VENOCO, INC.

3Q Update

November 2011

www.venocoinc.com

VQ LISTED NYSE

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, a potential inability to complete production sales and other transactions on the terms, and in the time periods, Venoco expects, 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, 2010, 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 full implementation of a CO2 flood and the production results and reserves of the flood as implemented. Forward looking statements made about the South Ellwood pipeline project are subject to risks and uncertainties relating to, among other things, the expected cost, completion date and price realizations when the project is completed. The Company's activities with respect to the Monterey shale are subject to numerous operating, geological and other risks and may not be successful. The Company's results in the onshore Monterey will be subject to greater risks than results in areas where it has more data and drilling experience. Results from the onshore Monterey project will depend on, among other things, the Company's 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 term discovery, as used in this presentation, refers to a petroleum accumulation or accumulations for which one or several exploratory wells have, in the company's judgment, established through testing, sampling and/or logging the existence of a significant quantity of potentially moveable hydrocarbons.

Company Overview

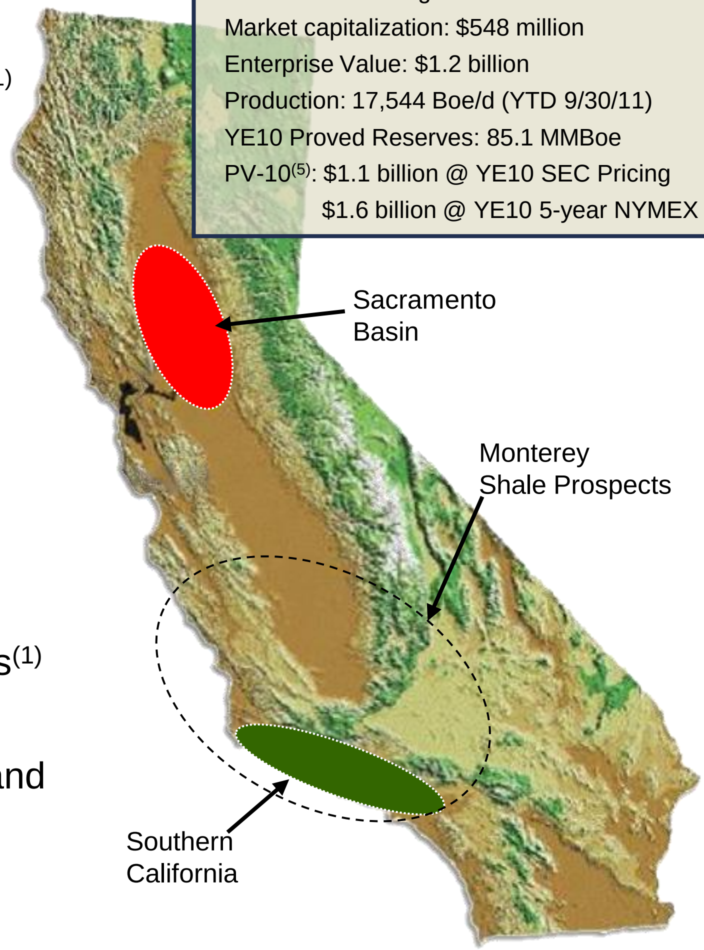
Sacramento Basin

- Natural gas assets
  - 47% of proved reserves(1)
  - 55% of production(2)
- Operate 2 of 3 largest natural gas fields in CA
- Hold ~265,000 gross / ~223,000 net acres(3)
- 2011: ~40 wells, 220 recompletions, 20 fracs

Southern California

- Oil focused assets
  - 53% of proved reserves(1)
  - 42% of production(2)
- South Ellwood, Sockeye and West Montalvo fields
- Numerous development opportunities

Share price: $8.90 (11/01/11)
Shares outstanding: 61.6 million
Market capitalization: $548 million
Enterprise Value: $1.2 billion
Production: 17,544 Boe/d (YTD 9/30/11)
YE10 Proved Reserves: 85.1 MMBoe
PV-10(5): $1.1 billion @ YE10 SEC Pricing
$1.6 billion @ YE10 5-year NYMEX Strip



Monterey Shale Prospects

- Began actively leasing Monterey shale formation properties in 2006
- Multi-year, multi-100 million barrel potential
- Hold ~312,000 gross / ~214,000 net acres(3)

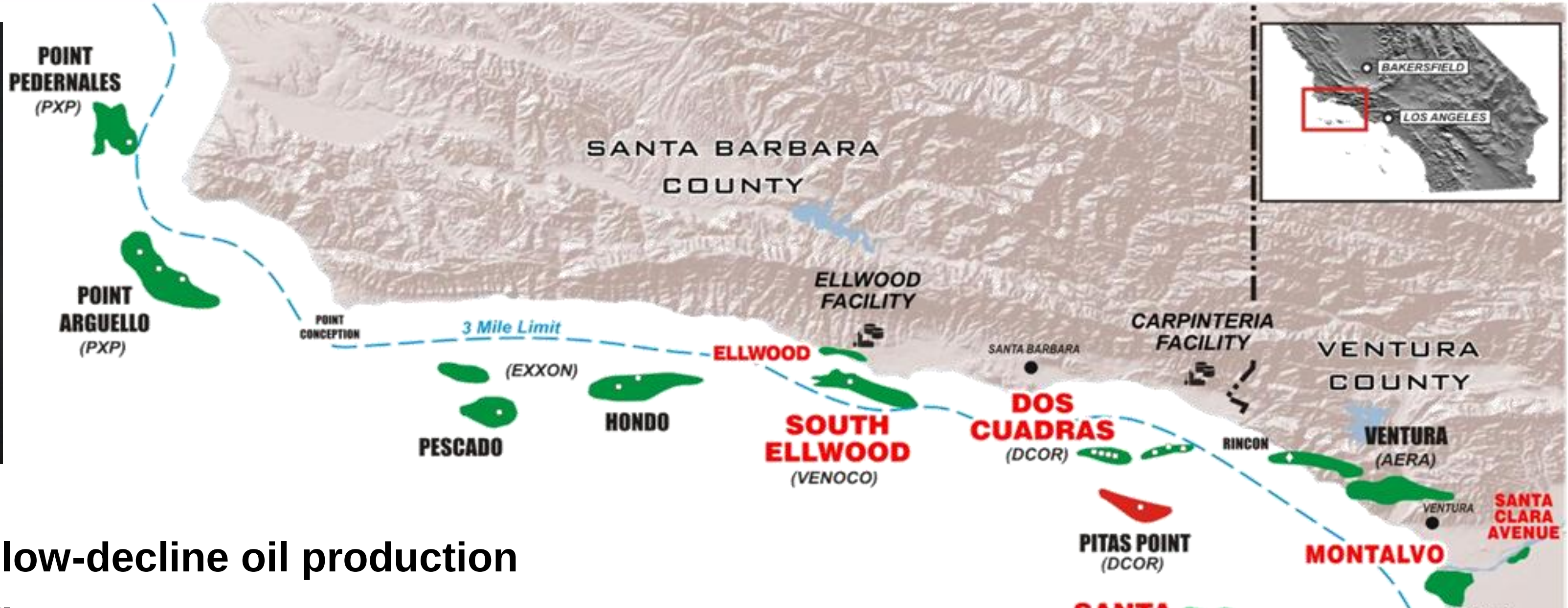
Hastings Field (Texas)

- Venoco retained 22.3% reversionary interest in CO_2 flood of the field
  - Denbury initiated CO_2 flood in Dec. 2010
- Venoco's net share of potential reserves estimated to be approximately 40 MMBoe with potential to begin booking proved reserves by mid-year 2012(4)

(1) Based on 2010 year end proved reserves.
(2) Based on 2010 production. Producing Texas properties, which were sold in a series of transactions during 2009 and 2010, represented ~3% of 2010 production.
(3) Sacramento Basin acreage position as of 12/31/10. Monterey shale acreage position as of 9/30/11 and includes 60,000 gross and 46,000 net acres with Monterey shale production or potential which are held by production at our legacy Southern California fields.
(4) Internal estimate of unrisked reserve potential. See "Net Asset Value & Unrisked Data" and "Cautionary Statement Regarding Forward Looking Information."
(5) See Appendix for a definition of PV-10 and the relevant GAAP reconciliation.

Properties Overview

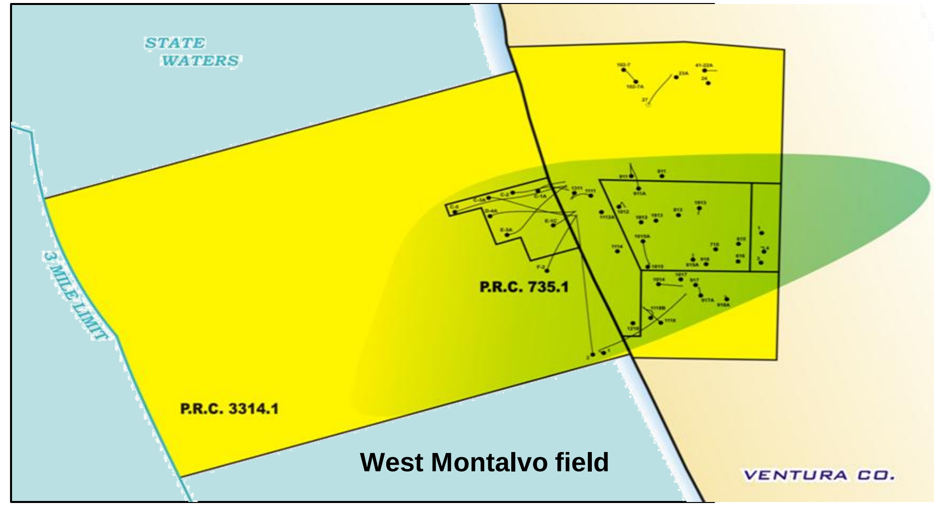
Legacy Southern California Assets



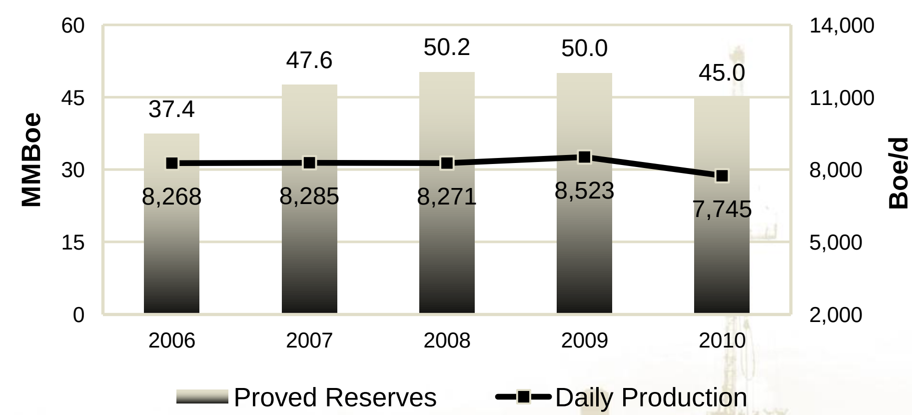
- **Long-lived, low-decline oil production**
- **Solid cash flow**
- **Monterey shale expertise – 14 years**
  - South Ellwood 1997
  - Sockeye 1999
- **Recognized by State and Federal regulators for safety & operating excellence**

Southern California Overview

- <u>California crude oil pricing tracking with BRENT</u>
  - 2011 company-wide ~$5 less than WTI (YTD)
  - 2012 company-wide expected to exceed WTI
- Low-decline oil fields
- Well-established production history
  - 53% of proved reserves(1)
  - 42% of production(2)
- Principal oil fields: ~85% of SoCal production
  - South Ellwood, Sockeye & West Montalvo
- 2011 capital program
  - South Ellwood – workovers & recompletions
  - Sockeye – 2 wells
  - West Montalvo – 6 wells, 5 recompletions
- South Ellwood pipeline: eliminates barging & expected to improve realizations ($5-7/bbl)
  - Under construction; completion in 1Q'12 subject to weather delays
  - Added 9 million BOE of proved reserves as of 9/30/11 at SEC pricing



Proved Reserves and Production



(1) Based on 2010 year end proved reserves.
(2) Based on 2010 production. Producing Texas properties, which were sold in a series of transactions during 2009 and 2010, represented ~3% of 2010 production.

