VENOCO, INC.
Monterey Shale Focused Analyst Day

Wednesday, May 26, 2010

New York Plaza Hotel

NOTE: Slides 82, 85 and 89 were updated as of July 14, 2010

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Cautionary Statement Regarding Forward Looking Information

Statements included in this presentation, other than statements of historical fact, are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Venoco, Inc. (“Venoco” or “the Company”) cautions that assumptions, expectations, projections, intentions, or beliefs about future events may, and often do, vary from actual results and the differences can be material. Some of the key factors which could cause actual results to vary from those Venoco expects include changes in natural gas and oil prices, the timing and cost of planned capital expenditures, the timing of permits and/or approvals, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, reserve estimates, cash flows and production and other costs, the availability and cost of gathering and transportation facilities and transportation arrangements, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as the Company’s ability to access them, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting Venoco’s business. More information about the risks and uncertainties relating to Venoco's forward-looking statements may be found in the Company’s SEC filings, including under the heading "Risk Factors" in Venoco's Annual Report on Form 10-K for the year ended December 31, 2009, and are incorporated herein by reference. You should not place undue reliance on these forward-looking statements, which speak only as of the date of this presentation. Forward looking statements made about the Hastings Complex and the contract with Denbury Resources are subject to business risks and uncertainties not in Venoco’s control including, but not limited to the implementation of a CO_2 flood and the production results and reserves if the flood is implemented. Forward looking statements made about the South Ellwood pipeline and lease extension projects are subject to risks and uncertainties relating to, among other things, the receipt of the governmental consents and approvals necessary to pursue the projects. The Company may not be able to complete its search for a joint venture partner relating to the Monterey shale on acceptable terms, in a timely manner, or at all. The Company’s activities with respect to the Monterey shale are subject to numerous operating, geological and other risks and may not be successful. Our results in the onshore Monterey will be subject to greater risks than results in areas where we have more data and drilling experience. Results from our onshore Monterey project will depend on, among other things, our ability to identify productive intervals and drilling and completion techniques necessary to achieve commercial production from those intervals. Except as otherwise required by law, Venoco does not undertake any obligation to update any forward-looking or other statements as a result of new information, future events or otherwise.

Estimates of unproved reserves or resources which may potentially be recoverable through additional drilling or recovery techniques are by their nature more uncertain than estimates of proved reserves and accordingly are subject to substantially greater risk of not actually being realized by the Company.

The Company

Applying new technology to revitalize legacy assets

Venoco is an independent energy company engaged in the acquisition, exploitation and development of oil and natural gas properties primarily in California.

Monterey Shale

- World Class Source Rock
- Largest U.S. Oil Shale Play[1]
- Southern California Multi 100-Billion Barrels of OOIP[2]
- Venoco is the “pure” Monterey play with >350 Monterey barrels OOIP per share
- Leased >80% of onshore undeveloped acres in the last 3 years

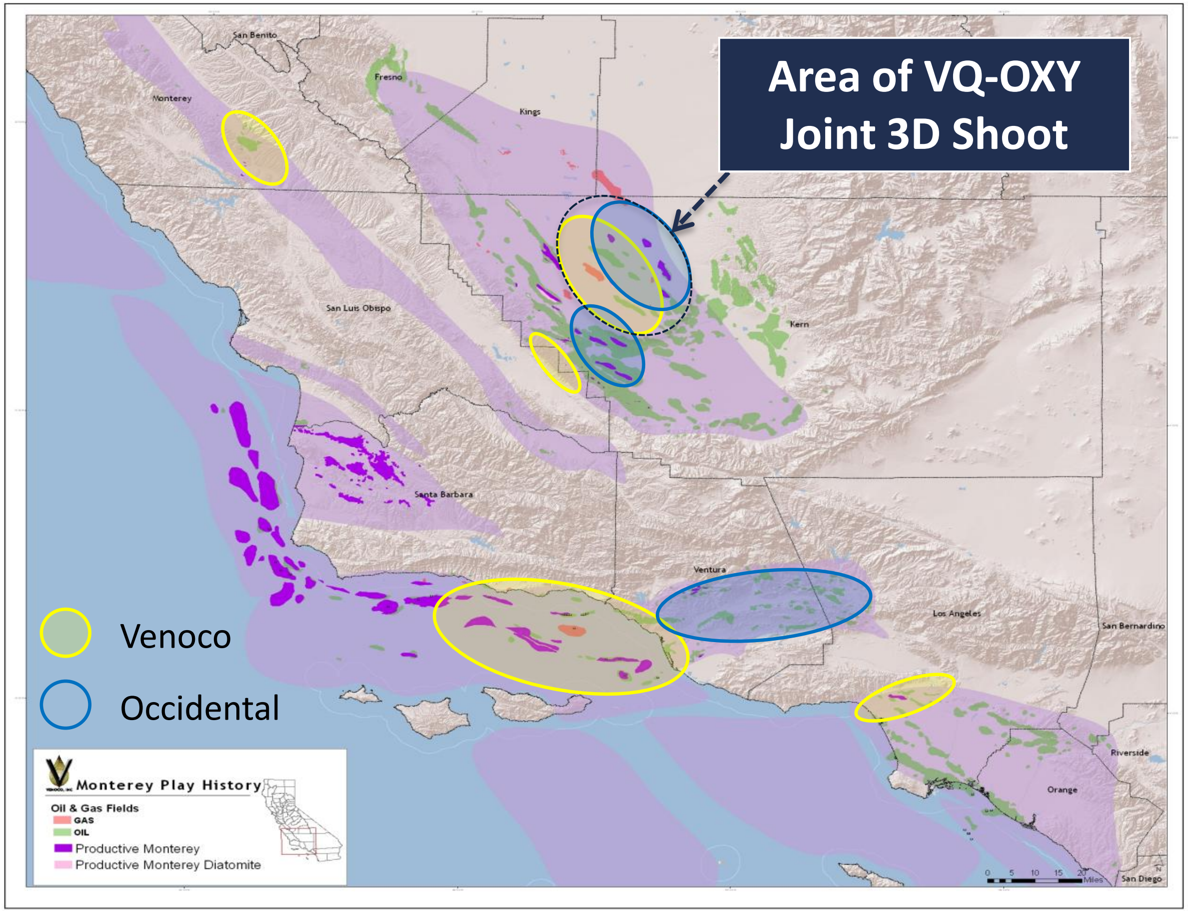
California E&P	Mkt. Cap $MM (5/21/10)	California Acreage (Net)	Monterey Acreage (Net)	Monterey Acres / $MM Market Cap
Venoco	$653	383,000	155,000	237
OXY	$64,490	1,300,000	873,000	14
PXP	$3,190	116,400	70,000[3]	22
NFG	$3,880	23,100	14,000[3]	4
BRY	$1,550	6,500	6,500	4

Why does opportunity exist?

- Majors have dominated since early 1900s
- F&D in heavy oil fields best use of capital
- Exploration teams built in early 1980s cut as oil price drops
- Venoco founded in 1992 to acquire non-core assets in CA
- Venoco acquires Monterey production in 1997, 1999
- Venoco begins regional study in 2005

(1) Based on cum oil production to date.
(2) Internal estimates of Southern California oil basins.
(3) Venoco internal estimates of potential Monterey acreage.
(4) Based on estimated OOIP per 640 acre section of 80 MMBOE.

Monterey Competitive Landscape



Significant Competitors

- Majors – Primarily Chevron and AERA (Shell & Exxon)
  - Dominated since early 1900s
  - Focused on heavy oil
- Occidental
  - Acquired many producing fields
  - Acreage positions within certain Venoco target areas
- Lack of “Super-Independents” in California
- Venoco most active leasing Monterey

The Heart of Venoco's Monterey Expertise

(Venoco field ownership in red text.)

- Operating Expertise
  - 13 years Monterey production
    - South Ellwood 1997
    - Sockeye 1999
  - U.S. MMS 'SAFE Award' for *Operating Excellence* (Platforms Gail & Grace)
  - California Division of Oil & Gas *Lease Maintenance Awards*:
    - Ellwood Onshore Facility
    - Santa Clara Avenue Field

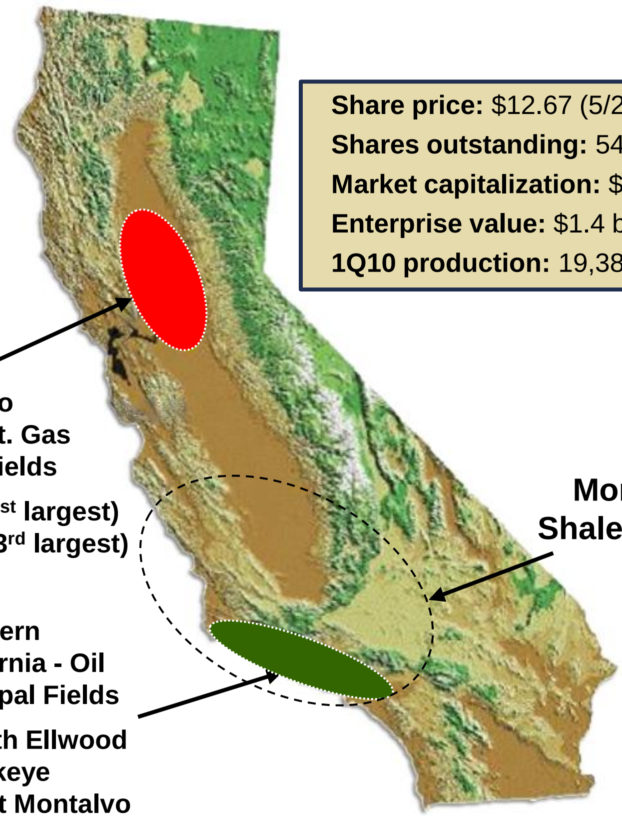
– Offshore Monterey tests @ commercial rates

– Existing Offshore Monterey Production

Company Highlights

Solid Core Assets

Share price: $12.67 (5/21/10)
Shares outstanding: 54.5 million
Market capitalization: $653 million
Enterprise value: $1.4 billion
1Q10 production: 19,384 BOE/d



Venoco's statewide leasehold approx. 380,000 net acres

Large Development Opportunities

- Key year for Monterey Shale Exploitation
  - Frac/acidize offshore wells (M2)
  - Drill 10 wells onshore prospect areas (including exploitation wells)
- Sacramento Basin Infill Program
- Southern California Fields Development
- Hastings CO_2 upside in Texas (retained)

Portfolio Highlights

- Concentrated positions
- Shallow declines
- YE '09 Reserves 98.3 MMBOE
  - PV-10[(1)] of $801.1 million @ YE09 SEC pricing
  - PV-10[(1)] of $1.7 billion @ YE09 5-Yr NYMEX Strip
- Oil-weighted – reserves & revenue
- 97% of properties operated

(1) See Appendix for a definition of PV-10 and the relevant GAAP reconciliation.

Strategy & Capital

Strategy

- Pursue oily opportunities
  - Monterey Shale Exploitation – multi-year, multi-100 million barrel
  - Existing producing assets – enhance low-decline assets
- Develop Large Inventory in Sacramento Basin
  - 700 locations at 20-acre spacing – 7 year inventory
  - Down spacing to 10-acres could double locations
  - Selective hydraulic fractures
  - Exploratory prospects
- Selective Acquisitions
  - Bolt-on opportunities in and around existing production
  - Focus on California
  - Screen opportunities against Monterey exploitation economics

Funding Capital Needs

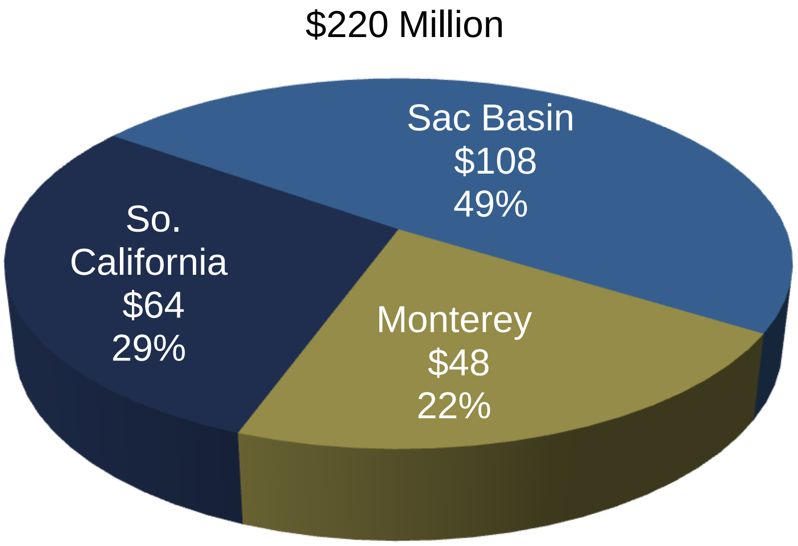
- Internal cash flow
- Sale of assets
- Joint ventures
- Capital markets transactions

Experienced Management Team

Name	Title	Prior Affiliations	Years Experience
Tim Marquez	Chairman, CEO (& majority VQ shareholder)	Unocal, founded Venoco in 1992	30
Bill Schneider	President	Unocal	>25
Tim Ficker	CFO	KPMG	>20
Ed O'Donnell	SVP, Coastal California	Unocal	>30
Kevin Morrato	VP, Sacramento Basin	General Atlantic, UMC	>25
Mike Wracher	VP, Exploration	Mobil	>20
Ted Carlsen	Manager, Unconventional	Unocal, Occidental	>25
Luis Chirinos	Engineering Director	Petro-Hunt, Schlumberger	>30
Terry Anderson	General Counsel	Santa Fe Energy Resources	>30
Doug Griggs	CAO	Ernst & Young	>25
Mike Edwards	VP, Corporate & Investor Relations	Landman, Venoco 1994	>25

2010 Capital Spending

Estimated Capital by Business Unit



Increased 2010 capital budget by $40 million to $220 million

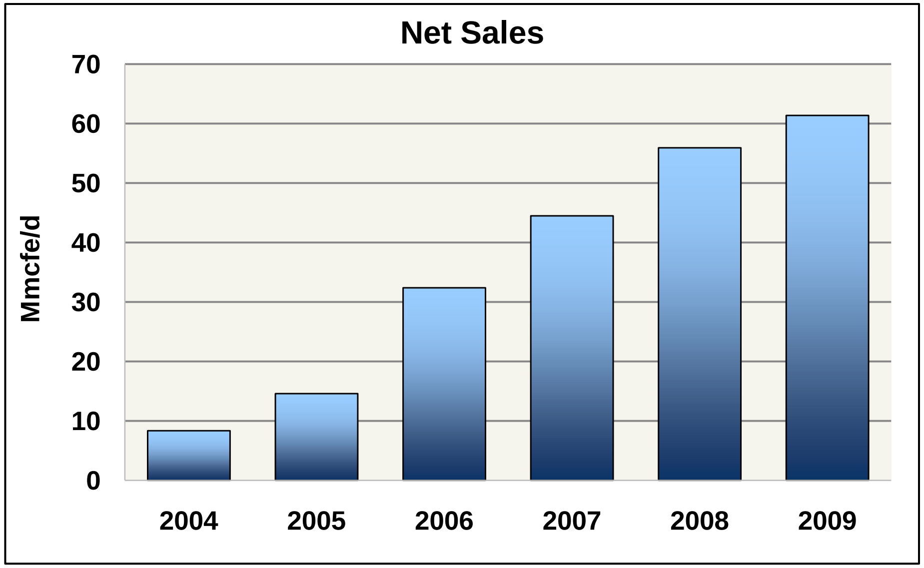
- Portion of Texas proceeds plus reallocation of Texas and Southern California budgets
- Accelerate Sacramento Basin activity and Monterey Shale exploitation

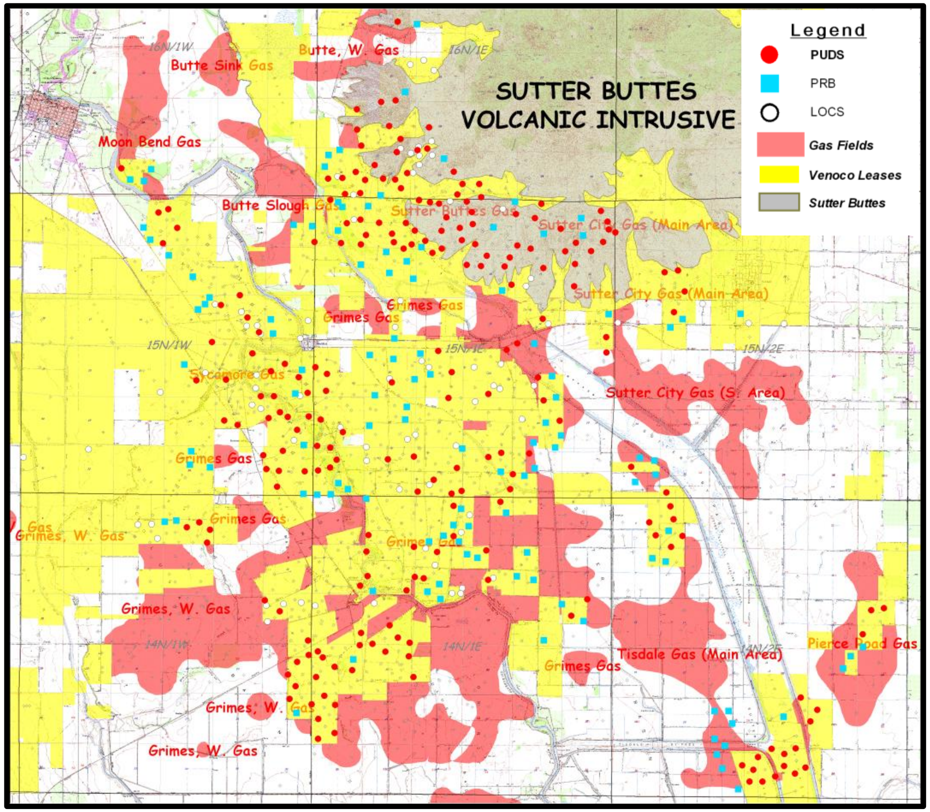
- **Advance "oily" projects in 2010 and 2011**
  - Emphasize oil in portfolio
  - Robust inventory of oil projects
- **Monterey Exploration & Exploitation**
  - Drill 10 wells (including exploitation wells)
  - Acquire 3-D seismic data
  - Continue to build acreage position
- **Sacramento Basin**
  - Drill ~100 wells, 250 recompletions, and 10 fracs
- **Southern California**
  - Drill 3 wells at West Montalvo
  - Sockeye
    - Drill dual-completion well (M4) (producer/Lower Topanga injector)
    - Monterey well (M2) – frac'd horizontal, redrill & acidize second horizontal
  - 5 workovers at South Ellwood

References to 'well' or 'wells' refer to gross well(s).

Sacramento Basin

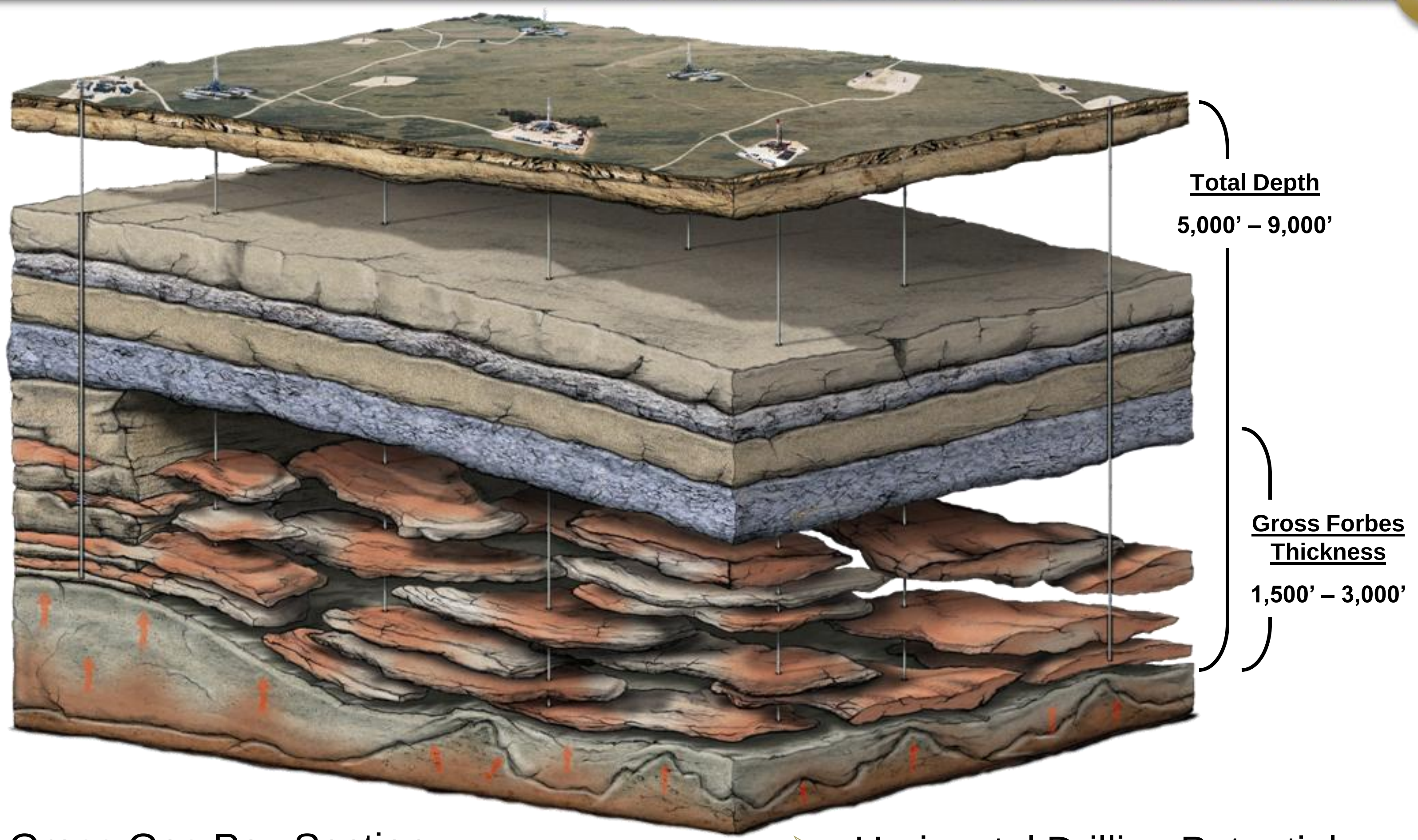
- Largest gas producer & most active operator in Basin
  - Drilled approximately 400 wells since 2005
  - Drilled 86% productive wells in 2009
- Extensive inventory for future activity
- Positive gas differential significantly enhances economics (LTM +$0.32)
- 2010 Plans: drill ~100 wells, 250 recompletions, and 10 Fracs





- Approximately 700 Locations at 20-Acres
- Future Location Potential
  - Down Spacing / Step Out Drilling / Deeper Horizons (Guinda) / Exploratory

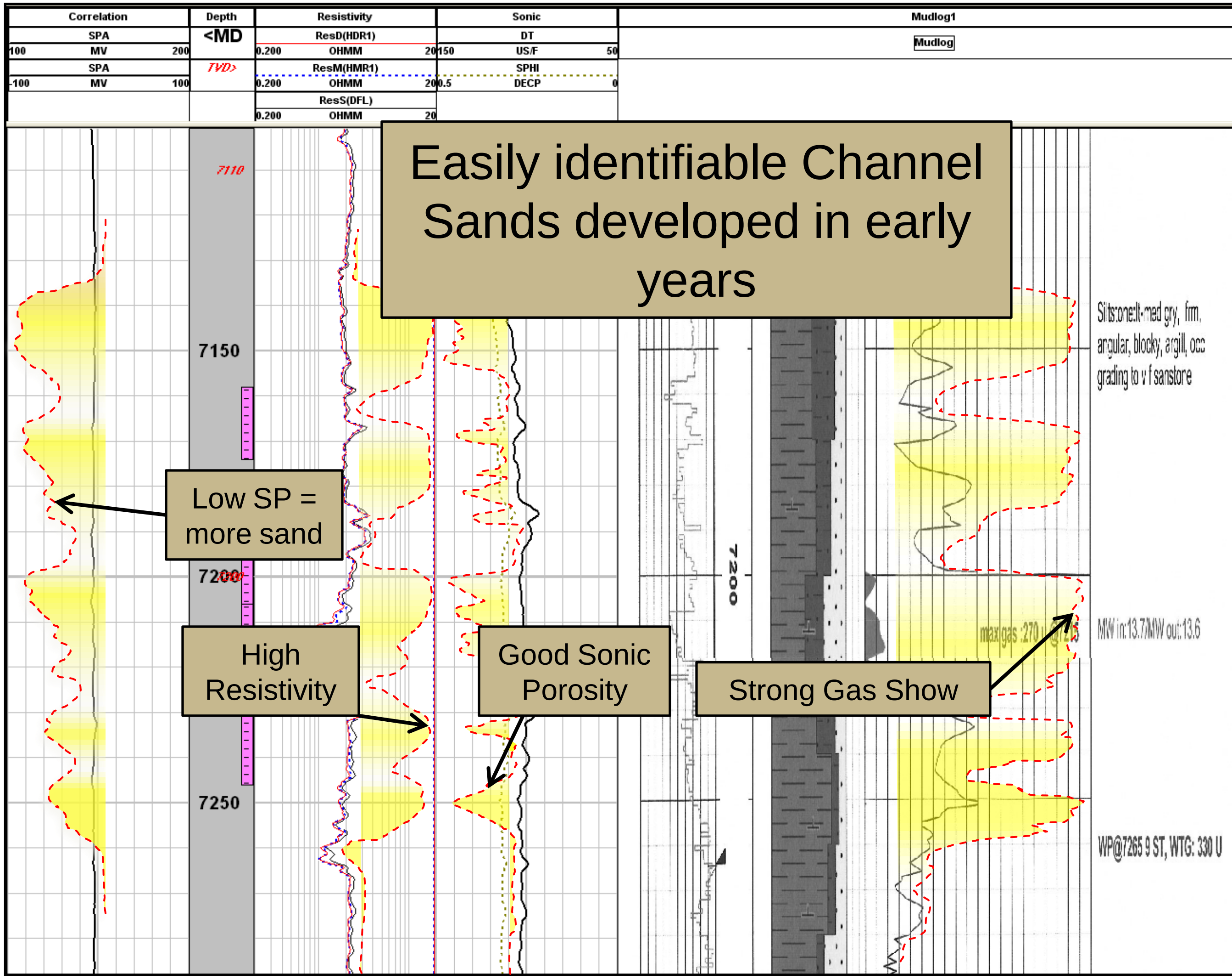
Sac Basin – Forbes Fm Geological Model



- Thick Gross Gas Pay Section
- Proven Down Spacing Infill Opportunities
- Multiple Stacked Gas Charged Objectives
- Adding more low-resistivity pay to behind-pipe inventory
- Horizontal Drilling Potential
- Multiple Isolated Reservoir Types
- Hydraulic Frac Stimulation Upside

Sac Basin – Reinterpreting Pay

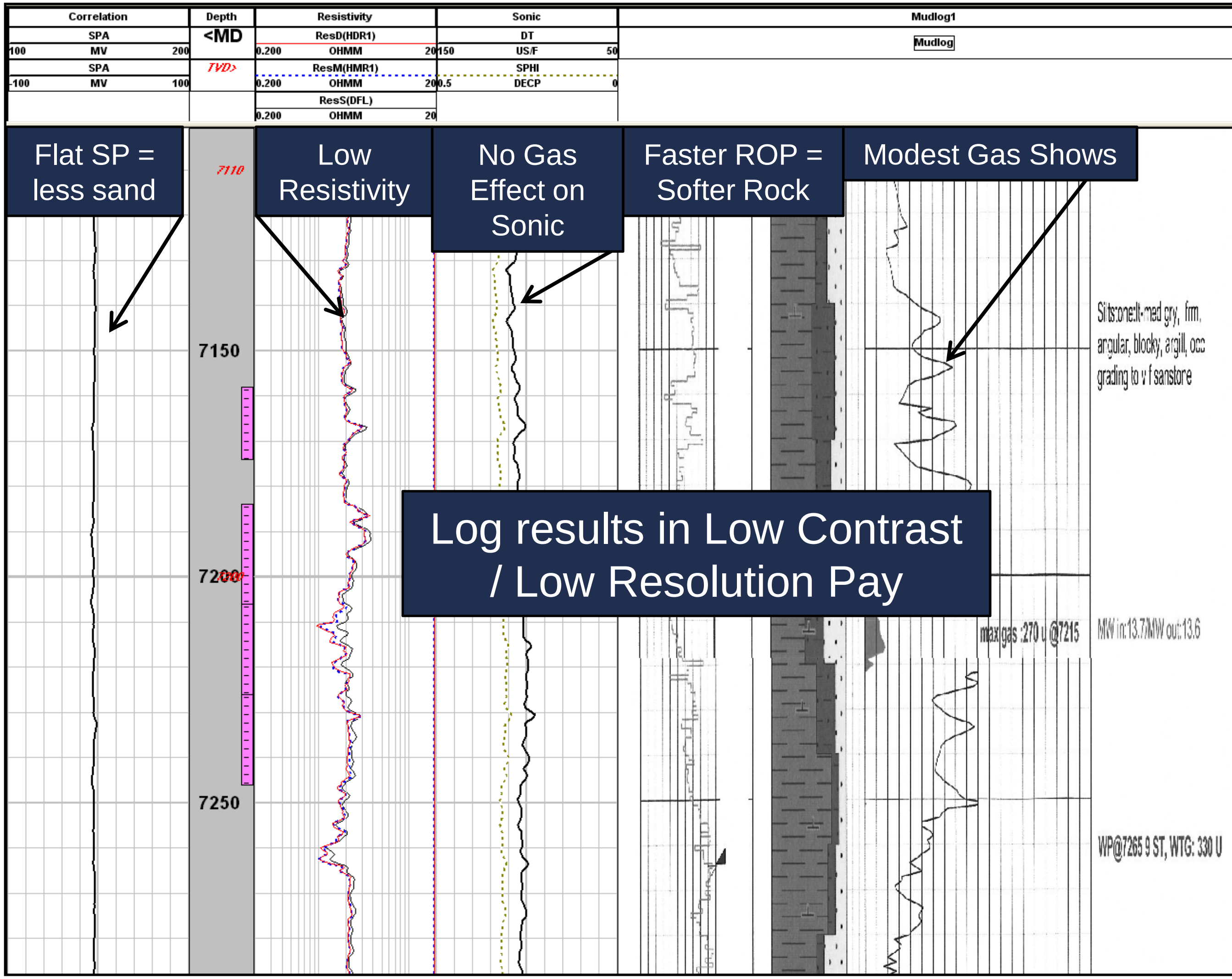
Low Contrast/Resolution vs.. Traditional Channel Sand



More Typical Results:
(Channel Sand Pay)

Sac Basin – Reinterpreting Pay

Low Contrast/Resolution vs.. Traditional Channel Sand



Sycamore Field
Sutter County

Drilled 6/2007
Zone Open 5/2009

100 MCF/D Flat for 1 year @ 100 psi

Frac'd 4/2010

Post-Frac Rate
900 MCF/D @ 1800 psi

However, we've been successful in learning to identify additional pay in these distal laminates.

