

**Raymond James**  
**33<sup>rd</sup> Annual Institutional Investor**  
**Conference**

**March 4-7, 2012**



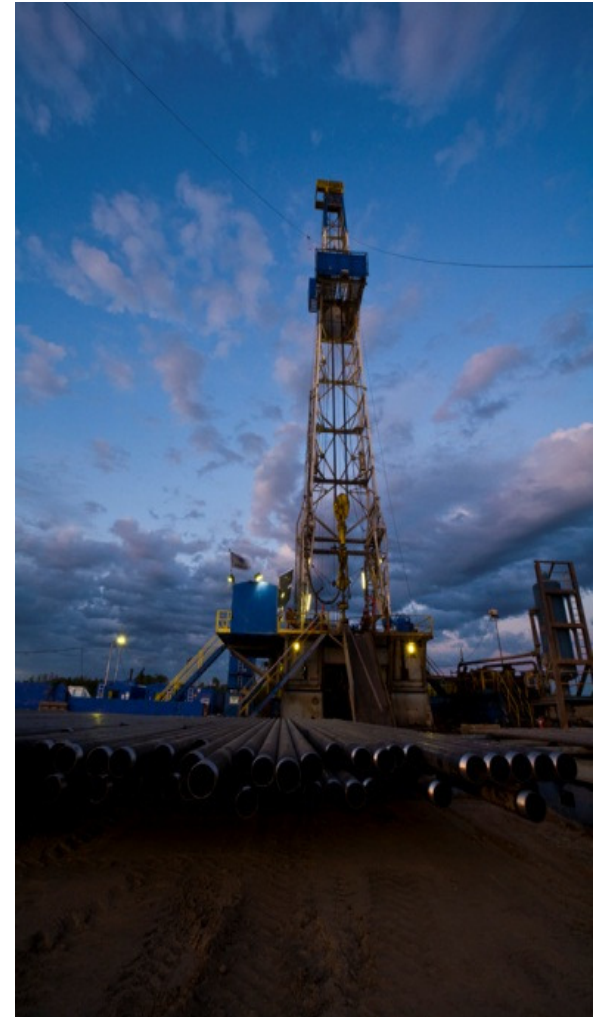
# Cautionary Language

Except for historical information contained herein, statements in this presentation, including information regarding the business of the Company, may contain “forward looking statements” within the meaning of securities laws, including forecasts and projections. The words “will,” “believe,” “budget,” “anticipate,” “plan,” “intend,” “estimate,” “forecast,” and “expect” and similar expressions are intended to identify forward looking statements. These statements involve known and unknown risks, which may cause SM Energy’s actual results to differ materially from results expressed or implied by the forward looking statements. These risks include such factors as the volatility and level of oil, natural gas, and natural gas liquids prices, the uncertain nature of the expected benefits from the acquisition, divestiture, or joint venture of oil and gas properties, the uncertain nature of announced divestiture, joint venture, farm down or similar efforts and the ability to complete such transactions, uncertainties inherent in projecting future rates of production from drilling activities and acquisitions, the ability of midstream service providers to purchase or market the Company’s production, the ability of purchasers of production to pay for those sales, the availability of debt and equity financing for purchasers of oil and gas properties, the ability of the banks in the Company’s credit facility to fund requested borrowings, the ability of derivative counterparties to settle derivative contracts in favor of the Company, the imprecise nature of estimating oil and gas reserves, the availability of additional economically attractive exploration, development, and property acquisition opportunities for future growth and any necessary financings, unexpected drilling conditions and results, unsuccessful exploration and development drilling, drilling and operating service availability, the risks associated with the Company’s commodity price risk management strategy, uncertainty regarding the ultimate impact of potentially dilutive securities, and other such matters discussed in the “Risk Factors” section of 2011 Annual Report on Form 10-K, which the Company filed with the Securities and Exchange Commission on February 23, 2012. The forward-looking statements in this presentation speak as of the date of this presentation. Although SM Energy may from time to time voluntarily update its prior forward looking statements, it disclaims any commitment to do so except as required by securities laws.

Proved reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. In this presentation, the Company uses the terms “probable,” “possible,” “3P,” and “resources.” Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations (subject to other conditions). Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. SM Energy also uses the term “EUR” (estimated ultimate recovery), which is the sum of reserves remaining as of a given date and cumulative production as of that date. Estimates of probable and possible reserves included in 3P reserves and 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.

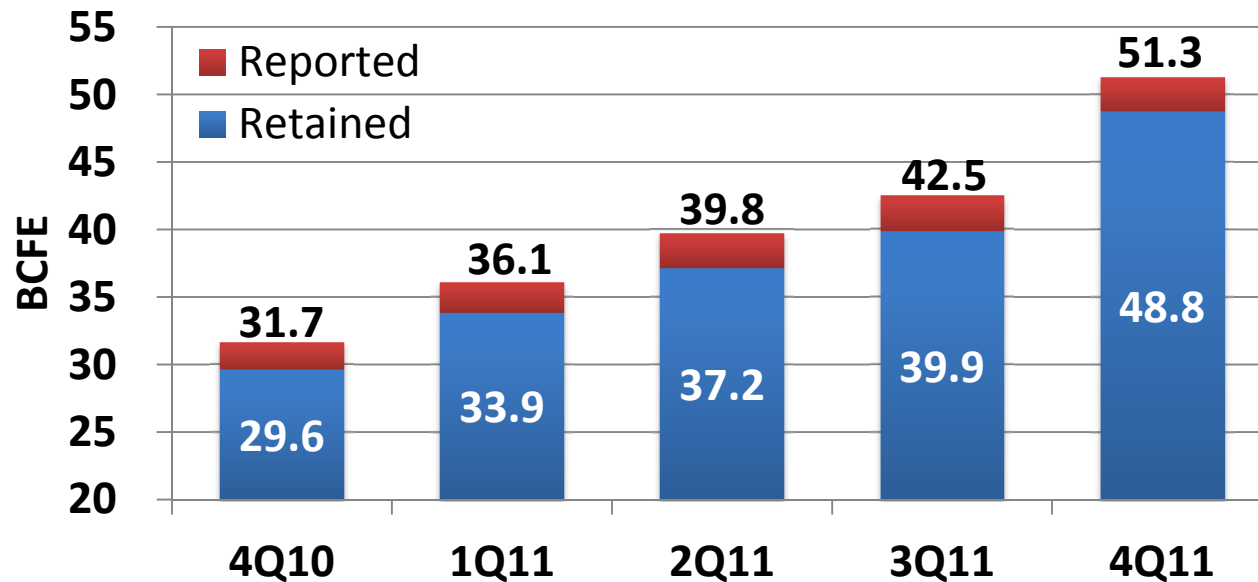
# SM Energy – Strategy And Current Focus

