Venoco, Inc.

BMO Capital Markets

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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 full implementation of a CO2 flood and the production results and reserves if the flood is implemented. Forward looking statements made about the South Ellwood pipeline project 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. 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 Company

VENOCO, INC.

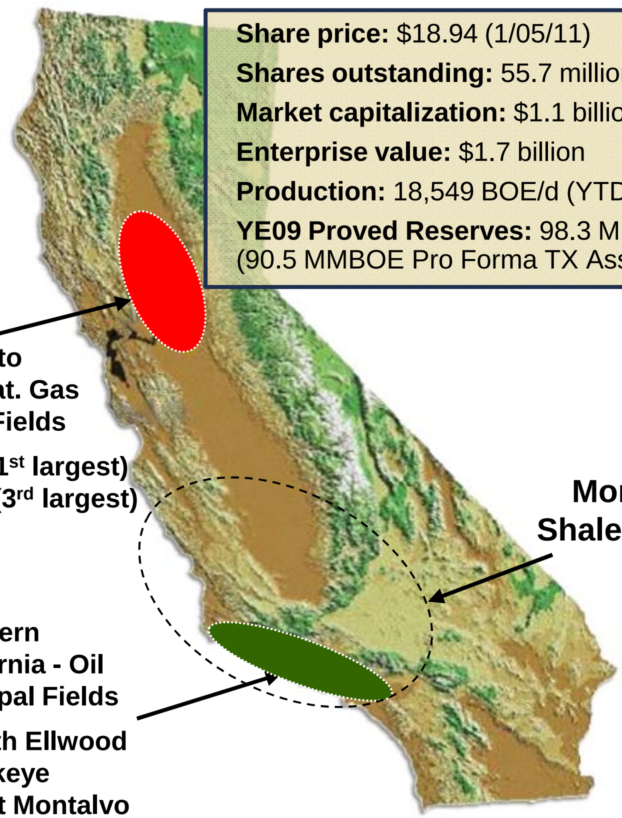
Applying new technology to revitalize legacy assets

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

Company Highlights

Solid Core Assets

Share price: $18.94 (1/05/11)
Shares outstanding: 55.7 million
Market capitalization: $1.1 billion
Enterprise value: $1.7 billion
Production: 18,549 BOE/d (YTD 9/30/2010)
YE09 Proved Reserves: 98.3 MMBOE
(90.5 MMBOE Pro Forma TX Asset Sale)



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

Strategy

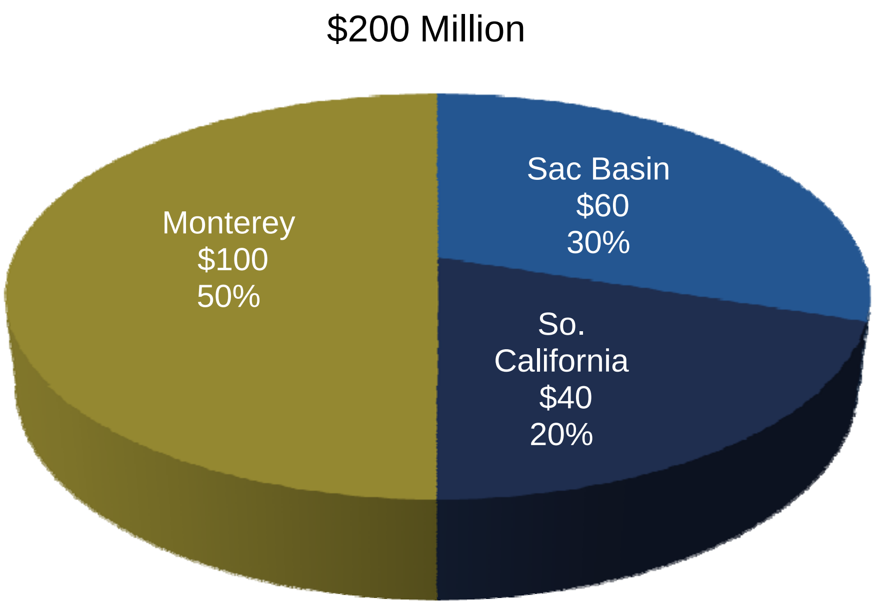
- Pursue oily opportunities
  - Monterey shale exploitation – multi-year, multi-100 million barrel potential
- Develop large inventory in Sacramento Basin
  - 700 locations at 20-acre spacing – 7 year inventory
- Use legacy, low-decline Southern California oil assets and legacy Sac Basin gas assets to fund bulk of Monterey drilling
  - Fund shortfalls with JVs, non-core asset sales, capital market transactions

Portfolio Highlights

- Concentrated positions
- Shallow declines
- Oil-weighted – reserves & revenue
- 97% of properties operated
- Large acreage position in Monterey shale and Sacramento Basin
- 22.3% reversionary working interest in Hastings (TX) CO_2 flood – Denbury initiated flood in Dec. 2010

2011 Capital Spending

Estimated Capital by Business Unit



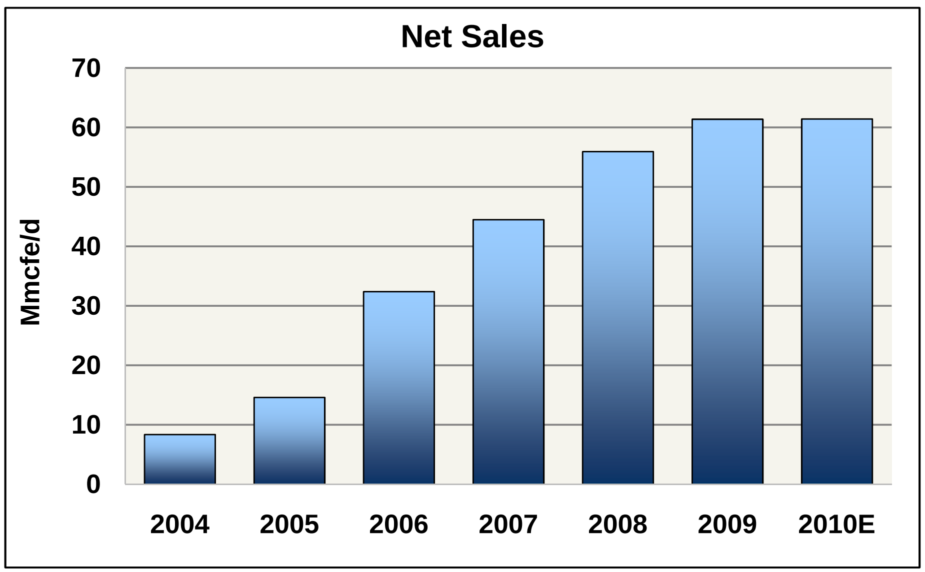
- **Continue to advance “oily” projects**
- **Monterey Evaluation & Development**
  - Drill 22 horizontal (development) completions & 8 vertical (evaluation) wells
  - Complete joint 3-D seismic shoot (50/50 with Oxy)
  - Continue to build acreage position
  - Pursue JV opportunities for original 30+ prospect areas
- **Southern California**
  - Drill 2 wells at West Montalvo
  - Drill 1 well at South Ellwood and 6 recompletions (Monterey)
  - Drill 1 well at Sockeye (Monterey)
- **Sacramento Basin**
  - Approximately 40 wells, 220 recompletions, and 20 fracs

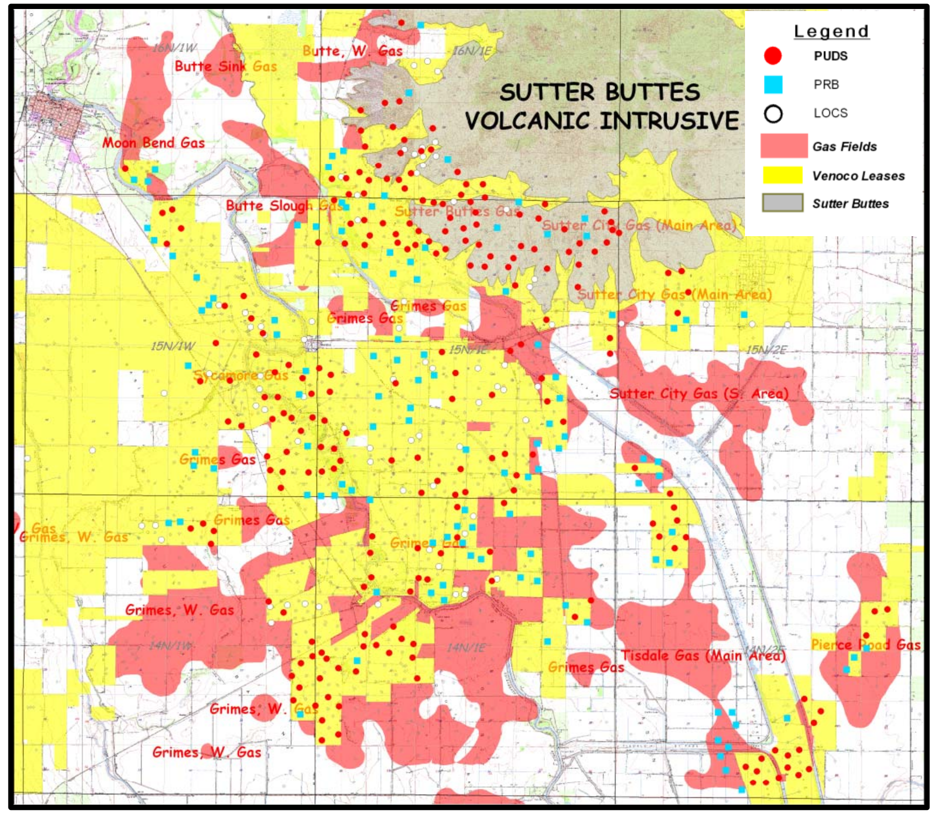
References to ‘well’ or ‘wells’ refer to gross well(s).