Monterey Shale Activity

Venoco Areas of Operations

Business Strategy

- Maintain high operational control
- Continue to acquire prospective acreage

Acreage Strategy

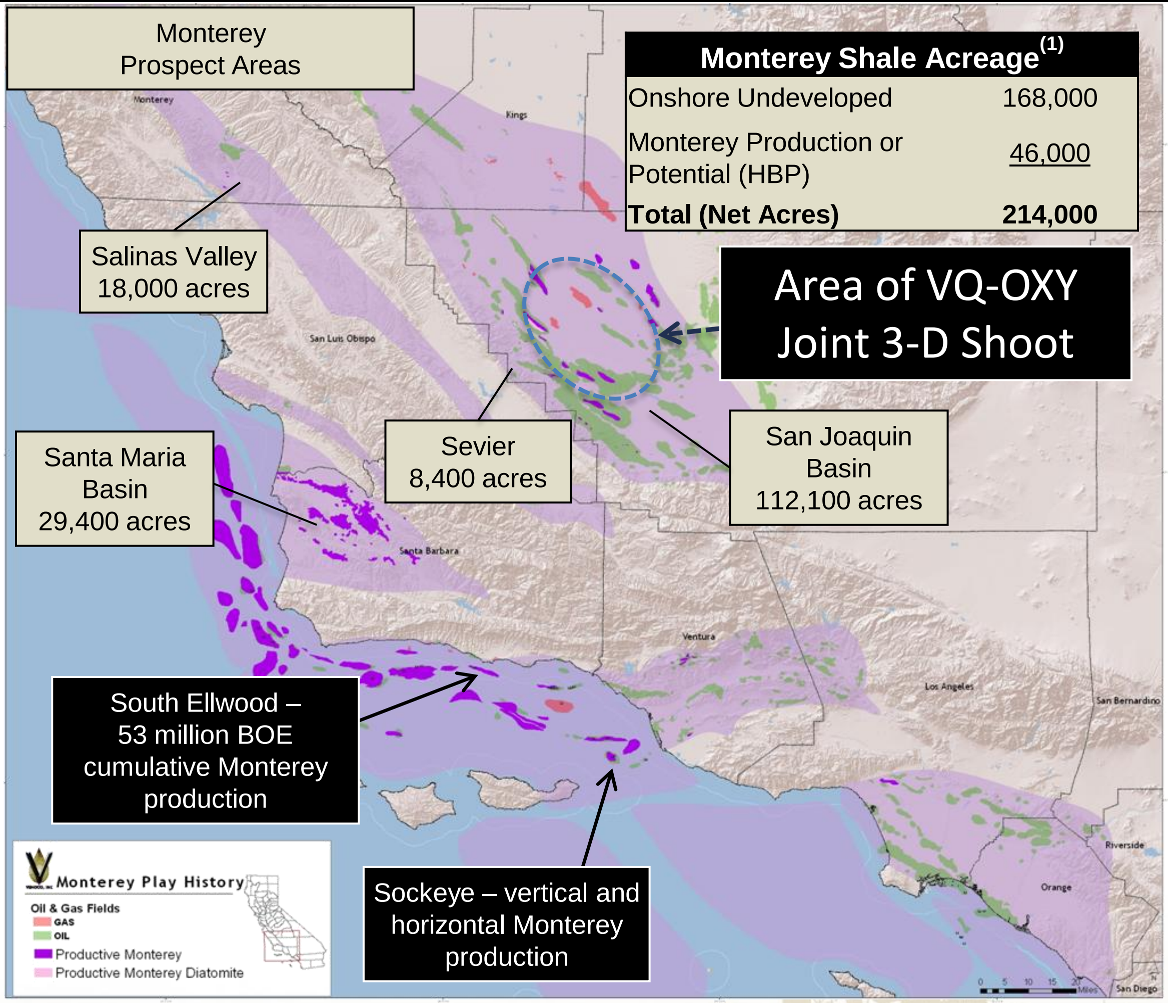
- Light Oil
- Structural features
- Natural fractures
- Moderate depths
- Favorable operating environment

2011 Capital Program

- $100 million budget
- ~15 gross wells planned
- Completed 3-D seismic shoot
- Increase net acreage position

Current Status

- Drilling 4th delineation well in Sevier
- Testing 3rd delineation well in Sevier
- 1st delineation well 30-day avg. 43 BOE(2)
- 2nd delineation well 26-day avg. 165 BOE(2)



Monterey Shale Acreage(1)	
Onshore Undeveloped	168,000
Monterey Production or Potential (HBP)	46,000
Total (Net Acres)	**214,000**

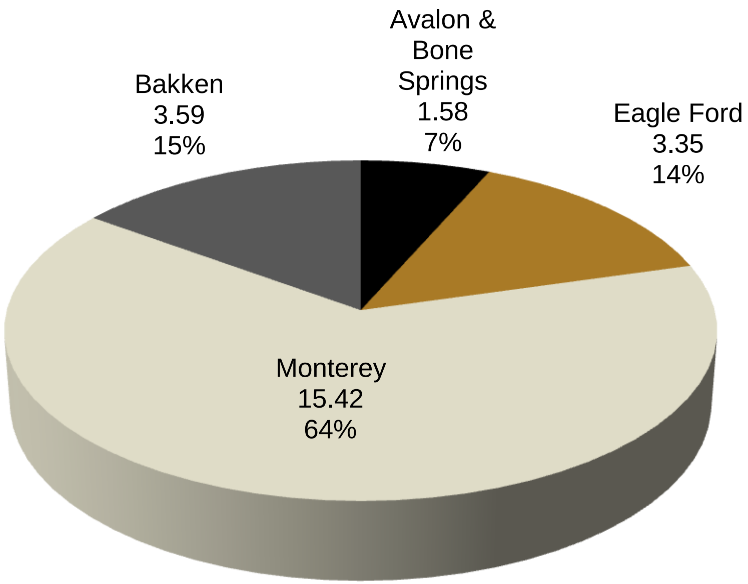
(1) Onshore undeveloped is as of 9/30/11. HBP acreage as of 12/31/10. (2) Production from one zone; additional zones to be tested.

EIA Assessment of Technically Recoverable Shale Oil Resources(1)

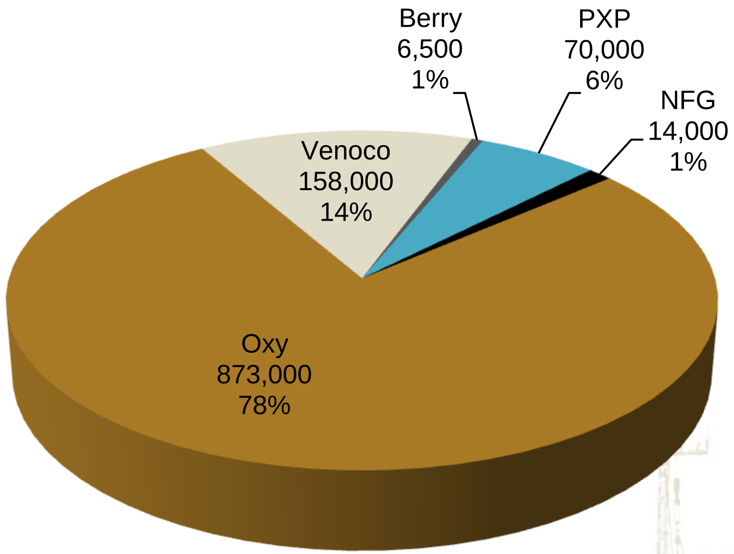
VII. West Coast Regional Summary *(excerpt from page 73 of review)*

The West Coast region includes shale oil plays in the San Joaquin and Los Angeles Basins (Figure 31). Located within these basins is the Monterey/Santos shale oil play with a total area estimated at 1,752 square miles. The reviewed play has an average EUR of 550 MBO per well and approximately 15.42 Bbbl of technically recoverable oil.

Technically Recoverable Resource 23.94 Billion Barrels by play



Monterey Area Reviewed = 1,752 sq. miles (1,121,500 acres) by company



(1) All data from U.S. Energy Information Administration, “Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays”, July 2011. http://www.eia.gov/analysis/studies/usshalegas/pdf/usshaleplays.pdf

(2) Venoco acreage is 214,000 net acres as of 9/30/11.

Monterey Geology – Basins

Sockeye
Total – 86 MMBO
Monterey – 17 MMBO

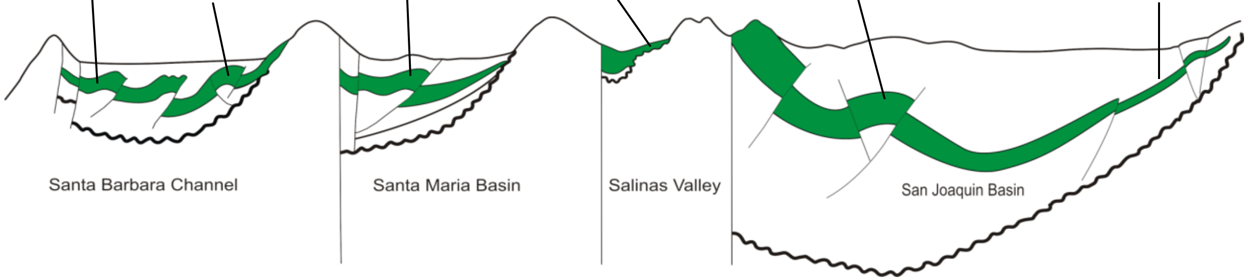
Orcutt
Total – 227 MMBO
Monterey – 175 MMBO

Elk Hills
Total – 1.4 BBO
Monterey – 86 MMBO

South Ellwood
Total – 120 MMBO
Monterey – 111 MMBO

San Ardo
550 MMBO(1) from Sandy Facies within Monterey

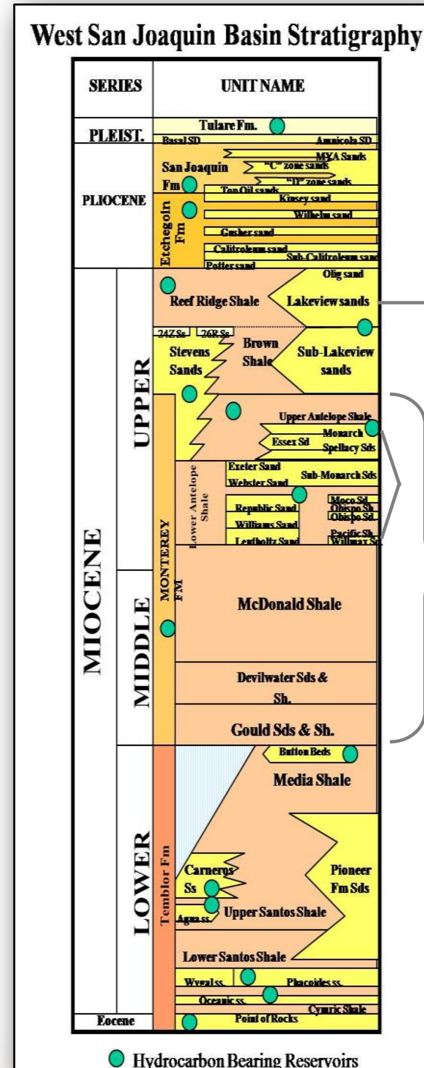
North Shafter
Total – 13 MMBO
100% Monterey



← 135 Miles →

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

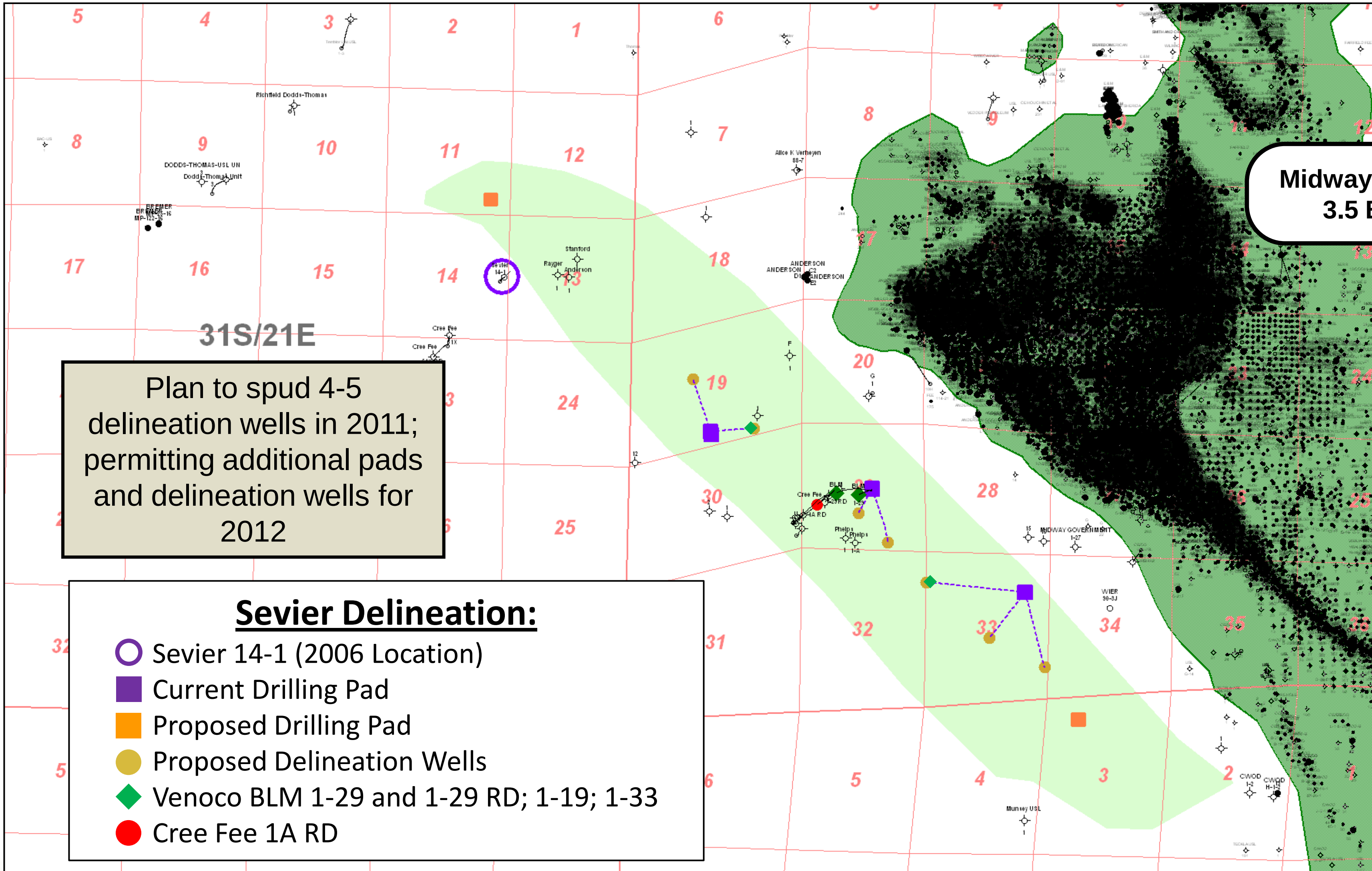
(1) Monterey production comingled with other reservoirs. Red text – Venoco fields.