- **Resource plays in North America**
  - ✓ Enter early
  - ✓ Focus on full-cycle returns
  - ✓ Maintain a strong balance sheet
- **Current major development areas**
  - ✓ Eagle Ford shale
  - ✓ Bakken/Three Forks

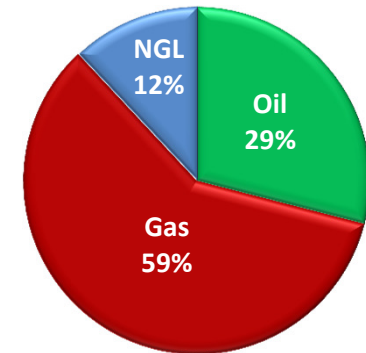


## 2011 Year in Review – Production

**Record production in 2011 of 169.7 BCFE (28.3 MMBOE), a 54% increase over 2010**

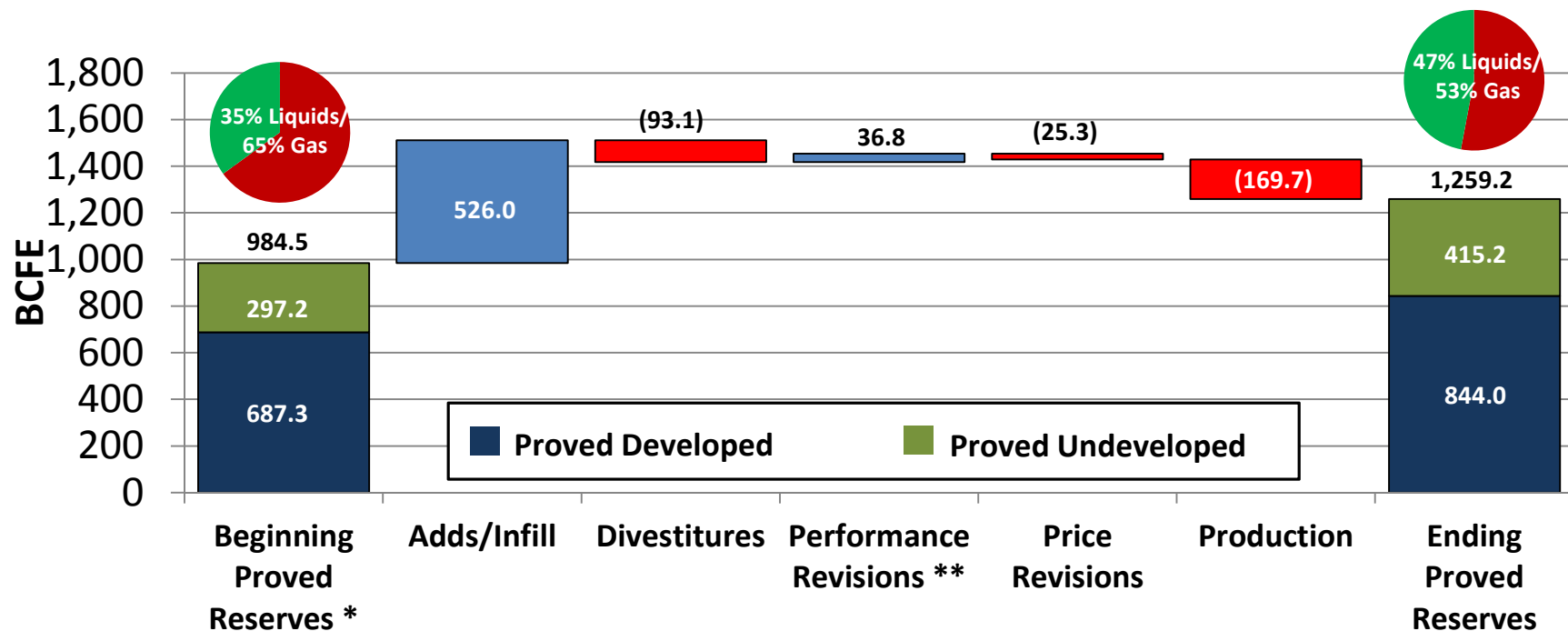


**FY11  
Production Mix**



- **Total Eagle Ford shale program drove growth at SM in 2011 with over 275% production growth compared to 2010**

# Year in Review – 2011 Proved Reserves



- Drilling reserve replacement, excluding revisions of 310%
- Liquid volumes of proved reserves increased 73% year over year
- PUD percentage remains relatively flat from 30% at YE 10 to 33% at YE 11

