of reservoir characteristics is limited to filling the data gaps, in between the drilled wells, to fit into an appropriate geological model either by interpolation of geologic data or geostatistics. In either case, the final models of key petrophysical parameters are not always accurate and may typically differ from the real reservoir. The same set of sparse data may lead to a different set
of conclusions regarding the depositional processes and/or environment. Take for example the case of a braided river system with wells only on the flanks of the system. The conventional seismic interpretation may not help to demarcate the braided feature. From the wells, the most viable interpretation would be conceptualizing a two-channel system of the reservoir, thus excluding the major reservoir facies of the braided system. Even with high-density well data, identification of major sedimentological depositional structures along with any nondepositional features greatly helps the petrophysical delineation of the reservoir.

The conventional seismic resolution limit of one-fourth of the seismic wavelength (1 ms for a typical seismic survey) may not permit perfect estimation of the reservoir heterogeneities, in the absence of a well-defined geological depositional structure.

With the advanced computing power and portability of workstation software to the desktop, the current state-of-the-art reservoir characterization inadvertently includes volume visualization and geobody analysis, which enable exposure of information normally hidden in the data. This also facilitates creation of new insight into the geophysics interpreter’s mind and vision. Interpretation of structural and stratigraphic features of a reservoir using volume visualization and geobody analysis technique is widely accepted now because of its speed, accuracy, completeness, and efficiency of interpretation.

The objective of the present investigation is to critically analyze 3D seismic data of a clastic reservoir to analyze various seismostratigraphic sequences and geobody elements,
which in turn would help to identify, delineate, and demarcate the various reservoir subunits based on their depositional signatures and geological characteristics. In chapter 2, I first review the regional geological setting vis a vis basin evolution and reservoir architecture and characteristics to gain a first hand knowledge on the geological complexities that made the reservoir highly heterogeneous. In chapter 3, I then perform a seismostratigraphic analysis to understand the sequence stratigraphy of the reservoir, which helps in defining various sequence boundaries, thus helping to compartmentalize the reservoir into a set of 4th order sequences within the Miocene period. In chapter 4, I then perform volume-based visualization and geobody analysis to identify and delineate the seismogeomorphological features which play a major part in compartmentalization of reservoir facies in the reservoir. Finally, in chapter 5, I summarize the results of my investigation and discuss how this investigation may be extended further.
Chapter 2

Regional Geology

The initial geological observations of the San Joaquin Valley date back to the late 1800’s (Shedd, 1932). During the early 1900’s, due to the discovery of oil fields of McKittrick (in 1887), Coalinga (in 1887), and Kern River (in 1901), the geological study of sedimentary rocks in the valley gained momentum and the knowledge about its geology advanced as the oil exploration activities increased subsequent to these discoveries. The geological research progressed greatly after World War II due to increasing demand of crude oil and free exchange of scientific knowledge across the world (Bartow, 1991).

Hoots et al. (1954) published the first generalized review of the Cenozoic history of the valley, which was further updated stratigraphically by Repenning (1960) and Hackel (1966). Based on analysis of benthic foraminiferal faunas from marine Tertiary rocks from the southern part of the valley, Bandy and Arnal (1969) attempted to quantify the basin subsidence and uplift. Further research on these Tertiary marine sequences brought out an apparent synchronicity of depositional cycles on the eastern and western halves of the valley although both east and west sides show different types of depositional sequences and facies (Foss, 1972). In the last three decades, the focus of research has been directed towards the
tectonic mechanisms, which control the various aspect of the basin evolution (Nilsen and Clarke, 1975). Harding (1976) analyzed and linked the structural evolution of the west side folded complex to different phases of the growth of the San Andreas Fault. Other researchers have linked the origin of the San Joaquin basin to plate tectonic processes (Blake et al. 1978; Dickinson and Snyder, 1979; and Howell et al. 1980). Recent advances in sequence stratigraphy and global tectonic in light of plate tectonics play a major role in the continuing revision of the regional stratigraphy. The research and development based on these concepts have greatly advanced in understanding and identification of the timing of depositional events from widely separated and non-unique lithogroups of the San Joaquin basin (Bartow, 1991).

2.1 Geological Setting

The San Joaquin basin is a strike-slip basin and hence shows complex tectonics (Bridges and Castle, 2003). It is located in the southern part of the 700 Km. long Great Valley of California. It is an asymmetric structural trough with a broad, gently inclined eastern flank and a relatively narrow western flank, the later becomes a steep homocline in the northern part of the valley (Figures. 1 and 2). In the southern part, it becomes a belt of folds and faults. The basin trough contains Upper Mesozoic to Cenozoic sediments which reach over 9 Km. thickness in the west-central part of the valley and at the south end (Bartow, 1991). He believes that the basin was a fore-arc basin, which was mostly open to the Pacific Ocean on the west during late Mesozoic and early Cenozoic periods. During the late Cenozoic, the basin
was converted into a transform-margin basin. The sediments were deposited on a westward tilted basement of Sierra Nevada plutonic, mafic, ultramafics, and metamorphic rocks of Jurassic age (Cady, 1975; Page, 1981). Bailey et al. (1964) propose that towards the west of the valley, both Mesozoic and early Tertiary Great Valley sequences along with the underlying ophiolite sequences are juxtaposed with the Franciscan Complex along a the Coast Range thrust (Figure. 3).

The basin is separated from the Sacramento basin to the north by the buried Stockton arch and Stockton fault (Figure. 3). To the south, the basin is separated from the Maricopa-Tejon sub basin by the buried Bakersfield arch. Bartow (1991) observed that the Cenozoic strata in the San Joaquin basin thicken southeastwards from about 800 m. in the north (western part of the Stockton arch) to over 9,000 m. in the south (in the Maricopa-Tejon sub basin in the south). He also observed that the Mesozoic and early Tertiary Great Valley sequence thins out southeastward and is absent at the Bakersfield arch. Both arches had no appreciable structural relief but could contribute to this huge sedimentation during Cenozoic period due to basin tilting phenomena associated with regional thrusting and plate kinematics. The Tertiary depocenters of these basins coincide with the depocenters of the Pleistocene and Holocene basins (Buena Vista and Kern Lakes basins to the south and the Tulare Lake basin in the central part) of the Valley (Bartow, 1991).

The San Joaquin Valley is on the southern side of the Great Valley and Fall in the western Cordillera of North America. Although it shows discrete geomorphic and structural styles
similar to that of the western Cordillera, the geology is inherently variable in stratigraphy and structural styles of deformation due to various Cenozoic intermittent uplifts and subsidence associated with the evolution of the Valley (Bartow, 1991). The Neogene sediments mostly consist of a thick marine section in the southern part and a thin non-marine section in the northern part of the basin. In addition, from a structure point of view, there exists a complex folded system in the western side of the basin while the eastern side has a little deformed sedimentary due to differential tectonic process which caused a north-south tilting and a western uplift of the valley.

The basin is of great economic importance due to numerous oil fields (Figure. 1). Peters et al. (1994) have reported even oil seepages. A generalized stratigraphic column for the basin shows the stratigraphic position of source rocks and oil field/oil stain distribution (Figure. 4). Oil, seeps and stains are mostly concentrated between Eocene to Middle Miocene Formations with sporadic occurrences in Upper Cretaceous (Oil City) and between Mio-Pliocene to Pleistocene (Cymric oil field, Tulley and Cattle oil stain). Peter et al. (1994) observed that the source rocks were from Cretaceous, Eocene, and Miocene periods. They established that due to geological complexities experienced by the basin, there are wide variations in the organic content of the source rocks and mixed oil quality over the entire basin. The oil from northern part may be tied to the Eocene Kreyenhagen shales. In eastern side of the San Andreas Fault, the oil stain might have been generated by relatively low-matured Miocene McDonald shale (the equivalent of Monterey Formation). On the western side of San Andreas Fault, the Soda Lake Shale of the Vaqueros Formation might have been the source rocks. Peters et al. (1994)
suspected that the Moreno Formation might have contributed the source rocks for the Oil City oil seep.

A brief review of the regional geological complexities of the San Joaquin Valley, the tectonics and various controls on sedimentation is presented below to illustrate the tectonics and depositional complexities of the basin.

2.2 Tectonics and Major Controls of Sedimentation

The San Joaquin Valley consists of five different tectonic blocks (Figure. 3, Bartow, 1991). These are:

1) Northern Sierran Block (NSB),

2) Southern Sierran Block (SSB),

3) Northern Diablo Homocline (NDH),

4) West-side Fold Belt (WFB), and

5) Combined Maricopa-Tejon subbasin and South-margin deformed belt (M-TS).

The NSB, located between the Stockton fault and the San Joaquin River, lies on the east limb of the valley syncline (Figure. 3). It is the least deformed block of the valley with a southwest tilt of 1-2° and minor late Cenozoic normal faults.
The SSB, located between the San Joaquin River and the Bakersfield arch (Figure. 3) is similar to the NSB in terms of structural style. However, it is more deformed than NSB with a southwesterly tilt of 4-6° and shows Miocene/Pre-Miocene normal faults heading north to northwest with throws up to 600m at places.

The NDH, located between the Stockton arch and Panoche Creek, lies on the western limb of the valley and shows locally faulted homoclines with northeast dips. It includes the northeast flank of the northern Diablo Range (Figure. 3). This block represents a complex history of Cenozoic deformation caused by reverse faulting with dips ranging from 30 to 50°. Most of the folding is of Neogene age, a few are of Paleogene age. Evidence of post-Eocene uplift of the Stockton arch is observed from the fact that the Paleogene units truncate at the base of the Valley Springs Formation along the Diablo Homoclone. The presence of coarse alluvial fan deposits derived from the Diablo Range marks the beginning of the Neogene uplift of the Diablo Range during the late middle to late Miocene. But the principal Neogene uplift of the Diablo Range began during Pliocene and Pleistocene and resulted in forming the angular unconformity at the base of Tulare Formation (Bartow, 1985, Raymond, 1969).