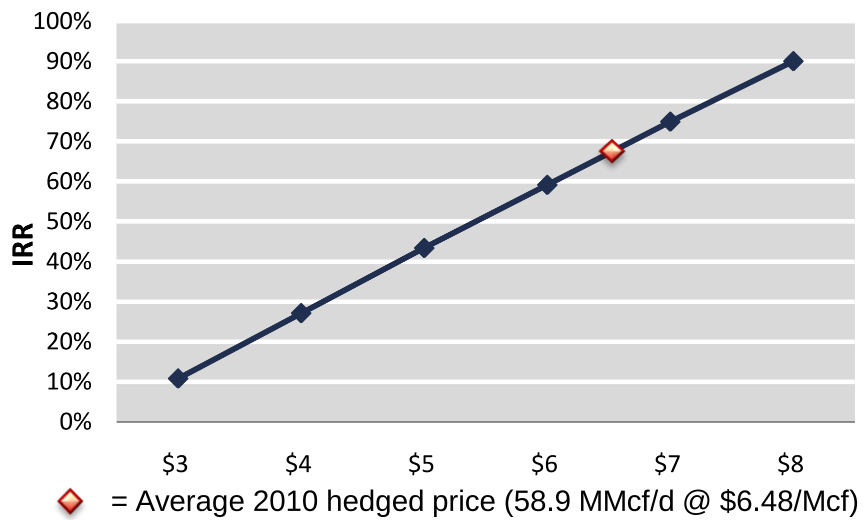
Actual Results:
Low Contrast/Resolution Pay

Sac Basin Economics

Current Economics of the Sacramento Basin[1]	
Drill and Complete	$800
Workovers	$75
Total Well Cost ($000)	**$875**
Gross IP Rate (Mcf/d)	650
Gross Reserves (Bcf)	0.7
Lifting Costs ($/Mcf)	$0.65
LTM Basis Differential ($/Mcf)	$0.32
Weighted Average PUD Working Interest	90%
Weighted Average PUD Revenue Interest	75%

Sacramento Basin wells with 3 to 4 years of production history and two workovers typically have an Estimated Ultimate Recovery (EUR) of approximately 0.7 Bcf.

Type Curve IRR Sensitivity[1]



(1) Based on actual costs for 2H09. Reserve and performance based on 12-31-09 reserve report. Data assumes successful well; 2009 success rate was 86%. IRR excludes costs such as G&A, land acquisition, and interest expense.

Potential Net Asset Value[1]

Total Proved Reserves per fully diluted share[6] = $16.99

Commodity Price Assumption: 5-Year Strip as of 12/31/09[2]

		PV-10[3]/ NAV ($MM)	Risk Factor[8]	Risked Value[8]
Proved Reserves[3]	**101.3 MMBOE**	**$1,670**	100%	**$1,670**
Probable Reserves[4]				
Southern California (excluding South Ellwood)	5.5 MMBOE	$133	80%	$107
South Ellwood	14.6 MMBOE	$270	90%	$243
Sacramento Basin	5.4 MMBOE	$33	100%	$33
West Hastings - CO2 Flood (3rd Party Reserves - Phases 1-4)	17.7 MMBOE	$225	50%	$113
Additional Unrisked Resources[4]				
West Montalvo Development	11.0 MMBOE	$166	40%	$67
Sac Basin 20-acre Infill Drilling / Frac / Recompletions	46.0 MMBOE	$436	70%	$305
Sac Basin 10-acre Infill Drilling	39.2 MMBOE	$211	70%	$148
Hastings - CO2 Flood (East Hastings & Addt'l Upside on Phases 1-4)	11.5 MMBOE	$257	10%	$26
Onshore Monterey Shale[9]	456.0 MMBOE	$5,967	30%	$1,790
Potential Asset Value[5]	**708.3 MMBOE**	**$9,369**		**$4,501**
	(as of 3/31/10)			
	Total Debt	**($715.2)**		**($715.2)**
	Cash	**$0.6**		**$0.6**
	Net Debt	**($714.6)**		**($714.6)**
	Fair Value of Commodity Derivatives	**$54.7**		**$54.7**
	Fair Value of Interest Rate Derivative	**($31.4)**		**($31.4)**
	Net Balance Sheet Items	**($691.3)**		**($691.3)**
	Fully Diluted Shares Outstanding[6]	**57.61**		**57.61**
	Total Potential Asset Value per fully diluted share[7]	**$150.63**		**$66.13**

(1) Does not include estimates of final proceeds from Texas asset sale. (2) On 12/31/09, the 5-year strip averaged $87.04/Bbl and $6.43/Mcf, ranging from an average of $81.16/Bbl and $5.79/Mcf in 2010 to $91.09/Bbl and $6.84/Mcf in 2014. Average 2014 prices were used for future years. (3) See Appendix for a definition of PV-10 and the relevant GAAP reconciliation. (4) See "Net Asset Value & Unrisked Resource Estimates." (5) Amounts other than 12/31/09 PV-10 values of proved and probable reserves at 5-year strip pricing are based on internal estimates of unrisked reserve potential. See "Net Asset Value & Unrisked Resource Estimates." (6) Common stock equivalents do not assume application of treasury stock method. (7) Potential Net Asset Value or Proved Reserves less net debt and the estimated fair value of interest rate and commodity derivatives included in the balance sheet at 3/31/10. NAV per share based on shares outstanding and common stock equivalents at 3/31/10. (8) Risk factor figures are intended to be illustrative of internal estimates of the relative riskiness of the company's projects, but do not purport to reflect all risks associated with the development of the projects , production of the associated oil and natural gas or receipt of proceeds therefrom. For example, the risk factor of 100% for the company's proved reserves is intended to show that the development of those reserves is expected to be less subject to risk than the other projects described, not that there are no risks associated with that development. See "Cautionary Statement Regarding Forward Looking Information." Similarly, risked value figures do not purport to represent the fair market value of the projects shown for reasons described in "Net Asset Value & Unrisked Resource Estimates."

(9) NAV at flat $80 oil and $5 natural gas prices. Assumes approximately 1,000 wells with estimated per well recovery of approximately 400 MBbls. See Monterey development and economic assumptions outlined within the "Operations & Development" and "Financial Summary" sections of this presentation. Exploitation & development contemplates an evaluation drilling program to help understand the potential on the company's acreage and determine what development plans may be economic. The number of locations makes assumptions about the proportion of the acreage which may meet our economic criteria. The actual development plan could vary significantly from our estimates in terms of timing, cost and extent of activity and results obtained.

Monterey Shale

Mike Wracher
Vice President, Exploration

Today's Agenda

Monterey Overview and Venoco's Opportunity

Monterey Primer – Luis Chirinos, Engineering Director
- History of Monterey production and its technical drivers

Characterizing the Monterey – Marc Kamerling, PhD, Senior Geologist
- Monterey geology and geophysical properties

Characterizing Monterey Production – Mike Wracher, VP Exploration
- Monterey reservoir performance

Operations & Development – Ed O'Donnell, Sr. VP Southern California
- Asset optimization and three pilot development projects

Financial Summary & Wrap Up – Tim Marquez, Chairman & CEO
- 5-Year Monterey Forecast and NAV

Questions & Answers

The Monterey

- **Enormous Original Oil in Place**
  - Venoco estimates >20 billion barrels OOIP[(1)] on onshore undeveloped acreage
- *“The best analog for the Monterey is the Monterey”*
  - Monterey has produced more oil than any other shale
  - Monterey fields account for 2.5 billion barrels of recoverable oil
- Venoco has identified 30 key areas within current onshore Monterey acreage position
- Recent advances in “unconventional” development technology have the potential to unlock immense reserves in the Monterey
  - Much current Monterey production from conventional traps and natural fractures
  - We expect future development to be driven by modern reservoir characterization and highly deviated frac’d/acidized completion techniques

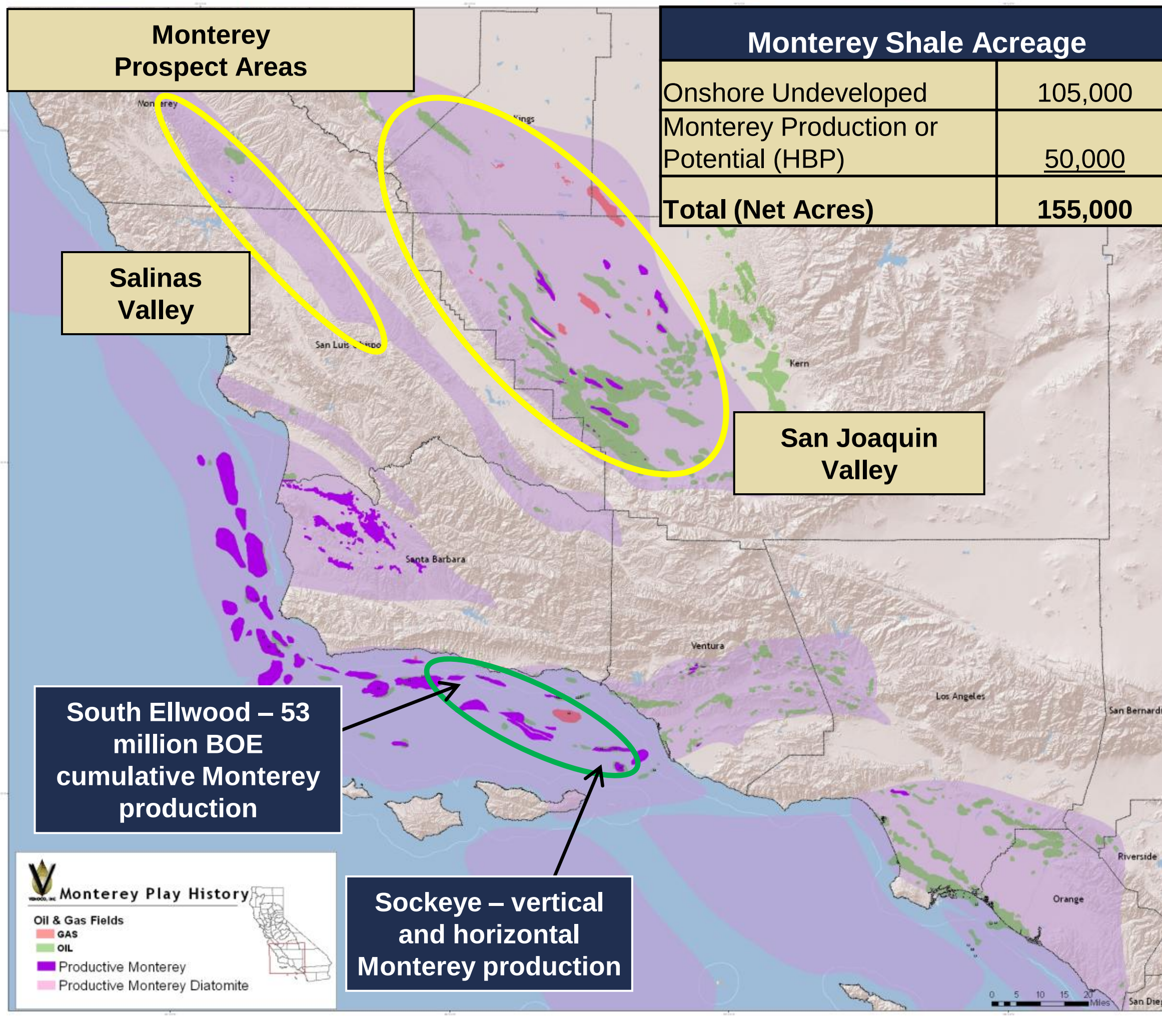
(1) Internal estimates.

Monterey Shale Activity

Venoco Areas of Operations

- **Business Strategy**
  - Control the play
  - Ending current joint venture discussions
- **Acreage Strategy**
  - Light oil
  - Natural fractures
  - Moderate depths
  - Favorable operating environment
- **2010 Capital Plans**
  - Drill 10 wells
  - Increase net acreage to 200,000 total
  - $48 million budget
  - Acquire 3-D seismic
- **Current Status**
  - Evaluating all Monterey basins
  - Drilling 3rd evaluation well
  - Initiating pilot developments in 3 areas
  - Actively Leasing – all projects are referred to in generic terms

Monterey Shale Acreage	
Onshore Undeveloped	105,000
Monterey Production or Potential (HBP)	50,000
Total (Net Acres)	**155,000**



Three Year Opportunity

- Increase total acreage position to 350,000 net acres
- Drill original 30 evaluation areas and 60-80 development wells
- 3-year capital expenditures of approximately $350 million
- Estimated Monterey production approaching 40,000 BOE/d by 2014(1)
- Modeled resource ~500 million BOE(1)
- Unrisked NAV >$5 billion(1)
- Additional resource upside: Each 1% recovery = ~200 million BOE

	Activity	2010	2011	2012
Evaluation	Drilling	7 wells	8 wells	12 wells
	Seismic	Initiate 500 sq. mile joint VQ-OXY seismic acquisition	Complete joint seismic acquisition	
	Land	Lease 60,000 additional net acres	Lease150,000 additional net acres	
Development	Drilling	3 wells	22 wells	38 wells
Capital		$48 million	$120-140 million	$160-180 million

(1) See Monterey development and economic assumptions outlined within the “Operations & Development” and “Financial Summary” sections of this presentation. Also see “Cautionary Statement Regarding Forward Looking Information” and “Net Asset Value & Unrisked Resource Estimates.”

Monterey Primer

Luis Chirinos

Engineering Director

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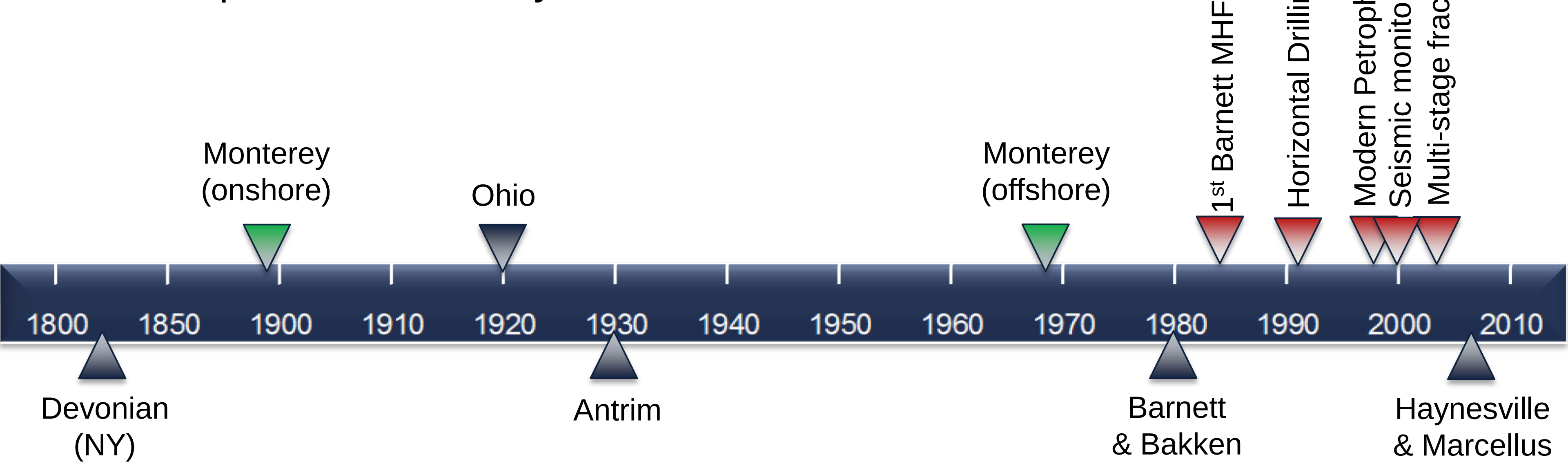
History of Shale Production

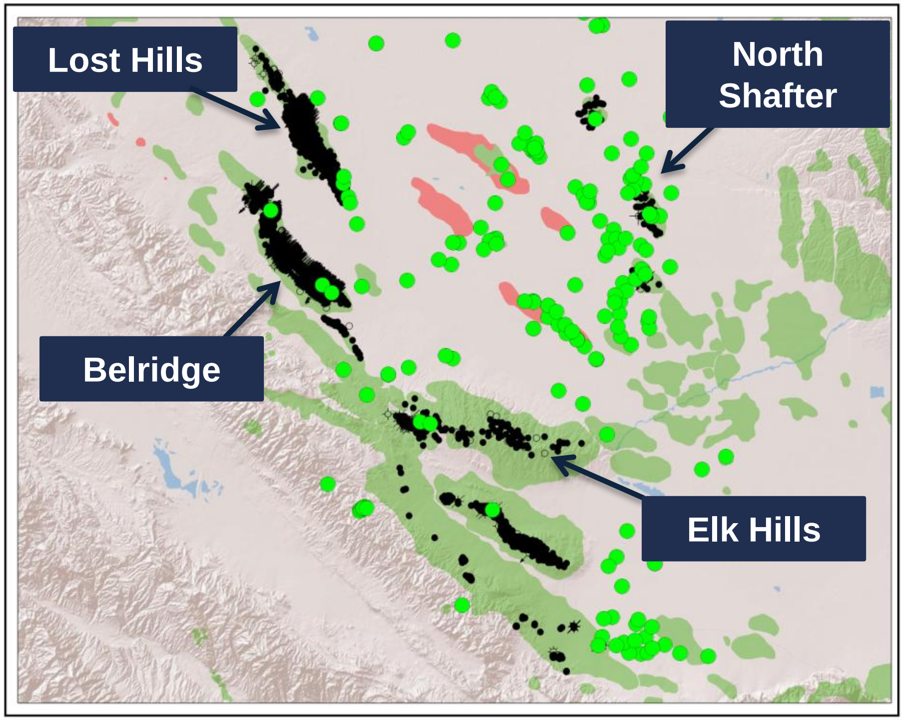
- Long history of production from organic shales
- Monterey has produced for over a century
  - Technology to fully exploit its potential is very recent
- Technical drivers
  - Drilling methods, completion technology, production optimization, analysis



Monterey – Abundant Data Exists

- Massive amount of data has been collected in the Monterey
- >300 wells have penetrated the Monterey in our areas of interest
  - ~200 of those wells tested or produced from the Monterey
  - We have analyzed the logs on over 50 of these wells

Wells penetrating the Monterey

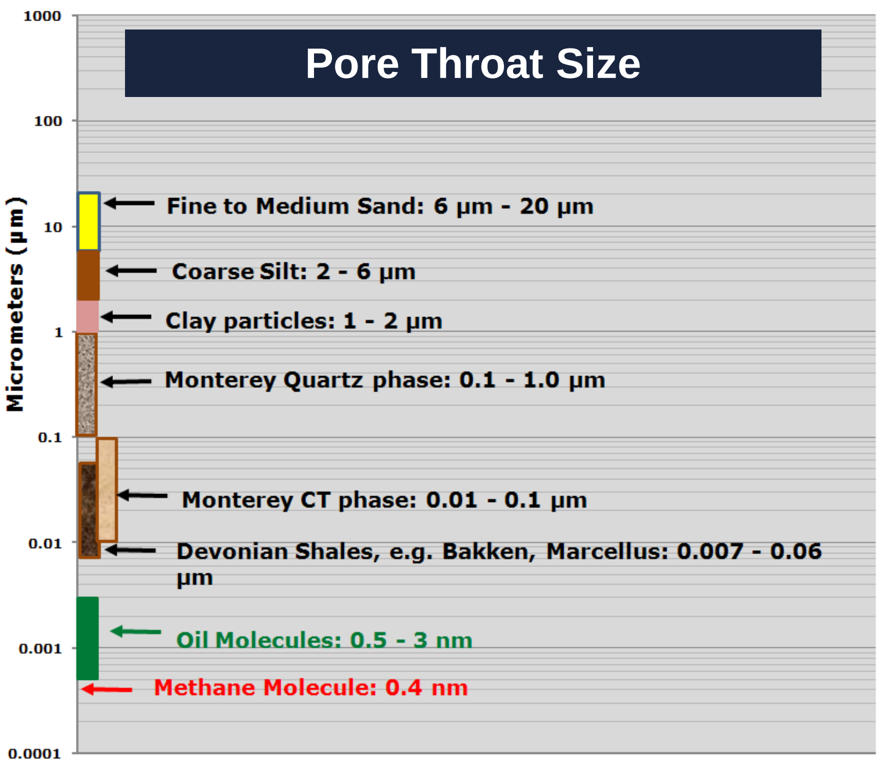


Overview of wells and logs by region

Prospect Area	Wellbores penetrating Monterey	VQ acquired open hole logs	Tests or production Monterey	Additional wells studied
One	43	17	33	292
Two	62	49	12	18
Three	200	100	151	2,950
Total	305	166	196	3,260

Controls on Productivity And Reserves

- Fracture Dominated
  - Productivity controlled by the Number + Frequency + Aperture + Orientation of fractures
  - Storage proportional to fracture volume
  - High peak rate
  - High initial decline, flattening according to areal extent of fractures
- Matrix Dominated
  - Pore throat size controls permeability
  - Storage proportional to porosity
  - Peak rate proportional to matrix permeability. May require hydraulic fracturing
  - Decline proportional to storage volume
- Dual Porosity
  - Best permeability if open fractures
  - Storage partitioned between matrix and fractures
  - High peak rate
  - Moderate decline depending on matrix permeability



Identifying Quality Matrix

Key Rock & Fluid Properties

- Brittleness
- Thickness
- Depth
- Porosity / Permeability
- Oil Gravity / Oil in place

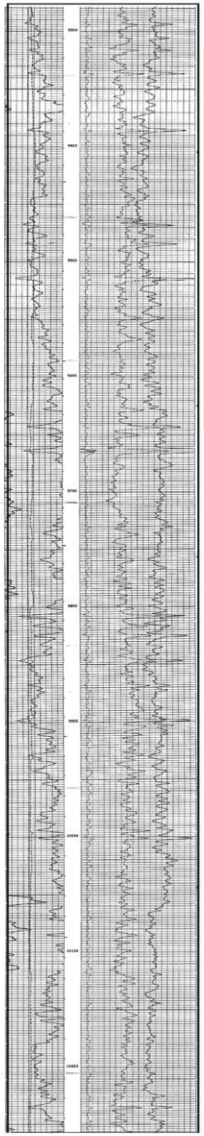
Enabling Technologies

- Modern petrophysical methods
- Modern drilling and completion techniques
  - Horizontal drilling – single and multi-lateral
  - Massive hydraulic fracturing
  - Multi-stage stimulation
  - Seismic monitoring

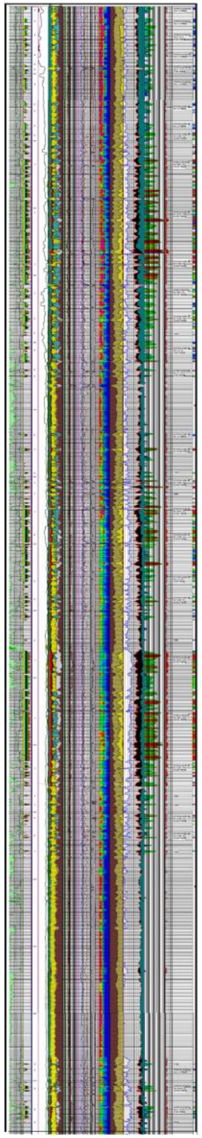
Economic Drivers

- Reserves per well
- Production rate
- Well cost

Petrophysics: Identifying Sweet Spots

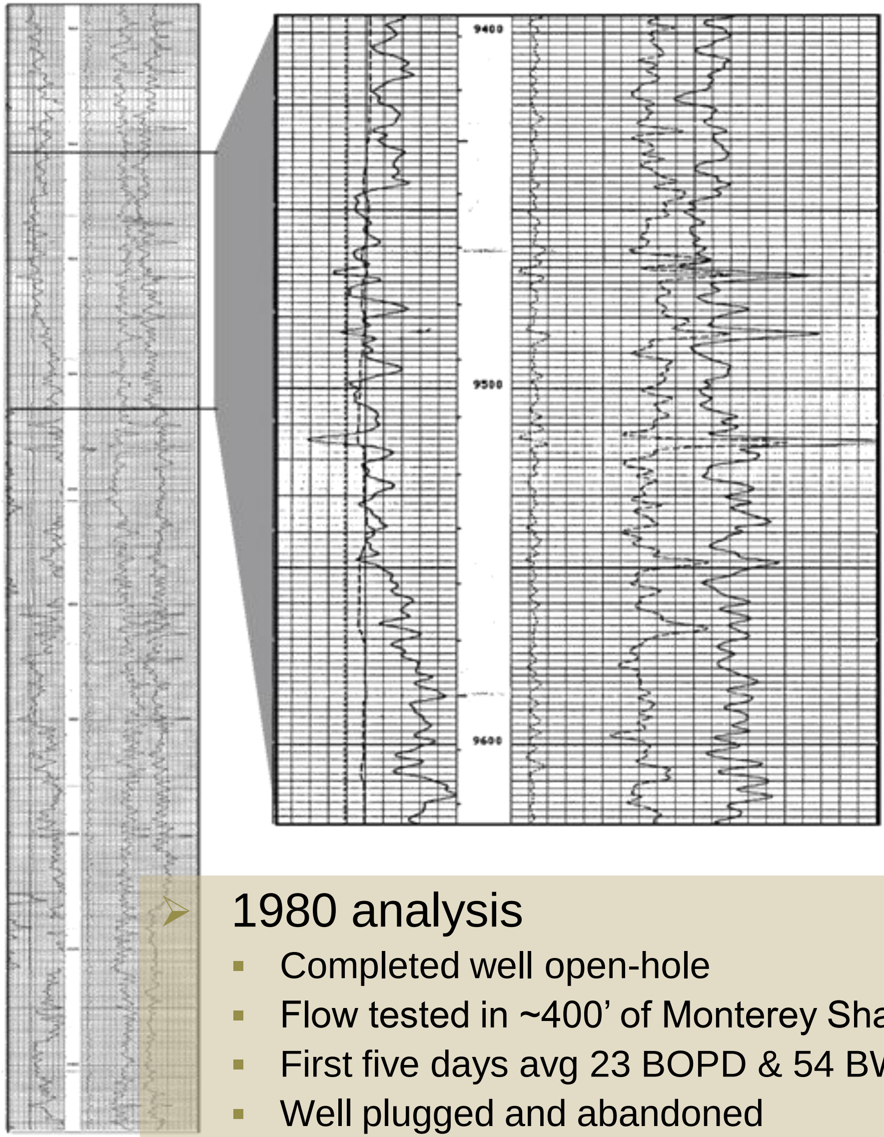


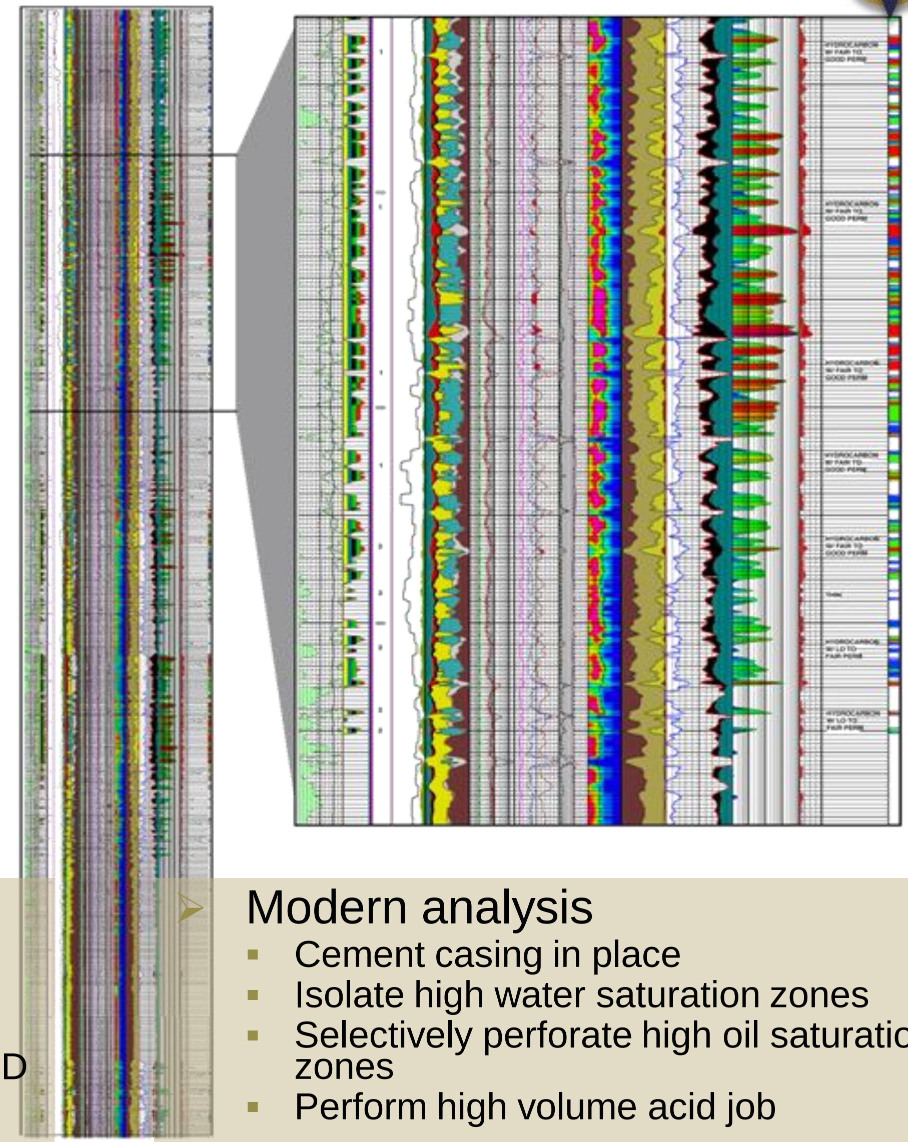
- An old well on our acreage
- Drilled before modern evaluation methods were available



