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Advanced Reservoir Characterization in the Antelope Shale to Establish the Viability of C02 Enhanced Oil Recovery in California's Monterey Formation Siliceous Shales

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TITLE: **ADVANCED RESERVOIR CHARACTERIZATION IN THE ANTELOPE SHALE TO ESTABLISH THE VIABILITY OF CO2 ENHANCED OIL RECOVERY IN CALIFORNIA'S MONTEREY FORMATION SILICEOUS SHALES**

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Objective

The primary objective of this research is to conduct advanced reservoir characterization and modeling studies in the Antelope Shale reservoir. Characterization studies will be used to determine the technical feasibility of implementing a CO_2 enhanced oil recovery project in the Antelope Shale in Buena Vista Hills Field. The Buena Vista Hills pilot CO_2 project will demonstrate the economic viability and widespread applicability of CO_2 flooding in fractured siliceous shale reservoirs of the San Joaquin Valley. The research consists of four primary work processes: Reservoir Matrix and Fluid Characterization; Fracture Characterization; Reservoir Modeling and Simulation; and CO_2 Pilot Flood and Evaluation. Work done in these areas is subdivided into two phases or budget periods. The first phase of the project will focus on the application of a variety of advanced reservoir characterization techniques to determine the production characteristics of the Antelope Shale reservoir. Reservoir models based on the results of the characterization work will be used to evaluate how the reservoir will respond to secondary recovery and EOR processes. The second phase of the project will include the implementation and evaluation of an advanced enhanced oil recovery (EOR) pilot in the United Anticline (West Dome) of the Buena Vista Hills Field.

Summary of Technical Progress

Outlined below is a status report on the tasks that were performed during the 1st Quarter of 1998. Overall the project remains on budget and on schedule. For the 2nd Quarter of 1998 we plan to place the 653Z-26B well on production, complete core floods, finish the 3D earth model, complete the reservoir simulation. We also will make presentations at the Pacific Section AAPG Ventura, the AAPG Annual Convention, Salt Lake City, Society of Petroleum Engineers Regional Meeting in Bakersfield and Archie Conference in Kerrville, Society of Professional Well Log Analysts Annual Meeting in Keystone, and the Society of Exploration Geophysicists Annual Convention in Dallas.

<u>Task A. Characterize the Brown Shale and Antelope Shale</u>

Task A.4. Fracture Characterization

Task A.4.B. Crosswell Seismic

Professor Ken Bube, a Chevron Petroleum Technology Company (CPTC) consultant, spent several days at TomoSeis, Inc. modifying their velocity imaging code to address stability issues that were affecting our ability to obtain accurate well ties in velocity. These modifications are now being tested and will be applied to the BV Hills data set shortly. Improved velocity models may result in dramatically improved reflection images.

Task A.4.E. Core Fracture Analysis

Wayne Narr and Haiqing Wu of Chevron Technology Company (CPTC) have completed their characterization of the natural fractures in the 653Z core. The core (952' total) contains joint-like fractures, minor faults, and sigmoidal veins (CPTC concentrated mostly on the joints and faults). Density of fracture occurrence varies through the well, with more faults near the top of the core and more joints in the central part. The joints in this well are extremely sparse and very small, hence their effect on productivity is probably not great. Both open and sealed faults are present; their effect on productivity is much more difficult to estimate due to the possible large size of some of the faults. The faults are varied in their degree of openness, orientation, and type, hence no logical pattern to the faults is evident.

Also during the 1st Quarter of 1998, Judson Jacobs and Atilla Aydin of Stanford University have continued their efforts on determining the role that sigmoidal veins play on hydrocarbon migration. Extensive outcrop, thin-section and SEM studies have provided both evidence for the formation mechanism of the veins as well as underscoring their importance on hydrocarbon production from the Buena Vista Hills field.

A field analogue has been designated for the sigmoidal veins that are observed in the 653Z core. There are significant siliceous shale outcrops along the northern California coast which exhibit a similar style of deformation to that which is observed in Buena Vista Hills core. The Laguna Creek outcrop, located approximately five miles north of the city of Santa Cruz, provides an excellent field analogue. The outcrop is composed of Opal-CT siliceous shale which displays a similar occurrence of sigmoidal vein zones as observed in the core. Also it is possible to observe the interactions of individual veins in a three-dimensional sense at this site, as well as noting the relationship of the veins to other deformational structures.