The WFB comprises the southwest side of the valley (Figure. 3). It is located in between Panoche Creek on the north and the Elk Hills in the southwestern side. It includes the southern Diablo and the Temblor Ranges. The belt is characterized by Cenozoic faults and folds trending slightly oblique to the San Andreas Fault (NNW-SSE). In the northern part, the
folding occurred in the Neogene and its intensity increased southeastward along the belt and southwestward towards the San Andreas Fault (Bartow, 1991).

M-TS covers the region between Maricopa-Tejon sub basin and the south-margin deformed belt (Figure. 3). It is the most deformed part of the basin which had experienced a late Cenozoic shortening due to thrusting at the south margin and also due to significant Neogene subsidence north of the thrust belt (Bartow, 1991).

Sedimentation in the San Joaquin basin is mainly governed by tectonism, and to a lesser extent, by eustatic sea level changes and allocyclic factors like climate (Bartow, 1991). As a whole, the sedimentary record depicts the complex interplay of all of these factors. Thick sediments in the southern San Joaquin basin indicate the effect of tectonic subsidence. Moreover, the location of the basin along an active continental margin generated prolonged tectonic activity during the Cenozoic. Most of the marine sequences are unconformity bounded and are easy to correlate within the basin. In a few cases, the equivalent non-marine sequence may be correlated based on the position of the bounding surfaces.

Plate movements greatly influenced the tectonics and hence the evolution of the basin. A subduction zone has prevailed at the western margin of North America during Cenozoic times when the oceanic Kula plate subducted obliquely under the North American plate (Page and Engebretson, 1984). Bartow (1991) proposed that the rapid rate of convergence might have made this subduction zone to be of low angle. The fast convergence rate is also observed by
the presence of relatively displaced arc magmatism eastward from the Sierra Nevada into
Colorado (Lipman et al. 1972; Cross and Pilger, 1978). This oblique subduction at the central
California margin continued until end of the Eocene when the Farallon plate displaced the
Kula plate (Page and Engebretson, 1984). A decrease in convergence rates in the late Eocene-
Oligocene periods steepened the subduction zone and the volcanism, associated with the
subduction process, migrated southwestward from Idaho and Montana into Nevada (Lipman

2.3 San Andreas Transform

The evolution of the San Andreas transform plays a key role in shaping up the broad aspects
of regional geology and structural provinces.

A triple junction is the location where three tectonic plates are in contact with each other.
The boundary between any two of the plates can be either a spreading center (ridge), a
transform (fault), or a subduction zone (trench). The Mendocino triple junction (MTJ) and the
Rivera triple junction (RTJ) were formed about 30 Ma ago off the coast of Northern
California because of geometrical consequences of the motions of three tectonic plates, the
oceanic Gorda plate, the oceanic Pacific Plate and the North America Plate (Figure. 5,
Atwater, 1970; Furlong and Schwartz, 2004). The MTJ created a trench and two fault
systems. The Gorda Plate subducted under the North America plate to the east along the
Cascadian Subduction Zone to make the trench. The right-lateral Mendocino Fault developed at the boundary between the oceanic Pacific Plate and the relatively younger oceanic Gorda plate. Another right-lateral transform fault system, famously known as the San Andreas Transform, originated because of the collision of the East Pacific rise with the North America plate during subduction (Engebretson et al. 1985). The migration of the MTJ northward along the central California coast coincided well with pulses of initial subsidence in Neogene sedimentary basins near the continental margin and with eruptions at local volcanic centers in the Coast Ranges (Dickinson and Snyder, 1979). The northern end of the San Andreas Transform terminated at the MTJ. The RTJ moved southeastward and created a ridge-trench-fault system, which formed the California Continental Borderland and the Gulf of California.

The transform gradually lengthened as the MTJ and RTJ migrated northwestward and southeastward along the continental margin due to an unstable configuration. The configuration was instable because the prior trench and newly developing transform were not collinear (the trend of the 3 plate boundaries did not intersect at a single point). It induced a series of extensional tectonic events (Dickinson and Snyder, 1979; Ingersoll, 1982). The motion of the Pacific plate changed to a northerly direction at about 5 Ma which gave generalized compression normal to the San Andreas Transform (Minster and Jordan, 1984) contributing to compressional deformation at the western side of the San Joaquin Valley (Bartow, 1991).
2.4 Other Tectonic Factors

Beside plate tectonics, there are other regional tectonic events which also influenced the evolution of the San Joaquin basin (Bartow, 1991).

A clockwise rotation of the southernmost Sierra Nevada as evident in paleomagnetic data produced large en echelon folds in the southern Diablo Range related to Late Cretaceous and early Tertiary right-lateral strike-slip movement on the proto-San Andreas fault (McWilliams and Li, 1985; Harding, 1976). The proto-San Andreas fault is a large-scale shear zone, developed to accommodate the right-lateral motion of the Farallon plate during it’s subduction under the North America plate. Twisting and wrenching along the plate boundary resulted in the formation of a series of ridges and basins along the California coast (Bartow, 1991). Transgression and regression took place in the basins due to this tectonic force which caused the basins to rise and subside periodically. Also, large volume of sediments from the ridges were deposited in fluctuating depositional environments – from deep, offshore marine to shallow, near shore marine, and even erosional surfaces as the basin floor must have risen above the surface of the ocean at different times.

The tectonic effect caused by the accretion of Tujunga terrane to the North American craton (in Mojave region) during the late Paleocene might have accelerated the formation of the echelon folding (Harding, 1976; McWilliams and Li, 1985). The uplift of the Stockton
arch in the early Tertiary served as a provenance (source location of sediments) for the Cenozoic sediments (Hoffman, 1964).

Before the actual arrival of the Pacific spreading ridge (East Pacific Rise) near the North American plate subduction boundary, the younger buoyant lithosphere component associated with the ridge was subducted in the southern part of the California during mid-Oligocene time. This event had an effect on the southernmost San Joaquin basin as it resulted to a regional uplift of southern California and formation of fault-bounded alluvial deposition contributed to the growth of the basin (Nilsen, 1984; Crowel, 1987).

The extensional tectonism in the Basin and Range provinces due to faulting in the Miocene age caused by the westward movement of the Sierra Nevada block had an effect on evolution of the San Joaquin basin. The arch-trench system on the plate boundary was developed due to the extensional stress regime in the Oligocene age. The transition from compression to intra-arc extension took place as the subduction angle steepened due to increased overburden hydrostatic pressure in the deep lithosphere. The intra-arc extension was replaced by the back-arc extension probably due to a change in direction of subduction and the southwestward migration of the eastward limit of the subduction-associated magmatism. The intra-arc and the back-arc extension were oriented at right angles to the subduction plate boundary and might have contributed to the compression of the San Joaquin basin (Zobak et al. 1981). During late Miocene, due to the associated Basin and Range left-lateral faulting, the basin shifted westward and created a bend in the San Andreas Fault which caused a change in
structural style and varied rate of sediment deposition in the basin (Bohannon and Howell, 1982).

The Neogene wrench tectonism due to a deep-seated thrusting along the southwest side of the basin near the San Andreas Fault gave rise to a series of en echelon folds, which deformed the San Joaquin Miocene deposits into a series of anticlines and synclines. The structural styles and the geometry of the Miocene sedimentary deposits within the San Joaquin basin varied spatially as evident in the stratigraphic records (depositional hiatus, provenance and spatial distribution of degree of sediment load within the Temblor) near the end of Saucesian time (Harding, 1976; Bridges and Castle, 2003). The depositional facies and structural styles of various hydrocarbon trap formations of the oil fields located in the western side of the San Joaquin basin were governed by this tectonism (Beyer, 1995, Graham, 1985). In stratigraphic records, synsedimentary deformation is reflected in the distribution, facies and sedimentary packaging of strata due to the presence of local unconformities within the Temblor formation might have been the effect of the Neogene wrench tectonism (Graham, 1985).

The deep-seated Cenozoic thrusting in the west side of the Sierra block due to northeastward movement of a wedge (an accretionary prism deposit located just below the north American plate at the subduction zone) of the Franciscan complex, between the Great Valley sequence and crystalline basement initiated the Cenozoic activity in the Coast Range thrust (Wentworth et al. 1984). The Franciscan complex contains mélanges of sedimentary rocks, serpentinite, and blueschist in a sheared matrix and fine greywacke derived from the
top of the Farallon plate as escarpment during the subduction process. The Great Valley sequence consists of layered sedimentary sequences derived from volcanic sources deposited in the fore-arc region toward east (Wentworth, 1985; Wentworth et al. 1984; and Hoots et al. 1954).

The latest uplift of Sierra Nevada is believed to have taken place during the late Miocene period due to thermal thinning of lithosphere below Sierra Nevada. The lithosphere thinned as the subduction zone associated with the Mendocino triple junction passed northward (Mavko and Thompson, 1983). The acceleration in the San Andreas Fault slip rate during this period further deformed the already folded Sierra Nevada. The process contributed to the rapid subsidence of the southern San Joaquin basin in the late Miocene period (to maintain isostacy) and shaped the evolution of the San Joaquin basin as lot of space was created to accommodate sediments (Dickinson and Snyder, 1979; Davis, 1983). Furthermore, fault-normal compression in the early Pliocene (5 Ma) generated many folds and reverse faults parallel to the San Andreas Fault to accommodate the resulting strain (Zobak et al. 1987). Engebretson et al. (1985) opined this compression might be the cause for the uplift of the Temblor and the Diablo Ranges, which formed the oil fields of the basin shallower.

The San Joaquin basin was formed at the end of the Mesozoic on the southern part of an extensive forearc basin associated with the subduction of the Farallon plate under the North American plate. During the Cenozoic, the basin was gradually transformed into the present day hybrid intermontane basin. The geologic processes comprised a gradual restriction of the
marine influx to the basin due to uplift of the northern part of the basin in the late Paleogene period. In the Neogene period, the marine influx towards the westside of the basin was partially cut off due to uplift of the Diablo and the Temblor Ranges (Bartow, 1991; Harding, 1976). During late Neogene and Quaternary, the fluvial to lacustrine sediments were deposited in the basin (Marchand, 1977; Marchand and Allwardt, 1981).