- Old logs re-processed with new petrophysical model
- Identifies oil reservoirs

Petrophysics: Identifying Sweet Spots



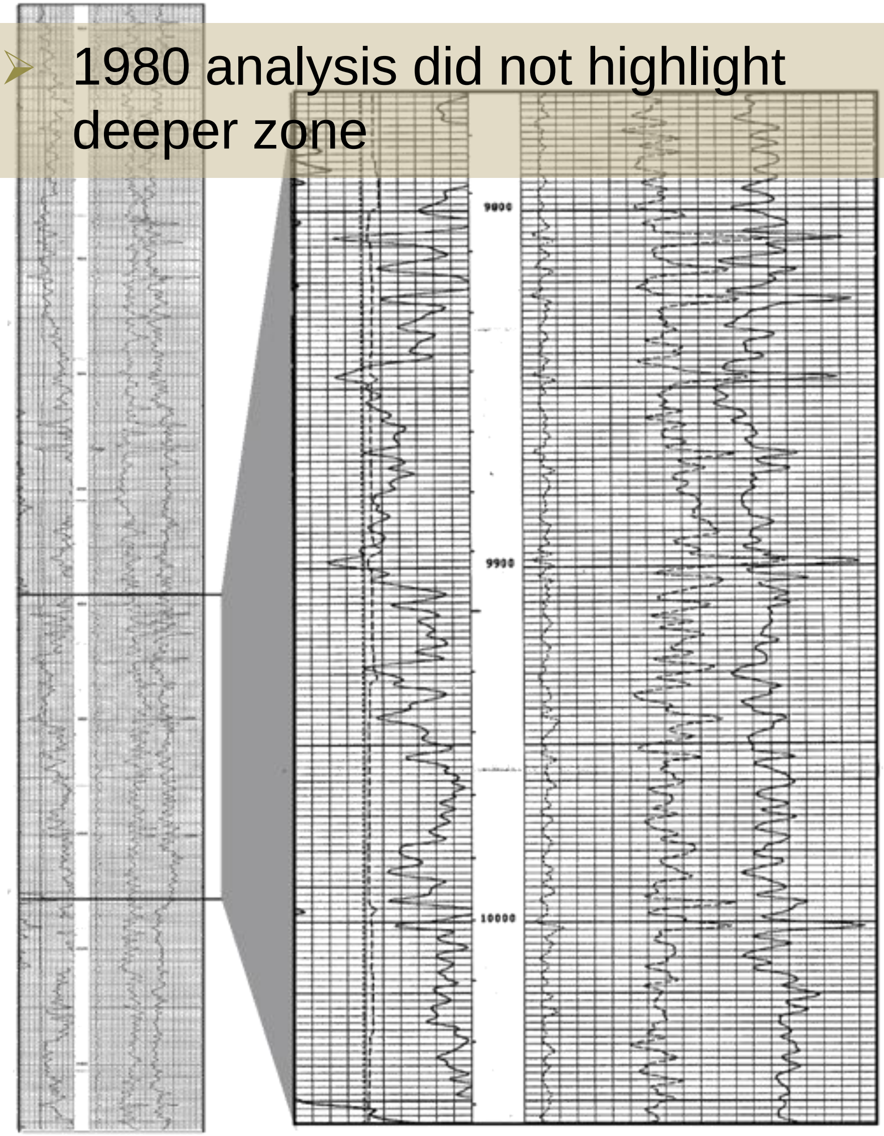


- 1980 analysis
  - Completed well open-hole
  - Flow tested in ~400' of Monterey Shale
  - First five days avg 23 BOPD & 54 BWPD
  - Well plugged and abandoned

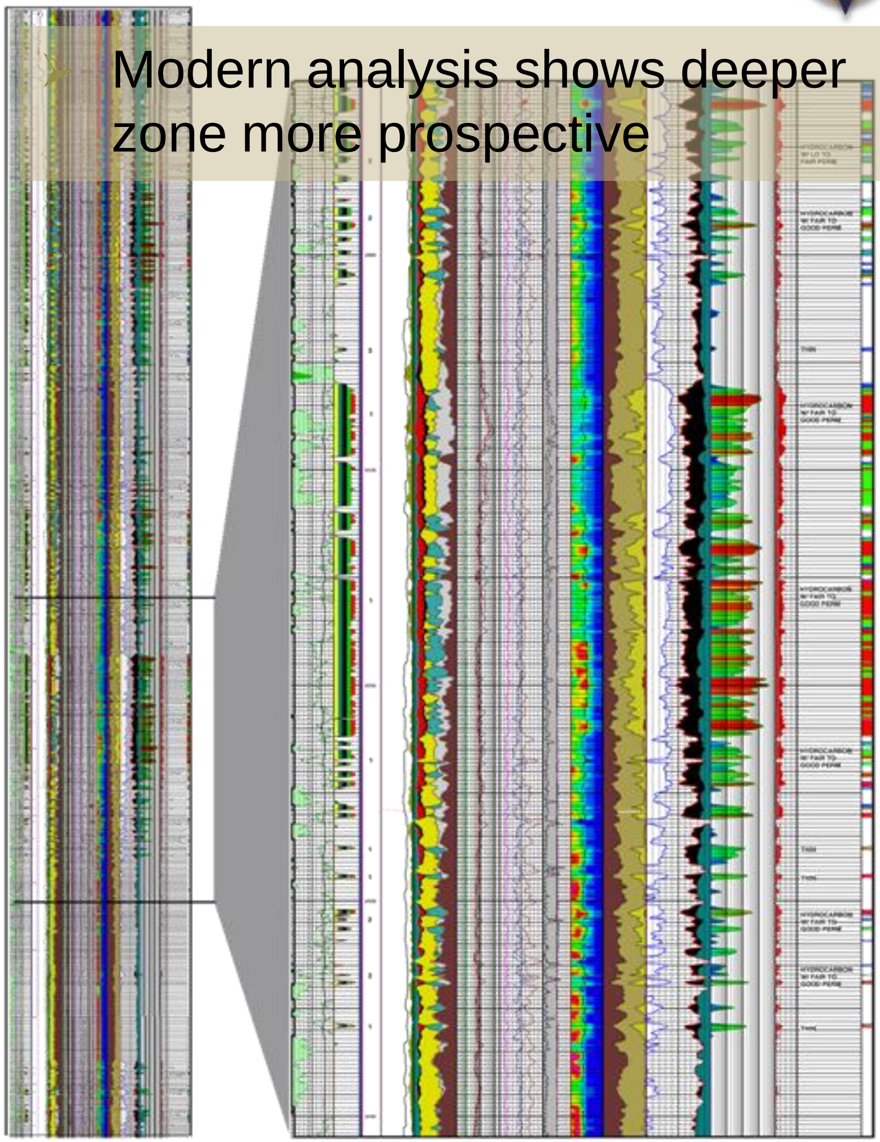
- Modern analysis
  - Cement casing in place
  - Isolate high water saturation zones
  - Selectively perforate high oil saturation zones
  - Perform high volume acid job

Petrophysics: Identifying Sweet Spots

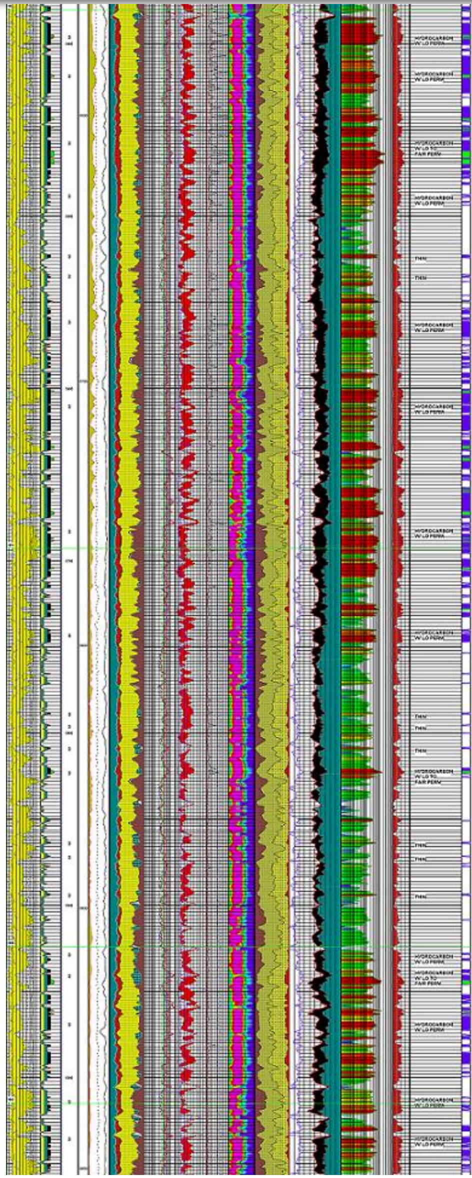
- 1980 analysis did not highlight deeper zone



- Modern analysis shows deeper zone more prospective



Petrophysics – Refining the Model



Venoco offshore well

- Newly drilled
- Good petrophysical results
  - Oil saturation and permeability
- Recently acidized
- Producing over 500 BOEPD

The Technology of Shale

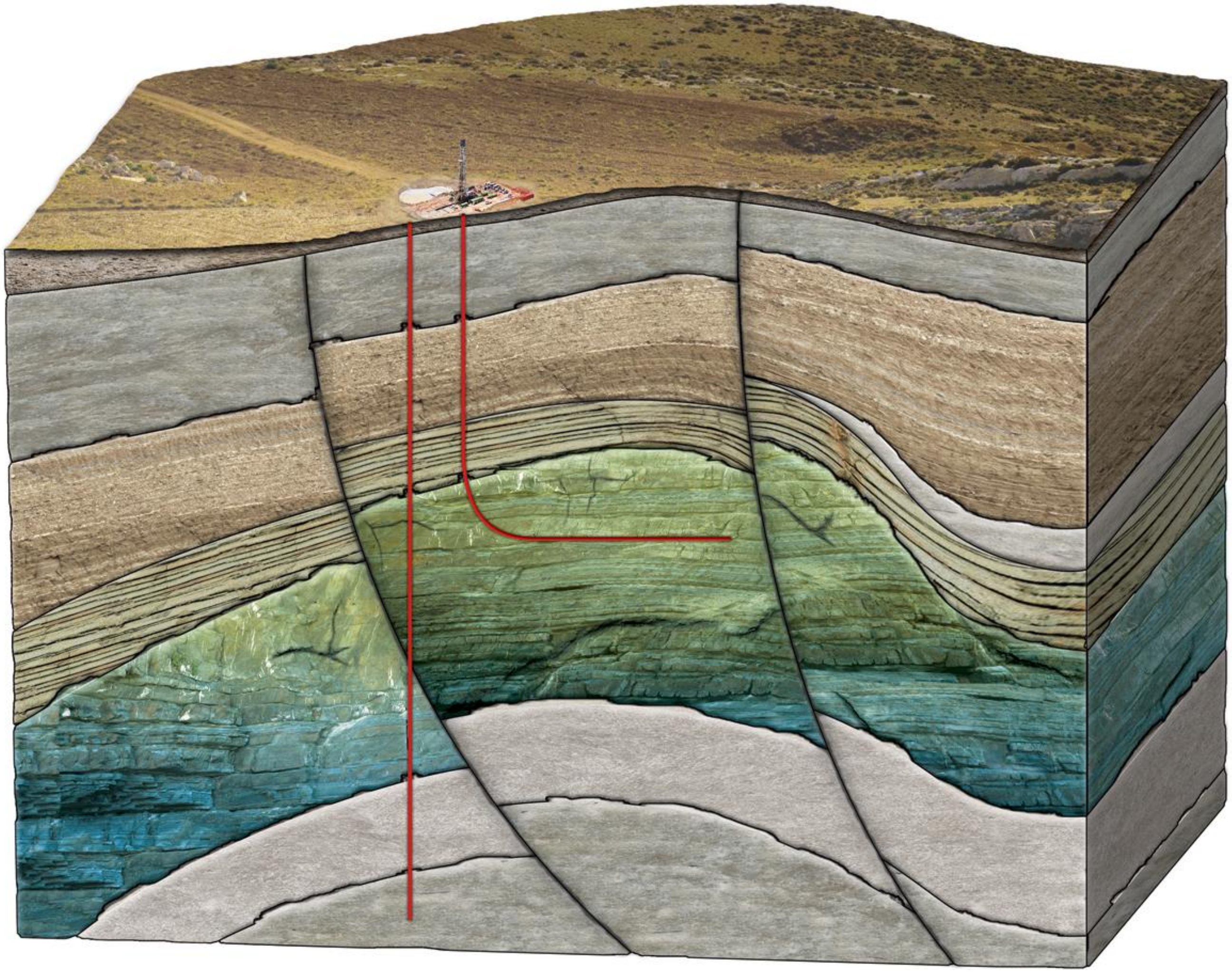
Drilling and Completions Technology

- Vertical Wells
  - Barefoot completions
  - Slotted liners
  - Acidized
  - Propped fracs

- Horizontal Wells
  - Slotted liners
  - Perforate/acidize
  - Hydraulic fracturing
    - Single stage
    - Multi-stage
    - Swell packer assemblies
    - Multi-stage plug & perf
    - Multi-well interference fracs

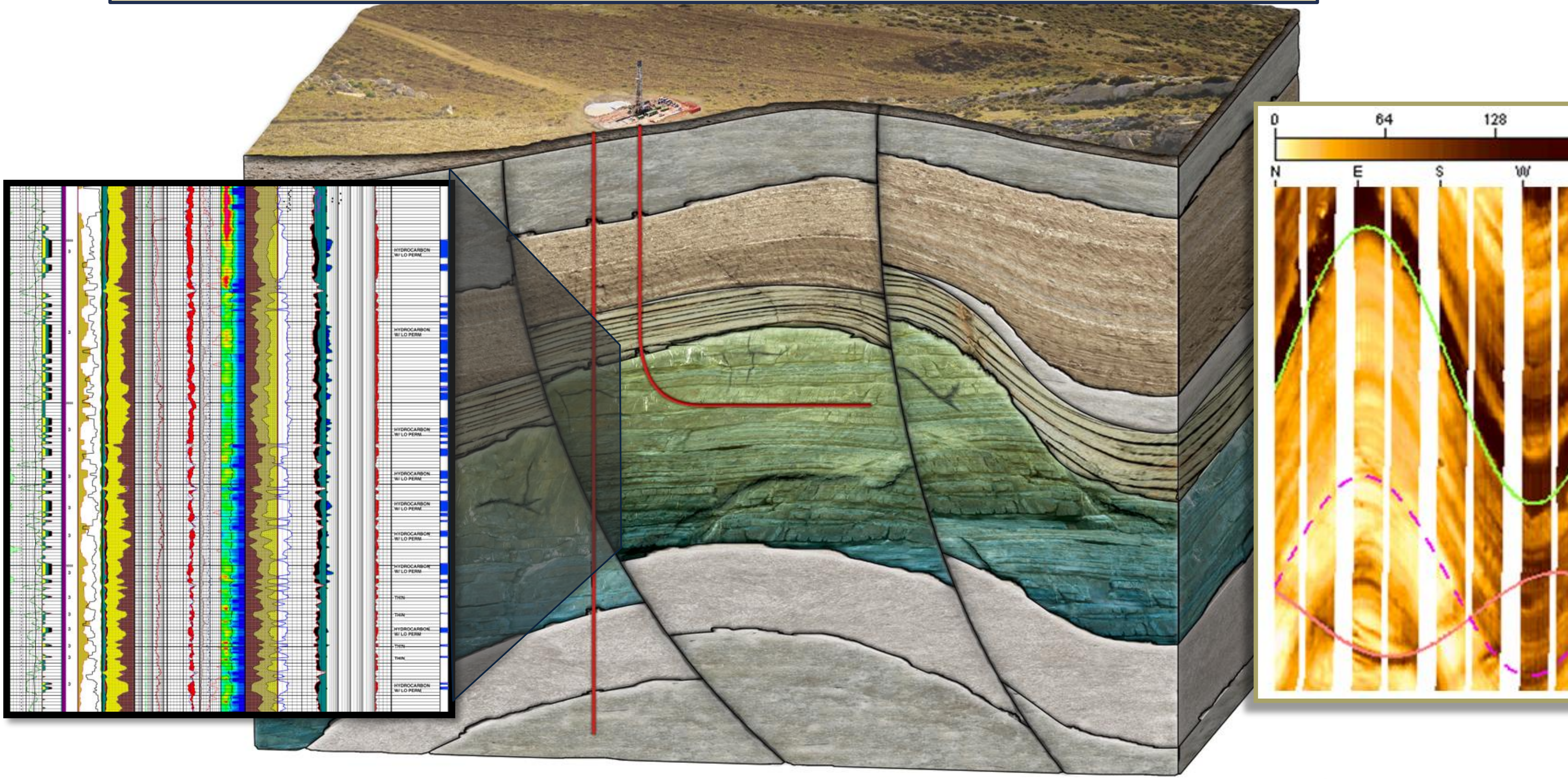
Theoretical Monterey Vertical vs. Horizontal Well

- Combination Matrix/Natural fracture system



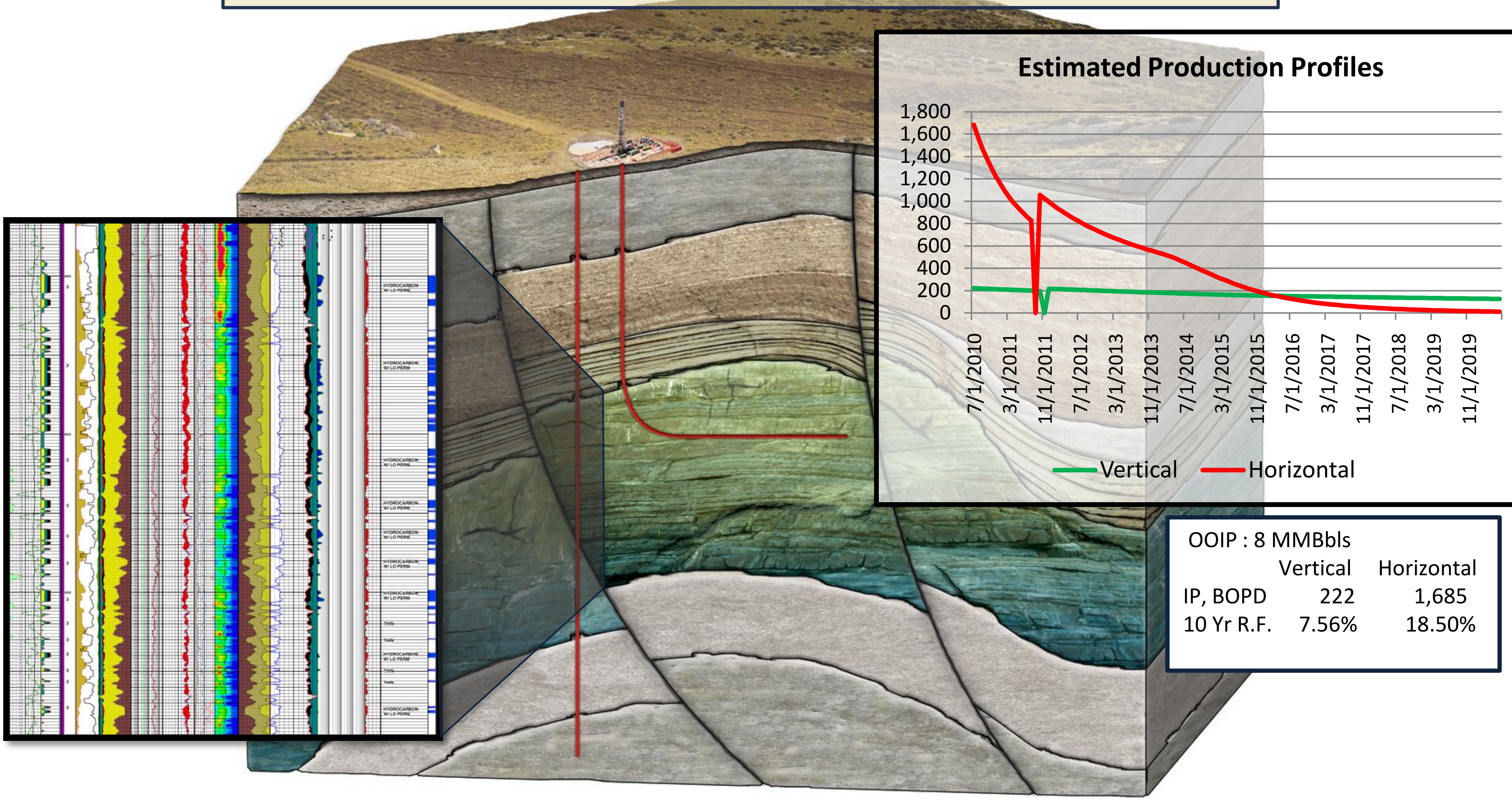
Theoretical Monterey Vertical vs. Horizontal Well

- Vertical well petrophysical analysis shows low permeability in matrix
- Fracture Identification Log not available
- Inferred fracturing from high initial production rates



Theoretical Monterey Vertical vs. Horizontal Well

- Reservoir modeled as Matrix/Fracture system
- Calculated theoretical performance of vertical and horizontal wells



OOIP : 8 MMBbls

	Vertical	Horizontal
IP, BOPD	222	1,685
10 Yr R.F.	7.56%	18.50%

Comparing Shale Plays

- The Monterey compares very favorably to unconventional oil plays
- Enormous amounts of hydrocarbons in place

Reservoir	TVD	Thickness (ft)	Oil Gravity	Perm (md)	Por. (%)	Oil Sat.	TOC (%)	OOIP / 640 acres (MMBbls)	EUR / 640 acres (MMBbls)
Middle Bakken[1]	8,500' to 10,500'	140'	42°	.005 – 0.2	5	75%	6-20%	5	0.50
Niobrara	2,000' to 8000'	>150'	39°	n/a	6	50%	5%	40	n/a
Eagle Ford	8,000' to 14,000'	250'	45°	0.0013	12	72%	4.7%	30	1.57
Monterey Project C	7,000' to 14,000'	500 - 6000'	42°	1.3 - 18.7 [2]	13 - 29	61%	5%	84	3.10

(1) From USGS Paper 1653.
(2) Venoco net pay estimates based on 1 millidarcy or better permeability.

Primer – Monterey vs. Bakken

- Producing Monterey reservoirs have EUR's in excess of 2.5 billion BOE(1)
  - The Monterey is the source rock for over 37 billion BOE in producing California fields
  - For comparison, the Bakken is expected to produce 3 to 4 billion BOE
    (U.S. Geological Survey Assessment (April 10, 2008)

Reservoir	TVD	Net Pay (ft)	Oil Gravity	Perm (md)	Por. (%)	Oil Sat.	BHT (º F)	OOIP / 640 acres (MMBbls)	EUR/640 acres (MMBOE)
Middle Bakken(2)	8,500' to 10,500'	8' – 14'	42º	.005 – 0.2	8 – 10	75%	240º	5	0.5
Monterey Project A	6,000' to 11,500'	193'(3)	33º	3.73	25	49%	228º	71	2.1
Monterey Project B	9,900' to 11,000'	242'	27º	1 – 18.9	26	53%	233º	97	2.4
Monterey Project C	7,000' to 14,000'	44 – 387'	42º	1.3 – 18.7	13 - 29	61%	264º	84	3.1

(1) Assumes 250MMBOE Belridge. 200MMBOE for Lost Hills.
(2) From USGS Paper 1653.

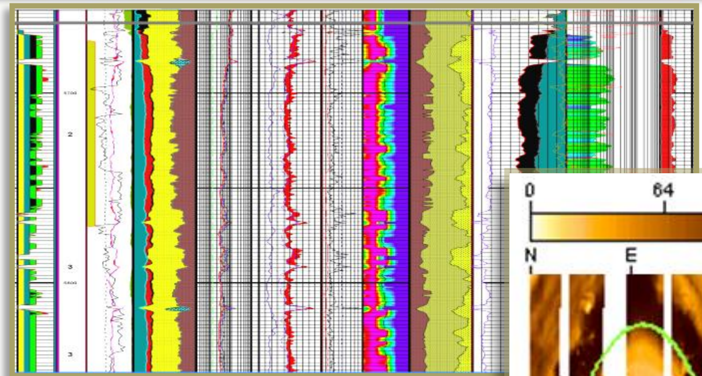
Monterey – Extremely Rich Reservoir

- Even when reservoir properties are marginal, the Monterey is capable of delivering strong results

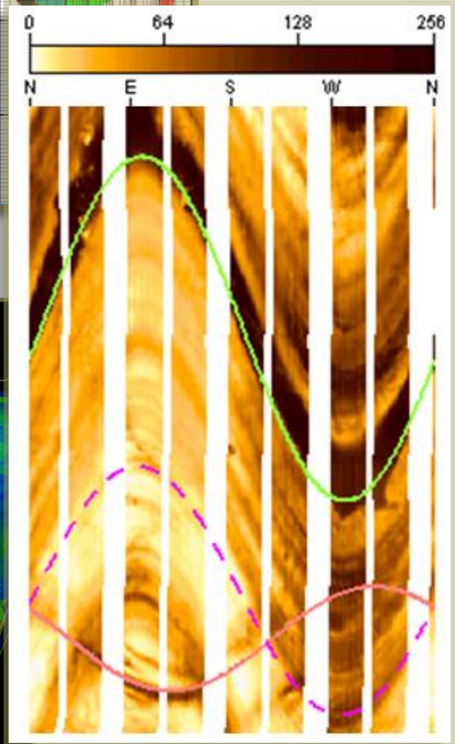
Characteristic	Min. Value (Avg.)	Field	Peak Rate (well)	Avg. Well EUR	Comments
Oil Gravity (API)	6º	Saticoy	100+ BOPD	-	100+ BOPD production was achieved without steam assistance
Permeability	0.05 md	Rose	825 BOPD	235 MBO	Field was completed using 2,500’ laterals with gel based fractures
Oil Saturation	45%	Monterey Project C	1,118 BOPD	800 MBO	Low average oil saturation in Monterey Field / good EUR for moderate depth
Recovery Factor	0.8%	Rose	825 BOPD	235 MBO	Despite low recovery factor, field EUR is 6 MMBOE
Net Pay	40’	North Shafter	1,550 BOPD	425 MBO	Smallest net pay in the Monterey with a full field development
Porosity	20%	Elk Hills	1,100 BOPD	725 MBO	Large scale acid jobs proved to be most effective form of stimulation

Shortening the Monterey Learning Curve

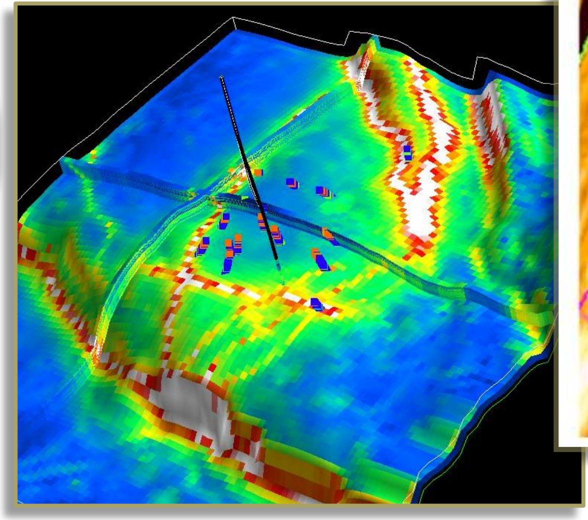
- Tools to Maximize Value
  - Identify Key Shale Properties
  - Analyze legacy data
  - Identify sweet spots
  - Find by-passed pay
  - Classify reservoir types
  - Fit-for-purpose technologies
- Size of The Prize
  - 200 MMBbls per 1% recovery factor improvement



- **Petrophysical Analysis** – Identifies areas of highest matrix permeability

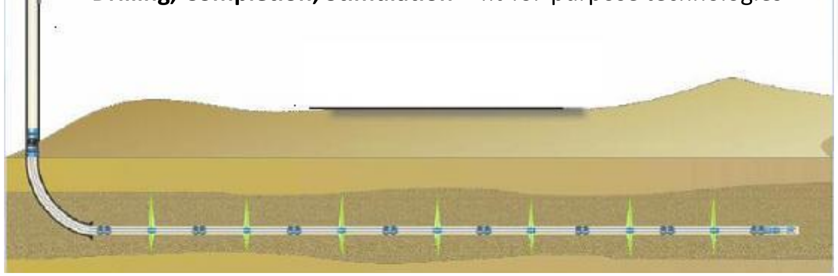


- **Fracture Identification Log** – Locates natural fractures



- **Geomechanical** – Design optimal lateral well path

- **Drilling, Completion, Stimulation** – fit-for-purpose technologies



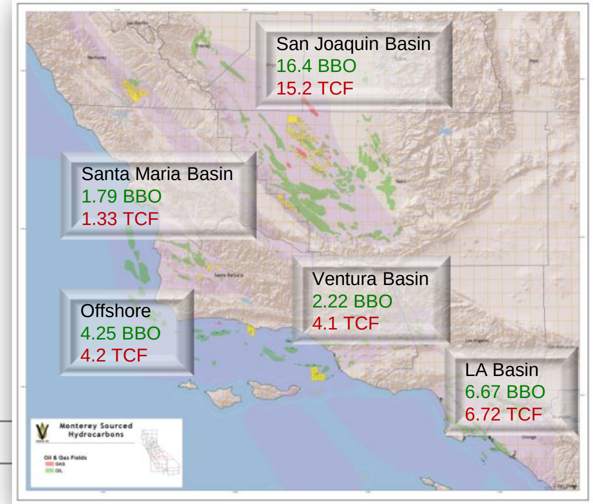
Characterizing the Monterey

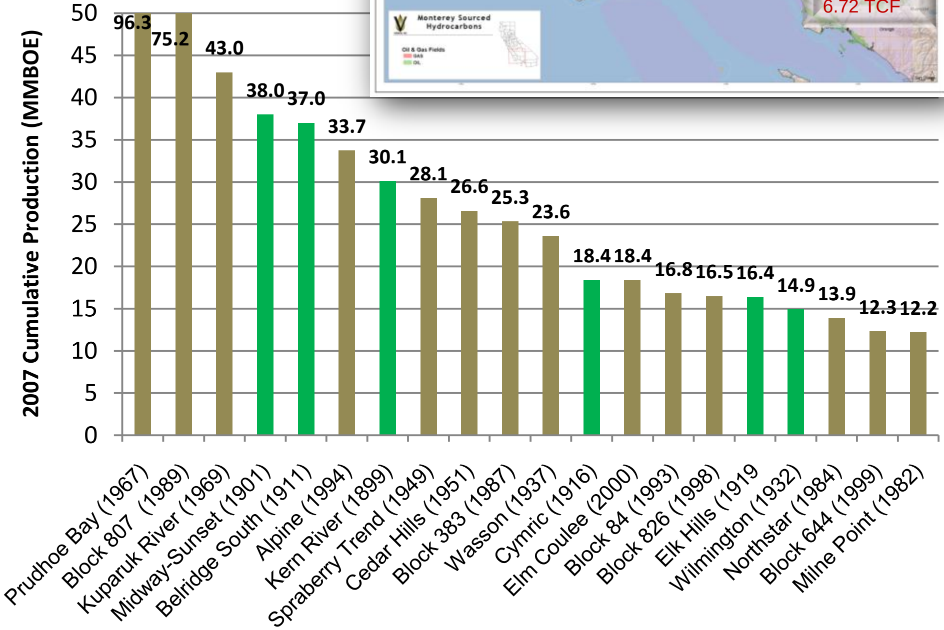
Marc Kamerling, PhD
Senior Geologist

VQ LISTED NYSE

Monterey Production & Reserves

- Prolific Source Rock
  - 2007 – Sourced 6 of the 20 largest US oil fields
    - Monterey fields are 20-50 years older than the other fields
  - Monterey Sourced Fields
    - 31.33 BBO
    - 31.55 TCF
- Excellent Reservoir Rock
  - Known Monterey Fields
    - EUR = 2.5 BBO(1)
    - Additional Monterey production has been commingled, so actual production and ultimate recovery from the Monterey is higher





Top 20 Producing Oil Fields in the United States in Calendar Year 2007(2)

(1) 2007 Annual Report of the State Oil & Gas Supervisor.
(2) 2007 DOE Oil Field Study

Producing Monterey Fields[1]

- South Belridge[2] = 540 MMBO
- Hondo = 317 MMBO
- Cat Canyon[2] = 335 MMBO
- Point Arguello = 208 MMBO
- Orcutt[2] = 175 MMBO
- Pescado = 147 MMBO
- Elk Hills = 86 MMBO
- Point Pedernales = 77 MMBO
- South Ellwood = 72 MMBO
- North Belridge = 71 MMBO
- Lost Hills = 71 MMBO
- Sacate = 70 MMBO
- Lompoc = 48 MMBO
- Sockeye = 17 MMBO
- Buena Vista = 36 MMBO

- Zaca = 33 MMBO
- Santa Clara Off[2] = 28 MMBO
- Santa Maria = 23 MMBO
- Oakridge = 17 MMBO
- N. Shafter = 13 MMBO
- Ojai = 10 MMBO
- Barham Ranch = 6 MMBO
- Rose = 6 MMBO
- Careaga Canyon = 5 MMBO
- Monument Jct = 5 MMBO
- Railroad Gap = 1 MMBO
- Santa Clara On = 1 MMBO
- McKittrick = 1 MMBO
- Sargent = 1 MMBO

Total Monterey EUR ~ 2.5 Billion Barrels (12/31/2007)

(1) 2007 Annual Report of the State Oil & Gas Supervisor couple with Internal Analysis and estimates.
(2) Monterey production comingled with other reservoirs.