Additional turbidite sand targets

Monterey section (500-3,000' thick)

Sevier Delineation



Plan to spud 4-5 delineation wells in 2011; permitting additional pads and delineation wells for 2012

Sevier Delineation:

- Sevier 14-1 (2006 Location)
- Current Drilling Pad
- Proposed Drilling Pad
- Proposed Delineation Wells
- Venoco BLM 1-29 and 1-29 RD; 1-19; 1-33
- Cree Fee 1A RD

Sevier – Type Curve & IRR Sensitivity(1)

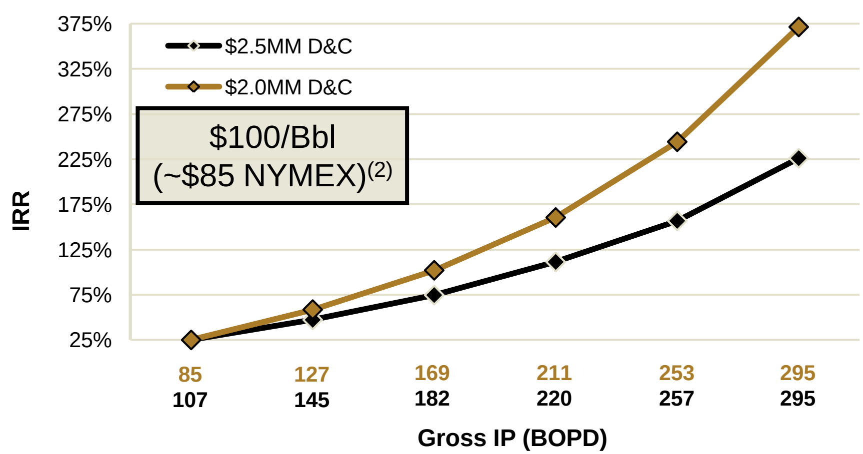
Status: Discovery announced

- Potential Original Oil in Place: 1.36 BBO
- Recovery Factor: 6.5%
- Potential Net Reserves: 70.3 MMBO
- Net Productive Acres: 6,000
- Development Well Count: 300
- Single Well Economics
  - Gross D&C Cost = $2.5 MM
  - EUR = 233 MBO (net)

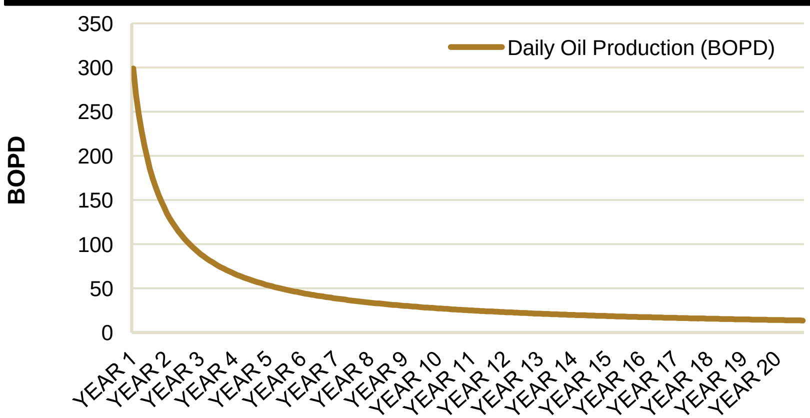
    IP = 295 BOPD
  - NPV-10 = $7.6 MM

    Flat Pricing: $100/BO and $4/MCF
  - ROR = >100%

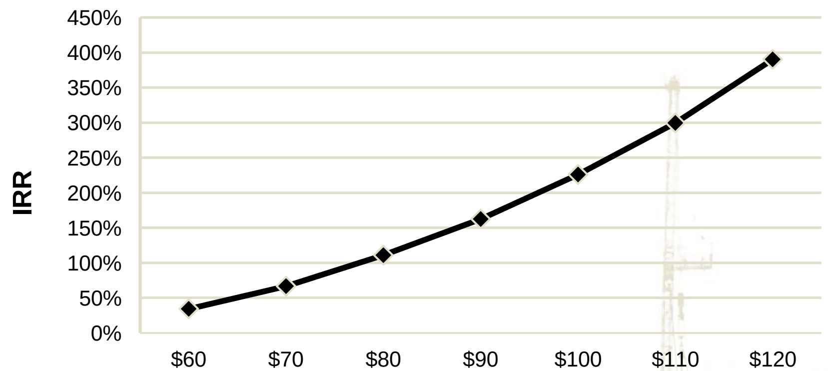
IRR Sensitivity to D&C and IP



Sevier Type Curve (Vertical)



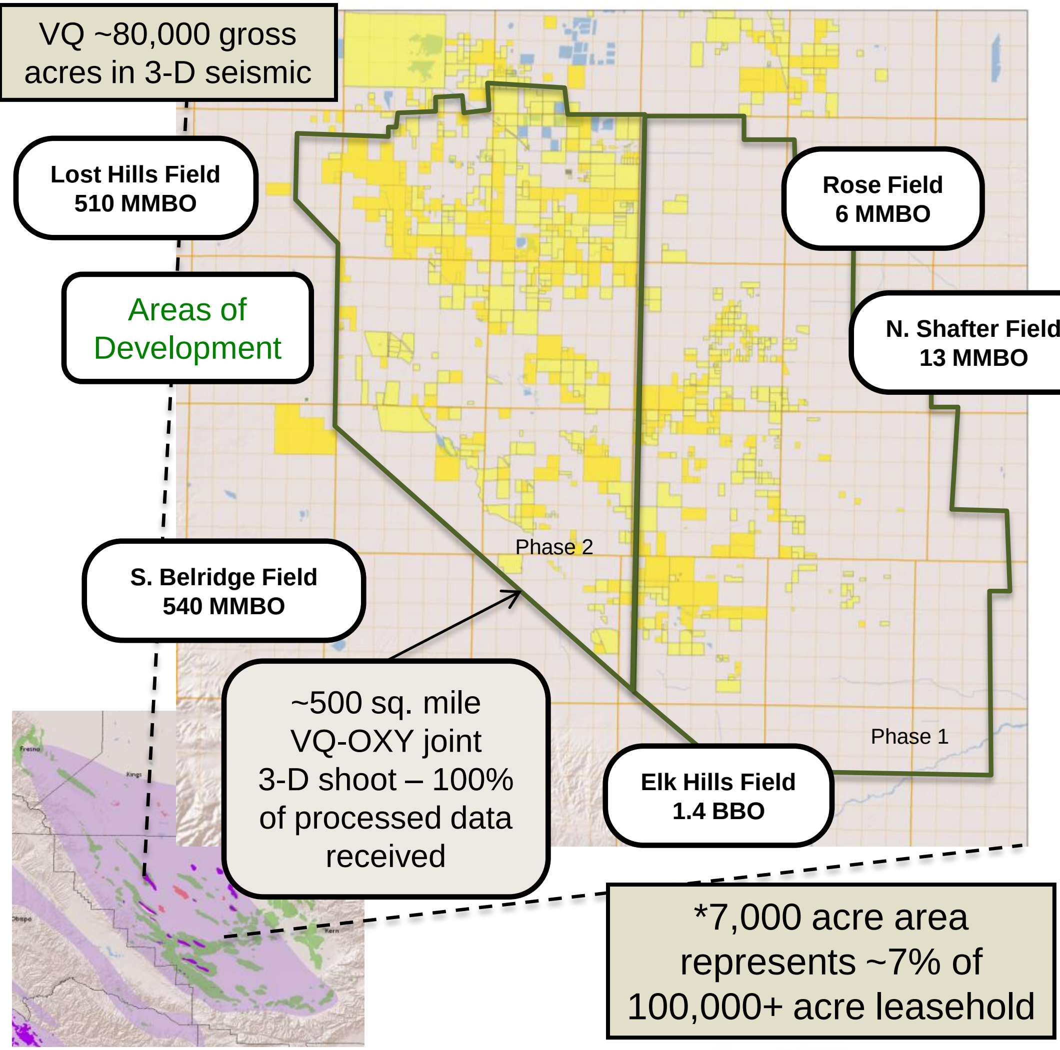
Type Curve IRR Sensitivity to Oil Price(2)



(1) All data reflects unrisked estimates that are generally based on deterministic volumetric calculations that utilize Venoco's and historical drilling results in a given area and represent our current understanding of the reservoir properties. The estimates reflect modeled data and not the results of wells drilled to date. Capital costs incurred for use in economics estimates include run-rate drilling and completion costs and facility investments, but exclude costs such as capitalized G&A, land acquisition, and permitting costs. See "Cautionary Statement Regarding Forward Looking Information" and "Net Asset Value & Unrisked Data."

(2) Net price received at field. During 2011, California postings have been at a premium to WTI.

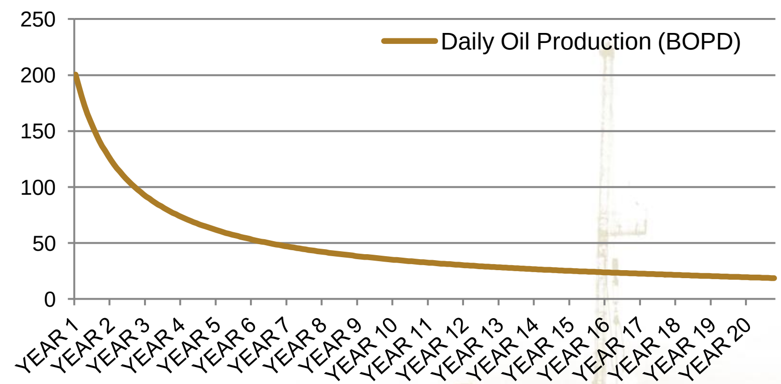
Greater San Joaquin



Status: Testing, drilling, evaluating[1]

- Potential Original Oil in Place:1.4 BBO
- Recovery Factor: 3.0%
- Potential Net Reserves: 33.8 MMBO
- Net Productive Acres: 7,000*
- Development Well Count: 140
- Single Well Economics
  - Gross D&C Cost = $2.5 MM
  - EUR = 240 MBO (net)
    IP = 200 BOPD
  - NPV-10 = $6.6 MM
    Flat Pricing: $100/BO (~$85 NYMEX)[2]
  - ROR = >100%

