An Advanced Fracture Characterization and Well Path Navigation System for Effective Re-Development and Enhancement of Ultimate Recovery from the Complex Monterey Reservoir of South Ellwood Field, Offshore California

Final Technical Report

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Abstract

Venoco Inc, intends to re-develop the Monterey Formation, a Class III basin reservoir, at South Ellwood Field, Offshore Santa Barbara, California.

Well productivity in this field varies significantly. Cumulative Monterey production for individual wells has ranged from 260 STB to over 10,000,000 STB. Productivity is primarily affected by how well the well path connects with the local fracture system and the degree of aquifer support. Cumulative oil recovery to date is a small percentage of the original oil in place. To embark upon successful re-development and to optimize reservoir management, Venoco intended to investigate, map and characterize field fracture patterns and the reservoir conduit system.

In the first phase of the project, state of the art borehole imaging technologies including FMI, dipole sonic, interference tests and production logs were employed to characterize fractures and micro faults. These data along with the existing database were used in the construction of a new geologic model of the fracture network. An innovative fracture network reservoir simulator was developed to better understand and manage the aquifer's role in pressure maintenance and water production.

In the second phase of this project, simulation models were used to plan the redevelopment of the field using high angle wells. Correct placement of the wells is critical to intersect the best-developed fracture zones and to avoid producing large volumes of water from the water leg. Particular attention was paid to those areas of the field that have not been adequately developed with the existing producers.

In cooperation with the DOE and the PTTC, the new data and the new fracture simulation model were shared with other operators. Numerous fields producing from the Monterey and analogous fractured reservoirs both onshore and offshore will benefit from the methodologies developed in this project.

This report presents a summary of all technical work conducted during Budget Periods I and II. Venoco elected to terminate the project after Budget Period II and not to proceed with the activities planned for Budget Period III.

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Introduction

The Field Demonstration site for this Class III (basin clastic) Program Proposal is the South Ellwood Field located offshore California. The Monterey Formation is the main producing unit in the South Ellwood Field and consists of fractured chert, porcelanite, dolomite, and siliceous limestone interbedded with organic mudstone. This reservoir has an average thickness of 1,200 feet, and lies at subsea depths of approximately - 3,500' to -5,000'. The Monterey is divided into seven major units numbered from M1 through M7 based largely on gamma ray correlations across the field. The most heavily fractured units are the porcelanites in the M2 and the cherts and dolomites in the M6. The hydrocarbon column is more than 2400' thick and this leads to considerable variation in fluid properties from light oil at the crest to a tar mat just above the oil-water contact.

Venoco and USC jointly submitted an application to conduct a DOE co-operative investigation of the Monterey formation at South Ellwood in June 2000. The DOE granted this application in July 2000.

Executive Summary

Venoco and USC prepared a proposal for a DOE sponsored joint investigation of the fractured Monterey formation. It was agreed that Venoco would construct the geologic model for the field and gather new reservoir data as appropriate. USC would then develop a simulation model that would be used to optimize future hydrocarbon recovery. Joint Venoco-USC teams were established to manage the flow of data and insure that Venoco and USC activities remained synchronized. A co-operative agreement was signed with the DOE on July 31, 2000.

During Budget period I (July 31, 2000 - September 30, 2003), Venoco worked with USC to develop a new geological and engineering model of the Monterey formation. This cooperative work between USC and Venoco has made several contributions to the tech transfer goal of the U.S. Department of Energy. The most significant of these were; the development of an interactive database on the Monterey Formation, a new simulation algorithm for the description of fracture-controlled Monterey Reservoirs, a pattern recognition method for analysis of well log data, enhanced water shut-off techniques and reprocessing of the 1982 3D seismic survey data to improve the geologic structural model. USC stopped participating in the project after the conclusion of Budget Period I activities.

The primary goal of the Budget Period II (October 1, 2003 – March 31, 2006) was to develop the new fault blocks identified as a result of the field re-evaluation conducted during Budget Period I. A Middle Sespe prospect was identified by an exploration well drilled from a jack-up in 1985. We have used the reprocessed 3D to image the South Ellwood structure at Sespe level. 3120-15RD4 was drilled during 2004-2005 to appraise this Middle Sespe structure. A second exploratory well was completed during the Fourth Quarter of 2005 to test the North Flank block of the Monterey. Neither well has produced oil in commercial quantities. Further development of these prospects has been suspended. As a consequence, Venoco decided not to proceed with the field re-

development activities proposed for Budget Period III and terminated the project at the end of March 2006.

On a more positive note, Venoco completed reconfiguring the Holly production separators and is now separating most of the produced water offshore for re-injection into two Monterey disposal wells 3120-10 and 3242-8RD4. Approximately 9000 BWPD is now re-injected offshore and three high water cut wells have been returned to production.

Experimental

Not applicable for the work performed.

Task 0.1 Consolidation of Regional Fracture Data

A literature survey was conducted to review published studies on the tectonic and diagenetic control on the formation of fractures in the Monterey Formation. The Monterey formation is unusual in that it forms both the source and reservoir rock for major petroleum reserves in southern California. The porosity and permeability in these reservoirs are almost entirely due to fractures and faults that occur on a wide range of scales from submillimeter in brecciated chert beds to kilometers in major faults. Strategies for the optimal development of Monterey reservoirs depend on knowledge of the geometry of these fracture networks.

Observed fracture patterns reflect both the lithology and tectonic history of the Monterey formation. The intensity of fracturing is largely controlled by the lithology while the orientation reflects the tectonic history.

Tectonic History

About 30 my B.P. the East Pacific Rise collided with the trench at the North American – Pacific plate boundary in southern California changing the relative motion from convergence and subduction to strike-slip displacement along the newly formed San Andreas fault system. This change in tectonic style initiated the formation of several basins that became “depocenters” for both continental terrigenous and marine organic sediments. Rapid basin subsidence and marine transgression began about 22.5 my B.P. and was so rapid that it outpaced sediment accumulation. Continental sediments were trapped in near shore estuaries and deltas and the basins became starved of terrigenous sediments. About 15 to 13 my B.P. a major climatic reorganization from preglacial to glacial conditions caused oceanic upwelling and associated diatomic plankton blooms leading to an increased biogenic silica influx to the sediment starved basins. Anoxic conditions at depths between 500 and 900 m preserved the organic rich sediments by eliminating microorganisms at these depths. The Monterey formation, deposited between about 17.5 and 6 my B.P., reflects this unusual combination of circumstances. It was deposited as a diatomaceous and coccolithic, foraminiferal ooze devoid of terrigenous sediment. The resultant sedimentary rock is diatomaceous, phosphatic, dolomitic, and rich in organic matter. The composition can be extremely variable from location to location.

The history of basin formation and subsequent deformation is complex and controversial. It is complicated by paleomagnetic evidence that the entire region experienced a 90° clockwise rotation between about 16 and 6my B.P., presumably associated with the right-lateral strike-slip motion at the plate boundary.

From 6my B.P. till the present, the Ventura basin has been subject to NE-SW compression associated with the “big bend” in the San Andreas Fault. This has resulted in a deepening of the basin and extensive folding. Under the northern Santa Barbara Channel, folding is geometrically simple with fold axes running approximately E-W. Warping of the Monterey was gentle between 6 and 2my B.P. Rapid deformation began about 2 my B.P. and continues at a reduced rate today. Virtually all the faults and open fractures in the Monterey formation are associated with this folding.

Fracture Patterns in the Monterey

The intensity of fracturing in the Monterey depends primarily on composition and degree of diagenesis of the rock. Silica rich beds are altered from opal-A to opal-CT to quartz (chert) becoming increasingly brittle with each transformation. The calcareous rocks are similarly embrittled by the alteration to dolomite.

The orientation of fractures is determined by the tectonic deformation. Fractures are associated either with faulting or folding. Large scale faults tend to divide the reservoirs into compartments, but they play a minor role in the storage and transport of hydrocarbons. The vast majority of fractures are associated with the folding. Since most of the folding occurred between 2 and 0.5 my B.P, it reflects the current NE-SW compression.

Large scale folding in the Monterey is slightly asymmetric and has associated large scale thrust faulting. This structure is apparent in seismic section where the thrust faults are identifiable because they offset lithologic horizons. Less apparent in seismic section are the numerous breccia zones that play the major role in hydrocarbon storage and transport. Brecciated zone can appear as either dikes, which cut bedding planes at a high angle, or sills which follow the bedding planes. These latter are also called "stratigraphic breccia" because they tend to be confined to individual brittle strata. Breccia dikes tend to be oriented either subparallel to the fold axis or within 30° of being orthogonal.

The stratigraphic breccia sills are formed by folding brittle strata. Folding is accommodated by slip between brittle and more ductile beds. More ductile layers tend to flow while the more brittle layers, especially the chert, tend to fracture. The brittle layers sometimes contain microscopic highly fractured "drag folds" caused by the slip at their boundaries with more ductile beds. The cores of some large scale folds are very tight and also contain highly brecciated brittle layers. Some folds tighten with depth while others become more gentle. It is difficult to differentiate these two cases using seismic data that does not penetrate the core of most folds.

Task 1 – Database

The change in ownership from ARCO to Mobil and now to Venoco has resulted in different formats of data. Task I of Budget Period I included designing a database, digitizing records, populating the database, and providing a graphical representation.

Two platforms for the South Ellwood database were considered, a CD-ROM version and a web-based intranet system. The CD-ROM version is an access database. The access database was designed and populated first. A design map of this version is shown in Figure 1. The limitations of Microsoft Access were felt when dealing with a wide variety of data in different formats. Due to these limitations the Access version of the database is in three different sub-databases. It rapidly became apparent that a static database on CD would be impractical as new data was continually being gathered during completion of the project.

The web-based intranet version of the database is the new dynamic version of the South Ellwood Database. This version contains all data that is in the CD-ROM version plus new diagnostic data. A site map of this new design is shown Figure 2. Aside from continued population and design a few key design aspects are being created and applied. First is a search engine for the whole database web site. This will enable a first time user to type in any type of data and all the pages containing that data will be given. The second design aspect is application of real time the production diagnostic plots. This will have the diagnostic plots generated directly from the production data and thus as the production data is updated the diagnostics will reflect that change immediately.

Table 1-Inventory of Data for the South Ellwood Field

	Raw	Interpreted	Summaries
Reservoir	PVT, DST, Well test, Water & oil & gas analysis, Pressure, Capillary Pressure Test	PVT & DST & Well Test & Pressure diagnostic, Fracture Indicator	Pressure history by well
Completion	Directional Survey, Fluid Entry	Well bore Diagram	Slots and Well Utilization
Production	Tables	Diagnostic plots	Work over Summary
Geologic	Fracture Azimuth, Core Photos, X-ray diffraction, Well Log data	Fracture Data, Lithology Descriptions, Core Analysis, Core Fracture Study, 3D geologic, Seismic, 3D Fracture Model	Core Data Summary, Formation Tops
Historical	Well History	Event Calendar	Summary of well histories
Maps		2D Structure, Cross section, Production Bubble	

Table 2-Status of Data Preparation

Data Type	<i>Available As</i>	Converted to:
PVT data	<i>Hard Copy Only</i>	Scanned into GIF & pdf format
DST data	Excel format/outdated software	Used excel & written to pdf format
Well Test	<i>Hard Copy Only</i>	Scanned into GIF & pdf format
Water Analysis	<i>Hard Copy Only</i>	Scanned into GIF & pdf format
Gas Analysis	<i>Hard Copy Only</i>	Scanned into GIF & pdf format
Oil Analysis	<i>Hard Copy Only</i>	Scanned into GIF & pdf format
BH Pressure	<i>Hard Copy Only</i>	Scanned into GIF & pdf format
Capillary Pressure Data	<i>Hard Copy Only</i>	Scanned into GIF & pdf format
Fracture Indicators	Hard copy logs & digitized data	Digitized into LAS format
Dipmeter Data	Hard copy logs & digitized data	Not converted
Workover Summary	Access Database	Exported & written to pdf format
Directional Survey	Word document	Converted & written to pdf
Fluid Entry Surveys	Excel document	Converted & written to pdf
Well Bore Diagrams	Visio document	Converted & written to pdf
Production Data	Access Database	Exported & written to pdf format
Fracture Azimuth	Hard copy logs & digitized data	Not converted
Core Photos	Hard Copy Only	Scanned into GIF & pdf format
X-Ray Diffraction data	Hard Copy Only	Scanned into GIF & pdf format
Fracture aperture Data	Hard Copy Only	Scanned into GIF & pdf format
Lithology Descriptions	Hard Copy Only	Scanned into GIF & pdf format
Core Analysis	Hard Copy Only	Scanned into GIF & pdf format
Well Log data	Access Database	Exported & written to pdf format
3D Geologic Model	None	Not converted
Maps	Hard Copy Only	Not converted
Seismic	SEG Y Tapes	Not converted

Figure 2 - Site map for the Web based version of the South Ellwood database

Fig. 3 Main Page of the Web site

Task II – New Data

Reservoir Pressure Data

In March 2001, we measured Bottom hole pressure in six long term shut-in wells:- 3120-4, 3120-6-2, 3242-7-1, 3242-10-1, 3242-14 and 3242-17. Data from four of the wells shows that the reservoir pressure ranges from 1260-1320 psi at the datum of 3881' SS. There is no evidence for aquifer support from the northern boundary fault. A higher than normal pressure in 3242-7-1 suggests that influx from the former 308 lease is occurring.

