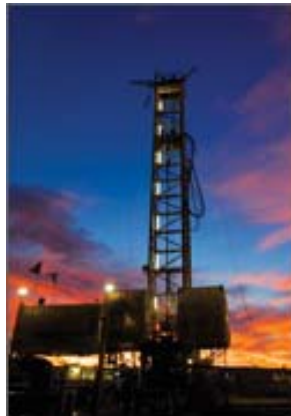


MARINER ENERGY, INC.

ONSHORE | OFFSHORE



IPAA Oil & Gas Investment Symposium
April 13, 2010

Important Information About Forward-looking Statements

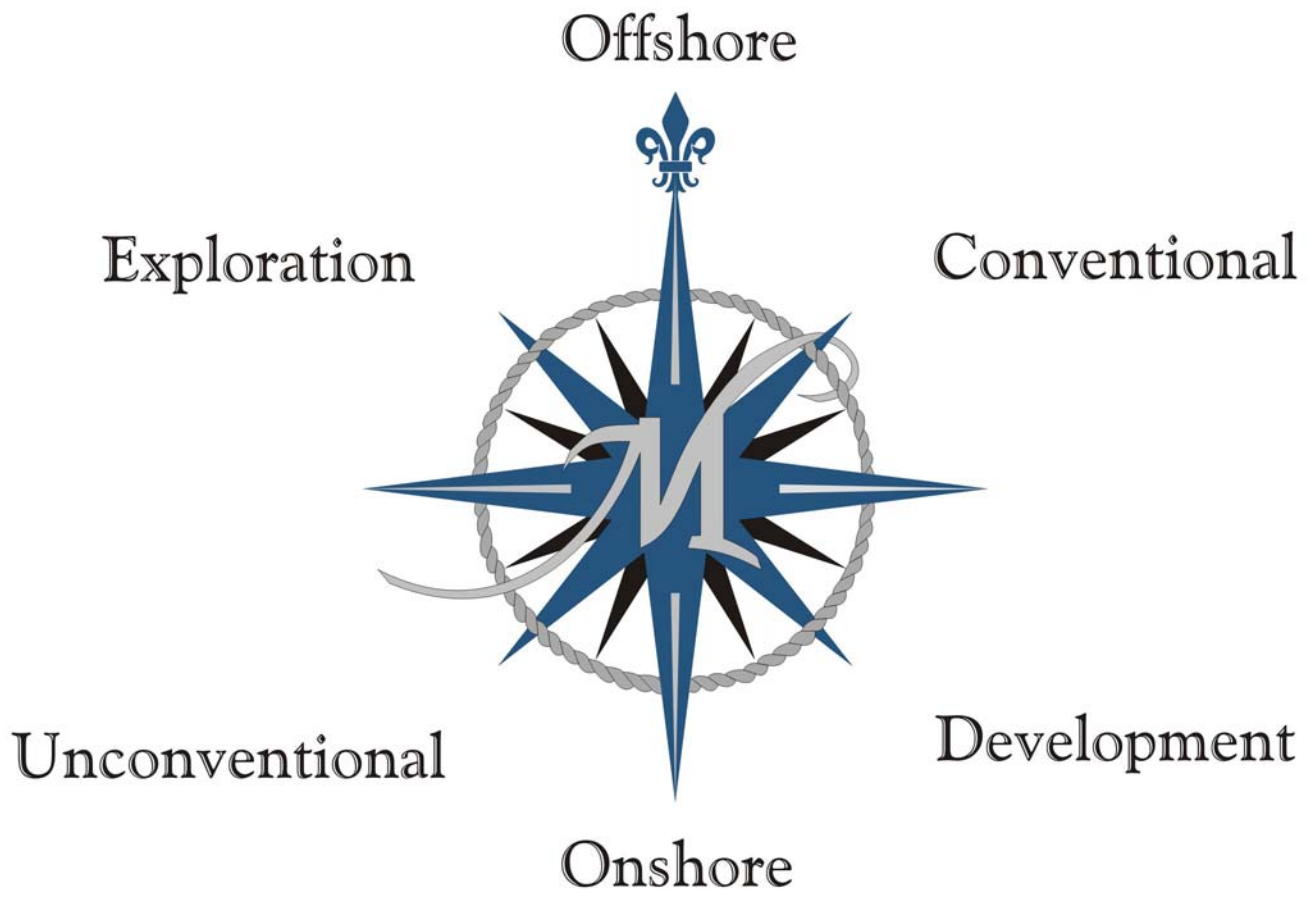
This presentation includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, that address activities that Mariner assumes, plans, expects, believes, projects, estimates or anticipates (and other similar expressions) will, should or may occur in the future are forward-looking statements. Our forward-looking statements generally are accompanied by words such as “may”, “will”, “estimate”, “project”, “predict”, “believe”, “expect”, “anticipate”, “potential”, “plan”, “goal”, or other words that convey the uncertainty of future events or outcomes. Forward-looking statements provided in this presentation are based on Mariner’s current belief based on currently available information as to the outcome and timing of future events and assumptions that Mariner believes are reasonable. Mariner does not undertake to update its guidance, estimates or other forward-looking statements as conditions change or as additional information becomes available. Estimated reserves are related to hydrocarbon prices. Hydrocarbon prices used in estimating reserves may vary significantly from actual future prices. Therefore, volumes of reserves actually recovered may differ significantly from such estimates. Mariner cautions that its forward-looking statements are subject to all of the risks and uncertainties normally incident to the exploration for and development, production and sale of oil and natural gas. These risks include, but are not limited to, price volatility or inflation, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating future oil and gas production or reserves, and other risks described in Mariner’s latest Annual Report on Form 10-K and other documents filed by Mariner with the Securities and Exchange Commission (SEC). Any of these factors could cause Mariner’s actual results and plans of Mariner to differ materially from those in the forward-looking statements. Investors are urged to read Mariner’s latest Annual Report on Form 10-K and other documents filed by Mariner with the SEC.

“Proved” oil and gas reserves are those that can be estimated with reasonable certainty to be economically and legally producible under existing economic conditions, operating methods and government regulations. “Probable,” “possible” and “non-proved” reserves, reserve “potential” or “upside” or other descriptions of volumes of reserves potentially recoverable involve estimates that by their nature are more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of actually being realized by Mariner. The SEC generally does not permit a company’s filings with the SEC to include estimates or estimated values of oil or gas resources other than reserves due to concern that resources other than reserves are too speculative and may be misleading.

This presentation does not constitute an offer to sell or a solicitation of an offer to buy any securities of Mariner.

March 2010





Mariner Energy Transformation

Unique, Multi-faceted, Multi-Disciplined, Diversified E&P Company

Proved Reserves (YE 2009)

- ~ 1.087 Tcfe (181 MMboe) - Ryder Scott engineered
- ~ 56% onshore
- 53% gas, 47% liquids
- 12% increase from prior year
- Reserve replacement cost: \$3.24 / Mcfe (1)
- 190% reserve replacement rate from all sources (1)

Significant unbooked, de-risked potential from recent deepwater discoveries, including Lucius, Heidelberg, Wide Berth, Bushwood and Dalmatian

Exploration Prospect Inventory

(ME estimated net unrisked, YE 2009)

- Deepwater ~ 8.4 Tcfe (1.4 Bboe)
- Shelf ~ 2.2 Tcfe (367 MMboe)

DeGolyer and MacNaughton estimated that ME's top 26 deepwater prospects hold prospective resource potential of ~1.28 Bboe, net unrisked

Development / Exploitation

- >3,000 non-proved drilling locations in the Permian
- Numerous low-risk exploitation Shelf opportunities

(1) See appendix for calculation.