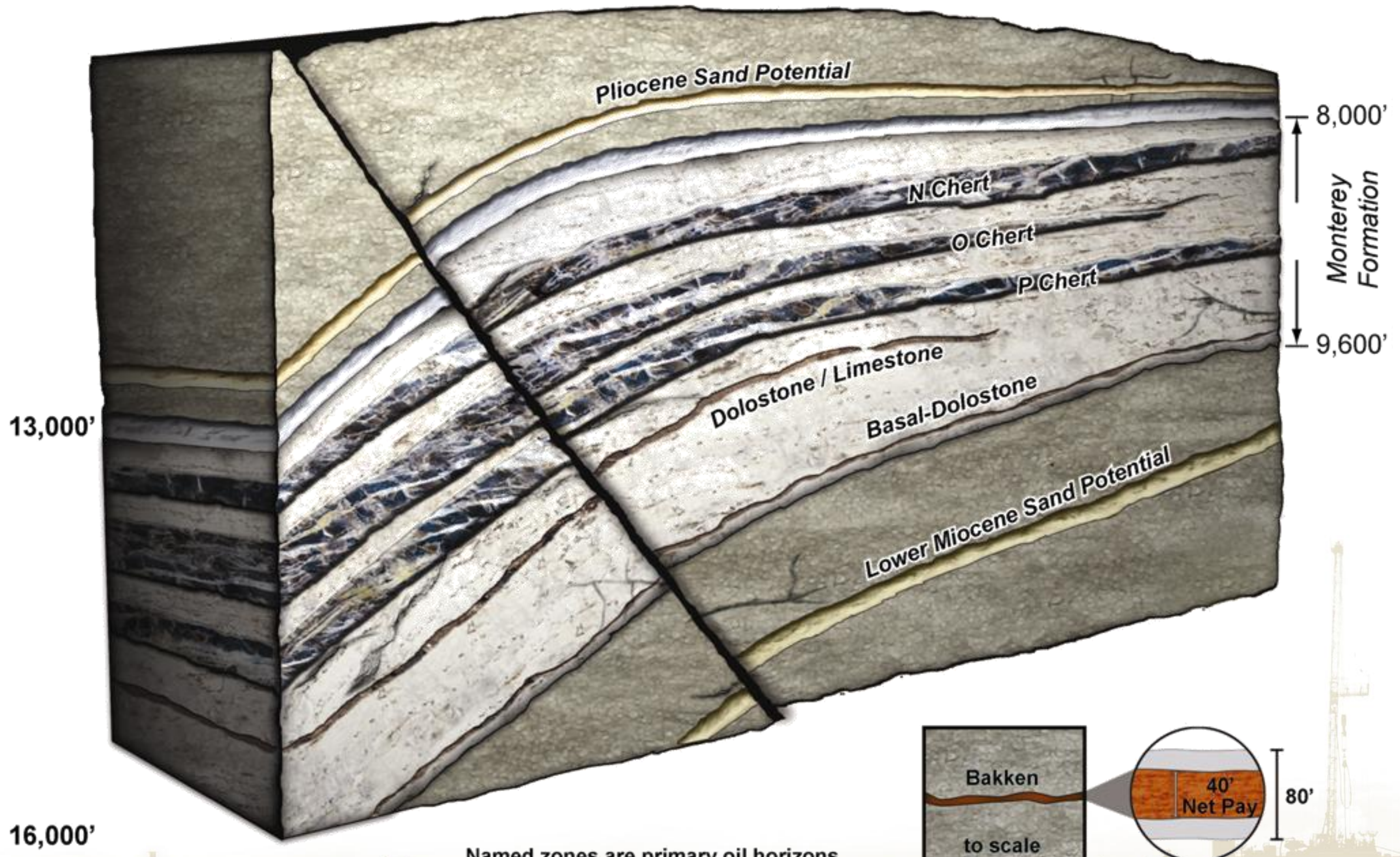
San Joaquin Decline Curve (Vertical)[1]



(1) All data reflects unrisked estimates that are generally based on deterministic volumetric calculations that utilize Venoco's and historical drilling results in a given area and represent our current understanding of the reservoir properties. The estimates reflect modeled data and not the results of wells drilled to date. Capital costs incurred for use in economics estimates include run-rate drilling and completion costs and facility investments, but exclude costs such as capitalized G&A, land acquisition, and permitting costs. See "Cautionary Statement Regarding Forward Looking Information" and "Net Asset Value & Unrisked Data."

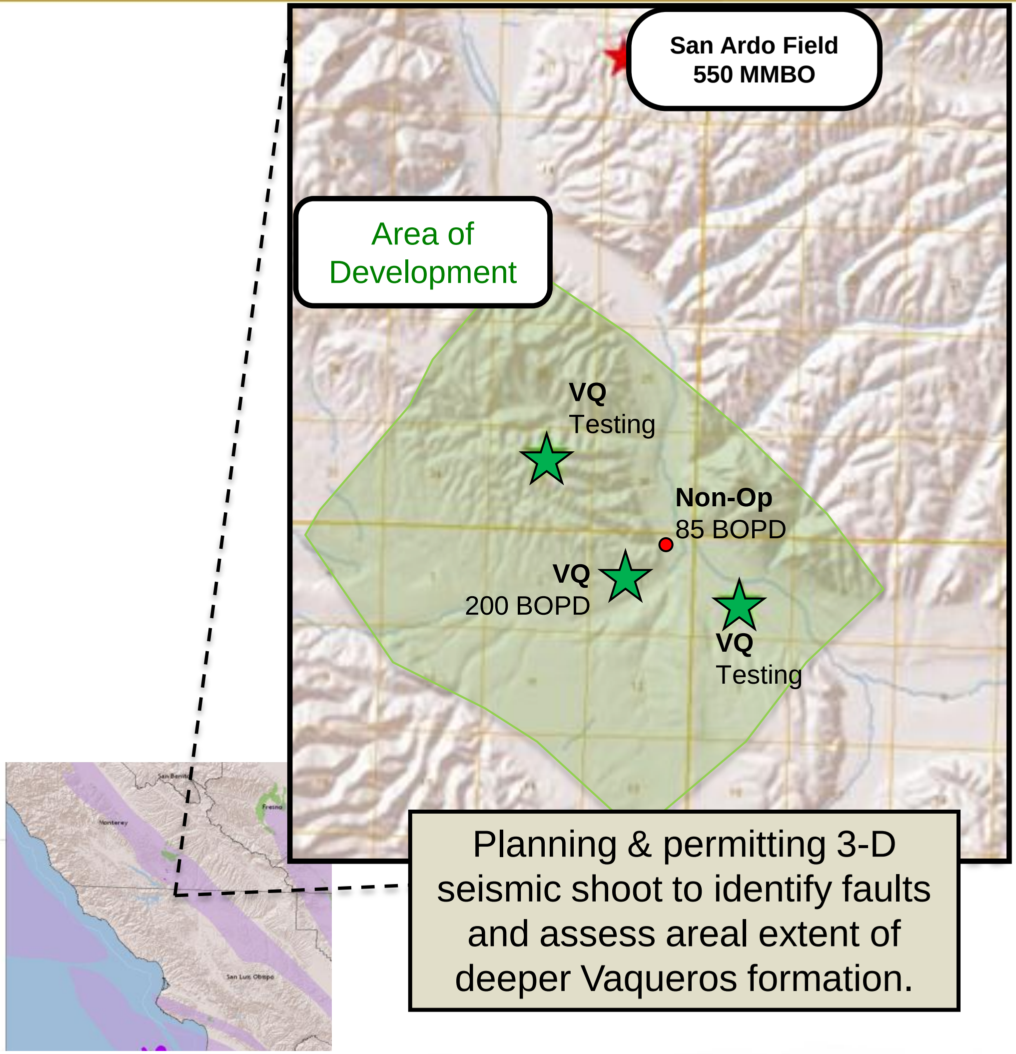
(2) Net price received at field. During 2011, California postings have been at a premium to WTI.

Greater San Joaquin



Named zones are primary oil horizons

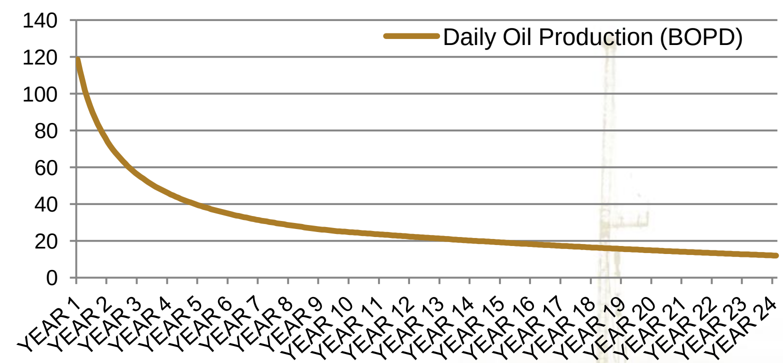
Salinas Valley



Status: Discovery announced(1)

- Potential Original Oil in Place: 1.1 BBO
- Recovery Factor: 4.0%
- Potential Net Reserves: 34.4 MMBO
- Net Productive Acres: 7,360
- Development Well Count: 184
- Single Well Economics
  - Gross D&C Cost = $2.7 MM
  - EUR = 187 MBO (net)
    IP = 120 BOPD
  - NPV-10 = $4.8 MM
    Flat Pricing: $100/BO (~$85 NYMEX)(2)
  - ROR = >75%

Salinas Decline Curve (Vertical)(1)



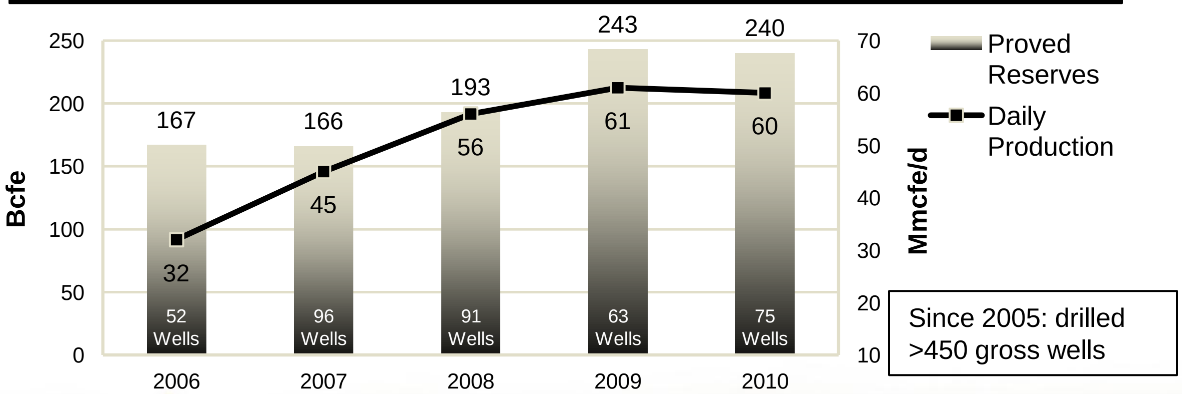
(1) All data reflects unrisked estimates that are generally based on deterministic volumetric calculations that utilize Venoco's and historical drilling results in a given area and represent our current understanding of the reservoir properties. The estimates reflect modeled data and not the results of wells drilled to date. Capital costs incurred for use in economics estimates include run-rate drilling and completion costs and facility investments, but exclude costs such as capitalized G&A, land acquisition, and permitting costs. See "Cautionary Statement Regarding Forward Looking Information" and "Net Asset Value & Unrisked Data." Production rates shown for individual wells reflect testing results not ongoing production.

(2) Net price received at field. During 2011, California postings have been at a premium to WTI.