Additional pressure build-up data were obtained during the platform shut down in December 2001. Quartz pressure gauges were hung in five wells 3120-12, 3242-13, 3242-19, 3242-18 and 3272-7-1 and remained in the hole during a 10 day platform shutdown. Reservoir pressure is similar to the values measured in March 2001 i.e. 1300 psi. There is a slight pressure gradient of 40 psi between the most Westerly well 3120-12 and the most Easterly producer 3242-18. This data supports the idea that fluid is influxing from the lease extension area to the East. This information was of significant importance for history match studies. The data gathering was repeated during the field shutdowns in December 2002 and November 2003.

All the pressure build-up data that is available for the Monterey formation since initial production in 1971 has been reanalyzed in a consistent manner using the Kappa Saphir pressure transient analysis package. It became evident during this analysis that it could take many weeks for the bottom hole pressure in a given well to build up to a true reservoir pressure particularly if it had been on production for a long time prior to the test. Therefore previous reservoir studies that had used instantaneous static bottom hole pressures could be misleading. The most representative data is obtained from initial build-up tests on recently completed wells or from long build-ups where the entire field had been shut-in. The following Table summarizes the interpretation of these tests:

Table 3 South Ellwood Monterey Pressure History from build-up tests

Well	Test Date	Gauge Depth MD	FSIBHP psia	P* psia	Perm md	Skin	P* at Datum psia
3120-8	4/1/1971	3500	1615	1615	NA	NA	1778
3120-8	1/31/1972	3593	1634	1643	68.9	-6	1778
3120-8	4/25/1972	3580	1634	1655	29.8	-1.8	1794
3242-5	6/6/1972	3593	1516	1525	6.3	-5	1804
3120-3	5/30/1972	3168	1498	1504	7.3	-4.2	1778
3120-3	2/7/1974	3203	1325	1608	4.2	-5.8	1794
3242-2	2/7/1974	3315	1354	1597	2.2	-3.4	1818
3120-6-2	7/6/1974	4042	1677	1764	8.2	6.8	1840
3120-6-2	9/8/1974	4055	1529	1726	3.8	-4.4	1795
3242-10	10/12/1977	4081	1532	1532			1748
3120-7-3	11/18/1977	3615	1394	1452	6.2	-4.7	1762
3120-15-1	10/1/1980	4508	1556	1585	1.7	-0.4	1738
3120-10	9/27/1981	3657	1398	1570	26.6	-6.2	1621
309-8	6/22/1982	3898	1760	1781	237	-0.4	1790
208-102	2/23/1985	4417	1786	1805	3.9	0	1690
3242-19	11/6/1985	4278	1153	1746	3.15	-3.6	1651
3242-19	3/1/1986	3850	1237	1347	0.01	13.1	1410
3120-16	5/16/1986	7959	1642	1652	7.1	-5.6	1570
3242-13	9/27/1986	3538	1147	1252	14.8	-4.2	1460
3120-8	6/9/1994	3334	1074	1224	1.7	-1.9	1438
3242-18	11/29/2001	6630	1143	1189	30.8	7.9	1376
3120-12	12/2/2001	5652	1113	1142	101	29.9	1320
3242-19	12/2/2001	3333	1036	1381	0.69	-1.2	1620
3242-7-2	9/2/2002	6111	970	1060	23.3	-4.6	1399
3242-7-2	12/2/2002	6111	974	1051	37.7	5.5	1436
3120-12	12/2/2002	5652	1093	1127	34.3	2.2	1298
3242-9	12/2/2002	6040	1078	1096	78.1	15.1	1320
3242-18	5/19/2003	6630	1087	1100	58	-2.1	1287
3120-16	11/2/2003	6709	1226	1249	65.2	10.4	1345
3242-18	11/2/2003	6630	1101	1151	44.3	-2.6	1337
3242-15	4/6/2004	5279	1014	1015	386	-2.8	1275
3242-12	5/14/2004	4638	1055	1108	14.7	-6.0	1324
3242-18	11/4/2004	6630	888	1173	32.6	2.6	1360
3120-18	1/16/2006	3360	922	1110	1.07	-3.2	1433

Plotting this pressure data against cumulative oil production, we see reservoir pressure has decreased just 400 psi for a cumulative production of 55 MMBO. The shape of this graph would seem to indicate early pressure support from a gas cap while later in the life of the field aquifer and/or microfracture support is more important. The outlying pressure points (309-8, 208-102 and 3120-18) show that some areas of the field are less affected by production from the central area. A material balance study of this data suggests that the effective oil-in-place is only 400 MMBO compared to the volumetric oil-in-place of 1-2 Billion BO.

Figure 4 South Ellwood Monterey Reservoir Pressure History

Production Logs

Between 2001 and 2002, we attempted state of the art production logs (GHOST and DEFT tools) on 6 wells. The DEFT or Flo-View tool is an electrical imaging device that distinguishes between water and hydrocarbons. The GHOST tool is an optical imaging device that distinguishes between gas and oil. The probes are arranged circumferentially inside a spring loaded cage that expands to fill the cross-section of the casing. Five of these production logging runs were successfully completed, identifying 3 clear water shut offs.

The production logs from 3120-9, 3242-12 and 3242-18 indicated a good possibility existed to shut off bottom water. In particular, the log in 3242-18 shows that 90% of the produced water is coming from the open hole section of the Monterey M6. The logs for 3120-12 and 3120-16 indicated no clear water shut-off possibilities. The small tubing size (2-3/8") in 3242-9 precluded running wireline rollers and the tools could not be run to bottom in this highly deviated well. In subsequent wells we have been able to pump the tools down in these circumstances. Based on these logs, Venoco ran thru-tubing bridge plugs in three wells in March 2002. The results of these plug backs were not always successful. The plugback in 3120-9 actually reduced oil production.

Table 4 Production History of 3120-9RD1

DATE	GROSS	CUT	NET	WATER	NET MCF	GOR
1/15/2002	1280	84%	205	1075	934	4.556
1/16/2002	1040	83%	177	863	738	4.169
1/24/2002	1893	90%	189	1704	1381	7.307
1/25/2002	1870	91%	168	1702	1442	8.583
1/26/2002	1828	90%	183	1645	1290	7.049
1/27/2002	1829	90%	183	1646	1290	7.049
1/31/2002	1874	84%	300	1574	1300	4.333
2/3/2002	1893	85%	284	1609	908	3.197
2/3/2002	1344	98%	27	1317	499	18.481
2/18/2002	1831	90%	183	1648	835	4.362
2/27/2002	576	80%	115	461	1148	9.983
2/28/2002	454	74%	118	336	1158	9.814
3/2/2002	504	80%	101	403	999	9.891
3/7/2002	433	69%	134	299	804	5.992
3/14/2002	556	71%	161	395	826	5.13
3/17/2002	1140	78%	251	889	1337	5.327
4/5/2002	677	77%	156	521	941	6.032
4/6/2002	321	80%	64	257	544	8.5
4/7/2002	550	82%	100	451	615	6.15
4/8/2002	511	79%	107	404	594	4.673
5/12/2002	589	83%	100	489	555	5.55
5/13/2002	538	89%	59	479	514	8.711
5/14/2002	531	80%	106	425	484	4.566
5/24/2002	686	84%	110	576	468	4.255
5/25/2002	558	68%	179	379	530	2.961
5/26/2002	260	70%	78	182	451	5.782
5/27/2002	608	75%	152	456	615	4.046
5/28/2002	549	90%	55	494	573	10.418
5/29/2002	635	88%	76	559	573	7.539
5/30/2002	496	90%	50	446	467	9.34
5/31/2002	474	86%	66	408	487	7.379
6/1/2002	603	88%	72	530	581	9.683
6/2/2002	273	74%	71	202	350	4.929
6/3/2002	473	82%	85	388	500	5.882
6/19/2002	591	76%	142	449	484	3.408
6/20/2002	547	56%	241	306	492	2.041
7/30/2002	360	78%	79	281	554	7.013
7/31/2002	330	88%	40	290	338	8.45
8/1/2002	322	84%	52	270	564	11.059
8/7/2002	301	78%	66	235	529	8.015
8/8/2002	311	76%	75	236	614	8.187
8/21/2002	345	75%	86	259	530	6.163
8/22/2002	344	74%	86	255	531	5.966
8/23/2002	338	72%	95	243	593	6.242
9/5/2002	347	87%	45	302	561	12.467
10/4/2002	301	85%	45	256	470	10.444
11/1/2002	319	74%	83	236	541	6.518
12/13/2002	345	88%	41	303	739	18.024
1/3/2003	242	78%	53	189	438	8.264
1/4/2003	246	78%	54	192	451	8.352
2/10/2003	321	89%	35	285	665	19
2/20/2003	369	90%	37	332	562	15.189
4/4/2003	337	80%	67	270	798	11.91

We came to the conclusion that the way the detectors were arranged inside the cage allowed the light hydrocarbons to pass undetected on the high side of these deviated wellbores. Schlumberger has subsequently developed the Flo-Scan Image tools where the detectors are arranged in a line covering the full internal diameter of the casing. In 2006, we ran a second suite of Flo-Scan image logs in 3120-9 and 3120-16.

Figure 5 Flo-Scan Image log for 3120-9RD1

Figure 6 Flo-Scan Image log for 3120-16

Using the results of the Flo-Scan Image log, a bridge plug was set at 7675' in 3120-16 during a workover in June 2006 and this has reduced the water cut from 84 to 73%. As you can see in the above plot, the bridge plug was set below the lowest point of significant oil entry. Below this point, the perforations are producing only water and gas.

3242-12 Through Tubing Plugback

Based on a production log run during 2001, a through tubing plug had been set in 3242-12 during February 2002. This plug had been set in the middle of the M6A perforations and had no detectable effect on the production from the well. Production from the M6A appeared to be bypassing the bridge plug due to poor cement or through the extensive M6 fracture system. A second bridge plug was set on August 10th 2003, at 6450' between the M4 and M6A perforations where the cement bond was excellent. This time the plugback shut off 400 BWPD.

Table 5 Production History of 3242-12

Wellname	DATE	GROSS	CUT	NET	WATER	INJ. MCF	NET MCF	GOR	API	BEAN	CSG PSI	TBG PSI
3242-12	6/7/2003	1314	82%	237	1077	684	417	1.759	20.5	128	730	170
3242-12	7/5/2003	1299	82%	234	1065	708	764	3.265	20.5	128	780	180
3242-12	8/3/2003	1370	80%	274	1096	670	508	1.854	20.8	128	750	175
3242-12	8/10/2003	1298	90%	130	1168	677	608	4.677	20.8	128	700	160
3242-12	8/11/2003	1276	76%	306	970	663	496	1.621	20.8	128	690	130
3242-12	8/12/2003	1112	77%	256	856	694	552	2.516	20.8	128	670	160
3242-12	8/14/2003	1077	48%	560	517	687	530	0.946	20.8	128	670	130
3242-12	8/15/2003	839	81%	159	680	693	466	2.931	20.8	128	670	140
3242-12	8/16/2003	1064	80%	213	851	696	782	3.671	20.8	128	740	160
3242-12	8/17/2003	805	82%	145	660	827	468	3.228	20.8	128	780	190
3242-12	8/18/2003	877	78%	193	684	732	446	2.311	20.8	128	760	180
3242-12	8/19/2003	799	94%	48	751	771	407	8.479	20.8	128	800	140
3242-12	8/20/2003	884	94%	53	831	539	433	8.17	20.8	128	800	140
3242-12	8/27/2003	1063	92%	85	978	468	428	5.035	20.8	128	625	150
3242-12	9/12/2003	696	88%	84	612	776	412	4.905	20.8	128	710	140
3242-12	9/13/2003	850	80%	170	680	633	381	3.824	20.8	128	650	120

3242-7-2 Production Log

3242-7-2 was the first well drilled by Venoco on Holly platform. The well was sidetracked from 3242-7-1 at a depth of 3274 ft. and drilled eastward to tap reserves in the lower Monterey near the eastern limit of the lease. The hole was built up to an angle of between 67° and 72° from vertical except for an interval from about 7000'-7500' where angles as high as 75° were reached. The top of the Monterey was encountered at 5672' and zone 1 to just into zone 2 were penetrated before crossing an expected fault at 5810' (MD) and drilling back into Sisquoc Formation. The top Monterey in the main fault block was encountered at 6274' (MD) and a fairly complete section of Monterey into Zone 3 was drilled down to 7000' where Monterey strata

dipping steeply 85° to the north were encountered. By about 7300' (MD) the beds were dipping steeply, mostly to the south, until about 7500' where the dip of the strata gradually flattened out to around 20°-15° southerly dips. This steeply dipping interval was difficult to correlate as the well drilled through it along strike. Below this interval a fairly "normal" section from Monterey zone 3 (repeated) through 7 was encountered. Circulation was lost at a depth of 7600' and never regained. Therefore no cuttings were available for examination.

Modern logs including Schlumberger's Formation Micro-Image Tool and the Dipole Sonic Tool were run to better describe the fracture system. The Lower M5, M6 and M7 (8320-9022') were perforated selectively using the FMI log to pick the most heavily fractured zones. The perforations were acid washed with mud acid and a 3-1/2" gas lift completion run. Well production began on July 1st 2002 with a water cut of over 95%. To determine the point of water entry, Schlumberger ran their tools on August 1st 2002 and observed two major entries of water at 8550'-8437'. All the hydrocarbons were mainly coming in the top set of perforations from 8334'-8414'. The oil-water contact was determined to be -3735' SS, some 300' higher than expected. On September 21st 2002 all but the top 80' of M5/M6 perforations (8334-8414') were plugged back with a thru-tubing bridge plug. Additional perforations were shot through tubing in the M5 on October 26 and the M3-M4 on November 8, 2002. These perforations were not acidized and do not appear to be producing.

