The Pennsylvania State University

The Graduate School

College of Earth and Mineral Sciences

TIME-LAPSE (4D) SEISMIC INVESTIGATION OF THE I3 AND TA2 SANDS, KILAUEA FIELD, GREEN CANYON BLOCK 6, GULF OF MEXICO

A Thesis in

Geosciences

by

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Submitted in Partial Fulfillment
of the Requirements
for the Degree of

Master of Science

August 2001

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Abstract

3D seismic data from 1985 and 1995 are used to investigate time-lapse seismic amplitude changes in the I3 and TA2 reservoirs of the Kilauea field, Green Canyon Block 6. The I3 sand shows significant amplitude dimming downdip which follows structure and is interpreted to represent a region swept by water as the original gas-water contact moved vertically 160 feet due to production from the A16 well. The TA2 sand also displays amplitude dimming low on structure and this dimming is attributed to the TA2 water contact migrating 750 feet vertically due to production. Amplitude brightening is present above the water swept region of the TA2 sand and potentially represents bypassed pay. Amplitudes near the A9 well decrease between surveys. This dimming is interpreted to result from a localized increase in condensate saturation near the A9 borehole brought on by a 1400 psi pressure drop in the TA2 which caused the reservoir to cross the dew point. Gas was preferentially produced, leaving behind liquid condensate which increased the acoustic impedance and caused the amplitudes to decrease between seismic surveys.

Normalization of the 1985 and 1995 seismic volumes included rebinning, brute shifting, bandpass filtering, Wiener filtering and amplitude balancing using parameters derived in downdip aquifer volumes. After normalization, amplitude difference maps were produced for both sands investigated. Time-lapse amplitude differences were then correlated to production and wireline data.

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Acknowledgements

Financial support for time-lapse research at Penn State Geosciences is provided by Chevron, Conoco, Statoil, and Texaco. Landmark Graphics Corp. provided the interpretation software and Roger Anderson provided the Lamont 4-D Software. Texaco supplied the seismic, wireline, production and paleo data. I thank geoscientists Betsy Strachan and Ken Reynolds from Texaco for their assistance throughout this project.

Dr. Peter Flemings is responsible for guiding this endeavor. The enthusiasm he displays in his courses and for research is unsurpassed. I am extremely grateful for the teamwork provided by members of the Basin Research Group and Petroleum GeoSystems at Penn State. Jim Ashbaugh, from Pennsylvania General Energy, was instrumental in interpreting the engineering and production data. Tucker Burkhart's 4D research provided the foundation for this entire project.

My parents deserve the largest acknowledgement for the immense support they provided throughout my undergraduate and graduate studies at Penn State. I love them dearly and can never thank them enough for their encouragement.

Introduction

Time-lapse seismic (4D) is the investigation of seismic attribute changes through calendar time. By acquiring multiple vintages of multichannel seismic data over the same location, changes in seismic amplitude can be studied. Previous studies have focused on normalizing two vintages of data in order to produce seismic amplitude difference volumes. This allows many horizons to be studied simultaneously.

This study normalizes multiple seismic surveys in order to produce time-lapse amplitude difference maps, not the traditional three-dimensional difference volumes. Although this approach is slower to execute, normalizing each sand independently results in a potentially more robust normalization. The two vintages of seismic data must be normalized in order to remove acquisition and processing differences. After normalization, a seismic event is mapped in both surveys and amplitudes along the event are extracted. The amplitude maps are differenced to yield amplitude changes that occurred between seismic surveys. We then correlate the time-lapse amplitude differences to changes in pore fluids and reservoir pressures brought on by production from the reservoirs investigated.

Burkhart et al. (2000) used two vintages of multichannel seismic data to show time-lapse seismic amplitude changes in two reservoirs within the South Timbalier Block 295 field. The K8 sand was determined to be a solution-gas drive reservoir which showed amplitude brightening over the five years between collecting the seismic data. This amplitude increase was interpreted to result from gas exsolution caused by pressure decline during production. Burkhart et al. (2000) found the K40 sand to be a strong water drive reservoir which showed amplitude dimming due to pore water saturation increasing as the oil-water contact moved upwards. When water replaced oil, the acoustic impedance increased and resulted in a decrease in seismic amplitudes.

Key and Smith (1998) used pre-waterflood and post-waterflood seismic data sets, synthetic seismic volumes, and an extensive reservoir model to investigate the feasibility of time-lapse monitoring at the Ekofisk field in the North Sea. Johnston et al. (2000) described two methods of calculating time-lapse differences for the B80 reservoir of the Lena field, Mississippi Canyon Block 281. The inexpensive, rapid-analysis method of normalizing post-stack legacy seismic was compared to the more rigorous and time-consuming reprocessing method where both volumes of raw field data are subjected to identical processing streams.

Although both techniques illuminated gas cap expansion, the authors had greater confidence in results produced by the more expensive reprocessing method, which is better suited to application in steeply dipping strata. Seismic modeling of gas-injection regions showed a 7% decrease in impedance resulted in a 100% change in seismic amplitude (Johnston et al., 2000). This emphasizes that small impedance changes caused by changing reservoir pore fluids and pressures can produce significant time-lapse amplitude differences.

Doyen et al. (2000) used three vintages of seismic data and a comprehensive 4-D earth model to identify bypassed pay in the Upper Brent sands of the Statfjord field, North Sea. Time-lapse seismic impedance changes were calibrated against saturation changes observed at wellbores in order to construct saturation maps. These 4D seismic-derived saturation maps correlate with predictions made by flow simulators and indicated several regions where bypassed pay may exist. 4D seismic differences also matched those predicted by synthetic seismic modeling and were used to confirm large saturation changes predicted by the flow simulation model. Their end result was a package which integrated several seismic volumes, well data, synthetic seismic, and a reservoir flow model to optimize recovery.

For this time-lapse study, two volumes of legacy 3D seismic data collected over Green Canyon Block 6 are used to investigate seismic amplitude changes in two reservoir sands of the Kilauea field, the I3 and TA2. The calculated seismic differences for each sand are then correlated to production and pressure data. The first seismic survey was collected prior to production in 1985 and the second survey was acquired in 1995, after substantial reserves were produced from both sands. These seismic data were not collected with the intention of being used for time-lapse purposes and as a result, the acquisition and processing parameters differ between the two data sets. A seismic normalization process is employed to address these differences. After normalization, amplitude maps are differenced to show regions where seismic amplitudes have brightened (troughs increased in amplitude) or dimmed (troughs decreased in amplitude) between the 1985 and 1995 survey.

The I3 sand shows significant dimming low on structure. The TA2 also shows downdip dimming, but the 4D results are complicated by both dimming and brightening higher on structure, above the interpreted gas-water contact at the time of the 1995 survey. These regions of amplitude change are then correlated to migrating hydrocarbon contacts, changing fluid saturations, and pressure changes within the reservoirs due to production.

Background

The Kilauea field is located 200 miles (322km) southwest of New Orleans, Louisiana on the shelf-slope break in the northern Gulf of Mexico (Figure 1). The Kilauea 'A' platform, a conventional fixed structure, was set in 1989 in 622 feet (190m) of water. Production began in 1990 and by 1998, 25 million barrels of oil equivalent had been produced. The total production rate in 1998 was 51 million cubic feet of gas per day and 1800 barrels of oil per day.

Fourteen reservoir sands produce oil and gas at Kilauea. These reservoirs extend from southwestern Green Canyon Block 6 into northwestern Green Canyon Block 50 (Figure 2). The unconsolidated layers of sand and shale within this salt-withdrawal mini-basin terminate against a combination of salt and a normal fault on the west and north sides of the field (Figure 3). The reservoirs within the Kilauea field dip southeast at 10 to 30 degrees. Structure and stratigraphy combine to form the traps.

The I3 and TA2 sands are found at depths of approximately 4100 and 6500 feet (1250 and 1981 meters, 1500 and 2100 milliseconds two-way time) below the sea surface, respectively (Figure 3). Paleontological data show these sands are associated with the highest occurrence of the benthic foraminifera, *Trimosina denticulina* (0.65 Ma., Figure 3) (Shaffer, 1990). Deposition occurred in the Middle Pleistocene in paleo-environments ranging from mid to outer shelf for the I3 sand and from outer shelf to upper slope for the deeper TA2 sand.

The I3 reservoir is composed of very fine-grained sand with an average permeability of 550 millidarcys and 30% porosity. Net sand thickness in the I3 ranges from 100 to over 300 feet (30-91m) across the Kilauea field and log data suggest the sand continues to thicken basinward (Figures 4a and 5). Net pay for the I3 ranges from 100 to 200 feet (30-61m) in the northern portion of the field (Figure 4b and 5). The I3 sand is a gas reservoir.