2.5 Subsidence history and Paleobathymetry

The Cenozoic subsidence history of the San Joaquin basin in relation to regional tectonics is not well studied (Bartow, 1991), except that it may be inferred from paleobathymetry data and from the present day characteristics of different stratigraphic units such as basinward-thickening trends of various strata. The studies by Dickinson et al. (1987) and Olson et al. (1986) suggest that the rapid subsidence periods may have occurred in late Paleocene-earliest Eocene, middle Eocene, latest Oligocene-early Miocene, and middle-late Miocene. Uplifts occurred during the Oligocene and between the early to middle Miocene period (Bartow, 1991). A thorough analysis of these rapid subsidence events may help in formulating the geohistory analysis, which may help in reconstructing the history of the basin evolution at different geological ages. In addition, the subsidence analysis may help in correlating the resultant sea level changes which control the rate and amount of sedimentation in the basin.
Figures 6(a) to 6(j) depict the succession of the regional paleobathymetry trends from late Paleocene to Pleistocene in the San Joaquin basins, as compiled from published maps and modifications based on recent sedimentological and stratigraphic data (Bartow, 1991). Bartow (1991) constructed these maps based on palinspastic reconstruction assuming 305 km. of Neogene right-lateral slip of the San Andreas Fault (Graham, 1978) and an unspecified amount of early Paleogene right slip on the proto-San Andreas Fault (Clark et al. 1984).

2.6 Eustatic Sea-level Changes

The early Cenozoic sedimentary history of the San Joaquin basin is characterized by extensive basin wide spread of depositional sequences. During the late Cenozoic period, localized shorter duration thin sequences were also deposited. The change in styles of deposition took place during the Oligocene when the convergent continental margin was transitioned into a transform margin. The effect of tectonics (subduction and proto-San Andreas fault related) had greater influence on the Paleogene basin history than the change in eustatic sea level (Bartow, 1991). Bartow observed the regression at the end of the upper Paleocene-lower Eocene may be inferred from the global sea level fall as it created a wide-spread unconformity that can be correlated to several areas of Europe and hence, may be attributed to global eustatic sea level falls rather than tectonism. Based on reviews of structural and sedimentological analyses of the basin outcrops by several researchers, Bartow (1991) opines that all other Pleogene regressions may be the effect of falls in eustatic sea level. During the
Neogene, the eustatic sea level effects are less apparent except for a middle Miocene highstand which resulted in wide spread transgressions in the San Joaquin basin (Graham et al. 1982; Haq et al. 1987).

2.7 Climate

The climate, along with tectonic processes, and sea level changes, play an important role for sediment composition (facies) and deposition. The climate affects the rate and amount of deposition in any basin. In an arid climate, the rate of sedimentation is slow which contributes to deposition of thin stratigraphic units. In a wet climate as the water discharge to the basin is more, thicker stratigraphic units are deposited in the basin.

The San Joaquin basin experienced warm global climates in the Late Cretaceous, which changed into a cool glacial climate in the Quaternary. The Eocene experienced the warmest climates due to a low latitudinal temperature and high precipitation (Frakes, 1979). In the Oligocene, the glacial condition prevailed in Antarctica which caused a decrease in sea water temperature and led to a cooler global climate. Temperatures warmed to a lesser degree as that of the Eocene during late Oligocene, Miocene (Addicott, 1970). In the late Pliocene, the Sierra Nevada experienced the effect of the alpine glaciations (Frakes, 1979).
The occurrences of quartz-kaolinitic sandstone, lignite, and laterites in the Eocene reflect the prevailing warm and tropical climate condition (Bartow, 1991). The sedimentation from glaciers in Sierra Nevada constituted the San Joaquin basin alluvial sediments during the late Pliocene. The pluvial climate of the Pleistocene contributed to the creation of a series of lakes in the San Joaquin Valley (Bartow, 1991).

The preceding discussion on the role and effect of various geologic processes including the effect of plate movements that acted to shape up the evolution of the San Joaquin basin from Cenozoic to Neogene clearly indicates the structural, sedimentological and depositional complexities that the basin had experienced in the geological past.
Chapter 3

3  Study Area

My study area lies in the southern part of the ChevronTexaco’s West Coalinga oil field in California (Figure. 7). The aerial extent of the study area is about 1 x 3 miles out of the field total of 2 x 14 miles. My study focuses on identification and delineation of various geologic depositional process features within the Temblor reservoir of the West Coalinga field. I use 3D poststack seismic data merged from volume of different seismic volumes, which were acquired independently between 1996 and 2000. I analyze the merged poststack seismic data to ascertain sequence stratigraphic, paleogeomorphic depositional features and their spatial distribution over the area of study.

3.1  Coalinga Heavy Oil Field

Coalinga is a giant oil field in the San Joaquin valley of California with an extremely complex subsurface stratigraphy that has produced over 850 million barrels oil (MBO) of API gravity 20\(^0\). It is a mature oil field with an abundance of core and seismic data. The field has been oil and gas producing from the clastic Temblor formation (Miocene) since the early 1900’s, and is now in its tertiary development stage. The Coalinga anticline is one of a series of echelon folds that modify the generally homoclinal eastern flank of the Diablo range along the west
side of the San Joaquin Basin of California (Figure. 8). The reservoir units are cropping out few miles to the north of the reservoir (Bridges and Castle, 2003).

The Coalinga field is divided into East Coalinga and West Coalinga based on the structural set up (Figure. 9), which influences production and distribution of producing wells. A northwest-southeast trending anticline (Coalinga nose) separates the two fields. The nose and its eastern part crosses regional strike and extends about five miles along the southeast plunge of the nose (Clark et al. 2001b). The West Coalinga field parallels the upturned, monoclinal west margin of the basin.

The field is part of the Kreyenhagen-Temblor petroleum system that derives oil from organic-rich shale of the Middle Eocene Kreyenhagen Formation (shale) as observed from the geochemical data analysis of the Kreyenhagen 74X-21H well (Peters et al. 1994). The reservoir trap is stratigraphic in nature. The reservoir rocks outcrop at the west margin where historical oil seeps and breaches were reported. The tight outcrops and solidified tar mats in the near surface of these outcrops provide the sealing mechanism (cap rocks) of the Temblor reservoirs (Figure. 10). The accumulated heavy oil is produced by steam injection which fractionates the high-gravity oil beneath these sealants into low-gravity crude (Clark et al. 2000). At places, shales and calcite-cemented sandstone in the upper part of the Top Temblor (C-sand of Bates, 1985) create an effective top seal in the reservoir (Clark et al. 2001b). The reservoir rocks are highly heterogeneous due to its proximity to the tectonically disturbed San Andreas transform.
3.2 Reservoir Characteristics

The Temblor Formation sandstone contributes 90 percent of the total oil production as of 2001 (Clark et al. 2001b). The average well depths range from 500 to 4500 feet. As of 2001, the total number of wells was 4000. The reservoir shows an average porosity of 0.34 and permeability ranging from 20 to 4000 millidarcies. The reservoir is about 700 feet thick in the east margin of the field (down dip), but gradually thins towards west as it is truncated by the overlying Etchegoin Formation, which is a Pliocene oil producer. The reservoir rocks crop out along the west margin of the field. The oil seeps on the outcrops which were the pathfinder for the discovery of the field, ceased flowing as the field underwent development. Presently, about 2000 wells are under production by steam injection. About three to four barrels of steam are being pumped into the reservoir for every single barrel of oil recovery. The field requires more steam to be injected to produce oil than most other heavy oil reservoirs in the San Joaquin basin due to its geological complexities (Clark et al. 2001b).

3.3 Production History

The first producing well, known as “Wild Goose”, was drilled in 1887 in the northwestern part of the field near the tar seeps of Oil City. The well penetrated a fractured Cretaceous section and produced ten barrels of oil per day (BOPD). The well “Blue Goose” in the Oil
City shale produced about 1000 BOPD in 1897 (Clark et al. 2001a), but the fractured reservoir declined rapidly and explorationist’s attention was drawn to the Temblor sandstone in the Coalinga Nose anticline on the east side of the field and towards the west of Coalinga in the homoclinal limb. The prolific producing well, known as “Silivertip” (10,000 to 20000 BOPD), was drilled in 1909 (Arnold and Anderson, 1910; Kaplow, 1945). Production from the field reached 53,500 BOPD in 1912, but gradually declined to 9,000 BOPD during 1930s. Most of the wells produced a few barrels of heavy oil (10-20$^\circ$ API gravity) per day. Extensive drilling activities during World War II increased the production figure to 29,000 BOPD, which declined gradually until Shell Oil Company started with steam injection in 1961 (Clark et al. 2001a). The tertiary recovery phase started in 1979. With a dramatic increase in the steam injection rate, the crude oil production figure reached 34,000 BOPD in 1991, but the annual production figure kept on fluctuating depending on the steam injection activities (Figure. 11). As of 2001, the field was producing about 25,000 BOPD of oil from 2000 wells with a steam injection of 80,000 barrels per day (Clark et al. 2001b).

3.4 Reservoir Architecture

Reservoir architecture of a field describes the producing reservoir as well as the non-productive rocks in three dimensions. Two components describe the architecture. The first one deals with the structural and stratigraphic aspects of geological chrono-stratigraphic surfaces and the second component demonstrates the litho-facies distribution between these surfaces.
The time-significant surfaces cover sequence stratigraphic elements such as down lap truncations, flooding surfaces and regressive unconformities. These surfaces are better characterized on seismic data than on a geological model because 3D high-resolution seismic provides data without gaps over long scales. The litho-facies distribution results from mapping of rock-facies from well, cores and outcrops. Generally, they are interpolated over the field area based on some geological concepts and modeling. However, forward modeling of well data to interpret seismic data and/or their inversion with the help of well data to ascertain the geological parameters/signatures, along with the use of these geological data, often helps in identifying the litho-stratigraphy of a field with a greater degree of confidence. Properly delineated reservoir architecture helps in planning and execution of field development and production.