A second pressure build-up test, conducted in December 2002, shows that the productivity index of the well has dropped from 5.2 to 1.3 BFPD/psi since the well has been plugged back. Interestingly the build-up now exhibits the behavior of a radially composite system with a positive skin factor. However, the reservoir pressure and effective permeability did not appreciably change from the pre-plugback values.

Figure 7 3242-7-2 December 2002 Pressure Buildup Horner Plot

Log-Log plot: dp and dp' [psi] vs dt [hr]

Table 6 3242-7RD2 Production Log Interpretation

Reservoir Zone	Perforations Depth (ft)	Oil			Water			Gas		
		Downhole <i>bb/d</i>	Surface <i>bb/d</i>	%	Downhole <i>bb/d</i>	Surface <i>bb/d</i>	%	Downhole <i>bb/d</i>	Surface <i>1000 ft3/d</i>	%
Zone 1a	8334.00 - 8354.00	37.500	33.978	23.8	0.000	0.000	0.0	140.188	59.901	18.7
Zone 1b	8356.00 - 8402.00	102.431	92.744	65.1	106.467	104.613	10.6	222.491	102.478	29.8
Zone 1c	8404.00 - 8414.00	2.795	2.528	1.8	0.000	0.000	0.0	9.095	3.989	1.2
Zone 2a	8427.00 - 8446.00	9.693	8.764	6.2	421.741	414.204	42.1	326.074	133.497	43.6
Zone 2b	8448.00 - 8466.00	0.000	0.000	0.0	0.000	0.000	0.0	35.957	13.263	4.8
Zone 2c	8468.00 - 8514.00	4.136	3.738	2.6	198.007	194.449	19.8	8.308	4.842	1.1
Zone 3a	8554.00 - 8578.00	0.043	0.039	0.0	270.093	265.149	27.0	5.736	3.961	0.8
Zone 3b	8580.00 - 8620.00	0.000	0.000	0.0	0.000	0.000	0.0	0.000	0.000	0.0
Zone 3c	8622.00 - 8644.00	0.702	0.633	0.4	123.938	121.590	dflow	0.000	0.856	0.0
Zone 4a	8659.00 - 8704.00	0.000	0.000	0.0	38.099	37.377	dflow	0.000	0.233	0.0
Zone 4b	8706.00 - 8744.00	0.000	0.000	0.0	204.414	200.529	dflow	0.000	1.259	0.0
Zone 5a	8762.00 - 8784.00	0.000	0.000	0.0	-32.823	-32.199	xflow	0.000	-0.203	0.0
Zone 5b	8786.00 - 8809.00	0.000	0.000	0.0	-252.037	-247.246	xflow	0.000	-1.567	0.0
Zone 6a	8844.00 - 8864.00	0.000	0.000	0.0	-75.611	-74.167	xflow	0.000	-0.472	0.0
Zone 6b	8866.00 - 8886.00	0.000	0.000	0.0	21.687	21.267	dflow	0.000	0.136	0.0
Zone 6c	8888.00 - 8929.00	0.000	0.000	0.0	202.216	198.204	dflow	0.000	1.266	0.0
Zone 7a	8952.00 - 8978.00	0.000	0.000	0.0	-343.474	-336.639	xflow	0.000	-2.162	0.0
Zone 7b	8980.00 - 9035.00	0.000	0.000	0.0	118.284	115.930		0.000	0.748	0.0
Below survey	9036.00 - 9075.00	0.000	0.000	0.0	0.000	0.000	0.0	0.000	0.000	0.0
Total		157.300	142.424		1001.000	983.063		747.848	322.024	

Figure 8 3242-7RD2 August 2002 Production Log Interpretation

A workover was conducted during February 2003. Additional perforations (7160-8310') in the vertical beds, M2 Repeat, M3 Repeat and M4 Repeat were shot using tubing conveyed guns on February 14th, 2003. All the perforations from M2 repeat through M5 were acid stimulated using a conventional 12-3% HCl/HF mud acid. The tubing was re-run and the well placed back on production on February 18th. The new perforations significantly increased the oil production to over 800 BOPD.

In April 2003, the gas production jumped to over 3 MMcf/d. A production log was run in August 2003 to identify the source of this gas production.

A Schlumberger production logging string consisting of the Ghost and DEFT Flow View tools, a turbine spinner, gradiomanometer and pressure and temperature transducers was run on August 7th 2003. It was only feasible to perform a shut-in pass and three up passes due to extreme tool drag. It later appeared that the through tubing bridge plug set at 8420' in September 2002 had moved up the hole to 7800' and became entangled with the production logging string. A small amount of oil and gas was being produced from the perforations below the stuck plug at 7800' even under the highest drawdown conditions of 70 psi. Essentially all of the well's oil water and gas production 389 BOPD, 907 BWPD and 2 MMcf/d was coming from the zone of vertical beds that was perforated from 7160-7465'. The drawdown on these perforations was less than 50 psi which translates to a productivity index of 26 BPD/psi. A minor amount of oil and gas was being produced from the M2 repeat perforations (7495-7650'). The plug was later removed from the well on October 31st 2003.

Table 7 Production History of 3242-7-2

Wellname	DATE	BFPD	CUT	BOPD	BWPD	GL MCF	NET MCF	GOR	API	CSG PSI	TBG PSI
3242-7	7/1/2002	704	98%	14	688	395	30			815	125
3242-7	7/2/2002	703	98%	14	689	422	3	0.214		805	130
3242-7	7/4/2002	1510	99%	15	1495	474	120			825	170
3242-7	7/5/2002	1545	99%	15	1530	606	26	1.733		825	185
3242-7	7/6/2002	1699	96%	34	1665	817	17	0.500		850	200
3242-7	7/7/2002	1637	90%	164	1473	844	119	0.726		860	200
3242-7	7/8/2002	1356	90%	136	1220	817	255	1.875		840	180
3242-7	7/9/2002	1979	97%	59	1920	883	248	4.203		870	210
3242-7	7/10/2002	1951	96%	78	1873	975	269	3.448		870	210
3242-7	7/11/2002	1938	97%	97	1841	1134	242	2.494		840	200
3242-7	7/12/2002	1887	95%	94	1793	1134	54	0.574		840	200
3242-7	7/13/2002	1834	95%	92	1742	1134	54	0.587		850	200
3242-7	7/14/2002	1782	96%	71	1711	1134	110	1.549		860	200
3242-7	7/15/2002	1791	93%	125	1666	1132	112	0.896		860	190
3242-7	7/16/2002	1750	91%	157	1592	962	302	1.924		865	200
3242-7	7/17/2002	1723	90%	172	1551	863	381	2.215		865	180
3242-7	7/18/2002	1604	89%	176	1428	857	407	2.313		865	210
3242-7	7/21/2002	1612	91%	145	1467	955	388	2.676		875	200
3242-7	7/23/2002	552	98%	11	541	937	69	6.273		880	120
3242-7	7/24/2002	1270	96%	51	1219	893	113	2.216		860	160
3242-7	7/25/2002	1522	91%	137	1385	893	469	3.423	21.5	865	190
3242-7	7/25/2002	1393	92%	111	1281	912	401	3.613	21.5	870	190
3242-7	7/31/2002	780	90%	78	702	411	268	3.436	21.5	835	200
3242-7	8/1/2002	1397	90%	140	1257	1048	306	2.186	21.5	870	200
3242-7	8/2/2002	1643	82%	296	1347	442	438	1.480	21.5	760	150
3242-7	8/5/2002	1575	91%	142	1433	414	466	3.282	21.5	735	150
3242-7	8/13/2002	1504	87%	195	1309	442	489	2.508	21.5	740	160
3242-7	8/17/2002	1491	81%	283	1208	442	477	1.686	21.5	750	150
3242-7	8/22/2002	1452	85%	218	1234	475	273	1.252	21.5	740	150
3242-7	8/23/2002	1432	87%	186	1246	475	273	1.468	21.5	740	140
3242-7	8/28/2002	1424	86%	199	1225	494	311	1.563	21.5	750	150
3242-7	9/1/2002	1473	80%	295	1178	429	347	1.176	21.5	745	155
3242-7	9/5/2002	1231	92%	98	1133	546	209	2.133	21.5	835	135
3242-7	9/6/2002	1524	91%	137	1387	572	320	2.336	21.5	880	125
3242-7	9/18/2002	1469	86%	193	1185	533	272	1.409	21.5	790	150
3242-7	9/19/2002	1360	88%	163	1197	488	317	1.945	21.5	795	150
3242-7	9/20/2002	1329	86%	186	1143	494	311	1.672	21.5	785	150
3242-7	9/22/2002	660	62%	251	409	385	244	0.972	21.5	780	100
3242-7	9/23/2002	897	64%	323	574	494	233	0.721	21.5	785	160
3242-7	9/24/2002	800	67%	264	536	507	259	0.981	21.4	775	145
3242-7	9/25/2002	715	62%	272	443	507	163	0.599	21.4	785	145
3242-7	9/26/2002	768	67%	253	515	598	163	0.644	21.4	845	130
3242-7	9/27/2002	679	64%	244	435	520	241	0.988	21.4	820	105
3242-7	9/29/2002	886	69%	275	611	520	168	0.611	21.4	760	120
3242-7	10/3/2002	896	78%	197	699	520	156	0.791	21.5	785	125
3242-7	10/16/2002	500	70%	150	350	520	78	0.520	21.5	780	120
3242-7	10/18/2002	879	66%	299	580	520	107	0.358	21.5	780	140
3242-7	10/19/2002	864	76%	207	657	520	150	0.725	20.5	800	130
3242-7	10/20/2002	807	78%	178	629	520	150	0.843	20.5	800	130
3242-7	10/27/2002	812	79%	171	641	677	82	0.480	21.5	865	130

3242-7	10/28/2002	569	82%	102	467	677	120	1.176	21.5	880	110
3242-7	10/29/2002	544	65%	190	354	780	173	0.911	21.5	880	135
3242-7	10/30/2002	540	70%	162	378	664	75	0.463	21.5	860	130
3242-7	10/31/2002	508	78%	112	396	481	102	0.911	21.5	780	110
3242-7	11/1/2002	483	70%	145	338	429	154	1.062	21.5	860	110
3242-7	11/6/2002	552	82%	99	453	466	118	1.192	21.5	780	120
3242-7	11/7/2002	559	74%	145	414	559	258	1.779	21.5	780	130
3242-7	11/9/2002	760	84%	122	638	703	160	1.311	21.5	865	140
3242-7	11/10/2002	649	83%	110	539	846	88	0.800	21.5	890	140
3242-7	2/22/2003	1546	90%	155	1391	520	125	0.806	21.5	935	125
3242-7	2/23/2003	1668	94%	100	1568	520	182	1.820	21.5	935	100
3242-7	2/24/2003	1747	89%	192	1555	520	60	3.200	21.5	935	160
3242-7	2/25/2003	1702	60%	681	1021	553	490	0.720	21.5	950	160
3242-7	2/26/2003	1714	62%	651	1063	533	539	0.828	21.5	950	170
3242-7	2/27/2003	1747	63%	646	1101	552	520	0.854	21.5	960	160
3242-7	2/28/2003	1708	51%	837	871	533	568	0.679	21.5	950	160
3242-7	3/1/2003	1662	54%	765	897	520	610	0.797	21.5	945	150
3242-7	3/2/2003	1466	51%	719	746	520	581	0.808	21.5	940	160
3242-7	3/3/2003	1606	60%	642	964	651	218	0.339	21.5	985	155
3242-7	3/4/2003	1544	45%	849	695	390	335	0.395	21.5	880	140
3242-7	3/6/2003	1107	90%	111	997	539	272	2.450	21.5	950	170
3242-7	3/7/2003	1500	57%	645	855	549	262	0.406	21.5	960	140
3242-7	3/8/2003	1400	58%	588	812	552	344	0.585	20.5	955	140
3242-7	3/9/2003	1241	59%	509	732	527	342	0.672	21.5	960	125
3242-7	3/10/2003	1350	53%	634	716	572	297	0.468	21.5	960	150
3242-7	3/14/2003	1662	50%	831	831	919	240	0.289	21.5	1020	185

Figure 9 August 2003 Production Log from 3242-7-2

A new generation Flo-scanner log was run using a tractor tool in May 2006. This log showed that although the zone of vertical beds is still contributing the majority of the production, the original perforations are still producing a significant volume of oil and gas with little water production.

Figure 10 May 2006 Flo-Scan Image log for 3242-7RD2

3242-18 Production Log

The first Schlumberger production log was run in March 2001. This well was completed with a combination of perforated casing through the M2-M5 zones and an open section that ran from the M5 to the base of the Monterey. The production log indicated that 46% of the water production was coming from the open hole section. Although this open hole section had produced more than 7 MMBO, it appeared that it had watered out. In March 2002, a thru tubing bridge plug was set in the well at the casing shoe to isolate the open hole section. This workover was very successful, reducing the water cut from 80 to 50% and increasing oil production from 877 to 1100 BOPD.