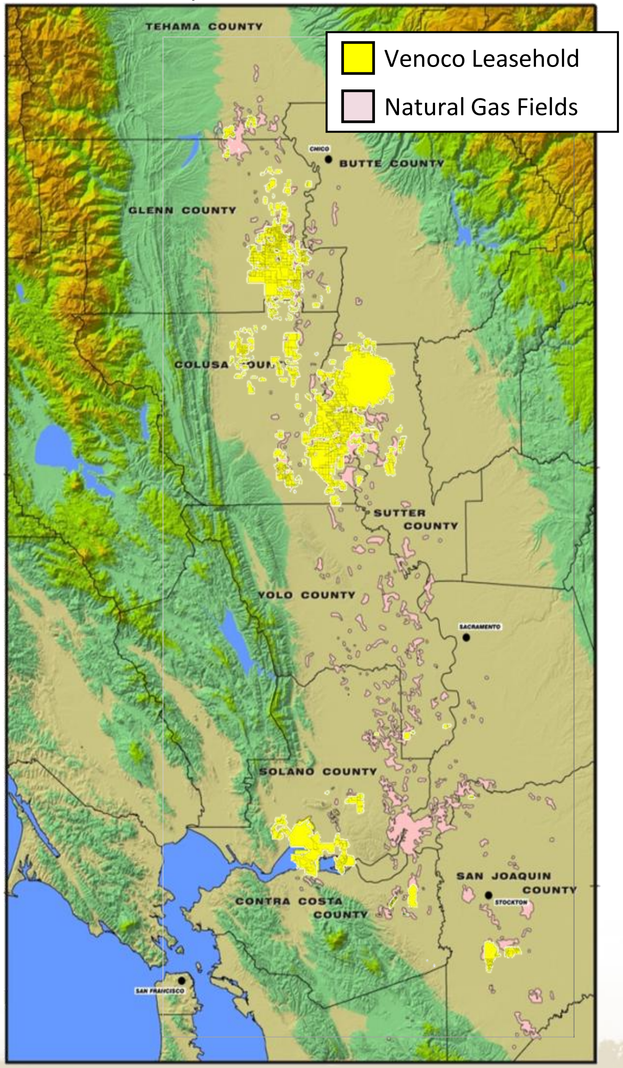
Sacramento Basin Overview

- Stable production – good economics – positive cash flow
- Drilled ~100 10-acre spaced wells; proving the tighter 10-acre concept
- 1,600+ infill drilling locations 10-acre or greater (Forbes Formation)
  - 457 booked locations (287 proved)
  - Reserve potential approximately 800 Bcf[2]
- Drilled 20+ Guinda formation wells
  - Willows resource potential ~600 Bcf[2]
  - Grimes resource potential ~260 Bcf[2]
- <u>Strategy at >$4.50/mcf</u>: ramp up drilling, activity & production

Proved Reserves and Production

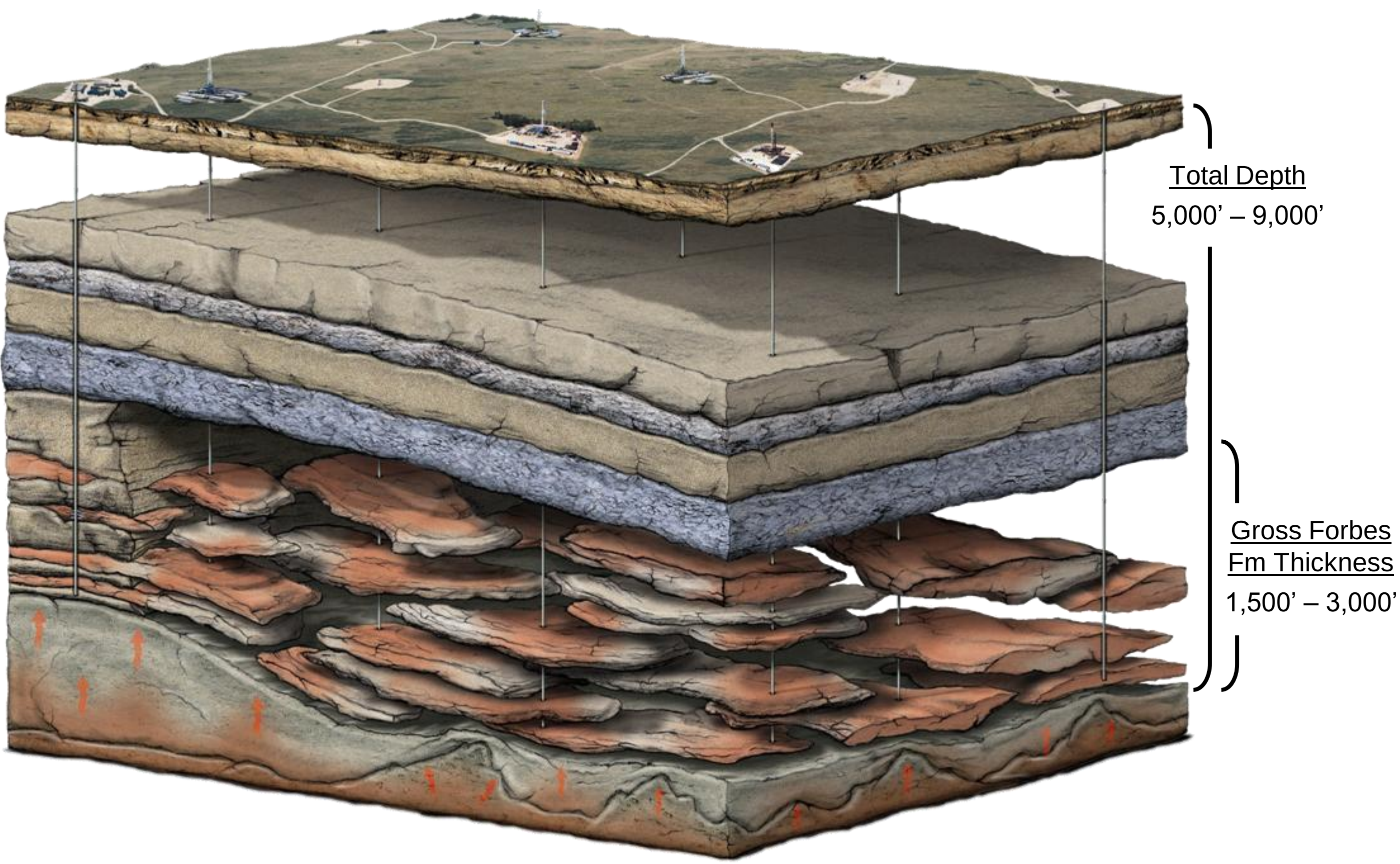


~223,000 net acres[1]



(1) Acreage position as of 12/31/10.
(2) Internal estimate of unrisked reserve potential. See "Net Asset Value & Unrisked Data" and "Cautionary Statement Regarding Forward Looking Information."

Sacramento Basin Geology



- Thick gross pay section
- Proven down spacing infill opportunities
- Multiple stacked gas charged objectives
- Adding more low-resistivity pay to behind-pipe potential
- Horizontal drilling potential
- Multiple isolated reservoir types
- Hydraulic frac stimulation upside

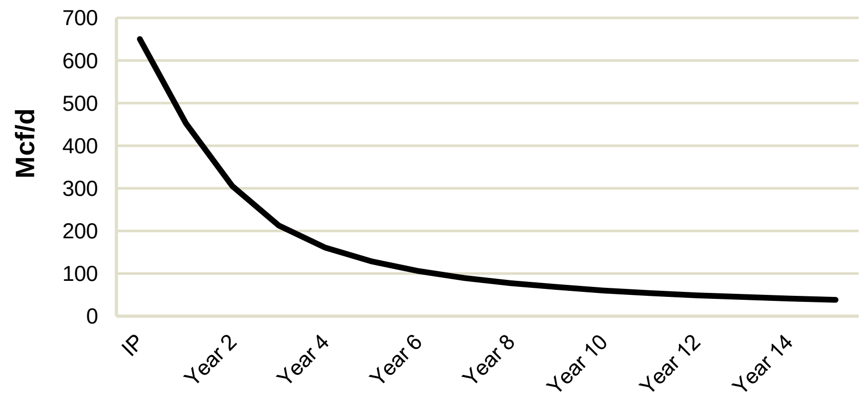
Sacramento Basin Economics

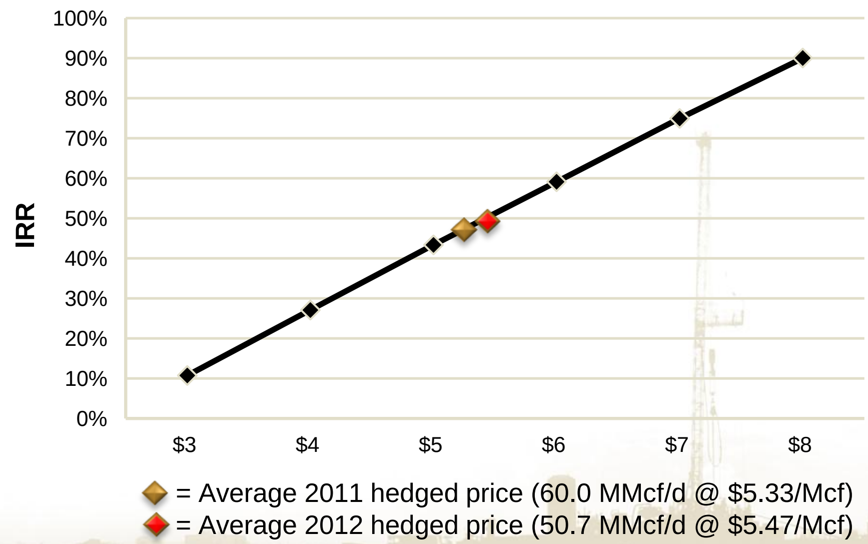
Current Economics of the Sacramento Basin[1]

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)	($0.65)
Transportation and Gathering ($/Mcf)	($0.20)
LTM Basis Differential ($/MMbtu) to Henry Hub	**+$0.23**
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 and IRR Sensitivity[1]





(1) Based on actual costs for 2010. Reserve and performance based on 12/31/10 reserve report. Data assumes successful well; 2010 success rate was 83%. IRR excludes costs such as G&A, land acquisition, and interest expense.

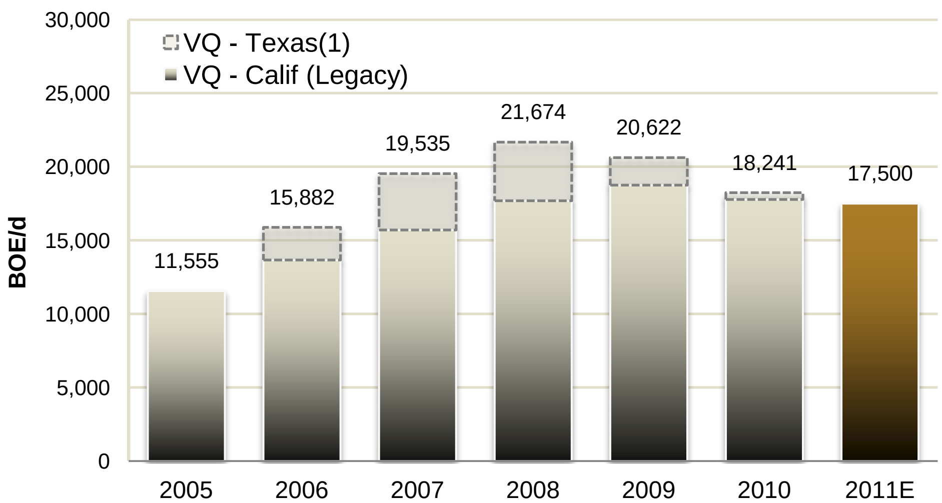
Financial Overview

Financial Strategy

- Grow Adjusted EBITDA and net asset value through low-risk projects and Monterey shale development
- Use legacy, low-decline Southern California oil assets and legacy Sac Basin natural gas assets to fund bulk of Monterey drilling
- Demonstrated commitment to maintain a strong balance sheet
- Continue to Focus on Costs
  - Maintain low operating cost per BOE
  - Realize efficiencies in capital program
- Flexibility to actively manage capital budget
  - Operate >95% of our properties – ability to control our capital spending
  - Able to shift capital expenditures to Oil or Natural Gas projects based on pricing
  - Minimal contractual obligations – limited drilling/rig/land commitments
- Aggressively utilize oil and gas derivatives to proactively limit downside commodity risk
- Continue to preserve financial and operating flexibility through potential joint-ventures and operating partnerships
- Monetize Hastings 22.3% WI Back-in
  - CO_2 injection initiated Dec. 2010 – RTP expected late 1Q12

Historical Performance and Guidance

Average Net Daily Production



Historical Production by Region (BOE/d)	2009	2010	9-Mos. Ended 9/30/11	2011 Guidance
Sacramento Basin	10,230	10,033	10,381	
Southern California	8,523	7,745	7,163	
Texas (and other)(1)	1,869	463	0	
Total	**20,622**	**18,241**	**17,544**	**17,500**

Historical Financial Results ($/BOE)	2009	2010	9-Mos. Ended 9/30/11	2011 Guidance
LOE	$12.65	$12.65	$14.90	$15.00
Prod'n/Prop Taxes	$1.35	$1.01	$1.00	$1.00
DD&A Expense	$11.46	$11.79	$13.32	$13.00
G&A Expense(2)	$4.63	$4.78	$4.79	$4.75
Adjusted EBITDA (MM)(3)	**$192.9**	**$218.1**	**$151.8**	

(1) Company sold its producing Texas assets in a series of transactions during 2009 and 2010.
(2) Net of amounts capitalized and excluding stock-based compensation, costs related to the Special Committee's review of a going-private proposal from the company's Chairman and Chief Executive Officer, and Texas severance costs. See appendix for GAAP reconciliation.
(3) See appendix for a definition of Adjusted EBITDA and a GAAP reconciliation.