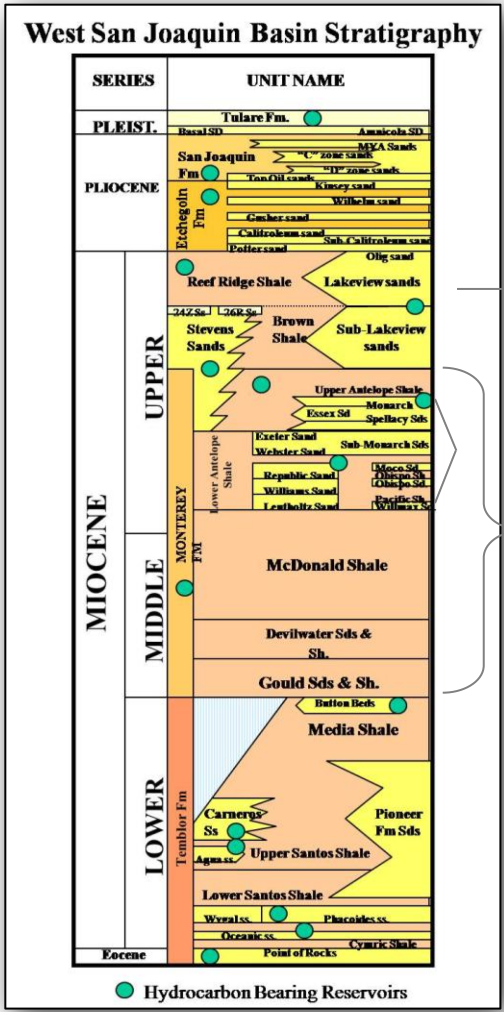
Monterey Opportunity

Monterey Overview

- Dominated by Legacy fields
- Diverse reservoir styles
  - Structural – South Ellwood
  - Structural-Matrix – Elk Hills
  - Stratigraphic – North Shafter
- Peak generation – 1 million years to the present

Monterey outcrop and oil seep from fractures

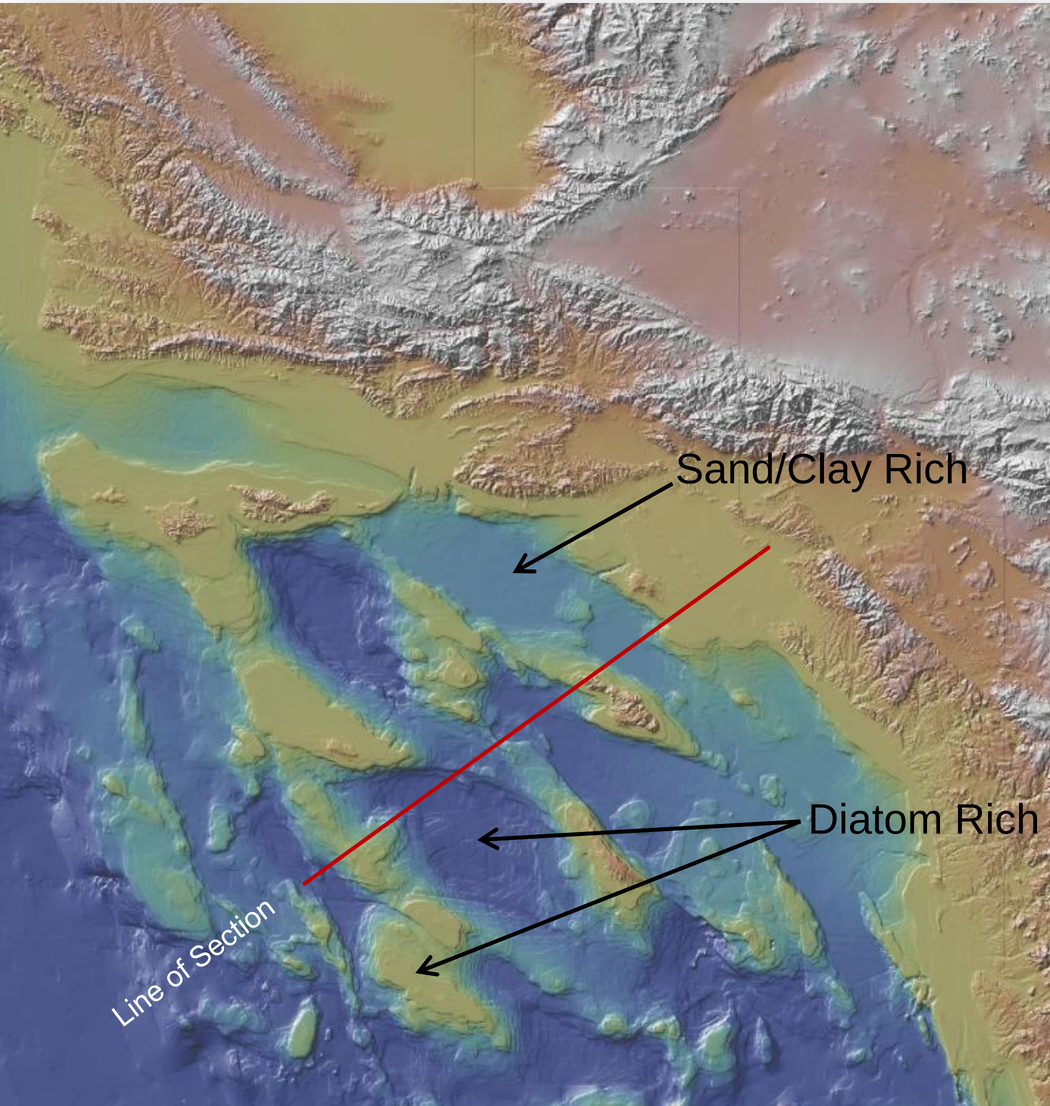
Type Section



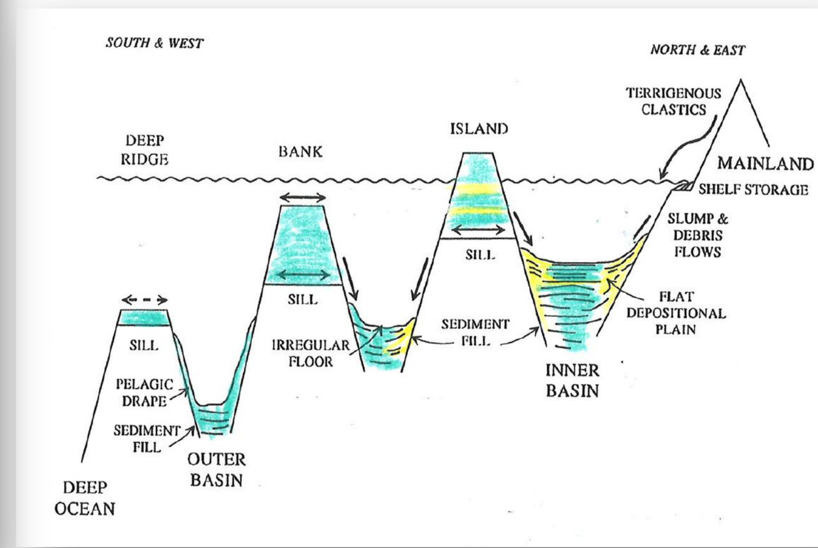
Additional turbidite sand targets

Monterey section (500 – 3,000' thick)

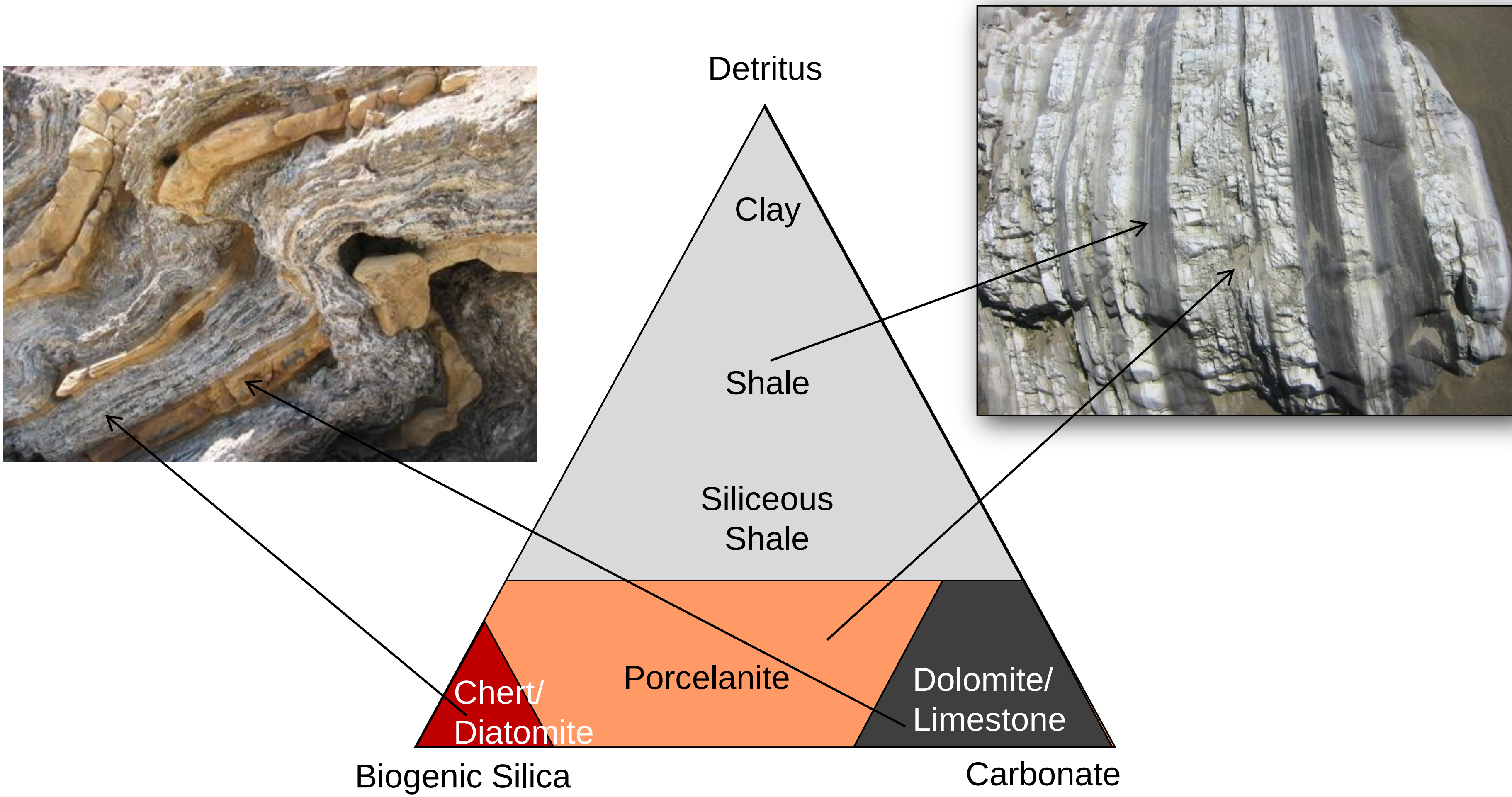
Monterey Shale – Deposition



- Biogenic Shale
  - Concentrated in protected or distal environments
- Deep Marine Sands
- Deposited during unique Miocene environment
  - Siliceous Shales – Diatoms
  - Limestones – Foraminifera
  - Clay/Mud Shales – terrigenous detritus and/or non-deposition (phosphates)

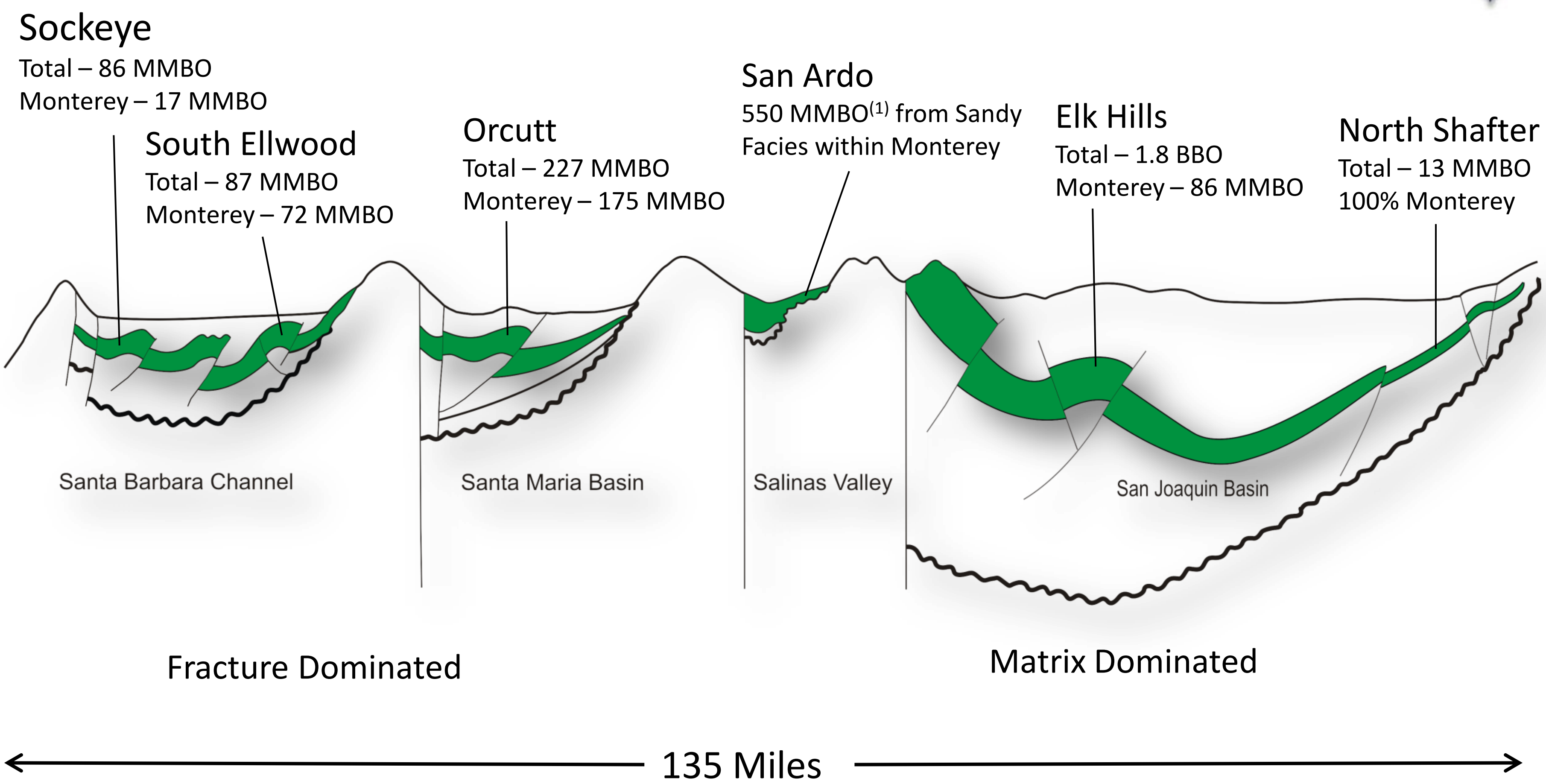


Geology – Rock Composition



All rock types can be found in each field area

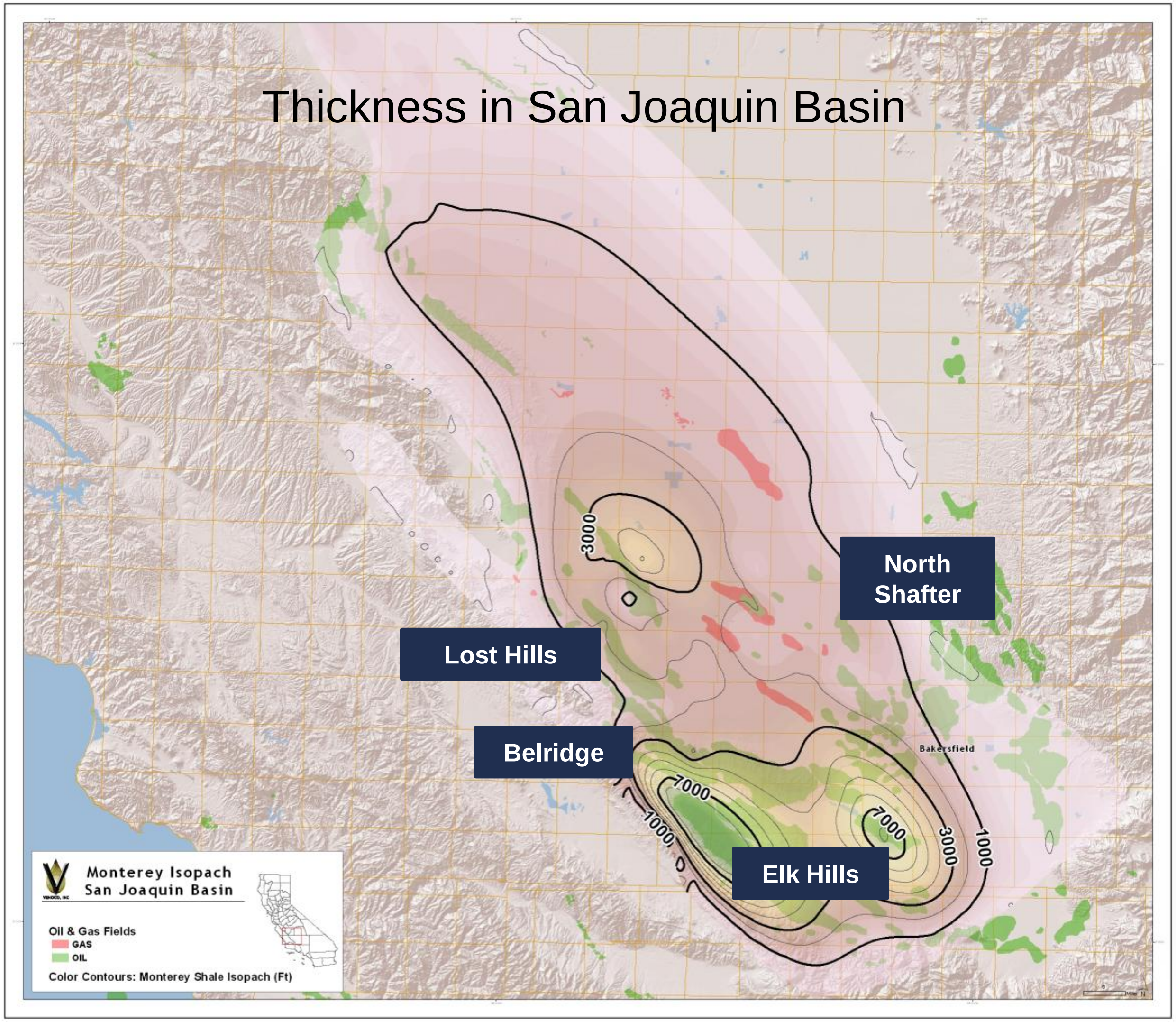
Monterey Geology – Basins

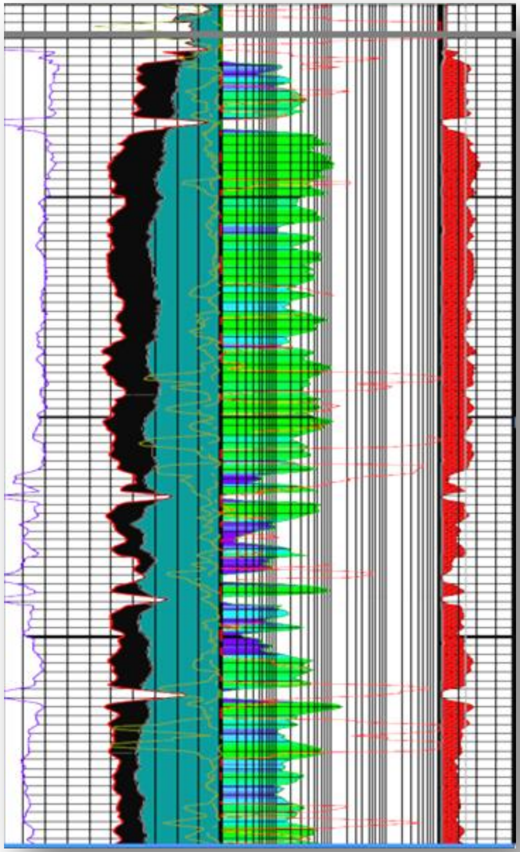


Fields and Estimated Ultimate Recovery – Monterey estimates are from unconventional reservoirs

(1) Monterey production comingled with other reservoirs.

Monterey Shale

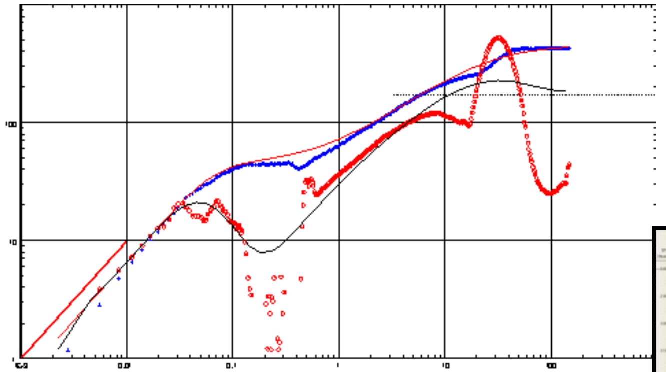




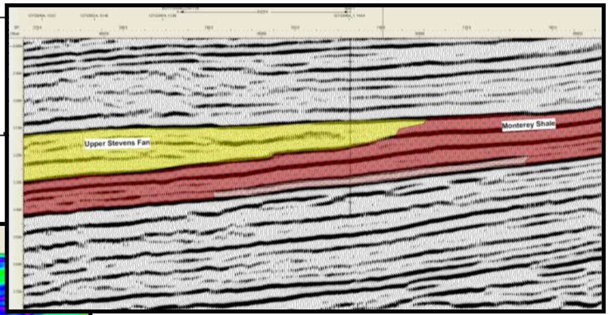
Monterey Shale is up to 8,000' thick in the San Joaquin Basin, with average thickness between 1,000' and 2,000'

Monterey Characterization

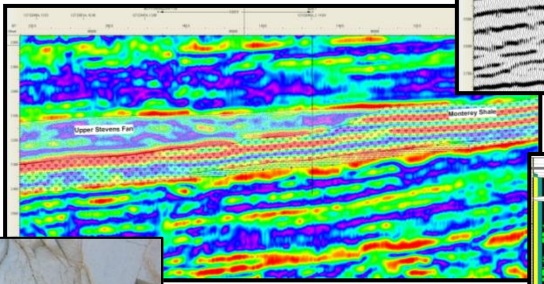
- Interpretation
- Reservoir testing
- Seismic
- Geothermal
- Fracture studies
- Petrophysics
- Geopressure
- Oil Properties
- Source studies



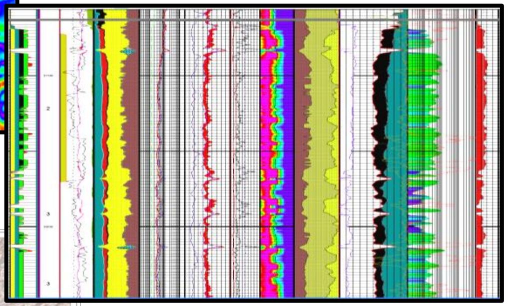
- Pressure Build-up analysis



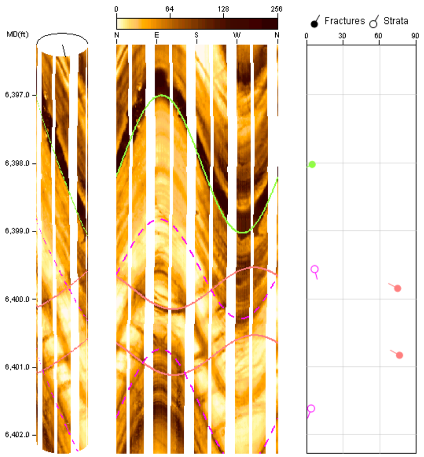
- 2-D Seismic Line at San Joaquin



- 2-D Seismic at San Joaquin

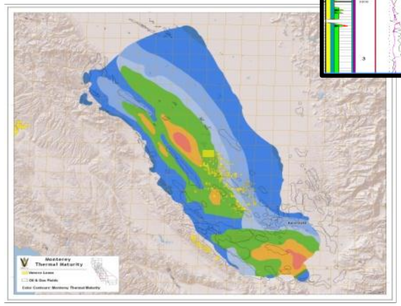


- Petrophysical Analysis



- FMI Log from Sockeye

- Outcrop Analysis



- Regional work San Joaquin

Characterizing Monterey Production

Mike Wracher
Vice President, Exploration

VQ
LISTED
NYSE

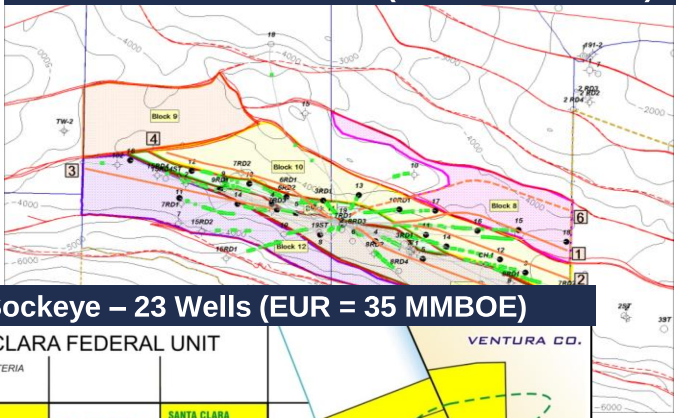
Monterey Reservoir Types

- Fracture Dominated Monterey
  - Majority of Production from natural fractures
    - Micro (Elk Hills) or Macro (South Ellwood)
    - Matrix contribution to some extent
- Matrix Dominated Monterey
  - Minimal natural fracture network
    - Stimulation required – historically, propped fracs
    - Some immature silica phase (SE Lost Hills, South Belridge)
- Dual Porosity Monterey (Fracture & Matrix)
  - Optimal Monterey Reservoir
    - Natural fractures = high initial rates & recoveries
    - Matrix system feeds fracture network
    - Highest recovery factors
    - Best of both Worlds!