Figure 11 March 2001 Production log for 3242-18

As a result of the successful workover, we elected to convert the well from gas lift to electric submersible pump (ESP) in August 2004. However, the well experienced a loss in productivity on conversion from gas lift. When the pump developed a flaw in April 2005, we decided to take advantage of the pump change to selectively stimulate the perforations that the 2001 production log indicated were oil producing. In May 2005 the perforation intervals (7392—7772') were acidized and a new ESP was run causing a water cut increase from 65% to 95%. The ESP completion was pulled in August 2005 and a gas lift string was run. Schlumberger's production logging tools was run August 10th and compared to the last production log from March 2001. From this production log, a bridge plug had been set to abandon the open hole section from 8520-10098' because this was producing 1200 BWPD with no oil influx. The August 2005 log showed that the bottom set of perforations in the 7-5/8" casing (8320-58') was producing 920 BWPD and the Water Flow Log detected that flow was occurring outside the 7-5/8" casing. On the 2001 log this set of perforations was only contributing 160 BWPD under similar producing conditions. It was determined that the acid had inadvertently been spotted on this bottom set of perforations and had opened up a communication path behind pipe to the open hole section. The bottom set of perforations was squeezed and the ESP completion rerun. The water cut has now returned to a normal level of 65% and the production has increased to over 1900 BOPD.

The new production log from 3242-18 and successful squeeze prompted a re-evaluation of the source of water production in those wells using Flo View tools. This data was loaded in GoCad to see if there would be a correlation between point of water entry and proximity to faults. Six wells have modern suites of logs – 3120-9RD1, 3120-12, 3120-16, 3242-7RD2, 3232-12 and 3242-18. Perforations in close proximity to one of five seismically identified faults – purple, tan, yellow, cyan and green seem to produce anomalous quantities of water and free gas for their structural position. Perforations down hole from these fault intersections appear to produce relatively clean oil where the Monterey is well fractured. Since this data appears to show that the oil-water contact is moving unevenly across the field with significant water production only in the fracture zones closest to the major faults, the wells such as 3120-12 and 3120-9RD1 may have recompletion opportunities if the uphole water entry points can be squeezed off. Recompletion for these two wells is planned to take place during 2006.

Figure 12 Relationship of anomalous water production with fault surfaces in new geologic model

Figure 13 3242-18 Production Log August 2005

Flo View Tool

The FloView tool makes four hold up measurements around the wellbore. A probe is used as a sensor that measures the local hold up water. More than four probes are required to log a horizontal well. The addition of a second tool makes the FloView^{Plus} measurement with a total of eight probes distributed across the wellbore. Most of the probes will now register a continuous phase of either hydrocarbon or water but a probe close to the water-oil interface will see some bubbles. MapFlo processing of the field data is then used to produce borehole cross sections and a value of water holdup.

Water Flow Log (WFL)

The WFL, Water Flow Log, works in the presence of flowing water where a neutron pulse activates some of the flowing oxygen. This activated oxygen decays rapidly with the emission of gamma rays, which are detected as a peak in a gamma ray detector signal some time after the neutron burst.

The **time** from the middle of the neutron burst to the peak of the gamma ray detector signal is measured. Given the **distance** from the neutron generator to the gamma ray detector a water **velocity** is computed. Multiple detectors allow a large velocity range to be measured. In horizontal or monophasic flow regimes the velocity measured corresponds to the mean water velocity.

Under favorable conditions the area under the gamma ray peak can also be processed to give the water flow rate (known as the 'flow index').

Flo-Scan Image Log (FSI)

The three-phase flow analysis in horizontal well requires the accurate estimate of gas, oil and water holdup and phase velocities. Previously measurements made in horizontal wells relied on measurement of water velocity and holdup which were then used to model oil velocity. Spinner velocities from the conventional full bore and in-line spinners are often unreliable because a stratified flow has layers of oil, water and gas moving at

separate velocities, all of which have some influence on the spinner. The FSI overcomes this problem through the use of 5 mini-spinners at different levels in the bore hole. Coupled with the ability of the tool to scan across the flow by moving the measurement arm, the 5 spinners provide a velocity profile across the pipe cross section. On one side of the tool's retractable arm are the four miniature spinners designed to measure the well fluid velocity profile. On the other side are arrays of five electrical DEFT and five optical GHOST probes for measuring localized water and gas holdups, respectively. Additionally, a fifth miniature spinner and a sixth pair of electrical and optical probes on the tool body measure flow properties on the low side of the well. The FloScan Imager system is run eccentric, lying on the low side of the well with its arm deployed across the vertical diameter of the wellbore. The arm is extended to a length equal to the diameter of the production tubulars, so it serves as a caliper, providing the area measurements needed to calculate flow rates. The example below shows real time outputs from the FSI on 3120-16 with the tool stationed in three-phase flow. The visualization output shows the holdup profile from the optical and electrical probes as a cross section across the well bore. The left hand box shows the individual velocities detected by the spinners across the cross section of the pipe.

73679.776000 s

Schlumberger

Station at 7050'

74824.152000 s

Schlumberger

Station at 6890'

75546.296000 s

Schlumberger

Station at 6780' Gas Entry

The FloScan Imager tool uses a maneuverable arm to deploy sensors along the vertical axis of nonvertical wells to obtain velocity and holdup measurements in mixed and segregated flow regimes.

Task III-Reservoir Studies

The South Ellwood Field, discovered in 1964, was originally developed in the Lower Miocene Rincon and Vaqueros Sandstones. The overlying Middle Miocene Monterey Formation later was recognized as commercially productive and quickly became the primary reservoir. The field currently delivers 4000 BOPD and has produced 69 MMBO and 66 BCFG as of May 2006. The field was re-interpreted in the mid 1980's utilizing 1983 vintage 2D and 3D seismic data. Integrated geologic study continued in the early 90's based on the original structural interpretation. South Ellwood has always been mapped as a faulted, slightly asymmetric, elongate EW anticline with a major bounding reverse fault along the south flank and a long north flank. The prolific Coal Oil Point seeps have generally been associated with the crest of the structure.

Venoco acquired the South Ellwood in 1997 and initiated a modern reservoir characterization study of the field. Monterey stratigraphic picks have not changed significantly from previous interpretations. The 3D seismic was completely reprocessed and reinterpreted in 1999. A 3D geologic model was built incorporating the new seismic interpretation as well as logs, dipmeter, core and outcrop information. Improved seismic imaging has led to important structural changes. The overall structural trap is a 2-way fault and dip trap. The north flank was truncated with a new major fault just to the north of well 3242-18. The north and northwest bounding faults are large down-to-the-north and west faults with normal sense displacement, similar to the Refugio Fault, which crops out to the north onshore. The north-bounding fault intersects the sea floor and is the source of the La Goleta and Holly seeps.

The seismic reprocessing was repeated again in 2003. The new data from drilling 3120-18 in 2005, reduced the significance of the north fault and a completely different geological model was developed that re-incorporated a large North flank synclinal block.

South Ellwood 3D seismic re-processing

The South Ellwood 3D survey was shot by ARCO in 1983. This survey was shot as a series of 2D lines which were then processed in 3D. Image quality is poor within the core of the South Ellwood anticline and to the north. The survey was re-processed in 1999 using post-stack migration algorithms. This processing was a great improvement over the earlier ARCO and Mobil processing. However, the South Ellwood area has extremely steep dips that cannot be accurately imaged with post stack migration used in the 1999 re-processing. In an effort to improve image quality within the field proper the survey was re-processed using pre-stack time migration algorithms by Seismic Ventures Inc. in Houston. This process places the original unstacked traces in a more accurate position, leading to more accurate structural positioning and is critical for the steep dips encountered in this 3D area. Part of the re-processing involved careful velocity analysis using Velocity Image Point software from Seismic Ventures. The results of the re-processing did indeed reveal more details of the field structure and conformed more to the structure revealed by wells, particularly dipmeter data.

Figure 14 N-S Reprocessed Line 260 showing North Flank Syncline near 3242-10

Data quality improved markedly in the area of the North Flank prospect lying just to the north of the main field. The old reprocessing failed to resolve the presence of a large syncline that was identified from the dipmeters run on two exploratory wells drilled by Arco in the 1970's (3242-10 and 3120-15). 3242-10 tested a small amount of oil from the Monterey in the North flank block. The new reprocessing confirms the existence of the syncline and establishes drillable prospects updip of 3242-10 on each limb of the syncline. Venoco drilled a downdip test well, 3120-18, into the North Flank block in 2005. The potential reserves for the North flank are from 30-50 MMB.

Figure 15 Generalized North-South Cross Section showing North Flank Syncline Prospect

The new interpretation resulted in improved locations and orientations of numerous faults, and the top and base of the Monterey Formation and several shallower and deeper horizons. In addition several faults which were imaged very poorly or not at all in the earlier processing can now be mapped with the pre-stack time migration processing. The horizon and fault surfaces have been converted from seismic two-way travel time to depth using velocity functions developed from velocity check shot surveys in the State 208-102, State 3242-19, and State 309-8 wells. Sonic logs from the State 3120-1, and the State 309-9 wells were converted to travel time curves and used to improve the velocity model and the interpretation. The velocities along the crest of the structure are fairly consistent (Figure 16). However, the velocity at the State 309-9 well is a bit faster because it drilled through an up thrust block.

Figure 16 Two-way travel time vs depth for wells at South Ellwood Field.

In order to improve the structural interpretation along the northern margin of the field we have also resorted to mapping with 1983 vintage 2D seismic surveys that extend further north than the 3D survey. These were re-examined in light of the newly re-processed 3D survey. The data are of poor quality but were still useful for mapping surface faults and fold traces. This work helped fill the gap between the field area and the coastal outcrops and revealed several faults and folds that aided in the interpretation of the structural picture around the north and western areas of the field.

The new and revised faults and stratigraphic horizons interpreted from the pre-stack time migration 3D seismic volume were exported as time surfaces. These surfaces in two-way travel time were then converted to depth using the velocity data. Fault surfaces were then compared to faults observed in the wells that had been loaded into the 3D geologic model. Being able to view the fault surfaces interpreted from the seismic reflection software and the faults interpreted from the well data in 3 dimensions greatly improves the interpretation process. This is typically an iterative process. Fault cuts in the wells posted in the seismic reflection software are used to identify important faults and map them. Often fault cuts in the wells could be assigned to a particular fault by comparing the fault cuts to fault surfaces in the 3D model. Minor adjustments could be made to the fault surfaces generated from the seismic reflection data so that they matched the faults identified in the wells. This helps to correct for local velocity variations. The top and base of the Monterey formation were also re-mapped using the re-processed seismic reflection data. These were exported as surfaces in two-way travel time, converted to depth, and imported into the 3D software.

Figure 17 Image of 3D Geologic Model for South Ellwood looking West.

Lithology Indicator System

Original wells drilled in the South Ellwood Field included conventional measurements such as SP, resistivity, formation density, sonic travel time, gamma ray, and caliper log. In more recent wells they also include dual induction laterolog, compensated neutron formation density, spectralog, and four-arm caliper log. Cannon noticed early on that

expected well log responses were not observed in the Monterey Formation. The Monterey was known as the Monterey Shale because of the lack of character on the SP log. Based on the lithological description from outcrop studies, core photos, and mud logs, a host of lithological units may be observed within a typical Monterey column.

From the analysis of published studies and statistical review of data for the South Ellwood Field, we have developed a classification system as shown in Figure 18. Type A, the most prolific sections of the Monterey are the fractured and/or brecciated intervals with very high permeability often indicated by mud invasion, borehole size increase and reversal of the resistivity curves. These intervals show very poor core recoveries. This type can be easily distinguished from Type D, the shaly section, which also exhibits an increase in borehole size, higher neutron porosity vs. density porosity relation and low resistivity measurements. Type B, corresponding to the dolomitic section, exhibits mud cake buildup with indication of low to medium porosity and permeability. Type C includes all the units within the Monterey that contain rock of some finite porosity and permeability and behave similar to granular type sandstone layers. This includes sections of the Opal CT type rocks. Presence of mud cake and normal invasion, as indicated by separation of the deep and shallow resistivity tools, are initial indicators of this type of flow unit. In type E, a hard streak is exhibited with its characteristics low sonic travel time. Finally, type F signifies the presence of highly laminated cherty sections composed of various stages of silica diagenesis; this is indicated by relatively perfect hole size, high resistivities and low gamma ray.

A controlling factor, affecting the well log responses, is the amount of detrital material within each of the indicated flow units. An increase in detrital material is associated with increase in neutron porosity, gamma ray and a lowering of resistivity. To identify these intervals with production potential, (IWPP), a systematic screening process is followed. The low gamma ray intervals are identified. The caliper log is examined to determine hole size increase or mud cake buildup. Intervals with perfect hole size are excluded. The invasion pattern is then studied for mud invasion vs. only fluid invasion. Intervals are also examined to exclude those with high detrital content.

To distinguish the lithology types, the caliper observations are further cross checked. All the intervals indicating hole enlargement are then checked for shale content by examining the neutron porosity vs. density porosity relationship. All the intervals that have neutron porosity higher than density porosity are excluded. A look at the mud invasion pattern will confirm the identification of the brecciated or fractured interval from the dolomitic or Opal CT sections. The double check is to correct any interval missed by the caliper. A further investigation into the relationship between neutron porosity and density porosity in the intervals, where there is mud cake buildup, will distinguish between dolomitic sections and Opal CT. The Opal CT will read a higher porosity.

After applying many statistical methods to the data, we developed a pattern recognition technique using a radar diagram approach. The seven log signals; gamma ray, density porosity, neutron porosity, sonic travel time, deep and shallow resistivity, and caliper, were placed on the radar diagram with the high signal reading on the outside and thus the low in the center. Each signal was normalized to a characteristically high reading for the Monterey formation. The radar diagram has an axis that reads from 0 to 1 - see Fig 19. The six lithological units have very distinct characteristics.

Figure 18 – Expected lithological units.

Fig.19 shows the radar diagram for a typical productive brecciated interval.