Total Acreage (April 2010)

- Onshore: ~240,000 net acres
- Offshore: ~ 879,000 net acres

Unconventional (April 2010)

- ~96,000 acres net / 134,000 gross

ME Debt

- \$300 MM 7 ½% Senior Notes due 2013
- \$300 MM 11 ¾% Senior Noted due 2016
- \$300 MM 8% Senior Notes due 2017
- \$1 billion secured revolving credit facility with an \$800 MM borrowing base (~\$300 MM drawn down at YE 2009)
- Moody's Corporate Rating, B2, Stable
- S&P Corporate Rating, B+, Stable

Risk Management

Member of OIL Insurance Limited, cost-effective industry-owned insurance facility

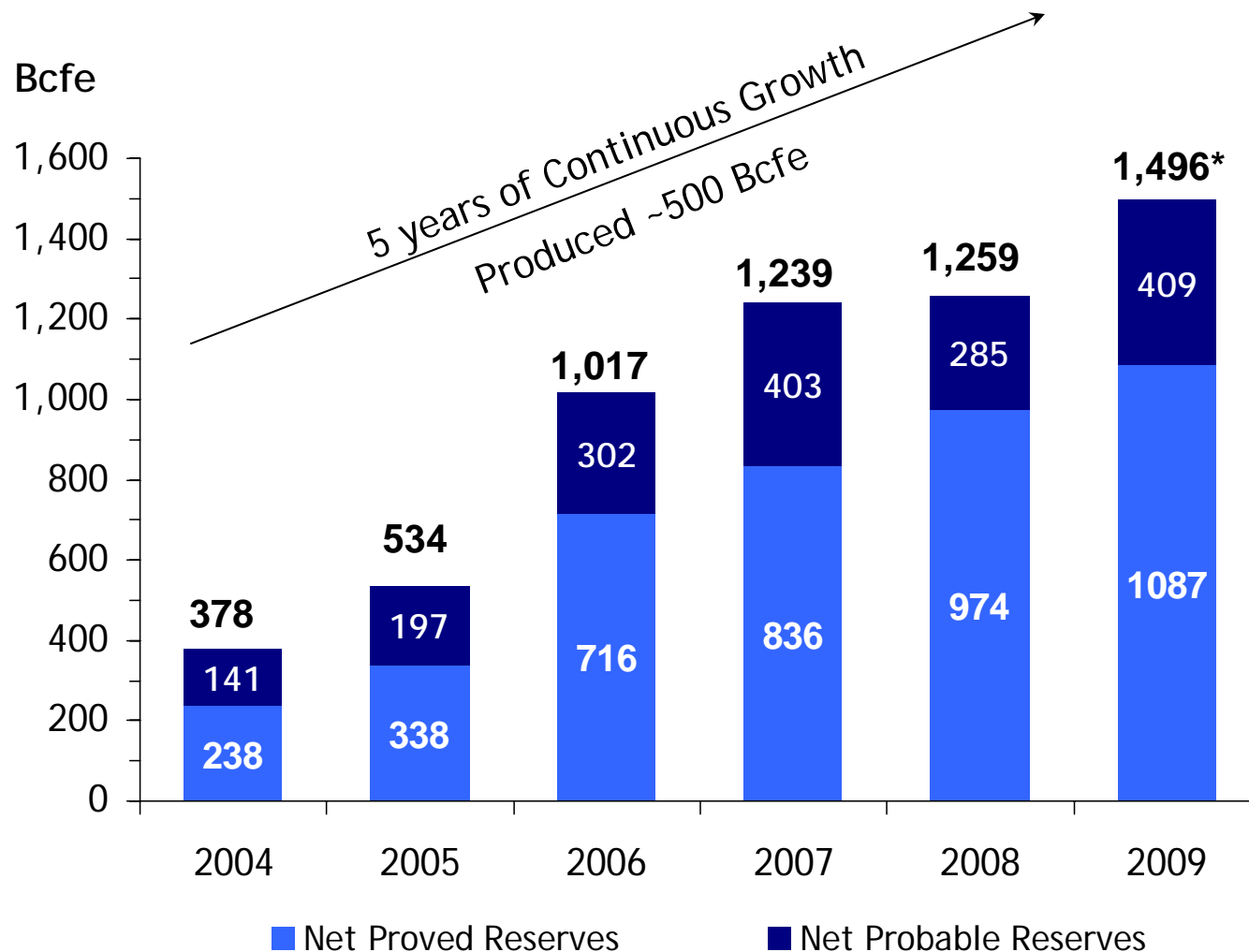
NYSE Stock Symbol: ME

~101.8 MM basic shares outstanding at YE 2009



Historical Reserves Growth (Proved & Probable)

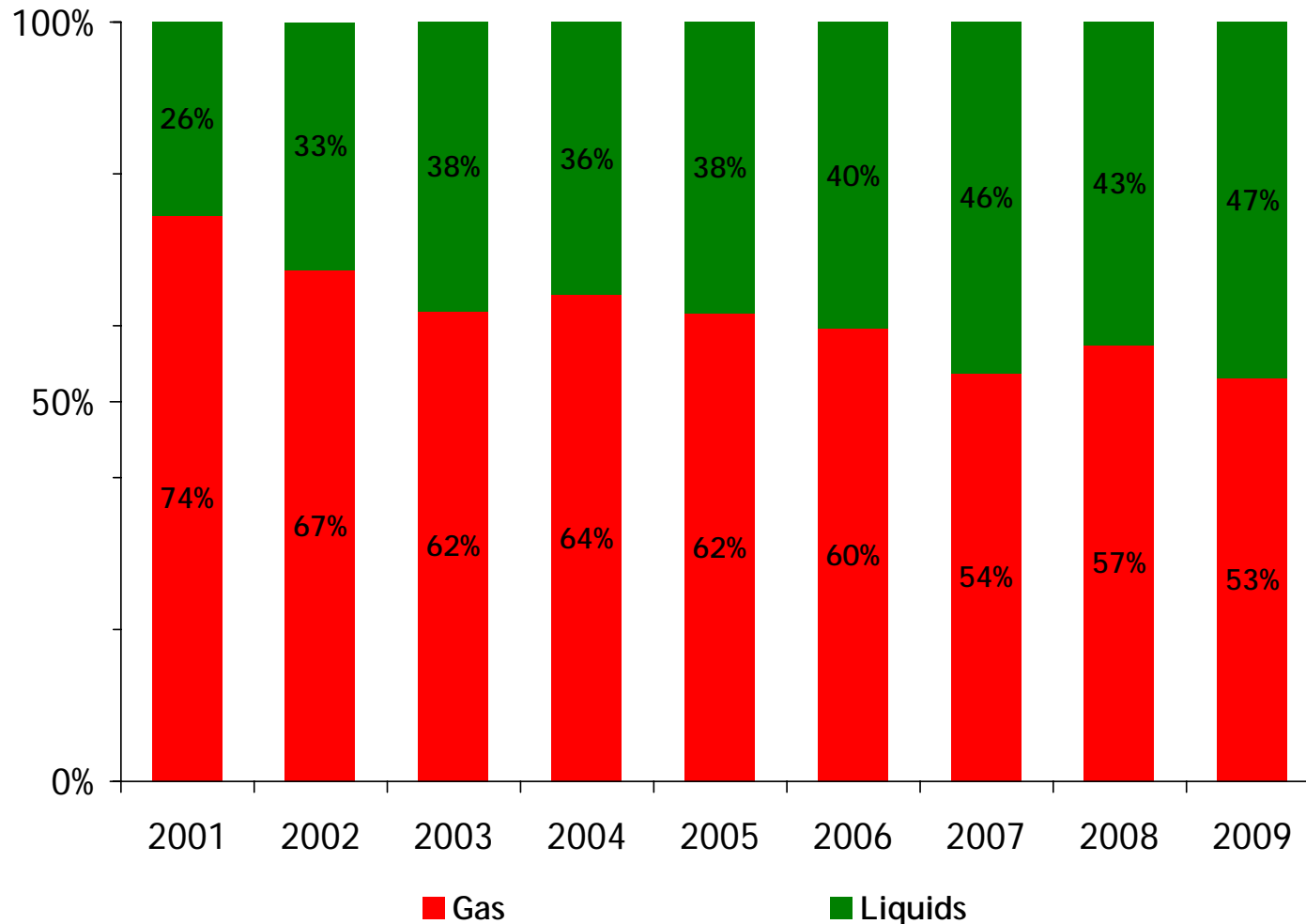
Deminimus Negative Revisions Over Past 6 Years



* Ryder Scott estimated proved and probable reserves as of 12/31/09 excluding ~29 Bcfe of probable reserves