A strong link has been established between the occurrence of sigmoidal veins and hydrocarbons. Outcrop, thin-section and scanning electron microscope (SEM) studies all indicate that sigmoidal veins serve as conduits for hydrocarbon migration. Examination of the veins at the Laguna Creek outcrop and other sites along the northern California coast show that in most cases, there is a relationship between zones of veins which are hydrocarbon-stained to those which are crosscut by oil-bearing breccia zones and fractures.

Microscale observations of sigmoidal veins from the 653Z well reveal the presence of hydrocarbons in two forms. Hydrocarbon staining occurs predominantly along the vein margins, but is also evident in fractures that form within vein interiors. The hydrocarbon does not appear as a massive deposit, but rather coats the diatom grains. Occasionally, however, we do observe individual hydrocarbon droplets. These deposits are dispersed within the opening-mode (Mode I) fractures that regularly form parallel to the vein margins. SEM images of the fractures from unpolished rock samples clearly demonstrate that these Mode I fractures are completely filled with hydrocarbons. Gas chromatographic analysis of the sample shows that it is a highly biodegraded oil.

An examination of core from another well of the Buena Vista Hills field was also conducted during the 1st Quarter of 1998. Core from the 32-26B well shows a similar style of deformation as observed in the 653Z core. Though the core was aged and secondary mineral salts had precipitated over all free surfaces, they were still able to identify and measure the orientation of a number of sigmoidal vein zones. Vein orientations relative to bedding are consistent with the measurements that were obtained from 653Z well.

Task A.4.K. Attenuation Imaging

In the 4th Quarter of 1997, Jerry Harris (Stanford University) had used a newly developed inversion algorithm to produce a 3-D consistent velocity and attenuation model for the Buena Vista Hills crosswell seismic dataset. The resulting images represent what are believed to be the first 3-D inverted images produced from crosswell seismic field data. However, because of hardware limitations, Stanford had to decimate the data by 50% in order to complete the 3-D inversions (and even then a typical inversion took up to one week to run).

During the 1st Quarter of 1998, Stanford ordered a new workstation with sufficient memory to allow them to run the full 3-D tomography inversion without decimation. The new computer should be received in April. In preparation for this, Stanford has been working on improving the tomography algorithm code so that the Buena Vista Hills data can be reprocessed using the full, undecimated, dataset.

Task A.5. Wireline Log Analysis

Task A.5.A. Complex Lithologic Analysis

Schlumberger applied the elementary analysis (ELAN) model developed in the Buena Vista Hills 653Z well to the McKittrick field 342-17Z well. The McKittrick field reservoir is predominantly siliceous shale, of the same phase (Opal-CT) as the Buena Vista Hills reservoir, so it was thought the Buena Vista Hills model may be successfully applied in the McKittrick field. ELAN total porosity matched core porosity in the McKittrick well, but computed oil saturation was appreciably higher than core oil saturation and computed clay volume was too low.

It was recognized that the Photoelectric Factor (PEF) log was reading anonymously high in the McKittrick 342-17Z well, so it was linearly decreased until it was brought into line with the PEF for the Buena Vista Hills 653Z well. After running the Buena Vista Hills ELAN using the standard triple combo logs and modified PEF log in the McKittrick well, it was found that ELAN computed porosity and oil saturation in the McKittrick well agreed closely with those from core, and the computed clay volume was more credible. This test shows that the model developed for Buena Vista Hills can be applied to other siliceous shale fields in the San Joaquin Valley.

Task A.6. Characterize Flow Units

Task A.6.B. Develop Flow Unit Transform

Core Laboratories has developed core-log integration models using the extensive core and log data that was acquired from the 653Z well. The objective of the study was to develop a model which may be used to extend the previously completed conventional core analysis HU (hydraulic units) zonation of the 653Z well to the older wells in Buena Vista Hills in order to determine productive zones, and facilitate future well completions and reservoir management. Four different models were developed: deterministic, probabilistic, Neural Network, and nuclear magnetic resonance (NMR) based probabilistic. The validity and robustness of the models were checked by comparison with measured data within the 653Z cored intervals.