The TA2 reservoir is composed of very fine-grained sand with an average permeability of 1200 millidarcys and 30% porosity near the top of structure. Downdip wells produce from sand with an average permeability of 320 millidarcys and 26% porosity. The TA2 net sand thickness is less than the I3, ranging from 40 to 100 feet (12-30m) thick across the field and thins basinward, towards the south-east (Figures 6a and 7). The TA2 net pay thickness reaches a maximum of 50 feet (15m) in the center of the field and extracted 1985 seismic amplitudes follow net sand and net pay contours (Figures 6a and 6b). The TA2 sand is a gas cap reservoir with a small downdip oil rim.

Normalization

The two seismic volumes used in this 4D study were not collected for time-lapse purposes. Because of this, the acquisition parameters and data processing flows were dissimilar (Table 1). To correct for these differences, we normalized the seismic volumes so they are as similar as possible in areas where no production has occurred. Normalization remedies the differences in trace spacing, frequency bandwidth, trace shape and amplitude between the 1985 and 1995 volumes. The normalization methodology used here is similar to that of Burkhart et al. (2000).

Normalization parameters are derived using downdip aquifer volumes where it is assumed no production effects are present. These parameters are then used to normalize the entire volume. Our approach differs from previous work because each sand is normalized independently. Another difference is our methodology yields normalized amplitude maps which are suitable for differencing as opposed to previous studies which produced normalized 3D cubes of seismic data. The variables used in normalization are defined in Table 2.

Rebin

The regional 1995 survey was rebinned to match the bin spacing of the 1985 survey. This was accomplished using an inversely weighted linear interpolation which uses the four nearest 1995 traces to create the rebinned 1995 trace,

$\hat{S}$ (Figure 8).

$$\hat{S} = \frac{A_1 S_4 + A_2 S_3 + 3 S_2 + A_4 S_1}{A_1 + A_2 + A_3 + A_4} \tag{1}$$

This step yielded a new cube, the rebinned 1995 volume which is identical in size and has the same trace spacing (82x41ft, 25x12.5m) as the 1985 seismic volume.

Define Subvolumes and Aquifer Volumes

The second step of normalization is to cut subvolumes for each sand from the 1985 and rebinned 1995 cubes (85-I3, rebinned 95-I3, 85-TA2, and rebinned 95-TA2) (Figures 2 and 3). These subvolumes are used to normalize each sand independently. The I3 subvolumes extend from 1200 to 1800ms and the TA2 subvolumes extend from 1904 to 2760ms. The subvolume two-way time thicknesses were chosen to include only as much seismic as necessary to complete the normalization and still image the sand being investigated. This served to minimize the affects other sands have on our normalization calculations. The areal extent of the subvolumes were sized to include all of the sand's reservoir and a portion of its aquifer.

Aquifer volumes located inside the I3 and TA2 subvolumes are composed of 729 traces (27x27 traces in map view) (Figure 3). Subsequent normalization parameters are calculated in these downdip aquifer volumes.

Bulk Shift

For each sand, the traces of the 1995 aquifer volume are cross-correlated with traces from the 1985 aquifer volume to determine appropriate shifts in the x,y, and z directions (in-line, cross-line, and time) (Table 3). Each sand's 1995 subvolume is bulk shifted to maximize the correlation between its aquifer volumes. Bulk shifting mitigates some positioning discrepancies induced by different seismic acquisition and processing.

Bandpass Filter

A bandpass filter was applied to all seismic data to make the frequency bandwidths between the two vintages more similar (Figure 9). Frequencies from 0-40 Hertz were retained. A 40Hz high-cut was chosen because it allowed both sands to be imaged sufficiently and ultimately mapped after bandpassing, while still removing high frequency noise from the data sets. Bandpass filtering is the only process applied to the 1985 data, all other processes are applied to the 1995 data in this normalization.

Wiener Filter

Cross-equalization (Wiener) filters are developed for each sand's aquifer volumes to increase the correlation between data sets. These filters are also known as optimum, match, or least-squares filters (Robinson and Treitel, 1967). The filters are calculated using the downdip aquifer volumes for each sand and then applied to the entire 1995 bandpassed subvolumes. For every pair of traces in an aquifer volume, a Wiener filter is calculated which reshapes the 1995 trace to match the 1985 trace. These Wiener filters are derived by minimizing the energy of the difference of the two traces in a least-squares sense (Robinson and Treitel, 1967). The Wiener filters are then averaged together to yield one filter which is applied globally to that sand's 1995 bandpassed subvolume. After Wiener filtering we are left with the following four subvolumes of data: bandpassed 1985-I3, Wiener filtered 1995-I3, bandpassed 1985-TA2, and Wiener filtered 1995-TA2.

Amplitude Balance

The final step of normalization is to balance the amplitudes between the 1985 and 1995 data. From both the bandpassed 1985 and Wiener filtered 1995 subvolumes, the amplitudes along the I3 and TA2 horizons are extracted where these horizons intersect their respective aquifer volumes (called the **aquifer surface**). For each sand and vintage of data, the mean and standard deviation of amplitudes in these aquifer surfaces are calculated (Tables 4 and 5).

Equation 2 is a geometric mean regression which uses the mean and standard deviation of each sand's aquifer surfaces to scale the 1995 amplitude extraction values, (y_i) (Burkhart et al., 2000).

$$\hat{y}_i = \left(\frac{\sigma_x}{\sigma_y}\right)\left(y_i - \left[\bar{y} - \frac{\sigma_y \bar{x}}{\sigma_x}\right]\right) \tag{2}$$

Equation 2 reduces to the following two expressions for scaling the 1995 amplitude extractions:

$$\text{I3 Sand} \quad \hat{y}_i = (1.46)(y_i + 328.36) \tag{3}$$

$$\text{TA2 Sand} \quad \hat{y}_i = (2.25)(y_i + 437.04) \tag{4}$$

Amplitude balancing forces the 1995 aquifer surface mean and standard deviation to be similar to those of the Bandpassed 1985 aquifer surface (Tables 4 and 5) (Figures 10 and 11).

Each step of normalization improved the correlation (r) between the 1985 and 1995 aquifer volumes (Figures 12a and 12b). The aquifer volumes for each sand were differenced after every step of normalization in order to monitor changes in amplitude statistics. The standard deviation of the difference volumes decreases after each normalization step, which also indicates the correlation between the 1985 and 1995 aquifer volumes improves after each normalization step (Tables 6 and 7). Seismic differences resulting from acquisition and processing were reduced by calculating normalization parameters using downdip aquifer volumes and applying the required corrections to the 1995 subvolumes for each sand.

Difference Maps

The amplitude balanced 1995 extractions are subtracted from the bandpassed 1985 extractions to produce an amplitude difference map for each horizon

(Figures 13 and 14, Tables 8 and 9). These difference maps illuminate time-lapse amplitude changes for each sand. If the aquifer for each sand is free from production effects and the normalization was successful, the amplitudes will be near zero in the downdip aquifer on difference maps (Figures 13d and 14d).

On difference maps, bright colors represent bins where the absolute amplitude of the seismic troughs has increased or “brightened” between surveys (acoustic impedance has decreased over time). Darker colors represent where the absolute amplitude of the seismic troughs has decreased or “dimmed” between surveys (acoustic impedance has increased over time).

If amplitude extractions for a particular horizon include positive values (peaks), the darker colors on a difference map represent where these peaks have increased in amplitude through time and bright colors indicate where peaks have decreased in amplitude through time. The gas-water contact of the I3 sand is imaged as a peak in the 1985 seismic data (Figure 13a).

Convert to Standard Deviation

For each sand, the standard deviation of the amplitudes on the difference map aquifer surface is calculated (Tables 4 and 5) (Figures 15a and 16a). All difference map amplitude values are then divided by this standard deviation. This converts the amplitude difference maps into units of standard deviation (Figures 17a and 18a).

This conversion is statistically useful for distinguishing which time-lapse amplitude changes have a higher probability of resulting from changes in rock properties and fluid saturations as opposed to being induced by noise (error) between data sets. Amplitude changes with magnitudes less than two standard deviations have been shaded grey on the difference maps (Figures 15b,16b,17b and 18b). This removes time-lapse amplitude differences which are equal in magnitude to 95% of the amplitude differences observed in the downdip aquifer surface for each sand. We assume amplitude differences less than two standard deviations are small enough to be indistinguishable from noise.