The Temblor Formation represents the interplay of shallow marine and non-marine depositional environments. The clastic shallow, unconsolidated reservoir is very heterogeneous in nature, as it is mostly bounded by unconformities. Outcrop and well data analysis identifies the Temblor Formation as an upward deepening depositional succession. Geological studies of outcrops, cores and gamma ray log (Bridges and Castle, 2003) showed that the reservoir is subdivided into three distinct depositional environments representing a near-shore fluvial dynamic depositional setting intermingled with depositional erosional hiatuses. Figure 12 shows a generalized stratigraphy of the Coalinga area. The Temblor formation (lower to middle Miocene) overlies the Kreyenhagen crystalline clastics of Eocene. The base of the Temblor is formed by an unconformity (Base Temblor) representing a time
period of 21 million years of non-deposition and aerial exposure (Bate, 1984; Bartow, 1991). The Base Temblor unconformity is considered equivalent to the bounding surface 1 (BS-1) of Bridges and Castles (2003) classification. This regionally extensive Base unconformity was the result of a low relative regional sea level (lowstand) in the basin due to tectonic uplift (Bridges and Castle, 2003). The top of the Temblor is demarcated by a regional angular conformity (Top Temblor) equivalent to BS-6 of Bridges and Castle (2003). The Santa Margarita Formation (upper Miocene) overlies the Temblor in the north. To the south, the Etchegoin formation (Pliocene) overlies this unconformity because the Santa Margarita Formation was eroded out. The Top Temblor unconformity represents a period of 5 million years of non-deposition and erosion (Bate, 1984; Bloch and Graham, 1991) caused by the tectonic uplift of Diablo Range (Harding, 1976; Bate, 1985). Based on litho-stratigraphic correlation and facies tract analysis, a regional unconformity (Button unconformity) demarcates the reservoir facies deposited on top of the Base temblor. This unconformity is equivalent to BS-3 (Bridges and Castle, 2003), a transgressive depositional lag with a base of Oyster bed which separates the shoreline facies “Button Beds” (Bridges and Castle, 2003) from the underlying lowstand and estuarine facies. The reservoir on top of the Button unconformity is overlain by the Valv unconformity identified by the presence of a diatomite bed right underneath (BS-5 of Bridges and Castle, 2003). The Valv unconformity was formed as a response to uplift caused by the beginning of rapid movement along the San Andreas Fault (Casey and Dickinson, 1976).
The surfaces BS-2 and BS-4 of Bridges and Castle (2003) are based on the facies changes observed in the sedimentological analysis of cores, outcrops, and the presence of barnacle shells there in. The formation thickness bounded by these surfaces are relatively thinner and are not being considered for the present seismic analysis as it is difficult to map these thin sequences on the seismic data.


Bridges and Castle (2003) carried out extensive analyses of cores and outcrops around Coalinga field and formulated five facies tracts. They attributed relative rise in sea levels caused by basin subsidence during the Temblor deposition to the occurrence of these facies tracts and attributed the cause of subsidence to the regional tectonic extension related to strike-slip movement associated with the San Andreas transform. The incised valley fill (IVF) facies tract was deposited on the Base Temblor unconformity on incisions into the Kreyenhagen Shale during the lowstand period. This tract was overlain by an estuarine facies caused by local subsidence and rapid sedimentation (Figure 13). The basin then experienced deposition of tide- to wave-dominated progradational facies on top of the Buttonbed unconformity probably due to the uplift of the Diablo Range (Hoots, 1954) and the associated relative sea level changes on the east side of the San Joaquin basin (Bloch, 1991). Diatomite were deposited above the tide to wave facies in brackish to shallow marine environments as a
The four unconformities (Base Temblor, Buttonbed, Valv, and Top Temblor in ascending order) described above play significant roles in the distribution and flow of fluids in the reservoir. The changes associated with the above facies tracts render the reservoir highly heterogeneous and highly variable in porosity and permeability distribution. Earlier research to delineate the reservoir focused more on borehole or exposed outcrops in the northern part rather than a detailed seismic integrated approach (Clark et al. 2001b). With the absence of extensive data continuity over the field, the gaps were filled by conceptual modeling which in some cases may introduce biased or inappropriate views (Clark et al. 2001b). The thicknesses between the three facies tracts within the Temblor Formation vary over the field due to the presence of dynamic paleo-topography of the basin caused by varying degrees of tectonic uplift and differential amounts of sedimentation through out the period of deposition and erosion. The seismic characters of these unconformable surfaces are subtle in nature and are easily overlooked in the field area without prior stratigraphic knowledge based on cores and outcrops (Clark et al. 2001b). I integrated the continuous 3D seismic data with the geological
data to verify, analyze, and map spatial distribution of these unconformities in the reservoir for a meaningful reservoir characterization. I looked for paleogeomorphic and depositional features on the seismic data which were the preserved resultants (features) of the various tectonic forces that acted on this complex strike-slip reservoir in the geologic past. I ascertained the lithology distribution of those features. My research may help future reservoir-flow-simulation studies for tertiary recovery of the Coalinga field, for example, by building advanced litho-stratigraphic models of the reservoir.
Chapter 4

Seismic Details

As discussed in chapter 3, during tertiary recovery phase of the field, about four barrels of the steam volume are injected to recover one barrel of crude oil. This may be due to the field’s inherent complex stratigraphy which makes it difficult to properly ascertain and delineate the spatial distribution of litho-facies and permeability. Without characterization of reservoir geometry and inter-well connectivity at adequately short scales, a lot of steam is wasted as steam injection is not confined to the development block. To gain a better understanding of the complex reservoir stratigraphy and a more accurate delineation of the reservoir, a number of 3D seismic surveys were carried out over the field between 1996 and 2000 (Figure. 14). A first 3D seismic survey covering about one square mile over section 36D towards the southern part of the field was obtained in 1996. This survey was designed to be a pilot study for data acquisition and quality control, but it was also intended to serve as a baseline for future time lapsed seismic surveys. A vibroseis source with a frequency range of 10-70 Hz was used for most of the survey. However, in the areas with complex topography or other access problems, dynamite sources were used instead. The frequency range between 25 and 30Hz was deemed the best and declared the desirable range for the upcoming surveys (Clark et al. 2001b). The second survey, covering an eight square miles area with the same acquisition parameters, was carried out in 1997. This
survey also overlapped with the first one over section 36D to study the effect of one year of steam injection into the block. The third survey in 1998 covered an area of two square miles over the north of the field. The subsequent 3D surveys in 1998 mostly covered the area towards the northern half of the field. Two additional 3D seismic surveys were carried out in 2000, covering both northern and southern parts of the field to provide a 4D seismic coverage for time lapse analysis.

The study area for my project covers sections from 36D, 25D, and 24D (Figure. 14). My 3D seismic data set is a merged poststack data cube from all these surveys. The CDP spacing is about 60 feet and the data set consists of 2,263,483 traces.

4.1 Effect of steam on seismic

The seismic surveys were carried out over the field while steam was being injected intermittently in the reservoir. Thus, the acquired seismic data are affected by the presence of varying proportion of steam in the reservoir. The reservoir rocks exhibit dramatic spatial and temporal changes in pore pressure, temperature, and fluid saturation due to the presence of steam (Ito et al. 1989; Wang and Nur, 1989). The temporal and spatial variations in rock properties cause seismic wave field distortions throughout the steamed regions of the reservoir. For the same formations, seismic impedance contrasts vary largely because of the presence of trapped steam, which causes misleading seismic reflections and diffractions.
The heated steam also influences amplitude variations in reflections because of the major velocity contrast in the reservoir where steam saturated (hot), oil-water saturated (cold) sandstone, or mudstone/shale are juxtaposed.

Velocity pull-down in seismic images associated with the thermal effects and amplitude focusing or attenuation is commonly observed. Detection and mapping of these changes may throw light on as of today oil distribution and fluid flow pattern over the area. This in turn may indicate the presence and continuity of porous and permeable zones in the reservoir which may allow optimization of the reservoir production strategy.

Variable vertical and lateral steam injection severely affects the seismic interpretation. Amplitude variability resulting from steam injection makes time-depth correlation difficult, as precise well to seismic ties are seldom possible. The wireline logs are recorded at different times during the development of the field with different generations of well logging technology and varying calibration of logging equipment. Also, the well logs recorded during and after the intermittent steam injection are affected by the presence of steam in the formation as steam trapped in the formation may affect the resistivity, porosity and interval velocity response of the reservoir rocks (Butler and Knight, 1995). The seismic data are also recorded at different times having differential effects of steam. Thus, the ties between data and well logs become problematic and vexing. The identification of sequence stratigraphic elements like offlap, onlap, and truncation analyses on seismic data becomes perplexing due
to the discontinuous nature of the reflector pattern and the associated dipping events. The problem is further complicated when the reservoir is comparatively thin, for example, in the Temblor formation.

4.2 Effect of merged data set

My data set is a merged from four different 3D seismic surveys carried out between 1996 and 2000 with overlapping areas. Each data set was acquired after injection of varying amounts of steam into the reservoir and with varying sources (vibroseis or dynamite). Signal-to-noise levels vary between surveys. Moreover, the static corrections applied to each of the 3D data sets during prestack processing may be different and inconsistent between surveys. There may be also differences in location of inlines and crosslines between surveys.

The oil production along with steam injection also affect the interval velocity of the reservoir rocks as after oil production, the depleted reservoir is saturated with a mixture of light hydrocarbon gases, carbon dioxide and monoxides, nitrogen and sulfur gases. These zones may behave like an air-saturated lithology which affected the velocities, amplitudes, and reflections.