Three Lithology types indicative of producing potential are:

Type A - fractured and/or brecciated intervals.

Type B - dolomitic intervals.

Type C - granular type sandstone layers.

Note: Identification Type B and C indicators have been grouped as Type B/C to expedite log review.

A number of difficulties arose when the correlation between these IWPP (Intervals with Production Potential) and the actual productivity of the wells were examined. For some wells, there was a substantial history of workover changes in the completed intervals. The changes in the well completion, resulting from adding new intervals or abandonment of wet intervals, affect cumulative productivity. For these wells, the initial completion was not descriptive of the well's entire history. The wells with very limited production histories were also eliminated from the correlation studies.

Our correlation and pattern recognition work shows that some of the IWPP's were overlooked and some intervals with no productivity were perforated along with wet intervals (see Fig 20). The initial WOR response identified the wells with initially wet perforated intervals.

Fig. 20 – Bar chart representing IWPP, perforated intervals and over perforation.

The expectation is that the wells with frequent occurrences of IWPP will be better producers. The fraction of total interval consisting of IWPP was also examined against the cumulative gross production (see Figure 21).

Fig 21 – Correlation between cumulative gross production and number of IWPP.

The points that are lie below the trend line are indicative of under perforation. The type of analysis is diagnostic for inclusion of untapped intervals. If we use cumulative oil production rather than gross production, the trend is not as perfect as that seen for the gross production. This is because several wells have initially wet completion intervals.

Well Log data set for two wells (wells 3120-16 and 3242-12) were selected to test the concept of pattern recognition method developed earlier in this project. Each well had a recent production survey run using Schlumberger's GHOST tool to accurately identify fluid entry. Each dataset was then reviewed to compare occurrences of the IWPP indicator with the actual producing, perforated zones in the well. Figure 22 shows a section of a calibration Log for 3120-16 with the lithology signal indicators noted in the lithology track of the log. The Type A signal appears in the perforated zone (depth 7390' to 7420') where fluid entry is identified by the GHOST tool (Track QOC Calc. of Log 3120-16). Additionally, Type A indicators are also found in unperforated zones of the well indicating bypassed intervals with production potential (IWPP).

Figure 22. Composite Computed Log for South Elwood Well 3120-16 (section from 7380' to 7480') IWPP noted in the Lithology Track.

Well logs from twelve wells from the South Ellwood Field were then reviewed to identify formation lithology and intervals with production potential (IWPP). The South Ellwood wells reviewed thus far are listed below.

Table 8. Log signal availability for twelve South Ellwood Wells

Well	Well Type	Complete Signal Suite
3120-03	Data	No - NP,DP,ST,RR,CL
3120-11	Data	No - GR,NP,DP,ST,
3120-15D1	Data	Yes - GR,NP,DP,ST,RR,CL
3120-15D2	Data	Yes - GR,NP,DP,ST,RR,CL
3120-16	Calibration/Data	Yes - GR,NP,DP,ST,RR,CL
3242-08RD4	Data	Yes - GR,NP,DP,ST,RR,CL
3242-10D1	Data	Yes - GR,NP,DP,ST,RR,CL
3242-12	Calibration/Data	No - GR,NP,RR,CL
3242-14	Data	Yes - GR,NP,DP,ST,RR,CL
3242-15	Data	Yes - GR,NP,DP,ST,RR,CL
3242-16	Data	Yes - GR,NP,DP,ST,RR,CL
3242-17	Data	Yes - GR,NP,DP,ST,RR,CL

The review of selected 3120 and 3242 wells have identified intervals with production potential based on a lithology pattern recognition system. Table 9 shows a summary of unperforated intervals with potential for production.

It was decided to use the technique to try and improve the productivity for well 3120-8. 3120-8 was the discovery well for the Monterey at platform Holly in 1969. The well initially flowed up the annulus at 2100 BOPD. It was an excellent good producer from the M6 and M7 units until 1978 when an inner string of casing was run to repair casing damage. The well is favorably located in the relatively under-produced central area under the Holly platform. There are no other nearby wells in the M6 and M7.

It was not possible to run the GHOST tool in view of the small diameter tubing size. On the basis of temperature logs and pattern recognition analysis of a limited set of open hole logs, it was decided to shoot 150' of both old and new perforations using 1-11/16" through tubing Pivot guns. The zone was then stimulated by bullheading a high rate mud acid treatment down the tubing in March 2002. The results were mixed in that the fluid production rate improved but the water cut also increased. The table below gives the before and after well test results for 3120-8.

Date	BFPD	WC	BOPD	BWPD	GL
3/1/02	112	72%	31	81	230
3/6/02	98	73%	26	71	228
3/12/02	98	82%	18	80	232
3/18/02	622	97%	19	603	250
3/19/02	528	80%	106	422	278
3/20/02	412	80%	82	330	274
3/30/02	391	70%	117	274	209
4/10/02	367	81%	70	297	257

Table 9- List of Potential Unperforated Intervals in some of the South Elwood Wells.

Well 3120-16		Well 3242-12		Well 3242-15		Well 3120-03		Well 3120-15D1		Well 3242-08RD4		Well 3242-17		Well 3242-16		Well 3120-15D2		Well 3242-10D1		Well 3120-11		Well 3242-14	
Dept h	L i t h · T y p e	Depth	L i t h · T y p e	De p t h	L i t h · T y p e	De p t h	L i t h · T y p e	De p t h	L i t h · T y p e	De p t h	L i t h · T y p e	De p t h	L i t h · T y p e	De p t h	L i t h · T y p e	De p t h	L i t h · T y p e	De p t h	L i t h · T y p e	De p t h	L i t h · T y p e	De p t h	L i t h · T y p e
6815P	A	5258	B/C	5235	A	3973	B/C	4655	B/C	3850	A	4446	B/C	4500	B/C	5470	A	3605	B/C	6007		4348	B/C
6828P	A	5315	B/C	5257	A	4003	A	4662	B/C	4008	B/C	4484	B/C	4618	B/C	5475	B/C	3612	B/C	6198	B/C	4440	B/C
6855	A	5345	N/A	5662	A	4013	A	4678	B/C	4038	C/D	4505	B/C	4697	A	5480	B/C	3632	B/C	6228	B/C	4527	B/C
6912P	A	5385	N/A	5305	A	4031	A	4763	B/C	4053	A	4536	A	4705	A	5496	B/C	3636	B/C	6251	B/C	4670	A
6923P	A	5445P,t	A	5312	A	4052	A	4775	B/C	4064	D	4887	A	5337	A	5999	B/C	3637	B/C	6258	HS	4677	A
6938P	A	5478P,t	A	5317	B/C	4062	B/C	4828	B/C	4095	A	4925	A	5383	A	5501	B/C	3641.5	B/C	6264	B/C	4853	A
6968P	B/C	5495P	B/C	5403	A	4071	A	4867	B/C	4115	A	5046	A	5343	A	5508	B/C	3646	A	6353	B/C	4956	A
6978P	A	5505	B/C	5412	B/C	4085	B/C	5045	F?	4250	A	5198	B/C	5892	A	5513	B/C	3651.5	B/C	6380	B/C	4976	A
6988P	B/C	5564P	B/C	5422	B/C	4108	B/C	5158	B/C	4262	A	5220	A	5914	B/C	5520	B/C	3658	B/C	6410	B/C	5146	A
7014	A	5579P	A	5460	A	4131	A	5308	B/C	4292	B/C	5305	A	5945	B/C	5528	B/C	3661.5	B/C	6418	A	5173	A
7035	B/C	5649P	B/C	5470	B/C	4139	A	5328	B/C	4335	B/C	5462	A	5985	B/C	5541	B/C	3665	B/C	6425	A	5188	B/C
7053	B/C	5671P,t	A	5505	B/C	4157	B/C	5340	B/C	4382	A	5497	A	6010	A	5551	B/C	3673	B/C	6438	A	5217	B/C
7070	A	5713P	B/C	5542	B/C	4190	A	5370	B/C	4463	A	5528	B/C	6015	B/C	5558	B/C	3680	B/C	6498	A	5308	B/C
7090P	A	5723P	B/C	5581	B/C	4208	A	5385	B/C	4808	B/C	5554	A	6020	A	5591	A	3690	B/C	6725	A	5322	A
7113P	A	5758P	B/C	5587	B/C	4233	B/C	5433	B/C	4850	B/C	5605	A	6195	A	5641	B/C	3700	B/C	6737	A	5334	B/C
7127P	A	5830	B/C	5621	A	4253	A	5482	B/C	4945	D	5612	A	6340	B/C	5645	B/C	3707	B/C	6740	A	5387	A
7138P	A	5846P	B/C	5630	B/C	4272	B/C	5509	B/C	4969	B/C	5635	B/C	6418	A	5677	B/C	3717	A	6940	A	5409	A
7153P	B/C	5872P	A	5637	B/C	4283	A	5611	B/C	5208	A	5673	B/C	6436	B/C	5688	A	3754	B/C	6953	A	5433	A
7159P	A	5912P	B/C	5642	B/C			5632	B/C	5359	A	5685	A	6515	A	5698	B/C	3764	B/C	7005	B/C	5689	A
7172P	A	5936P	B/C	5652	B/C			5665	B/C	5390	A	5737	A	6655	B/C	6116	B/C	3769	B/C	7018	A	5754	A
7187P	A	5956	B/C	5685	A			5677	B/C	5410	A	5790	B/C	6870	B/C	6120	B/C	3775	B/C	7023	A	5793	B/C
7195P	A	5982	B/C	5710	A			5694	B/C	5439	B/C	5803	A	6915	B/C	6131	B/C	3777	B/C	7029	A	5834	B/C
7208P	A	6002	B/C	5718	A			5704	?	5459	B/C	5832	A	6935	B/C	6156	B/C	3779	B/C	7098	A	5852	B/C
7215P	A	6023	B/C	5770	A			5721	B/C	5482	B/C					6206	B/C	3785	B/C	7127	A	5857.5	B/C
7227P	A	6052P	A	5838	A			5762	B/C	5528	B/C					6212	B/C	3788	B/C	7430	B/C	5876	B/C

Well 3120-16		Well 3242-12		Well 3242-15		Well 3120-03		Well 3120-15D1		Well 3242-08RD4		Well 3242-17		Well 3242-16		Well 3120-15D2		Well 3242-10D1		Well 3120-11		Well 3242-14	
Depth	Lith. Type	Depth	Lith. Type	Depth	Lith. Type	Depth	Lith. Type	Depth	Lith. Type	Depth	Lith. Type	Depth	Lith. Type	Depth	Lith. Type	Depth	Lith. Type	Depth	Lith. Type	Depth	Lith. Type	Depth	Lith. Type
7237P	A	6072P	A	5843	A			5777	B/C	5592	B/C					6227	B/C	3795	A	7466	A	5894	A
7242P	A	6085P	A	6113	A			5792	B/C	5619	B/C					6252	B/C	3798	B/C	7520	A	5899	A,C
7258P	B/C	6102	A	6132	A			5808	B/C							6261	SH	3805	A	7536	B/C	5909	B/C
7268P	A	6115	A	6150	A			5834	B/C							6278	A?	3813	A	7566	A		
7295P	A	6129	A	6157	B/C			5840	B/C							6288	SH?	3816	B/C	7613	A		
7305P	A	6138	A	6216	A			5851	B/C							6303	B/C	3820	B/C	7638	A		
7317P	B/C	6162	A	6220	A			5898	B/C							6310	B/C	3826	B/C	7668	B/C		
7320P	A	6178P	B/C	6227	A			5921	B/C							6327	B/C	3831	B/C	7698	B/C		
7340P	A	6200P,t	A	6315	B/C			5982	B/C							6333	B/C	3838	B/C	7715	B/C		
7355	B/C	6224P	B/C	6461	A			6005	B/C							6344	A	3845	B/C	7727	B/C		
7370	B/C	6240P		6428	A			6028	B/C							6348	A	3971.5	B/C	7740	A		
7385	A	6246P	A	6485	A			6039	B/C							6367	B/C	3974.5	B/C	7745	A		
7403P	A	6275P	B/C	6487	A			6054	B/C							6375	B/C	3983	B/C	7759	B/C		
7411P	A	6309	B/C	6708	A			6093	B/C							6382	A	3994	B/C	7769	A		
7415P	A	6335	A	6718	A			6150	B/C							6400	B/C	4001	B/C	7789	B/C		
7422P	B/C	6348	A	6735	A			6205	B/C							6418	A	4022	A				
7446P	A	6405	B/C	6855	A			6250	B/C							6444	B/C	4223	B/C				
7455	A	6486	B/C	6867	A			6272	B/C							6451	SH?	4228	A				
7470	A	6510P	A	7104	B/C			6317	B/C							6458	B/C	4233	B/C				
7475	A	6545	A	7148	B/C			6345	B/C							6489	A	4243	A				
7490P	A	6570	A	7289	A			6385	B/C							6492	B/C	4238	B/C				
7525P	D	6610P	A	7301	A			6404	B/C							6507	B/C	4250	A				
7532P	B/C	6643P	A	7318	A			6450	B/C							6518	B/C	4261	B/C				
7560P	A			7398	B/C			6474	B/C							6556	B/C	4268	B/C				
7587P	B/C			7525	A			6505	B/C							6558	B/C	4273	B/C				
7595P	B/C			7538	B/C			6547	B/C							6580	B/C	4278	A				
7608P	A			7558	A			6586	B/C							6595.5	B/C	4382	A				
7617P	A			7572	B/C			6614	B/C							6610	B/C	4391.5	B/C				
7630P	A			7595	B/C											6627	B/C	4398.5	B/C				

Well 3120-16		Well 3242-12		Well 3242-15		Well 3120-03		Well 3120-15D1		Well 3242-08RD4		Well 3242-17		Well 3242-16		Well 3120-15D2		Well 3242-10D1		Well 3120-11		Well 3242-14	
Dept h	L it h · T y p e	Depth	Li th · T y p e	De pt h	Li th · T y p e	De pth	Li th · T y p e	De pth	L it h · T y p e	De pth	L it h · T y p e	De pth	L it h · T y p e	De pth	L it h · T y p e	Dept h	Li th. Ty pe	Dept h	Li th · T y p e	De pth	Li th · T y p e	Dept h	Lit h. Typ e
7643P	A			7675	A											6640	B/C	4403	A				
7668	B/C			7735	A											6700	B/C	4470	A				
7675	B/C			7750	A											6712	B/C	4475	B/C				
7688	B/C															6737	B/C	4478	A				
7702P	A															6740	B/C	4488	A				
7712P	A															6770	B/C	4494	?				
7722P	A															6805	B/C	4500	B/C				
7785P	A															6746	?	4593	B/C				
7795P	A															6754	B/C	4605	A				
7815P	A															6891	B/C	4608	B/C				
7840P	A															6925	A	4634	A				
7855P	A															6940	A	4637	A				
7870	A															6951	B/C	4666	A				
7883	A															6962	B/C	4770	B/C				
7942P	A															6970	?	4787	B/C				
7982P	A															6988	B/C	4695	B/C				
8010P	A															6990	?	4810	B/C				
																7005	A	4818	?				
																7017	A	4876	B/C				
																7100	B/C	4886	B/C				

Pipeline Network Model for Fractured Reservoirs

Four methods exist to characterize and model fractured reservoirs: continuum single porosity modeling, continuum dual porosity modeling, continuum stochastic modeling and discrete fracture network modeling.