Time-Lapse Results

I3 Sand

The top of the I3 reservoir is imaged in both the 1985 and 1995 seismic volumes as a trough. These large negative amplitudes are shaded bright yellow and red on amplitude extractions (Figures 13a and 13b). The downdip aquifer region, colored in darker green and blue, is also imaged as a trough in the seismic data, but with smaller amplitude than the reservoir. The original I3 gas-water contact (OGWC) is imaged as a peak on the 1985 amplitude extraction (Figure 13a). These positive amplitudes are shown in purple and follow structure.

Difference maps for the I3 sand show two areas of significant amplitude change between seismic surveys (Figure 17b). Region 1 shows dimming, where amplitudes have decreased over time. This dimmed region follows structure and extends from the original I3 gas-water contact, updip to the 1995 A16 perforations (Figure 17a). Region 2, southwest of the A16 perforations, shows both amplitude brightening (red and yellow) and dimming (blues) through time (Figure 17b). It is unclear if the dimming in Region 2 is an extension of the dimming found in Region 1. The brightening observed in Region 2 represents the largest amplitude increases calculated for the I3 sand. The largest amplitude decrease on the I3 difference maps is found along the deepest part of the reservoir, along the 1525ms contour line (Figure 17b). These purple colors represent where troughs have decreased substantially in size or peaks have gotten larger.

TA2 Sand

The top of the TA2 is imaged as a seismic trough whose amplitude is greater in the hydrocarbon filled portion of the reservoir, than in the downdip aquifer (Figures 14a and 14b). In 1985, the largest amplitudes are found in the northern part of the field, near the A9 well and amplitudes decrease to the southwest (Figure 14a). This amplitude decrease coincides with a decrease in net sand and net pay thickness (Figures 6a and 6b).

Four areas of significant amplitude change are identified on the TA2 difference maps (Figure 18b). Region 1 is the largest area of dimming and extends from the original TA2 oil-water contact, upward beyond the A5st, A5st3, and A12 wells. This dimming covers the oil rim and parallels structure. Region 2 is a smaller zone of amplitude dimming located high on structure, near the A9 well (Figure 18b). The dimming associated with Region 1 and Region 2 blends together in map view. Region 3 is a zone of amplitude brightening located primarily above the oil rim dimming. Region 4 is a zone of amplitude brightening located north of the A9 well (Figure 18b). This amplitude increase occurs along the edge of the TA2 reservoir, where net sand and net pay thickness decrease greatly (Figures 6a and 6b).

Production

I3 Sand

Between 1985 and 1995, 12 billion cubic feet of natural gas were produced from the I3 sand using the A16 well (Figures 5 and 19a). Gas production declined rapidly and water production increased several months after flow initiated in October, 1992 (Figure 19a). Gas production continued to fall and water production remained close to 2000 barrels per day until January 1996. At that time, the original perforations were plugged and abandoned and new ones 130 feet higher in the A16 well were installed (Figures 5 and 17a). Gas production from these new perforations never matched that of the first set and these new ones also watered out quickly (Figure 19a). The shut-in bottom hole pressure remained fairly consistent between 1985 and 1995, only dropping several hundred p.s.i. (Figure 19b and Table 10).

TA2 Sand

20 billion cubic feet of natural gas, 390,000 barrels of oil, and 150,000 barrels of condensate were produced from five wells in the TA2 sand between 1985 and 1995 (Figures 20 and 21). The A9 well is responsible for the majority of gas and condensate production (Figures 7 and 20a) and the downdip three wells are responsible for the oil production (Figures 21 and 22). The A11 well produced for ten days in April and May of 1996 before being shut-in due to small quantities of gas and high volumes of water being produced. Between seismic surveys, the

TA2 shut-in bottom hole pressure dropped 1400 p.s.i. (Figure 23a and Table 11).

The A9 well produced 150 barrels of condensate per day and between 4,000 and 10,000 cubic feet of gas per day prior to the 1995 seismic survey (Figure 20a). The amount of condensate produced decreased and gas produced steadily increased just prior to the 1995 seismic survey. Water production from the A9 well is extremely low until it spikes in 1997, two years after the second seismic survey.

The three downdip wells in the oil rim, A12, A5st, and A5st3, had similar production histories (Figure 21). Oil production starts initially high and then decreased within the first year as gas production increased. Eventually, the gas production also decreased as water production exceeded the volume of oil produced per day. Water broke through into all three oil rim wells at least one year prior to the 1995 seismic survey.

Interpretations

I3 Sand: production

Gas production in the A16 well dropped at the same time water production rose rapidly (Figure 19a). This rise in water production is interpreted to represent the A16 perforations being swept by the gas-water contact (Figure 24). The well was able to pull enough gas to the perforations from above to remain profitable until 1996, when new perforations were installed 130 feet (40m) higher up the wellbore (Figure 5).

I3 Sand: amplitude changes

The dimming in Region 1 is interpreted to represent an area swept by water as production from the A16 well caused the gas-water contact to move up structure (Figure 17b). As the gas-water contact approached the A16 perforations, the seismic velocity and density of the downdip region increased as pores were swept by water (Figure 5). The velocity and density increase in Region 1 caused the acoustic impedance to increase and resulted in the time-lapse amplitude decrease observed on the I3 difference map (Wang, 2001) (Figure 17b).

The dashed red line on Figure 17a is the interpreted location of the gas-water contact at the time of the 1995 seismic survey and represents a 160 foot (49m) vertical displacement of the water contact. The new contact was drawn along the upper limit of the amplitude dimming and coincidentally intersects the A16 perforations in map view. It is unclear whether the dimming observed in

Region 2 resulted from the updip movement of the gas-water contact (Figure 17b). The dimming of Region 2 may be attributed to water coning towards the A16 perforations.

The brightening found in Region 2 is problematic (Figure 17b). This small zone of amplitude increase is distinguishable on the original amplitude extractions as large amplitude values (Figures 13a and 13b). It is difficult to attribute this brightening to pressure decline in the reservoir because between surveys, the shut-in bottom hole pressure dropped only several hundred p.s.i. (Figure 19b). Large amplitude increases are only associated with Region 2, they are not found everywhere above the interpreted 1995 gas-water contact (Figure 17b). It is unclear whether the time-lapse amplitude changes of Region 2 result from noise between surveys or were brought on by changing water and gas saturations between surveys.

I3 Sand: volumetrics

The A16 well in the I3 sand produced 12 bscf (billion standard cubic feet) between seismic surveys. Using the amplitude difference map (Figure 17b), wire-line and core data, the original volume of gas in place (OGIP) found in water-swept Region 1 is calculated to be 20 bscf (Equation 5 and Table 12).

$$\text{OGIP} = \frac{(S_{gas})(\phi)(V)}{B_{gas}} \tag{5}$$

The formation volume factor (B_{gas}) had to be estimated because PVT data (pressure versus temperature) was not available for the fluids at Kilauea. The ratio of produced gas to OGIP (12 bscf/20 bscf) shows approximately 60% of the OGIP in the water swept region was produced and 40% remains in the reservoir.

I3 Sand: geology

The I3 sand is extremely thick and according to net sand calculations from well logs, continues to increase in thickness downdip (Figures 4a and 5). The I3 sand is interpreted to be a large sheet sand due to its massive thickness and large aerial extent. This interpretation is supported by the I3 shut-in bottom hole pressure which decreased only slightly during production (Figure 19b). The large size of the downdip aquifer was able to maintain reservoir pressure as fluids were produced from the updip A16 well.

There is a zone of amplitudes surrounding the A11 well on the I3 difference map which did not dim between seismic surveys (Figure 17). This lack of amplitude decrease around the A11 well is interpreted to represent a region of bypassed pay which was not swept by the rising water contact. Log and core data indicate this region is more shale prone, has lower permeability and has lower porosity than surrounding sand (Tables 13 and 14, Figures 5 and 25). Due to the low permeability, the gas around the A11 well was not able to move to the A16 perforations (Figure 17b). Impedance near the A11 well remained constant between surveys and no significant amplitude changes are observed on difference maps because this low permeability region was not swept by water.

TA2 Sand: production

Oil and gas production decreased as water production rose significantly over a year prior to the 1995 seismic survey in the three wells found in the TA2 oil rim (Figures 21 and 22). These increases in water production are interpreted to represent water breaking through into the perforations of the three downdip wells (Figure 24). As reserves were produced from the oil rim wells and the A9, the oil-water contact migrated upward. Each oil rim well watered out as the oil-water contact continued to move up-structure. The water contact eventually reached the A11 well, which produced high volumes of water for ten days in 1996 (Figure 18a).