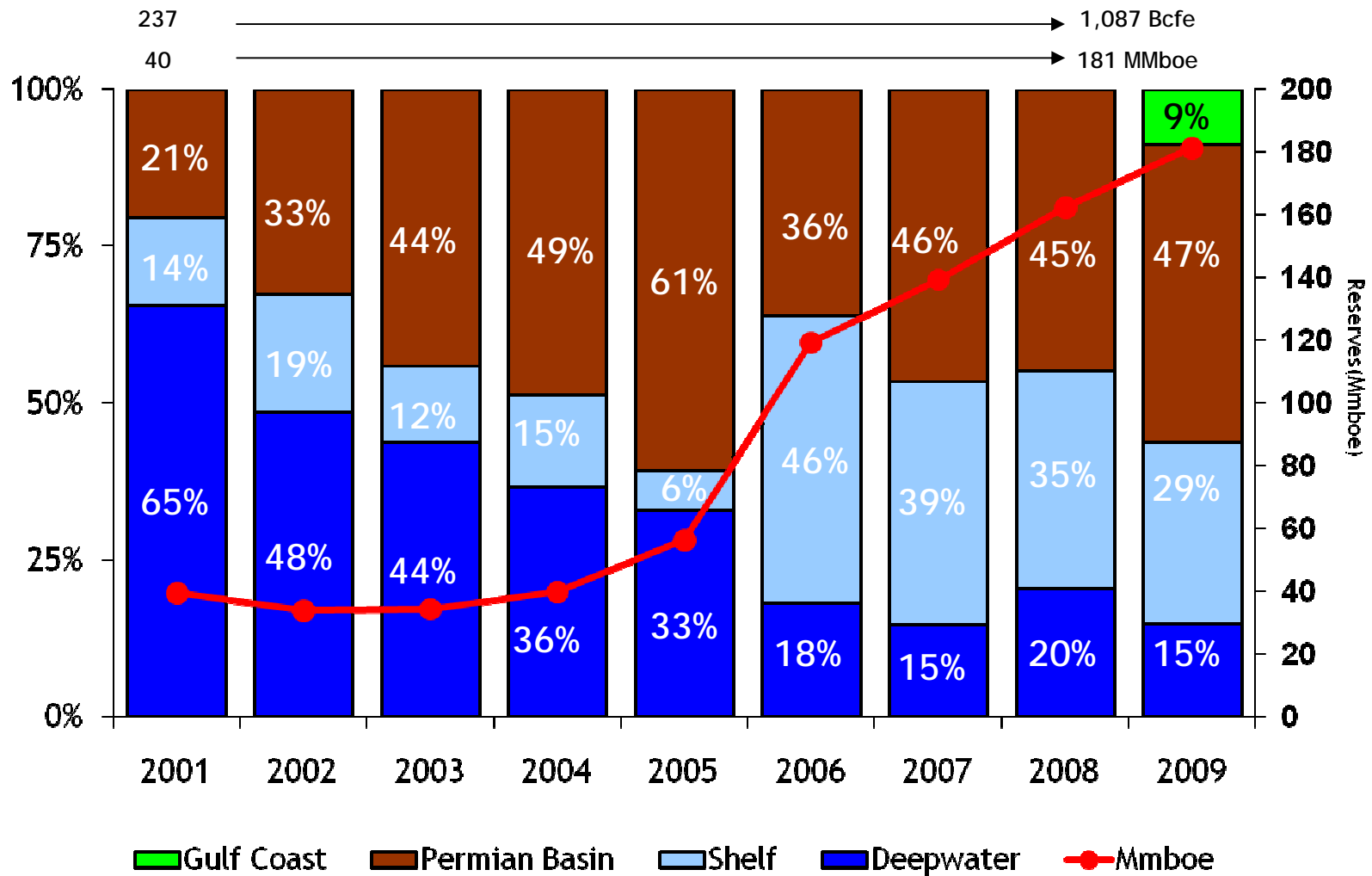
Historical Distribution of Liquids vs. Gas (Proved Reserves)* Excludes Recent Oil Field Discoveries, e.g., Lucius and Heidelberg