Sacramento Basin

- Largest gas producer & most active operator in Basin
  - Drilled over 400 wells since 2005
  - Drilled 86% productive wells in 2009
- Positive gas differential significantly enhances economics (LTM +$0.23)

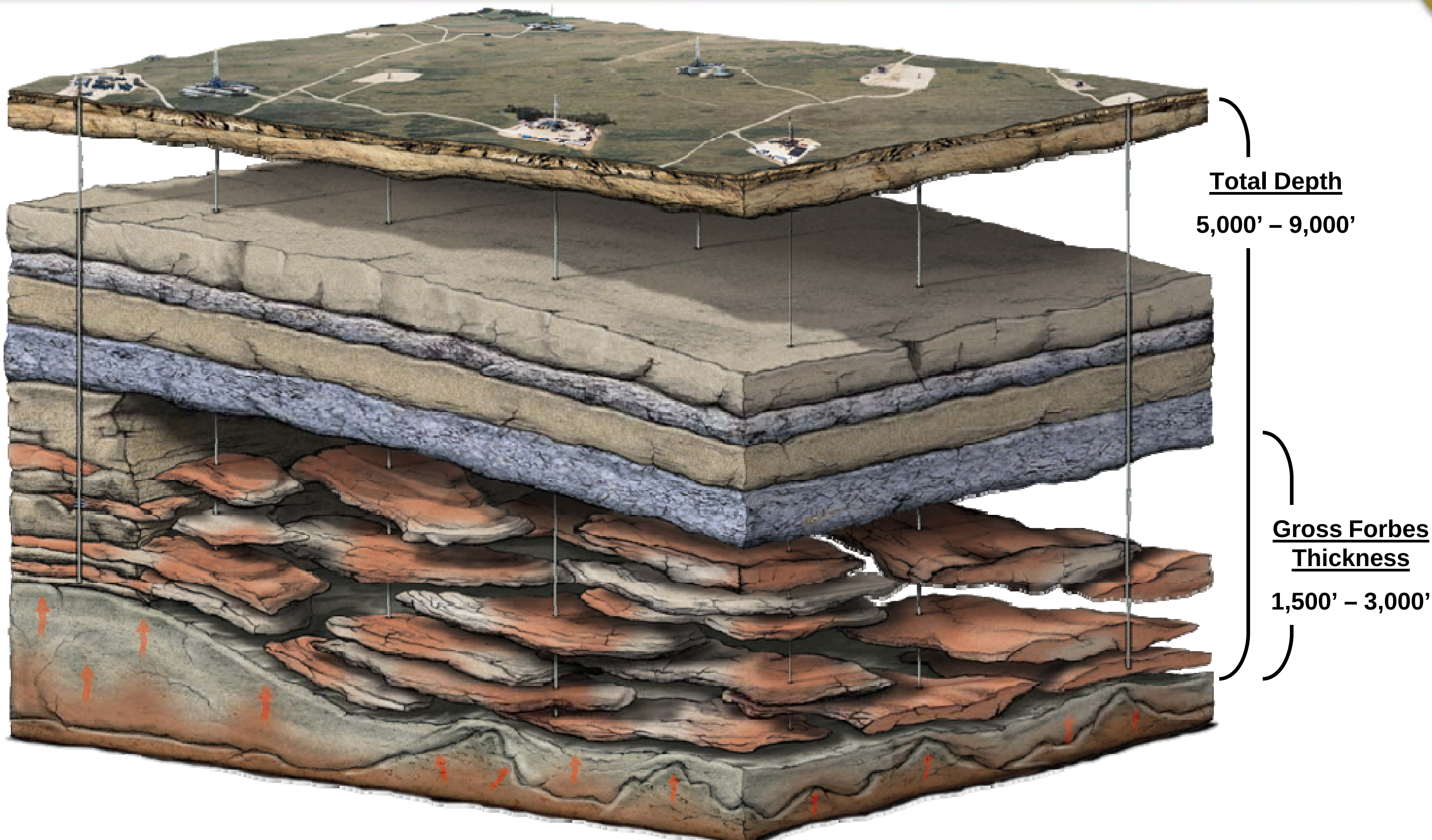
Planned Activity	2010	2011
New Wells	~100	~40
Recompletions	225	220
Fracs	12	20





- Extensive inventory for future activity
  - Approximately 700 Locations at 20-Acres
- Additional Potential
  - Low-risk Exploration / Down Spacing / Step-Out Drilling / Deeper Horizons (Guinda)

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

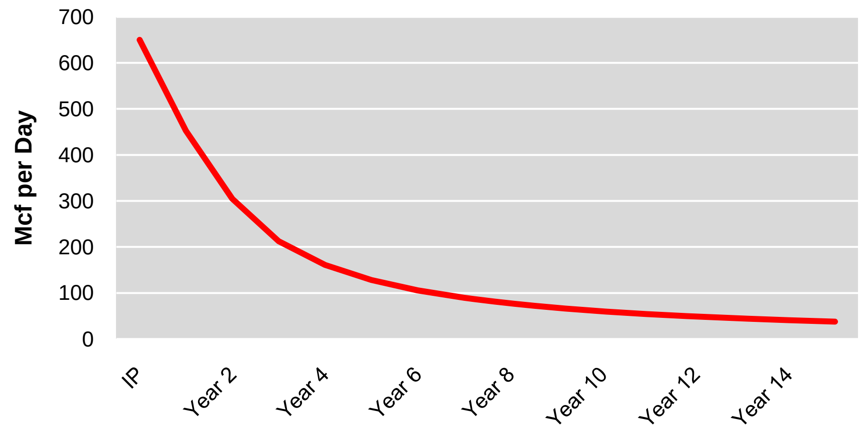
Sac Basin Economics

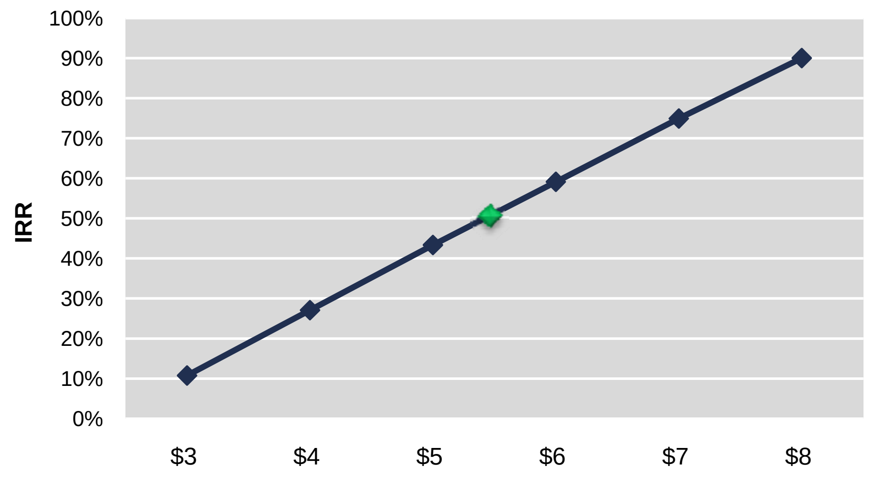
Current Economics of the Sacramento Basin[1]

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)	$0.65
Transportation & Gathering ($/Mcf)	$0.20
LTM Basis Differential ($/Mcf)	$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 & IRR Sensitivity[1]

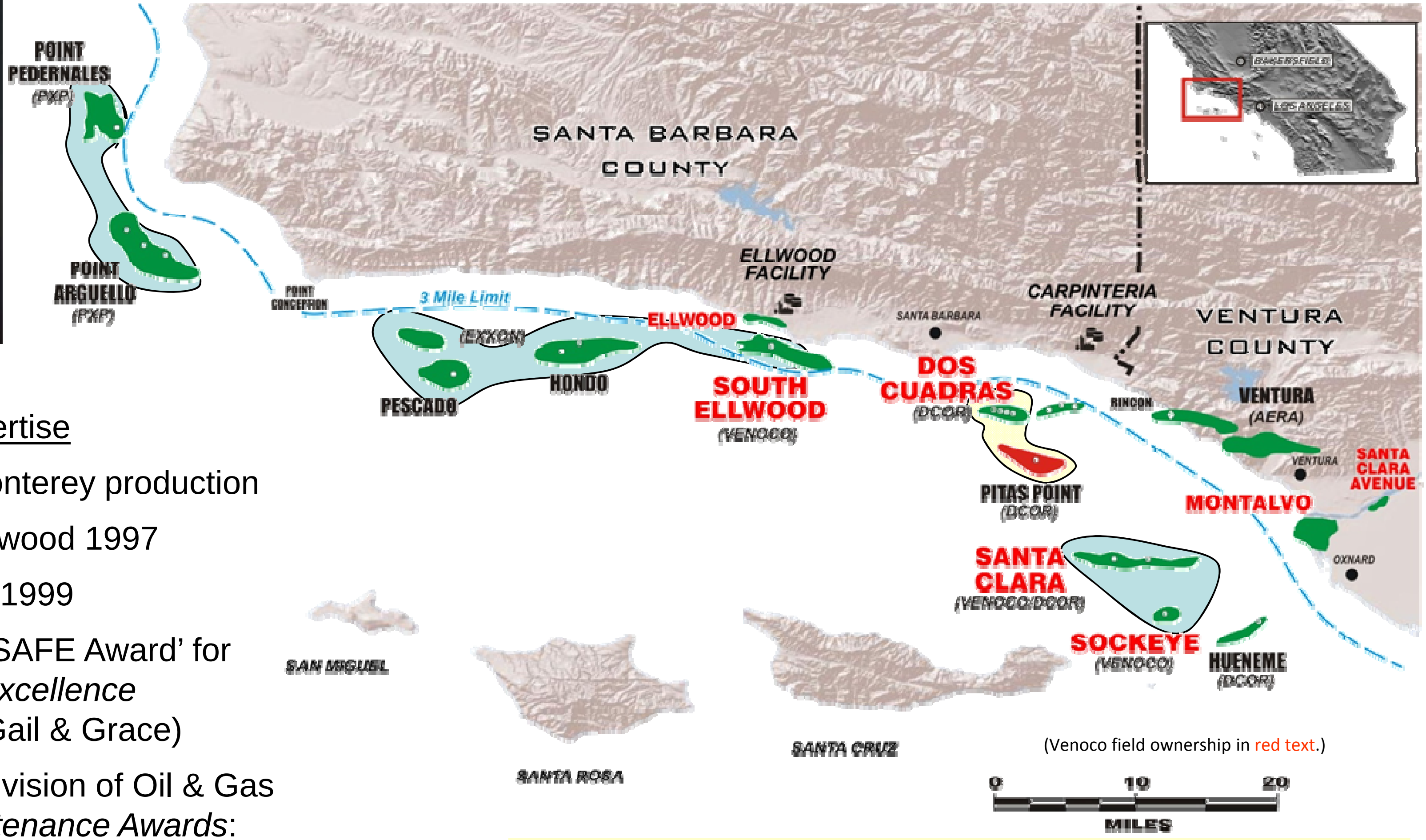




= Average 2011 hedged price (60.0 MMcf/d @ $5.43/Mcf)