Early in 1994, the updip A9 well's condensate-gas ratio changed (Figures 7 and 20). Gas production rose as condensate production declined. This change in condensate-gas ratio is hypothesized to result from the 1400 p.s.i pressure drop in the TA2 sand which caused the TA2 reservoir to cross the dew point (Figure 23) (Burcik, 1957 and Craft et al., 1991). When the dew point was crossed, liquid oil began condensing in the reservoir near the A9 wellbore (Figure 18a). As condensate dropped out in the reservoir, less condensate was carried to the surface by the gas being produced. This caused the decline in the condensate-gas ratio (Figure 20b). The gas was more mobile than the liquid condensate and was preferentially produced by the A9 well.

TA2 Sand: amplitude changes

Region 1 on the difference maps is interpreted to represent an area swept by water between the two seismic surveys (Figure 18b). As reserves were produced from the oil rim and the updip A9 well, the original oil-water contact migrated approximately 750 feet vertically (Figure 18a). As hydrocarbons were removed, water replaced oil and gas in the downdip portion of the reservoir. This increase in pore water saturation increased the acoustic impedance and caused the time-lapse amplitude decrease (dimming) observed on the difference maps (Wang, 2001). The 1995 gas-water contact is interpreted to be found at the top of the dimmed amplitudes of Region 1 (Figure 18).

The dimming associated with Region 2 is interpreted to be caused by the increase in condensate saturation near the A9 wellbore as pressure in the TA2 dropped and the dew point curve was crossed (Figures 18b and 23). As gas was preferentially removed, condensate was left behind. This increase in liquid condensate saturation increased the impedance between seismic surveys. The increase in impedance caused the time-lapse amplitude dimming observed in Region 2 on the TA2 difference map (Figure 18b).

The time-lapse amplitude brightening observed in Region 3 is interpreted to represent a region of bypassed pay which was not swept by water between the 1985 and 1995 seismic surveys (Figure 18b). As wells produced from the TA2 sand, the gas in Region 3 was not able to flow towards the A9 well, possibly due to permeability barriers. If Region 3 were swept by water between seismic surveys, we would expect the impedance to increase and yield time-lapse amplitude dimming, similar to Region 1. Texaco is recompleting a well (March 2001) located close to Region 3 in an attempt to recover pay from this area.

Significant amplitude brightening is found in Region 4, due north of the A9 well (Figure 18b). This brightening may represent bypassed pay which is trapped near the edge of the TA2 sand or could be an erroneous amplitude change induced by our normalization and mapping. Without well control in this region, it is difficult to suggest with any confidence these amplitude changes are real or noise.

TA2 Sand: volumetrics

390,000 barrels of oil were produced from the TA2 oil rim between seismic surveys (Figures 18a and 21). The original volume of oil in place (OOIP) in the TA2 oil rim was 1,500,000 stock tank barrels (STB) (Equation 6 and Table 15).

$$\text{OOIP} = \frac{(S_{oil})(\phi)(V)}{(B_{oil})(5.615)} \tag{6}$$

The ratio of oil produced to OOIP (390,000 STB/1,500,000 STB) suggests the three oil rim wells produced 26% of the original oil found in the TA2, the rest remains in the reservoir.

The updip A9 well had a condensate-gas ratio (CGR) of roughly 15 STB/mmscf (stock tank barrels per million standard cubic feet) prior to the dew point hypothetically being crossed in February of 1994 (Figures 20b and 23b). Between the dew point being crossed and the 1995 seismic survey, 4,300 mmscf of gas and 58,400 STB of condensate were produced from the A9 well. According to the condensate-gas ratio (15 STB/mmscf), 64,500 STB of condensate should have been produced in that time period. This indicates, at the very least, 6,100 STB of condensate were left in the reservoir near the A9 well. By converting from STB to reservoir volume ($V_{con\text{-}res}$) and distributing this unproduced volume of condensate over the dimmed region observed on the amplitude difference map (Region 2, Figure 18b), the minimum condensate saturation (S_{cond}) around the A9 well is calculated to be 0.4% (Equations 7 and 8, and Table 16). The reservoir porosity and water saturation are assumed to remain constant through time and the formation volume factor for condensate (B_{cond}) was estimated (Table 16).

$$V_{con\text{-}res} = (STB)(B_{cond})(5.615) \tag{7}$$

$$S_{cond} = \frac{(V_{con-res})}{(\phi)(V)} \tag{8}$$

It is interpreted that after the dew point was crossed, the water saturation (S_w) remained at 30%, the gas saturation (S_{gas}) dropped from 70% to at least 69.6% and condensate saturation (S_{cond}) rose from 0% to at least 0.4% in the region where seismic amplitudes dimmed surrounding the A9 well of the TA2 sand (Figure 18b).

TA2 Sand: geology

Net sand maps show the TA2 sand is much thinner than the I3 sand and does not thicken downdip like the I3 sand (Figures 4 and 6). The TA2 reservoir is interpreted to be a relatively narrow channelized sand deposit which resulted from sediments filling in a small topographic low at the time of deposition. This sand has since been tilted towards the modern day basin center (southeast) and filled with hydrocarbons. The net sand map shows the sand is thickest in the center of the reservoir and thins on all flanks (Figure 6). The very thin (<120 feet, 37m) and potentially less continuous nature of the TA2 sand help justify the large reservoir pressure pull-down experienced during production (Figure 23a). Wireline logs indicate the TA2 sand is more blocky and less shale prone towards the north, which leads to the interpretation that sediments were deposited from the north or northeast (Figures 7, 18b, 22, and 26).

Porosity and permeability are greatest in the middle of the TA2 sand, as opposed to near the contacts with the super and subjacent bounding shale layers (Tables 17, 18, and 19 and Figure 18b). Although average permeability and porosity tends to be higher at the north end of the reservoir near the A9 well, there is insufficient wireline and core data in the south to help justify the interpretation that amplitude brightening in Region 3 on amplitude difference maps represents bypassed pay (Figure 18b). Sidewall core data from the A6 well and wireline logs from the #2 well (updip side of Region 3, Figure 18b) show similar permeability and porosity values to the logs and core taken from the downdip A12 well (Tables 18 and 19 and Figures 22 and 26). The gamma ray log for the #2 well shows the TA2 sand is more blocky and less shaley than at the downdip A12 well (Figures 22 and 26). Without core or wireline data from the center of Region 3, the low permeability and bypassed pay interpretation rests solely on the time-lapse seismic difference maps and production data for the TA2 sand (Figure 18b).

Discussion

Unlike previous 4D studies, we have chosen to difference amplitude maps, not volumes of seismic data. The steep dipping strata and different processing flows used on the Kilauea seismic data prevented us from producing difference cubes. Although going back to pre-stack field data and reprocessing both vintages using identical streams would possibly allow differencing the two seismic volumes, our methodology was designed to be applied to 'off the shelf' legacy data in order to gain reasonable time-lapse results without the financial and temporal costs associated with reprocessing pre-stack data.

The differences in two-way travel time (ms) between the 1985 picks and rebinned 1995 picks for both horizons were calculated (Figure 27) and compared to the differences between picks from the fully normalized 1985 and 1995 volumes (Figures 28 and 29). In both the pre-normalization and post-normalization two-way time difference maps, the 1995 picks were subtracted from the 1985 picks for each sand. We found there are significant travel time differences to the mapped horizons in the 1985 and 1995 volumes, even after normalization (Figures 28 and 29). These differences are due to acquisition and processing differences which still exist after normalization. These two-way travel time differences manifest themselves as dip angle and depth discrepancies between sands in the normalized 1985 and 1995 volumes (Figure 29). These differences in dip angle and depth to the sands justify using difference maps as opposed to difference volumes.

There are two distinct areas on the two-way time difference maps where extremely large travel time differences between the 1985 picks and normalized 1995 picks exist (Figure 28). These are found along A to A’ on Figure 28a and B to B’ on Figure 28b. These areas coincide with two regions of questionable seismic amplitude change on our amplitude difference maps (Figures 17b, Region 2 and 18b, Region 4). The picks for both sands and both vintages of data were double checked and I am left with no reasonable explanation why the two-way time to the sands in these areas are so different (Figures 28 and 29). I have confidence the amplitude differences are related to the changes in two-way time between vintages of data, but am uncertain why these two-way time changes are concentrated in small areas and are not observed everywhere along structure or along the entire edge of salt, etc.