The Continuum Single Porosity and the Continuum Stochastic Modeling may be too simplistic for typical fractured reservoirs, while the Discrete Fracture Network Modeling may be impractical because of the intensive computation required. The Continuum Dual Porosity Modeling is the one most used but still requires intensive computational work and needs to solve four unknowns.

The Pipeline Network Model for Fractured Reservoirs is an alternative model proposed by Ershaghi and Voskanian for fractured reservoirs. This model needs to solve only two unknowns making it faster than the Continuum Dual Porosity Model. It requires less computation time than the Discrete Fracture Network Modeling but is more realistic than the Continuum Single Porosity Modeling, maintaining the concept of fast flow channels.

Figure 23 shows the schematics of this model in two-dimensional case. The same procedures can be used for three-dimensional situations. The major fractures in a reservoir are simplified to a regularly connected pipeline network. The pipelines can be arbitrarily connected in 3D space according to the fracture distribution in the same space. The radius of each section of the pipeline may have different diameters, which are generated from the knowledge of major fracture locations and their flow capacity in the reservoir. These pipelines serve as the flow channels in the reservoir. This simplification makes the pressure calculation much easier than in the Discrete Fracture Network Model. Each intersection of the pipelines is embedded in a matrix block that has storage equivalent to all micro-fractures and granular storages in that block. The interchanging flow between matrix and its embedded pipelines is assumed to occur only at the junction of pipelines. Figure 24 shows the details of the fluid interaction between pipelines and matrix storage. It is assumed that, due to capillary pressure effects, water enters the matrix storage and oil leaves the storage.

Figure 23. Schematic of pipeline network model.

Figure 24. Schematics of interaction between fracture and matrix storage.

According to the fluid dynamics in pipelines, the transient flow for pipe connecting junction “i” and “j” can be expressed by

$$\frac{L_j}{g A_j} \frac{dQ_{ti,j}}{dt} = H_j - H_i - K_j Q_{ti,j} |Q_{ti,j}|^m \quad (1)$$

where “j” is the index of the junctions that have pipelines connecting to junction “i”, L_j is the length of the pipe, A_j is the cross section area, $Q_{ti,j}$ is the total fluid flow rate in the pipe, m and K_j represents either Darcy-Weisbach or Hazen-Williams head loss coefficient of the pipe, and H_i and H_j denote head at “i” and “j” junctions, respectively. Here we assume that: (a) the total fluid flow satisfies the head loss equation; (b) flow

and pressure vary slowly. The latter assumption enables us to neglect the head variation with time. This assumption can be eliminated in the future work to include the fast pressure variation during each time interval. Note that there is a nonlinear term at the right hand side of the equation (1). If we make the linearization for (1) and take finite difference for time derivative, we obtain

$$\frac{L_j}{g A_j} \frac{Q_{ti,j}^{n+1} - Q_{ti,j}^n}{\Delta t} = H_j^{n+1} - H_i^{n+1} - K_j Q_{ti,j}^n \left| Q_{ti,j}^n \right|^m \quad (2)$$

where n denotes the initial time step and $n+1$ denotes new time step to be calculated from the model. We take H_i and H_j at $n+1$ time step in (2) (whenever there is no indication of the time step for a property, it either means that the property is not time variation or it is calculated at n time step). Eq. (2) can be solved for Q^{n+1}

$$Q_{ti,j}^{n+1} = \frac{(H_j^{n+1} - H_i^{n+1})\Delta t + \frac{L_j}{g A_j} Q_{ti,j}^n}{\frac{L_j}{g A_j} + K_j \left| Q_{ti,j}^n \right|^m \Delta t} \quad (3)$$

At each junction, the continuity equation for each phase fluid reads

$$\sum_{j=1}^{N_i} Q_{bi,j}^{n+1} + E_{bi}^{n+1} = 0 \quad (4)$$

where $\beta = o$ and w , denoting oil and water phase, N_i denotes the number of surrounding junctions connecting to the junction “ i ”, and $E_{\beta i}$ denotes the phase exchange at junction “ i ”. The total flow continuity equation is then

$$\sum_{j=1}^{N_i} Q_{ti,j}^{n+1} + \sum_{b=o,w} E_{bi}^{n+1} = 0 \quad (5)$$

Substituting (3) into (5) to eliminate the flow rate at $(n+1)$ time, we have

$$\sum_{j=1}^{N_i} \frac{(H_j^{n+1} - H_i^{n+1})\Delta t + \frac{L_j}{g A_j} Q_{ti,j}^n}{\frac{L_j}{g A_j} + K_j \left| Q_{ti,j}^n \right|^m \Delta t} + \sum_{b=o,w} E_{bi}^{n+1} = 0 \quad (6)$$

Now, we need to propose an interaction model for E_{oi} and E_{wi} . Here, the expressions used in double porosity model are utilized, i.e.

$$E_{bi} = T_{mbi} (p_{mbi} - p_i) \quad (7)$$

and capillary equation

$$p_{mci} = p_{moi} - p_{mwi} \quad (8)$$

The head of fluid flow at each junction can be obtained by the following formulation

$$H_i = Z_i + \frac{p_i}{g_i} \quad (9)$$

Upon substitution of (7) and (9) into (6), and then elimination of P_{mwi} from (8), the Eq. (6) can be written as

$$\sum_{j=1}^N \frac{(Z_j - Z_i + \frac{p_j^{n+1}}{g_j} - \frac{p_i^{n+1}}{g_i}) \Delta t + \frac{L_j}{g A_j} Q_{ti,j}^n}{\frac{L_j}{g A_j} + K_j \left| Q_{ti,j}^n \right|^m \Delta t} - T_{moi}^n (p_{moi}^{n+1} - p_i^{n+1}) - T_{mwi}^n (p_{moi}^{n+1} - p_{mci}^n p_i^{n+1}) = 0 \quad (10)$$

In equation (10), we also used linearization for calculating matrix transmissivity, T_{moi} and T_{mwi} and capillary pressure P_{mci} at n time step. There are two unknowns, junction pressure, P_i (and other junction pressure P_j), and matrix oil phase pressure, P_{moi} . For each junction in the network, we can write down one such equation. They form a large system of algebraic equations. To close the equation system, we employ fluid flow equations for matrix to proceed continuously.

$$f_i \frac{\partial S_{oi}}{\partial t} = -T_{moi} (p_{moi} - p_i) \quad (11)$$

$$f_i \frac{\partial S_{wi}}{\partial t} = -T_{mwi} (p_{mwi} - p_i) \quad (12)$$

$$S_{mwi} + S_{moi} = 1 \quad (13)$$

Combine equation (11) and (12), use condition (13) and (8), we have following equation associated with previous mentioned two unknowns

$$(T_{moi}^n + T_{mwi}^n) p_i^{n+1} - (T_{moi}^n + T_{mwi}^n) p_{moi}^{n+1} + T_{mwi}^n p_{mci}^n p_i^n = 0 \quad (14)$$

In the above equation, transmissibility is also linearized to n time step. Equation (10) and (14) constitute our new fractured reservoir simulation model. If there are J junctions in our system, we can solve the equation system that consists of $2J$ equations with $2J$ unknowns, P_i and P_{moi} . After these two pressures are obtained, matrix saturations can be calculated from (11) and (12). Then, transmissibility and exchange fluid flow E_{oi} and E_{wi} can be updated. Substitute the solved head at $n+1$ time into (3), we are able to estimate total flow rate at new time step. Finally, through conservative equations (4) and (5), flow rate for each phase at new time step are obtained. These procedures can be repeated to calculate quantities at further time step.

Because the above model only needs to solve 2 unknowns simultaneously for all nodes and the governing equations are very simple, it is much faster than Continuum Double Porosity Model that requires solving an equation system with 4 unknowns. It will have significantly less computational work than that of a Discrete Fracture Network model since this new model does not try to generate real fractures. By maintaining the concept of fast flow channels, i.e., pipelines, it is also more realistic than Continuum Single Porosity models that average fracture transmissibility with that of the matrix. This model can be extended to accommodate to any 3D geological structure without losing its

simplicity. Boundary conditions are constant pressures at the oil water contact and wellbore, plus well production rates.

PNM Calibration Work

This is an example of a three chimney model. The case study included examining the pressure profile with and without injection into the bottom aquifer.

Figure 25 Water Saturation profiles without Injection

Figure 26 Water Saturation Profile for the Test Case of Three Fracture Chimneys with water injection.

Figure 27 Comparison of Pressure Profiles with and without water Injection

The model has been tested against CMG STARS on 3D, 2-phase (Oil and Water) with dual-porosity (matrix and fracture) problems. Comparison studies were prepared between PNM and CMG models to simulate fluid flow production in “Chimneys”. Figures 28 to 34 show results of an example for three chimneys model

Figure 28: Example of Three Chimneys Model (x-z Coordinate)

Figure 29: Example of Three Chimneys Model (x-y Coordinate)

Figure 30: Water Saturation After 5 Years Production (x-z)-CMG Model

Figure 31: Water Saturation After 5 Years Production (3-D)-CMG Model

Figure 32: Water Saturation Distribution After 5 Years Production (x-z)-PNM Model

Figure 33: Water Saturation Distribution After 5 Years Production (x-y)-PNM Model

Figure 34: Water Saturation After 5 Years Production (layer-4)-PNM Model

The coding for a fully 3D, 3-Phase (oil, water, gas) and dual porosity (matrix and fracture) was finished. We substantially improved the Graphic Users Interface (GUI) for the software making it more user friendly.

Updated First Screen of the PNM Model

We incorporated a help section to orient the user with the file naming protocols.

We included additional options for generating graphical representation of the simulation results.

Menu options for Performance Plots

We also included capabilities for generating 2-D cross sectional representation of saturation and pressure data at various time steps. The model has been successfully tested against CMG STARS on 3D, three phase (Oil and Water and gas) with dual-

porosity (matrix and fracture). The model was released to the public in its final form in August 2003.

Fracture Study

Dipmeter reprocessing/analysis was conducted on all available dipmeter logs in the field. Schlumberger recovered archived data for dipmeters from 11 highly deviated wells. No more preserved digital data appears to exist as the remaining wells were drilled prior to 1970. We optimized the methodology for presenting borehole breakouts and fracture picks. An analysis of the data suggests that the maximum stress direction for the South Ellwood field is North-South. Borehole breakouts are observable and oriented East-West. This agrees with regional stress data for the Santa Barbara Channel.

Venoco also contracted with Dr. Laird Thompson to analyze the fracturing at South Ellwood field from the Formation Micro Imager (FMI) log collected by Schlumberger on the Venoco State 3242-7RD2 well. Dr. Thompson compared fracturing observed in that well to fracture data obtained from the 3242-19 Monterey Formation core and a borehole televiewer log run in the Arco State 208-102 well. Findings to date indicate that the open fracture swarms are oriented to the northeast more easterly than the N20°E current maximum horizontal stress orientation. These open swarms are most often associated with either shear failure consistent with the N20°E stress orientation, or reverse fault failure consistent with a S30°E stress orientation. The modern stress field orientation is different from the one present at the time of structural deformation.

Figure 35 shows a type of fault that is difficult to see without image logs: a bed parallel fault with no apparent offset visible in the wellbore. A 3 foot thick breccia interval is present in the fault zone. Several of these faults were found over the logged interval in 3242-7RD2, with breccias interbedded with the thin-bedded sediments. Note through-going fractures in the interval between the two faults. (left) an unwrapped cylinder that shows all the data around the borehole wall (note that north is on the left and right of the image), (center) a cylinder view of the data (a pseudo-core from the wellbore data), and (right) a dip

tadpole plot. The dip tadpoles show the magnitude of the dip with the “body” of the tadpole and the direction of the dip with the “tail” of the tadpole

FMI fault interpretation
Rose diagram of dip
directions of faults

FMI fracture interpretation
Rose diagram of dip
directions of fractures.
Strike directions will be
perpendicular.