(1) Based on actual costs for 1H10. Reserve and performance based on 12-31-09 reserve report. Data assumes successful well; 1H10 success rate was 85%. IRR excludes costs such as G&A, land acquisition, and interest expense.

The Heart of Venoco's Monterey Expertise



(Venoco field ownership in red text.)

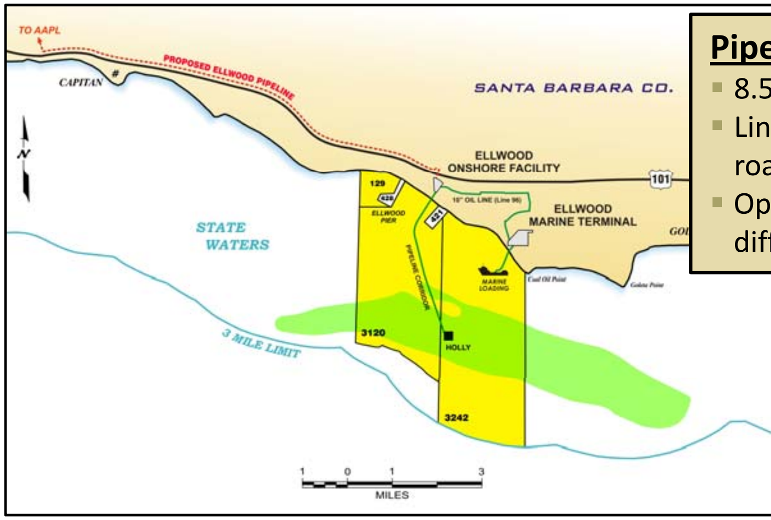
- Operating Expertise
  - 13 years Monterey production
    - South Ellwood 1997
    - Sockeye 1999
  - U.S. MMS 'SAFE Award' for *Operating Excellence* (Platforms Gail & Grace)
  - California Division of Oil & Gas *Lease Maintenance Awards*:
    - Ellwood Onshore Facility
    - Santa Clara Avenue Field

– Offshore Monterey tests @ commercial rates

– Existing Offshore Monterey Production

Low-Decline, Legacy Oil Properties

South Ellwood Field – Platform Holly

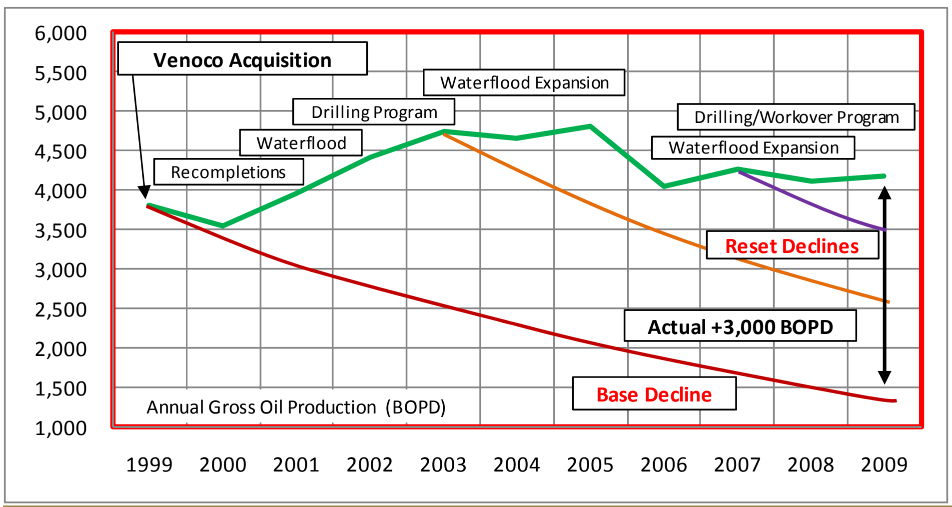


Pipeline to Replace Barge:

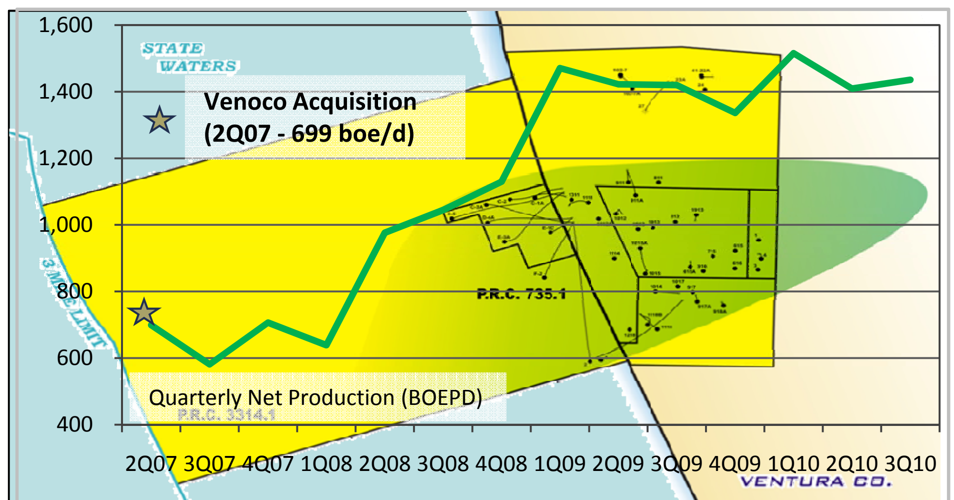
- 8.5 mile route to AAPL tie-in
- Line buried beneath existing roads & other disturbed areas
- Opportunity to reduce oil price differentials

- ~7,950 Boe/d produced from Southern California through first 9 months of 2010
  - 3 fields (South Ellwood, Sockeye, and West Montalvo) represent ~85%