The majority of amplitude dimming observed on difference maps (Figures 17b and 18b) was explained by increasing water saturation which increased the acoustic impedance. Density (RHOB) and sonic (DT) logs through several Kilauea reservoirs and aquifers were used to confirm increasing the water saturation, increases the impedance (Table 20, Figures 7, 22, 25, and 26). The logs for the A11 well show the typical trend recorded by DT and RHOB logs (Figure 25). Density and seismic p-wave velocity decrease when going from the subjacent shale, upwards into a water-filled sand (Figure 25). The density and velocity then decrease more when a hydrocarbon-water contact is breached. Another decrease in density and velocity would be seen if going upwards from oil into gas in the same sand (A12 well, Figure 22). Density and velocity increase substantially when exiting the top of a hydrocarbon bearing sand (Figure 25). The impedance logs (density*velocity) were produced from the RHOB and DT logs and the results were averaged and summarized in Table 20.

These acoustic impedances were then used to calculate reflection coefficients for the different boundaries observed in the I3 and TA2 sands (Tables 20 and 21). The percent change in reflection coefficient for the gas and oil swept regions of the I3 and TA2 were approximated (Table 22). These changes in reflection coefficient represent an upper bounds on the magnitude of change expected because residual hydrocarbons were not accounted for, 100% water sweep was used. Residual oil and gas would lower the impedance of the sand and ultimately result in a greater reflection coefficient at that shale-sand boundary. This would result in a smaller percent change in reflection coefficient when going from unswept 1985 to swept 1995 than shown in Table 22.

Amplitude maps show the downdip TA2 oil rim amplitudes dimmed by roughly 40% near the A5st3 well between surveys (Figure 14), which compares to a predicted maximum reflection coefficient change of -49% (Table 22). Burkhart (1997) found amplitudes dimmed between 50% and 100% in water swept regions of the K40 reservoir, South Timbalier block 295. In these areas, residual oil saturation was 22%. Burkhart (1997) concluded sand thickness influenced amplitude differences, with thinner sand in the swept region showing less amplitude change through calendar time.

After the normalization was completed and interpretations made for the I3 and TA2 sands, the original methodology was questioned. Were all of the steps necessary? What steps could be omitted in order to expedite the normalization and still arrive at similar conclusions? In order to answer these questions, a new methodology was tested. The raw 1985 seismic data were used along with the rebinned 1995 seismic volume. The I3 and TA2 horizons were mapped in both vintages and then amplitude balancing of the 1995 maps proceeded using the same aquifer surface (27x27 traces) as in the original normalization.

This is called the “quick” methodology because subvolumes, bulk shifting, bandpass filtering, and Wiener filtering have been intentionally eliminated (Tables 4 and 5). Amplitude difference maps were produced after the 1995 maps were normalized using the “quick” method (Tables 8 and 9). The amplitude balanced 1995 map was subtracted from the raw 1985 map for both sands (Figures 30 and 31). These I3 and TA2 “quick” amplitude difference maps were then converted to standard deviations of amplitude change using the same methodology as our original normalization (see page 12) (Figures 32a and 33a). Two standard deviations of amplitude change or less were then shaded grey on the “quick” I3 and TA2 difference maps (Figures 32b and 33b).

Eliminating many of the original normalization steps results in the amplitude statistics for maps and volumes having larger standard deviations. An example of this is comparing the original aquifer surface statistics to the “quick” aquifer surface statistics, both before and after differencing the horizons (Tables 4 and 5).

Although the “quick” method (rebin and amplitude balance) does not address as many of the inherent acquisition and data processing differences found in the 1985 and 1995 data, the “quick” amplitude difference maps look nearly identical to those produced by the more robust and time consuming original normalization method (compare Figures 17b and 18b to 32b and 33b). I believe the same interpretations would have come from the “quick” method, as produced by the original method used in this study. I recommend applying a bandpass filter and bulk shifting one of the volumes because these steps are not time intensive and are fairly simple to include in the normalization flow. Wiener filtering is the only step I would potentially skip in future time-lapse normalizations where I intended to difference amplitude maps.

Conclusions

The tops of both the I3 and TA2 sands are imaged as seismic troughs due to the drop in acoustic impedance when traveling from the superjacent shales into the slower, less dense sands of the two reservoirs investigated. For both sands, the hydrocarbon bearing reservoirs are imaged with larger amplitude troughs than their downdip water-filled aquifers. Two vintages of seismic data were normalized using downdip aquifer volumes, which are assumed to be free from production effects. Normalization parameters were calculated in the aquifer volumes and then applied updip to the reservoir regions for each sand studied. The normalization methodology used subvolumes of seismic so the two sands could be normalized independently. The 1995 seismic data were rebinned, bulk shifted, bandpass filtered, Wiener filtered, and amplitude balanced to match the 1985 seismic data.

Seismic amplitude difference maps for the I3 sand show a large region of dimming where amplitudes decreased between seismic surveys (Figure 17a). This dimming was correlated to the high volume of water produced from the A16 well in 1995. Production from the I3 sand pulled the gas-water contact 160 feet (vertically) up structure to the A16 perforations (Figures 5 and 24). The increase in water saturation in the I3 pores increased the acoustic impedance and caused the 4D amplitude dimming.

Production from the TA2 resulted in a 750 feet (vertically) upward migration of the gas-water contact between the 1985 and 1995 seismic surveys (Figures 18a and 24). Dimming observed low on structure in the TA2 is correlated to the migration of the water contact up structure and is supported by the oil rim wells watering out prior to 1995 (Figure 21). A region of dimming near the A9 well in the TA2 sand was attributed to a large reservoir pressure drop between surveys which forced the reservoir to cross the dew point curve (Figures 18b and 23). Condensate saturation in the reservoir increased as gas was preferentially produced by the A9 well, illustrated by the decreasing condensate-gas ratio (Figure 20). Removing the gas and leaving behind liquid condensate increased the impedance and resulted in the dimming observed on amplitude difference maps. There is a region of brightening in the TA2 sand updip from the A12 well which is thought to represent bypassed pay (Region 3, Figure 18b). Log and core data from nearby wells are unable to verify this claim.

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Tables

Table 1: Acquisition and Processing Parameters

parameter	Geco-Prakla 1985	Diamond 1995
sail direction	91/271	90/270
source interval	25m	31.25m
cable length	2975m	6000m
fold	30	48
sample rate	4ms	4ms
trace length	7000ms	10500ms
final bin size	25x12.5m	12.5x20m

Table 2: Nomenclature

Variable	Description	Units
$\hat{S}$	Rebinned 1995 trace	none
A_1, A_2, A_3, A_4	Areas surrounding trace location of 1985 survey, bounded by 1995 survey trace locations	m^2
S_1, S_2, S_3, S_4	Amplitudes from the 1995 survey	none
y_i	1995 amplitude map value prior to amplitude balancing	none
$\hat{y}_i$	1995 amplitude map value after amplitude balancing	none
σ_x	Standard deviation of amplitudes extracted from the 1985 aquifer surface	none
σ_y	Standard deviation of amplitudes extracted from the 1995 aquifer surface	none
$\bar{x}$	Mean value of amplitudes extracted from the 1985 aquifer surface	none
$\bar{y}$	Mean value of amplitudes extracted from the 1995 aquifer surface	none
r	Seismic correlation coefficient	none
n	Number of values in a correlation calculation	none
S_{gas}	Gas saturation	none
ϕ	Porosity	none
V	Bulk volume of hydrocarbon bearing rock	ft^3
B_{gas}	Formation volume factor for the gas	ft^3/scf
S_{oil}	Oil saturation	none
B_{oil}	Formation volume factor for the oil	bbls/STB
$V_{con\text{-}res}$	Volume of condensate at reservoir conditions	ft^3
STB	Stock Tank Barrels	STB
B_{cond}	Formation volume factor for the condensate	bbls/STB
S_{cond}	Condensate saturation	none

Table 3: Calculated Bulk Shifts

	In-line shift	Cross-line shift	Time shift
1995 I3 sub-volume	none	none	-4ms
1995 TA2 subvolume	25m	none	-24ms

Table 4: I3 Aquifer Surface Amplitude Statistics

Aquifer Surface	Mean	Standard Deviation
Original Normalization		
Raw 1985	-1831	736
Bandpassed1985	$\bar{x}$=-1851	σ_x=607
Rebinned 1995	-2898	858
Wiener Filtered 1995	$\bar{y}$=-1597	σ_y=416
Amplitude Balanced 1995	-1852	607
Difference Map	0.05	771
“Quick” Normalization		
Raw 1985	$\bar{x}$=-1831	σ_x=736
Rebinned 1995	$\bar{y}$=-2898	σ_y=858
Amplitude Balanced 1995	-1831	736
Difference Map	-0.07	916