The comparison of measured to predicted permeability for the Neural Network, the probabilistic model, and the NMR model indicates a fairly good match. This is particularly true in the high permeability sands. It was not possible to obtain a good deterministic model due to the large errors in core analysis data, particularly in the low permeability sand. Of the four models developed, the Neural Network model gives the best results. This model can be applied to future wells with modern logging suites (Deep Resistivity, Bulk Density and Thermal Neutron). Unfortunately it can not be applied to the old wells in Buena Vista Hills (Spontaneous Potential and Resistivity) unless synthetic curves are created using a Neural Network program.

Task A.7. Develop 3D Earth Model

Work on the final quality control of 1demensional property data generated from well curves was finalized early in the 1st Quarter, 1998. This was done by using marker data to stratigraphically constrain interval-averaged map plots of thickness, porosity, permeability, and "sandiness" data. These plots were then used to identify anomalous well data values which were reviewed and either corrected or eliminated due to previously unidentified problems with the input log curves.

Efforts to generate sandiness property curves (i.e., proportion sand/siltstone to shale) for each of the Brown/Antelope Shale wells in the dataset were completed using a neural net transform. In this case, the neural net trained on 5 quality-controlled wells with core. Training wells included the 653Z, 552, and the 522A-2 on the United Anticline, and wells 523 and 555 on the Honolulu Anticline. Based on quality-controlled data for these 5 training wells, we obtained a predictive "sandiness" curve with an R correlation coefficient of 0.92.

A neural net permeability transform that more completely captures the range of air permeability measured in the 653Z core for the Brown/Upper Antelope Shale interval was also completed during the past quarter. This was accomplished using a transform based on deep resistivity (DRES), shallow resistivity (SRES), and normalized SP (VSH_RAWS) log curves from the 653Z well. The transform produced a quality-controlled predictive permeability curve with an R correlation coefficient of 0.82.

Marker-constrained interval facies were completed across the United Anticline in BV Hills. These facies were then used to conditionally simulate reservoir properties. Criteria in this automated facies analysis procedure included producing separable facies relative to reservoir properties. We were reasonably successful using analytical strategies that searched for cyclicity in the facies (which is consistent with a turbiditic depositional setting). The analyses were conducted in FaciesFinder and incorporated a mixture of deterministic (geological concepts) and geostatistical criteria.

Two property-simulated sgrid volumes were created for use in subsequent reservoir simulation modeling. The first covers the entire Brown/Upper Antelope Shale sections (in the TMC - P2 interval) on the United Anticline and has 4 ft thick layers. The second was restricted to a ¼-pattern that encompasses only the Upper Antelope Shale (P Pt - P2 interval). The latter is 440 ft X 440 ft, has only two wells within it: 653Z as an injector and a neighboring well (553) as a producer, and has layers that average 0.5 ft in thickness.

The properties, of permeability, porosity and "sandiness" were conditionally simulated for these volumes using FaciesFinder. Oil saturation was subsequently added to the model using functionality in Gocad++. The ¼-pattern element volume was expected to be used for production simulation by Ray Tang of CPTC in April,1998.

Lastly, in preparation for demonstrating the 3D model results in a booth at the AAPG Pacific Section Convention in Ventura, California on April 29 - May 1, 1998, Silicon Graphics (SGI) was contacted to see if a high-end workstation could be loaned to Chevron. SGI approved our request and will loan us a SGI Octane workstation for use in displaying our property simulated sgrid models at the convention.

<u>Task B. Preliminary Preparation for CO2 Injection</u>

Task B.2. Initiate Fluid Characterization and Lab Displacement Tests

The mixed lithology of the B.V Hill reservoir provides challenges and opportunities for designing an effective CO2 injection project. The large permeability contrasts between the sands and the siliceous shale may result in poor sweep efficiency in the shale, whereas, the high permeability sands may also act as easy flow paths for CO_2 to reach more oil if CO_2 can enter the shale by gravity. Therefore we designed an experimental and numerical simulation to evaluate the potentials of designing an effective CO_2 injection project in Buena Vista Hills and in similar siliceous shale reservoirs.