Sockeye Field – Platform Gail



West Montalvo Field

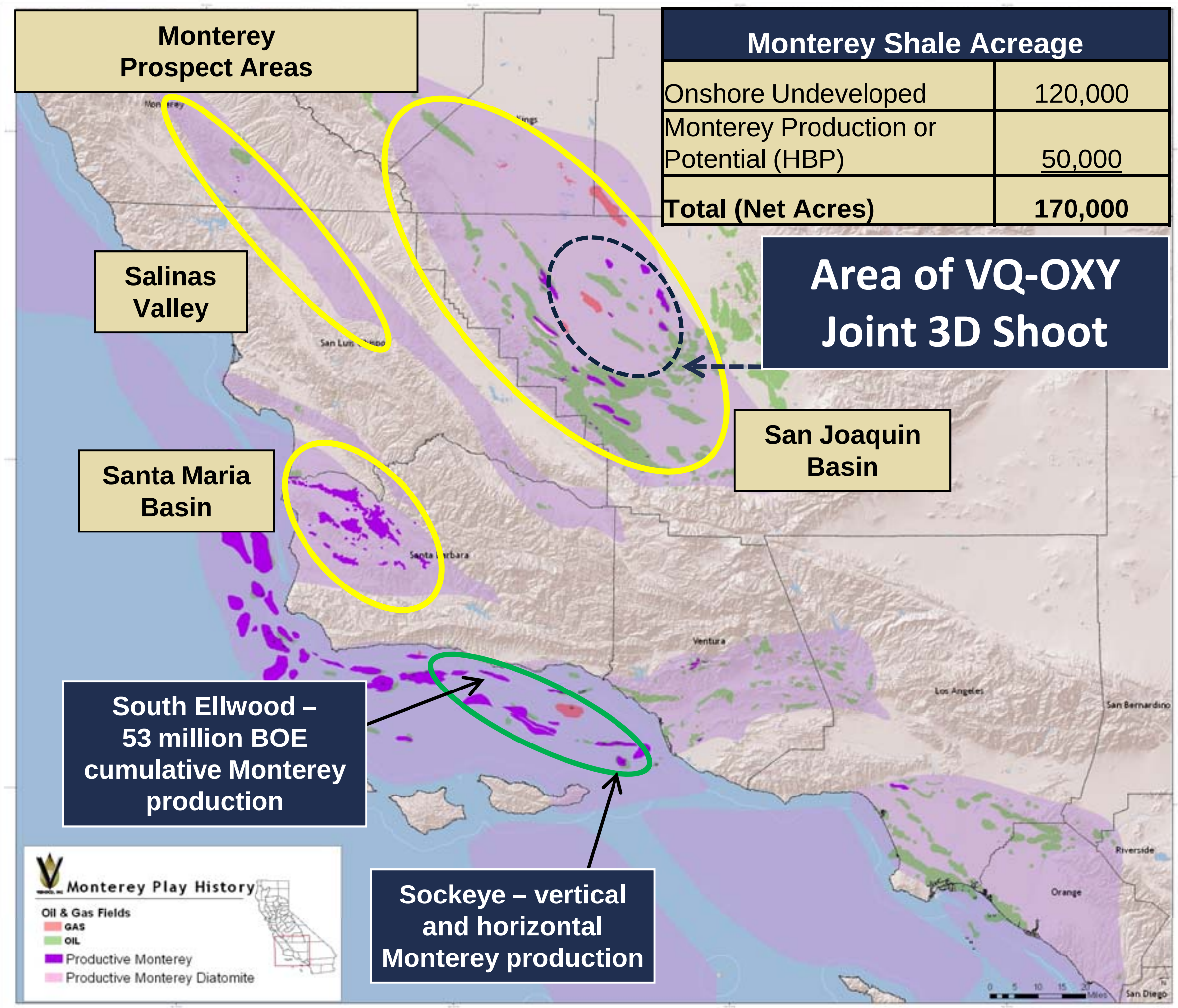


Monterey Shale Activity

Venoco Areas of Operations

- **Business Strategy**
  - Control the play
- **Acreage Strategy**
  - Light oil
  - Natural fractures
  - Moderate depths
  - Favorable operating environment
- **2011 Capital Plans**
  - Drill 30 gross wells – 22 horizontal
  - Increase net acreage
  - $100 million budget
  - Complete 3-D seismic shoot
- **Current Status**
  - TD'd 7th evaluation well in December
  - Completing 2nd & 3rd horizontal well
  - Drilling 4th horizontal well
  - Drilling 8th evaluation well

Monterey Shale Acreage	
Onshore Undeveloped	120,000
Monterey Production or Potential (HBP)	50,000
Total (Net Acres)	**170,000**



Monterey Shale

- World Class Source Rock
  - Sourced 6 of the largest U.S. oil fields[1]
- Largest U.S. Oil Shale Play[2]
- Sourced Multi 100-Billion Barrels of OOIP[3] in Southern California
- 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 (1/05/11)	California Acreage (Net)	Monterey Acreage (Net)	Monterey Acres / $MM Market Cap
Venoco	$1,054	383,000	170,000	161
OXY	$79,128	1,300,000	873,000	11
PXP	$4,592	116,400	86,000	19
NFG	$5,518	23,100	14,000[4]	3
BRY	$2,410	6,500	6,500	3

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) 2007 DOE Oil Field Study.
(2) Based on cum oil production to date.
(3) Internal estimates of Southern California oil basins.
(4) Venoco internal estimates of potential Monterey acreage.

Monterey Geology – Basins

Sockeye
Total – 86 MMBO
Monterey – 17 MMBO

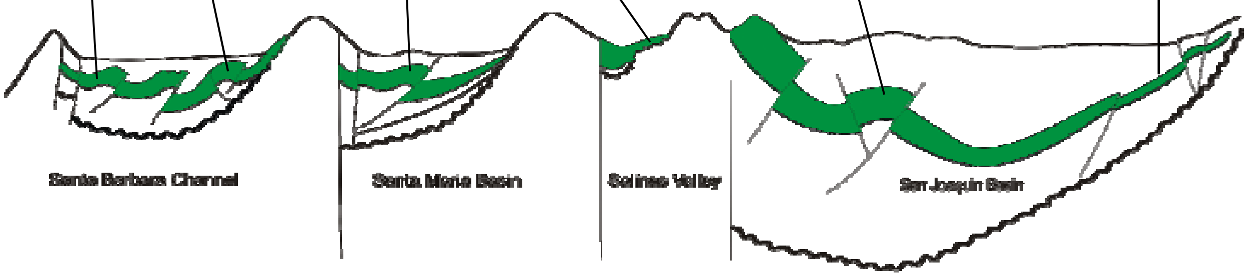
South Ellwood
Total – 87 MMBO
Monterey – 72 MMBO

Orcutt
Total – 227 MMBO
Monterey – 175 MMBO

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

Elk Hills
Total – 1.8 BBO
Monterey – 86 MMBO

North Shafter
Total – 13 MMBO
100% Monterey



Fracture Dominated

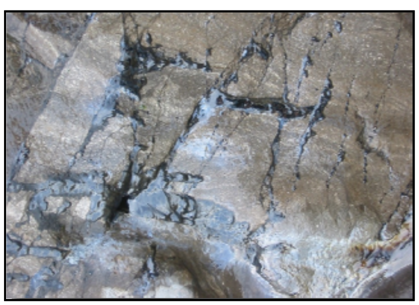
Matrix Dominated

← 135 Miles →

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

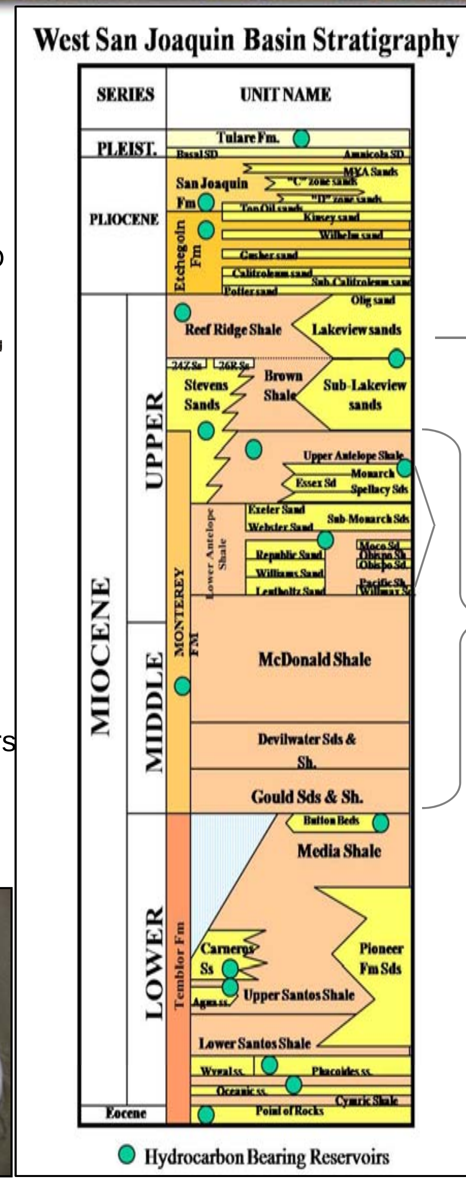
(1) Monterey production comingled with other reservoirs. Red text – Venoco fields.

Fracture Dominated



Dual Porosity

Matrix Dominated

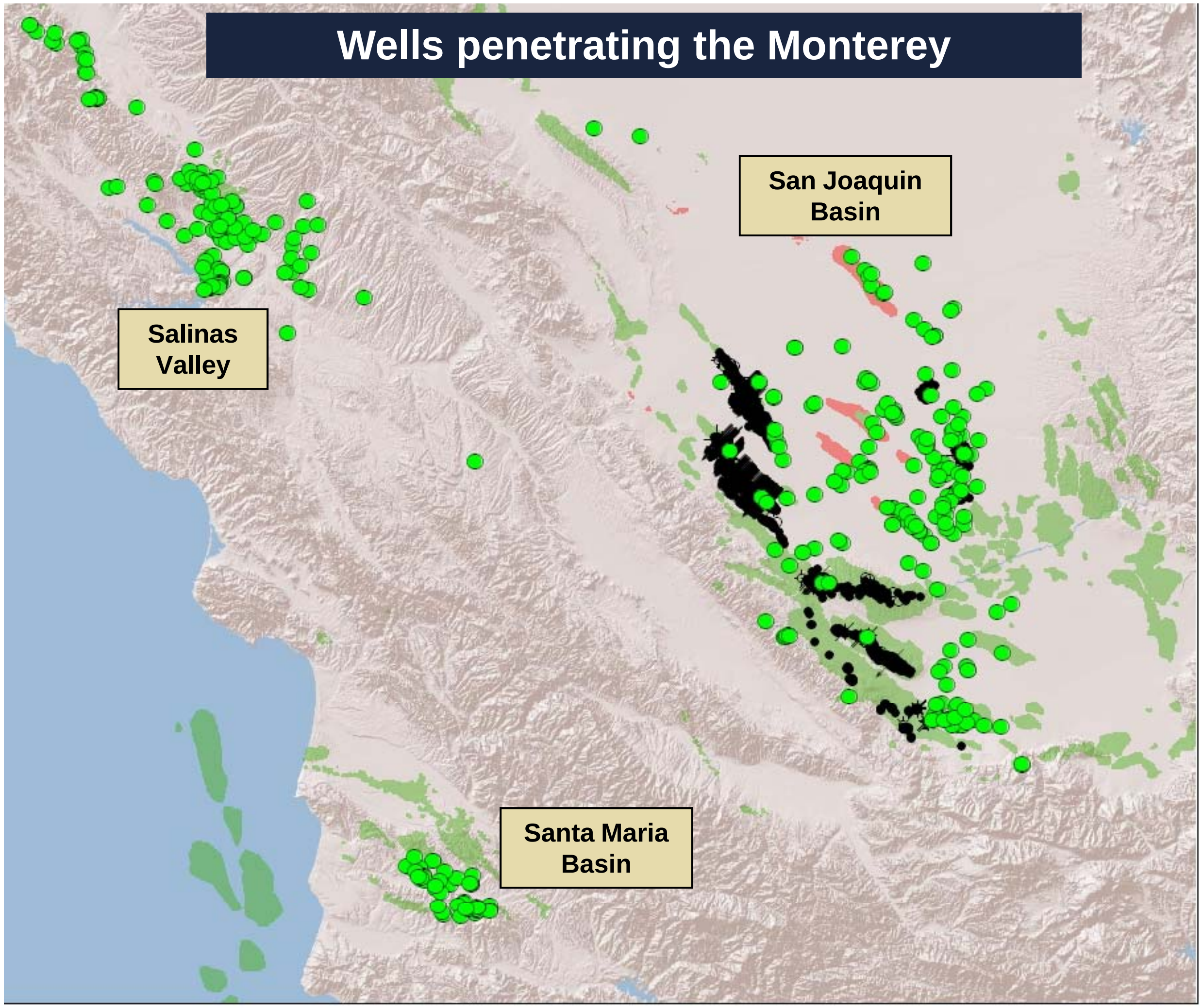


Additional turbidite sand targets

Monterey section (500 – 3,000' thick)