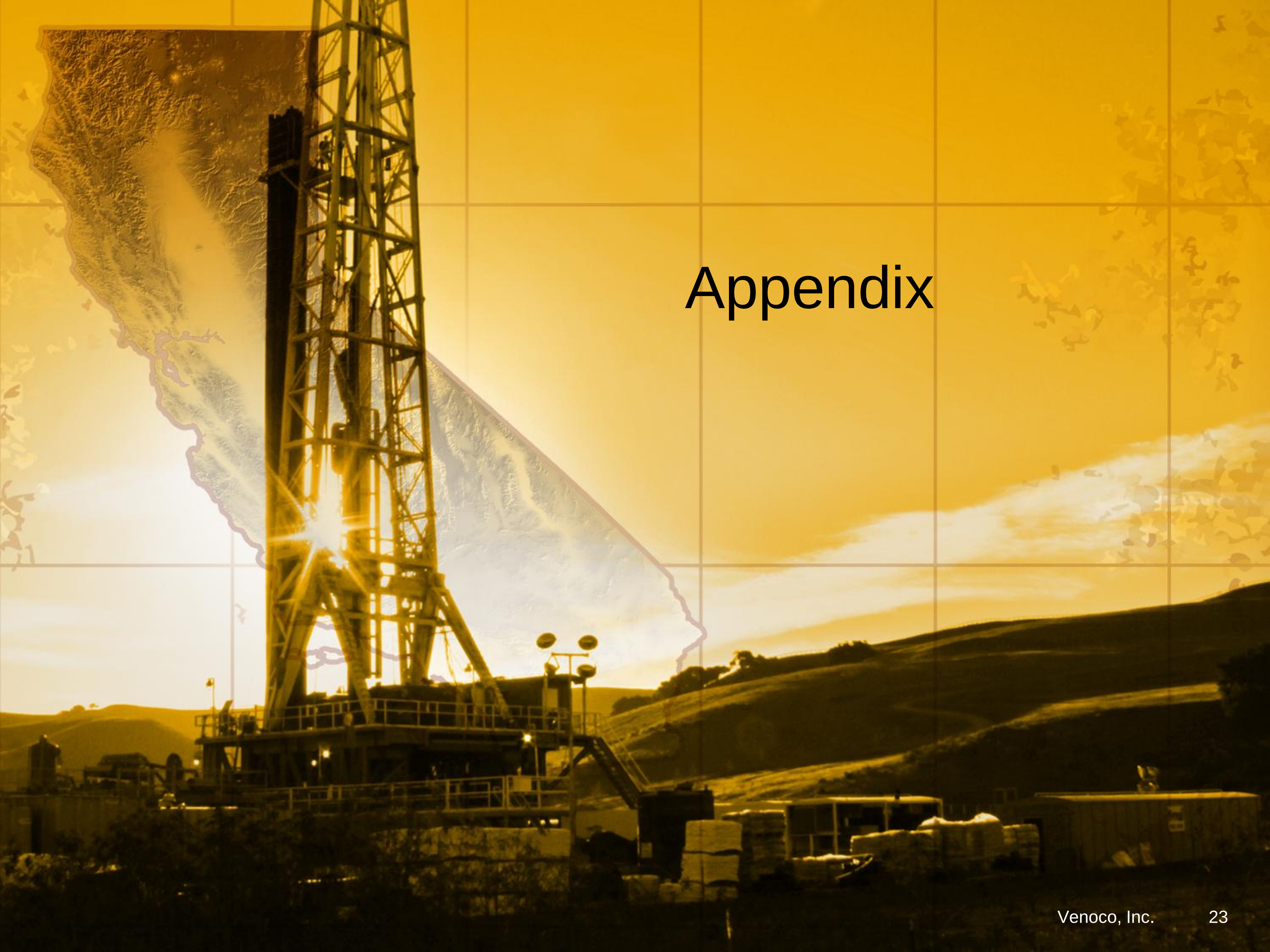
2011 Projections @ Various Commodity Prices

		Average Commodity Price for 4Q11 ($ in Million)[1]			
NYMEX Price - Oil/Gas	**Guidance**	**$85/$3.75**	**$90/$3.75**	**$95/$3.75**	**$100/$3.75**
O/G revenue (unhedged)	17,500 BOE/d	$319.1	$322.5	$325.9	$329.2
Hedging effect[2]		17.8	17.4	16.9	16.5
Net O/G revenues		336.9	339.9	342.8	345.7
LOE	$15.00/BOE	(95.8)	(95.8)	(95.8)	(95.8)
Production and property taxes	$1.00/BOE	(6.4)	(6.4)	(6.4)	(6.4)
G&A[3]	$4.75/BOE	(30.3)	(30.3)	(30.3)	(30.3)
Other[4]		(4.6)	(4.6)	(4.6)	(4.6)
Adjusted EBITDA[5]		$198.9	$201.9	$204.8	$207.7
Interest expense		(63.6)	(63.6)	(63.6)	(63.5)
Amortization of deferred loan costs and commodity derivative premiums		(10.5)	(10.5)	(10.5)	(10.5)
DD&A	$13.00/BOE	(83.0)	(83.0)	(83.0)	(83.0)

(1) Projections include actual results and prices through 9 months and flat 4Q11 NYMEX prices as indicated. Assumes current basis differentials, which are higher than historical averages, between Midway Sunset and Buena Vista posted prices and NYMEX.
(2) Estimated realized hedge gains/losses.
(3) Excludes non-cash stock-based compensation charges and costs related to the Special Committee's review of a going-private proposal from the company's Chairman and Chief Executive Officer.
(4) Includes other revenue and transportation expense.
(5) Net income in 2011 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 2011 net income. See Appendix for a definition of Adjusted EBITDA and related disclosure.

Why Own Venoco?

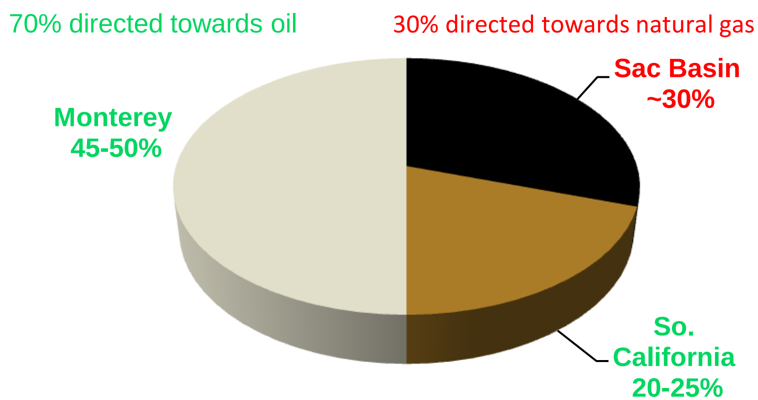
- Long-Lived, Oil-Leveraged Asset Base
  - Stable, Low-Decline Oil Production – Low Maintenance Capital
  - Oil Weighted: >65% 2010 revenue, 50% of 2010 proved reserves, 42% of 2010 production
- Solid Balance Sheet
  - Strong Hedge Positions
  - Strong Liquidity Position – No Near-Term Debt Maturities
- Monterey Shale – Multi 100-million barrel opportunity
  - Highly levered to Monterey with 60% of current oil production from legacy Monterey
  - 14 years building operations expertise in the Monterey
  - 5 years identifying and leasing exceptional onshore Monterey acreage position
- Large Portfolio of Development Projects
  - Sacramento Basin Infill; So. California Oil Fields; Hastings CO_2 Flood
- Significant management ownership
- Teams of Experienced Personnel
  - Advancing New Technologies to Optimize, Enhance and Expand Productive Capacity & Reserves



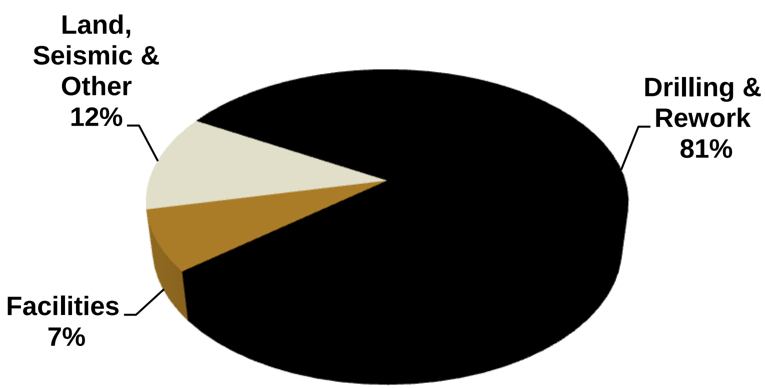
Appendix

Oil-Focused 2011 Capital Program

Estimated Capital by Business Unit



Estimated Capital by Activity

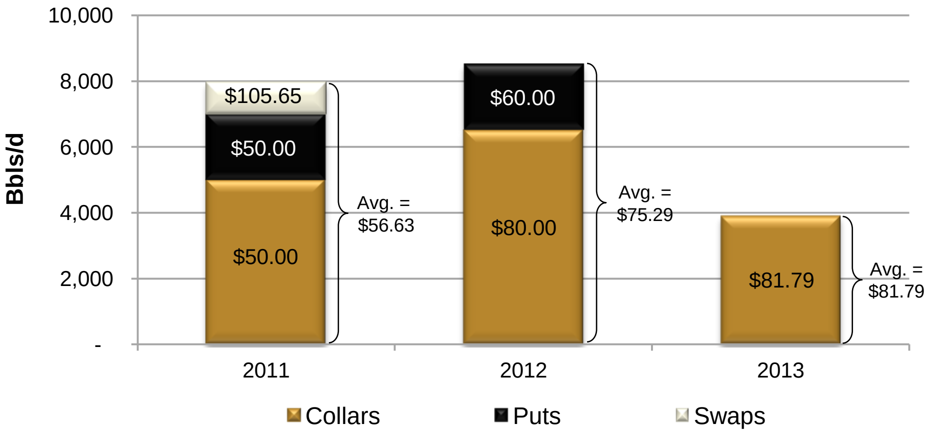


- **Monterey Evaluation and Development**
  - Plan to drill ~15 gross wells
  - Finished joint 3-D seismic shoot (50/50 with Oxy) – processed data in house this month
  - Continue to build acreage position
- **Southern California**
  - Drill 6 wells at West Montalvo and 5 recompletions
  - 3-6 recompletions at South Ellwood (Monterey)
  - Began construction of new, onshore pipeline
  - Completed 2 wells at Sockeye (Monterey)
- **Sacramento Basin**
  - Approximately 40+ wells, 220 recompletions, and 20 fracs

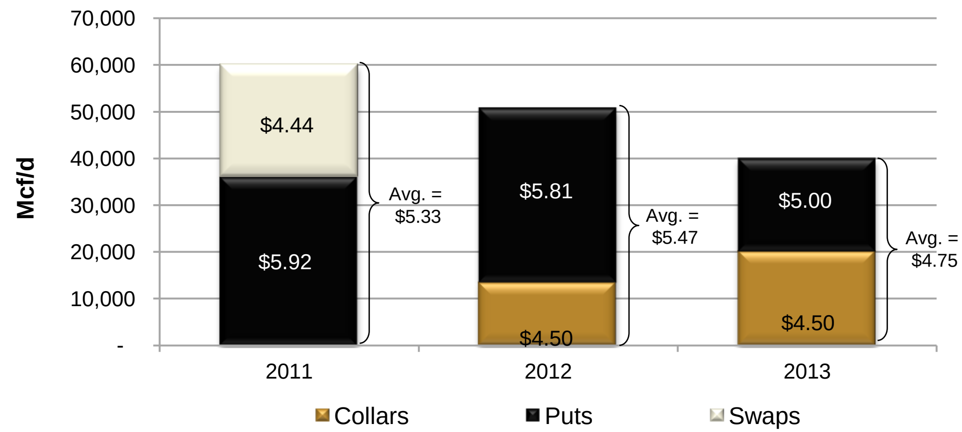
Note: References to 'well' or 'wells' refers to gross well(s).