We have finished the waterflood and CO_2 flood experiments in a composite core. The composite core consists of 9 plugs of 1.5 inches in diameter. The plugs were cut from the sands in the 653Z well at the depth from 4413.10 to 4491.15 ft. The composite core was first cleaned by flowing methanol and toluene and then fully saturated with reservoir brine. Stock tank oil was injected to reach initial water saturation Swi (45.73%). Re-combined live oil was then injected to saturate the core with live oil. Both the water flood and the CO_2 flood were conducted at the reservoir temperature (160 F). Water flood was performed at the rate of 4cc/hr. 2.6 PV of brine was injected and resulted in residual oil saturation (Sorw) of 26.58%. CO_2 flood was performed with the down-stream pressure of 2600psi. About 2.5 HCPV of CO_2 was injected at a rate of 1.0 cc/hr. The residual oil saturation at the end of the CO_2 flood was 11.7%. These results suggest that CO_2 flood can be efficient in high temperature reservoirs, in which the minimum miscibility pressure (MMP) is significantly higher than that in low temperature reservoirs (for example, 90 F). We are in the process of building one-dimensional compositional models to simulate the experimental results.

The CO_2 flood in the mixed lithology core continues to produce oil at a relatively constant rate (about 0.6 cc/day). Gas chromatographic analysis of the produced oil suggests that CO_2 extracts hydrocarbons that are lighter than C25. Up to date, we have recovered about 70% of OOIP. The relatively high oil recovery indicates that CO_2 injection can be efficient in mixed lithology systems. We have started building a conceptual model of the experimental system to evaluate the major oil recovery mechanisms involved in the process.

Task B.3. Develop Field Scale Compositional Simulation

Two sets of simulation models are at various stages of construction to investigate the recovery mechanisms at the core scale and to estimate field scale performance. The core scale model represents the mixed-lithology experiment where CO_2 channels through a high permeability zone and oil is recovered from the low permeability siliceous shale by crossflow mechanisms. The coreflood simulation model is 3D and contains 6800 active cells. The phase behavior is represented by a 6-component equation-of-state model that was developed from reservoir condition CO_2-oil measurements.

For the field scale simulations, results from the 3D earth modeling effort are being used to investigate the sweep and recovery behavior of a potential pilot project. The procedure for coarsening the fine scale earth model is being developed for the flow simulations.

Task B.4. Pre-injection Evaluation of the Target Drive Zone

Task B.4.A. Perforate and Evaluate Drive Interval

Stage #1: Hydraulic propped fracture treatments were attempted in two different Upper Antelope Shale intervals in the 653Z well. The first attempt was made at a depth of 4200'-4210' MD (4145'- 4154' TVD). This 10 ft interval was selected, based upon its favorable hydrocarbon saturation and in-situ stress profile. The stress profile was constructed from dipole sonic log, (shear and compressional wave data), processed utilizing Chevron's proprietary Rock Mechanics Algorithm (RMA). The goal of the first hydraulic fracture was to cover both the Lower Brown Shale and the Upper Antelope Shale in a single treatment.

The stress profile generated by RMA indicated the minimum horizontal stress across the perforated interval was approximately 0.5 psi/ft or 2050 psi. Although this horizontal stress seemed low, reservoir pressure in this interval is accordingly low, approximately 700 - 800 psi. A series of diagnostic injections was pumped prior to the main treatment to determine the closure stress, the magnitude of near wellbore friction (or fracture tortuosity) as well as the number of effective perforations accepting fluid. This data is contained in Table #1. During these injections, both surface and downhole tiltmeter arrays were employed, allowing the fracture azimuth, dip and height to be measured.

From the diagnostics injections pumped during Stage #1, the real-time downhole tiltmeter array indicated that there was excessive fracture height growth exceeding the top tiltmeter at 3950 ft. Little to no downward fracture growth was indicated by the downhole tiltmeter array. The cause of this excessive height grow is thought to be the induced fracture propagating into a poorly cement bonded interval, 20 ft above the perforations. Based on the fact that height growth was excessive, (the fracture was not going to cover the intended target interval of the upper Antelope Shale), and the near wellbore fracture complexities resulted in elevated ISIP and closure pressure gradients, it was decided to forego this interval and re-perforate lower in the Antelope Shale.

Elevated ISIP's (Instantaneous Shut-In Pressures) and closure pressure gradients, exceeded overburden gradients, indicated a horizontal or highly dipping fracture component was likely created. Figure #1 is a plot of the lithostatic overburden gradient derived from the openhole density log. It can be seen that the all 3 ISIP's from Stage #1 exceeded the overburden gradient. Surface tiltmeters results (Table #2) indicate that there was consistently no fracture azimuth from one injection to the next, and that there was a significant dipping (non-vertical) component to each fracture created. These multi-component fractures are most likely the cause of the high near wellbore friction (tortuosity).