Monterey – Abundant Data Exists

- 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



Comparing Shale Plays

- The Monterey metrics compare 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
Santa Maria Basin	7,000’ to 14,000’	500 - 6000’	42°	1.3 - 18.7 [2]	13 - 29	61%	5%	84	3.10[3]

(1) From USGS Paper 1653.
(2) Venoco net pay estimates based on 1 millidarcy or better permeability.
(3) See “Net Asset Value & Unrisked Resource Estimates.“

Three Year Opportunity

- Increase total acreage position to 350,000 net acres
- Drill original 26 evaluation areas and 60+ development wells
- 3-year capital expenditures of approximately $325 million
- Modeled resource ~400 million BOE(1)
- Unrisked NAV >$4.5 billion(1)
- Additional resource upside: Each 1% recovery = ~200 million BOE

	Activity	2010	2011	2012	3 year
Evaluation	Drilling	7 wells	8 wells	12 wells	27
	Seismic	Initiate 500 sq. mile joint VQ-OXY seismic shoot	Complete joint seismic shoot		
Development	Drilling	4 wells	22 wells	38 wells	64
	Total	11 wells	30 wells	50 wells	91
Capital(2)		$62 million	$100 million	$160-180 million	

(1) Unrisked development scenario based on the type curves for the individual basins included in this presentation. See footnotes relating to Salinas Valley, San Joaquin Basin, and Santa Maria Basin type curves and unrisked Monterey 5-year model. Also see "Cautionary Statement Regarding Forward Looking Information" and "Net Asset Value & Unrisked Resource Estimates."

(2) Total capital expenditures include costs for land, facilities, G&G, and other. 2010 & 2011 are budget estimates; 2012 budget has yet to be determined and the range shown is illustrative of a possible development scenario.

Initial Pilot Project Areas for Exploitation

Development Options

- Salinas Valley
  - 17,000 acres
  - 65 wells(1)
- San Joaquin Basin
  - 83,000 acres
  - ~750 wells(1)
- Santa Maria Basin
  - 20,000 acres
  - 70 wells(1)

MONTEREY SHALE DRILLING SCHEDULE

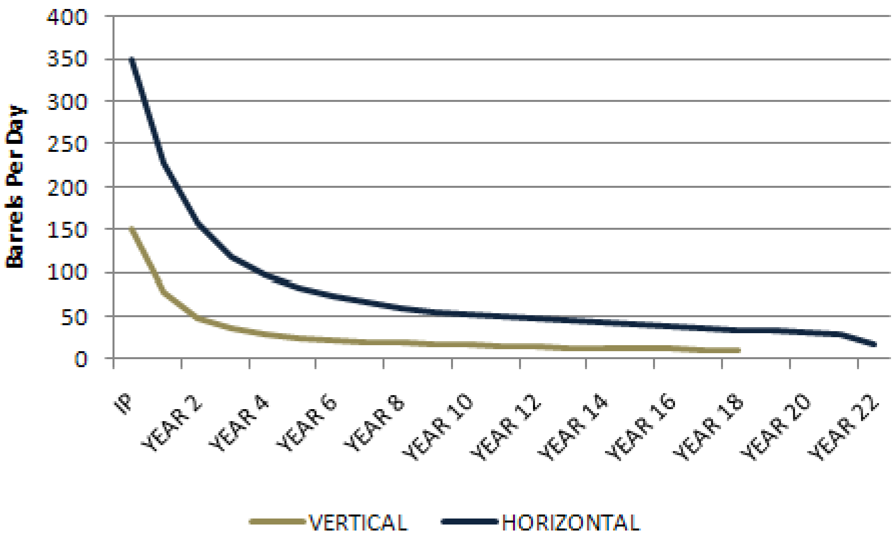
WELL	BASIN	VERTICAL or HORIZONTAL	STATUS(2)
1	Salinas Valley	Vertical	TA
2	San Joaquin	Vertical	Testing
3	San Joaquin	Vertical	Testing
4	San Joaquin	Vertical	TD'd (3)
5	San Joaquin	Vertical	Testing
6	San Joaquin	1st Horizontal	Uneconomic
7	Santa Maria	2nd Horizontal	Completing
8	San Joaquin	Vertical	Testing
9	Santa Maria	3rd Horizontal	Completing
10	San Joaquin	Vertical	TD'd
11	Salinas Valley	4th Horizontal	Drilling
12	San Joaquin	Vertical	Drilling

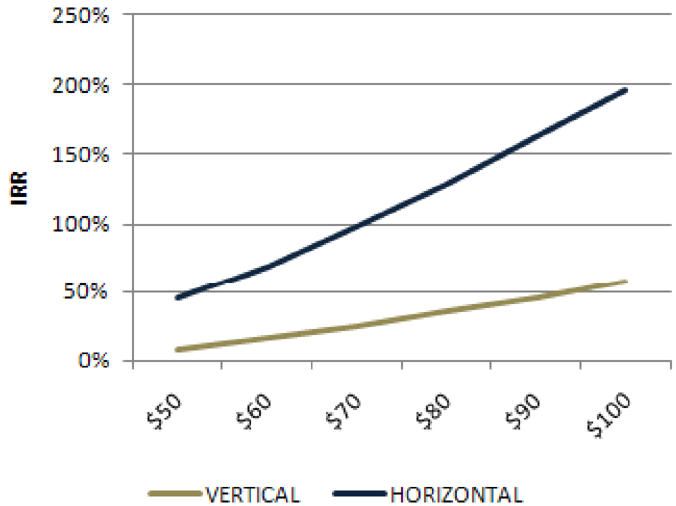
(2) As of 1/06/11
(3) Kicked off horizontal development Well 6 into a section identified in vertical wellbore.

(1) Unrisked estimates based on deterministic volumetrics, internal development plans for the individual basins, and analogous production profiles. See "Net Asset Value & Unrisked Resource Estimates" and "Cautionary Statement Regarding Forward Looking Information."

Salinas Valley – Type Curve

Vertical vs. Horizontal Type Wells(1)





Vertical Summary

- Capital Cost = $3.0 MM
  - LOE = $6.25 / BO
- EUR = 150 MBO
  - IP = 150 BOPD
- NPV10 = $2.1 MM
  - Flat Pricing: $80/BO & $5/MCF
- P/I = +0.70

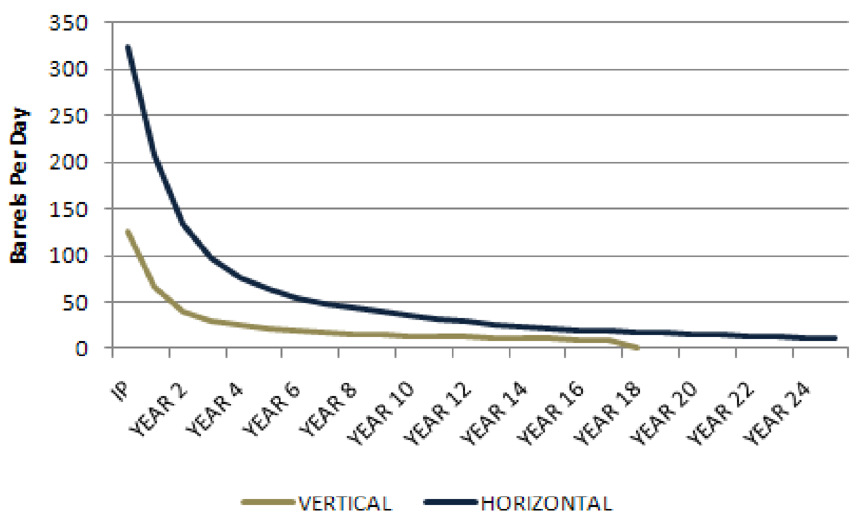
Horizontal Summary

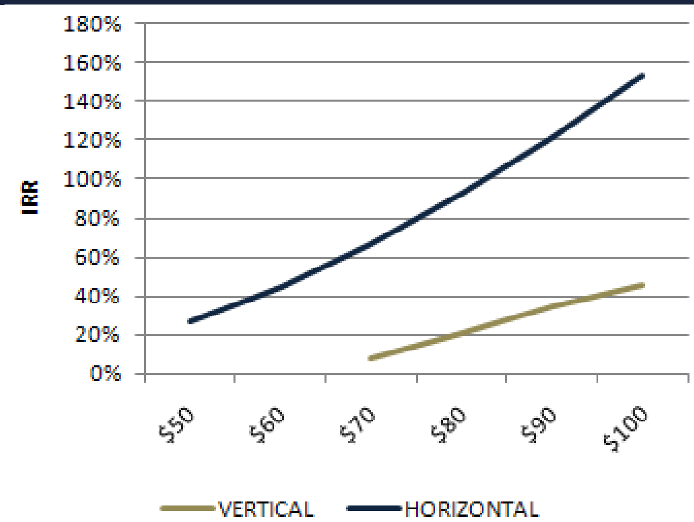
- Capital Cost = $4.5 MM
  - LOE = $6.25 / BO
- EUR = 525 MBO
  - IP = 350 BOPD
- NPV10 = $11.9 MM
  - Flat Pricing: $80/BO & $5/MCF
- P/I = +2.64

(1) Unrisked estimates based on deterministic volumetrics, internal development plans for the individual basins, and analogous production profiles. Estimates reflect modeled data and not results of wells drilled to date. See “Net Asset Value & Unrisked Resource Estimates” and “Cautionary Statement Regarding Forward Looking Information.” Excludes costs such as capitalized G&A, land acquisition, and facilities. Type well assumes 100% WI and 80% NRI.