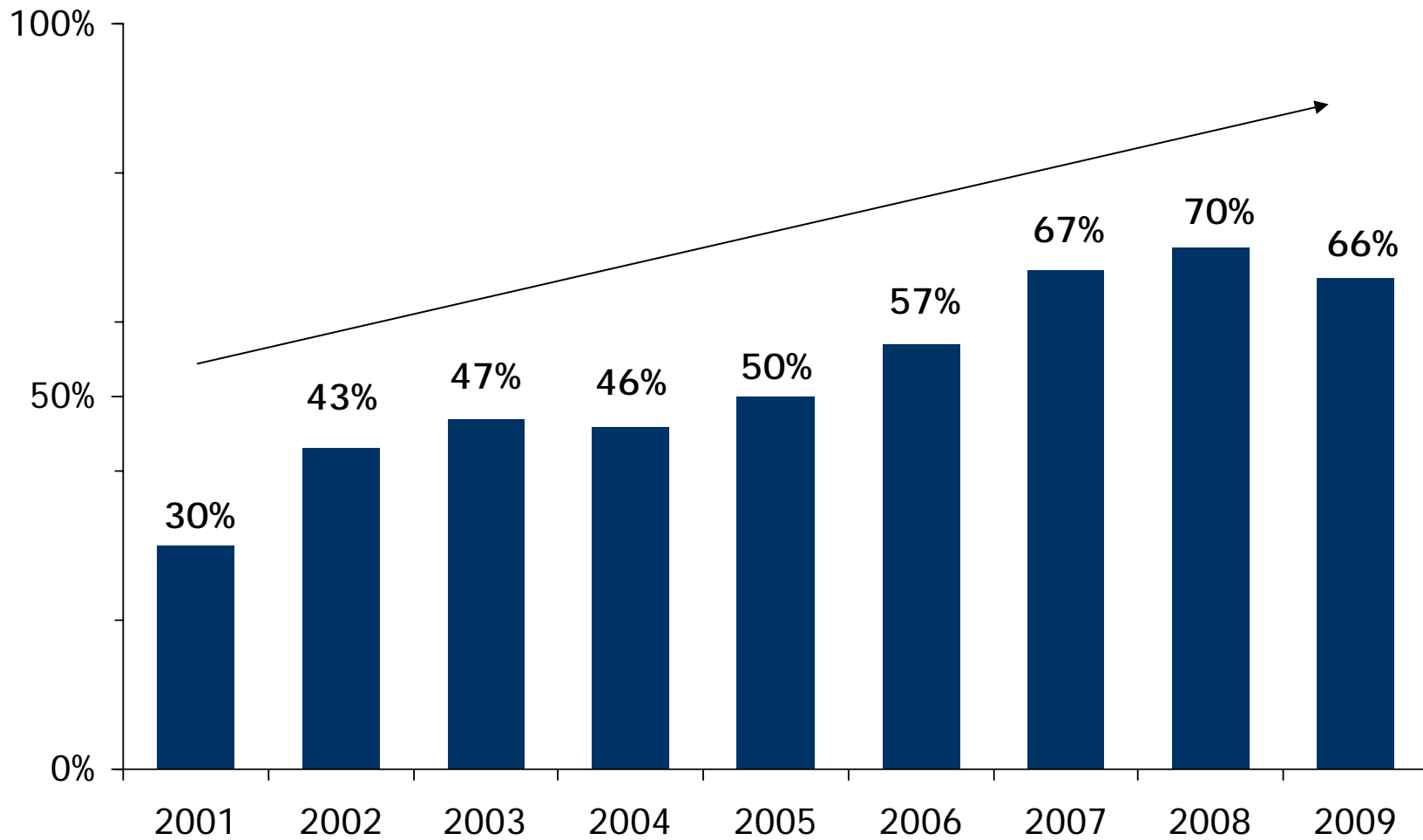
* Calculated using 6:1 gas/oil ratio



Transformation of Proved Reserve Base By Region

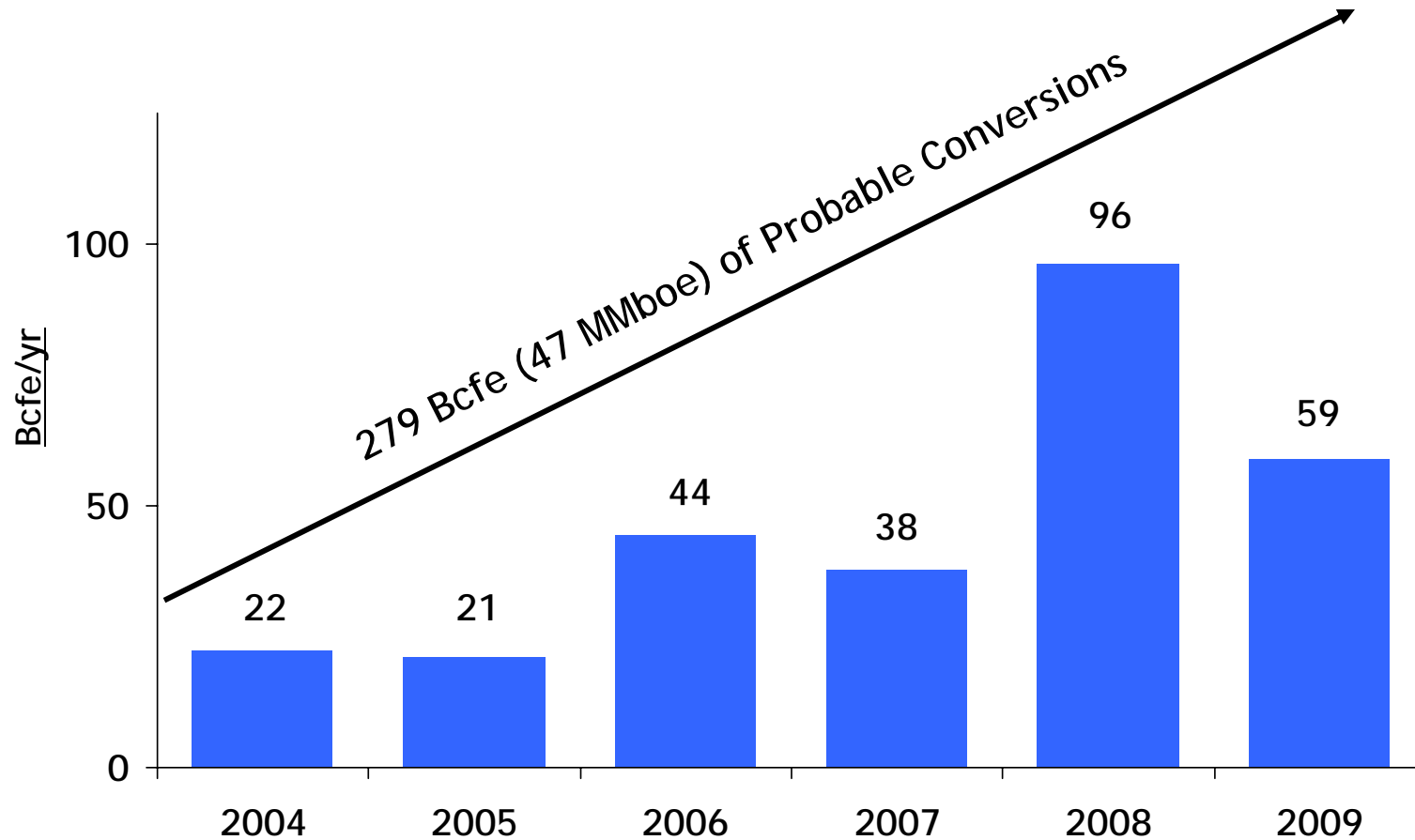


Percentage of Proved Developed Reserves



Probable to Proved Reserve Conversions

Average Conversion Rate (7 yrs): 41 Bcfe/yr (7 MMboe/yr)



* Ryder Scott estimated reserves as of 12/31/09



Deepwater Gulf of Mexico

Generate, Operate, Participate

- Solid track record of exploration success - ~67% from 2005-2009
- Regional 3D seismic inventory covering 2,500 OCS blocks
- Internally generated prospect inventory - ~8.4 Tcfe (~1.4 Bboe) net unrisks
- Participated in ~5-6 Tcfe (~833-1,000 MMboe) of discoveries (gross), much of which internally generated
- Core competence in subsea tieback execution - nearly 40 projects and 670 miles
- Strategy: drill several subsalt/lower tertiary (high impact) and several conventional amplitude (medium impact) wells annually. Generate new prospects to be pursued through lease sales and/or farm-ins. Trade into or acquire interest in high quality outside generated prospects.

2010 Deepwater Capital Budget: ~\$238 Million

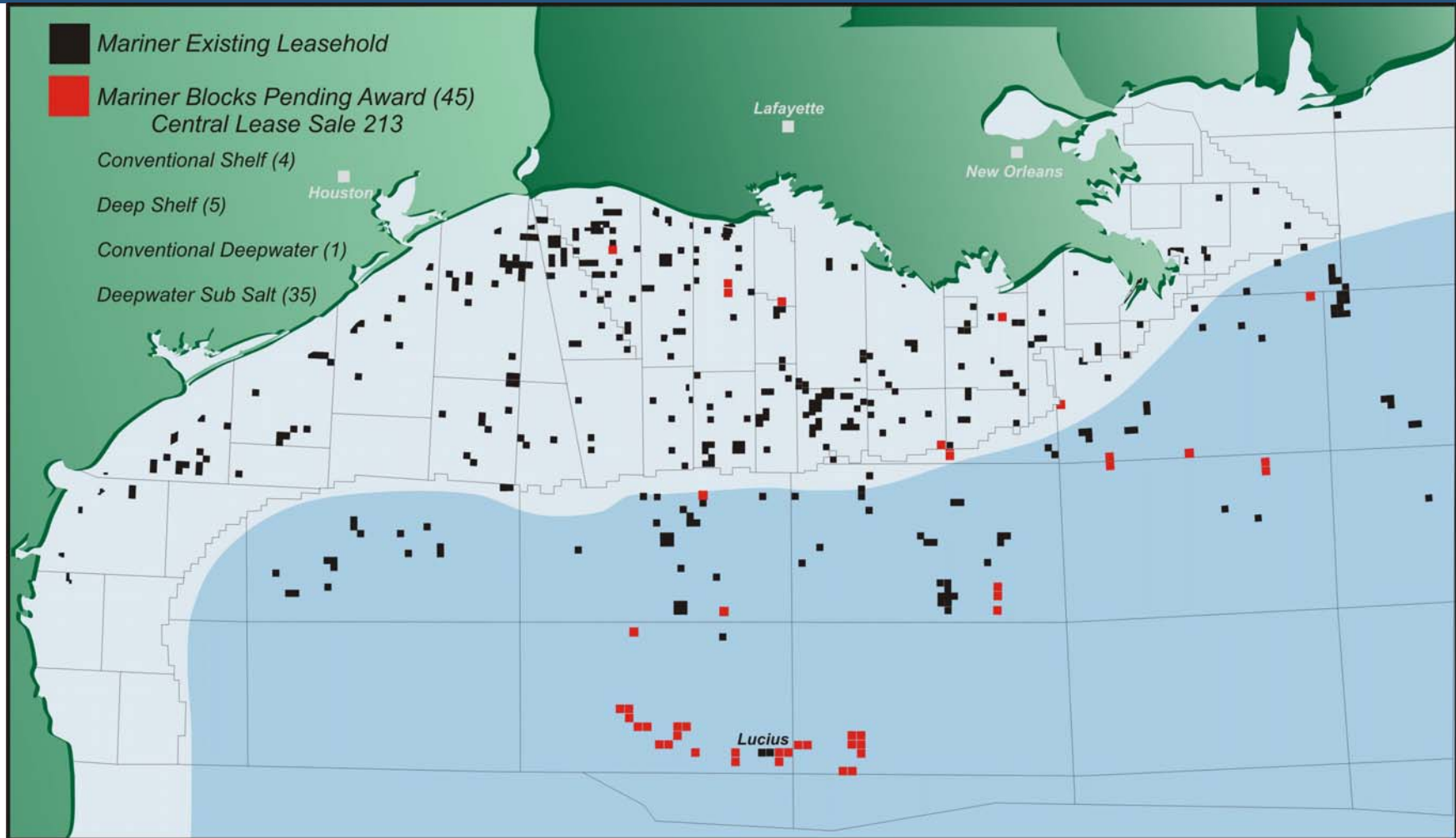
39% Exploration / 61% Development

2010 Deepwater Wells: 7-9



OCS Lease Sale 213 Results

45 Blocks (27 Prospects); Targeting Growth in Subsalt Miocene Play



Generic Deepwater Development Scenarios

Subsea Tieback

- 25-50 MMboe
- Processing capacity: 20,000 Bopd
- Gross costs: ~\$400 MM

New Mid-Size Spar

- 150-300 MMboe
- Processing capacity: 90,000 Bopd
- Gross costs: ~\$2 Bn

New Large Spar

- >300 MMboe
- Processing capacity: 120,000 Bopd
- Gross costs ~\$3 Bn

<i>Time Frame to IP:</i>	<i>2 years</i>	<i>5 years</i>	<i>5 years</i>
<i>ROR (base case):</i>	<i>~65%</i>	<i>~53%</i>	<i>~62%</i>
<i>NPV (base case, 8/8ths):</i>	<i>~\$1,100 MM</i>	<i>~\$4,900 MM</i>	<i>~\$7,700 MM</i>
<i>NPV (base case, 1% WI):</i>	<i>~\$11 MM</i>	<i>~\$49 MM</i>	<i>~\$77 MM</i>
<i>NPV Heidelberg (12.5% WI):</i>	<i>na</i>	<i>~\$612 MM</i>	<i>~\$962 MM</i>
<i>NPV Lucius (16.67% WI):</i>	<i>na</i>	<i>~\$816 MM</i>	<i>~\$1,283 MM</i>
<i>Total:</i>	<i>na</i>	<i>~\$1,428 MM</i>	<i>~\$2,245</i>

The scenarios above assume flat pricing of \$75 per Bbl and unrisks reserves. Lucius and Heidelberg are candidates for these types of developments.