Surface tiltmeter data corroborates well with the fracture pressure data. The surface tiltmeter data contained in Table #2 shows large volume multi-component fractures, both vertical and dipping, with no specific azimuth. This lack of a preferred fracture azimuth is an indication that the deviatoric stresses are fairly close in magnitude.

STAGE #2: New perforations were added from 4305'- 4315' MD (4244'- 4253' TVD) and the previous perforations were isolated utilizing a packer. Similar diagnostic injections were employed for Stage #2. The results are listed in Table #3.

Predicted stress values from the sonic log data were within 10% of the measured stress after diagnostic Injection #2. Subsequent injections only seemed to complicate near wellbore fracture complexities, as can be seen by the increase in ISIP, closure stress and near wellbore friction (tortuosity). Injection #4, which was a repeat of the crosslinked minifrac (Injection #3), met with injections pressures higher than the wellbore tubulars were rated. Further attempts to hydraulic prop fracture Stage #2 were aborted.

The downhole tiltmeter array did not indicate growth, vertical or otherwise, after injections 1a and 1b, indicating possible horizontal fracture growth. This conclusion is somewhat supported by the surface tiltmeter data listed below in Table #4, but ISIP, and closure pressure gradients were below those of the overburden gradient, making it unlikely that horizontal or severely dipping fractures were propagated. As in Stage #1, a lack of consistent fracture azimuth was evident from injection to injection.

Conclusion: Based on the pressure analysis and tiltmeter results, the conclusion can be drawn that a complex system of multiple fractures (vertical and non-vertical) were created during diagnostic injections for both stages 1 and 2. It is currently unknown what causes the propagation of multiple fractures, but it may be related to the finely laminated siliceous shale/sand sequences in the Antelope Shale. These micro-thin beds may delaminate at a given pressure after injection beings, severely limiting vertical fracture growth. The limited width of these non-vertical fractures thus causes a severe pressure increase during proppant placement, resulting in premature treatment termination.

Table #1: 653Z Stage #1 Frac Pressure Data

Diagnostic Injection #	Fluid Type	Surface ISIP (psi)	ISIP Gradient (psi/ft)	BH Closure Stress (psi)	Closure Pressure Gradient (psi/ft)	Near Wellbore Friction (psi)	Effective Perfs Open (40 shot)
1	2% KCL	2145	0.95	3295	0.79	2100	7
2	25lb linear gel	1951	0.90	3244	0.78	1086	11
3 (XL-Minifrac)	Crosslinked Gel 3 ppg prop. slug	2547	1.04	3485	0.84	1840	16