I observe that the reflectors are very discontinuous in the merged data set (Figures. 15(a)). These discontinuities may be due to either the geological complexities associated with
multistoried, stacked, and restacked channels with their changing depositional directions, as identified in subsequent chapters, or the effect of steam and oil depletion. I observe that the reflection and amplitude strength over the area is profoundly erratic and discontinuous in places that may be attributed to the effect of periodic steam injection activities during successive seismic data acquisition between 1996 and 2000. The reflectors in the central part of my study area between the upper 36D and lower 25D sections are more discontinuous by geology, which rendered interpretation very challenging and time consuming as reflector mapping was difficult and loop closing contradicts geological expectations in some places. The problem gets more pronounced where reflectors merge, for example, the merging of the Buttonbed and the Valv unconformities in the western part of the area at the boundary of sections 25D and 36D (Figure 19). The data set falsely suggest a heavily faulted environment. The significant static break due to a decrease of the interval velocity near the top of section 25D may be attributed to an excessive amount of steam that was placed into this section (William Kempner, 2003, personal communication), which caused a delay in time arrivals. The steam effect is further evidenced by the fact that all the reflectors above the reservoir look fairly stable, but inside the reservoir, there is a shift of about 100 ms for certain reflectors which gives the false impression of a faulted area. In addition, there is a significant static and frequency change observed at the boundary between sections 24D and 25D due to steam effect. A similar change is observed between sections 25D and 36D. I also observe that there are reflector misties between inlines and crosslines at these boundaries which become more pronounced toward the western edge of the area (Inlines 95 to 70).
I developed a novel technique (Mahapatra et al. 2003b) to solve some of the above difficulties associated with my merged data set which will be discussed in chapter 5.
Chapter 5

Seismostratigraphic Interpretation

I correlated density and sonic wireline logs of twenty-seven wells (Figure 16). The reservoir rocks show vertical variations in degree of sediment compaction trends. Shifting of the shale base lines is observed with respect to each unconformity bounded formation. The neutron porosity logs were examined where the exact picking of the unconformity was doubtful in density and sonic logs as variation in compaction factor also affects the porosity values. I identified the four unconformable surfaces (Base Temblor, Buttonbed, Valv, and Top Temblor) based on the shale base trend line shifting (Figures 17 and 18). The time equivalents of these unconformities were posted onto the poststack 3D seismic data. While trying to map these surfaces on the seismic data, I observed severe misties and reflector discontinuities on the seismic sections because the 3D data set was actually merged from different surveys acquired at different times in a geologically complex area with multiple phases of steam injection. Mapping these unconformity reflectors is problematic. Reverting to reprocessing the data was deemed too time consuming and beyond the scope of the present investigation. Instead, I developed a novel technique to aid the interpretation (Mahapatra et al. 2003b). I map a deeper, relatively continuous reflector and flatten it. The misties in the overburden are reduced considerably on this flattened volume and the continuity of the four unconformities within the reservoir is improved (Figure.
The flattened volume with appropriately time-shifted wireline data allows interpretation of the unconformities in the original discontinuous seismic volume.

After applying the flattening technique, the fourth-order unconformities within the Temblor formation were mapped on the seismic data. I confirmed that the reservoir is compartmentalized into three major vertical chronostratigraphic sequences (Figure. 19). In the western part of the study area, the Buttonbed and Valv surfaces appear to be merging which implies that a portion of the Buttonbed unconformity has been eroded by the overlying Valv unconformity (Figure. 19).

I observed the strike of the Temblor formation to be NNE-SSW. The two-way time thickness of the Temblor formation is between 240-260 ms (130-150 ms, 30-40 ms and 35-40 ms respectively for the formation confined between the Base Temblor and the Buttonbed, between Buttonbed and the Valv, and between the Valv and the Top Temblor). I also observed that the highest structural relief is towards western part of the study area.

In seismic data, offlap, onlap, and reflector truncation are observed against the unconformities (Figures. 20 and 21) which allow their identification as sequence boundaries. The zone between Buttonbed and Basal Temblor surfaces contains a multitude of channel cuts (Figure. 21). In the lower central part of the study area, these channels appear to be re-cut and re-stacked which is more prominently observed in the dip direction (Figure. 21). The depositional direction seems to be slightly changing over the field for different geologic time of deposition.
(from NW-SE to SW-NE). There is also a reflector mismatch when following reflectors from the north or the south, which may be an effect of the steam injection, statics, or data merge.

The seismostratigraphic analysis helped me to compartmentalize the unconformity-bounded reservoirs based on the wireline log analysis and unconformity-reflector mapping on the seismic data. The identification of various sequence stratigraphic elements (offlap, etc.) greatly helped me in mapping the unconformity at places where the reflections are distorted. It also helped in confirming the correctness of my reflector mapping and the presence of these fourth-ordered unconformities within the reservoir. The analysis of reflector trends and chronostratigraphic sequences enabled me to ascertain the geological picture of the reservoir rocks such as the strike and variation in the depositional direction of these sequences.
Seismogeomorphic Interpretation

6.1 Seismic Attributes

Seismic attributes are useful to help the qualitative interpretation of the seismic data. Seismic attributes are derived from basic seismic measurements. The attributes are useful to ascertain structure, lithofacies, and reservoir parameters of a field as attribute properties significantly vary with variation in lithology, geometry and structural pattern of deposition of various lithofacies in an area. The basic attributes may be grouped into the following classification (Brown, 1996).

- **Time-derived:** provide structural information.
- **Amplitude-derived:** provide stratigraphic and reservoir information.
- **Frequency-derived:** provide additional useful stratigraphic and reservoir information.

In addition, P- and S-wave attenuation is used to determine the nature of fluid in a reservoir (well logging) and may even throw some light on permeability. Most attributes are derived from poststack data, although prestack data allow computation of amplitude versus offset (AVO) which allow determination of fluids. The poststack attributes can be extracted
along one horizon or summed up over a window or formation. The values within a window may be taken as a whole representing gross attribute measurement or at selected time intervals within it. Hybrid attributes are generated by the combination of amplitude and frequency information. There are numerous attributes developed by considering varying contribution of different seismic parameters. Most of these are designed to suit a distinct geological setting. The use of various color schemes and illumination techniques for data display make attributes more accessible to the interpreter. The development of interactive workstations with visualization software has opened up a vast scope for development and application of seismic attributes.

Acoustic Impedance:

Acoustic impedance is defined as the product of velocity and density of rocks. The velocity may be a prime indicator of lithology in most of the cases. Although sonic log and seismic data give a fair estimate of velocity, a high-resolution velocity estimate is difficult to be measured precisely as it is affected by variation in density, pressure and temperature variation inherent to any litho-unit. Density of a litho-unit unit yields information about the lithology, fluid saturation, and reservoir parameters like porosity and fluid/gas occurrence and distribution. The product of density and velocity will serve a better lithology contrast and hydrocarbon/formation water indicator. A synthetic impedance seismogram is computed from sonic and density wireline logs. This seismogram is used to compute an impedance cube from seismic amplitude data by seismic inversion (Liner, 1997).
Coherence and Continuity:

The attributes measure the degree of similarity (continuity) or dissimilarity by using a variety of mathematical approaches similar to correlation (Marfurt et al. 1998). The attribute highlights discontinuities which may be the result of faulting or sedimentological depositional features including channel, levee, etc. Coherency is often studied on time or horizon slices. This attribute is free from interpreter biasness as it is computed for entire data volumes instead of interpreted horizons. Faults and channels are clearly distinguished in coherence time slices (Figure. 22, Bahorich and Farmer, 1995). It is different from the normal time slice in that the structural features are visible irrespective of the time slice orientation (strike or dip). The fault display resolution is better as the continuity attributes involves repeated simultaneous cross correlation calculation, yielding related attributes such as dip and azimuth of the correlation (Brown, 1996).

Dip:

The dip magnitude is a time derived horizon attribute which often brings out structural details like faults (Dalley et al. 1989). On the high precision automatically tracked time surface, time values are considered in relation to their immediate neighbors to form a local plane. The dip of that local plane is the attribute dip and its direction is considered the dip azimuth (Brown, 1996). Selective color display is chosen to suppress noise in the display. The dip/azimuth attribute can be used to control the performance of an autotracker and to establish further
structural details. A dip-azimuth combination attribute combines both the attributes in one display. A radial fault pattern may be identified with the help of this attribute. Coherence dip/azimuth is computed by comparing dip/azimuth around any reference trace to that of adjacent trace. Coherence is calculated for a range of dips within a small analysis window around a reference trace. The dip/azimuth combination that has the highest coherence is assigned to be the instantaneous dip/azimuth for the point at the center of the analysis window (Nissen, 2000).

Instantaneous attribute:

Instantaneous attributes concisely and quantitatively describe wavelet shape at any sample point. Instantaneous attributes are computed sample by sample, and show instantaneous variations of various parameters. Instantaneous attributes such as trace envelope, its derivatives, frequency and phase may be determined from complex trace analyses (Taner et al. 1979). The instantaneous attributes of amplitude, phase, and frequency at the peak of the trace envelope (known as wavelet attributes) provide a way of representing the size and shape of a reflection. For example, instantaneous frequency at the peak of the envelope is equal to the mean frequency of the wavelet amplitude spectrum and Instantaneous phase corresponds to the intercept of phase of the wavelet (Taner, 2001).

The instantaneous amplitude gives a measure of reflection strength (magnitude) and often serves as a lithology identifier. The instantaneous phase gives the polarity and symmetry
characteristics (a good indicator of lateral continuity). The instantaneous frequency is the time derivative of phase (Cohen, 1995; Barnes, 1991). The instantaneous frequency attribute responds to both wave propagation effects and depositional characteristics and can be used as an effective discriminator (Taner, 2001). It is a possible indicator of hydrocarbon and fracture zone (low frequency anomaly). Often higher frequencies indicate sharp interfaces such as exhibited by thinly laminated shales. Lower frequencies are indicative of more massive bedding geometry, e.g. sand-prone lithologies (Taner, 2001). He observed that in case of a thin bed “instantaneous frequencies jump or exhibit a negative sign. These sign reversals are caused by closely arriving wavelets. Therefore, the time derivative of the phase function will contain the indicators for thin beds, in the form of large variations of instantaneous frequency. Its smooth variation will relate to bedding characteristics.” Thus, the instantaneous attributes are excellent visual aids in interpretation. These attributes do not lend themselves to direct interpretation, except for isolated gas sand where they may be the direct indicator (White, 1991). These attributes may be logically, statistically or mathematically combined by in a fashion that exhibit their close relationship (hybrid attributes). Relationships between the attributes are observed either by multi linear regression or by neural net work analysis (Taner, 2001). These hybrid attributes may lead to a possible conclusive interpretation. Lynch and Lines (2004) describe that a display of various combination of instantaneous attributes, such as 3D structure, its color contrast, and a variable density plane which cuts through the display, may greatly help interpretation.
The instantaneous attributes are computed from the complex trace. A seismic trace can be expressed as the complex function,

\[ u(t) = x(t) + iy(t) \]

where \( x(t) \) is the real observed seismic trace, and \( y(t) \) is the complex conjugate of \( x(t) \) (Figure. 23).