Significant Hedging Program

Oil Downside Protection



Natural Gas Downside Protection



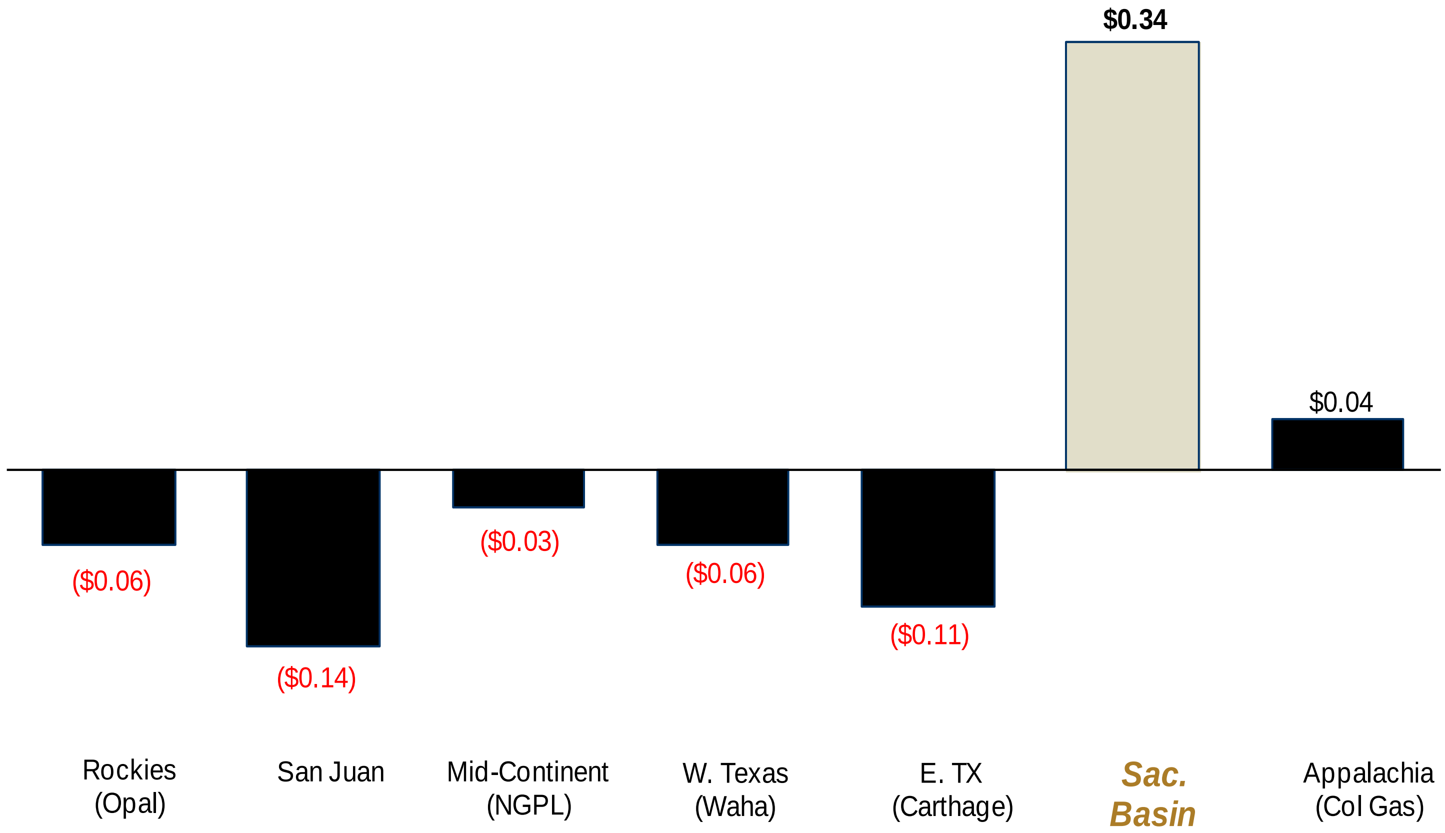
	Floor		Cap		Basis Swaps	
Current Crude Oil Deliveries for Production	**Weighted Avg BBLs/Day**	**Weighted Avg Prices**	**Weighted Avg BBLs/Day**	**Weighted Avg Prices**	**Weighted Avg BBLs/Day**	**Weighted Avg Prices**
Jan 1 - Dec 31, 2011	7,946	$ 56.63	5,946	$ 100.90	2,788	$ 9.30
Jan 1 - Dec 31, 2012	8,500	$ 75.29	6,500	$ 118.15	7,630	$ 6.90
Jan 1 - Dec 31, 2013	3,900	$ 81.79	3,900	$ 113.59	3,900	$ 5.88

	Floor		Cap		Basis Swaps	
Current Natural Gas Deliveries for Production	**Weighted Avg MMBtu/Day**	**Weighted Avg Prices**	**Weighted Avg MMBtu/Day**	**Weighted Avg Prices**	**Weighted Avg MMBtu/Day**	**Weighted Avg Prices**
Jan 1 - Dec 31, 2011	60,000	$ 5.33	24,000	$ 4.44	57,224	$ 0.11
Jan 1 - Dec 31, 2012	50,700	$ 5.47	13,400	$ 5.25	47,400	$ 0.28
Jan 1 - Dec 31, 2013	40,000	$ 4.75	20,000	$ 5.40	-	-

Note: Hedges are based on NYMEX WTI (oil) and NYMEX Henry Hub (natural gas). Crude oil basis swaps attempt to fix the differential between NYMEX WTI and ICE Brent on a portion of our expected production. Natural gas basis swaps attempt to fix the differential between the NYMEX Henry Hub price and the PG&E City Gate price on a portion of our expected production. Positions shown are as of November 1, 2011.

Sac Basin – Superior Realizations Enhance Economics

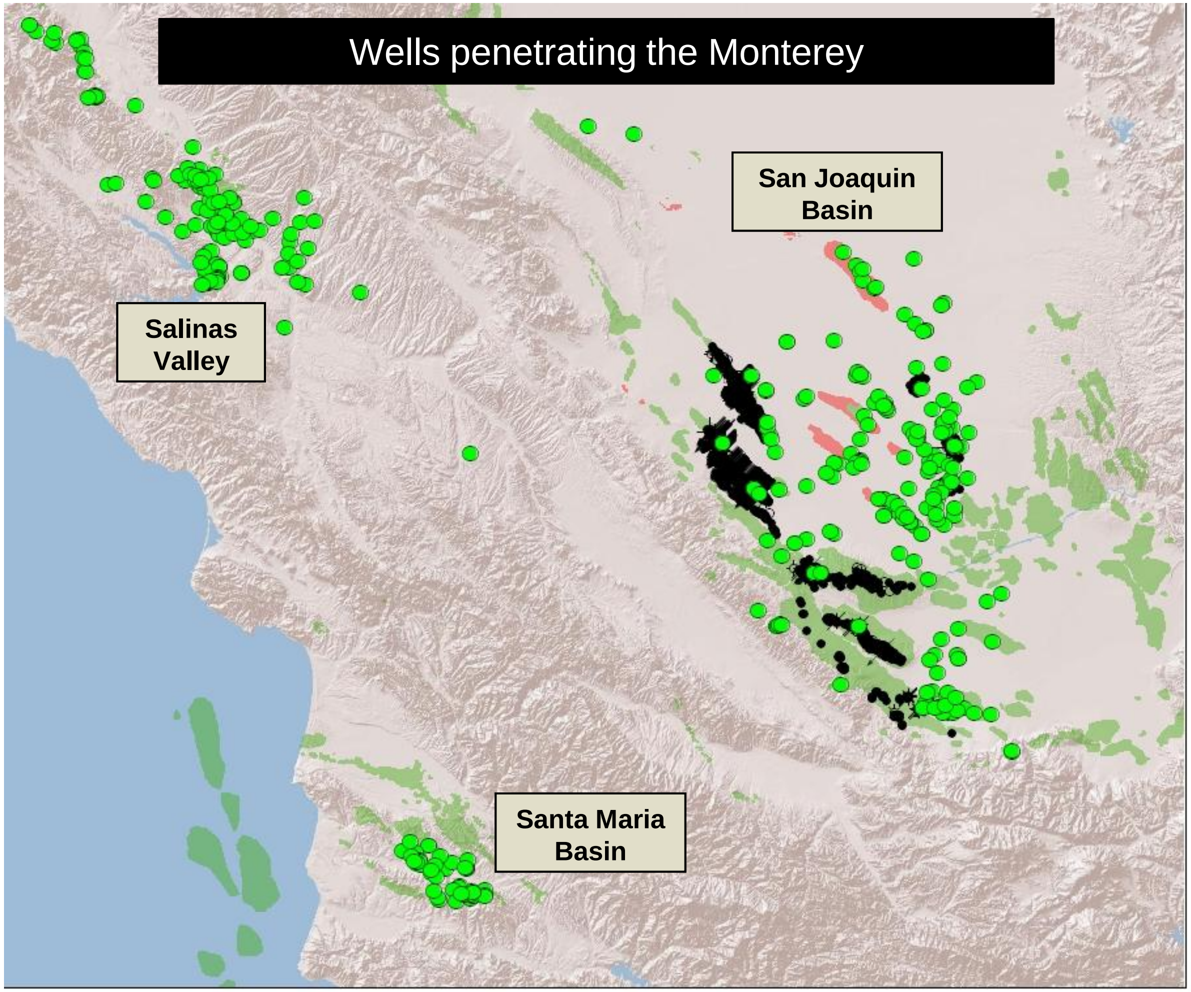
Natural Gas Basis Differentials ($ per MMBtu)
Based on $3.52 per MMBtu Henry Hub Average November 2011 price



Source: NGI Bidweek Survey – November 2011.

Monterey – Abundant Data Exists

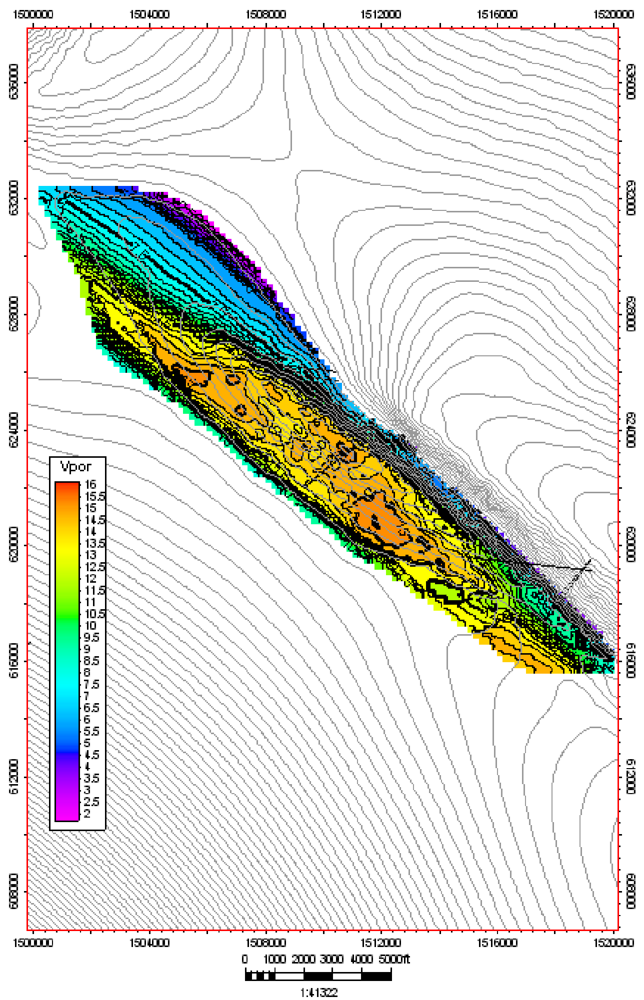
- World class source rock
  - Sourced 6 of the largest U.S. oil fields[(1)]
  - Sourced multi 100-billion barrels of OOIP[(2)]
- Massive amount of data has been collected in the Monterey
- >17,000 wells have penetrated the Monterey in our target basins
  - >11,000 of those wells tested or produced from the Monterey
  - We have acquired >1,100 digital logs
    - Shale-petrophysical analysis on more than 50 of these wells



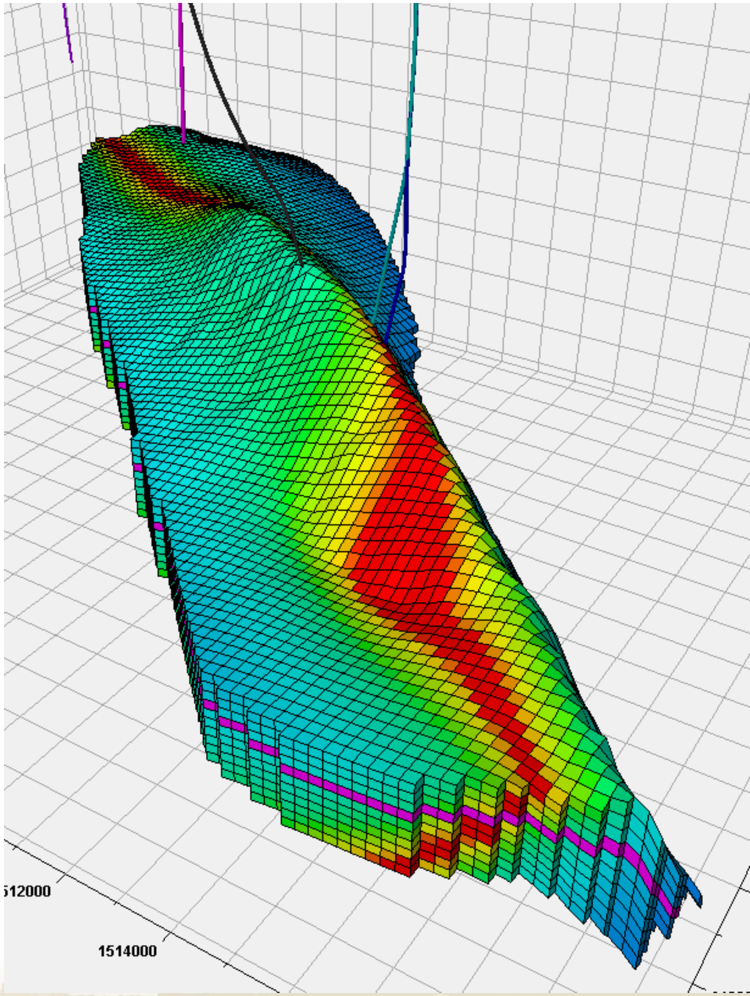
(1) 2007 DOE Oil Field Study.
(2) Internal estimates of Southern California oil basins.