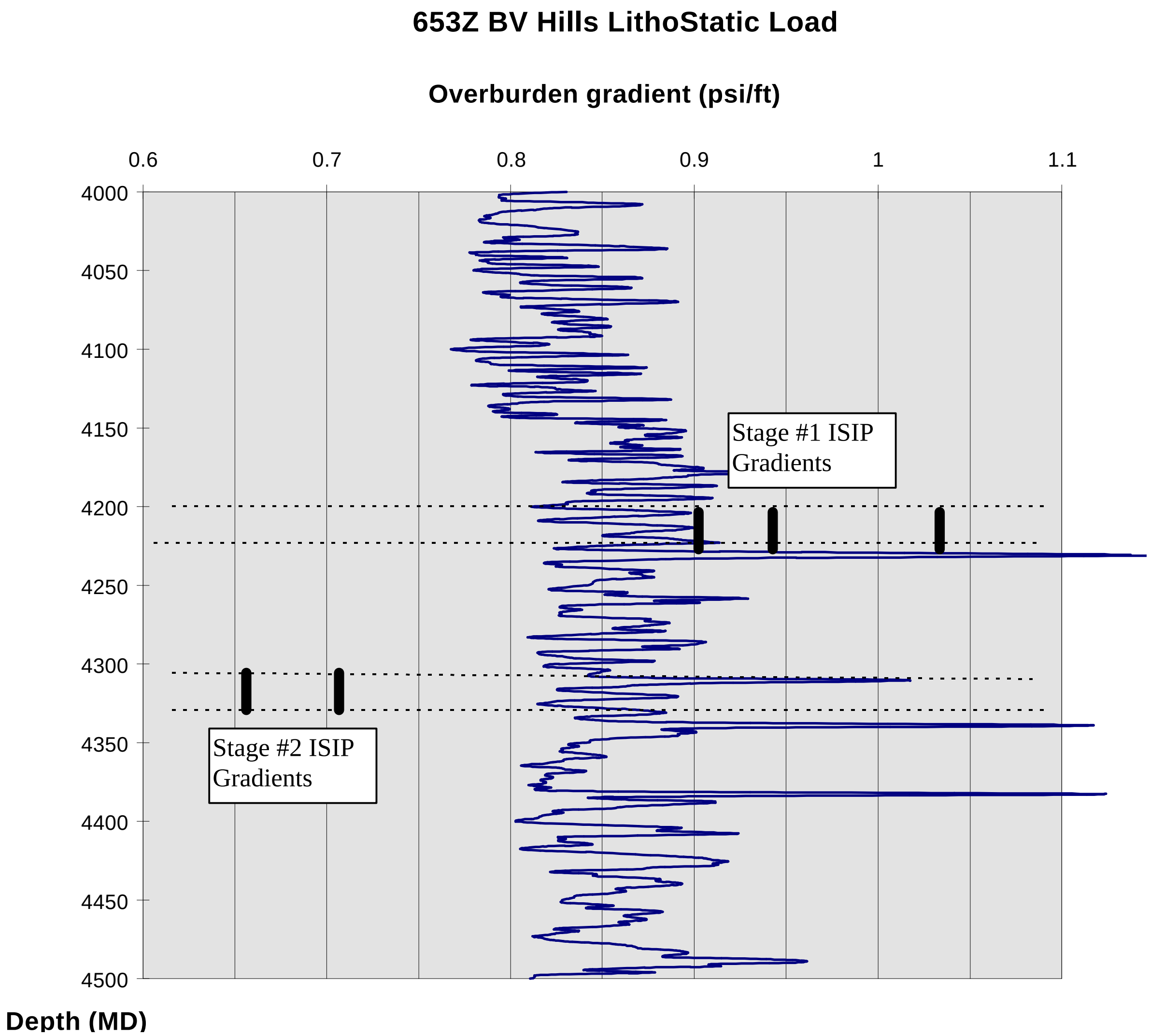

Figure #1

Table #2: 653Z Stage #1 Surface Tiltmeter Data

Diagnostic Injection #	Injected Volume (bbls)	Tiltmeter Frac Type	Azimuth	Dip	Volume % of Total Component
1	123	Vertical	N 80øWñ 8ø	68ø ñ 8ø Down to the SW	46%
1	123	Dipping	N 2ø Wñ 8ø	57ø ñ 8ø Down to the W	54%
2	95	Vertical	N 32ø E ñ 8ø	78ø ñ 8ø Down to the NW	59%
2	95	Dipping	N 76ø Wñ 25ø	46ø ñ 25ø Down to the SW	41%
3	181	Vertical	N 64ø Eñ 12ø	87øñ 10ø Down to the NW	45%
3	181	Dipping	N 5ø Wñ 12ø	39ø ñ 8ø Down to the SW	55%

Table #3: 653Z Stage #2 Frac Pressure Data

Diagnostic Injection #	Fluid Type	Surface ISIP (psi)	ISIP Gradient (psi/ft)	BH Closure Stress (psi)	Closure Pressure Gradient (psi/ft)	Near Wellbore Friction (psi)	Effective Perfs Open (40 shot)
1a	15% HCl	N/A	N/A	N/A	N/A	N/A	N/A
1b	2% KCL	N/A	N/A	N/A	N/A	N/A	N/A
2	30lb Linear Gel	938	0.66	1877	0.45	450	20
3 (Minifrac)	Crosslinked Gel 3 ppg prop. slug	1215	0.72	2677	0.63	600	10
4 (Minifrac)	Crosslinked Gel 2 ppg prop. slug	Screenout Treatment Terminated	Screenout, Treatment Terminated	Screenout Treatment Terminated	Screenout Treatment Terminated	Screenout Treatment Terminated	Screenout Treatment Terminated