The vector length of the real and complex conjugate amplitude values at an instant in time results in the instantaneous amplitude \( r(t) \). Instantaneous amplitude as an attribute is a continuous measure of reflectivity strength along a seismic trace. Instantaneous phase \( f(t) \) is assessed by the angular deviation of this vector from the real axis. Instantaneous phase is independent of instantaneous amplitude, hence independent of reflectivity strength. Instantaneous frequency is the rate of change of instantaneous phase as a function of time. It is fairly stable for a large amplitude envelope of high signal to noise ratio data. The instantaneous attributes of frequency and phase are amplitude independent and are often severely affected by noise, which sometimes renders them uninterpretable (Taner, 2001). The imaginary part of the complex signal is called the quadrature and is formed by applying a 90° phase shift to the real trace. It is often used to check the quality of the data analysis.

Presently, there are many different attributes being used by the industry. The following attributes may throw some light on the lithofacies, structure, and reservoir properties.

Reflection strength (amplitude envelope):
It is a measurement of the complex trace amplitude which may be visualized as the envelope of seismic trace. It is defined as the total energy of the seismic trace and is independent of phase. The maximum reflection strength corresponds to the combined envelope of both peak and troughs in the real seismic. The reflection strength values are always "greater than" or "equal to" zero (Partyka, 2000). It is the square root of the trace energy and hence, may show where the maximum energy occurs. Taner et al. (1979) define reflection strength $e(t)$ as:

$$e(t) = [r^2(t) + q^2(t)]^{1/2}$$

Where,

- $e(t) =$ energy envelope,
- $r(t) =$ real seismic trace, and
- $q(t) =$ quadrature seismic trace

High reflection strength may be associated with major lithologic changes as well as oil and gas accumulations. Subtle lithological changes which may be inconspicuous in the seismic data may be delineated with the help of this attribute (Lynch and Lines, 2004). High reflection strength is often associated with gas content in the pore space. The area of bright spot (high amplitude) indicates the presence of gas (Lynch and Lines, 2004). Reflection strength variations may correspond to changes in acoustic rock properties and bed thickness and may also be used to distinguish massive reflectors from thin-bed composites (Partyka, 2000). In an unconformity, the energy strength will vary as lithology along the unconformable surface changes.
Structure influences reflection strength attributes. For example, in a highly faulted zone, the reflection strength may not be the true representative of the subsurface lithologic signatures as the amplitudes may be affected by the coincidental juxtaposition of faulted lithologic units having the same or nearly same acoustic impedance. A proper designing of attribute extraction time window considering the throw and heave of the faults often helps. Also in domal structure, where thin beds are deposited as layers over the dome, variation in porosity is completely independent of amplitude (Hirsche et al. 1997).

Instantaneous Phase:

It is the angle between a rotating vector (formed by the real and imaginary components of the trace) and the real axis, measured as a function of time (Taner et al. 1979). Its values range from $-180^0$ to $+180^0$. It shows the lateral continuity of events (the phase angle changes with change in bedding continuity). It helps in detecting pinchouts, channels, fans, and internal geometries like different layer stackings, etc. I am interested in finding porous zones. The most likely place to find these zones will be in proper sedimentological structures and depositional features such as incised valley fill channels of lowstand sand deposits (a high-energy deposition with good sorting). Thus, the attribute may help in characterizing the porosity cube by interpreting these depositional features. Moreover, the wireline porosity information may be tied back to these features to aid interpretation.
Instantaneous frequency:

It is derived as the rate of change of the instantaneous phase as a function of time. It may reveal abrupt changes. High attribute values may be indicator of porosity/permeability features. Low frequency shadows may be associated with the reflectors below gas sands, condensate, oil reservoirs, and steam.

Instantaneous bandwidth and Instantaneous dominant frequency:

Instantaneous bandwidth and instantaneous dominant frequency can be used as complex trace attributes (Taner et al. 1979; Taner and Sheriff, 1977). Instantaneous bandwidth is the absolute value of the rate of change of the instantaneous amplitude divided by the instantaneous amplitude (Barnes, 1993). Instantaneous dominant frequency is the square root of the sum of the squares of the instantaneous frequency and instantaneous frequency and is always positive (Barnes, 1993). Instantaneous bandwidth and instantaneous frequency are independent of each other where as instantaneous dominant frequency is dependent on both the instantaneous frequency and instantaneous bandwidth. These attributes help in interpreting gas zone in a seismic record (Barnes, 1993) as they show a low frequency zone beneath a highly attenuated zone (gas sand).

Response attributes:
Response attributes exhibit a blocky appearance when plotted because one value is obtained for each energy envelope lobe and is returned as a constant for the entire time width of the envelope lobe from trough-to-trough. Response attributes for frequency, amplitude, phase and energy may be derived from the peak of the envelope. These attributes are easier to interpret than a matching instantaneous attributes in the presence of noise. Response frequency is the value of instantaneous frequency at the peak of the amplitude envelope and is a measure of the dominant frequency of the waveform contained within the envelope (Bodine, 1984). It is useful in measuring dominant frequency variations from energy lobe to energy lobe. It is independent of energy and phase. This attribute may be useful for identifying shadow zones beneath the gas accumulation and may be used for porosity/permeability indicator as the lateral/vertical continuity of this shadow zone can be broadly delineated even if in the presence of noise (the response attributes may not affected by noise as only one value per lobe is chosen). The response phase is the dominant phase of the waveform. It is independent of amplitude, and useful in measuring phase variations from energy lobe to energy lobe. The response length attribute is the half-length of the energy envelope from energy trough to trough. One value is obtained for each energy lobe and is returned as a constant for the entire time width of the energy lobe from trough to trough. It is independent of phase and amplitude (Bodine, 1984). The half-length attribute provides a measure of seismic reflection stability and help in characterizing the complexity of the seismic waveform within the energy envelope. In case the response length is laterally stable but the other response attributes are unstable, then waveform variability may probably an effect of tuning rather than by a poor signal to noise or unstable (detached) reflection (Partyka, 2000).
Apparent polarity:

It is the polarity of the real trace at the amplitude envelope peak. Polarity refers to the sign of reflection coefficient at the interface. For a normal incidence on an interface, reflection coefficient is related to densities and velocities of upper and lower mediums.

\[
R = \frac{\rho_2 V_2 - \rho_1 V_1}{\rho_2 V_2 + \rho_1 V_1}
\]

where, \(\rho_2\) and \(\rho_1\) are the densities of the lower and upper media; \(V_2\) and \(V_1\) are the velocities of the lower and upper media. The product of density and velocity is also called acoustic impedance.

Sheriff (1984) assigns a positive polarity to a seismic wave shape when the acoustic impedance of the lower medium is greater than that of the upper one (positive reflection coefficient). A negative polarity on a seismic wave shape occurs when the acoustic impedance of the lower medium is lesser than that of the upper medium (negative reflection coefficient). Thus, the polarity at an interface is either +1 or -1 depending upon the impedance contrasts.

Levin (1986) first published the application of polarity reversal in seismic exploration. The relative polarity (apparent) reversal is related to the variation in acoustic impedances at the interface boundary, hence its sign may tell about the elastic properties of the subsurface surrounding the interface. It often is a hydrocarbon indicator as for an oil or gas zone underlying a hard trap rock, a polarity reversal (-1) is observed. It may help to ascertain the
gas-oil-water contact of a reservoir (based on simultaneous analysis of amplitude and polarity anomalies). The lateral relative density contrast of a reflector in a reservoir may be modeled based on the behavior of the polarity sign over offset, and an approximate idea about the relative porosity distribution in formation may be made.

Perigram:

This attribute is obtained by subtracting a running average amplitude value from each data value in an amplitude envelope (reflection strength). The process converts strictly the positive reflection strength data into negative to positive alternating data. The resultant displays make the energy maxima more obvious in seismic section (Gelchinsky et al. 1985). This attribute provides a broader distribution of amplitude values which may allow more precise isolation of a particular range of the amplitude envelope. Like reflection strength, the perigram may provide useful information on lithology (as it is an amplitude envelope of amplitude greater than the running average) but because the perigram data contain both positive and negative values, more number of colors can be assigned to the data ranges which help in interpretation.

Besides the above attributes, like integrated absolute amplitude, amplitude weighted phase, dominant frequency, second derivative instantaneous amplitude, raw seismic, etc. may provide some relationship with the lithology and reservoir properties. Another attribute may be generated by mathematically transforming attributes taking their reciprocal, square, logarithm, and square root.
Many advanced visualization techniques are being utilized for better attribute analysis to predict subsurface properties. Correct and appropriate selection of any attributes (hybrid or multiple attributes) along with these visualization techniques may help to analyze a particular geological situation more effectively.