San Joaquin Basin – Type Curve

Vertical vs. Horizontal Type Wells[1]





Vertical Summary

- Capital Cost = $3.0 MM
  - LOE = $9.00 / BO
- EUR = 125 MBO
  - IP = 125 BOPD
- NPV10 = $1.0 MM
  - Flat Pricing: $80/BO & $5/MCF
- P/I = +0.33

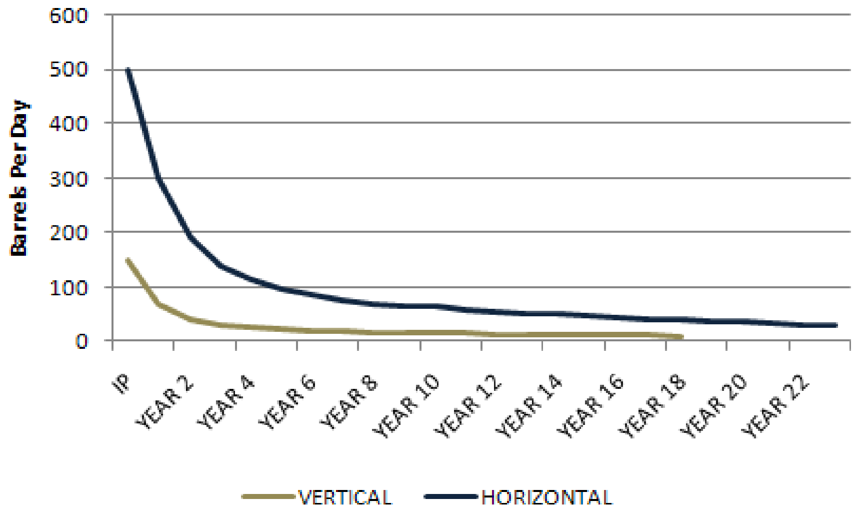
Horizontal Summary

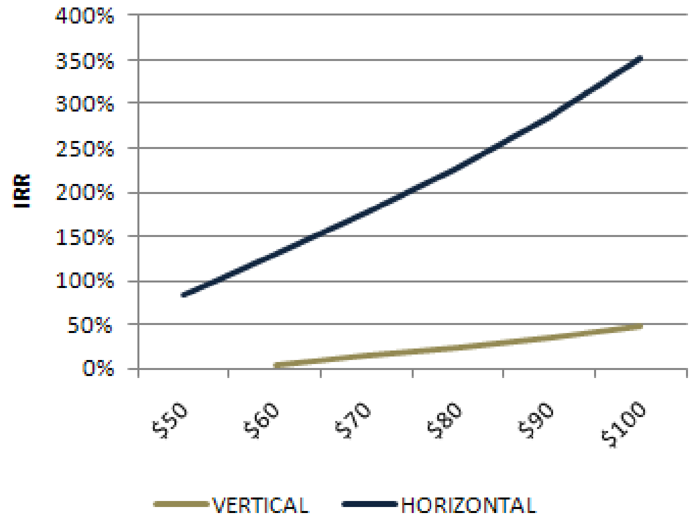
- Capital Cost = $4.5 MM
  - LOE = $9.00 / BO
- EUR = 425 MBO
  - IP = 325 BOPD
- NPV10 = $8.0 MM
  - Flat Pricing: $80/BO & $5/MCF
- P/I = +1.79

(1) Unrisked estimates based on deterministic volumetrics, internal development plans for the individual basins, and analogous production profiles. Estimates reflect modeled data and not results of wells drilled to date. See “Net Asset Value & Unrisked Resource Estimates” and “Cautionary Statement Regarding Forward Looking Information.” Excludes costs such as capitalized G&A, land acquisition, and facilities. Type well assumes 100% WI and 80% NRI.

Santa Maria Basin – Type Curve

Vertical vs. Horizontal Type Wells(1)





Vertical Summary

- Capital Cost = $2.0 MM
  - LOE = $6.85 / BO
- EUR = 125 MBO
  - IP = 150 BOPD
- NPV10 = $1.5 MM
  - Flat Pricing: $80/BO & $5/MCF
- P/I = +0.49

Horizontal Summary

- Capital Cost = $4.0 MM
  - LOE = $6.85 / BO
- EUR = 650 MBO
  - IP = 500 BOPD
- NPV10 = $15.6 MM
  - Flat Pricing: $80/BO & $5/MCF
- P/I = +3.88

(1) Unrisked estimates based on deterministic volumetrics, internal development plans for the individual basins, and analogous production profiles. Estimates reflect modeled data and not results of wells drilled to date. See "Net Asset Value & Unrisked Resource Estimates" and "Cautionary Statement Regarding Forward Looking Information." Excludes costs such as capitalized G&A, land acquisition, and facilities. Type well assumes 100% WI and 80% NRI.

Financial Overview & Wrap Up

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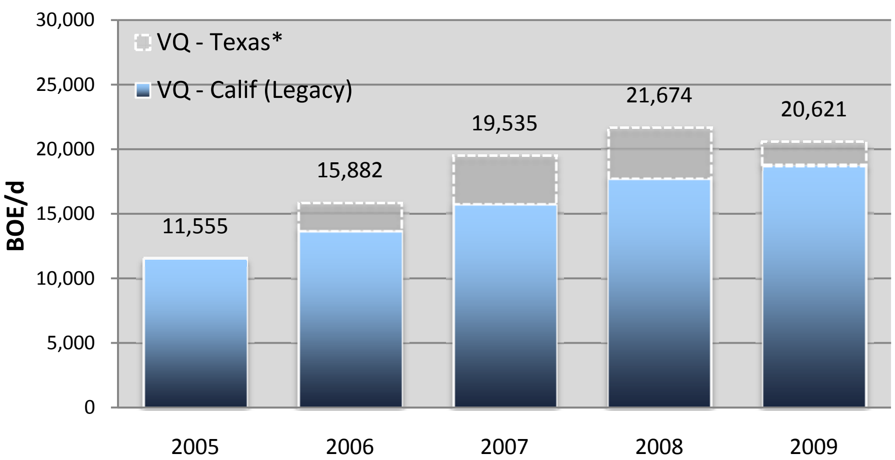
9-Months YTD Performance & 2011 Guidance

Average Net Daily Production



2011 production guidance of 19,500 BOE/d

- Risked onshore Monterey production of 2,000 BOE/d and slight decline from legacy assets

Historical Production by Region (BOE/d)	3Q09	2Q10	3Q10	9-Mos. Ended 9/30/10	2011 Guidance
Sacramento Basin	10,498	9,864	10,284	9,990	
Southern California	8,207	7,744	7,803	7,941	
Texas (and other)	1,559	582	0	618	
Total	**20,264**	**18,190**	**18,087**	**18,549**	**19,500**

Historical Financial Results ($/BOE)	3Q09	2Q10	3Q10	9-Mos. Ended 9/30/10	2011 Guidance
LOE	$13.55	$13.65	$12.44	$12.67	$14.25
Prod'n/Prop Taxes	$1.48	$0.82	$1.05	$1.05	$1.20
DD&A Expense	$11.79	$11.32	$11.70	$11.49	$13.00
G&A Expense(1)	$4.82	$5.10	$4.31	$4.73	$4.75
Interest Expense(2)	$7.97	$9.39	$9.08	$9.08	$8.70
Total Expenses	**$39.61**	**$40.28**	**$38.58**	**$39.02**	**$41.90**
Adj. EBITDA (mm)(3)				$148.1	

(1) Net of amounts capitalized and excluding stock-based compensation and Texas severance costs. See Appendix for a reconciliation of G&A per BOE.
(2) Includes interest expense, realized (gain) loss on interest rate swap and amortization of deferred loan costs.
(3) Please see Appendix for a definition of Adjusted EBITDA and a reconciliation to net income (loss).
* Company sold its producing Texas assets in a series of transactions during 2009 and 2010.

2011 Projections @ Various Commodity Prices

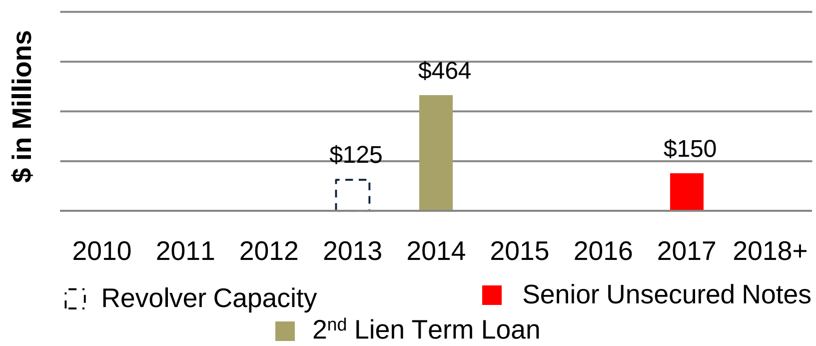
		Average Commodity Price for Full Year ($ in Million)[1]			
Price - Oil/Gas	Guidance	$70/$3.50	$75/$4.00	$80/$4.50	$85/$5.00
O/G revenue (unhedged)	19,500 BOE/d	$282.3	$308.3	$334.4	$360.4
Hedging effect [2]		40.0	29.1	18.1	7.2
Net O/G revenues		322.3	337.4	352.5	367.6
LOE	$14.25/BOE	(101.4)	(101.4)	(101.4)	(101.4)
Production & property taxes	$1.20/BOE	(8.5)	(8.5)	(8.5)	(8.5)
G&A[3]	$4.75/BOE	(33.8)	(33.8)	(33.8)	(33.8)
Other[4]		(2.2)	(2.2)	(2.2)	(2.2)
Adjusted EBITDA[5]		$176.4	$191.5	$206.6	$221.7
Cash interest and realized interest rate derivative gain/(loss)		(59.1)	(58.9)	(58.7)	(58.3)
Amortization of deferred loan costs and commodity derivative premiums		(10.0)	(10.0)	(10.0)	(10.0)
DD&A	$13.00/BOE	(92.5)	(92.5)	(92.5)	(92.5)

(1) Full year projections and flat NYMEX prices as indicated.
(2) Estimated realized hedge gains/losses.
(3) Excludes non-cash stock-based compensation charges.
(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.