Modern flow mechanisms within the field are now compartmentalized by (a) the scale of individual fault blocks (e.g. the 208-102 block vs the 3242-7RD2 block) and (b) the scale of structural “packages” within these fault blocks – packages that are bounded by bed-parallel faults. It is anticipated that enhanced flow will occur (a) along the individual fold axes within the fault flocks, (b) across the fold axes of these structures and (c) down into the aquifer along major through-going faults.

Production Type Curve Analysis:

In this field, the wells that intersect highly fractured and brecciated intervals are the most prolific producers. Historical production data on individual wells were examined using a type curve approach. The early production decline, from fracture-controlled period, was used to estimate equivalent permeability-thickness product for individual wells. The matching process is similar to the method suggested by Fetkovich for homogeneous reservoirs. Deviation from this model, attributed to a support system, is compared with two plausible systems. The two systems compared are the dual-fracture model published by Al-Ghamdi and Ershaghi, which is selected for its representation of network of micro fractures as the main support system, and the dual porosity/permeability models which are the most commonly used models in commercial simulators to represent naturally fractured reservoirs.

Conceptual dual porosity models representing naturally fractured reservoirs predict several logarithmic cycles of time data before support from a tight matrix can be recognized as shown in Fig. 36. For tight rocks susceptible to fracturing, Al-Ghamdi and Ershaghi proposed a dual fracture system where the support to major fractures is from a network of microfractures illustrated in Fig. 37. Because of high interporosity coefficients attributed to the high permeability of microfractures, the onset of the support system(s) occurs faster than that observed in dual porosity tight matrix systems. This support system is, however, of smaller storativity characteristics than those observed in granular matrix rocks.

The dual fracture reservoir model can be used to interpret declining production rates from a naturally fractured reservoir and to obtain representative values of interporosity flow and fracture storativity. This type curve is illustrated in Fig 38.

Fig. 36 Dual Porosity decline Type Curve

Dual Fractures

Fig. 37 Dual Fracture system introduced by Al-Ghamdi & Ershaghi for a NFR

Fig.38 Dual Fracture decline Type Curve for w=0.01

Permeability Estimation From Production Data

Applying the type curve approach discussed in the previous quarterly report, we analyzed the production data for the South Ellwood field. Using this technique, most South Ellwood wells yielded time ratios in the range 1.5-2.9.

Fig.39 Decline characteristics for 3120-11

Using this value in the type curve for dual fracture systems (fig 40) yields a value for lambda in the order of 0.0003; a range not supported by the actual permeability characteristics of the matrix rocks in the Monterey reservoirs.

Fig.40 Dual Porosity & Dual Fracture,
Ratio of t_d^*/t_d vs. λ

Using early time rate-time performance data, representative values of permeability thickness are calculated for different wells and plotted on a bubble map for South Ellwood in Fig. 41.

Fig. 41 Kh bubble map of various South Ellwood wells

The larger the bubble on the bubble map indicates a larger value of kh. This map demonstrates that adjacent wells can have distinct values of kh due to the heterogeneities found in a naturally fractured reservoir. The map indicates an areal variation exists in the permeability trend.

USC Compartmentalized Dual Fracture Simulation Model

Two generations of simulation models were built to study recovery mechanisms in the Monterey. The first used an earlier geologic model built using The Dynamics Graphics software, Earthvision. This software served as a visualization tool for realization of direct and indirect fracture data using various fracture indicators. The second model was built in GoCad using the new geologic model created using the reprocessed pre-stack migration seismic data.

Major features of the USC dual fracture model were:

1. Flexibility in the gridding process to add sub faults for history matching purposes.
2. Implementation of exact well trajectories ranging from vertical to highly deviated single laterals
3. Data from well 3120-8 at 3570 feet MD is used and adjusted to obtain representative curves of oil formation volume factor, solution gas ratio, and oil viscosity at the particular API gravity value. Based on the field observations, the API gravity varied from a minimum of 15 to a maximum of 32. Therefore, these two values formed the basis for the upper and lower API gravity tables used in the model. An intermediate API gravity is generated, based on the trends observed from the samples, in order to improve model stability.
4. The properties of the gas are assumed to be constant throughout the field.
5. Initial relative permeability sets for fractured systems will be obtained from production data.
6. There are no laboratory analyses of core samples from which the gas/oil relative permeability behavior could be measured. A synthetic normalized curve that best models the field behavior is used. The critical gas saturation is set to zero allowing gas to flow immediately from the grid cell based on the cell's saturation. The endpoints values are as follows:
Critical gas saturation=0.0
Residual oil saturation (with respect to gas)=0.30
Relative permeability of oil to gas at minimum gas saturation=0.70
Relative permeability of gas at residual oil saturation=0.15
7. Because the bulk of the majority of the production is from the fracture system, capillary pressure is assumed to be zero throughout all saturation ranges.
8. In general, most of the wells in the South Ellwood field are high angle or close to horizontal, while a few, near platform Holly, are nearly vertical. The horizontal completion can range from 1000 feet to over 4000 feet in length. Most wells currently have completions or have had completions in all seven layers of Monterey horizons. Most wells have been re-completed several times, with many zones being added, re-perforated, or plugged-back through the course of history.
9. The South Ellwood field does not have any structural faults to compartmentalize the field into separate blocks. A sloping/sealing fault on the north side of the field is incorporated to model the northern boundary of the field structure. A Cartesian gridding scheme is selected, resulting in a grid dimensioned by 228 cells in the x-direction and 60 cells in the y-direction. Each grid cell's dimensions are approximately 200 feet long by 200 feet wide (Figure 42). We postulated the

existence of compartmentalization in the behavior of the South Ellwood Field. Deterministic information about reservoir compartmentalization was derived from the study of fluid recoveries and variations of fluid properties from individual wells. Had the blocks been in total communication, differences would have rapidly disappeared by density-driven convection. Their preservation indicates a barrier to fluid flow exists among the compartments. Recognition of such isolated blocks substantially improves the accuracy of history matching of the individual wells.

Figure 42: 3-D image of formation, showing areal gridding and three constant layers(looking from the east)

Figure 43: 3-D presentation of compartmentalized reservoir model

Figures 44 through 50 show the results of final history matching runs (total field case). Performance forecasting was initiated for the compartmentalized reservoir model. Figures 35 through 37 show latest field-wide prediction plots for the preliminary forecast. Figures 51 through 54 show the results of preliminary well-by well history matching for wells 3242-18 and 3120-9RD1.

Figure 44: Field Pressure History Match

Figure 45: Field Cumulative Oil History Match

Figure 46: Field GOR History Match

Figure 47: Field WOR History Match

Figure 48: Field Oil Rate Forecast

Figure 49: Field GOR Forecast

Figure 50: Field WOR Forecast

Figure 51: GOR History Match for 3242-18

Figure 52: WOR History Match for 3242-18

Figure 53: GOR History Match for 3120-9RD1

Figure 54: WOR History Match for 3120-9RD1

Dual Porosity Simulation Model

A new dual porosity simulation model of the Monterey was constructed using CMG after the geological model was modified as a result of the seismic reprocessing study. Fluid properties were allowed to vary from fault block to fault block and vertically through the reservoir. The model has been history matched and is being used to predict performance for the future North Flank wells. The following figures show the comparison of the model oil production rate and reservoir pressure with the historical data.

The top of the Monterey Formation surface was built in GOCAD using the 3D seismic reflection data, well picks, and dipmeter data. Faults mapped from the seismic reflection data and well cuts were also entered. These faults cut the Monterey surface. To create the base Monterey surface, true stratigraphic thickness of the Monterey formation was used from field well data. This thickness was input into the 3D model to create a grid for reservoir simulation. The grid has 7 layers to represent the major geologic subdivisions based on gamma ray behavior.

This is still a work in progress as the fault pattern was completely changed as a result of drilling 3120-18 in 2005. The model will have to be updated to reflect the new data.

Figure 55 History Match Plots for Dual porosity Model

South Ellwood Monterey from GoCad7/04

South Ellwood Monterey from GoCad7/04

X-Ray Diffraction Studies

Prior to drilling 3120-18, samples from core from North Flank exploration well 309-9, drilled by Arco in 1982, were recovered from the University of Texas core repository in Houston and sent out for X-ray diffraction analysis. This type of analysis is used to determine whether the silica phase of the Monterey rock is in the opal A (amorphous silica), opal-cristobalite, or quartz phase. Monterey reservoir quality is normally believed to be the highest where the siliceous rocks have been thermally altered to the quartz phase. The results show that the Monterey Formation in the 309-9 well is entirely in the quartz phase up to the highest sample available (M3). Perhaps more significantly, no opal CT was observed. The South Ellwood field Monterey rocks generally lie within the transition from opal CT to quartz and typically have some opal CT even among the rocks largely in the quartz phase. The new XRD data suggests that the 309-9 area that is now relatively shallow, was once buried much deeper and may originally have been the source rock for the South Ellwood field. It also indicates that the North Flank of the field is most likely entirely in the quartz phase and of the highest reservoir quality.

A map of the Monterey zones that occur at the opal cristobalite to quartz transition was created from the Monterey gamma-ray zone correlations. The transition depth marks a large change in rock properties in the siliceous rocks with the quartz having higher matrix density and increased fracturing. This transition was picked using X-ray diffraction (XRD) data from Mobil and Arco and neutron-density logs for wells without XRD data. This map revealed that the quartz phase rocks occur at or near the top of the Monterey Formation toward the north of the field but progressively deeper in the Monterey Formation to the south. This suggests that better reservoir rock occurs along the north flank of the structure than the south flank of the field. Quartz phase reservoir rock should occur at a depth on the south flank of the field that has as yet not been penetrated by wells. A northwest-southeast trending fault that is difficult to map from the seismic data is clearly revealed by this map.

Figure 56 Map of Location of Opal CT/Quartz Transition at South Ellwood

Core Lab later performed X-ray diffraction studies on cuttings from 3120-18, the Venoco North Flank well. Although this data confirmed that the Monterey was mainly in the quartz phase, a pressure build-up conducted on the well during January 2006 showed a very low effective permeability of 1 md even after acid treatment. Therefore a study was undertaken to compare DST and pressure transient data for all wells where compositional XRD data had been obtained.

Figure 57 3120-18 X-ray Diffraction data

As the following series of slides shows, there is no strong correlation between the percentage of quartz in the Monterey and well productivity. This highlights the need to run image logs on new Monterey wells as the primary guide for selecting completion intervals.

Figure 58 3242-9 X-ray Diffraction data

Figure 59 3120-10 X-ray Diffraction data

Figure 60 208-102 X-ray Diffraction data

Figure 61 3242-7RD1 X-ray Diffraction data

Figure 62 3242-13 X-ray Diffraction data

Figure 63 309-8 X-ray Diffraction data

Task IV-1—Produced Water Re-Injection

The Holly separators (V-107 and V-108) were originally designed for three phase operation but they usually operate in two phase mode, separating produced gas for shipment to Ellwood via the 6" gas line. Venoco commissioned a study by Natco of the three phase separation capacity of the two Holly production separators. This study showed that the production separators can be reconfigured at minimal cost to separate up to 40,000 BFPD at Holly.

During March 2006, the first Holly group separator (V-107) was retrofitted with new internals to allow three phase water separation. Upgrades included a new proprietary "Porta Test Revolution" inlet separation device, a higher water weir and new water level control, alarm and shutdown instrumentation. The "Porta Test Revolution" inlet separation device utilizes centrifugal force to separate gas from the liquid without foaming. The higher water weir allows longer liquid retention time to provide more complete water oil separation.

Two new 125 HP positive displacement pumps each capable of delivering 5000 BWPD at 1000 psi were installed and placed in service on April 12th, 2006. Two wells, 3120-10 and 3242-8RD4, were converted to water injection service during the first quarter of 2006. Well 3242-8-4 is a very low volume producer completed in the Monterey M2 through M6 units. 3120-10 was an idle well completed in the Upper Monterey M1-M3 units. Additional perforations were shot in the Lower Monterey in both wells to improve water placement. We have been able to shut down the second production separator (V-108) and are currently injecting a total of 9000 BWPD into the two wells. Three wells that had been shut-in for many years due to high water cuts were returned to production for an additional 50 BOPD. Only 4000 BWPD is being separated at Ellwood and injected into the onshore disposal well.

Task IV-2—Downhole Water Separation ESP's

Venoco conducted a review of Platform Holly modifications that would be required to accommodate additional ESP wells. Holly is run on shore power and the load factor for the subsea power cable must be closely monitored. We have developed a plan to raise primary separator pressure to 200 psi and mothball a 1500 HP sales gas compressor that boosts separator gas to pipeline operating pressure. This would free up enough spare power to supply five new ESP wells. Venoco plans to install three of these pumps during 2006. Since the retrofitted production separators will have sufficient capacity to meet all future production forecasts, we have decided to use conventional ESP's with no downhole separation capacity.

Task IV-3—Development of New Fault Blocks

Sespe Well 3120-15 RD4

We used the reprocessed 3D seismic data to confirm the trapping mechanism and size of a Middle Sespe accumulation that was identified by Arco's exploration well 208-102, drilled in 1985. This well was drilled to the west of South Elwood field to test sandstone reservoirs in the middle Sespe to Coldwater formations. Strong oil indications were seen in the Middle Sespe. The logs indicate approximately 200' of net oil pay. However, Arco lost the bottom hole section of this well before they could conduct a DST.