The Coalinga reservoir is clastic in nature and highly heterogeneous due to deposition of varied litho-facies in different geological time periods due to the fact that the basin experienced a succession of paleo-environments ranging from incised fill to subtidal. Localized unconformities delineate the reservoir into different petrophysical blocks where reservoir properties are believed to be different. I choose instantaneous attributes such as instantaneous amplitude, reflection strength (total absolute amplitude) and perigram to help me to delineate the reservoir in terms of reflectivity as it gives information about spatial distribution of the varied lithologies, both vertically and laterally in the reservoir. The instantaneous frequency and response attributes help in isolating abrupt changes to characterize reflection zones, bedding, etc. while mapping of the unconformities. Instantaneous phase attributes help in delineating and mapping the unconformities as it is a good indicator of lateral discontinuities. Moreover, it is independent of seismic amplitude strength, which helps to analyze both the strong and weak amplitude strengths. It helps in mapping the unconformities in low seismic amplitude zones. I use geometrical attribute such as coherency to ascertain the degree of similarity (continuity) or dissimilarity between adjacent traces to ascertain any conspicuous sedimentological depositional features in the
reservoir. I also examine seismic attribute volumes of acoustic impedance, dip magnitude and dip azimuth to check for the presence of any anomalous geological depositional signatures in the data set, which in turn will help me in volume visualization and interpretation.

6.2 Geovolume Visualization and Interpretation

Seismic resolution depends on seismic wavelength. The seismic wavelength is directly proportional to velocity and indirectly proportional to frequency (wavelength is the ratio of velocity and frequency). In the subsurface, velocity gradually increases with depth and the frequency decreases with depth, which produces an increased wavelength, thus making the seismic resolution poorer in deeper horizons (Brown, 1996). Within the past few years, advanced computing power enable to stretch the resolution limit to the maximum possible with the help of the new technology ‘Geovolume Visualization and Interpretation (GVI)’. These techniques help to demarcate and delineate the reservoir into sub-units based on depositional signatures and geological units. Various statistical techniques and stochastic modeling of reservoir rocks conditioned with well log and seismic data can subsequently be applied to stretch the resolution limit in the data to the maximum possible. The technology and philosophy of GVI differs dramatically from conventional line-based interpretation and includes new interpretation strategies and methodologies. It allows 3-D seismic interpreters to rapidly analyze enormous data volumes by tapping the mind's eye and by incorporating
seismic attributes into interpretations much earlier in the interpretation process. Kidd (1999) categorizes two basic types of visualization:

- Map-based (surface visualization)
- Volume-based (volume visualization)

Surface visualization results from mapping individual horizons and faults, and then re-interpreting them collectively in 3D space as a 3D model. It is the logical product of conventional interpretation.

Volume visualization assumes that the seismic reflectivity of the subsurface represents a model of the subsurface’s structural, stratigraphic, and amplitude features in 3D space (Kidd, 1999). The process starts with volume visualization, followed by volume interpretation and defines volume visualization as a method of seismic interpretation in which the geophysicist directly evaluates the seismic reflectivity of the subsurface in 3D space by applying various levels of transparency to the data. Volume visualization provides a method for geoscientists to quickly interpret and evaluate complex structural, stratigraphic, and amplitude features in 3D space.

The four main techniques of GVI are recognition, color, motion, and isolation (Sheffield et al. 2000). Recognition of any anomalous feature helps to distinguish characteristics of feature to be delineated. This is followed by further processing, such as assigning a proper
color and transparency scheme to represent different amplitude ranges of an attribute which may enhance those recognized characteristics for visualization and geobody mapping (Meyer et al. 2001). Using an appropriate color scheme, which clearly separate various attribute’s amplitude ranges with contrasting colors, the resultant seismic image is a direct representation of the seismic attribute distribution (Kidd, 1999). Depth cueing, a process which refers to a phenomenon where the more distant objects are rendered with a lower intensity than nearer objects, is helpful for color viewing. It selectively blends image colors with the background color with an increase of viewpoint distance from the front object which improves the perception of depth and shape for 3D objects. Lighting and color intensity are also important components associated with the color viewing. Motion allows observation how the seismic data are related in space and time. Moving an observer’s viewpoint with respect to an interpreted horizon (distance, orientation, etc) helps in interpreting the horizon. Projection, a process by which 3D objects are graphically displayed according to their spatial relationship on a two-dimensional plane, often help in the visualization and interpretation process (Foley, et al., 1990). Isolation, the ability to separate events of interest from other data, is another key feature of GVI. This is achieved by rendering the opacity values for the extraneous attribute values (such as noise, non-reservoir units, etc.) and creating a relatively transparency scheme for marginally important amplitudes. It helps in illuminating stratigraphic and geomorphic architecture within the reservoir (Harvey et al. 2000).

I use Landmark’s *Earthcube* to render various instantaneous attributes volumes with a properly designed opacity editor wherein the extraneous seismic attribute values are assigned
transparent colors for my visualization analysis. Figure 24 shows an architectural setting of Temblor reflectors in color over the entire area of my study. The basal plain portion of the Figure 24 is shown with more zooming (spatial magnification) than the walls and diagonals for a better three-dimensional display. I observe multiple channel stack geometry patterns in both inline and crossline at the same location (Figure. 25). With the help of the chosen opaqueness and color scheme for a selected range of absolute amplitude attributes, I show a cube depicting the overall stratification pattern of the reservoir (Figure. 26). By applying a different set of opacity parameters and color scheme for the reservoir absolute amplitude, I further analyze the bed disposition in the reservoir. Figure 27 depicts these stratal dispositions in time and oblique slices in different directions in the reservoir.

Looking on a NE-view of the reservoir, I observe two prominent channel systems in Figure 28, a major one on top and another in the bottom part of the reservoir. The top one seems to be laterally and vertically extensive and gradually shifts towards ESE-SE. The bottom one is seen towards the west of the study area and shifts towards SSE (upper left side of Figure 28). Figures 29 and 30 show cubes of total absolute amplitude (reflection strength) envelopes which depict the lithofacies distribution pattern of the reservoir. Figure 31 shows the opacity editor with the chosen transparency scheme versus amplitudes for display in Figure 30. It is interesting to note that these attribute volumes depict two distinct distribution patterns of seismo-lithofacies over the field based on higher values of reflection strength seismic attributes (Mahapatra, et al. 2004). The most prominent and vertical extensive one is at the top. The vertical extension of the bottom one is comparatively lesser than the top one.
The major lithofacies associated with the channel deposits (yellow bodies in Figure 30) may be sands (high seismic reflection strength) as evidenced by the presence of hydrocarbon (highest reflection strength amplitude values) within these units and my knowledge that the reservoir rock is sands. The highest reflection strength amplitudes may also be due to the presence of trapped steam and/or air in the reservoir. Irrespective of the nature of material contributing to this high amplitude, their occurrences indicate that the reservoir facies containing them is porous and has to be sandy.

The top group of seismic facies is observed to contain the zone C and B of the reservoir (Figure. 19, Mahapatra et al. 2004) signifying different facies characteristics than the underlying section as it is populated with high values of reflection strength attributes. The occurrence of top group lithofacies may be attributed to the presence of the Buttonbed and Valv unconformities (Figure. 30). The bottom group (lower part of zone A in Figure. 19) represents the incised valley fill deposition over the Base Temblor. The absence of any prominent reservoir rocks between 550-700 ms in Figure 30 (sandwiched in between the top and bottom reservoir rocks distribution) seems to represent the estuarine deposits where less or no significant reservoir rocks are normally expected in the area (as evident from the lack of high reflection strength attribute values). The absence of prominent estuarine reservoir rocks in the Coalinga area is further evident as per the outcrop, core and wireline log analysis by Bridges and Castle (2003). They observed that the estuarine deposit is mainly composed of intercalations of claystone, siltstone, and fine grained sandstone.
Careful GVI helps in segmenting the study area into channel and non-channel bearing volumes. Further, the entire volume is also subdivided into sub-units based on the position of these three unconformities in the Temblor Formation based on my seismostratigraphic analysis. These six subunits may be used for further stochastic modeling of the reservoir to improve the steam injection and placement of infill wells for optimizing the present tertiary crude oil production from the field.
Chapter 7

Discussion

Reservoir characterization and model building are necessary steps to develop an oil field (Mahapatra, et al. 2003a). It combines stratigraphic analyses, the detection of paleogeomorphic features, and integrates geologic and seismic data. Identification of major sedimentological depositional structures along with any non depositional features greatly helps the petrophysical delineation of the reservoir. The lateral continuity of different reservoir units is better characterized on seismic data than on well data because 3D high-resolution seismic data provide information without gaps over long scales. The resulting reservoir model is based on lithological parameters estimated from well cuttings, core, and wireline logs. The lithologic and petrophysical gaps between the wells are filled by interpolation or geostatistics. In either case, the final models of key petrophysical parameters are not always accurate and may differ from the real reservoir.

The objective of the present investigation is to analyze 3D seismic data of the highly heterogeneous clastic Coalinga reservoir to map various seismostratigraphic sequences and geobody elements which in turn help to identify, delineate, and demarcate the various reservoir subunits based on their depositional signatures and geological characteristics.

The reservoir in the Temblor Formation represents the interplay of shallow marine and
non-marine depositional environments (Clark, et al. 2001b; Bate, 1985; Bate, 1984). The clastic shallow, unconsolidated reservoir is very heterogeneous in nature, as it is mostly bounded by unconformities and subdivided into three distinct depositional environments representing a near-shore fluvial dynamic depositional setting intermingling with depositional erosional hiatuses. The four unconformities (Base Temblor, Buttonbed, Valv, and Top Temblor in ascending order) within the reservoir play significant roles in the distribution and flow of fluids in the reservoir (Clark, et al. 2001b). The Base Temblor unconformity separates the underlying Kreyenhagen shales from the Temblor and represents an incised valley-estuarine fill-up setting. The overlying Button unconformity represents the transition to tide and wave dominated shoreline facies, which in turn is capped by the Valv unconformity representing a sub-tidal dominated facies. The top Temblor unconformity separates the Temblor from the overlying Santa Margarita formation (Bridges and Castle, 2003). The thicknesses between the three facies tracts within the Temblor Formation vary over the field due to the presence of dynamic paleo-topography of the basin caused by varying degrees of tectonic uplift and differential amounts of sedimentation through out the period of deposition and erosion (Bartow, 1991). All but the BS-2 and BS-4 of Bridges and Castle (2003) can be mapped on seismic data, while the BS-2 and BS-4 can only be identified on wireline logs and outcrops.