Sevier – Pore Volume 3-D Model

Reservoir Net Pore Volume Map



3D Relief of Pore Volume Mapping

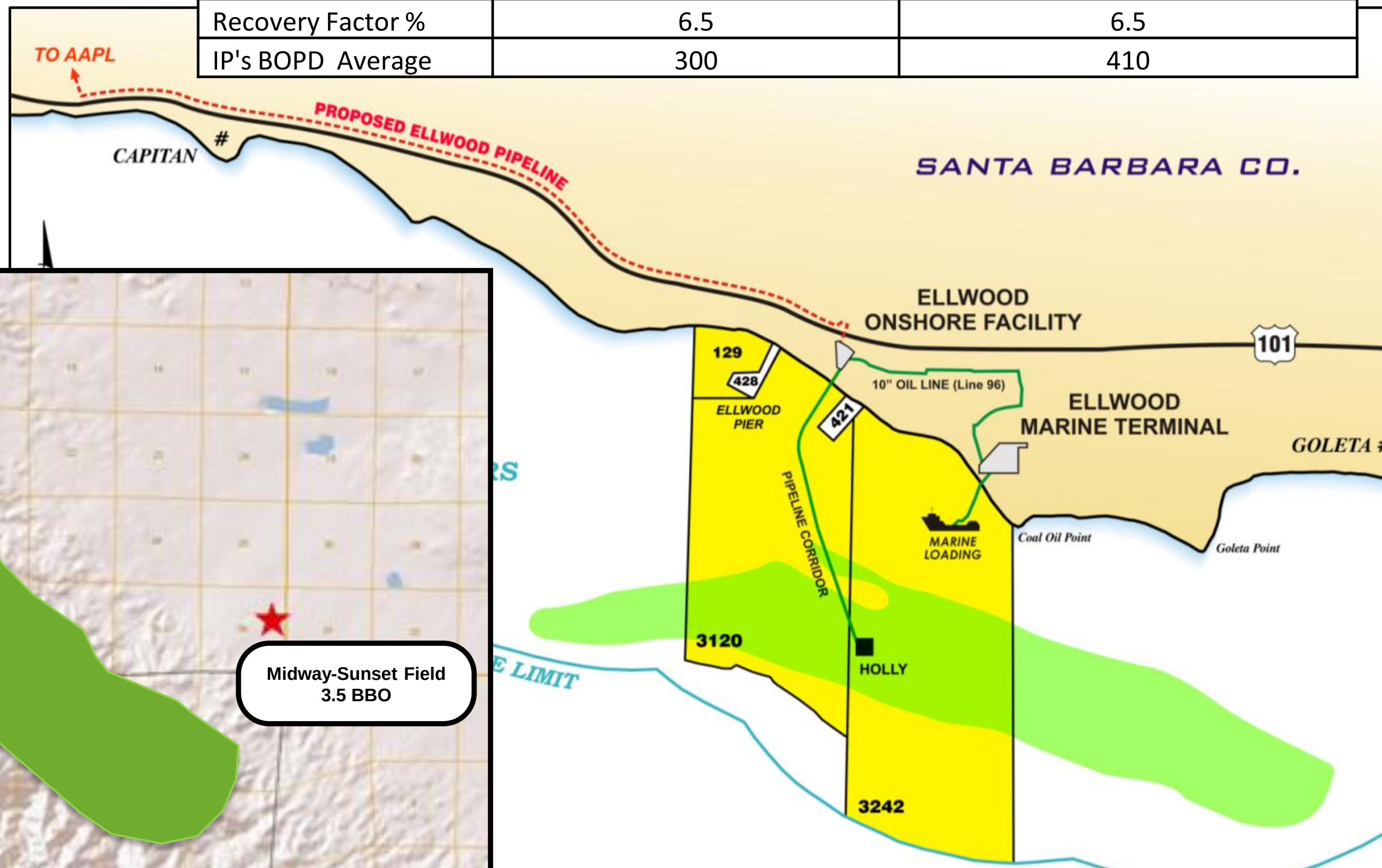


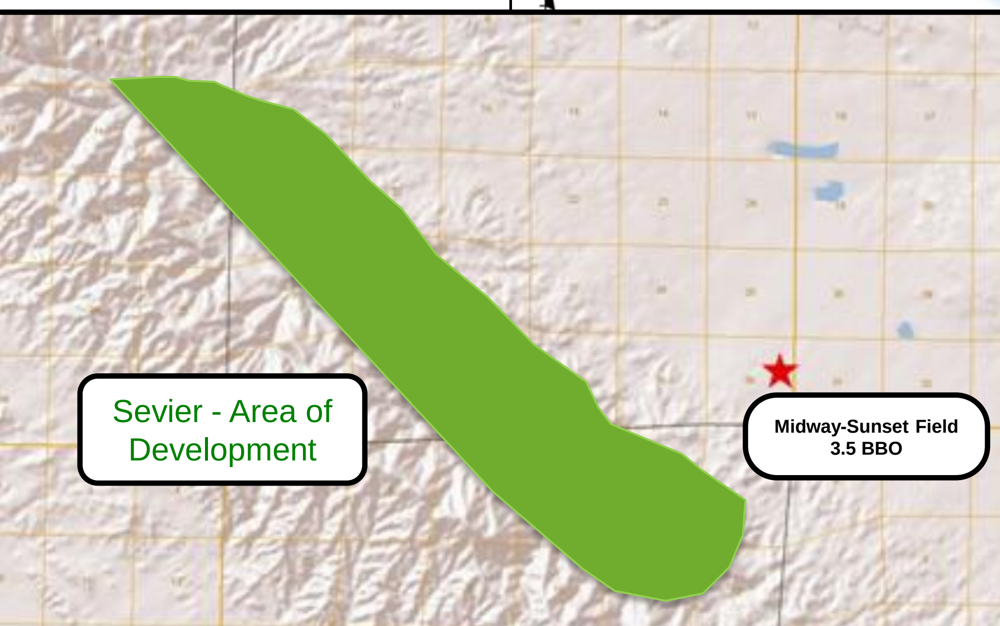
<u>Wells NW to SE (l to r) & spud date</u>

- Venoco: Sevier 14-1 (2006)
- Frantzen: Cree Fee 1ARD (1983)
- ARCO: Cree Fee 1A (1984)
- Venoco: BLM 1-29 (2010)
  - Cut 67' of core & 30 sidewalls.
- Venoco: BLM 1-29RD (2011)
- Keck CWOD 1-2 (1956) (off mapped area)

Sevier – South Ellwood Comparison

	Sevier Potential[1]	South Ellwood (Venoco leases)
OOIP BBO	1.3	1.1
EUR MMBO	89	120
Thickness ft	565	1,000
Recovery Factor %	6.5	6.5
IP's BOPD Average	300	410





(1) All data reflects unrisked estimates that are generally based on deterministic volumetric calculations that utilize Venoco's and historical drilling results in a given area and represent our current understanding of the reservoir properties. The estimates reflect modeled data and not the results of wells drilled to date. Capital costs incurred for use in economics estimates include run-rate drilling and completion costs and facility investments, but exclude costs such as capitalized G&A, land acquisition, and permitting costs. See "Cautionary Statement Regarding Forward Looking Information" and "Net Asset Value & Unrisked Data." Production rates shown for individual wells reflect testing results not ongoing production.

Historical Operating Data

	Years Ended December 31					Nine Months Ended Sep 30
	2006	2007	2008	2009	2010	2011
Production (BOE/d)	15,882	19,535	21,674	20,622	18,241	17,544
Oil component	59%	56%	52%	45%	42%	38%
Oil & Gas Sales ($000)	$268,822	$371,450	$554,270	$267,163	$290,608	$241,533
LOE per BOE	$14.18	$15.05	$16.86	$12.65	$12.65	$14.90
Production & Property Taxes per BOE	$0.91	$1.69	$1.98	$1.35	$1.01	$1.00
G&A per BOE	$4.88	$4.46	$5.43	$4.91	$5.64	$5.82
Adjusted EBITDA(1) ($000)	$148,715	$214,311	$304,013	$198,628	$218,088	$151,759
Realized Prices per Unit:						
Oil, Excl Hedges (BBL)	$55.92	$63.63	$89.28	$50.60	$68.86	$90.06
Gas, Excl Hedges (MCF)	$6.04	$6.61	$8.21	$3.84	$4.34	$4.16
Blended, Excl Hedges (BOE)	$47.82	$53.04	$69.91	$35.50	$43.99	$49.73
Blended, Excl Hedges (Mcfe)	$7.97	$8.84	$11.65	$5.92	$7.33	$8.29

(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 fees. In connection with the repayment of the second lien term loan, the company settled interest rate derivative swaps in February 2011 for $38.1 million, resulting in a significant realized interest rate derivative loss for Q1 2011. For purposes of the above per BOE metric, the settlement cost of $38.1 million was excluded from the calculation of interest expense.

Net Asset Value & Unrisked Data

References in this presentation to Asset Value, Net Asset Value (NAV), or NPV-10, collectively, “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 2010 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 recently-adopted SEC rules.

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, 2010
Standardized measure of discounted future net cash flows	$ 902,901
Add: Present value of future income tax discounted at 10%	225,795
PV-10 at year-end SEC prices	$ 1,128,696
Add: Effect of NYMEX 5-year strip at December 31, 2010	440,514
PV-10 at NYMEX 5-year strip at December 31, 2010	$ 1,569,210

Per BOE G&A

We also provide per BOE G&A expenses excluding share-based compensation costs, costs related to the Special Committee's review of a going private proposal from the company's Chairman and Chief Executive Officer, and severance costs associated with the sale of Texas assets. We believe that these non-GAAP measures are useful in that the items excluded do not represent cash expenses directly related to our ongoing operations. These non-GAAP measures should not be viewed as an alternative to per BOE G&A expenses as determined in accordance with GAAP.

UNAUDITED ($ in thousands, except per BOE amounts)	Quarter Ended			Year Ended		Nine Months Ended
	9/30/10	6/30/11	9/30/11	12/31/09	12/31/10	9/30/11
G&A per BOE Reconciliation						
G&A expense	$ 8,624	$ 8,824	$ 9,236	$ 36,939	$ 37,554	$ 27,889
Less:						
Share-based compensation expense	(1,097)	(1,319)	(1,303)	(2,124)	(4,503)	(4,076)
Special Committee-related costs	-	-	(892)	-	-	(892)
Texas severance costs	-	-	-	-	(1,254)	-
G&A Expense Excluding Share-Based Comp	7,167	7,505	7,041	34,815	31,797	22,921
MBOE	1,664	1,598	1,588	7,527	6,658	4,790
G&A Expense per BOE Excluding Share-Based Comp	$ 4.31	$ 4.70	$ 4.43	$ 4.63	$ 4.78	$ 4.79

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)	2006	2007	2008	2009	2010	Nine Months Ended 9/30/11
Net Income (Loss)	$ 23,951	$ (73,372)	$ (391,132)	$ (47,298)	$ 67,520	$ 31,892
Interest, Net	48,795	60,115	54,049	40,984	40,584	44,678
Realized Interest Rate Derivative (Gains) Losses	96	(135)	10,231	18,479	18,094	41,147
Income Taxes	15,650	(46,200)	11,200	(14,400)	(1,300)	-
Amortization of Deferred Loan Costs	3,776	4,197	3,344	2,862	2,362	1,715
DD&A	63,259	98,814	134,483	86,226	78,504	63,810
Accretion of Asset Retirement Obligation	2,542	3,914	4,203	5,765	6,241	4,821
Ceiling Test Impairment	-	-	641,000	-	-	-
Loss on Extinguishment of Debt	-	12,063	-	8,493	-	1,357
Share-based Payments	3,050	3,278	3,064	2,824	5,653	4,966
Special committee-related costs	-	-	-	-	-	892
Texas Severance Costs	-	-	-	-	1,254	-
Amortization of Derivative Premiums and Other Comprehensive Loss	8,181	11,546	7,694	24,985	24,808	5,970
Unrealized Commodity Derivative (Gains) Losses	(21,079)	122,779	(184,459)	71,511	(39,356)	(9,425)
Unrealized Interest Rate Derivative (Gains) Losses	494	17,312	10,336	(1,803)	13,724	(40,064)
Adjusted EBITDA	$ 148,715	$ 214,311	$ 304,013	$ 198,628	$ 218,088	$ 151,759