Financial Strategy

- **Grow Adjusted EBITDA and net asset value through low-risk projects and Monterey shale development**
- **Flexibility to actively manage capital budget**
  - Operate 97% of our properties – ability to control our capital spending
  - Able to shift capital expenditures to Oil or Natural Gas projects based on pricing
  - Minimal “required” annual spending – limited drilling/rig/land commitments
- **Aggressively utilize oil and gas derivatives to limit downside risk**
- **Continue to preserve financial and operating flexibility through potential joint-ventures, operating partnerships, sales of non-producing properties, and/or equity issuance**
- **Continue to focus on reducing leverage**
- **Monetize Hastings 22.3% WI Back-in**
  - CO_2 injection initiated Dec. 2010
- **Solid Debt Position**
  - Low blended rate for term debt
- **Continue to Focus on Costs**
  - Maintain low operating cost per BOE
  - Realize efficiencies in capital program

Debt Maturity



Potential Net Asset Value

Total Proved Reserves per fully diluted share[4] = $15.65

Commodity Price Assumption: 5-Year Strip as of 12/31/09[1]

		PV-10[2]/ NAV ($MM)	Risk Factor[5]	Risked Value[5]
Proved Reserves	**101.3 MMBOE**	**$1,670**	100%	**$1,670**
Texas Asset Sale	**-7.4 MMBOE**	**($144)**	100%	**($144)**
Pro Forma Proved Reserves	**93.9 MMBOE**	**$1,526**		**$1,526**
Probable Reserves				
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	75%	$169
Additional Resources[3]				
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	25%	$64
Onshore Monterey Shale[6]	399.3 MMBOE	$4,631	30%	$1,389
Potential Asset Value	**644.2 MMBOE**	**$7,890**		**$4,051**
	(as of 9/30/10)			
	Total Debt	**($647.9)**		**($647.9)**
	Cash	**$0.0**		**$0.0**
	Net Debt	**($647.9)**		**($647.9)**
	Fair Value of Commodity & Interest Rate Derivatives	**$18.9**		**$18.9**
	Net Balance Sheet Items	**($629.0)**		**($629.0)**
	Fully Diluted Shares Outstanding	**57.34**		**57.34**
	Total Potential Asset Value per fully diluted share[4]	**$126.62**		**$59.69**

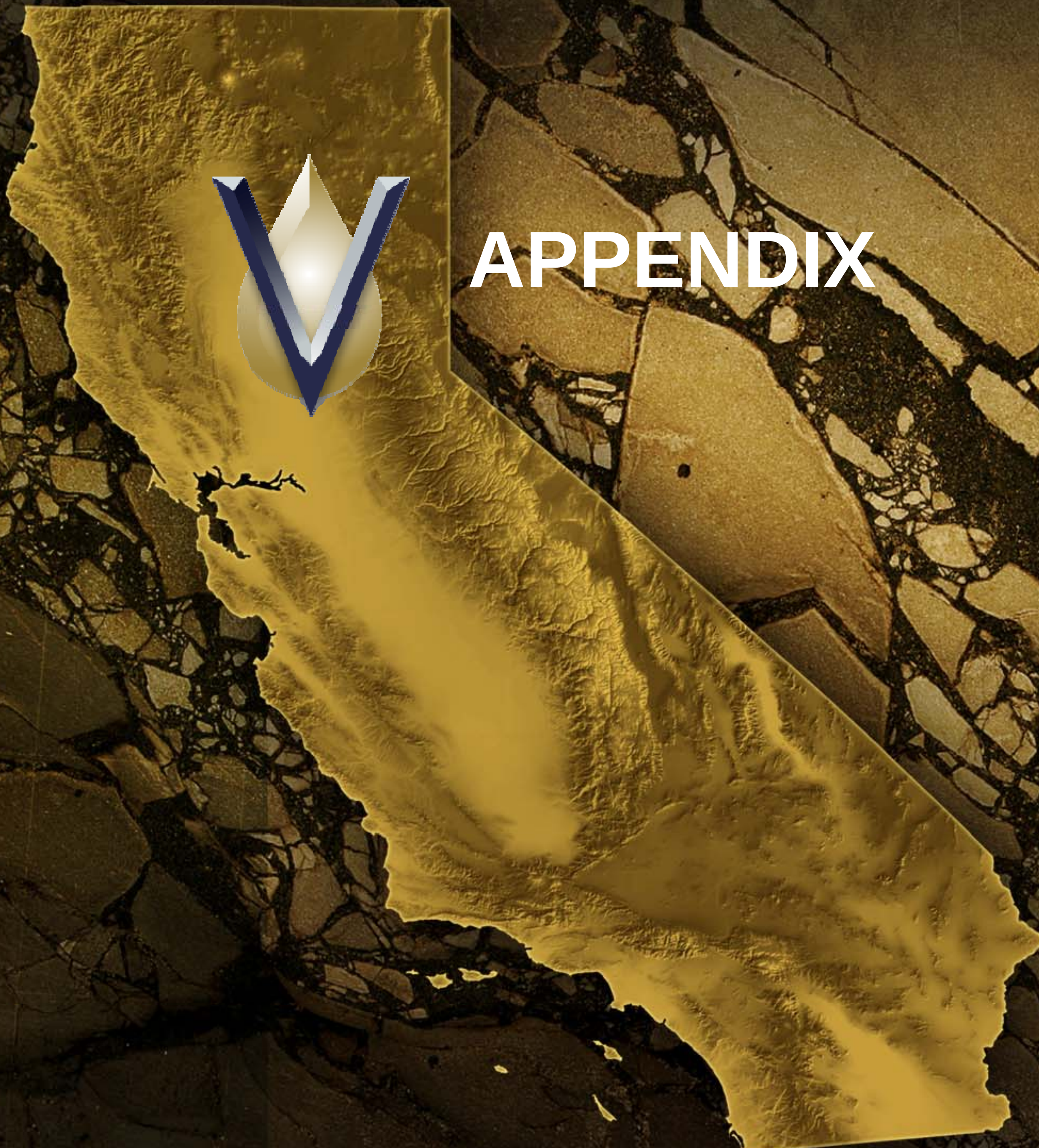
(1) On 12/31/09, the 5-year strip averaged $87.04/Bbl and $6.43/Mcf, ranging from an average of $81.16/Bbl and $5.79/Mcf in 2010 to $91.09/Bbl and $6.84/Mcf in 2014. Average 2014 prices were used for future years. (2) See Appendix for a definition of PV-10 and the relevant GAAP reconciliation. (3) Amounts other than 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." (4) PV-10 of Proved Reserves or Potential Asset Value, as applicable, less net debt and the estimated fair value of interest rate and commodity derivatives included in the balance sheet at 9/30/10. NAV per share based on shares outstanding and common stock equivalents at 9/30/10. Common stock equivalents do not assume application of treasury stock method. (5) 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."

(6) 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 footnotes relating to Salinas Valley, San Joaquin Basin, and Santa Maria Basin type curves. 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.

Why Own Venoco Shares?

- **Long-Lived, Oil-Leveraged Asset Base**
  - Stable, Low-Decline Oil Production – Low Maintenance Capital
  - Oil Weighted: ~65% 2009 revenue, 53% reserves
- **Solid Balance Sheet**
  - Strong Hedge Positions
  - Strong Liquidity Position – No Near-Term Debt Maturities
- **Monterey Shale – Billion barrel opportunity**
  - Highly levered to Monterey with 60% of current oil production from Monterey
  - 13 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
- **Management /Shareholder Alignment**
- **Teams of Experienced Personnel**
  - Advancing New Technologies to Optimize, Enhance and Expand Productive Capacity & Reserves

APPENDIX



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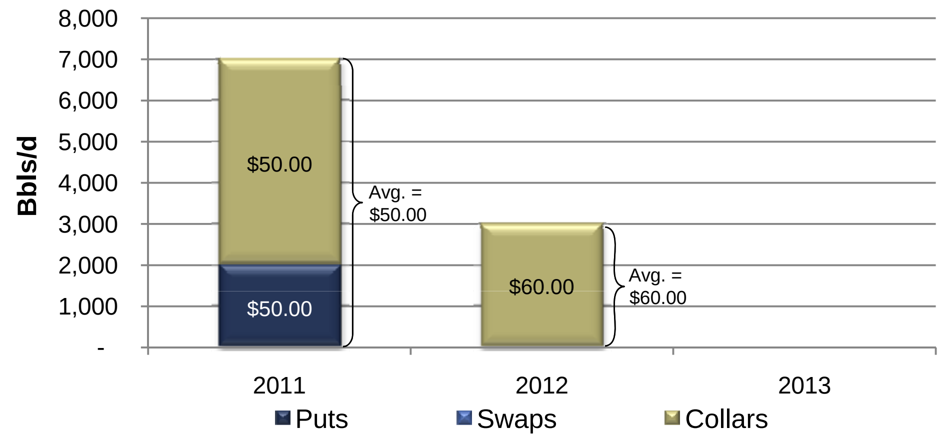
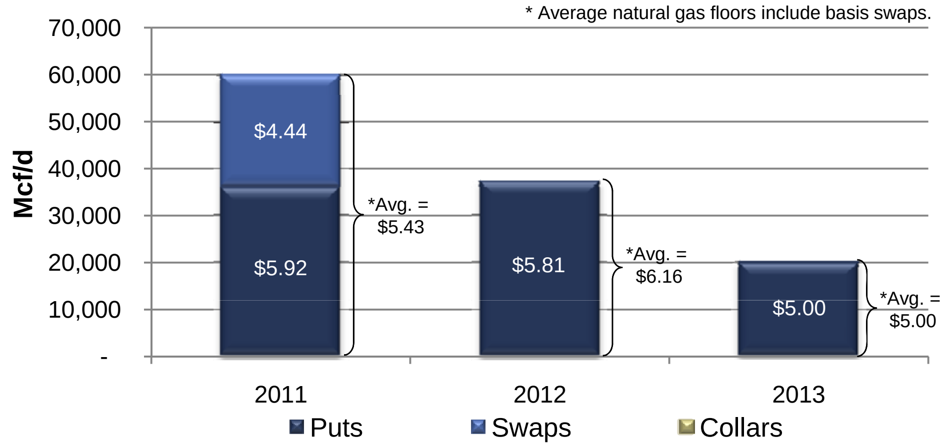
Significant Hedging Program