The seismic characters of these unconformable surfaces are subtle in nature and are easily overlooked in the field area without prior stratigraphic knowledge based on cores and outcrops (Clark, et al. 2001b). I integrated the continuous 3D seismic data with the geological
data to verify, analyze, and map spatial distribution of these unconformities in the reservoir for a meaningful reservoir characterization. I also looked for paleogeomorphic and depositional features on the seismic data which were the preserved resultants of the various tectonic forces that acted on this complex strike-slip reservoir in the geologic past.

The 3D seismic data is a merged poststack volume of different seismic datasets, acquired between 1996 and 2000. The seismic surveys were carried out over the field while steam was being injected intermittently and the reservoir was depleting due to simultaneous production (Clark, et al. 2001b), which affected the velocities, amplitudes, and reflections. The presence of varying proportion of steam in the reservoir causes seismic wave distortions and velocity pull down effects in different blocks of the reservoir. Amplitude variability resulting from steam injection makes time-depth correlation difficult and the ties between data and well logs become problematic and vexing (Mahapatra, et al. 2003b). The identification of sequence stratigraphic elements like offlap, onlap, and truncation analyses on seismic data becomes perplexing due to the discontinuous nature of the reflector pattern and the associated dipping events. Finally, the merging of seismic data acquired at different times causes misties between inlines and crosslines, and reflector discontinuities resembling faults. Each data set was acquired after injection of varying amounts of steam into the reservoir, with varying sources, signal-to-noise levels, and static correction. I observe a significant static break due to a decrease of the interval velocity near the top of section 25D which may be due to an excessive amount of steam that was placed into this section (William Kempner, 2003, personal communication). In addition, there is a significant static and frequency change observed at the
boundary between sections 24D and 25D due to steam effect. A similar change is also observed between sections 25D and 36D.

I carried out a seismostratigraphic analysis of the reservoir. I correlated density and sonic wireline logs and identified the four unconformable surfaces (Base Temblor, Buttonbed, Valv, and Top Temblor) within the Temblor reservoir based on the shale base trend line shifting. While trying to map these surfaces on the seismic data, I observed severe misties and reflector discontinuities on the seismic sections due to data merge and steam effects (Mahapatra, et al. 2003b). The reflectors in the central part of the study area are more discontinuous in nature due either the presence of inherent reservoir heterogeneities, or steam effects or both. I faced many problems in closing reflector loops as forced closing of loops at some places contradicts geological expectations.

I identified sequence stratigraphic elements such as offlap, onlap, and reflector truncation which allowed mapping of these unconformities. I identified the high order sequence boundaries and confirmed that the reservoir is compartmentalized into three major vertical chronostratigraphic sequences (Mahapatra, et al. 2004). The analysis of reflector trends and chronostratigraphic sequences enabled me to ascertain geological features such as the strike and variation in the depositional direction of the reservoir rocks. I observed the strike of the Temblor formation to be NNE-SSW and found the highest structural relief towards the western part of the study area. The zone between the Buttonbed and Basal Temblor surfaces contains a multitude of
channel cuts. In the lower central part of the study area, these channels appear to be re-cut and re-stacked. The depositional direction seems to be slightly changing over the field for different geologic time of deposition (from NW-SE to SW-NE).

I used instantaneous and volume based seismic attributes to study the clastic reservoir. These attributes helped mapping of the reflectors in the stratigraphic analysis as well as in the seismogeomorphic interpretation. I applied seismic Geovolume Visualization and Interpretation (GVI) techniques (Sheffield and Tatum, 2000; Kidd, 1999) to demarcate and delineate the reservoir into subunits based on stratigraphic and geomorphic architectures. The GVI analyses revealed two prominent channel systems within the reservoir which are recut and restacked at places (Mahapatra, et al. 2004). The more prominent and vertically more extensive one is at the top northern part of my area of study. A minor one is towards the northwestern part of the study area. The major channel system in the top northern part of the reservoir is gradually shifting towards ESE-SE and the minor channel system appears to be shifting SSE. A number of sedimentological features like bed stratification, and lithofacies distribution patterns are clearly observed by GVI. It is interesting to note that these attribute volumes show two distinctive distributions of reservoir rocks over the field based on higher values of reflection strength seismic attributes (Mahapatra, et al. 2004). The top group of seismic facies signifies different lithofacies characteristics than the underlying section as it is populated with high values of reflection strength attributes. The occurrence of top group lithofacies may be attributed to the presence of the Buttonbed and Valv unconformities. The bottom group coincides the incised valley fill deposition over the Base Temblor. The major lithofacies associated with the channel
deposits may be sands (high seismic reflection strength) as evidenced by the presence of hydrocarbon (highest reflection strength amplitude values) within these units and my knowledge that the reservoir rock is sands. The highest reflection strength amplitudes may also be due to the presence of trapped steam and/or air in the reservoir. Irrespective of the nature of material contributing to this high amplitude, their occurrences indicate that the reservoir facies containing them is porous and has to be sandy. I believe the area between the top and bottom clusters may represent the estuarine deposits as evident from the lack of reservoir facies (high reflection strength attribute values). The absence of prominent estuarine reservoir facies in the field was also observed by Bridges and Castle (2003).

The investigation helped in segmenting the study area into channel and non-channel bearing volumes. Furthermore, the entire reservoir volume was also subdivided into sub-units based on the position of these unconformities in the Temblor Formation.

These subunits may be used for further stochastic modeling of the reservoir to improve the steam injection and placement of infill wells for optimizing the present tertiary crude oil production from the geologically complex, heterogeneous, stratigraphic plays of the Coalinga field by constructing reservoir models that more closely mimic the petrophysics of the producing reservoir. In addition, I could attempt a seismic attribute to petrophysical parameter transformation based on linear multivariate regression or nonlinear neural networks. This transformation would be aided by my segmentation because a different transform could be employed for every unit. Further investigation into the physical and mathematical relationships
between seismic attributes and wireline log parameters would also clarify identification of seismic facies, channel forms, and lithology. Lastly, the merged data sets caused severe problems including misties, discontinuities, and changing wavelets. These problems would at least be reduced partially by reprocessing all data together in a consistent manner, although the effects of production and steam injection on the seismic data acquired in different years will remain an inherent problem.
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Figures and Tables

Figure 1. Map showing the oil fields, locations of oil seep, oil stain, and source rocks with their geological ages around the San Andreas fault and the San Joaquin basin. Location of the cross sections A-A' and B-B' in Figure 2 are shown. (After Peters et al., 1994)
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(compiled by Bartow, 1991)
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(compiled by Bartow, 1991)
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(compiled by Bartow, 1991)
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(Compiled by Bartow, 1991)
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(Compiled by Bartow, 1991)
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(compiled by Bartow, 1991)
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Figure 31. Opacity editor showing the histogram of absolute amplitudes (pink), and the chosen transparency level (curve in black inside the histogram) for different amplitude values (top of the figure) for obtaining the Figure 30).
<table>
<thead>
<tr>
<th>Facies tract</th>
<th>Thickness (m)</th>
<th>Lithology</th>
<th>Grain size</th>
<th>Sorting</th>
<th>Physical features</th>
<th>Biological features</th>
</tr>
</thead>
<tbody>
<tr>
<td>Incised valley</td>
<td>0–50</td>
<td>Basal conglomerate fining upward to sandstone, siltstone, and claystone</td>
<td>Very fine to very coarse sand; minor pebbles, cobbles, silt, and clay</td>
<td>Very poor to good</td>
<td>Stacked upward-finining intervals; trough and planar cross-bedding; mud intraclasts</td>
<td>Macrufossils rare; rare to common vertical burrows (Skolithos and Ophiomorpha) in siltstone and claystone Oostrea (oyster) fragments; common diatoms and foraminifers in siltstone; minor Teichichnus and common Glossifungites in claystone; minor wood and lignite Minor to common shells of Turritella, Cancellaria, Vaguerocella meriani (sand dollar), Aequipecten, Dosinia, Balanus gregarius (barnacle); horizontal and vertical burrows of Teichichnus, Macaronichnus, Diploricerion, Ophiomorpha Variable content of diatoms, radiolarians, and foraminifers; rare Quinqueloculina sp. (foraminifer); common Teichichnus and Terribellina burrows in claystone Rare shell debris, including gastropods, sand dollars, and Pecten; minor Skolithos burrows</td>
</tr>
<tr>
<td>Estuarine</td>
<td>15–21</td>
<td>Interlaminated to interbedded sandstone, siltstone, and claystone</td>
<td>Very fine to medium sand; minor pebbles, silt, and clay</td>
<td>Moderate</td>
<td>Bi-directional cross-bedding; ripple cross lamination; clay drapes and sand-mud couplets on foresets; mud intraclasts; rare glauconite</td>
<td></td>
</tr>
<tr>
<td>Tide- to wave-dominated shoreline</td>
<td>27–50</td>
<td>Cross-bedded sandstone, bioturbated sandstone, and claystone; minor siltstone, fossiliferous sandstone, and limestone</td>
<td>Very fine to coarse sand with minor pebbles, silt, and clay</td>
<td>Poor to moderate</td>
<td>Planar and trough cross-bedding; bi-directional cross-bedding; clay drapes and sand–mud couplets on foresets; mud intraclasts; minor shell-lag beds; rare glauconite</td>
<td></td>
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<tr>
<td>Diatomite</td>
<td>2.7–9.3</td>
<td>Variable proportions of claystone, siltstone, and sandstone; commonly cemented by carbonate</td>
<td>Predominantly fine sand, silt, and clay</td>
<td>Good</td>
<td>Thin to massive bedding</td>
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<tr>
<td>Subtidal</td>
<td>0–40</td>
<td>Massive bioturbated sandstone; thin intervals of siltstone and claystone</td>
<td>Fine to coarse sand, silt, and clay with dispersed granules and pebbles</td>
<td>Poor to moderate</td>
<td>Faint low-angle and planar cross-bedding; mottled bedding</td>
<td></td>
</tr>
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Table 1. Characteristics of facies tracts in the Temblor Formation. (after Bridges and Castle, 2003)