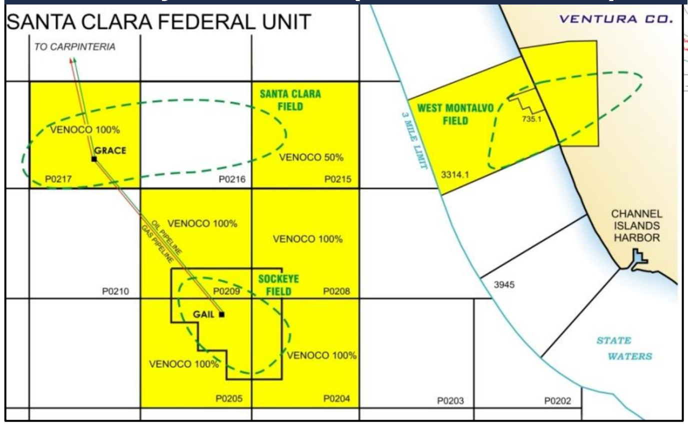
Fractured Monterey

- Prolific Producer of Monterey Fields
  - Single porosity system dominates
  - High IP, high EUR, and steep initial declines
  - Generally associated with offshore reservoirs
    South Ellwood
    Sockeye
  - Drainage Mechanisms
    - Depletion drive (Sockeye)
    - Water drive (South Ellwood)

South Ellwood – 28 Wells (EUR = 72 MMBOE)



Sockeye – 23 Wells (EUR = 35 MMBOE)

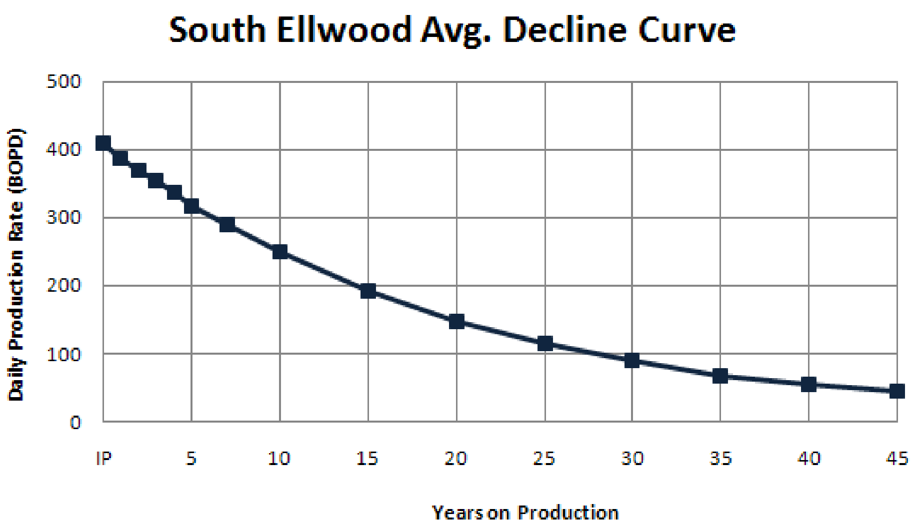


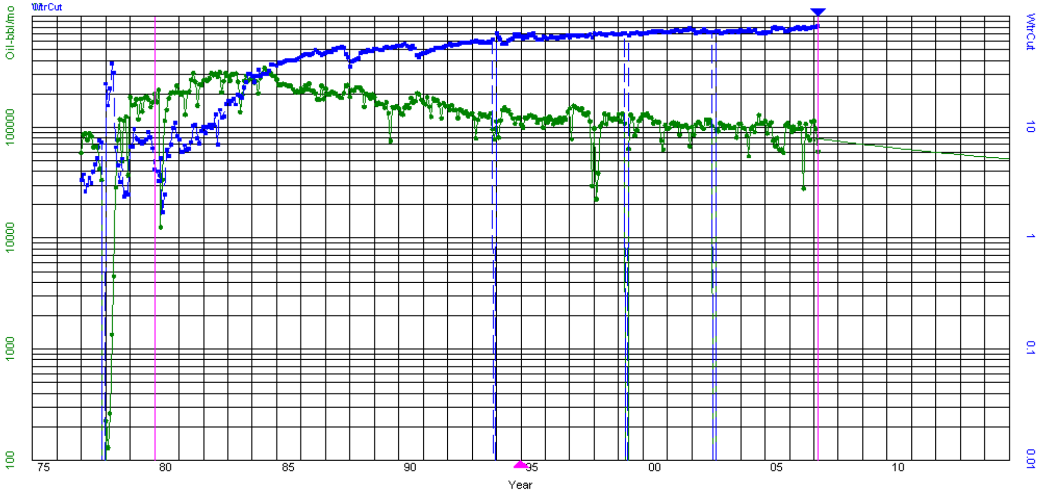
Field	Porosity (%)	Perm. (md)	Oil Sat. (%)	Height (Gross ft)	Recovery Factor	Fracture Characteristics
S. Ellwood	19%	1.4	25%	1,200	7.0-10.0%	Tectonic
Sockeye M-4	25%	3	40%	650	3.6%	Tectonic
Bakken	7%	0.5	70%	140	7.5%	Regional

Fractured Monterey – South Ellwood

Trend Analysis

- 28 productive wellbores
  - Exponential decline
    - Large contribution from natural fractures
    - Aquifer support
  - Average South Ellwood well
    - IP = 410 BOPD
    - EUR = 2.3 MMBO
- Field-wide EUR = 72 MMBO
  - Cum production = 56 MMBOE





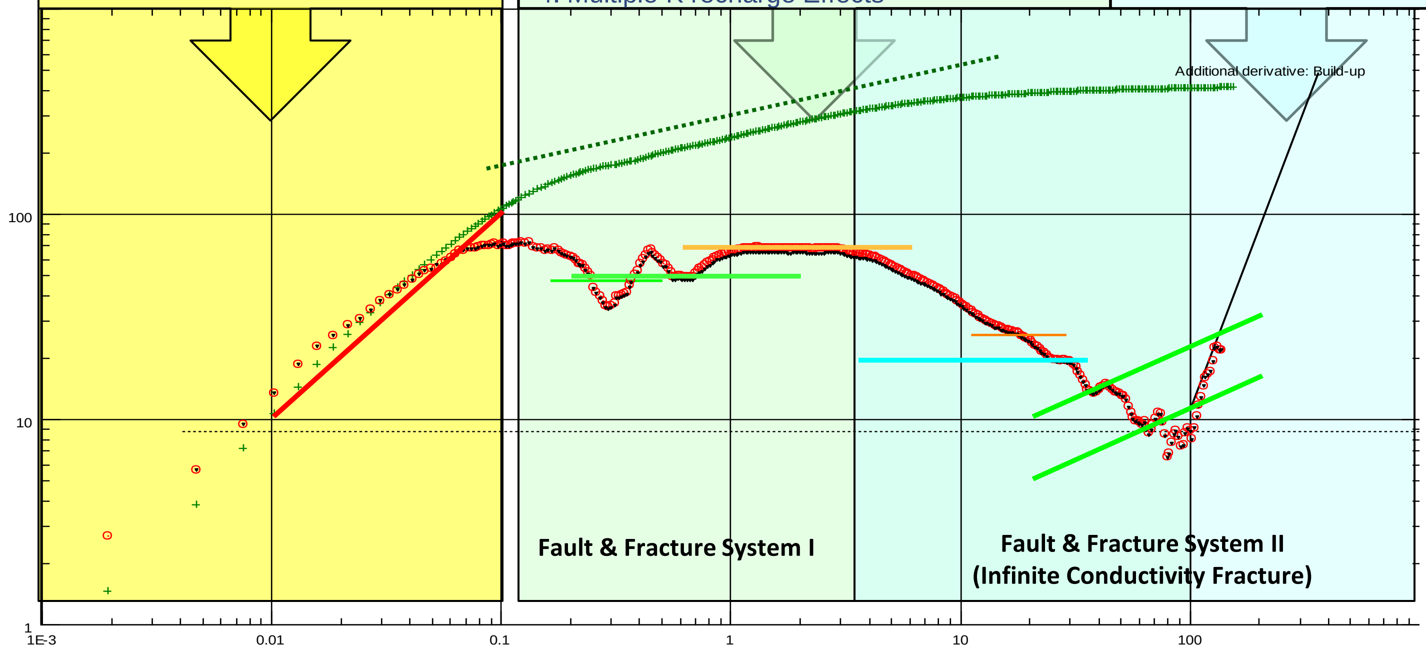
Quantifying Fractures – South Ellwood

- Pressure Transient Analysis: multiple fractures and faults
  - Example: 145 hour pressure build up (PBU) on 3242-7-2RD (December 2004)

Early Time Diagnostics:
Unit Slope:
- Constant Wellbore Storage
- Min fm damage
- High Storativity

Mid Time Diagnostics:
1. Multiple Φ & K behavior in the vicinity of well (< 1hr)
2. Radial & Homogeneous flow (~4 hrs)
3. Hemispherical Flow with Cross Flow
4. Multiple K recharge Effects

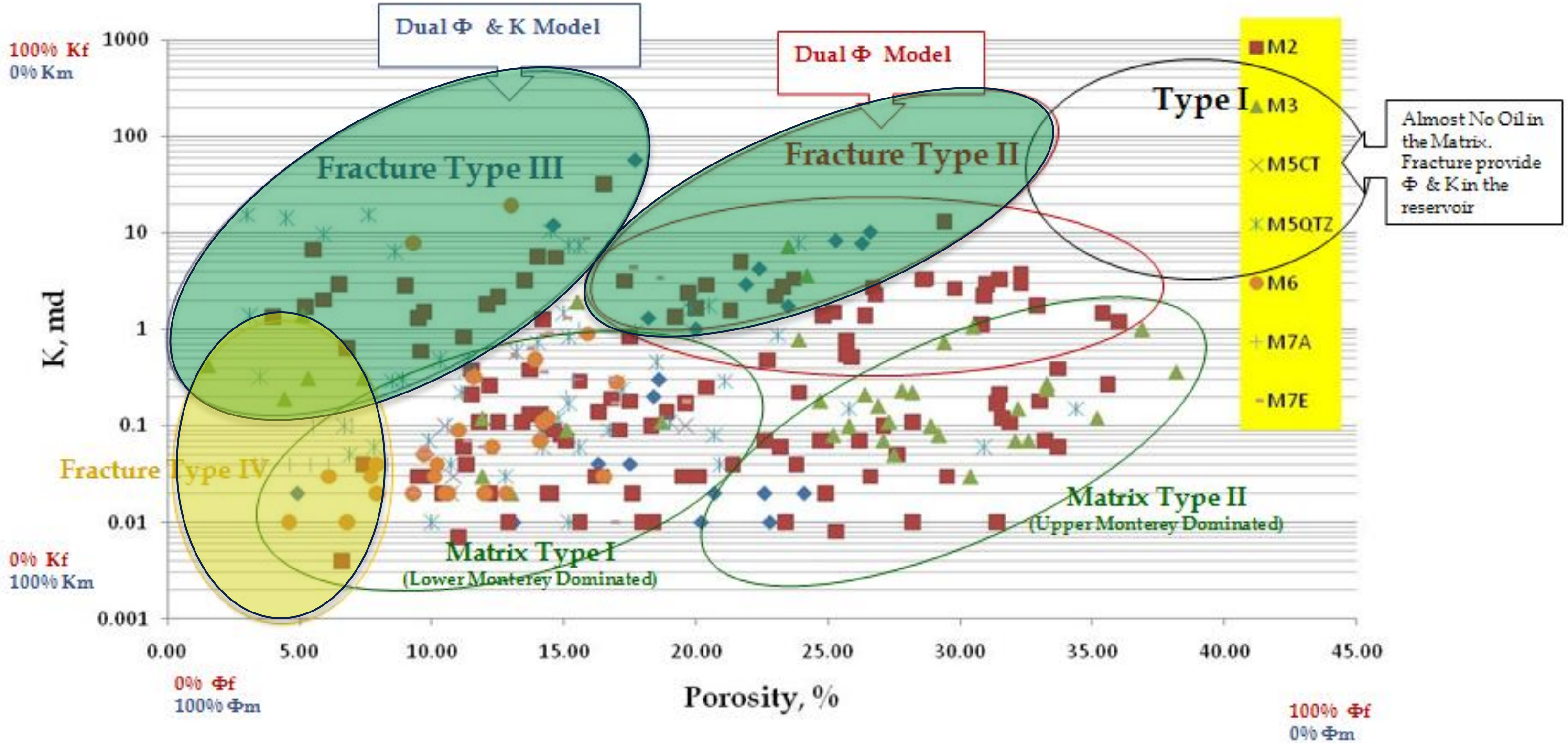
Late Time Diagnostics:
- Boundary or Infinite Conductivity Fracture?



Log-Log plot: p-p@dt=0 and derivative [psi] vs dt [hr]

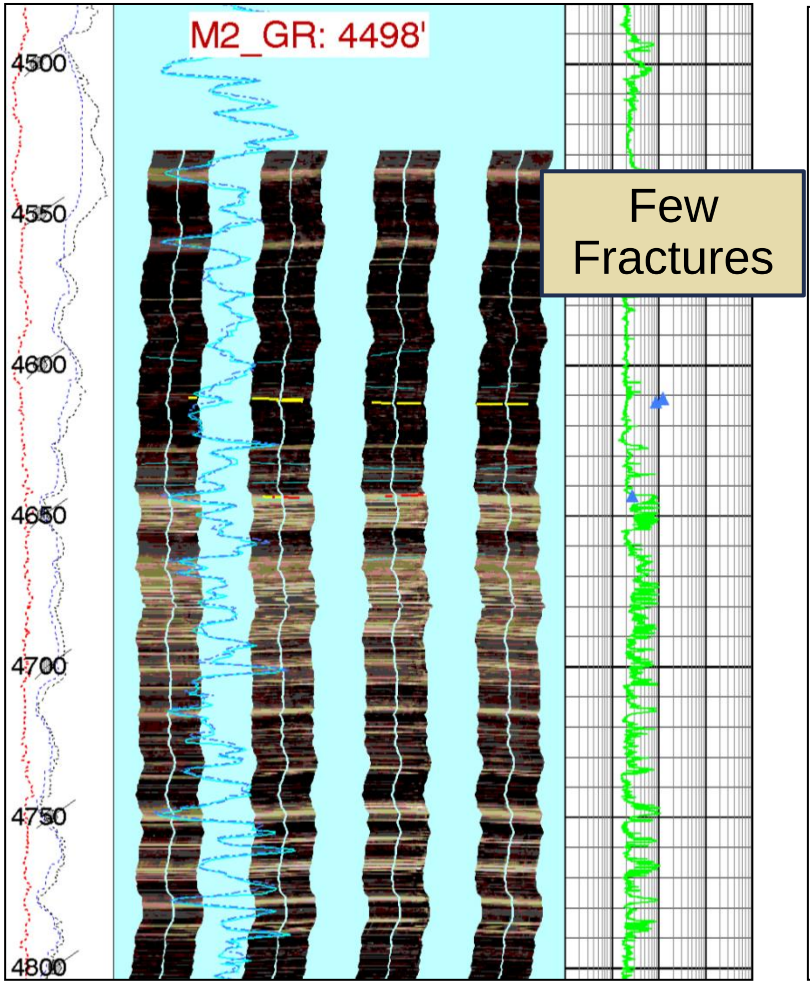
Quantifying Fractures – South Ellwood

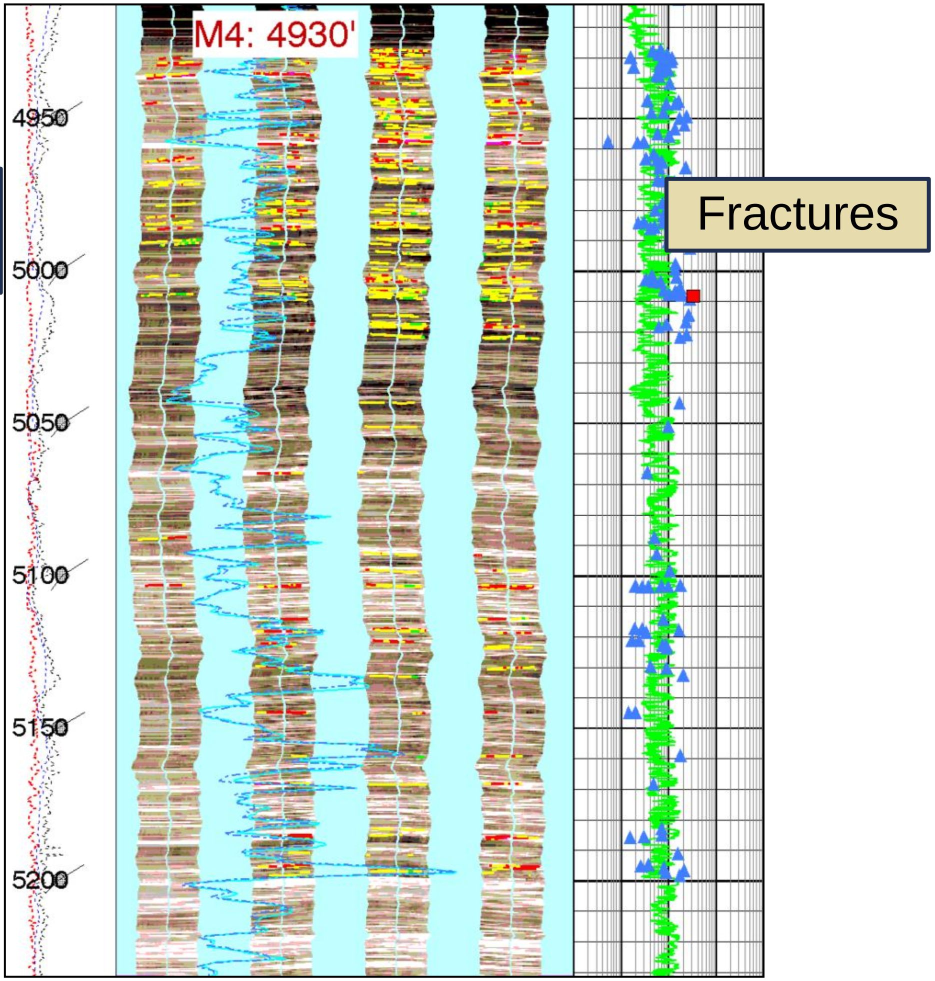
- Extensive Core Data Set
  - Why Characterize? Mapping, prediction, simulation – Depletion Planning!
  - Reservoir Categorization – 3 dominant fracture sets in the Monterey
    1. Fracture Type II – High Perm & Porosity – Primary Reservoir Contributor
    2. Fracture Type III – High Perm & Low Porosity.
    3. Fracture Type IV – Minimal



Fracture Dominated Reservoirs – Tools

Low Fracturing (Matrix Dominated)	Fracture Dominated

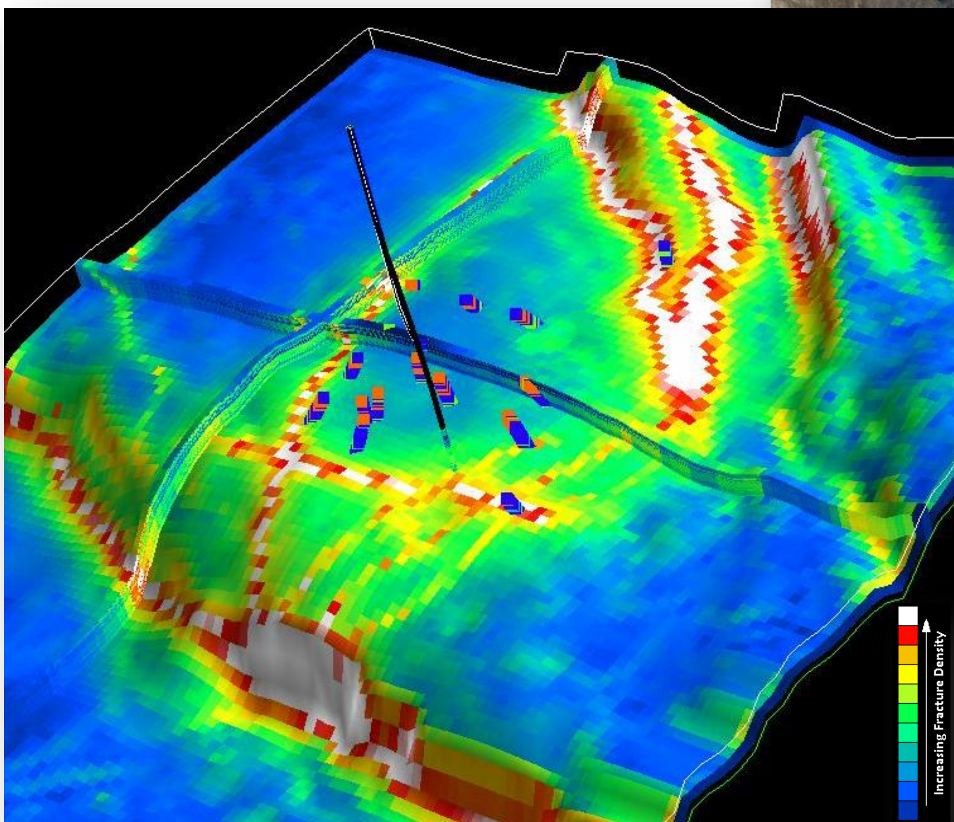


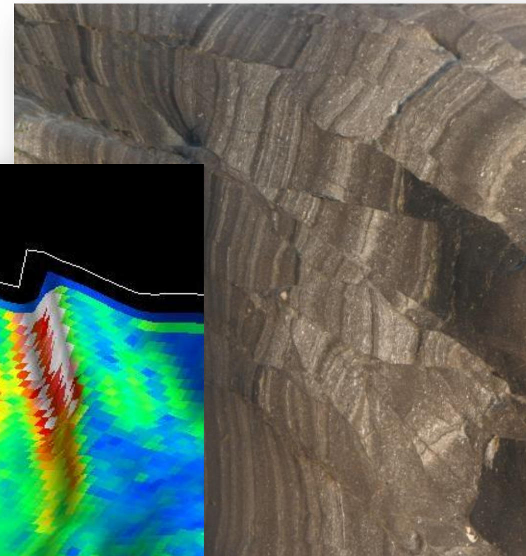


Fracture Dominated Reservoirs

- Controls on Fracturing
  - Lithology
    - Siliceous Shale
    - Limestone
    - Clay/Mud Shales
  - Diagenesis
  - Tectonism
    - Fault Proximity
    - Curvature

3D seismic control on fracture modeling





Fracture Density Modeling at Sockeye Field

Matrix Dominated Monterey

- Matrix System
  - Single porosity model
  - Storage capacity
  - Large permeability variation (matrix only)
    - Rose Field = 0.05 md
    - Petrophysically identified zones as high as 50 md
  - Drive mechanisms
    - Solution gas drive
    - Depletion drive

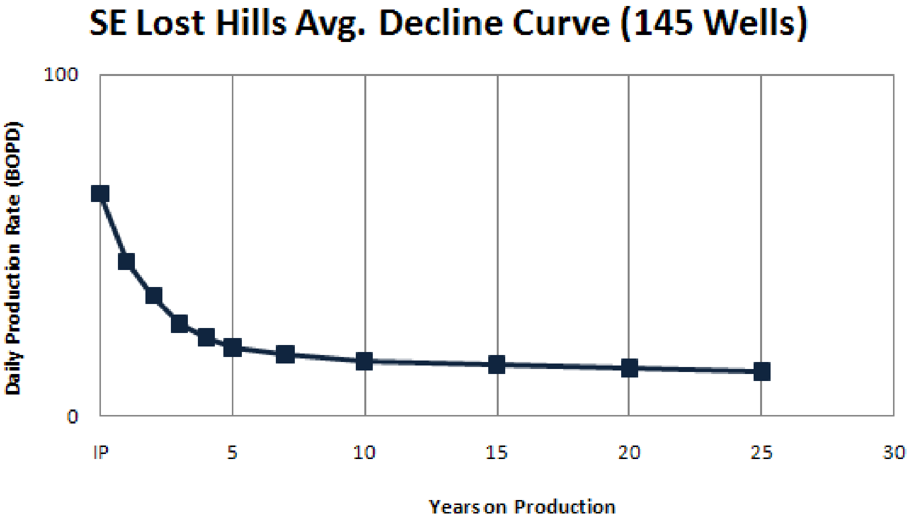
Field	Porosity (%)	Perm. (md)	Oil Sat. (%)	Height (Gross ft)	Recovery %	Gravity (API)
Lost Hills(1)	50%	0.1	45%	1,000’	10%	40º
S. Belridge(2)	70%	1.2	45%	3,000’	7%	24º
Sockeye M-2(3)	30%	0.7	39%	250’	2.5%	19º
Bakken(4)	9%	0.05	75%	12’	10%	42º

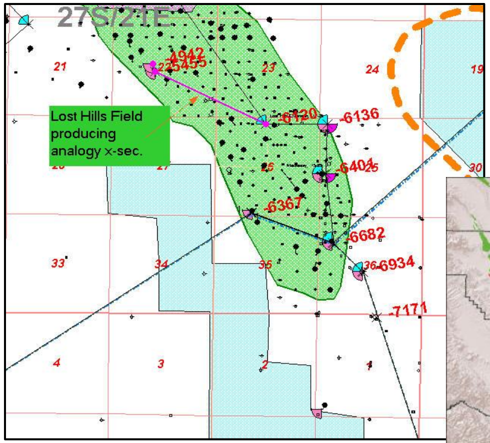
(1) Opal A Properties at Lost Hills.
(2) S. Belridge operator estimates.
(3) M2 Properties from Venoco Operated E-8 ST2 & E-17 RD.
(4) Middle Bakken Data Set

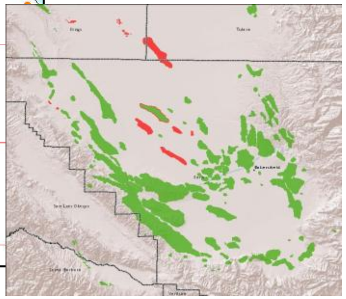
Matrix Dominated – SE Lost Hills Field

Trend Analysis

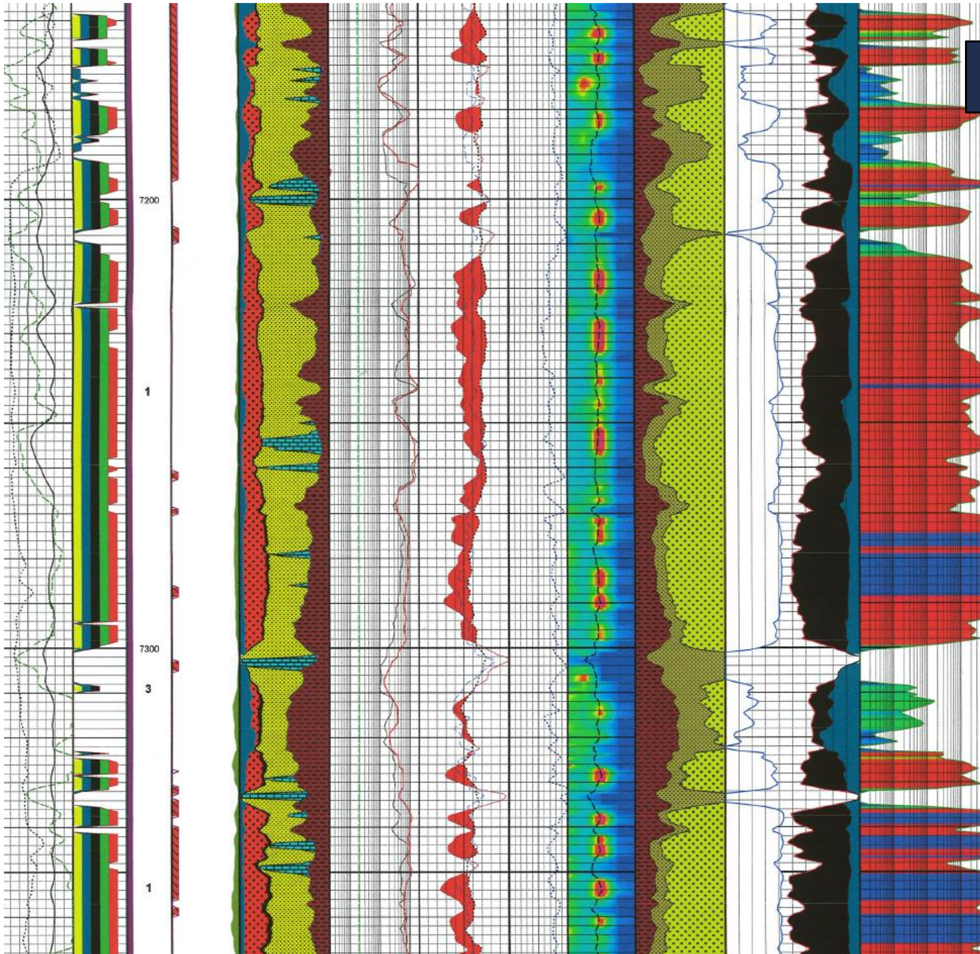
- 600+ Productive wellbores
  - All wells experience hyperbolic decline
  - Average SE Lost Hills well
    - IP = 65 BOPD
    - Water cut = 55%
    - EUR = 87 MBO
- Field-wide EUR = 71 MMBO
  - Cum production = 61 MMBOE



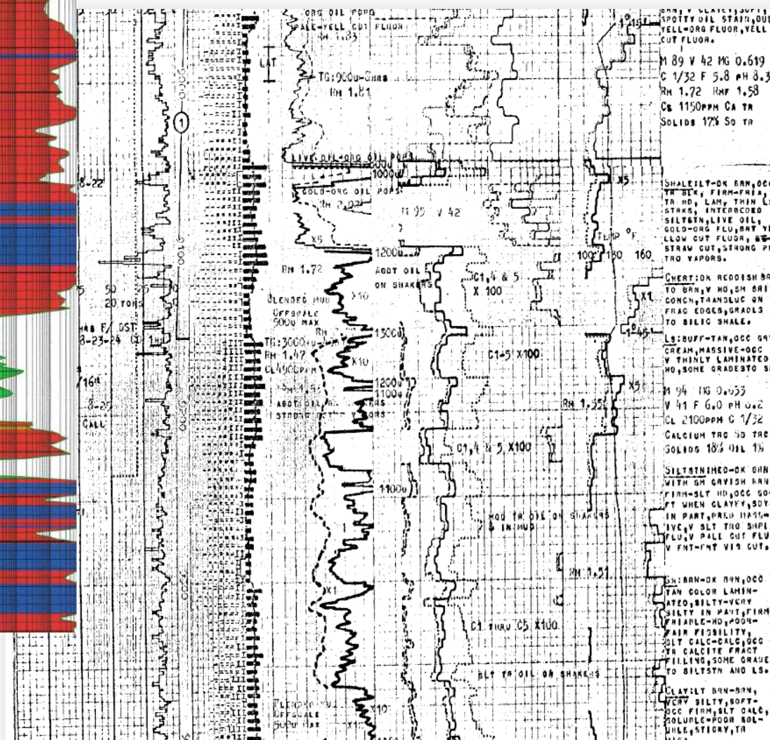




Matrix Reservoir Properties

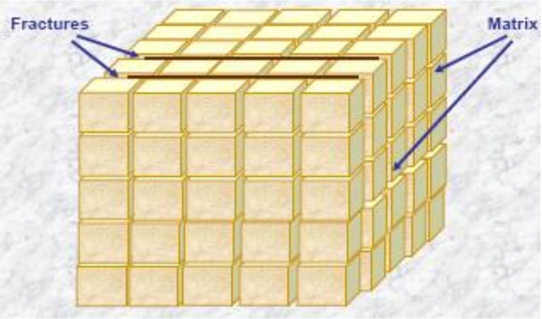


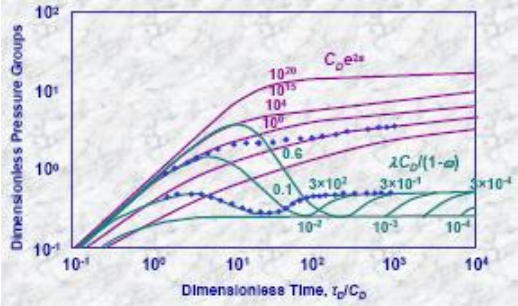
New Scoping Tools



Dual Porosity Monterey – Fracture & Matrix

- Optimal Reservoir for an Oil Shale
  - Sugar cube model (dual porosity)
    - Fractures tap into matrix to drain system
  - Most common system
  - Drivers
    - Phase changes – Rock type
    - Overprinted by fault & fold set
- Combined Monterey Depletion Mechanisms
  - Solution-gas drive (North Shafter & Rose Fields)[1]
  - Gravity drainage (Elk Hills – 31S anticline)[2]
  - Water & gas drive (Elk Hills anticlines)[2]
  - Combination drive
    - Solution + gravity (Elk Hills)[2]