Table 5: TA2 Aquifer Surface Amplitude Statistics

Aquifer Surface	Mean	Standard Deviation
Original Normalization		
Raw 1985	-3271	941
Bandpassed1985	$\bar{x}$=-3151	σ_x=941
Rebinned 1995	-3012	758
Wiener Filtered 1995	$\bar{y}$=-1834	σ_y=417
Amplitude Balanced 1995	-3144	939
Difference Map	-6.7	1287
“Quick” Normalization		
Raw 1985	$\bar{x}$=-3271	σ_x=941
Rebinned 1995	$\bar{y}$=-3012	σ_y=758
Amplitude Balanced 1995	-3271	941
Difference Map	-0.002	1340

Table 6: I3 Aquifer Volume Amplitude Statistics

Aquifer Volume	Mean	Standard Deviation
1985	6.8	1186
Rebinned 1995	11.6	1597
Difference	-4.9	1430
1985	6.8	1186
Brute Shifted 1995	13.7	1606
Difference	-7.0	1334
Bandpassed 1985	6.7	1091
Bandpassed 1995	14.0	1534
Difference	-7.0	1164
Bandpassed 1985	6.7	1091
Wiener Filtered 1995	12.0	789
Difference	-5.5	779

Table 7: TA2 Aquifer Volume Amplitude Statistics

Aquifer Volume	Mean	Standard Deviation
1985	2.3	1932
Rebinned 1995	-0.7	1657
Difference	3.0	2532
1985	2.3	1932
Brute Shifted 1995	-9.0	1661
Difference	11.0	1893
Bandpassed 1985	2.7	1907
Bandpassed 1995	-9.5	1622
Difference	12.0	1833
Bandpassed 1985	2.7	1907
Wiener Filtered 1995	-8.0	1253
Difference	11.0	1474

Table 8: I3 Amplitude Map Statistics

Map	Figure	Mean	Standard Deviation
Original Normalization			
Bandpassed 1985	13a	-2124	1830
Raw 1995	13b	-2657	2149
Rebinned 1995	none	-3189	2612
Amplitude balanced 1995	13c	-1705	1778
Difference map (10a-10c)	13d	-433	1621
Diff. map in standard dev.	17a,b	-0.56	2.10
“Quick” Normalization			
Raw 1985	30a	-2144	1888
Raw 1995	30b	-2657	2149
Rebinned 1995	none	-3189	2612
Amplitude balanced 1995	30c	-2080	2238
Difference map (30a-30c)	30d	-447	2174
Diff. map in standard dev.	32a,b	-0.49	2.37

Table 9: TA2 Amplitude Map Statistics

Map	Figure	Mean	Standard Deviation
Original Normalization			
Bandpassed 1985	14a	-5627	3845
Raw 1995	14b	-5073	3226
Rebinned 1995	none	-5572	3395
Amplitude balanced 1995	14c	-5508	4143
Difference map (14a-14c)	14d	-22	3101
Diff. map in standard dev.	18a,b	-0.02	2.41
“Quick” Normalization			
Raw 1985	31a	-5766	3825
Raw 1995	31b	-5073	3226
Rebinned 1995	none	-5572	3395
Amplitude balanced 1995	31c	-6454	4219
Difference map (31a-31c)	31d	470	3404
Diff. map in standard dev.	33a,b	0.35	2.54

Table 10: I3 Shut-In Bottom Hole Pressures

Well	Depth (Feet TVDSS)	Date (m/d/yr)	Pressure (psi)
A16	4354	11/12/92	2344
A16	4221	1/13/96	2108
A16	4221	8/18/96	1969
A16	4221	4/28/97	1906
A16	4190	11/2/98	1969

Table 11: TA2 Shut-In Bottom Hole Pressures

Well	Depth (Feet TVDSS)	Date (m/d/yr)	Pressure (psi)
A5st	7550	8/18/90	3857
A12	7492	3/18/91	3880
A5st3	7477	10/5/91	3753
A9	6644	1/2/92	3679
A5st3	7477	7/20/93	2840
A9	6644	7/22/93	2804
A9	6644	7/27/94	2408
A5st3	7477	7/28/94	2482
A9	6644	8/15/96	1784
A11	6801	8/10/97	1571

Table 12: I3 Gas Volumetrics

Symbol	Name	Value
OGIP	original gas in place	19,868,000,000 ft^3
S_{gas}	gas saturation from logs	0.88
ϕ	porosity from core	0.30
V	bulk rock volume of dimmed region from maps	451,550,000 ft^3
B_{gas}	estimated formation volume factor	0.006 reservoir ft^3/ standard cubic feet

Table 13: I3 Core Data, A16 Well

Measured Depth (Feet)	Permeability (millidarcies)	Porosity (%)
6029	4	19.3
6086	125	28.4
6150	350	29.9
6242	575	31.4
6304	1330	32.8
6378	560	30.0
6414	2250	33.3
6466	1600	32.3
6504	3090	33.4

Table 14: I3 Core Data, A11 Well

Measured Depth (Feet)	Permeability (millidarcies)	Porosity (%)
5331	830	29.6
5372	150	26.9
5423	70	23.1
5444	1520	30.3
5447	820	29.8
5469	1045	29.7
5480	305	28.2
5506	385	28.7
5531	440	30.7

Table 15: TA2 Oil Volumetrics

Symbol	Name	Value
OOIP	original oil in place	1,500,000 barrels
S_{oil}	oil saturation from logs	0.654
ϕ	porosity from core	0.26
V	bulk rock volume of dimmed region from maps	59,125,000 ft^3
B_{oil}	estimated formation volume factor	1.2 reservoir barrels/ stock tank barrels
(5.615)	correction to go from ft^3 to barrels	5.615 ft^3/barrel

Table 16: TA2 Condensate Volumetrics

Symbol	Name	Value
$V_{con\text{-}res}$	volume of surface condensate converted to reservoir volume	58,228 ft^3
STB	stock tank barrels of unproduced condensate	6,100 STB
B_{cond}	estimated formation volume factor	1.7 reservoir bbls/STB
(5.615)	correction to go from ft^3 to barrels	5.615 ft^3/barrel
S_{cond}	condensate saturation	0.004
ϕ	porosity	0.30
V	bulk rock volume of dimmed area from maps	47,517,000 ft^3

Table 17: TA2 Core Data, A9 Well

Measured Depth (Feet)	Permeability (millidarcies)	Porosity (%)
7528	7	19.7
7536	140	27.9
7548	810	30.5
7556	1750	33.7
7568	1275	31.5
7588	1540	31.5
7595	840	29.1
7606	170	25.6
7614	170	27.4

Table 18: TA2 Core Data, A12 Well

Measured Depth (Feet)	Permeability (millidarcies)	Porosity (%)
9440	800	32.6
9450	800	30.1
9466	1150	34.9
9478	1800	33.9
9510	1350	33.3
9531	600	31.0
9564	1100	33.6
9574	450	32.2
9588	110	29.5
9604	80	27.4

Table 19: TA2 Core Data, A6 Well

Measured Depth (Feet)	Estimated #2 well Measured Depth (Feet)	Permeability (millidarcies)	Porosity (%)
8014	7240	5	18.8
8020	7250	4	18.1
8026	7280	1470	31.7
8032	7290	1535	30.5
8050	7310	1240	29.9
8060	7330	260	26.8
8076	7350	18	21.3

Table 20: Acoustic Impedances

Strata	Density: RHOB logs (g/cc)	1/Velocity: DT logs (μ sec/ft)	Velocity (ft/ms)	Impedance (g/cc)(ft/ms)
shale	2.240	117	8.547	19.145
water sand	2.120	145	6.897	14.621
oil sand	2.078	187	5.348	11.112
gas sand	1.915	195	5.128	9.821

Table 21: Reflection Coefficients

Geologic Boundary (layer 1/layer 2)	Layer 1 Impedance (g/cc)(ft/ms)	Layer 2 Impedance (g/cc)(ft/ms)	Reflection Coefficient
shale/gas sand	19.145	9.821	-0.322
shale/oil sand	19.145	11.112	-0.265
shale/water sand	19.145	14.621	-0.134
gas sand/shale	9.821	19.145	0.322
oil sand/shale	11.112	19.145	0.265
water sand/shale	14.621	19.145	0.134
gas sand/oil sand	9.821	11.112	0.062
gas sand/water sand	9.821	14.621	0.196
oil sand/water sand	11.112	14.621	0.136

Table 22: Theoretical Reflection Coefficient Changes

Fluid Change	1985 Reflection Coefficient (unswept)	1995 Reflection Coefficient (100% swept)	% Change in Reflection Coefficient
Gas sand swept by water	-0.322	-0.134	-58%
Oil rim swept by water	-0.265	-0.134	-49%

Figure Captions

Fig. 1. Green Canyon Block 6 is located 200 miles (322km) southwest of New Orleans. The Kilauea platform is set in 622 feet (190m) of water on the continental shelf-slope break.