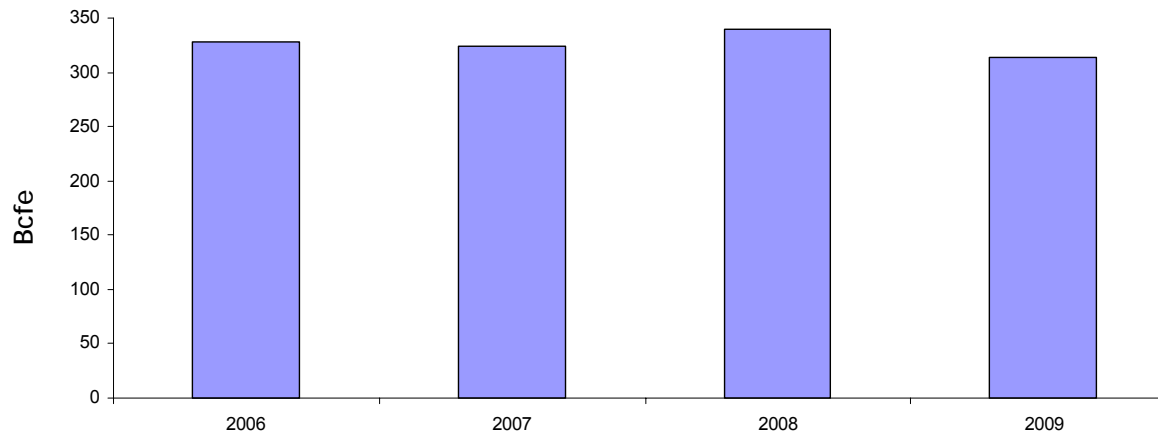


Shelf Gulf of Mexico

Create Excess Cash Flow

- Large inventory of exploitation opportunities; exploration prospect inventory of ~2.2 Tcfe (~367 MMboe) net unrisked. This excludes 2010 lease sale results.
- Flat reserve profile of ~320 Bcfe (~53 MMboe) 2006-2009, while producing ~235 Bcfe (39 MMboe)
- Strategy: create excess cash flow; extend asset life; achieve operating synergies

Shelf Proved Reserves 2006 - 2009



2010 Shelf Capital Budget: ~\$158 Million

26% Exploration / 74% Development

2010 Shelf Wells: 8-10

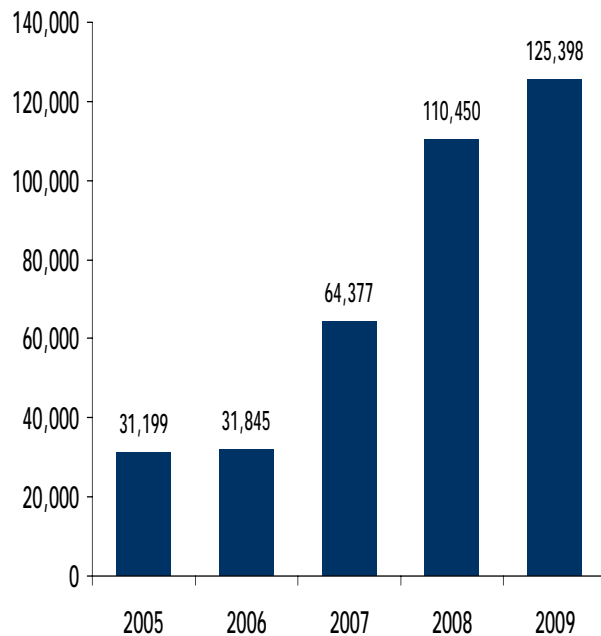


Onshore - Permian Basin

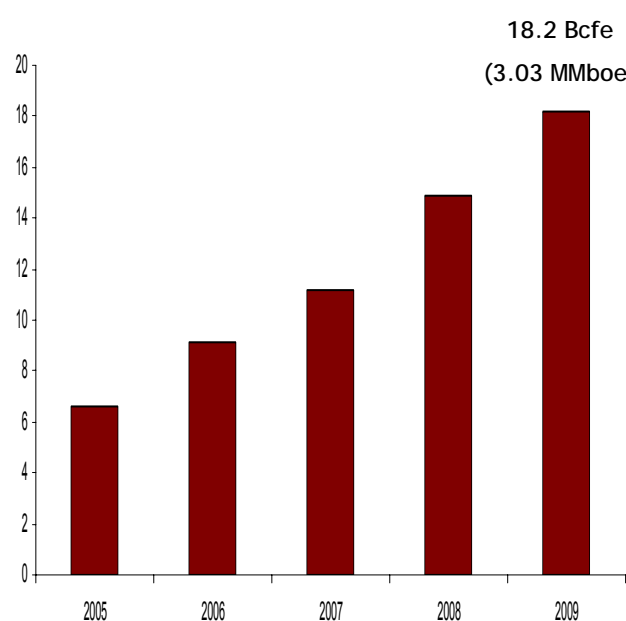
Pursuing More Predictable, Repeatable Operations

- Year-over-year increases in acreage, reserves, production
- High-margin product mix with ~60-80% liquids
- Several hundred proved drilling locations with several thousand potential locations
- Recent exploration success in ME-generated Wolfcamp play
- Strategy: expand long life oily assets to balance high rate GoM assets

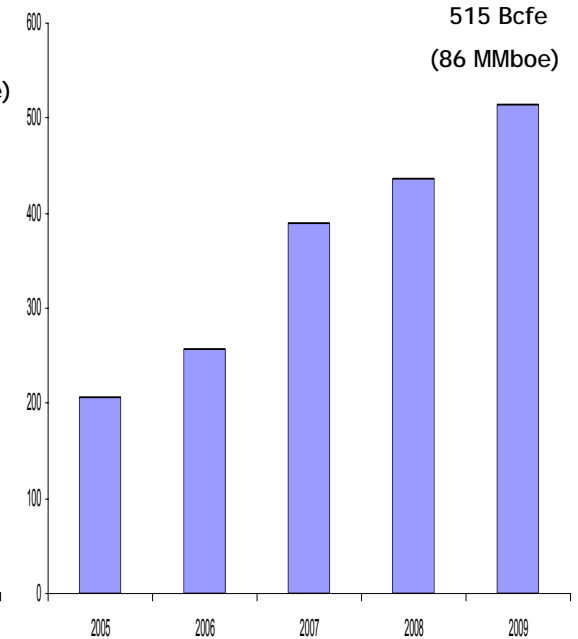
Permian Net Acreage Growth



Permian Production Growth



Permian Proved Reserves



Onshore - New Core Areas

Building Positions in Gulf Coast / Unconventional Plays

Gulf Coast

- Low-cost, high rate of return acquisition with low operating costs and ~\$83 million in potential tax benefits
- Establishes new core production area
- Increased focus on production and upside potential

Unconventional

- Targeting liquids-rich plays with relatively low entry costs in the Rocky Mountains (U.S. and Canada); South Texas and Permian Basin
- Acquired working interests in ~96,000 net acres in unconventional plays located in ND, WY, AR and NM
- Reviewing unconventional potential on existing asset base

2010 Onshore Capital Budget: ~\$192 Million

10% Exploration / 90% Development

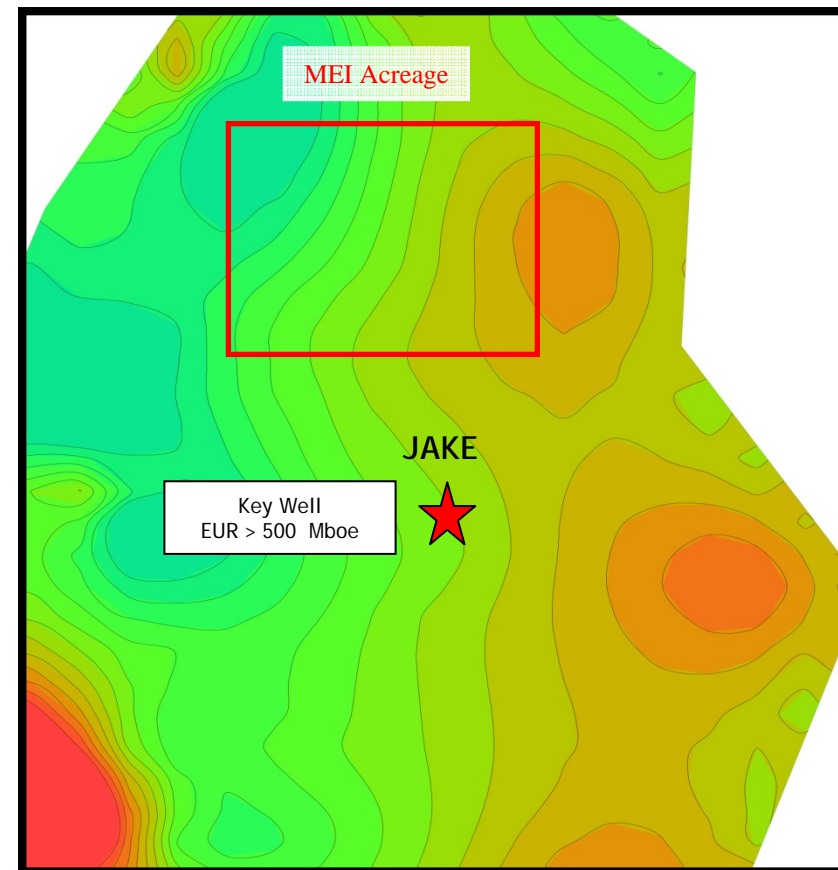
2010 Onshore Wells: 140-160



Mowry Shale Oil Play

Denver-Julesburg Basin, Wyoming

Typical Parameters	Estimated Values
DEPTH (TVD, feet)	7,000
GROSS THICKNESS (feet)	300
NET THICKNESS (feet)	175
TYPICAL LAND COST (\$/acre)	\$370
GROSS EUR (Mboe/well)	450
CAPITAL COST/well (\$MM/well)	3.3
GO FORWARD DEVELOPMENT COST(\$/Boe)	\$7.33
CAPTURED ACREAGE (Net acres)	54,000
FIRST LAND ACQUISITION	1/Q 2010
FIRST EXPLORATION WELL	4/Q 2010