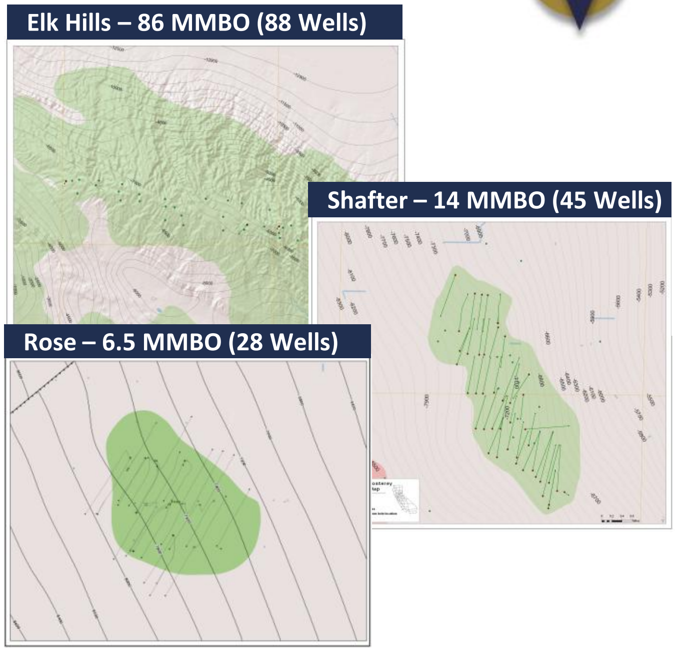


Dual Porosity Model and Idealized log-log PTA Graph for various compressibilities[3]

(1) SPE 83501 – Ganong, Hansen, & Connolly.
(2) AAPG Bulletin v. 85, No. 1 - Reid & McIntyre (2001)
(3) Pressure Transient Analysis – Lee (2009)

Combination Monterey – Fracture & Matrix

- Matrix Properties
  - Conventional measurement (core, petrophysics)
    - Direct relationship – Higher values = higher recovery
- Fracture Properties
  - Log analysis (FMI, XRMI)
  - Outcrop studies
  - Rock mechanical work



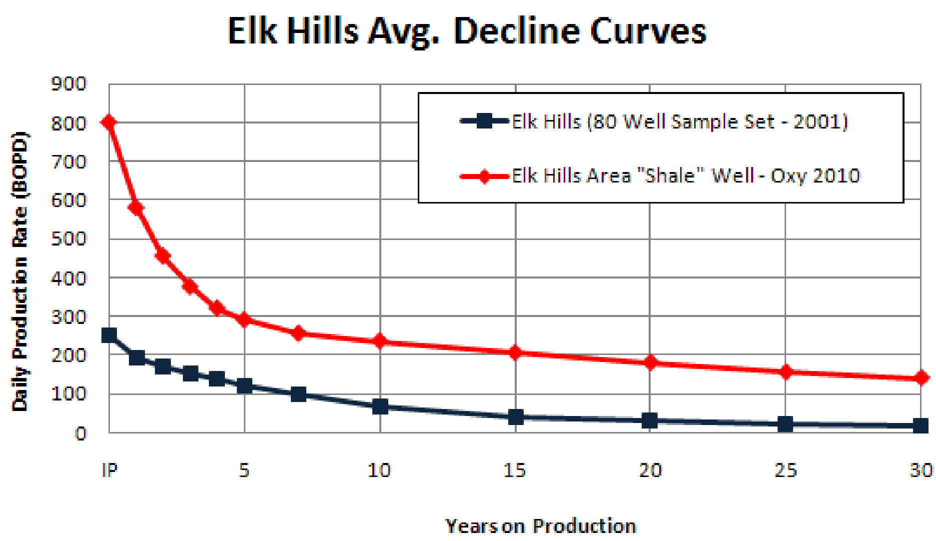
Field	Porosity %	Perm. (md)	Oil Sat. %	Height (Gross ft)	Recovery %	Gravity	Fracture Characteristics
Elk Hills	23%	0.8	55%	500	12.0	35º	Tectonic
Shafter	28%	1.2	40%	40	1.4	26º	Diagenetic + Tectonic
Rose	16%	0.05	45%	40	0.8	24º	Diagenetic + Tectonic
Niobrara[(1)]	14%	1.0	40%	250	22.0	36º	Tectonic

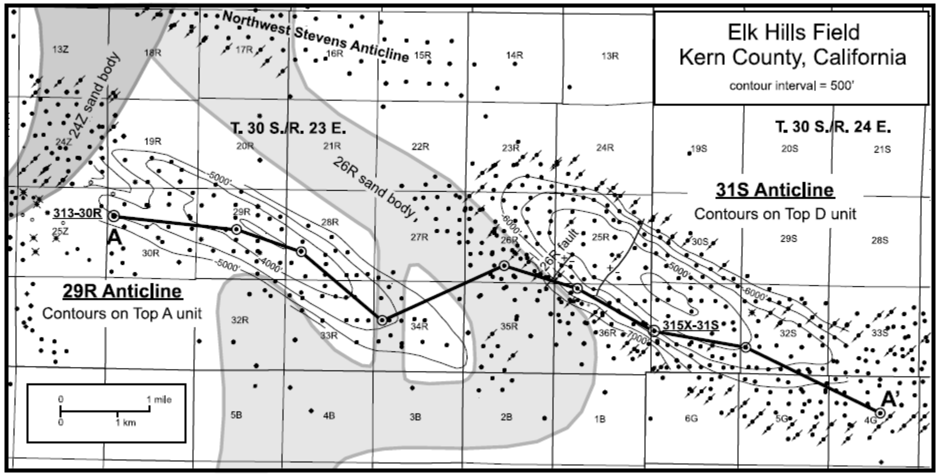
(1) SPE 13886 – Hollberg, Dahm, & Bath

Combination Monterey – Elk Hills Field

Trend Analysis

- 80 productive wellbores
  - Exponential decline
    - Good matrix and fracture network
    - Steeper decline than South Ellwood lower aquifer and gravity drainage support
  - Average Elk Hills well
    - IP = 250 BOPD
    - Water cut = 65%
    - EUR = 750 MBO
- Field Wide EUR = 86 MMBO
  - Cum production = 78 MMBOE

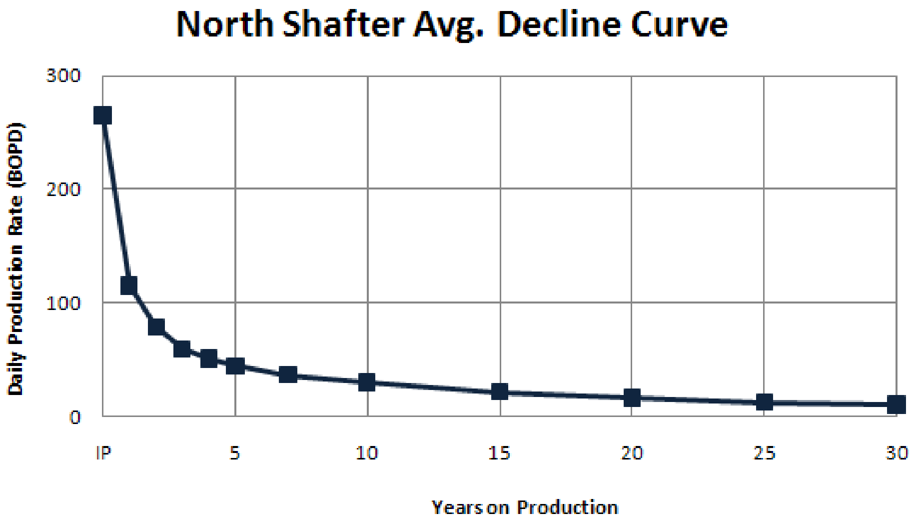


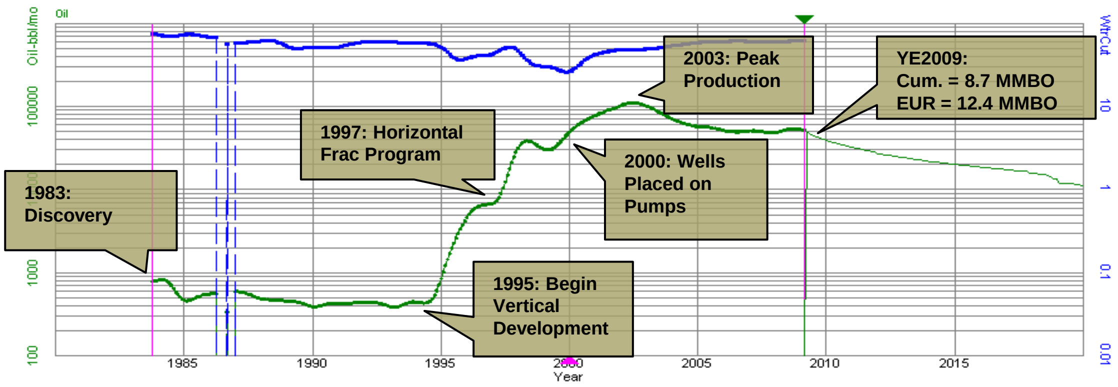


Combination Monterey – North Shafter Field

Trend Analysis

- 45 productive wellbores
  - General hyperbolic decline
    - Matrix contributes majority
    - 2,500’ lateral
    - Hydraulically fracture stimulated
  - Average Well
    - IP = 265 BOPD
    - Water cut = 55%
    - EUR = 435 MBOE
- Field-wide EUR = 13.7 MMBO
  - Cum production = 8.8 MMBOE



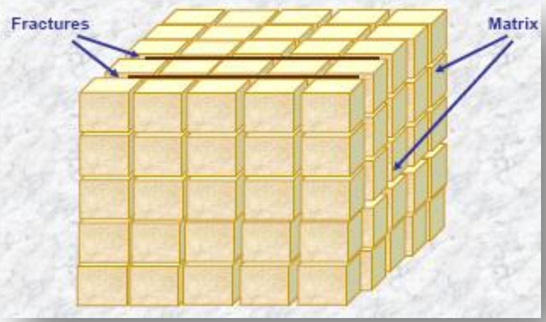


Combined Monterey – Completions

Development Techniques & Completions

- Fracture Dominated Monterey
  - Cemented Casing to isolate mobile water
    - Selective perforating of high fracture intervals
  - Large Scale HCL-HF Acid jobs are key!
  - Recompletion Programs
    - Production logs to identify high water cut intervals
    - Squeeze jobs and reperforating
- Matrix Dominated Monterey
  - Down spacing to Maximize Recovery
    - 10-acre spacing down to <1-acre spacing
  - Cemented casing and high density perforating (6-12 SPF)
  - Propped fracture stimulation
  - Water and steam flood enhanced oil recovery
- Combined Monterey (Matrix & Fractures)
  - Vertical & Lateral Programs (2,500'-3,500')
  - Cemented and uncemented casing
    - Large scale HCl-HF acid jobs
    - Gel based fracture stimulation
  - Artificial lift = rod pumps

Wrap Up



- Mixed Reservoirs
  - 92,000 Acres of Venoco Leases in combined reservoir
  - Wellbore geometry dependent on field characteristics
  - Best of Both Worlds: High IPs, shallow decline, long life
- Fracture Dominated Systems
  - 5,275 Acres of Venoco Leases fracture dominated only
  - Drill High Angle wells to target natural fracture systems
  - Expect high IPs with steep initial declines
- Matrix Dominated Systems
  - 8,225 Acres of Venoco Leases matrix dominated only
  - Drill lateral wellbores to maximize pay footage
  - Expect low IPs with shallow declines and long life

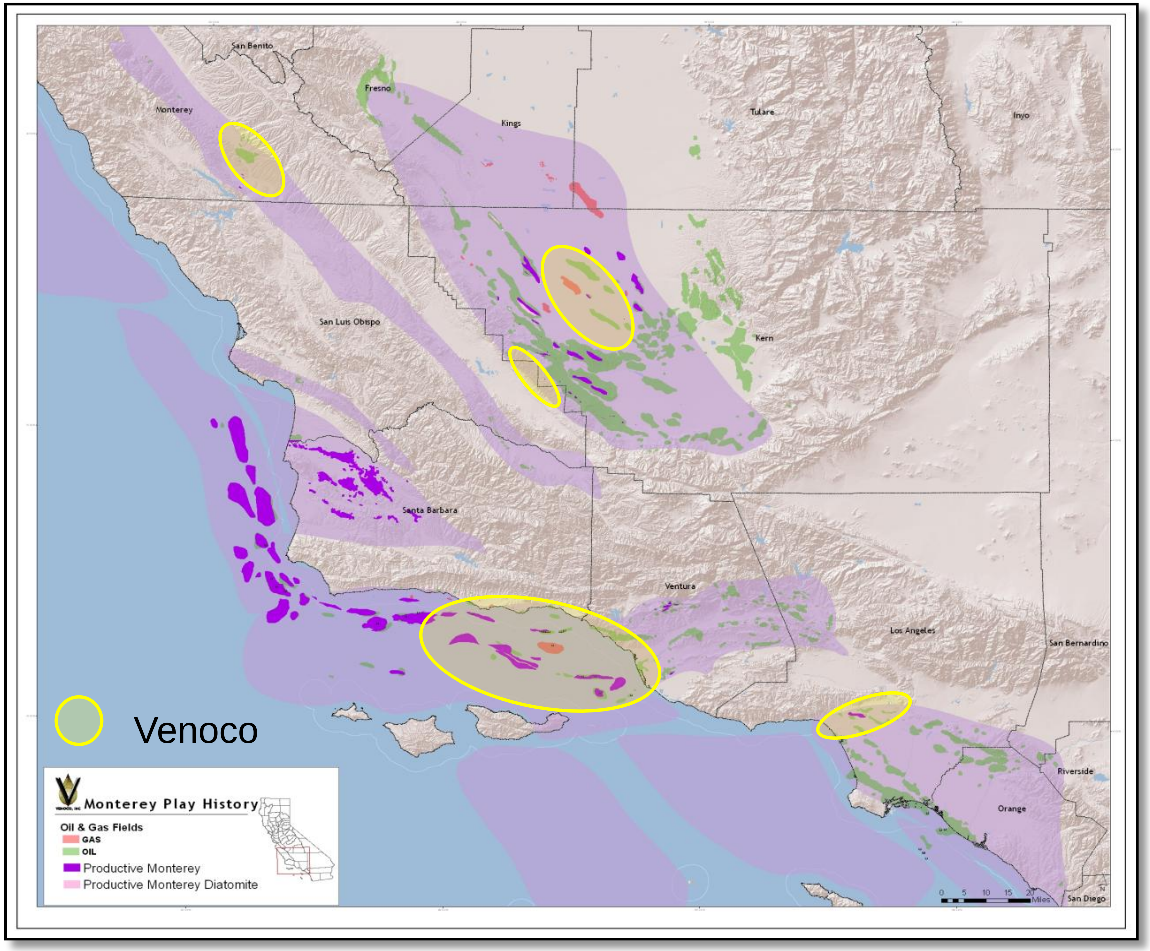
Does not include Venoco's 50,000 net HBP acres.

Operations and Development

Ed O'Donnell
Sr. Vice President, Southern California

VQ LISTED NYSE.

Turning Opportunity into Value



- 155,000 net acres in multiple basins
- 350,000 total net acre target
- 20+ Billion bbls OOIP
- 30 evaluation areas being worked
- Large database
- Well depths 6,000’-14,000’
- Formation thickness 500’-6,000’
- Multiple reservoir targets
- Light, sweet oil
- Experienced team
- Favorable oper. environment
- Nearby infrastructure & market

The Value Creation Process

Acquisition and Evaluation

- Acquire prime acreage
  - Be early, be quick, be cost effective
  - Screen for light oil, structural components, natural fractures, moderate depths, and well data
- Understand the rock and prioritize areas of interest
- Evaluate priority areas
  - Drill vertical pilot wells
  - Acquire data
    - Conventional coring
    - Petrophysics
    - Production
  - Test zones of interest and validate analytical techniques
  - Stimulate wells with targeted applications
  - Correlate and integrate various data
  - Characterize reservoir & development potential
- Transition to exploitation team

The Value Creation Process

Exploitation and Development

- Expand talented, multi-disciplinary team
- Continue to increase acreage position in hand-off areas
- Acquire 3D seismic
- Define development plan
- Acquire permits and build well locations
- Drill a variety of high-angle and horizontal wells
- Optimize well type, completions & stimulation techniques
- Design and construct facilities
- Develop “conveyor belt” process to reduce costs and increase NPV

The Value Creation Process

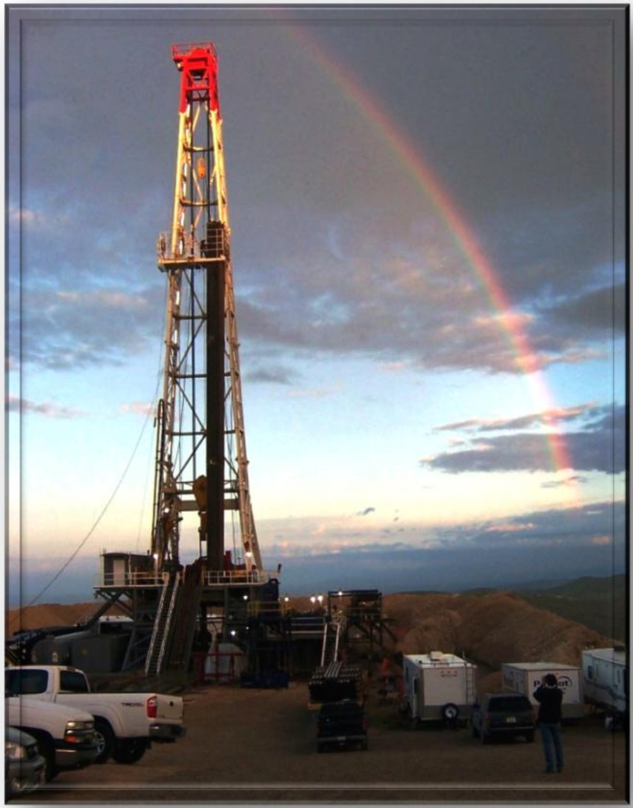
Near-Term Plans

- 2010 – Year of Science
  - Transition three project areas to exploitation
  - Initiate 10-12 well drilling program
  - Acquire additional acreage
  - Shoot 3D seismic
  - Permit future well locations
  - Design generic production facility
  - Expand organization
- 2011 – Year of Optimization
  - Transfer additional areas to exploitation
  - Ramp up to 3-4 drilling rigs
  - Drill 30-40 delineation and development wells
  - Reach 350,000 total net acre leasehold goal
  - Optimize completion and stimulation techniques

Initial Pilot Project Areas for Exploitation

Development Options

- Monterey Project "A"
  - 9,400 acres
  - 56 wells (160 acre spacing)
  - Fracture dominated reservoir
  - Initiated 1st Qtr 2010
- Monterey Project "B"
  - 7,500 acres
  - 38 wells (200 acre spacing)
  - Fractured & matrix reservoir
  - Initiate 4th Qtr 2010
- Monterey Project "C"
  - 12,500 acres
  - 75 wells (165 acre spacing)
  - Fracture dominated reservoir
  - Initiate 3rd Qtr 2010



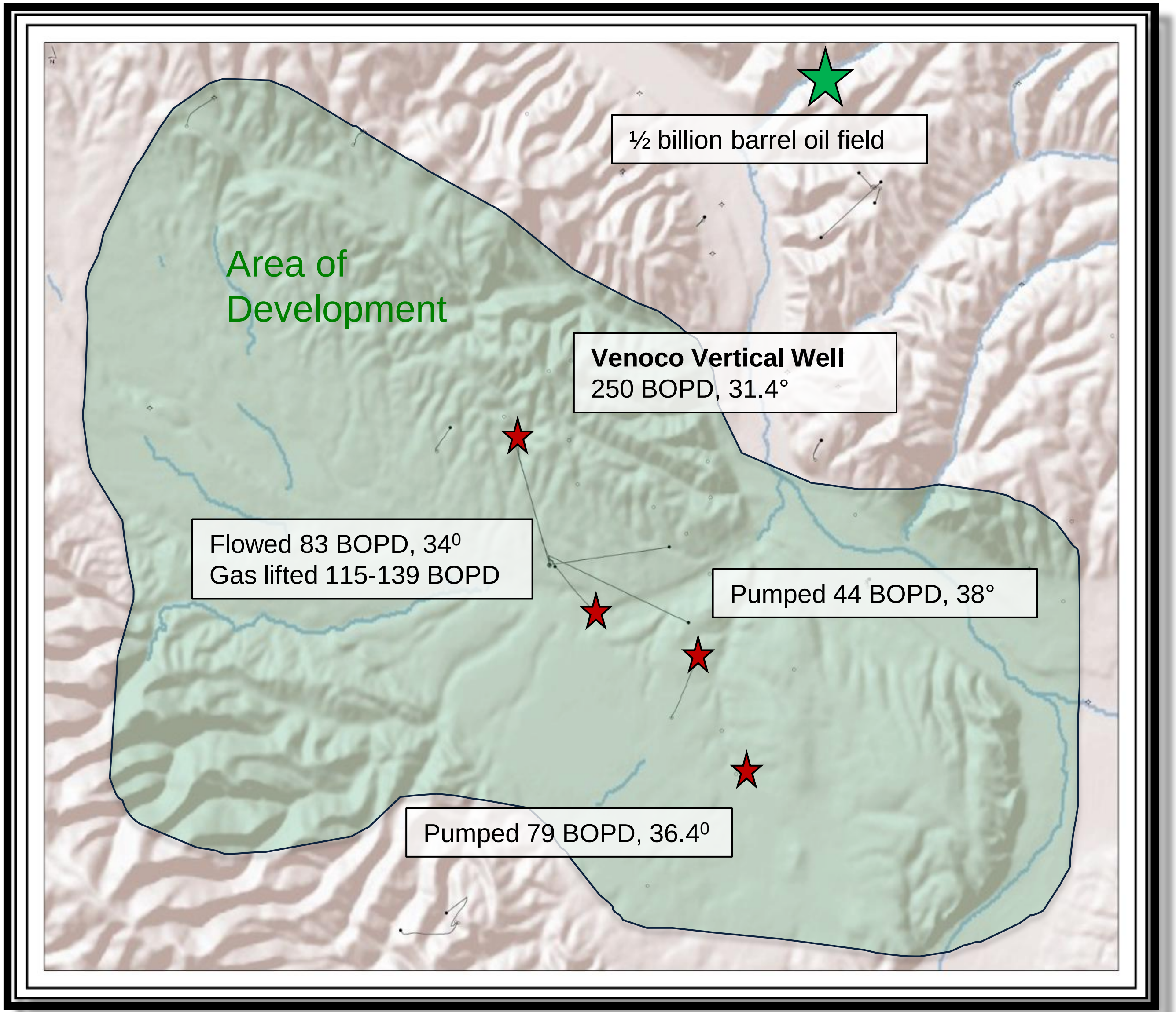
Venoco Monterey well drilled March, 2010

Monterey Project "A" – Overview

- Vertical Well History
  - 5 wells drilled in the 1980's – initial rates averaged 70 BOPD
  - Assortment of stimulation techniques
  - Venoco drilled well in 2008 – initial rate of 250 BOPD
  - High gravity oil – 31 to 38 degree API
  - Old wells were uneconomic at 1980's oil prices
- Horizontal Well Projections
  - Initial rates of 350 BOPD
  - Reserves of 525,000 barrels per well(1)
- Application of Modern Technology
  - Proprietary petrophysical analysis
  - Modern completion & stimulation techniques
- Development Plan
  - Pilot program of 5 delineation wells
  - 51 development wells

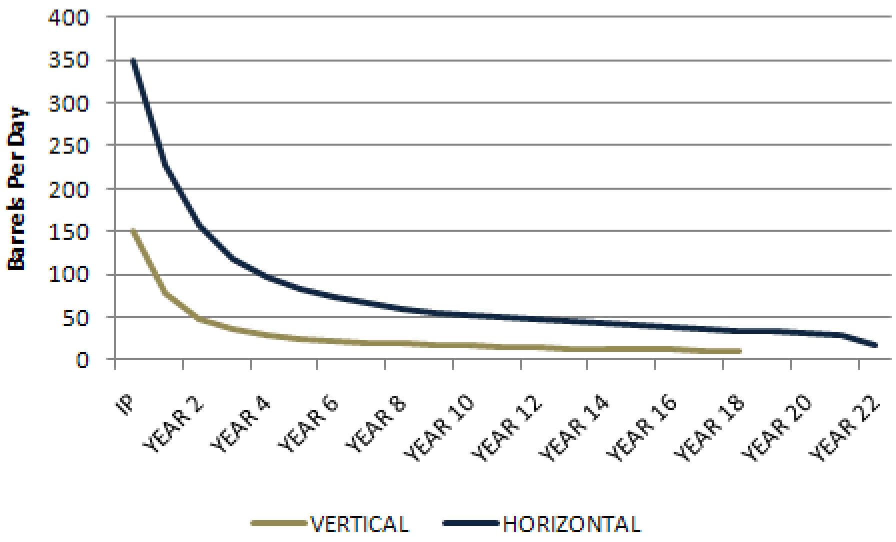
(1) Internal estimate of unrisked reserve potential. See "Net Asset Value & Unrisked Resource Estimates."

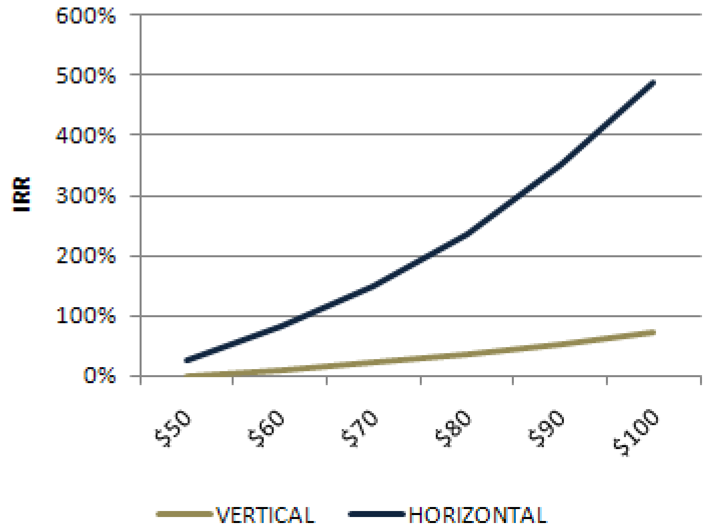
Project "A" – Early Test Results



Project "A" – Type Curve

Vertical vs. Horizontal Type Wells[1]





Vertical Summary

- Capital Cost = $2.0 MM
  - Water Hauling = $6.00 / BW ($18.00 / BO)
  - LOE = $5.50 / BO
- EUR = 150 MBO
  - IP = 150 BOPD
- NPV10 = $1.5 MM
  - Flat Pricing: $80/BO & $5/MCF
- P/I = +0.72

Horizontal Summary

- Capital Cost = $3.0 MM
  - Water Hauling = $6.00 / BW ($18.00 / BO)
  - LOE = $5.50 / BO
- EUR = 525 MBO
  - IP = 350 BOPD
- NPV10 = $8.7 MM
  - Flat Pricing: $80/BO & $5/MCF
- P/I = +3.45

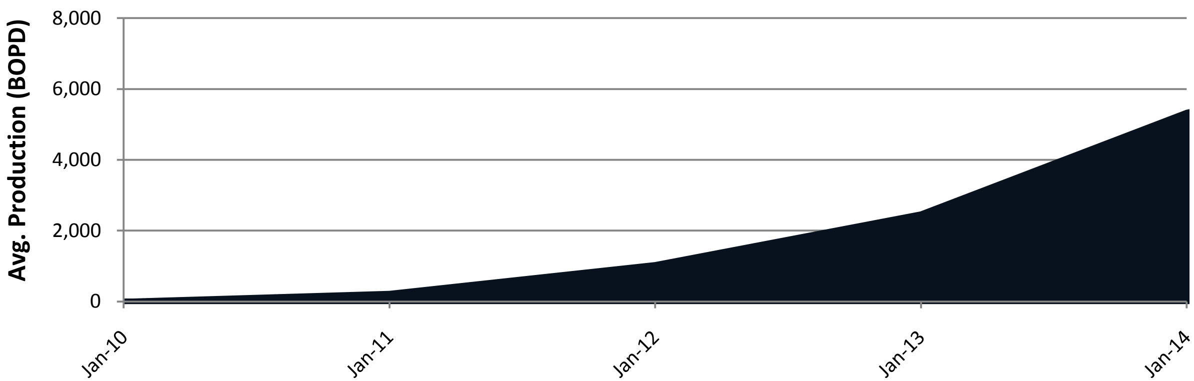
(1) Based on deterministic volumetrics, inferred drainage areas, and analogous production profiles. See "Net Asset Value & Unrisked Resource Estimates" and "Cautionary Statement Regarding Forward Looking Information." Excludes costs such as capitalized G&A, land acquisition, and interest expense. Type well assumes 100% WI and 80% NRI.