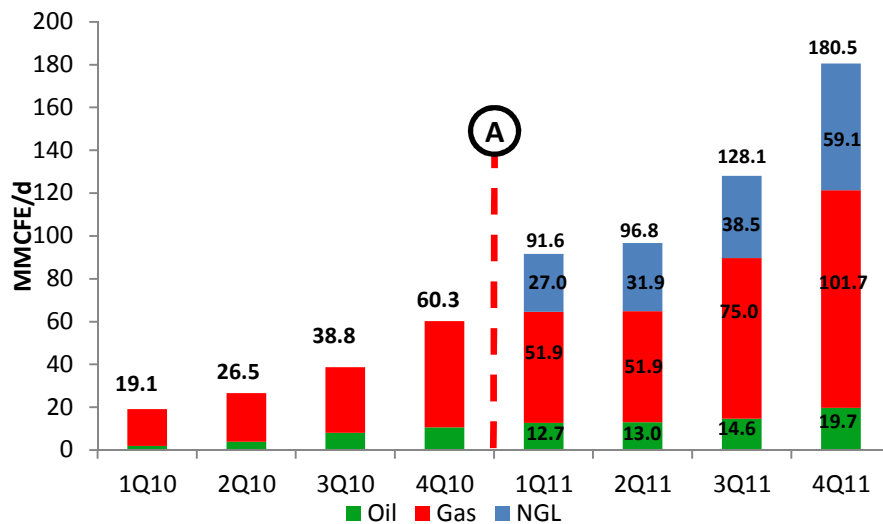
\* Beginning proved reserves are reported on a 2-stream production basis. At year-end 2011, the reported beginning reserves were not reclassified to conform to the current presentation given the immateriality of the volumes at year-end 2010.



\*\* Performance revisions include 59.5 BCFE of additions associated with the Company's conversion to 3-stream production reporting in 2011. 5

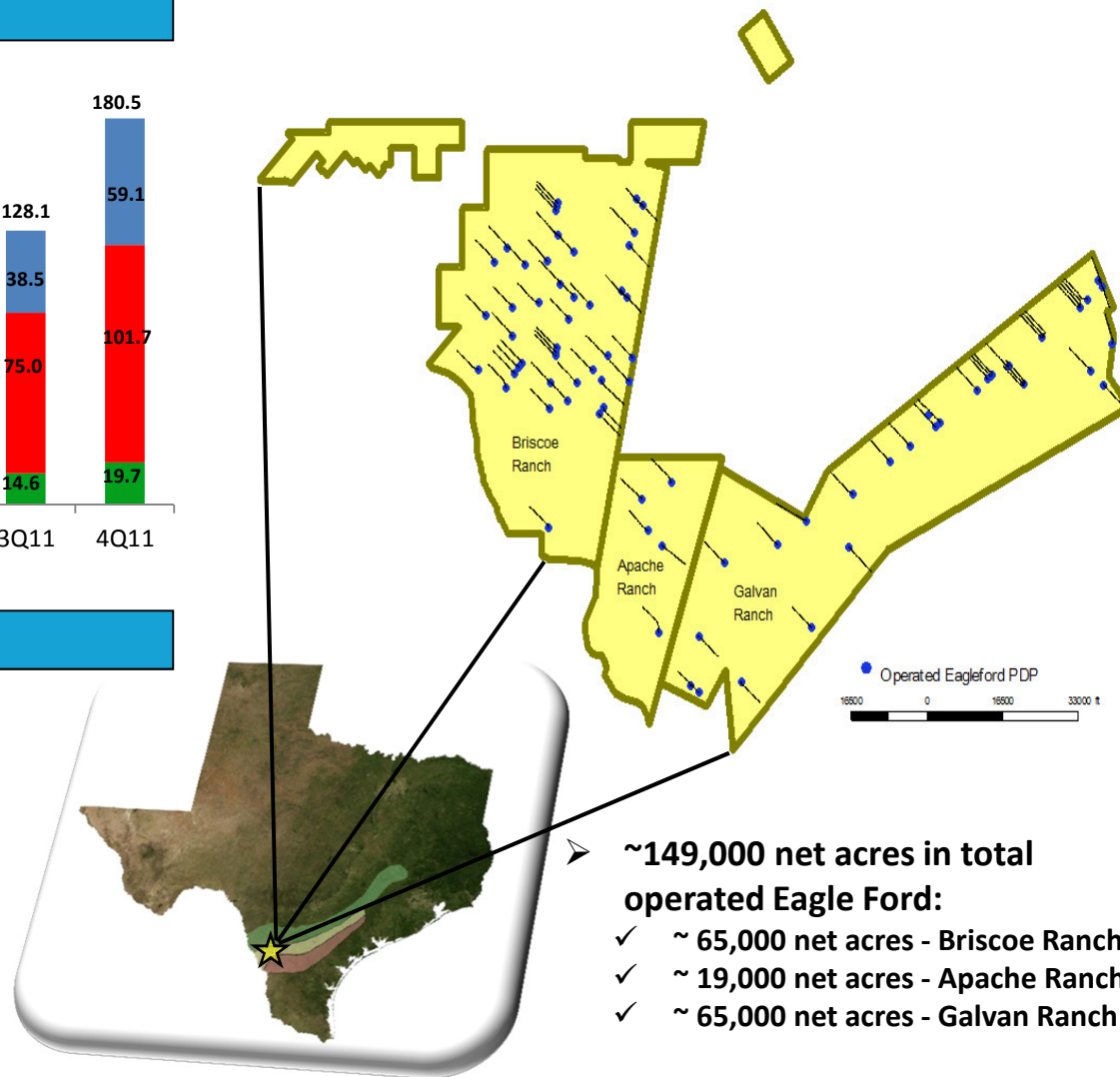
# Operated Eagle Ford Shale

## Net Production



## Year-End 2011 Statistics

- **Net Proved Reserves:**
  - ✓ PDP = 198 BCFE
  - ✓ PUD = 183 BCFE
- **Gross/Net Well Count:**
  - ✓ PDP = 84 / 82
  - ✓ PUD = 45 / 45