Fig. 2. The Kilauea platform is in the southwestern corner of Green Canyon Block 6 and produces from reservoirs which extend into GC50, to the south. Cross-section A-A' is shown in Figure 3. The thick solid box denotes the map view location of the I3 subvolume and the thin solid box locates the TA2 subvolume. The smaller dashed boxes are the aquifer volume locations for the two sands investigated. The thick dashed box (3) is the I3 aquifer volume and the thin dashed box (2) is the TA2 aquifer volume.

Fig. 3. Cross-section A-A' (located in Figure 2). The top of the I3 and TA2 sands and the highest occurrence of *Trimosina denticulina* (Trim A) are mapped with white dotted lines. All horizons terminate against salt and a normal fault to the west. The thick solid box corresponds to the I3 subvolume and the I3 aquifer volume is dashed and labelled #3. The thin solid box corresponds to the TA2 subvolume and the TA2 aquifer volume is dashed and labelled #2.

Fig. 4. The I3 sand was mapped in the bandpassed 1985 volume and seismic amplitudes along the mapped horizon were extracted. These maps show the bandpassed I3 sand amplitude extraction overlain with 100ft. net sand contours (4a) and 100ft. net pay contours (4b). Net sand thickens basinward and net pay is greater than 200 feet in the center of the reservoir. Contouring in the southwestern portion of the field was estimated due to the lack of well control. Net sand and net pay thicknesses were calculated from well logs (see Figure 5).

Fig. 5. Type logs for the I3 sand taken from the A16 well. Depth scales are TVDSS (true vertical depth sub-sea) and MD (measured depth along the borehole). The top of the I3 porosity is indicated by the increase in resistivity on the resistivity log. Three different sets of perforations were used in the A16 well as the water contact rose during production. Sand and shale baselines were chosen (35 and 95 gapi respectively) and averaged to yield the cut-off between shale and sand (65 gapi). For the A16 well, sediments with gamma ray values less than 65 gapi were classified as sand and their thickness was compiled for use in the construction of the I3 net sand map (Figure 4a). Net sand at the A16 well was calculated to be 197 ft. The cut-off between pay and no-pay for all resistivity logs was set at 2 ohmm. Sediments with greater than 2 ohmm of resistance were classified as hydrocarbon bearing and a thickness was compiled for use in the I3 net pay map (Figure 4b). Net pay at the A16 well was calculated to be 226 ft. If the calculated net pay was thicker than net sand for a particular well (such as here at the

A16 well), the net pay thickness was used for net sand contouring. This was done to ensure net sand was as thick or thicker than net pay values on our maps. This procedure for calculating net sand and net pay was used for all wells and for both sands. Sonic (DT) and density (RHOB) logs were not available for this well.

Fig. 6. The TA2 sand was mapped in the bandpassed 1985 volume and seismic amplitudes along the mapped horizon were extracted. These maps show the bandpassed TA2 sand amplitude extraction overlain with 20ft. net sand contours (6a) and 10ft. net pay contours (6b). Net sand thins basinward and there is over 50 feet of net pay in the north-central part of the TA2 reservoir. Net sand and net pay were calculated using the method discussed in Figure 5.

Fig. 7. Type logs for the TA2 sand taken from the A9 well. At this depth, the TA2 is gas charged. The gas is responsible for the large impedance decrease. The perforations for the TA2 sand are shown. A sand baseline of 25 gapi and shale baseline of 80 gapi yielded a sand cut-off of 52.5 gapi. Net sand for the A9 well was calculated to be 65ft. and net pay was 41ft. The logs extend down to the TA4 sand (not studied in this paper) in order to show the petrophysical properties of oil saturated sand. No logs exist for the downdip oil bearing portion of the TA2 sand so densities (RHOB) and velocities (1/DT) for oil sand were taken from the TA4 sand (see Tables 20 and 21). The contact separating gas and oil in the TA4 is easily seen as a density (RHOB) change at 8005 feet MD.

Fig. 8. Map showing trace spacing differences between the 1985 and 1995 seismic volumes prior to normalization. Seismic bins are 25m x 12.5m in the 1985 volume and 12.5m x 20m in the 1995 volume. The 1995 volume is rebinned to match the trace spacing of the 1985 seismic data using an inversely weighted linear interpolation (see text).

Fig. 9. Frequency spectra before and after a 0-40Hz bandpass filter was applied to the I3 (9a) and TA2 (9b) subvolumes.

Fig. 10. Amplitude histograms for the aquifer surface of the I3 sand. Amplitudes were extracted from the bandpassed 1985 (10a), Wiener filtered 1995 (10b) and amplitude balanced 1995 (10c) aquifer surfaces (see Figure 13 for aquifer surface location). Amplitude balancing, the final step of normalization, forces the mean and standard deviation of the 1995 aquifer surface amplitudes to be similar to those from the 1985 data. Each histogram is composed of 729 samples (each aquifer volume is composed of 729 traces and any mapped surface through the aquifer volume will have 729 amplitude values). Bin size for all histograms is 250.

Fig. 11. Amplitude histograms for the aquifer surface of the TA2 sand. Amplitudes were extracted from the bandpassed 1985 (11a), Wiener filtered 1995 (11b) and amplitude balanced 1995 (11c) aquifer surfaces (see Figure 14 for aquifer

surface location). Amplitude balancing, the final step of normalization, forces the mean and standard deviation of the 1995 aquifer surface amplitudes to be similar to those from the 1985 data. Each histogram is composed of 729 samples (each aquifer volume is composed of 729 traces and any mapped surface through the aquifer volume will have 729 amplitude values). Bin size for all histograms is 250.

Fig. 12. Plots showing the improvement in aquifer volume correlation (r) for the I3 sand (12a) and TA2 sand (12b) at four stages of normalization. Perfect correlation is 1.0. Correlation is calculated over a 4 sample (16ms) moving time window (Burkhart, 2000). All aquifer volumes are composed of 729 traces and the number of points (n) in each correlation window is 2,916 (729 traces x 4 samples per trace).

Fig. 13. Seismic amplitude and amplitude difference maps for the I3 sand. Amplitudes are extracted from the mapped I3 horizon (13a,b,c). Structure contours in two-way travel time (ms) are overlain. The A16 production well is shown with a red circle. (a) I3 amplitude map from the bandpassed (0-40Hz) 1985 volume. The red box shows the location of the I3 aquifer surface and aquifer volume. (b) I3 amplitude map from the 1995 volume, prior to normalization. (c) Fully normalized 1995 I3 seismic amplitude map. (d) I3 difference map is calculated by subtracting the normalized 1995 map from the 1985 map (13a-13c).

Fig. 14. Seismic amplitude and amplitude difference maps for the TA2 sand. Amplitudes are extracted from the mapped TA2 horizon (14a,b,c). Structure contours in two-way travel time (ms) are overlain. The green circles represent oil rim production wells. Red circles represent production gas wells. (a) TA2 amplitude map from the bandpassed (0-40Hz) 1985 volume. The red box shows the location of the TA2 aquifer surface and aquifer volume. (b) TA2 amplitude map from the 1995 volume, prior to normalization. (c) Fully normalized 1995 TA2 seismic amplitude map. (d) TA2 difference map is calculated by subtracting the normalized 1995 map from the 1985 map (14a-14c).

Fig. 15. Amplitude histograms for the I3 difference map (shown in Figure 13d). (a) Amplitude histogram for the aquifer surface of the I3 difference map. The mean amplitude is near zero because normalization forced the amplitude values of the 1985 and 1995 aquifer surfaces to be similar prior to differencing the maps. 729 amplitude samples make up the difference map aquifer surface. The histogram bin size is 250. (b) Amplitude histogram for the entire I3 difference map. Two standard deviations of aquifer surface amplitude change are found between the vertical lines. These amplitudes are shaded grey in Figure 17b. 9434 amplitude samples make up the I3 amplitude difference map. The histogram bin size is 500.

Fig. 16. Amplitude histograms for the TA2 difference map (shown in Figure 14d). (a) Amplitude histogram for the aquifer surface of the TA2 difference map. The mean amplitude is near zero because normalization forced the amplitude values of the 1985 and 1995 aquifer surfaces to be similar prior to differencing the maps. 729 amplitude samples make up the difference map aquifer surface. The histogram bin size is 250. (b) Amplitude histogram for the entire TA2 difference map. Two standard deviations of aquifer surface amplitude change are found between the vertical lines. These amplitudes are shaded grey in Figure 18b. 13543 amplitude samples make up the TA2 amplitude difference map. The histogram bin size is 500.