Project "A" – Unrisked Model(1)

Total Project "A" 5-Year Cash Flows ($M)

	2010	2011	2012	2013	2014
Wells Drilled	0	2	6	12	24
Cumulative Wells	0	2	8	20	44
Gross Production (BO/day)	0	304	1,405	3,344	7,231
Net Production (BO/day)	0	243	1,124	2,675	5,785
Net Revenue	0	6,426	29,673	70,632	152,758
Lease Operating Expenses	0	(2,409)	(11,121)	(26,472)	(57,253)
G&A Burden	0	(369)	(1,704)	(4,055)	(8,771)
Severance / Ad Valorem	0	(264)	(1,218)	(2,900)	(6,273)
Total Expenses	0	(3,041)	(14,044)	(33,428)	(72,297)
Net Operating Cash Flow	**0**	**3,385**	**15,629**	**37,204**	**80,461**
Cash Based Taxes	0	0	0	0	0
Development CapEx(2)	0	(6,000)	(18,000)	(44,000)	(72,000)
Free Cash Flow	**$0**	**($2,615)**	**($2,371)**	**($6,796)**	**$8,461**

Project "A" Daily Production Averages



Economic Assumptions

- Development Wells:
  - CapEx = $3.0 MM
  - IP = 350 BOPD
  - EUR = 525 MBO
  - Water Cut = 75%
  - GOR = 500 CF/BO
- Lease Operating Expenses:
  - Well Operations = $5.50/BO
  - Water Hauling = $6.00/BW ($18.00/BO)
  - Differential = -$4.00/BO
  - Flat Pricing Deck
    - Oil = $80/BO
    - Gas = $5.00/MCF
- 100% WI; 80% NRI

Economic Output

NPV = $307 MM
Pay Out = 4.49 years
ROR = 100+%
Gross EUR = 29.4 MMBOE

P/I = +2.54

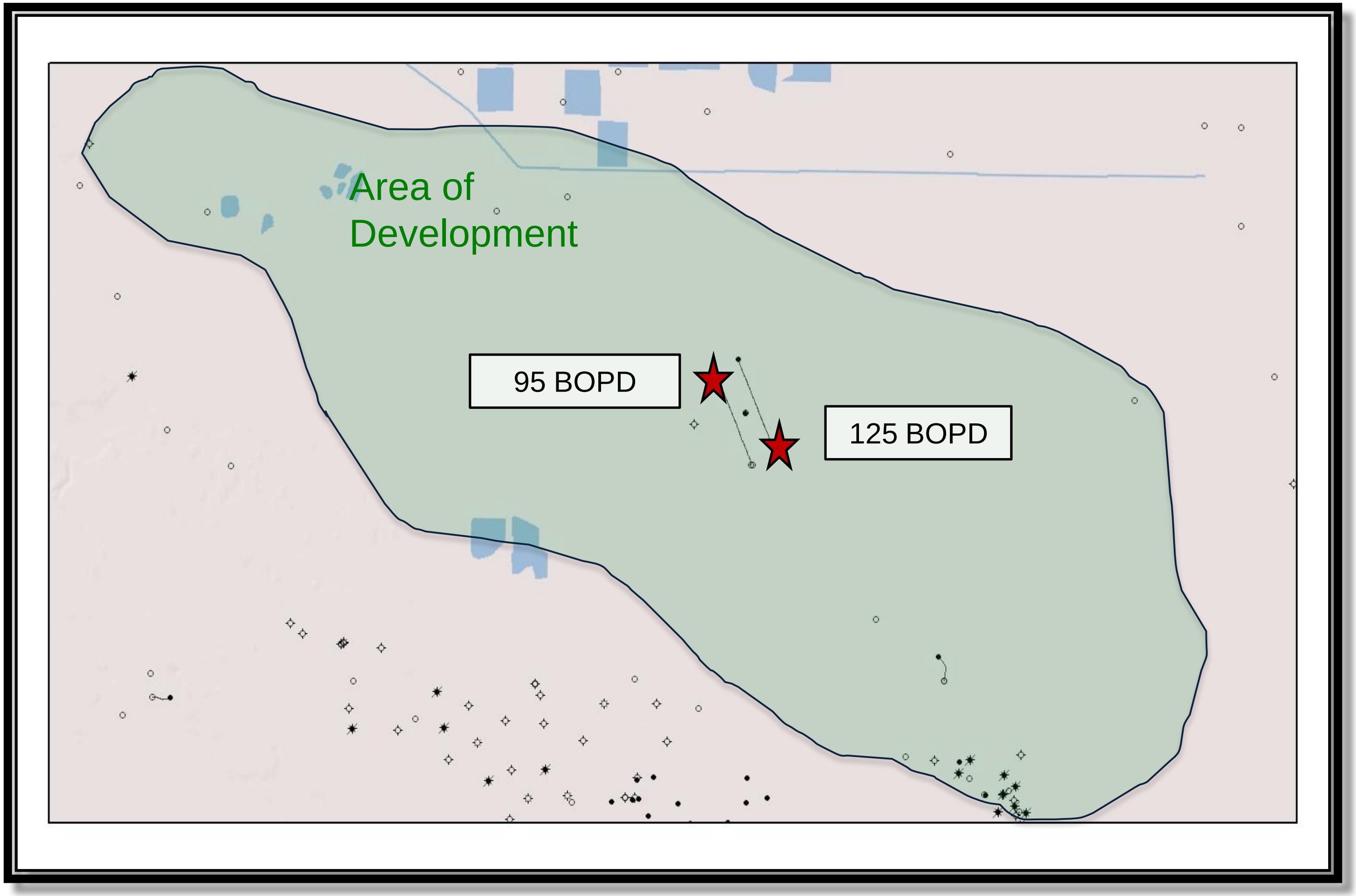
(1) All data shown is "unrisked," meaning that it is not discounted to reflect the risk of production impediments, unsuccessful development activity, permitting issues, cost increases and other potential problems. Our ability to achieve the results shown is subject to a wide variety of risks, as discussed in "Cautionary Statement Regarding Forward-Looking Information" and the "Risk Factors" section of our 2009 annual report on Form 10-K. See also "Net Asset Value & Unrisked Resource Estimates" and "Cautionary Statement Regarding Forward Looking Information." Type well assumes 100% WI and 80% NRI.
(2) Capital expenditures exclude costs such as capitalized G&A and land acquisition.

Monterey Project "B" – Overview

- Drilling History
  - Three vertical wells drilled since 2000 – data pilot holes
  - Two horizontal wells – initial rates of 95-125 BOPD
  - High gravity oil – 27 degree API
  - Less than optimal completion techniques
- Horizontal Well Projections
  - Initial Rates of 500 BOPD
  - Reserves of 750,000 barrels per well(1)
- Application of Modern Technology
  - Opportunities to apply modern completion techniques to existing wells
- Development Plan
  - 38 development wells

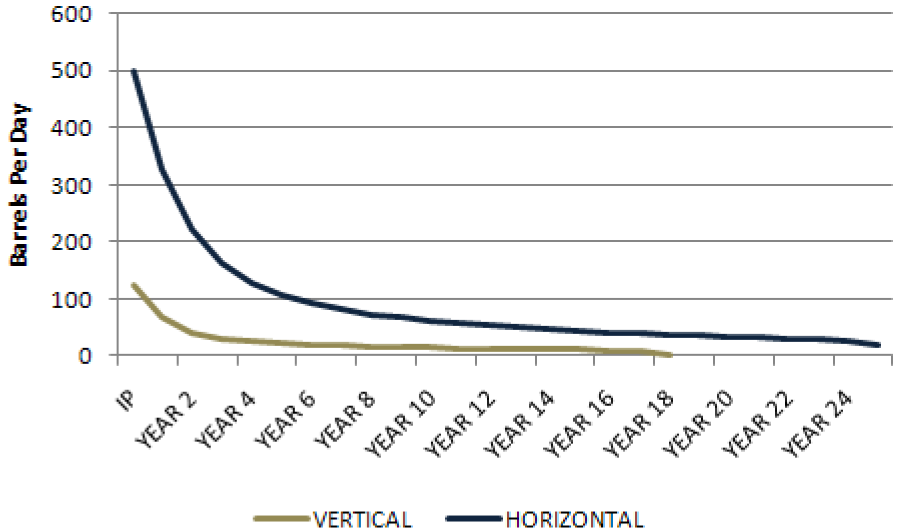
(1) Internal estimate of unrisked reserve potential. See "Net Asset Value & Unrisked Resource Estimates."

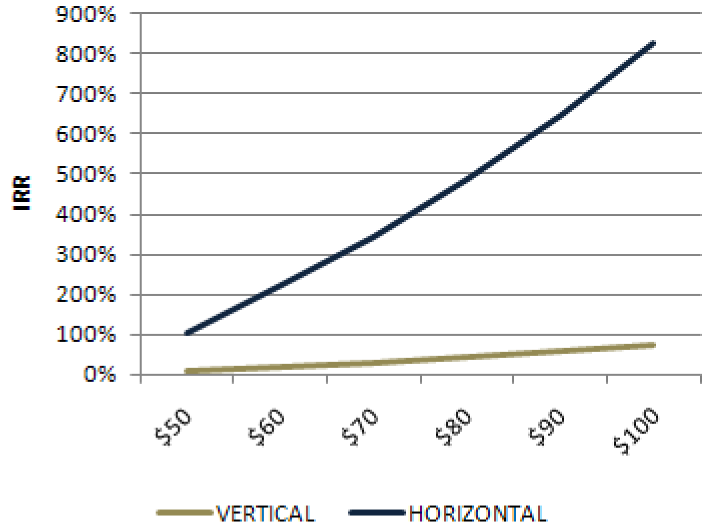
Project "B" - Early Test Results



Project "B" – Type Curve

Vertical vs. Horizontal Type Wells(1)





Vertical Summary

- Capital Cost = $2.0 MM
  - Water Hauling = $4.50 / BW ($6.75 / BO)
  - LOE = $7.50 / BO
- EUR = 125 MBO
  - IP = 125 BOPD
- NPV10 = $1.7 MM
  - Flat Pricing: $80/BO & $5/MCF
- P/I = +0.86

Horizontal Summary

- Capital Cost = $3.0 MM
  - Water Hauling = $4.50 / BW ($6.75 / BO)
  - LOE = $7.50 / BO
- EUR = 750 MBO
  - IP = 500 BOPD
- NPV10 = $16.2 MM
  - Flat Pricing: $80/BO & $5/MCF
- P/I = +5.39

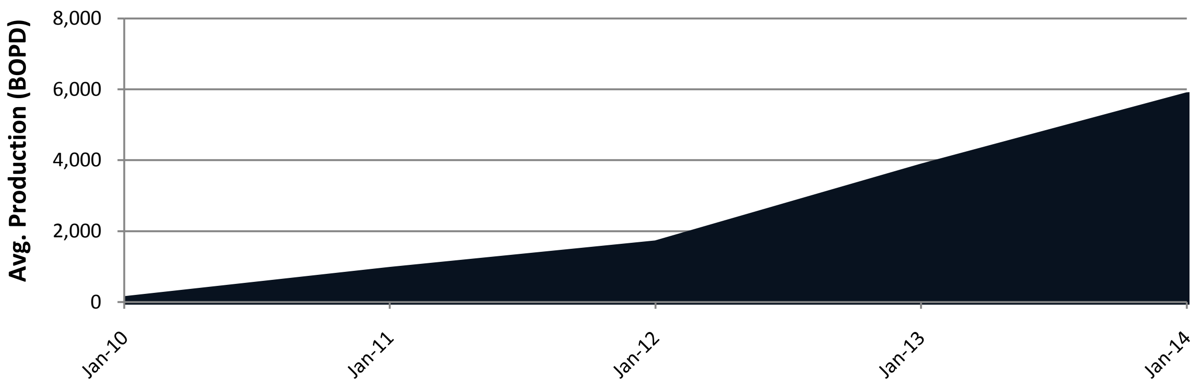
(1) Based on deterministic volumetrics, inferred drainage areas, and analogous production profiles. See "Net Asset Value & Unrisked Resource Estimates" and "Cautionary Statement Regarding Forward Looking Information." Excludes costs such as capitalized G&A, land acquisition, and interest expense. Type well assumes 100% WI and 80% NRI.

Project "B" – Unrisked Model[(1)]

Total Monterey "B" 5-Year Cash Flows ($M)

	2010	2011	2012	2013	2014
Wells Drilled	1	3	6	12	16
Cumulative Wells	1	4	10	22	38
Gross Production (BO/day)	121	1,239	2,250	5,183	7,908
Net Production (BO/day)	97	991	1,800	4,147	6,327
Net Revenue	2,616	26,772	48,629	112,009	170,897
Lease Operating Expenses	(581)	(5,948)	(10,804)	(24,885)	(37,968)
G&A Burden	(147)	(1,503)	(2,729)	(6,287)	(9,592)
Severance / Ad Valorem	(107)	(1,099)	(1,996)	(4,597)	(7,014)
Total Expenses	(835)	(8,549)	(15,529)	(35,768)	(54,574)
Net Operating Cash Flow	**1,781**	**18,223**	**33,100**	**76,240**	**116,323**
Cash Based Taxes	0	0	(3,228)	(4,155)	(9,830)
Development CapEx[(2)]	(3,000)	(9,000)	(18,000)	(44,000)	(36,000)
Free Cash Flow	**($1,219)**	**$9,223**	**$11,872**	**$28,085**	**$70,493**

Monterey "B" Daily Production Averages



Economic Assumptions

- Development Wells:
  - CapEx = $3.0 MM
  - IP = 500 BOPD
  - EUR = 750 MBO
  - Water Cut = 60%
  - GOR = 500 CF/BO
- Lease Operating Expenses:
  - Well Operations = $7.50/BO
  - Water Hauling = $4.50/BW ($6.75/BO)
  - Differential = -$1.85/BO
  - Flat Pricing Deck
    - Oil = $80/BO
    - Gas = $5.00/MCF
- 100% WI; 80% NRI

Economic Output

NPV = $440 MM
Pay Out = 1.11 years
ROR = 100+%
Gross EUR = 26.2 MMBOE

P/I = +4.99

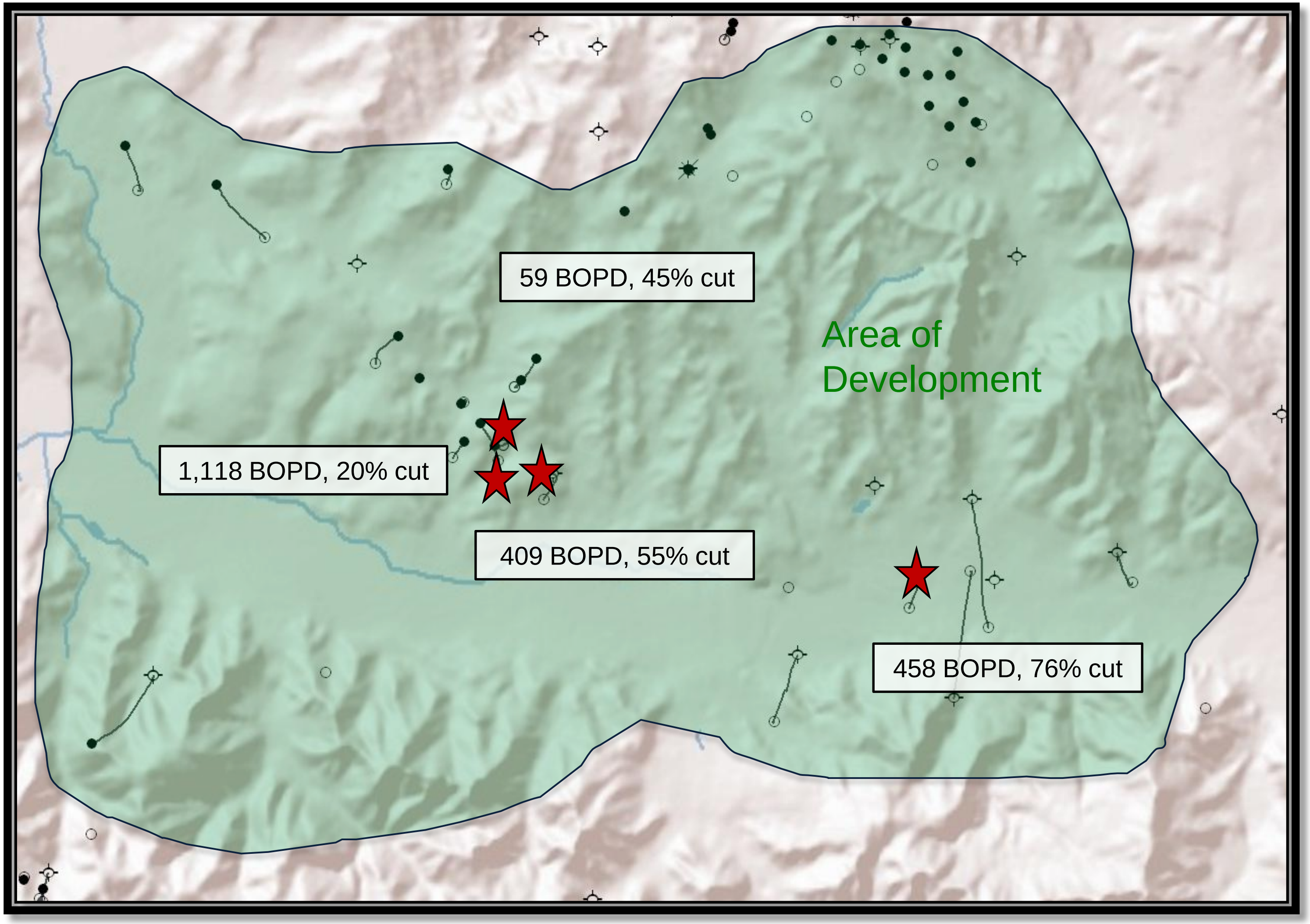
(1) All data shown is "unrisked," meaning that it is not discounted to reflect the risk of production impediments, unsuccessful development activity, permitting issues, cost increases and other potential problems. Our ability to achieve the results shown is subject to a wide variety of risks, as discussed in "Cautionary Statement Regarding Forward-Looking Information" and the "Risk Factors" section of our 2009 annual report on Form 10-K. See also "Net Asset Value & Unrisked Resource Estimates" and "Cautionary Statement Regarding Forward Looking Information." Type well assumes 100% WI and 80% NRI.
(2) Capital expenditures exclude costs such as capitalized G&A and land acquisition.

Monterey Project "C" – Overview

- Vertical Drilling History
  - 4 wells drilled in the 1980's – initial rates up to 1,100 BOPD
  - High gravity oil – 30 degree API
- Horizontal Well Projections
  - Initial rates of 700 barrels per day
  - Reserves of 800,000 barrels per well(1)
- Application of Modern Technology
  - Proprietary petrophysical model identifies untested potential pay
  - Horizontal drilling
  - Modern stimulations
- Development Plan
  - Pilot program of 5 delineation wells
  - 75 development wells

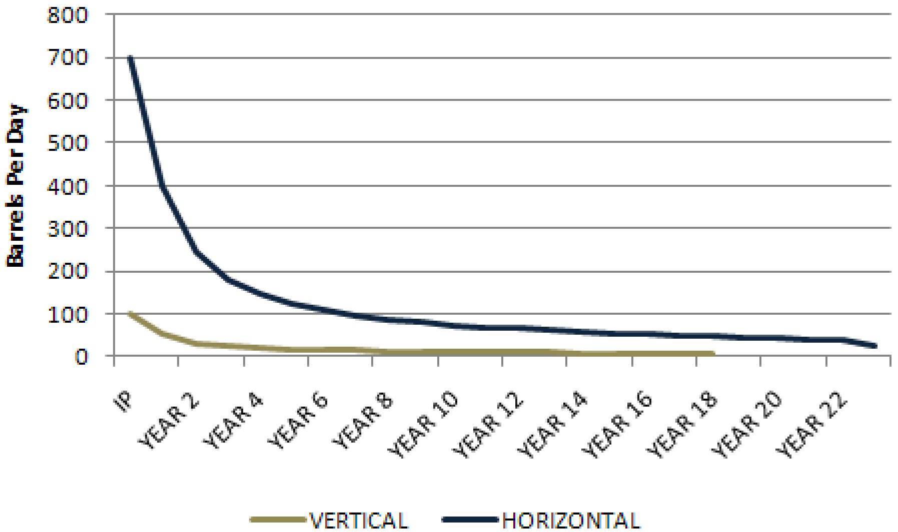
(1) Internal estimate of unrisked reserve potential. See "Net Asset Value & Unrisked Resource Estimates."

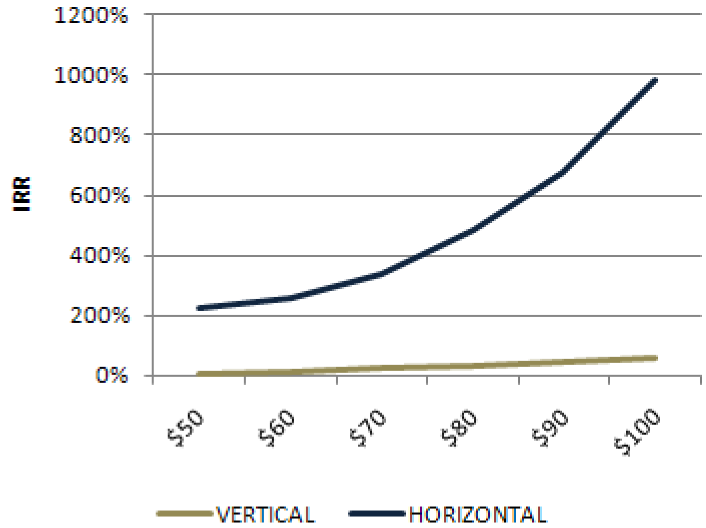
Project “C”– Early Test Results



Project "C" – Type Curve

Vertical vs. Horizontal Type Wells(1)





Vertical Summary

- Capital Cost = $2.0 MM
  - Water Hauling = $3.00 / BW ($6.00 / BO)
  - LOE = $6.35 / BO
- EUR = 100 MBO
  - IP = 100 BOPD
- NPV10 = $1.2 MM
  - Flat Pricing: $80/BO & $5/MCF
- P/I = +0.60

Horizontal Summary

- Capital Cost = $2.5 MM
  - Water Hauling = $3.00 / BW ($6.00 / BO)
  - LOE = $6.35 / BO
- EUR = 800 MBO
  - IP = 700 BOPD
- NPV10 = $21.9 MM
  - Flat Pricing: $80/BO & $5/MCF
- P/I = +8.74

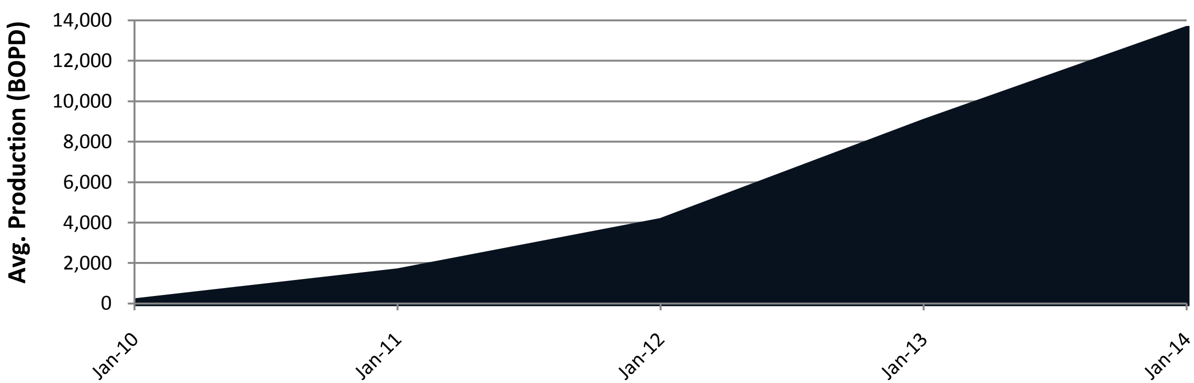
(1) Based on deterministic volumetrics, inferred drainage areas, and analogous production profiles. See "Net Asset Value & Unrisked Resource Estimates" and "Cautionary Statement Regarding Forward Looking Information." Excludes costs such as capitalized G&A, land acquisition, and interest expense. Type well assumes 100% WI and 80% NRI.

Project "C" – Unrisked Model[1]

Total Project "C" 5-Year Cash Flows ($M)

	2010	2011	2012	2013	2014
Wells Drilled	2	5	12	24	24
Cumulative Wells	2	7	19	43	67
Gross Production (BO/day)	223	2,843	7,248	15,924	24,061
Net Production (BO/day)	178	2,274	5,798	12,739	19,249
Net Revenue	4,125	52,609	134,113	294,648	445,235
Lease Operating Expenses	(709)	(9,047)	(23,062)	(50,667)	(76,562)
G&A Burden	(207)	(2,637)	(6,722)	(14,769)	(22,318)
Severance / Ad Valorem	(169)	(2,153)	(5,489)	(12,060)	(18,223)
Total Expenses	(1,085)	(13,837	(35,273)	(77,496)	(117,102)
Net Operating Cash Flow	**3,040**	**38,772**	**98,840**	**217,152**	**328,133**
Cash Based Taxes	0	0	(9,195)	(20,876)	(47,697)
Development CapEx[2]	(5,000)	(12,500)	(30,000)	(60,000)	(60,000)
Free Cash Flow	**($1,960)**	**$26,272**	**$59,645**	**$136,276**	**$220,436**

Project "C" Daily Production Averages



Economic Assumptions

- Development Wells:
  - CapEx = $2.5 MM
  - IP = 700 BOPD
  - EUR = 800 MBO
  - Water Cut = 66%
- Lease Operating Expenses:
  - Well Operations = $6.35/BO
  - Water Hauling = $3.00/BW ($6.00/BO)
  - Differential = -$2.50/BO
  - Flat Pricing Deck
    - Oil = $80/BO
    - Gas = $5.00/MCF
- 100% WI; 80% NRI

Economic Output

NPV = $1,314 MM
Pay Out = 1.07 years
ROR = 100+%
Gross EUR = 61.6 MMBOE

P/I = +9.76

NOTE: Slides 82, 85 and 89 were updated as of July 14, 2010

(1) All data shown is "unrisked," meaning that it is not discounted to reflect the risk of production impediments, unsuccessful development activity, permitting issues, cost increases and other potential problems. Our ability to achieve the results shown is subject to a wide variety of risks, as discussed in "Cautionary Statement Regarding Forward-Looking Information" and the "Risk Factors" section of our 2009 annual report on Form 10-K. See also "Net Asset Value & Unrisked Resource Estimates" and "Cautionary Statement Regarding Forward Looking Information." Type well assumes 100% WI and 80% NRI.
(2) Capital expenditures exclude costs such as capitalized G&A and land acquisition.