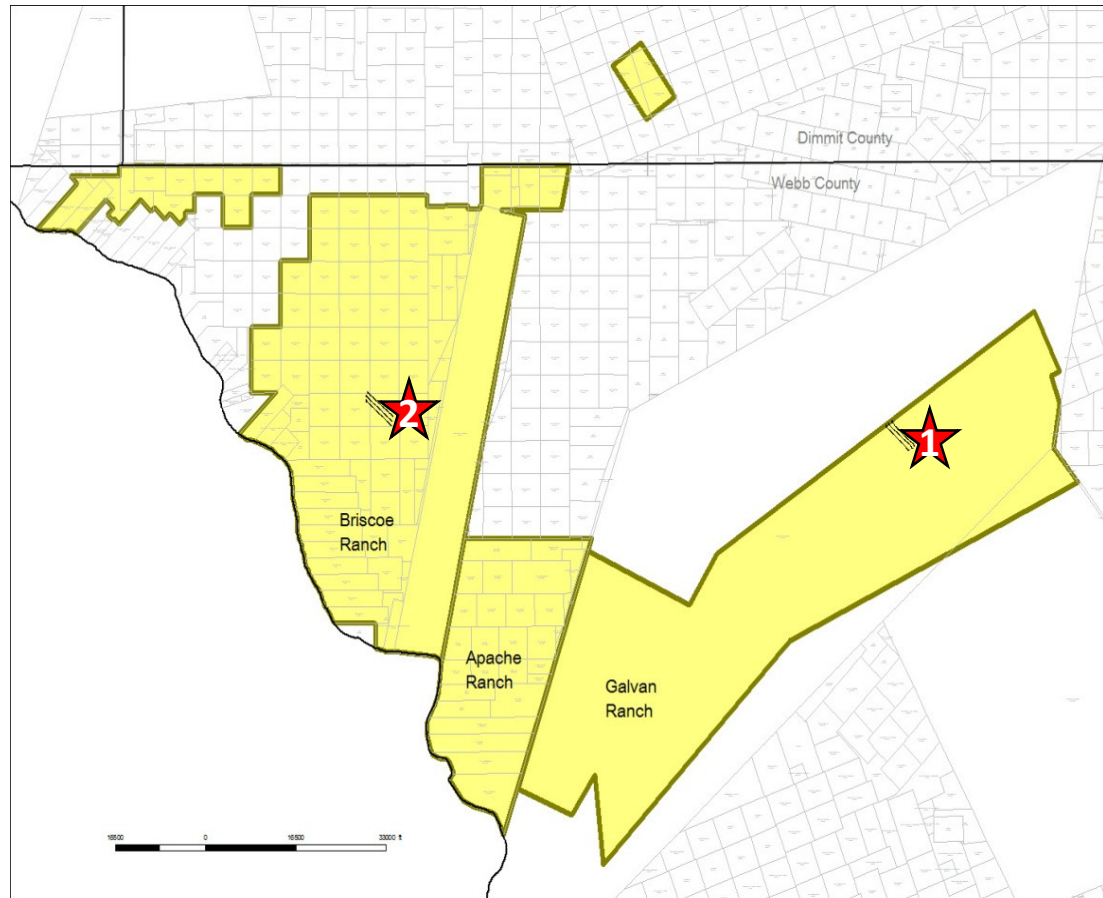


**(A)** Prior to 1Q11, SM reported gas production on a 2-stream wellhead sales reporting method. Beginning in 1Q11, SM Energy changed to a 3-stream sales reporting method. Amounts in prior periods have not been reclassified to conform with current presentation.

# Operated Eagle Ford – Spacing Tests

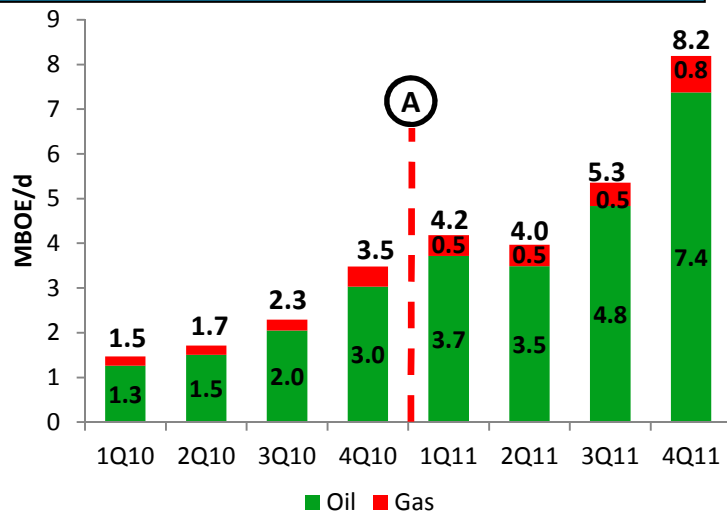
## Down Spacing Tests

- **Currently have two down-spacing tests with at least 6 months of data**
  
- **Results to date:**
  - ✓ **Test 1: Galvan Ranch – testing 625' or ~72 acre spacing**
    - ✓ Results show a 30% reduction in EUR per well
    - ✓ Data suggests ~900' or ~100 acre spacing
  
  - ✓ **Test 2: Briscoe Ranch – testing 625' spacing**
    - ✓ No interference detected
    - ✓ Data suggests spacing tighter than 625' is possible



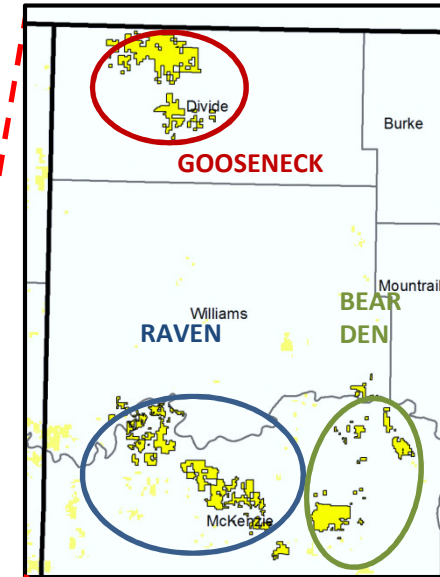
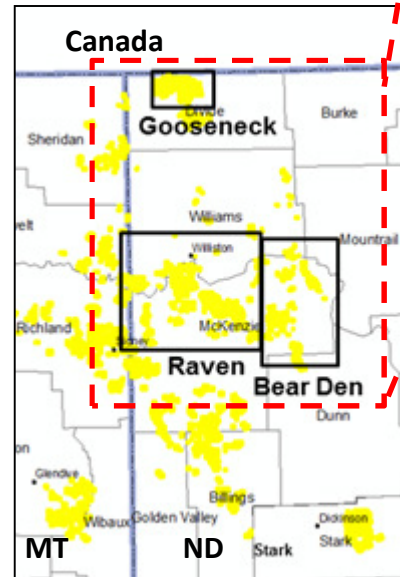
# Bakken/Three Forks Overview

## Net Production



## Year-End 2011 Statistics

- Focus Area Net Proved Reserves:
  - ✓ PDP = 10.9 MMBOE
  - ✓ PUD = 14.2 MMBOE
- Focus Area Gross/Net Well Count:
  - ✓ PDP = 155 / 47
  - ✓ PUD = 104 / 37



- Focus area net acreage:
  - ✓ Gooseneck: ~35,000
  - ✓ Raven: ~37,000
  - ✓ Bear Den: ~15,000

- Total Bakken/TFS Net Acreage
  - ✓ ~202,000

(A) Please see footnote on slide 6.