- Early low-cost entry point into basin
- Thick siliceous shale in the oil window at reasonable drilling depths
- Multiple significant acreage opportunities available
- Multiple significant acreage blocks available to lease



Sum of Parts Analysis Using Public Comps

As of 04/01/2010		\$/Share 4/1/2010	TEV ¹ (\$MM)	Reserves MMBOE	Proved Developed %	NGL & Oil %	Q409 Prod. MBOE/D	R/P	\$ EV/BOE ME EV Estimates
Permian									
Concho Resources ²	CXO	52.17	5,390	212	49%	67%	31	18.9	25.48
Arena Resources	ARD	34.26	1,265	69	37%	86%	7	27.3	18.27
Mariner Permian									Value Range \$MM : 1,568 - 2,187
Gulf Coast									
Crimson Exploration	CXPO	2.92	305	16	70%	28%	6	7.7	18.79
Swift Energy	SFY	32.50	1,662	113	50%	57%	24	12.9	14.71
Mariner Gulf Coast									Value Range \$MM : 233 - 298
Shelf									
Stone Energy	SGY	18.47	1,401	68	78%	47%	37	5.1	20.46
W&T Offshore	WTI	8.67	1,064	62	76%	55%	41	4.1	17.20
Mariner Shelf									Value Range \$MM : 903 - 1,074
Deepwater									
Proved				27	84%	25%	25	3.0	26.40 ⁴
Exploratory	1.4 BBOE of unrisks potential assuming \$0.60/BOE ⁵					88%			22.19 ⁴
Mariner Deepwater									Value Range \$MM : 1,438 - 1,552
Unbooked Deepwater Discoveries									
Lucius									816 - 1,283 ⁶
Heidelberg									612 - 962 ⁶
ME Total, Pro Forma Edge									Value Range \$MM : 1,428 - 2,245
ME Total, Pro Forma Edge									Value Range \$MM : 5,572 - 7,357
Less Debt (\$MM)									(1,186)
Estimated Market Cap (\$MM)									4,386 - 6,171
Shares Outstanding (MM)									101.8
Sum of Parts Estimated Equity Value (\$/Share)									\$43.08 - \$60.62
Actual Equity Value (\$/Share) as of 04/01/2010									15.60
Actual ME Value as a % of Sum of the Parts									26% - 36%

1. TEV based on market cap as of 04/01/2010 and net debt as of Dec. 31, 2009 SEC filings.

2. TEV pro forma for the \$219.2 million of proceeds from the issuance of 5.3475 million shares.

3. Mariner internal estimate.

4. 2007 - 2009 Transactions selected from IHS Herold data based on region. Regional average of \$/BOE of proved reserves was a weighted calculation according to transaction value. The deepwater premium applied is based on the deepwater to shelf ratio of the weighted average \$/BOE (129%). The premium is applied to the shelf comps of \$17.20 - \$20.46 derived in this table.

5. DeGolyer and MacNaughton unrisks potential estimates of 1.28 BBOE plus Mariner internal additional estimates of .12 BBOE; Mariner internal estimate of \$0.60/BOE.

6. Range is based on mid-size and large size spar base cases. NPV scaled up by actual WI of 16.6667% for Lucius and 12.5% for Heidelberg.

Capital IQ, Company Filings and Press Releases,
DeGolyer and MacNaughton Report, Mariner Internal Estimates.



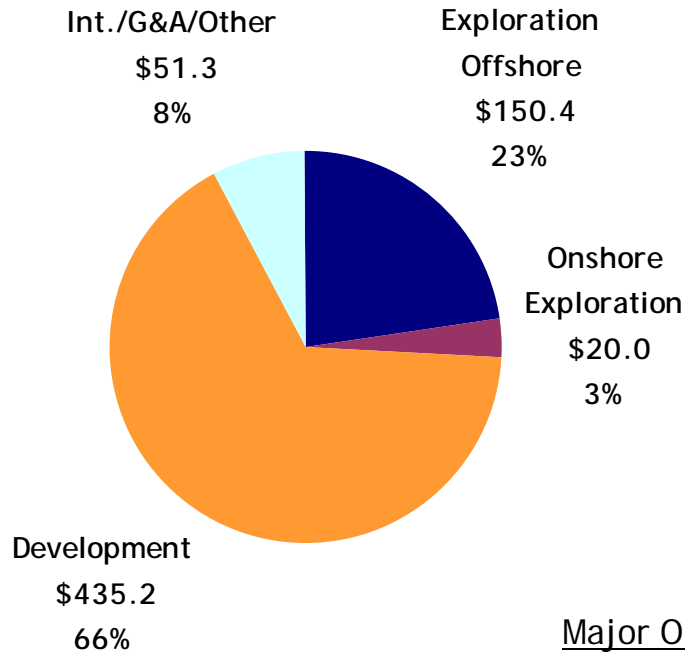
Appendix



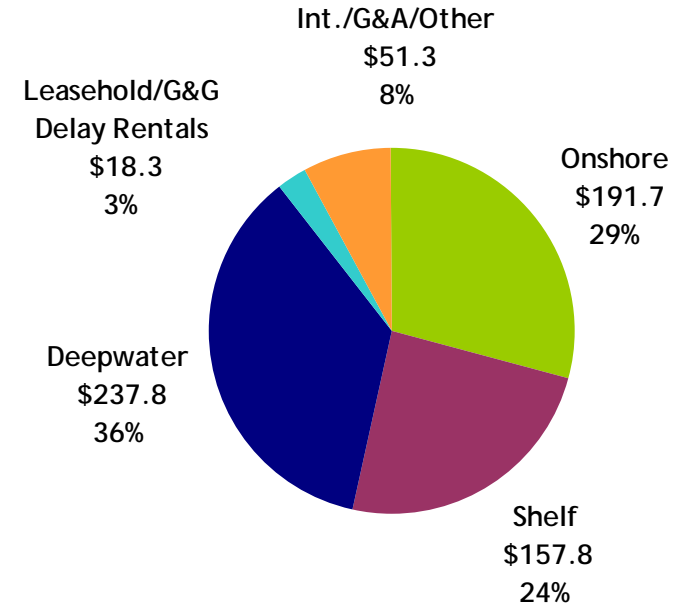
2010 Capital Investment Program

Transforming our Onshore and Deepwater Portfolios

CAPEX by Activity



CAPEX by Area



Major Operating CAPEX Components

- 2010 Operating CAPEX estimated at ~\$660 million*, excludes M&A and hurricane repairs
 - \$238 million deepwater program – ~7-9 wells including 2-3 subsalt
 - \$158 million shelf – ~8-10 wells and 30+ recompletions
 - \$192 million onshore program – including ~140 wells in the Permian Basin

* CAPEX may vary depending on industry conditions, such as commodity price changes and other factors



Generic Deepwater Development - Subsea

Economic Sensitivities – 2 Well, 40 MMbbl, 20 Mbopd Peak Rate

Net to 100% Working Interest	PV-10 * (\$MM)	ROR (%)
Base Case (2 Yrs. to IP, \$75/Bbl, \$5.0/Mcf, Capex \$400)	1,100	65
+/- \$10/Bbl	+/- 200	+/- 8
+/- + \$1.00/Mcf	+/- 25	+/- 1
+/- 20% Capex	+/- 100	+/- 8

* PV-10 is not a measure under generally accepted accounting principles in the United States of America (GAAP) and differs from the corollary GAAP measure “standardized measure of discounted future net cash flows” in that PV-10 is calculated without regard to future income taxes.