Table #4: 653Z Stage #2 Surface Tiltmeter Data

Diagnostic Injection #	Injected Volume (bbls)	Tiltmeter Frac Type	Azimuth	Dip	Volume % of Total Component
1a	21	Vertical	N 24øEñ 12ø	87ø ñ 10ø Down to the SE	46%
1a	21	Dipping	N 20øWñ 12ø	53ø ñ 8ø Down to the NE	54%
1b	9	Vertical	N 87øWñ 9ø	80ø ñ 8ø Down to the SW	67%
1b	9	Dipping	N 14ø Eñ 16ø	57ø ñ 15ø Down to the NW	33%
2	100	Vertical	N 12ø E ñ 20ø	78ø ñ 15ø Down to the SE	71%
2	100	Dipping	N 44ø Wñ 25ø	32ø ñ 20ø Down to the NE	29%
3	150	Vertical	N 77ø Eñ 13ø	86ø ñ 8ø Down to the NE	59%
3	150	Dipping	N 25ø Wñ 8ø	52ø ñ 8ø Down to the SW	41%
4	150	Vertical	N 69ø Eñ 17ø	81ø ñ 8ø Down to the SE	50%
4	150	Dipping	N 40ø Wñ 15ø	56ø ñ 14ø Down to the SW	50%

Task D. Technology Transfer

The following paper was presented at the DOE/ BDM OK/ PTTC Class Project Logging Workshop, Advanced Applications of Wireline Logging for Improved Oil Recovery, Denver, CO:
T. A. Zalan, M. F. Morea, D. R. Julander, and S. A. Denoo, Applying Integrated Formation Evaluation to Advanced Reservoir Characterization in California's Monterey Formation Siliceous Shales.

The following papers will be presented at the 1998 AAPG Annual Convention, Salt Lake City, Utah:
Britton, A. W., and Morea, M. F., Acoustic Anisotropy Measurements in the Siliceous Shale, 653Z-26B Well, Buena Vista Hills Field, California.

Campagna, D. J., Amos, J. F., and Mamula, N., Influence of Structure, Reservoir Compartments, and Natural Fractures on Oil and Gas Production in the Southern San Joaquin Basin, California.

Morea, M. F., Zalan, T. A., Julander, D. R., Beeson, D. C., and Britton, A. W., Advanced Reservoir Characterization of the Siliceous Shale, Buena Vista Hills, California: Integration of Geological, Geochemical, and Petrophysical Data.

The following paper has been accepted to the 1998 SPE Western Regional Meeting, Gems Session, Bakersfield, CA:
Zalan, T. A., Morea, M. F., Julander, D. R., and Denoo, S. A., Integrated Formation Evaluation in California's Monterey Formation Siliceous Shales, Buena Vista Hills Field, California.

The following paper has been accepted at the 1998 SPWLA Annual Convention, Keystone, Colorado:
Zalan, T. A., Morea, M. F., Julander, D. R., and Denoo, S. A., Applying Integrated Formation Evaluation to Advanced Reservoir Characterization in California's Monterey Formation Siliceous Shales.

The following paper has been submitted to the 1998 SPE Archie Conference, Kerrville, Texas:
Harris, J. M., Preliminary Results on 3-D Attenuation Imaging for Reservoir Characterization.

A booth has been reserved at the 1998 Pacific Section AAPG Convention, Ventura, CA:
Morea, M. F., Julander, D. R., Zalan, T. A., and Beeson, D. C., Advanced Reservoir Characterization of the Siliceous Shale, Buena Vista Hills, California. We plan to have displays reviewing our data and interpretations, and a workstation showing our 3D visualization/geologic modeling.

Three expanded abstracts have been submitted to the 1998 Annual International Meeting, Society of Exploration Geophysicists to be held in New Orleans:

Langan, R. T., Julander, D. R., Morea M. F., Addington, C. M. and Lazaratos, S. K., 1998, Crosswell seismic imaging in the Buena Vista Hills, San Joaquin Valley: A case history.

Wang, G., Harris, J. M., Magalhaes, C., Julander, D. R., and Morea, M. F., 1998, Buena Vista Hills 3-D attenuation and velocity tomography.

Washbourne, J. K. and Rector III, J. W., 1998, Crosswell seismic in three dimensions.

Data from this project has been given to Southwest Research Institute, San Antonio, TX and included in their project:

Parra, J. O., Characterization of Fracture Reservoirs using Static and Dynamic Data: from Sonic and 3D Seismic to Permeability Distribution, BDM Subcontract No. G4S51-731, and Prime Contract No. DE-AC22-94PC91008.