# Horizontal Granite Wash

- Total Net Acreage = 34,575
  - ✓ Marmaton = 34,575 \*
  - ✓ Missourian = 19,360\*

## Year-End 2011 Statistics

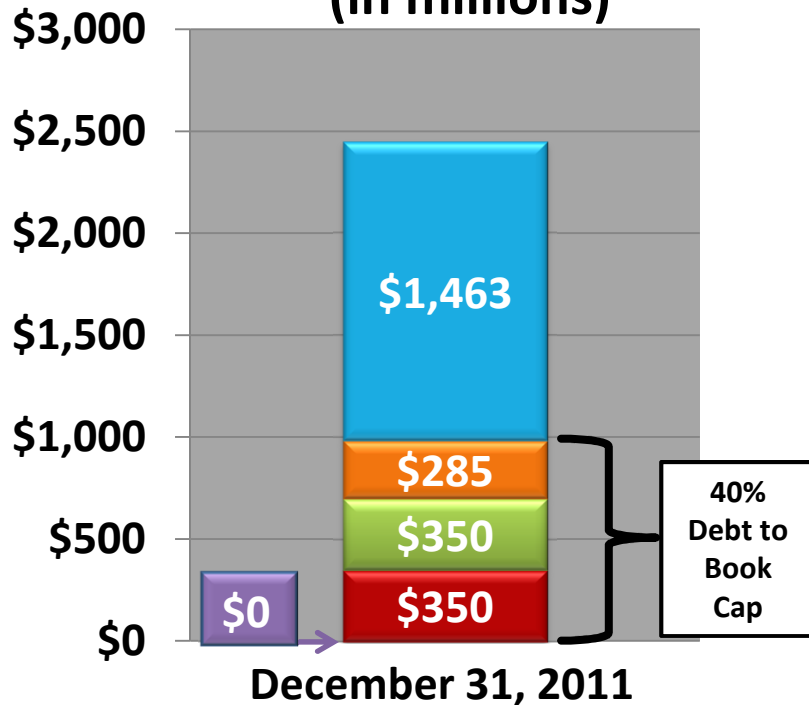
- Net Proved Reserves
  - ✓ Marmaton = 2.4 MMBOE
  - ✓ Missourian = 0.3 MMBOE
- Gross/Net Well Count
  - Marmaton:
    - ✓ PDP = 40 / 9
    - ✓ PUD = 4 / 1
  - Missourian:
    - ✓ PDP = 13 / 3



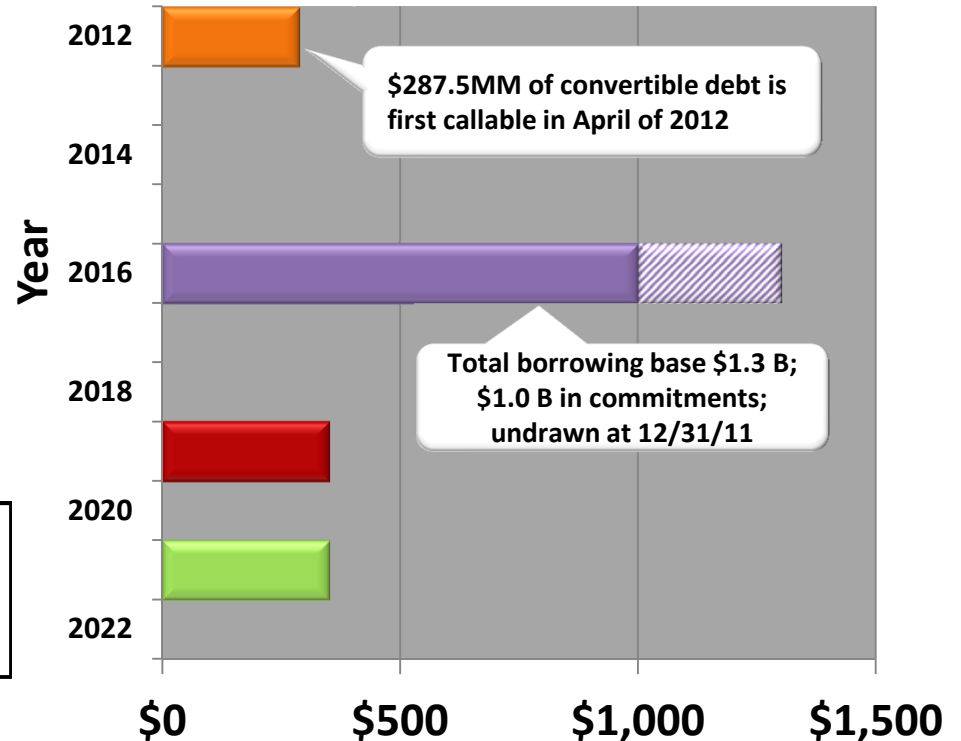
\* Note: Acreage figures provide the amount of acreage that is prospective for each respective interval.