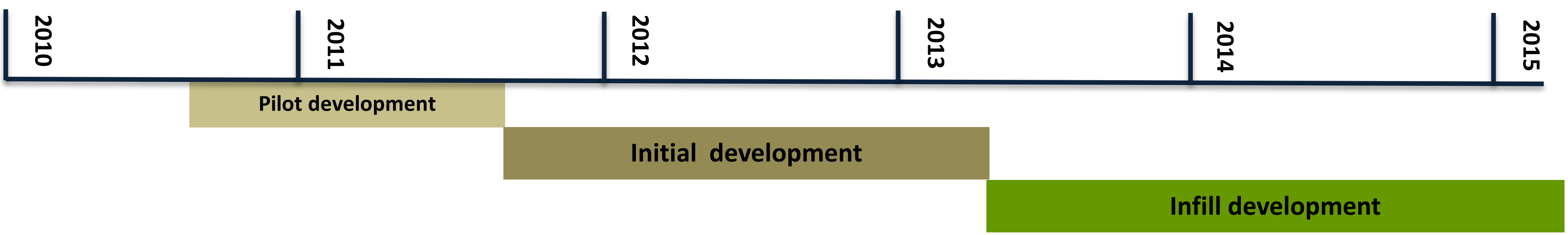
Infrastructure and Markets

- Extensive midstream and downstream network
- Access to multiple markets
- Strong profit margins
- New upstream facilities
  - Generic design
  - Modular, skid-mounted
  - Scalable

Monterey Capital Plan

	Activity	2010	2011	2012
Evaluation	Drilling	7 wells	8 wells	12 wells
	Seismic	Initiate 500 sq. mile joint VQ-OXY seismic acquisition	Complete joint seismic acquisition	
	Land	Lease 60,000 additional net acres	Lease150,000 additional net acres	
Development	Drilling	3 wells	22 wells	38 wells
Capital		$48 million	$120-140 million	$160-180 million

Projects A, B & C Timeline

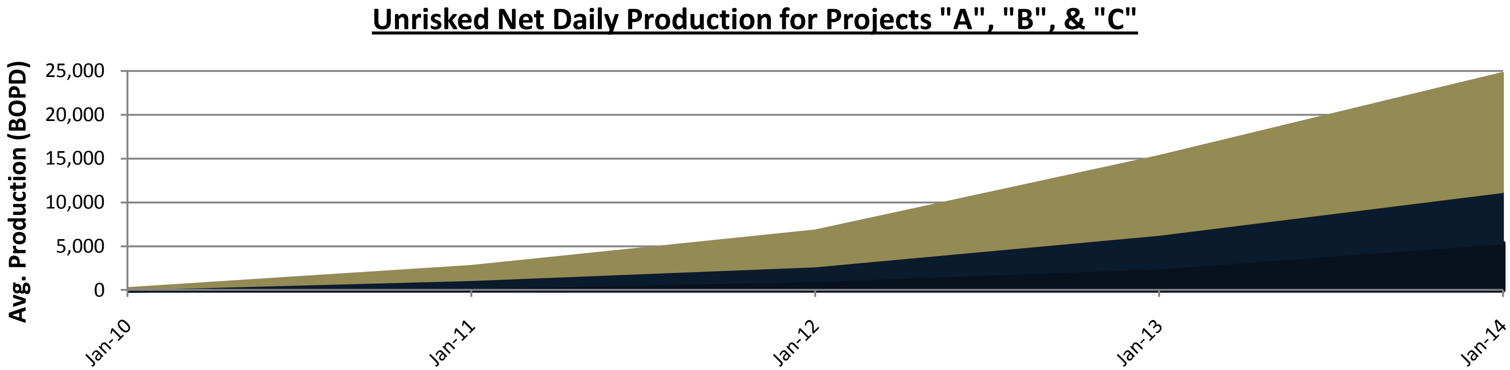


Project “A”, “B”, & “C” Unrisked Forecast[1]

Project "A", "B", & "C" 5 Year Unrisked Cash Flow ($M)

	2010	2011	2012	2013	2014
Total Wells Drilled per Year	3	10	24	48	64
Cumulative wells	**3**	**13**	**37**	**85**	**149**
Total Gross Production (MBOE)	126	1,601	3,979	8,924	14,308
Total Net Production (MBOE)	100	1,281	3,184	7,139	11,447
Net Daily net production (BOE/d)	**275**	**3,509**	**8,722**	**19,560**	**31,360**
Net revenue	6,741	85,808	212,415	477,288	768,890
Lease operating expense	(1,291)	(17,403)	(44,987)	(102,024)	(171,783)
G&A burden	(354)	(4,509)	(11,156)	(25,111)	(40,680)
Severance / ad valorem taxes	(276)	(3,516)	(8,703)	(19,557)	(31,510)
Total Expenses	**(1,920)**	**(25,428)**	**(64,846)**	**(146,693)**	**(243,973)**
Net Operating Cash Flow	**4,821**	**60,380**	**147,569**	**330,596**	**524,916**
Cash taxes	0	0	(11,508)	(24,521)	(55,326)
Total Capital Expenditures[2]	**(8,000)**	**(27,500)**	**(66,000)**	**(148,000)**	**(168,000)**
Free cash flow	**$(3,179)**	**$32,880**	**$70,061**	**$158,074**	**$301,590**

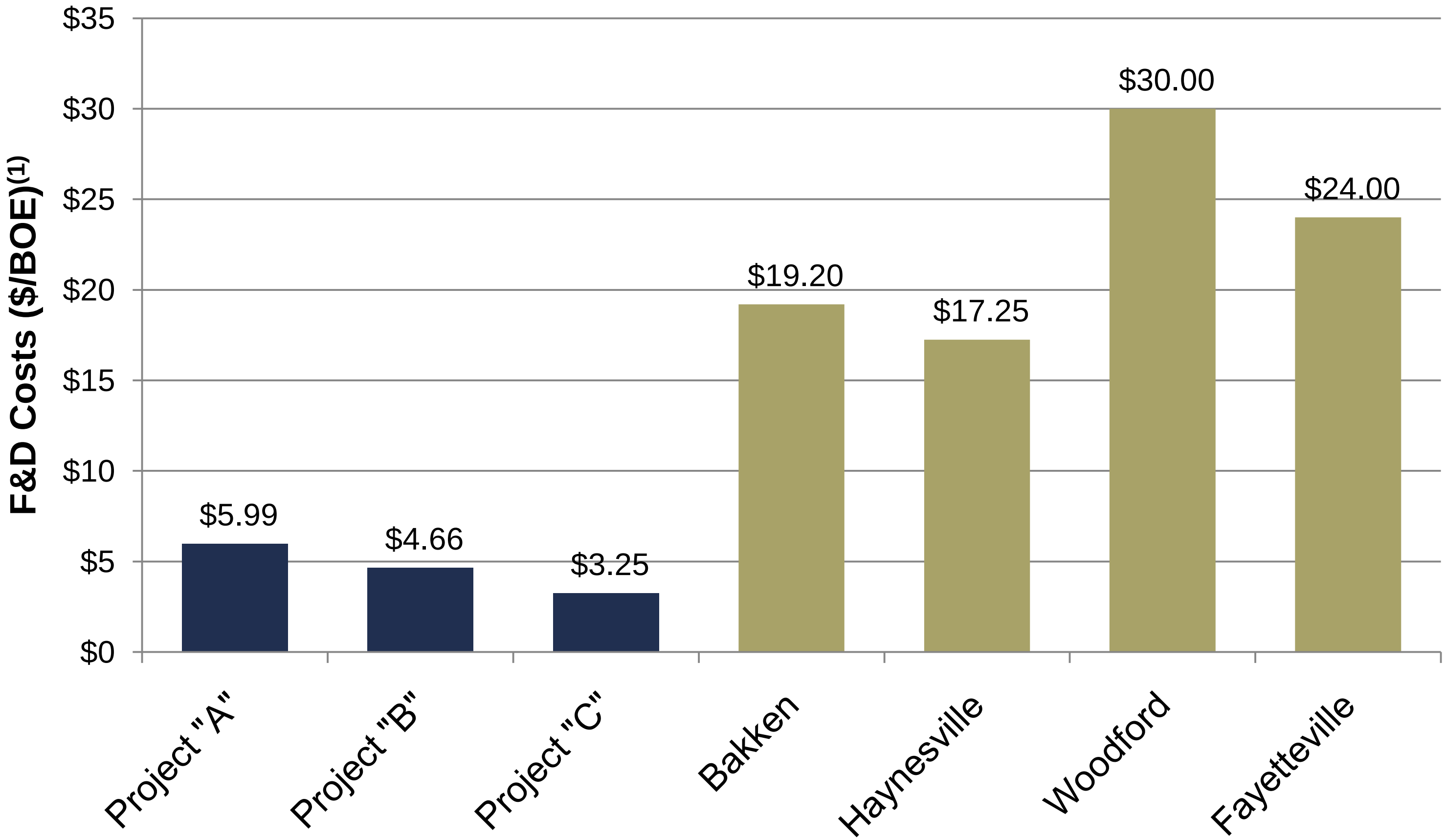
NOTE: Slides 82, 85 and 89 were updated as of July 14, 2010



(1) All data shown is “unrisked,” meaning that it is not discounted to reflect the risk of production impediments, unsuccessful development activity, permitting issues, cost increases and other potential problems. Our ability to achieve the results shown is subject to a wide variety of risks, as discussed in “Cautionary Statement Regarding Forward-Looking Information” and the “Risk Factors” section of our 2009 annual report on Form 10-K. See also “Net Asset Value & Unrisked Resource Estimates” and “Cautionary Statement Regarding Forward Looking Information.” Type wells assume 100% WI and 80% NRI.

(2) Capital expenditures exclude costs such as capitalized G&A and land acquisition.

Shale F&D Costs



(1) 15:1 BTU ratio used for BOE conversion based on current commodity pricing.
Source: Credit Suisse Natural Gas Sector Review: Examining the True Economic Cost of Shales (April 8, 2009) for estimates Haynesville, Woodford, and Fayetteville. Bakken estimates based on various industry sources. Monterey projects based on internal estimates. See also "Cautionary Statement Regarding Forward Looking Information."

Projects "A", "B", "C" Metrics

First 3 Monterey Projects Transitioned to Exploitation

- Productive Area: 29,400 acres
- Development Wells Required: 169
- Capital Investment: $498 million(1)
- Expected Ultimate Recovery: 117.2 MMBbls(2)
- Total F&D Cost: $4.25/bbl(2)
- NPV-10: $2,062 million(2)

(1) Estimated capital expenditures for full development of projects A, B, and C. (2) See "Net Asset Value & Unrisked Resource Estimates" and "Cautionary Statement Regarding Forward Looking Information."

Financial Summary & Wrap Up

Tim Marquez

Monterey 5-Year Forecast[1]

Unrisked Venoco Monterey Acreage Position 5-Year Cash Flows ($M)

	2010	2011	2012	2013	2014
Drilling					
Monterey "A-C"	3	10	24	48	64
Other Monterey	0	12	14	40	74
Evaluation Wells	7	8	12	12	12
Total Annual Wells Drilled	10	30	50	100	150
Cumulative wells	**10**	**40**	**90**	**190**	**340**
Net production (Mboe)					
Monterey "A-C"	100	1,281	3,184	7,139	11,447
Other Monterey	0	601	1,411	3,487	7,423
Evaluation Wells	0	0	0	0	0
Total Net Production (Mboe)	**100**	**1,881**	**4,595**	**10,626**	**18,869**
Total Net Daily production (Boe/d)	275	5,155	12,588	29,112	51,697
Net revenue	6,741	123,873	301,841	698,241	1,239,272
Lease operating expense	(1,291)	(25,677)	(64,762)	(151,135)	(276,482)
G&A burden	(354)	(6,417)	(15,638)	(36,186)	(64,260)
Severance / ad valorem taxes	(276)	(5,074)	(12,364)	(28,600)	(50,762)
Total Expenses	**(1,920)**	**(37,168)**	**(92,763)**	**(215,922)**	**(391,505)**
Net Operating Cash Flow	**4,821**	**86,705**	**209,078**	**482,319**	**847,767**
Cash Based Taxes	0	0	0	(13,677)	(41,175)
Capital expenditures					
Monterey "A"	0	(6,000)	(18,000)	(44,000)	(72,000)
Monterey "B"	(3,000)	(9,000)	(18,000)	(44,000)	(36,000)
Montetey "C"	(5,000)	(12,500)	(30,000)	(60,000)	(60,000)
Other Monterey	0	(38,250)	(45,500)	(145,000)	(270,500)
Evaluation Wells	(28,000)	(32,000)	(48,000)	(48,000)	(48,000)
Other[2]	(12,000)	(32,250)	(10,500)	(10,000)	(10,000)
Total Capital Expenditures	**(48,000)**	**(130,000)**	**(170,000)**	**(351,000)**	**(496,500)**
Free cash flow	**$ (43,179)**	**$ (43,295)**	**$ 39,078**	**$ 117,642**	**$ 310,093**

(1) All data shown is "unrisked," meaning that it is not discounted to reflect the risk of production impediments, unsuccessful development activity, permitting issues, cost increases and other potential problems. Our ability to achieve the results shown is subject to a wide variety of risks, as discussed in "Cautionary Statement Regarding Forward-Looking Information" and the "Risk Factors" section of our 2009 annual report on Form 10-K. Type wells assume 100% WI and 80% NRI.

(2) Land, G&G, and seismic capital expenditures.

Financing the Monterey

- Cash flow shortfall for first few years as we ramp up activity
- Will fund this shortfall through
  - Cash flow from other operations
  - Selective asset sales
  - Potential JVs within our Monterey portfolio
  - Capital markets

NOTE: Slides 82, 85 and 89 were updated as of July 14, 2010.

Monterey Net Asset Valuation (NAV)[1]

Area	Acreage	EUR	Well Count	Capital	NPV10	Discounted P/I
Project "A"	9,400	29.4 MMBO	56	$176 MM	$307 MM	+2.54
Project "B"	7,500	26.2 MMBO	38	$122 MM	$440 MM	+4.99
Project "C"	12,500	61.6 MMBO	76	$200 MM	$1,315 MM	+9.76
Other Monterey Projects	82,000	339 MMBO	800	$2,674 MM	$3,905 MM	+2.76
Total[2]	105,000	456 MMBO	1,090	$3,172 MM	$5,967 MM	+4.6

Net Asset Valuation assumptions[1]

- 100% WI; 80% NRI
- Gross EUR:
  - Project "A" = 525 MBO; IP = 350 BOPD; So = 25%
  - Project "B" = 750 MBO; IP = 500 BOPD; So = 40%
  - Project "C" = 800 MBO; IP = 700 BOPD; So = 33%
- Flat prices of $80.00 / BBO and $5.00 / MCF
- Per field differentials based on Buena Vista Benchmarks and inclusive of marketing expenses
- Severance / ad valorem taxes = 4.0%
- Capital Expenditures (D&C):
  - Project "A" & "B" = $3.0 MM
  - Project "C" = $2.5 MM
  - Other Project Areas = $3.25 MM
- Per Field LOE & Water Disposal Based off Nearby Data
- Does not include costs other than as described above (i.e., excludes costs such as G&A, land acquisition and interest expense).
- Unrisked Scenario based on P50 Probabilistic Volumetrics and Projected MY2010 Venoco Acreage Position

(1) Includes internal estimates of unrisked reserve potential. See "Net Asset Value & Unrisked Resource Estimates."
(2) Includes $204 MM to drill 51 evaluation wells from 2010-2014 (no production associated with test wells).

Potential Net Asset Value[1]

Total Proved Reserves per fully diluted share[6] = $16.99

Commodity Price Assumption: 5-Year Strip as of 12/31/09[2]

		PV-10[3] / NAV ($MM)	Risk Factor[8]	Risked Value[8]
Proved Reserves[3]	**101.3 MMBOE**	**$1,670**	100%	**$1,670**
Probable Reserves[4]				
Southern California (excluding South Ellwood)	5.5 MMBOE	$133	80%	$107
South Ellwood	14.6 MMBOE	$270	90%	$243
Sacramento Basin	5.4 MMBOE	$33	100%	$33
West Hastings - CO2 Flood (3rd Party Reserves - Phases 1-4)	17.7 MMBOE	$225	50%	$113
Additional Unrisked Resources[4]				
West Montalvo Development	11.0 MMBOE	$166	40%	$67
Sac Basin 20-acre Infill Drilling / Frac / Recompletions	46.0 MMBOE	$436	70%	$305
Sac Basin 10-acre Infill Drilling	39.2 MMBOE	$211	70%	$148
Hastings - CO2 Flood (East Hastings & Addt'l Upside on Phases 1-4)	11.5 MMBOE	$257	10%	$26
Onshore Monterey Shale[9]	456.0 MMBOE	$5,967	30%	$1,790
Potential Asset Value[5]	**708.3 MMBOE**	**$9,369**		**$4,501**
	(as of 3/31/10)			
	Total Debt	**($715.2)**		**($715.2)**
	Cash	**$0.6**		**$0.6**
	Net Debt	**($714.6)**		**($714.6)**
	Fair Value of Commodity Derivatives	**$54.7**		**$54.7**
	Fair Value of Interest Rate Derivative	**($31.4)**		**($31.4)**
	Net Balance Sheet Items	**($691.3)**		**($691.3)**
	Fully Diluted Shares Outstanding[6]	**57.61**		**57.61**
	Total Potential Asset Value per fully diluted share[7]	**$150.63**		**$66.13**

(1) Does not include estimates of final proceeds from Texas asset sale. (2) On 12/31/09, the 5-year strip averaged $87.04/Bbl and $6.43/Mcf, ranging from an average of $81.16/Bbl and $5.79/Mcf in 2010 to $91.09/Bbl and $6.84/Mcf in 2014. Average 2014 prices were used for future years. (3) See Appendix for a definition of PV-10 and the relevant GAAP reconciliation. (4) See "Net Asset Value & Unrisked Resource Estimates." (5) Amounts other than 12/31/09 PV-10 values of proved and probable reserves at 5-year strip pricing are based on internal estimates of unrisked reserve potential. See "Net Asset Value & Unrisked Resource Estimates." (6) Common stock equivalents do not assume application of treasury stock method. (7) Potential Net Asset Value or Proved Reserves less net debt and the estimated fair value of interest rate and commodity derivatives included in the balance sheet at 3/31/10. NAV per share based on shares outstanding and common stock equivalents at 3/31/10. (8) Risk factor figures are intended to be illustrative of internal estimates of the relative riskiness of the company's projects, but do not purport to reflect all risks associated with the development of the projects , production of the associated oil and natural gas or receipt of proceeds therefrom. For example, the risk factor of 100% for the company's proved reserves is intended to show that the development of those reserves is expected to be less subject to risk than the other projects described, not that there are no risks associated with that development. See "Cautionary Statement Regarding Forward Looking Information." Similarly, risked value figures do not purport to represent the fair market value of the projects shown for reasons described in "Net Asset Value & Unrisked Resource Estimates."

(9) NAV at flat $80 oil and $5 natural gas prices. Assumes approximately 1,000 wells with estimated per well recovery of approximately 400 MBbls. See Monterey development and economic assumptions outlined within the "Operations & Development" and "Financial Summary" sections of this presentation. Exploitation & development contemplates an evaluation drilling program to help understand the potential on the company's acreage and determine what development plans may be economic. The number of locations makes assumptions about the proportion of the acreage which may meet our economic criteria. The actual development plan could vary significantly from our estimates in terms of timing, cost and extent of activity and results obtained.

Wrap up slide

- Monterey Shale – Billion barrel opportunity
  - Most prolific/valuable shale play in U.S.
- Venoco – highly levered to Monterey
  - 60% of current oil production from Monterey
  - 13 years building operational expertise in the Monterey
- Exceptional Monterey acreage position
  - 5 years identifying and leasing onshore Monterey acreage
- Estimated Monterey production approaching 40,000 BOE/d in 2014
- Attractive F&D estimates - single digits

APPENDIX

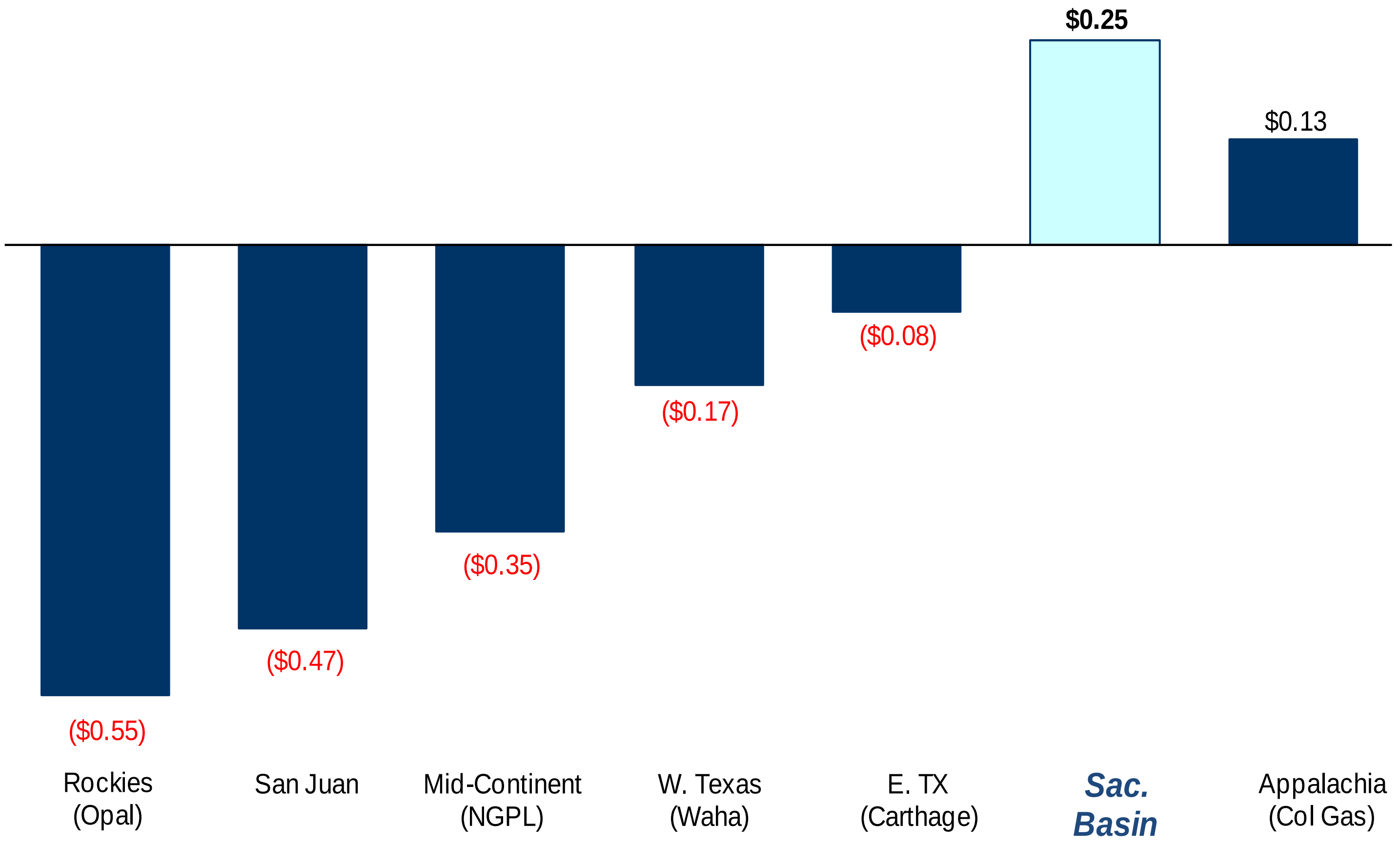
2010 Projections @ Various Commodity Prices

		Average Commodity Price for Remainder of Year ($ in Million)[1]			
Price - Oil/Gas	Revised Guidance[6]	$65/$4.00	$75/$4.50	$85/$5.00	$95/$5.50
O/G revenue (unhedged)	19,250 BOE/d	$277.7	$306.3	$335.0	$363.7
Hedging effect [2]		41.4	30.6	19.1	(3.1)
Net O/G revenues		319.1	336.9	354.1	360.6
LOE	$14.50/BOE	(101.9)	(101.9)	(101.9)	(101.9)
Production & property taxes	$1.65/BOE	(11.6)	(11.6)	(11.6)	(11.6)
G&A[3]	$4.50/BOE	(31.6)	(31.6)	(31.6)	(31.6)
Other[4]		(3.7)	(3.7)	(3.7)	(3.7)
Adjusted EBITDA[5]		$170.3	$188.1	$205.3	$211.8
Cash interest and realized interest rate derivative gain/(loss)		(56.8)	(56.6)	(56.5)	(56.4)
Amortization of deferred loan costs and commodity derivative premiums		(24.6)	(24.6)	(24.6)	(24.6)
DD&A	$12.00/BOE	(84.3)	(84.3)	(84.3)	(84.3)

(1) Projections include actual first quarter results.
(2) Estimated realized hedge gains/losses.
(3) Excludes non-cash stock-based compensation charges under FAS 123R.
(4) Includes other revenue and transportation expense.
(5) Net income in 2010 will be affected by certain items, such as interest expenses, that are excluded from our definition of Adjusted EBITDA. Further, net income in some prior periods has been significantly affected by price-related items excluded from our definition of Adjusted EBITDA such as unrealized commodity derivative gains and losses and impairment charges, and such items may also affect our 2010 net income. See Appendix for a definition of Adjusted EBITDA and related disclosure.
(6) Subject to completion of Texas Assets sales.

Sac Basin: Superior Realizations Enhance Economics

Natural Gas Basis Differentials ($ per MMBtu)
Based on $4.27 per MMBtu Henry Hub Average May, 2010 price



Source: NGI Bidweek Survey – May 2010.

Historical Operating Data

	Years Ended December 31					Three Months Ended March 31,
	2005	2006	2007	2008	2009	2010
Production (BOE/d)	11,555	15,882	19,535	21,674	20,622	19,384
Oil component	70%	59%	56%	52%	45%	45%
Oil & Gas Sales ($000)	$191,772	$268,822	$373,155	$555,917	$268,865	$82,501
LOE per BOE	$12.44	$14.18	$15.05	$16.86	$12.65	$11.95
Production & Property Taxes per BOE	$0.37	$0.91	$1.69	$1.98	$1.35	$1.27
G&A per BOE	$3.79	$4.88	$4.46	$5.43	$4.91	$5.39
Interest Expense per BOE (2)	$3.66	$9.09	$9.00	$8.52	$8.28	$8.78
Adjusted EBITDA (1) ($000)	$100,455	$146,173	$210,397	$299,810	$192,863	$53,181
Realized Prices per Unit:						
Oil, Excl Hedges (BBL)	$45.66	$55.92	$64.06	$89.69	$51.10	$69.29
Gas, Excl Hedges (MCF)	$7.45	$6.04	$6.61	$8.21	$3.84	$5.34
Blended, Excl Hedges (BOE)	$45.47	$46.37	$52.34	$70.08	$35.72	$47.28
Blended, Excl Hedges (Mcfe)	$7.58	$7.73	$8.72	$11.68	$5.95	$7.88

(1) See Appendix for reconciliation of Adjusted EBITDA to net income (loss). (2) Includes interest expense, realized (gain) loss on interest rate swap and amortization of deferred loan costs.

Derivative Transactions

Current Crude Oil Deliveries for Production	Floor BBLs/Day	Floor Weighted Avg Prices	Cap BBLs/Day	Cap Weighted Avg Prices
May 1 - Dec 31, 2010	8,000	$ 56.22	6,150	$ 83.32
Jan 1 - Dec 31, 2011	7,000	$ 50.00	5,000	$ 140.40
Jan 1 - Dec 31, 2012	3,000	$ 60.00	3,000	$ 121.10

Current Natural Gas Deliveries for Production	Floor MMBtu/Day	Floor Weighted Avg Prices	Cap MMBtu/Day	Cap Weighted Avg Prices
May 1 - Dec 31, 2010	58,900	$ 6.48	27,900	$ 7.25
Jan 1 - Dec 31, 2011	60,000	$ 6.31	12,000	$ 7.65
Jan 1 - Dec 31, 2012	37,300	$ 6.16		

Note: Hedges are based on NYMEX WTI (oil) and NYMEX Henry Hub (natural gas). Natural gas prices above reflect our use of basis swaps to fix the differential between the NYMEX Henry Hub price and the PG&E Citigate price on a portion of our expected production. Positions shown are as of May 1, 2010.

Net Asset Value & Unrisked Resource Estimates

References in this presentation to Asset Value or Net Asset Value (NAV) reflect the present value of estimated future revenues to be generated from the production associated with the asset or project in question, net of estimated production and future development costs and future plugging and abandonment costs, using indicated prices and costs without future escalation, and without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion, amortization and impairment and income taxes, and discounted using an annual discount rate of 10%.

While we believe that our NAV estimates are illustrative of the potential value of the projects and assets described, they do not purport to represent current or future market values of those assets or projects. The factors that could cause our estimates of NAV to be higher than market values include the following:

-- the NAV estimates are "unrisked," while estimates of current market value would take production, geologic and other risks into account, especially in the case of estimates that relate to existing or potential resources that do not meet the definition of proved reserves. See "Unrisked Resource Estimates" below and "Cautionary Statement Regarding Forward-Looking Information."

-- the NAV estimates assume that the development activities in question commence or have commenced as of the date of the estimate. In fact, many of these activities will not be commenced until some time in the future. Estimates of current market value would take this into account.

-- as noted above, the NAV estimates use indicated oil and natural gas prices and do not take into account our hedging activities; our actual future cash flows will be affected by subsequent changes in oil and natural gas prices and by our hedging activities.

Unrisked Resource Estimates

Included in this presentation are certain internal estimates of potential reserves we may develop in the future that are "unrisked," meaning that they are not discounted to reflect the risk of production impediments, unsuccessful development activity, permitting issues, cost increases and other potential problems. Our ability to obtain these potential reserves, and to produce the associated oil and natural gas, is subject to a wide variety of risks, as discussed in "Cautionary Statement Regarding Forward-Looking Information" and the "Risk Factors" section of our 2009 annual report on Form 10-K. Unrisked estimates of potential reserves are significantly more uncertain than estimates of proved reserves.

Probable Reserves

References in this presentation to probable reserves refer to third-party estimates prepared in accordance with the Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists and the Society of Petroleum Evaluation Engineers. Such estimates may not be identical to estimates prepared in accordance with the new SEC rules.

GAAP Reconciliations – Adjusted EBITDA

We use Adjusted EBITDA, as a supplemental measure of our performance that is not required by, or presented in accordance with, GAAP. We define Adjusted EBITDA as net income (loss) before the effect of the items below. We present Adjusted EBITDA because we consider it to be an important supplemental measure of our performance. Because the use of Adjusted EBITDA facilitates comparisons of our historical operating performance on a more consistent basis, we use this measure for business planning and analysis purposes, in assessing acquisition opportunities and in determining how potential external financing sources are likely to evaluate our business.

Adjusted EBITDA is not a measurement of our financial performance under GAAP and should not be considered as an alternative to net income (loss), operating income or any other performance measure derived in accordance with GAAP, as an alternative to cash flow from operating activities or as a measure of our liquidity. You should not assume that the Adjusted EBITDA amounts shown are comparable to Adjusted EBITDA or similarly named measures disclosed by other companies. In evaluating Adjusted EBITDA, you should be aware that it excludes expenses that we will incur in the future on a recurring basis. We compensate for these limitations by relying primarily on our GAAP results and using Adjusted EBITDA only on a supplemental basis.

(in thousands)	2005	2006	2007	2008	2009	Three Months Ended 3/31/10
Net Income (Loss)	$ 16,110	$ 23,951	$ (73,372)	$ (391,132)	$ (47,298)	$ 43,988
Interest, Net	13,673	48,795	60,115	54,049	40,984	10,124
Realized Interest Rate Derivative (Gains) Losses	-	96	(135)	10,231	18,479	4,509
Income Taxes	10,300	15,650	(46,200)	11,200	(14,400)	(200)
Amortization of Deferred Loan Costs	1,755	3,776	4,197	3,344	2,862	677
DD&A	21,680	63,259	98,814	134,483	86,226	19,974
Accretion of Asset Retirement Obligation	1,752	2,542	3,914	4,203	5,765	1,585
Ceiling Test Impairment	-	-	-	641,000	-	-
Loss on Extinguishment of Debt	-	-	12,063	-	8,493	-
Share-based Payments	-	3,050	3,278	3,064	2,824	1,323
Amortization of Derivative Premiums and Other Comprehensive Loss	4,701	8,181	11,546	7,694	24,985	5,657
Unrealized Commodity Derivative (Gains) Losses	32,236	(21,079)	122,779	(184,459)	71,511	(39,471)
Unrealized Interest Rate Derivative (Gains) Losses	-	494	17,312	10,336	(1,803)	5,015
Adjusted EBITDA	$ 102,207	$ 148,715	$ 214,311	$ 304,013	$ 198,628	$ 53,181

GAAP Reconciliations

Present Value of future net cash flows

The present value of future net cash flows (PV-10) is a non-GAAP measure because it excludes income tax effects. Management believes that before-tax cash flow amounts are useful for evaluative purposes since future income taxes, which are affected by a company's unique tax position and strategies, can make after-tax amounts less comparable. We derive PV-10 based on the present value of estimated future revenues to be generated from the production of proved reserves, net of estimated production and future development costs and future plugging and abandonment costs, using prices and costs as of the date of estimate without future escalation, without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion, amortization and impairment and income taxes, and discounted using an annual discount rate of 10%. Management also believes that the PV-10 based on the NYMEX 5-year strip pricing is useful for evaluative purposes since the use of a strip price provides a measure based on current market perception. The following table reconciles the standardized measure of future net cash flows to PV-10 (in thousands):

	December 31, 2009
Standardized measure of discounted future net cash flows	$ 692,805
Add: Present value of future income tax discounted at 10%	108,248
PV-10 at year-end SEC prices	$ 801,053
Add: Effect of NYMEX 5-year strip at December 31, 2009	868,916
PV-10 at NYMEX 5-year strip at December 31, 2009	$ 1,669,969