Generic Deepwater Development - Mid-size Spar

Economic Sensitivities - 270 MMbbl, 90 Mbopd Peak Rate

Net to 100% Working Interest	PV-10 * (\$MM)	ROR (%)
Base Case (5 Yrs. to IP, \$75/Bbl, \$5.0/Mcf, Capex \$2,200)	4,900	53
Accelerate IP one year	+ 500	+ 3
+/- \$10/Bbl	+/- 900	+/- 5
+/- +\$1.00/Mcf	+/- 50	+/- 1
+/- +20% Capex	+/- 250	+/- 2

* PV-10 is not a measure under generally accepted accounting principles in the United States of America (GAAP) and differs from the corollary GAAP measure "standardized measure of discounted future net cash flows" in that PV-10 is calculated without regard to future income taxes.



Generic Deepwater Development - Large Spar

Economic Sensitivities -400 MMbbl, 120 Mbopd Peak Rate

Net to 100% Working Interest	PV-10 * (\$MM)	ROR (%)
Base Case (5 Yrs. to IP, \$75/Bbl, \$5.0/Mcf, Capex \$3,000)	7,700	62
Accelerate IP one year	+ 800	+ 4
+/- \$10/Bbl	+/- 1,400	+/- 6
+/- \$1.00/Mcf	+/- 100	+/- 1
+/- 20% Capex	+/- 300	+/- 2
+/- 30 Mbopd	+/- 450	+/- 3

* PV-10 is not a measure under generally accepted accounting principles in the United States of America (GAAP) and differs from the corollary GAAP measure “standardized measure of discounted future net cash flows” in that PV-10 is calculated without regard to future income taxes.



Mariner's Subsalt Drilling Inventory

> 40 Prospects (with 19 Additional Pending MMS Award)

Size Range:	300 - >1,200 Bcfe (50 - >200 MMboe)
Projected Dry Hole Costs (gross):	\$40 - 100 MM
Projected Development Costs (gross):	\$400 - 3,000 MM
Target Working Interest:	10 - 50%

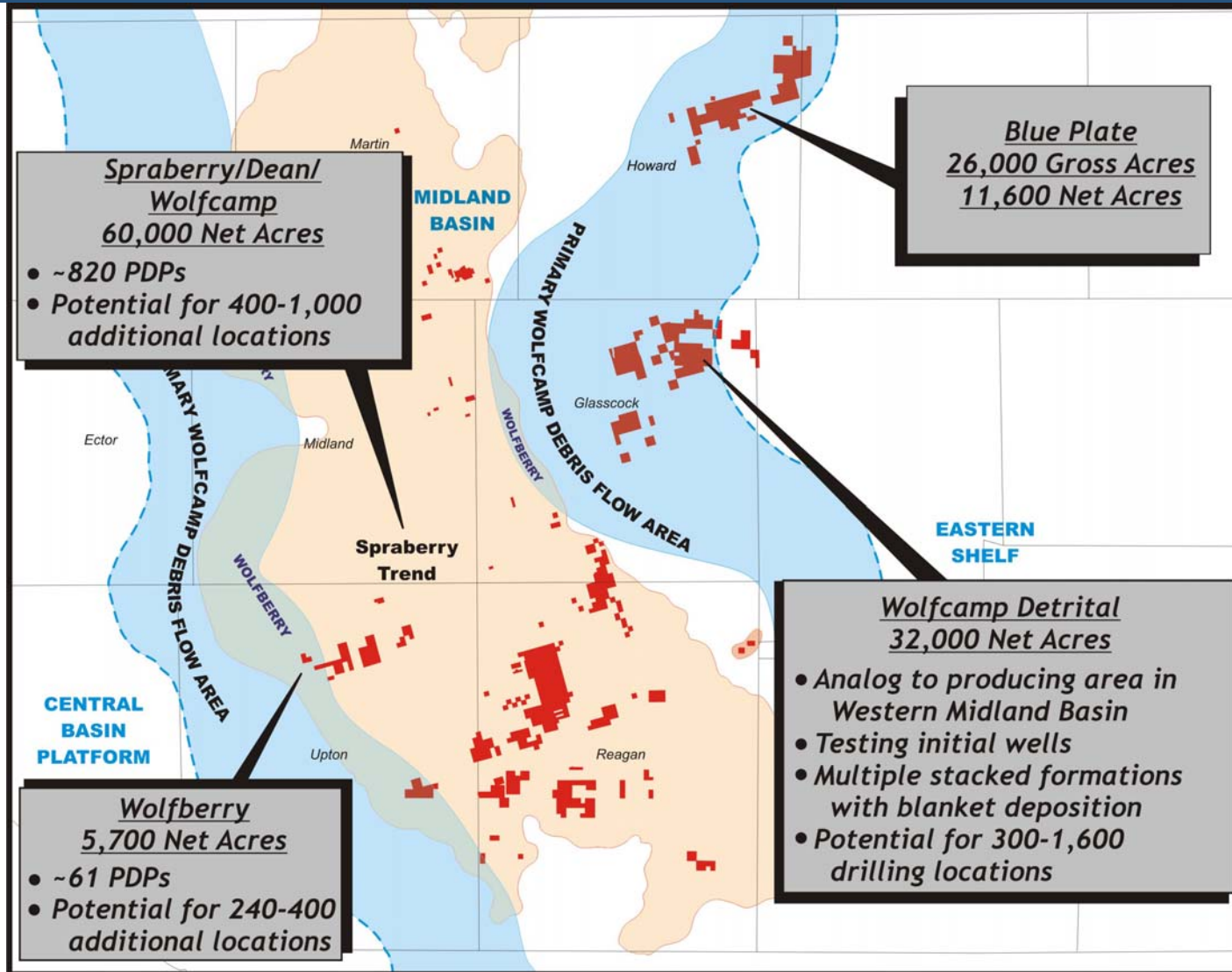
Mariner's Prospect Inventory

Larissa (GB 177)	Bimini (GB 213)
Backslice (GB 248)	Eagle Nest (GB 289)
Atrip (GB 373)	Maverick (GB 869)
Frosa (GB 904)	Top Mast (GC 143)
Staurolite (GB 230)	Santa Rita (GC 246)
Salt Branch (GC 363)	King Kong Deep (GC 473)
Springs Deep (GC 505)	Lyell (GC 550)
Boonville (GC 618)	Alexandrite (GC 771)
Owl Creek (GC 861)	Heidelberg Lower Miocene (GC 903)
Fastrill (KC 119)	Lucius Wilcox (KC 875)
Mandy Deep (MC 199)	



Permian Basin Expansion

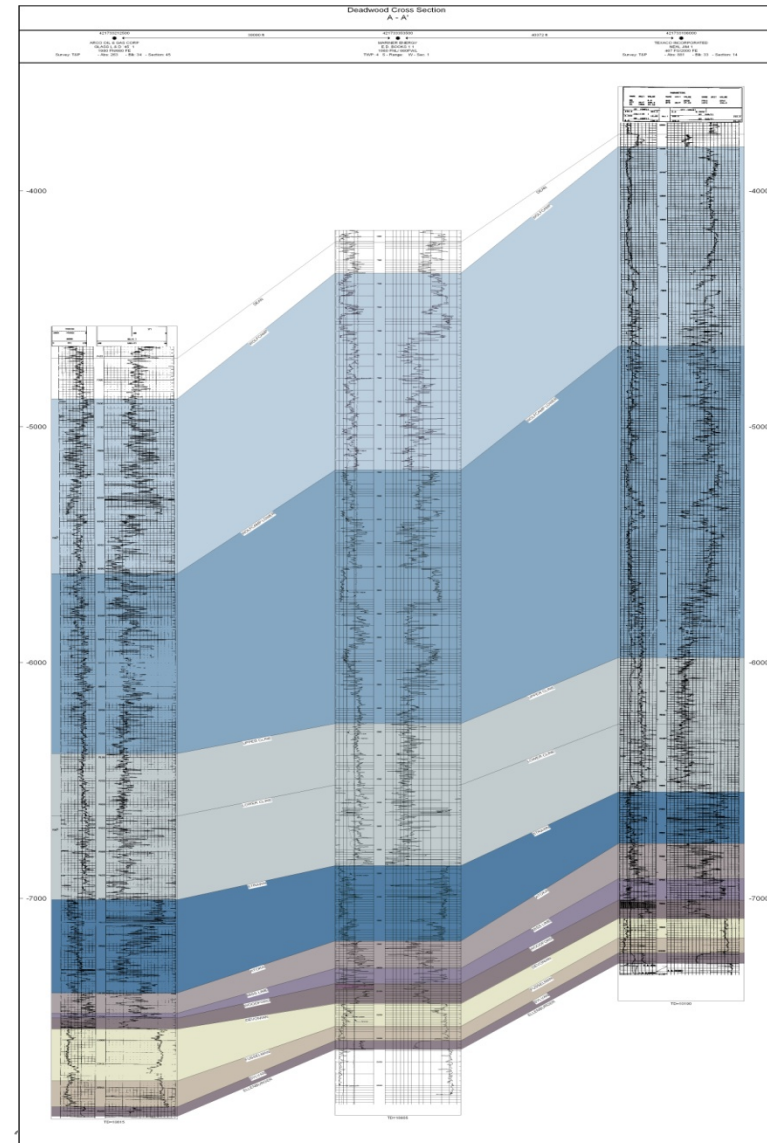
Year-end 2009 Acreage Positions



Deadwood Field

Glasscock County, Texas

- Over 3,000 gross feet of conventional and unconventional reservoir column
- WC/Up-Lwr Cline/Strawn/Atoka/Fusselman/Woodford/Ellenburger
- Large completion designs utilizing multiple frac stages
- ~ 150 Mboe EUR average expected
- Nearly 200 potential drilling locations on 160-acre spacing; more than 380 on 80-acre spacing