# Financial Position

## 4Q11 TOTAL BOOK CAPITALIZATION (in millions)

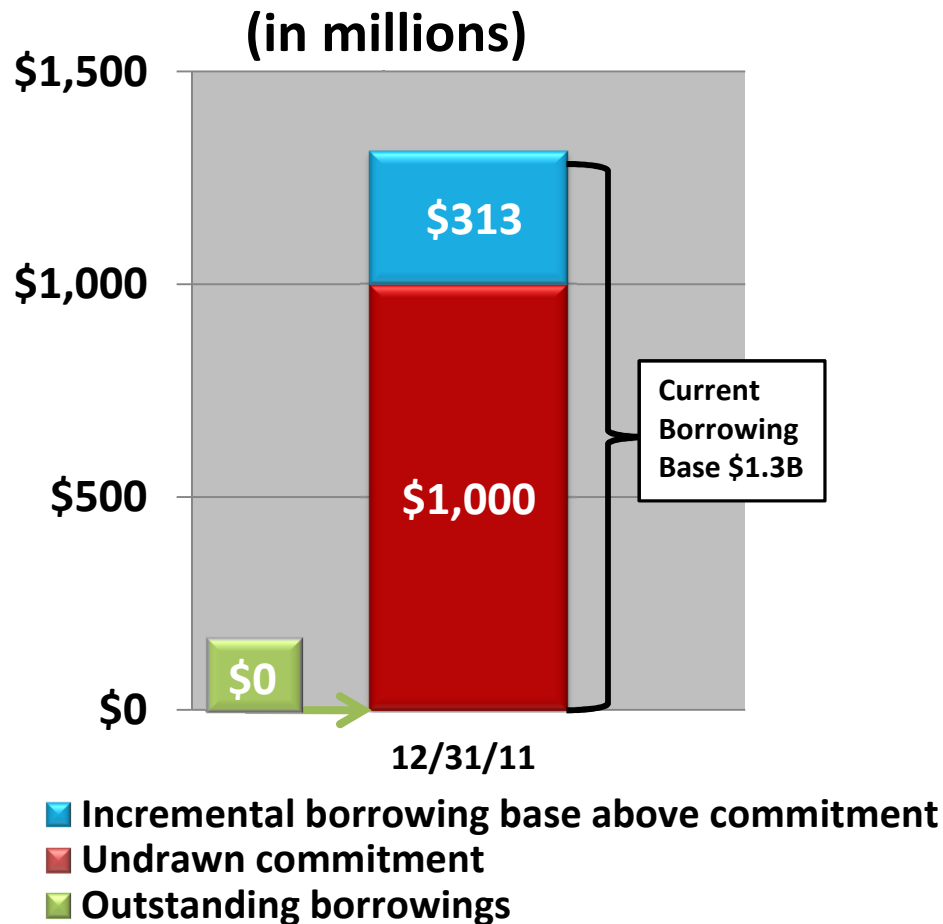


## DEBT MATURITIES (in millions)



- Stockholders' Equity
- 6.50% Senior Notes
- 3.50% Convertible Notes
- Credit Facility
- 6.625% Senior Notes

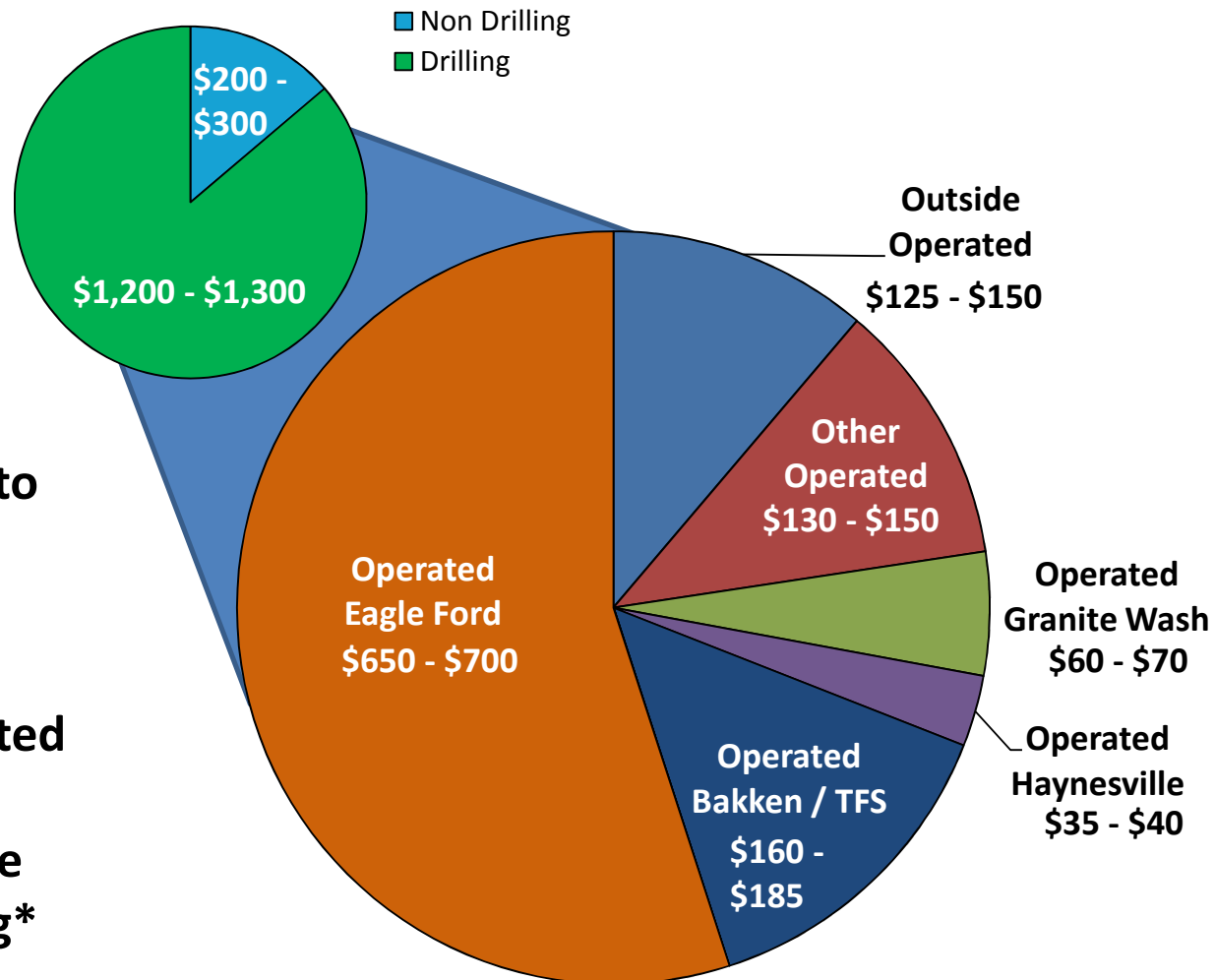
# Long-term Credit Facility



- Borrowing base stands at \$1.3 billion post November HY debt offering
- No borrowings drawn on credit facility as of December 31, 2011