Fig. 17. (a) I3 seismic amplitude difference map. Amplitude values converted to standard deviations (see page 12). Structure contours in two-way travel time overlain. The map view location of the A16 wellbore is dashed in yellow, the 1995 perforations are located with the red circle, the 1996 perforations are located with the orange circle and white dots represent well penetrations. The red dashed line is the interpreted 1995 gas-water contact. (b) Amplitude difference map shown in Figure 17a, but standard deviations less than 2 have been shaded grey. Structure contours in two-way time (ms) overlain. Region 1 shows 4D amplitude dimming and Region 2 shows both brightening and dimming. Core data for the A16 and A11 wells are found in Tables 13 and 14.

Fig. 18. (a) TA2 seismic amplitude difference map. Amplitude values converted to standard deviations (see page 12). Structure contours in two-way travel time overlain. The green circles show production oil wells and red circles show production gas wells. White dots represent well penetrations. The original oil-water (oowc) and original gas-oil (ogoc) contacts are shown with solid lines and the interpreted 1995 gas-water contact is shown with the dashed red line. (b) Amplitude difference map shown in Figure 18a, but standard deviations less than 2 have been shaded grey. Structure contours in two-way time (ms) overlain. Regions 1 and 2 show 4D amplitude dimming and Regions 3 and 4 show time-lapse amplitude brightening. Core data for the A9, A12, and A6 well are found in Tables 17, 18, and 19.

Fig. 19. (a) Production history for the A16 well in the I3 sand. Gas production falls off quickly as water increases. In 1996 the original perforations were abandoned and new ones 130 ft. higher up the wellbore were installed. (b) Plot showing I3 shut-in bottom hole pressure (SBHP) through time. The I3 reservoir pressure drops 400 psi between seismic surveys.

Fig. 20. (a) Production history for the updip A9 well in the TA2 sand. The ellipse indicates when condensate production falls and gas production increases. Water breaks through to the A9 perforations in 1997. (a) Plot showing the condensate-

gas ratio for the TA2 A9 well. The condensate-gas ratio begins decreasing steadily in early 1994.

Fig. 21. Production histories for the three downdip oil rim wells in the TA2 sand. The A5st (a), A5st3 (b), and A12 (c) wells watered out at least one year prior to the 1995 seismic survey.

Fig. 22. Suite of wireline logs for the A12 well at the TA2 sand. The perforations used to extract oil are shown with a circle. The contacts between gas-oil and oil-water are shown with dashed lines. Although the gamma ray log (GR) for the TA2 at the A12 well is less blocky than higher on structure (A9 well), the permeability and porosity is still very high in the middle of the sand (Tables 17 and 18). Sonic log (DT) was not available for this well.

Fig. 23. (a) Shut-in bottom hole pressure (SBHP) for the TA2 sand decreases 1400 p.s.i. between seismic surveys. (b) Hypothetical pressure versus temperature (pvt) diagram illustrating the path of reservoir fluids near the A9 well (Craft et al., 1991). It is estimated the dew point curve was crossed in February of 1994 based on the produced condensate-gas ratio (Figure 20). Liquid condenses in the reservoir after the dew point curve is crossed. Reservoir temperature is from actual well data.

Fig. 24. Cartoon showing the interpreted fluid contacts in cross-section in 1985 and 1995. The I3 gas-water contact rises vertically 160 feet and the TA2 water contact rises approximately 750 feet due to production from the sands.

Fig. 25. Suite of wireline logs for the A11 well at the I3 sand. An ILD (induction log, deep) resistivity log was not available so an SFLA (spherically focused log, averaged) resistivity log was substituted to show the hydrocarbon bearing interval (greater than 2 ohmm). The A11 well shows the gas-water contact for the I3 sand at 5550 ft. measured depth. At this contact, the density (RHOB) and seismic velocity (1/DT) increases due to the water saturation increase. The impedance log is calculated from the density and sonic logs (density*velocity) and shows the drop in impedance associated with going from shale into a gas reservoir. The impedance increases from gas sand to water sand and then increases again when exiting the I3 sand and entering the subjacent shale.

Fig. 26. Suite of wireline logs for the Texaco #2 exploration well at the TA2 sand. The gamma ray log (GR) is more blocky at this well than the oil rim A12 well (Figure 22). The presence of gas in the TA2 at this location is responsible for the low velocity, density and calculated impedance values.

Fig. 27. Pre-normalization two-way time difference maps for the I3 sand (27a) and TA2 sand (27b). Difference maps were constructed by subtracting the two-

way time picks (in milliseconds) for the rebinned 1995 data from the raw 1985 picks for each sand. The maps show significant two-way time differences between picks for the 1985 and rebinned 1995 data exist, especially in the downdip TA2 aquifer.

Fig. 28. Post-normalization two-way time difference maps for the I3 sand (28a) and TA2 sand (28b). Difference maps were constructed by subtracting the two-way time picks (in milliseconds) for the normalized 1995 data from the picks for the bandpassed 1985 data. Line A-A’ is shown in cross-section in Figures 29a and 29b. The purple region indicates where the 1985 picks are much shallower (~40 ms) than those for the 1995 volume. Line B-B’ is shown in cross-section in Figures 29c and 29d. The yellow-red region indicates where the 1985 picks are much deeper (~60 ms) than those for the 1995 volume. These two-way time differences indicate that after normalization, the sands still dip at different angles in the 1985 and 1995 volumes. Dip and position differences were the driving force behind differencing amplitude maps and not 3-dimensional volumes.

Fig. 29. Cross-sections along A-A’ and B-B’ from Figure 28 through the fully normalized 1985 and 1995 seismic volumes showing two-way time differences to the I3 and TA2 horizons. Interpretation picks for the 1985 data are yellow and the 1995 picks are in black. Figure 29a shows the I3 sand in 1985 and Figure 29b shows the I3 sand in 1995. The differences in two-way time between picks for the same horizon are apparent high on structure, near salt and the edge of sand. Figure 29c shows the TA2 sand in 1985 and Figure 29d shows the TA2 sand in 1995. The difference between picks for this horizon increase higher on structure.

Fig. 30. Amplitude extraction maps for the I3 sand. Figure 30a shows the amplitude extraction taken from the raw 1985 seismic data. Figure 30b shows the I3 extraction from the raw 1995 seismic data. Figure 30c is an I3 extraction from 1995 seismic data which has been rebinned and amplitude balanced (“quick” normalization). The bulk shifting, bandpass filtering, and Wiener filtering steps were intentionally omitted. Figure 30d is the amplitude difference map created by differencing the raw 1985 extraction and amplitude balanced 1995 extraction (30a-30c). Amplitude dimming is observed low on structure and is very similar to the amplitude difference maps produced using the more robust, original normalization (Figure 13d).

Fig. 31. Amplitude extraction maps for the TA2 sand. Figure 31a shows the amplitude extraction taken from the raw 1985 seismic volume. Figure 30b shows the TA2 extraction from the raw 1995 seismic volume. Figure 31c is a TA2 extraction from 1995 seismic data which has been rebinned and amplitude balanced (“quick” normalization). The bulk shifting, bandpass filtering, and Wiener filtering steps were intentionally omitted. Figure 31d is the amplitude difference map created by differencing the raw 1985 extraction and amplitude balanced 1995 extrac-

tion (31a-31c). Amplitude differences are similar to those produced using the more robust, original normalization method (Figure 14d).

Fig. 32. “Quick” normalization amplitude difference map for the I3 sand produced by subtracting the amplitude balanced 1995 amplitude map from the raw 1985 amplitude map. (a) This is an enlarged map of Figure 30d with amplitudes converted to standard deviations. Structure contours in two-way time are overlain and well penetrations are shown with white dots. (b) Amplitude difference map from Figure 32a with amplitude difference values of 2 standard deviation or less shaded grey. Downdip amplitude dimming (blue and purple) is similar to that observed on amplitude difference maps produced using the original normalization method (Figures 17a and 17b).

Fig. 33. “Quick” normalization amplitude difference map for the TA2 sand produced by subtracting the amplitude balanced 1995 amplitude map from the raw 1985 amplitude map. (a) This is an enlarged map of Figure 31d with amplitude values converted to standard deviations. Structure contours in two-way time are overlain and well penetrations are shown with white dots. (b) Amplitude difference map from Figure 33a with amplitude difference values of 2 standard deviations or less shaded grey. Amplitude differences are similar to those observed on difference maps produced using the original normalization method (Figures 18a and 18b).