The Venoco Sespe well was sidetracked out of the 9-5/8" casing of 3242-19 on 26 November, 2004. The well was renamed 3120-15RD4 by the California Division of Oil, Gas and Geothermal Resources since the producing interval is located on State lease PRC3120. The well reached a total depth of 14247' on January 17th 2005. Excellent gas shows were evident in the Sespe formation. A 2-7/8" completion string was run to test a barefoot section in the massive sands of the Gaviota formation from 12965-13650'. This zone tested wet with minor traces of gas. The reservoir pressure was estimated to be 5500 psi. During testing, the tubing plugged with mud. The tubing was cleaned out with coiled tubing and the completion recovered. TCP guns were run and set on a hanger to shoot the Middle Sespe sands. The completion string was rerun but it was not until six weeks later that the completion string was landed due to difficulties running the packer in the oil based mud completion fluid. The guns would not fire due to the presence of 60' of settled mud solids lying on top of the firing head. It was decided to pull the completion and recomplete the well with Calcium chloride brine. Recovery of the completion string took an additional two months as it required a washover string to clean out settled mud solids in the tubing-casing annulus.

A test was finally completed in October 2005. The Middle Sespe was perforated with TCP guns from 12515-12770'. Unfortunately the Middle Sespe tested at a very disappointing rate of 20 BFPD x 97% WC on gas lift. A set of memory gauges was hung in the well on November 5th, 2005 and a long term build-up was conducted until January 2006. The data indicated that the Middle Sespe was extremely tight with a permeability of 0.001 md.

The Upper Sespe was perforated through tubing from 11240-75', 11655-75' and 11850-60' during January and April 2006. The well last tested at 13 BOPD and 279 Mcf/d on gas lift.

A paleontological study of the cuttings from this well shows that it penetrated the Rincon and Vaqueros formations three times before finally passing into the Sespe at 10980' MD. The well may have passed through a big thrust fault at 13860 MD'. An examination of thin sections prepared from the cuttings shows that the sandstone intervals have undergone appreciable chemical compaction that has reduced permeability to virtually zero.

A contract geophysicist from Subsurface Consultants was brought in to review the current 3D seismic interpretation. The poor data quality in area of the North Flank play precluded much improvement in the current mapping. As a consequence, Venoco has decided to contract Fugro to shoot a low energy seismic acquisition program over the North Flank block to resolve some of these uncertainties. This program will be shot in the late summer of 2006.

The consultant was able to make better progress on the South flank of the field. He established the existence of a large thrust fault at the Rincon /Vaqueros level that sets up the structural high under the platform. The 3120-15RD4 well appears to have penetrated the footwall of this fault and missed the target sands of the Middle Sespe that looked prospective in the 208-102 exploration well.

Figure 64 Arbitrary Seismic Section showing Well 3120-15RD4 Crossing White Thrust fault

shomer@CORP7231A
01/20/06 10:33:50

Figure 65: Upper Sespe Pay in 3120-15 RD4

North Flank Well 3120-18

The Ames 3120-18 was drilled as a sidetrack from the 3242-13. It was renamed 3120-18 as it reached total depth on lease PRC3120. It was planned to test two objectives: The north limb of the South Ellwood field and the north limb of the bordering syncline (see Figure 66 based on old geologic mapping). The well was spudded on November 18, 2005 and successfully drilled to a total depth of 11,259' MD (-5,210' ss) on December 7, 2005.

The well was drilled smoothly with no mechanical problems and no loss of drilling fluid. Hydrocarbon shows of interest are present from 4,630-4,773' in the M3 and 6,407-6,498'/7,247-7,295' in a repeat section of the M1. The Monterey north limb of the syncline was encountered at 9,963, MD (5,047' TVDss) below the lowest known oil in the South Ellwood Field. Minor shows were observed from 10,300-11,109'.

Analysis of the Formation Micro Imaging log and dip-meter logs has lead to an enhanced structural interpretation of the northwestern portion of the South Ellwood field. Well 3120-18 penetrated five seismic scale faults: four with normal displacement and

one with reverse displacement. Bedding dips encountered ranged from 5° North-east to 88° South-Southwest.

The structural interpretation from logging results obtained in well 3120-18 is represented in Figure 67. After encountering the second normal fault (N2) the well paralleled the Upper Monterey (M1) along strike until it turned back to the northwest and crossed the N3 fault. North of the N3 fault the well entered the Sisquoc Formation and passed through an asymmetrical syncline. In the north limb of the syncline the Monterey section was encountered again with dips of 60°-70° South. The Reverse fault (R1) removed a small section of Monterey (M5). The well then encountered lower Monterey (M6a and M7a) north of the reverse fault with dips up to 88° South-Southwest reaching total depth at the very base of the Monterey. The reverse fault is believed to be part of the Red Mountain Fault complex (Figure 68).

Casing was set to 10,097' in the M1. The open hole Monterey interval below 10,097' was then acidized and put on production on December 30th 2005. It tested 1300 BWPD with no traces of oil or gas. The produced water is the closest to seawater composition of any Monterey well at Holly. A build-up test was conducted that showed the North limb of the syncline is being depleted by production from South Ellwood. The reservoir pressure was determined to be approximately 400 psi less than the initial South Ellwood pressure of 1760 psia. The effective permeability of this 1162' open hole section was estimated to be 1 md. This is a surprisingly low value considering the siliceous material in this section of the well was in the quartz phase and the beds were dipping at as much as 88 deg. The open hole interval was abandoned with a tubing plug and additional perforations were shot in North limb of the main field in fractured intervals of the M1 from 6,407-6,498' and 7,247-7,295' during January 2006. The new perforations tested 1300 BWPD on gas lift without acid. The interval 6,407' to 7295' MD (4,680-4,700' TVD ss) is above the lowest known oil of -4,800' for the main portion of the South Ellwood field but is down dip from all other producing wells and may indicate a drained portion of the field. The well will be re-completed as a water disposal well.

Figure 68: Top Monterey Subsea Structure Map & Lowest Known Oil

Task V- Project Management

Project review meetings were held on a monthly basis in Carpinteria. Individuals working on the project included:

Database:

I. Ershaghi (USC), Tim Rathmann (Venoco) and Kim Halbert (Venoco), H. Patel (USC), Katie Boerger (USC), Chris Knight (Venoco), Ursula Wiley (USC).

Reservoir Studies:

I. Ershaghi (USC), Steve Horner (Venoco), Zhengming Yang (USC), M. Kashfi (USC), Doddy Abdassah (USC), M. Heidari (USC), . Zahedi (USC), Anthony Taglieri (USC), Raymond Ohusuafr (USC), Lang Zhang (USC), Ursula Wiley (USC).

Geological/Geophysical Modeling

Ted Carlsen, Dick Bischke, Marc Kamerling, Chris Knight, Karen Christensen (Venoco)

Project Management:

Steve Horner (Venoco) and I. Ershaghi (USC)

Task VI-Technology Transfer

The tech transfer goals for this project were met through the preparation of SPE papers, hosting of meetings and making presentations to local chapters of professional societies.

9/19/2000

Presentation to Coast Geological Society: South Ellwood Field, Santa Barbara Channel: New Insight into Structures, Fractures, and Seeps. (Karen Christensen)

Two SPE papers were presented at the Western Regional meeting of the Society of Petroleum Engineers, March 25-30, 2001.

- Mapping of Permeability Structure in a Naturally Fractured Reservoir Using Field Performance Data SPE 68833 Juan A. Anguiano, U. of Southern California; Iraj Ershaghi, U. of Southern California; Karen I. Christensen, Venoco
- A New Diagnostic Method for Prediction of Producibility and Reserves of Wells Producing From the Monterey Formation Using Well-Log Data, SPE 68834; Ursula M. Wylie and Iraj Ershaghi, University of Southern California, and Karen Christensen, Venoco Inc.

4/10/2001

Presentation to GSA/AAPG. South Ellwood Field, Santa Barbara Channel, California: Is a Normal Fault Always Normal? (Karen Christensen)

4/10/2001

Presentation to GSA/AAPG. Three Dimensional interpretation of the Sockeye Structure: Santa Barbara Channel, California (Mike Wracher)

6/20-21/2001

Organized a workshop and a field trip on geological complexities of the Monterey Formation with the West Coast PTTC. Karen Christensen and Iraj Ershaghi presented talks on geology and reservoir engineering aspects of this formation.

6/13/2001

Presentation to Pacific Section SEG. New 3D Seismic Processing Data Results from the Santa Barbara Channel, Karen Christensen.

September 28, 2001

Presented South Ellwood geologic and fracture studies at a Santa Barbara City College Geoseminar (Karen Christensen, Venoco)

October 2, 2001

An Integrated Pipe Network Model for Simulation of Highly Fractured Reservoirs
SPE 71616 Presented at the SPE Fall Meeting in New Orleans.

Lang Zhan, SPE and Iraj Ershaghi, SPE, University of Southern California

Presented three papers related to the project at the Western Regional Meeting of
SPE in Anchorage Alaska, May 18-23, 2002.

- SPE 76782 A Method for Detection of Untapped Intervals in a Complex Lithology Fractured System. Anthony Taglieri, Doddy Abdassah, Iraj Ershaghi, University of Southern California and Kim Halbert, Venoco Inc.
- SPE 76755 Characterization of Flow Channels, Natural Fractures Orientation and Oil Water Contact Movement From Well Productivity Data. Alireza Zahedi, SPE and Iraj Ershaghi, SPE, University of Southern California, and Steve Horner, Venoco, Inc
- SPE 76781 Technology of Web Based Data Access for Reservoir Monitoring and Tech Transfer. Iraj Ershaghi, Ursula Wiley, Katie Boerger, Harshad Patil, University of Southern California, Steve Horner, Tim Rathmann and Kim Halbert, Venoco

Participated at the University of Oklahoma's Conference on Naturally Fractured Reservoirs in Oklahoma City, OK on Monday, June 3, 2002. Reservoir Characteristics of Fractured Reservoirs of the Monterey Formation, Iraj Ershaghi, U. of Southern California, Steve Horner and Karen Christensen, Venoco, Inc.

We conducted a second workshop followed by a field trip on geological and reservoir characterization issues of the Monterey formation during July 17-18, 2002 in Ventura California. We presented 3 talks related to the DOE project at this workshop and in a fourth talk we introduced the Web based data base.

SPE paper presented at the Society of Petroleum Engineers Annual Meeting in San Antonio Texas in October 2002. Simulation of Lithologically Complex and Fracture-dominated Monterey Production from the South Ellwood Reservoir (SPE 77739) (Zahedi, A, Abdassah, D, Ershaghi, I and Horner, S)

Presentations at the AAPG/SPE meeting in Long Beach California during May 2003.

- Fluid Conductivity in the South Ellwood Fault – Boles J. and Horner S.
- The Monterey Formation at South Ellwood – Kamerling M. and Horner S.
- Estimation of Microfracture Support from Analysis of Production data – Heidari M and Ershaghi

Poster session at the July 2003 National Meeting of AAPG in Salt Lake City Utah to introduce a computer aided system for detection of productive intervals from conventional logs. The paper was titled: "A Fuzzy Expert System for Detection of

By-Passed Intervals in a Geologically Complex Reservoir using Production-Calibrated Well Log Data” Ershaghi, M. Kashfi, K. Christensen, T. Rathmann.

During August 2003, we hosted a third Monterey Symposium and Field trip at the West Coast PTTC meeting in Camarillo, California. Venoco gave three presentations at the technical meeting.

An article on the project appeared in the December 2003 issue of World Oil magazine entitled Characterization, 3D visualization spur successful offshore redevelopment by Horner S, Kamerling M and Ershaghi I.

Marc Kamerling gave a presentation to the San Joaquin Geological Society on March 8, 2005 entitled The Monterey Formation at South Ellwood Field, Santa Barbara Channel, California

Steve Horner presented the Pool Engineering Report for South Ellwood Field to the Conservation Committee of California Oil and Gas Producers on May 4th, 2005.

A paper was presented at the May 2005 Pacific Section AAPG Meeting in Bakerfield: Enhancing Structural Interpretation with Borehole Stress Data from Dipole Sonic, Steve Grayson, Marc Kamerling and Lee Swager.

Steve Horner gave a presentation on reservoir engineering aspects of the South Ellwood field to an undergraduate geology class at University of California in Santa Barbara in February 2006.

Conclusions:

Venoco benefited greatly from this joint research project with the Department of Energy. Perhaps the most important achievements were:

- Reprocessed 1982 3D Seismic data using modern algorithms
- Constructed a new Monterey geological model using the reprocessed 3D seismic, dipmeter, BHTV, FMI and oriented core data
- Identified Eagle Canyon, North Flank and Middle Sespe fault block structures (60 MMB of new possible reserves)
- Ran new generation production logs to identify undesired water entry in six wells.
- Conducted Thru-tubing Plug backs in five wells for a 600 BOPD gain and 6 MMB of reserve additions
- Drilled the first Holly development well since 1986 (3242-7RD2). Well tested 833 BOPD and 2 MMcf/d and added 3 MMB of proved reserves
- Developed and released a stand-alone Pipeline Network Fracture Simulation Model
- Reconfigured the Holly production separators for three phase operation and commissioned offshore water injection.
- Drilled two exploratory wells (3120-15RD4 and 3120-18) to appraise prospects identified from the re-processed seismic data.

Unfortunately neither of these two exploration wells was commercially successful. Venoco has decided not to pursue further development of these prospects. Therefore, Venoco decided not to proceed with Budget Period III of the original proposal that consisted of planning a new series of development wells. Venoco decided to terminate the project and instead prepared the Final report.

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