# 2012 Capital Forecast

(\$ in millions)

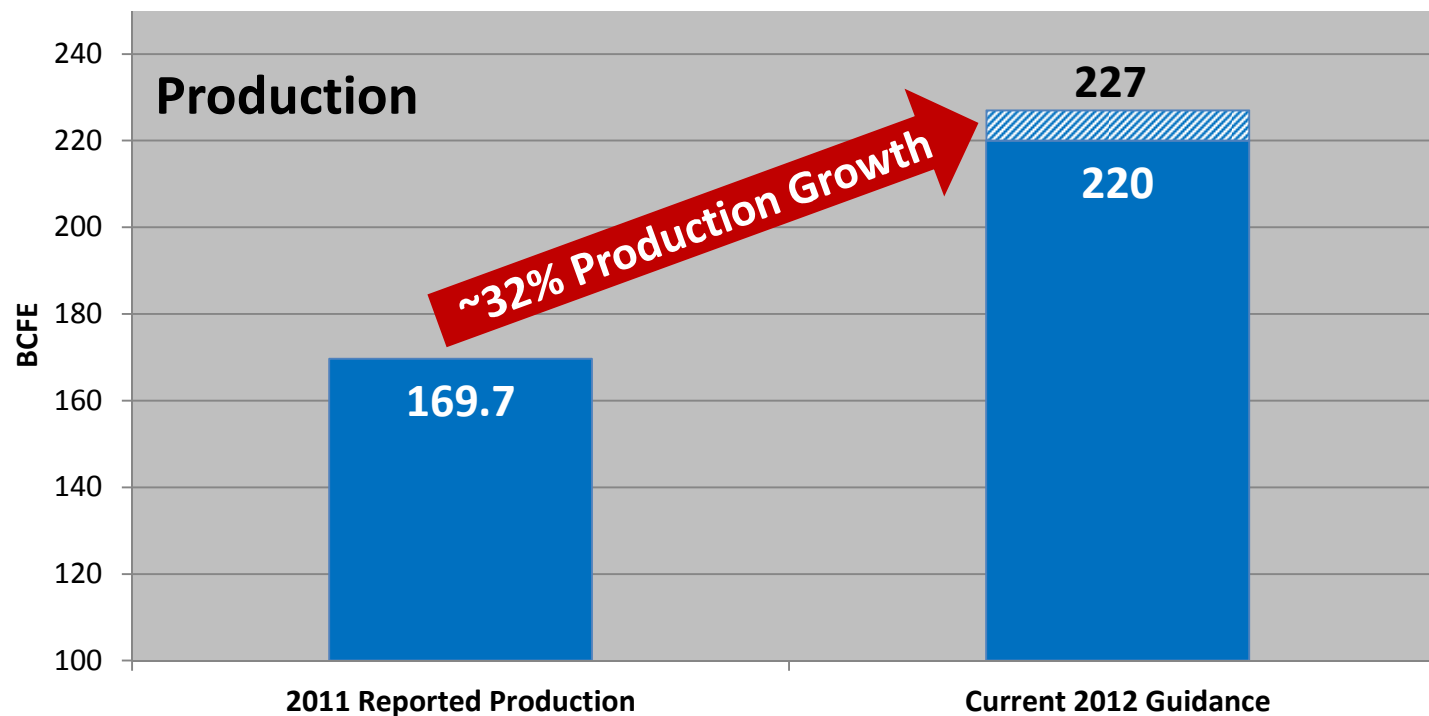


- Total Capital managed to \$1.4 – \$1.5 billion
- Approximately 90% of drilling to be SM operated
- Capital does not include Mitsui carried spending\*

\*SM Energy expects to be essentially 100% carried in 2012 for its non-operated Eagle Ford drilling program.

## 2012 Growth Outlook

- **SM is positioned to grow production by approximately 32% in 2012 based on the midpoint of current guidance assumptions**



## Key Takeaways

- **Record production and proved reserves in 2011**
- **SM has multi-year inventory of economic projects in its two largest plays**
- **Company is anticipating robust production growth in 2012 while preserving balance sheet**



# Appendix

# 4<sup>th</sup> Quarter 2011 Performance

## Performance versus Guidance

Production	4Q Actual Performance	4Q Guidance
Average daily production (MMCFE/d)	557.9	479 - 509
Total production (BCFE)	51.3	44.0 - 47.0
Oil production (as % of total)	29%	~30%
Natural gas production (as % of total)	56%	~58%
NGL production (as % of total)	15%	~12%

Costs		
LOE (\$/MCFE)	\$0.85	\$0.90 - \$0.96
Transportation (\$/MCFE)	\$0.60	\$0.64 - \$0.67
Production taxes (% of pre-derivative oil, gas, & NGL revenue)	4.8%	5%
G&A -- Cash (\$/MCFE)	\$0.50	\$0.48 - \$0.51
G&A -- Cash NPP (\$/MCFE)	\$0.09	\$0.11 - \$0.13
G&A -- Non-cash (\$/MCFE)	\$0.10	\$0.12 - \$0.14
<b>TOTAL G&amp;A (\$/MCFE)</b>	<b>\$0.69</b>	<b>\$0.71 - \$0.78</b>
DD&A (\$/MCFE)	\$3.26	\$2.90 - \$3.10
Non-cash interest expense (\$MM)	\$3.6	\$3.4