Calculation of Reserve Replacement Rate

	Oil (Mbbbl)	Natural Gas (MMcf)	Natural Gas Equivalent (Mmfe)	RRR		
31-Dec-04	14,255	151,933	237,465		Reserve replacement rate (RRR) for a period is calculated by dividing the sum of total reserve extensions, discoveries and other additions, revisions and purchases (i.e. acquisitions) by production for the same period.	
Revisions of previous estimates	835	963	5,971			
Extensions, discoveries and other additions	1,167	22,307	29,309			
Purchases of reserves in place	7,181	50,837	93,923			
Sales of reserves in place	-	-	-			
Production	(1,791)	(18,354)	(29,100)			
31-Dec-05	21,647	207,686	337,568	444%		
Revisions of previous estimates	8,685	(58,055)	(5,947)			
Extensions, discoveries and other additions	9,823	93,112	152,050			
Purchases of reserves in place	12,410	244,741	319,201			
Sales of reserves in place	(354)	(4,733)	(6,857)			
Production	(4,075)	(56,064)	(80,512)			
31-Dec-06	48,136	426,687	715,503	578%		
Revisions of previous estimates	5,690	2,506	36,643			
Extensions, discoveries and other additions	4,671	61,548	89,576			
Purchases of reserves in place	11,763	25,832	96,407			
Sales of reserves in place	(283)	(341)	(2,041)			
Production	(5,414)	(67,793)	(100,273)			
31-Dec-07	64,563	448,439	835,815	222%		
Revisions of previous estimates	(2,404)	(29,839)	(44,264)			
Extensions, discoveries and other additions	9,522	137,722	194,855			
Purchases of reserves in place	4,102	81,500	106,112			
Sales of reserves in place	(40)	(18)	(258)			
Production	(6,439)	(79,756)	(118,389)			
31-Dec-08	69,304	558,048	973,871	217%		
Revisions of previous estimates	3,081	(46,229)	(27,745)			
Extensions, discoveries and other additions	14,538	79,474	166,701			
Purchases of reserves in place	4,977	70,943	100,803			
Sales of reserves in place	-	-	-			
Production	(5,950)	(90,801)	(126,498)			
31-Dec-09	85,950	571,435	1,087,132	190%		
					3-yr Rolling RRR	
					3-yr Revisions	36,667
					3-yr Extensions, discoveries and other additions	270,935
					3-yr Purchases of reserves in place	509,531
					3-yr Production	(209,885)
					2005-2007	389%
					3-yr Revisions	(13,568)
					3-yr Extensions, discoveries and other additions	436,481
					3-yr Purchases of reserves in place	521,720
					3-yr Production	(299,174)
					2006-2008	316%
					3-yr Revisions	(35,366)
					3-yr Extensions, discoveries and other additions	451,132
					3-yr Purchases of reserves in place	303,322
					3-yr Production	(345,160)
					2007-2009	208%

Calculation of Reserve Replacement Cost

Reserve replacement cost is calculated by dividing hydrocarbon development, exploration and acquisition capital expenditures (which include capitalized internal costs and exclude hurricane expenditures net of insurance recoveries and non-cash changes to asset retirement obligations) for the period by net estimated proved reserve additions for the period from all sources, including acquisitions and divestitures. Our calculation of reserve replacement cost includes costs and reserve additions related to the purchase of proved reserves. The methods we use to calculate our reserve replacement cost may differ significantly from methods used by other companies to compute similar measures. As a result, our reserve replacement cost may not be comparable to similar measures provided by other companies. We believe that providing a measure of reserve replacement cost is useful in evaluating the cost, on a per-Mcfe basis, to add proved reserves. However, this measure is provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with generally accepted accounting principles. Due to various factors, including timing differences in the addition of proved reserves and the related costs to develop those reserves, reserve replacement costs do not necessarily reflect precisely the costs associated with particular reserves. As a result of various factors that could materially affect the timing and amounts of future increases in reserves and the timing and amounts of future costs, we cannot assure you that our future reserve replacement costs will not differ materially from those presented.

Reserve Replacement Cost	2007	2008	2009
Capital costs related to property acq, expl, and devel.	788.6	1,344.1	784.2
Hurricane expenditures, net of insurance recoveries	(12.3)	(60.1)	(6.6)
Proceeds from divestitures	4.1	0.0	0.0
Capital expenditures before divestitures (\$MM) (1)	780.4	1,284.0	777.6
Reserve additions (Bcfe)	222.6	256.7	239.8
Reserve Replacement Cost/Mcfe	\$3.51	\$5.00	\$3.24
Rolling 3-year capital expenditures			2,842.0
Rolling 3-year reserve additions			719.1
Rolling 3-year Reserve Replacement Cost/Mcfe			\$3.95

(1) Unaudited.



Reconciliation of Non-GAAP Measure: Operating Cash Flow

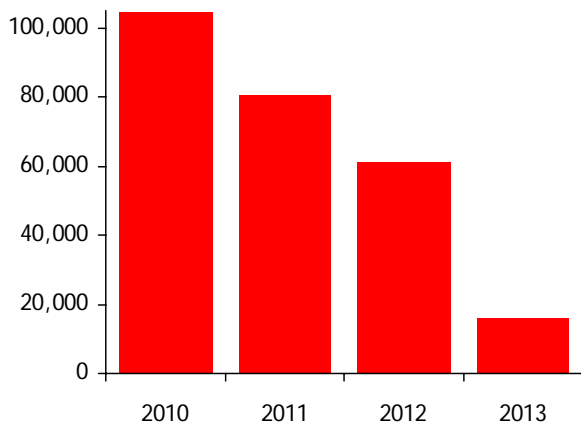
Operating cash flow ("OCF") is not a financial or operating measure under GAAP. The table below reconciles OCF to related GAAP information. We believe that OCF is a widely-accepted financial indicator that provides additional information about our ability to meet our future requirements for debt service, capital expenditures and working capital, but OCF should not be considered in isolation or as a substitute for net income, operating income, cash flow from operating activities or any other measure of financial performance presented in accordance with GAAP or as a measure of our profitability or liquidity.

	Years Ended December 31		
	2009	2008	2007
Cash flow from operating activities (GAAP)	\$ 577,669	\$ 862,017	\$ 536,113
Changes in operating assets and liabilities	(46,519)	23,870	86,497
Operating cash flow as presented (Non-GAAP)	531,148	885,887	622,610
Weighted average shares outstanding - diluted	95,607	87,491	86,126
Operating cash flow per fully diluted share	\$ 5.56	\$ 10.13	\$ 7.23

Hedging Program - 2010 through 2013

Average
MMBtu/D

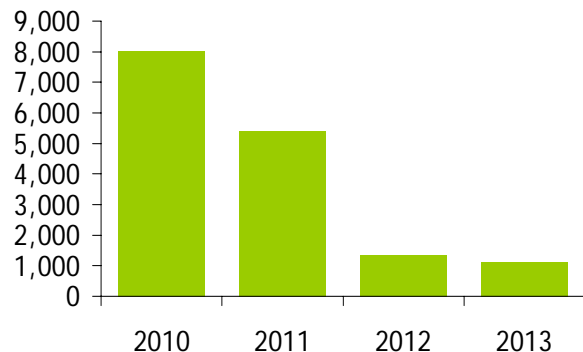
Natural Gas



Natural Gas Hedges	Quantity MMBtu	Wtd. Avg. Price
2010	38,239,145	\$5.607
2011	29,389,843	\$5.789
2012	22,338,802	\$6.115
2013	5,840,000	\$6.755

Average
Bbl/D

Oil



Oil Hedges	Quantity BBI	Wtd. Avg. Price
2010	2,931,866	\$72.876
2011	1,978,364	\$79.333
2012	494,100	\$80.765
2013	408,800	\$82.814