Oil Downside Protection



Natural Gas Downside Protection



	Floor		Cap	
Current Crude Oil Deliveries for Production	**BBLs/Day**	**Weighted Avg Prices**	**BBLs/Day**	**Weighted Avg Prices**
Jan 1 - Dec 31, 2011	**7,000**	**$ 50.00**	**5,000**	**$ 100.00**
Jan 1 - Dec 31, 2012	**3,000**	**$ 60.00**	**3,000**	**$ 121.10**

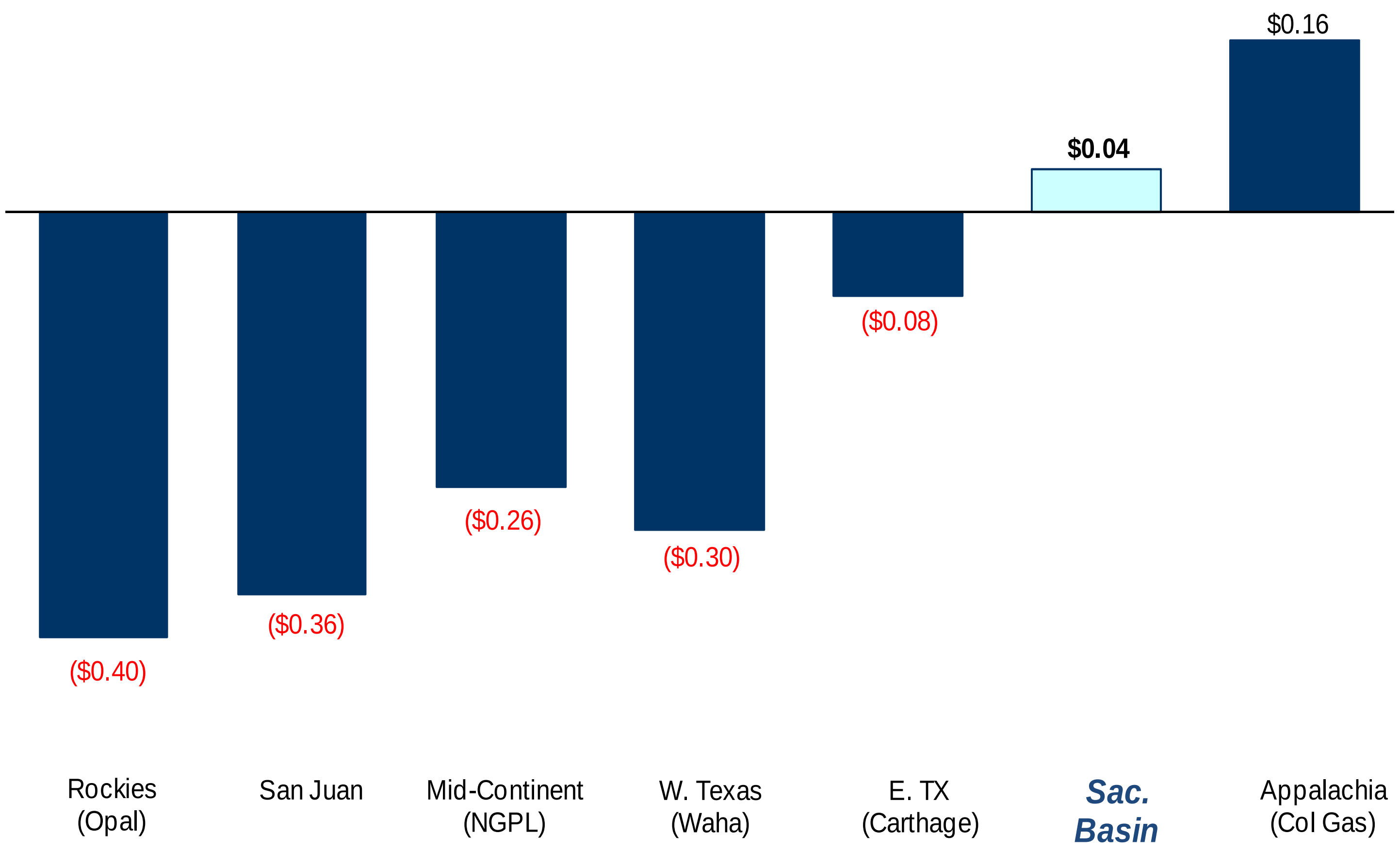
	Floor		Cap	
Current Natural Gas Deliveries for Production	**MMBtu/Day**	**Weighted Avg Prices**	**MMBtu/Day**	**Weighted Avg Prices**
Jan 1 - Dec 31, 2011	**60,000**	**$ 5.43**	**24,000**	**$ 4.71**
Jan 1 - Dec 31, 2012	**37,300**	**$ 6.16**	**-**	**$ -**
Jan 1 - Dec 31, 2013	**20,000**	**$ 5.00**	**20,000**	**$ 7.02**

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 January 1, 2011.

Sac Basin: Superior Realizations Enhance Economics

Natural Gas Basis Differentials ($ per MMBtu)

Based on $4.22 per MMBtu Henry Hub Average January 2011 price



Source: NGI Bidweek Survey – January 2011.

Historical Operating Data

	Years Ended December 31					Nine Months Ended September 30,
	2005	2006	2007	2008	2009	2010
Production (BOE/d)	11,555	15,882	19,535	21,674	20,622	18,549
Oil component	70%	59%	56%	52%	45%	43%
Oil & Gas Sales ($000)	$191,772	$268,822	$373,155	$555,917	$268,865	$220,597
LOE per BOE	$12.44	$14.18	$15.05	$16.86	$12.65	$12.67
Production & Property Taxes per BOE	$0.37	$0.91	$1.69	$1.98	$1.35	$1.05
G&A per BOE	$3.79	$4.88	$4.46	$5.43	$4.91	$5.62
Interest Expense per BOE (2)	$3.66	$9.09	$9.00	$8.52	$8.28	$9.08
Adjusted EBITDA (1) ($000)	$100,455	$146,173	$210,397	$299,810	$192,863	$148,077
Realized Prices per Unit:						
Oil, Excl Hedges (BBL)	$45.66	$55.92	$64.06	$89.69	$51.10	$67.78
Gas, Excl Hedges (MCF)	$7.45	$6.04	$6.61	$8.21	$3.84	$4.46
Blended, Excl Hedges (BOE)	$45.47	$46.37	$52.34	$70.08	$35.72	$43.56
Blended, Excl Hedges (Mcfe)	$7.58	$7.73	$8.72	$11.68	$5.95	$7.26

(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.

Net Asset Value & Unrisked Resource Estimates

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 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 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, 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

Per BOE G&A

We also provide per BOE G&A expenses excluding share-based compensation and Texas severance costs. 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.

	Quarter Ended			**Year Ended**	**Nine Months Ended**
UNAUDITED ($ in thousands, except per BOE amounts)	**9/30/2009**	**6/30/2010**	**9/30/2010**	**12/31/2009**	**9/30/2010**
G&A per BOE Reconciliation					
G&A expense	$ 9,607	$ 10,762	$ 8,264	$ 36,939	$ 28,435
Less:					
Share-based Comp	(616)	(1,068)	(1,097)	(2,124)	(3,248)
Texas severance costs	-	(1,254)	-	-	(1,254)
G&A Expense Excluding Share-Based Comp	8,991	8,440	7,167	34,815	23,933
MBOE	1,864	1,655	1,664	7,527	5,064
G&A Expense per BOE Excluding Share-Based Comp	$ 4.82	$ 5.10	$ 4.31	$ 4.63	$ 4.73

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	Nine Months Ended 9/30/10
Net Income (Loss)	$ 16,110	$ 23,951	$ (73,372)	$ (391,132)	$ (47,298)	$ 63,085
Interest, Net	13,673	48,795	60,115	54,049	40,984	30,539
Realized Interest Rate Derivative (Gains) Losses	-	96	(135)	10,231	18,479	13,563
Income Taxes	10,300	15,650	(46,200)	11,200	(14,400)	(400)
Amortization of Deferred Loan Costs	1,755	3,776	4,197	3,344	2,862	1,855
DD&A	21,680	63,259	98,814	134,483	86,226	58,191
Accretion of Asset Retirement Obligation	1,752	2,542	3,914	4,203	5,765	4,649
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	4,118
Texas Severance Costs	-	-	-	-	-	1,254
Amortization of Derivative Premiums and Other Comprehensive Loss	4,701	8,181	11,546	7,694	24,985	16,972
Unrealized Commodity Derivative (Gains) Losses	32,236	(21,079)	122,779	(184,459)	71,511	(69,034)
Unrealized Interest Rate Derivative (Gains) Losses	-	494	17,312	10,336	(1,803)	23,285
Adjusted EBITDA	$ 102,207	$ 148,715	$ 214,311	$ 304,013	$ 198,628	$ 148,077