	FY11 Actual	FY11 Guidance
Effective Income Tax Rate	36.5%	36.6% - 37.1%
% of Income tax that is current	-%	15% - 18%

## Net Income

- GAAP net loss of \$(120.7) million, or \$(1.89) per diluted share
- Adjusted net income (non-GAAP) of \$40.9 million, or \$0.60 per adjusted diluted share\*

## Cash Flow

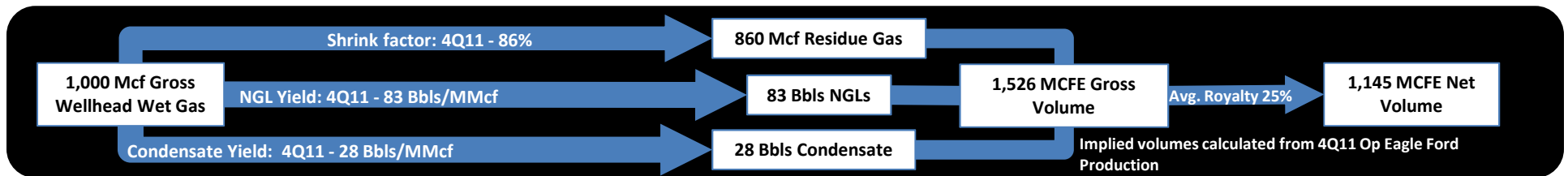
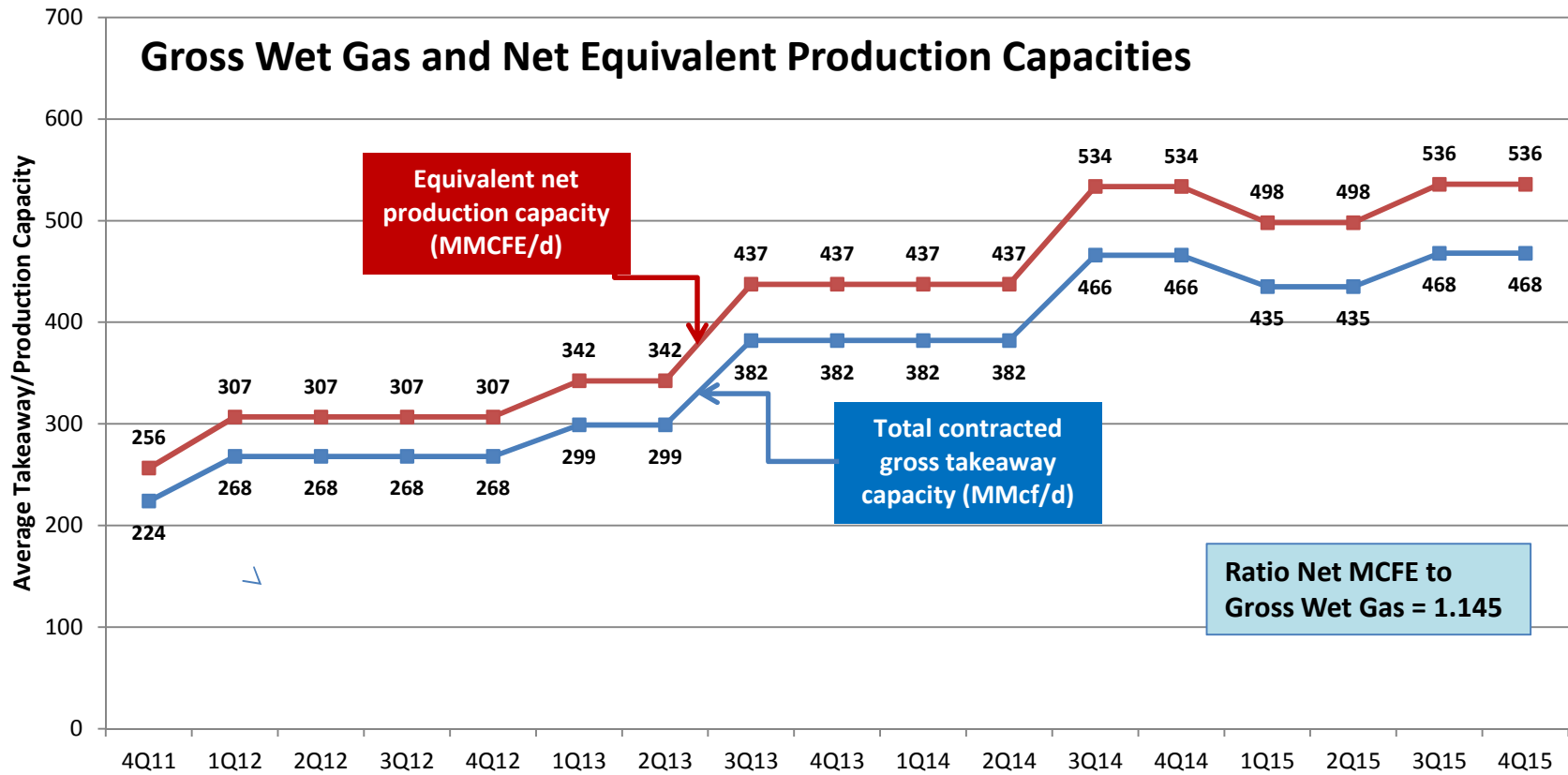
- GAAP cash flow from operating activities of \$270.8 million
- Operating cash flow (non-GAAP) of \$275.1 million\*

\* Please see adjusted net income and operating cash flow reconciliations in the Appendix.

# Guidance Update

	1Q12	FY 2012
Production (BCFE)	48.5 – 52.0	220 – 227
Average daily production (MMCFE/d)	533 – 571	601 – 620
LOE (\$/MCFE)	\$0.90 – \$0.96	\$0.90 – \$0.96
Transportation (\$/MCFE)	\$0.65 – \$0.70	\$0.73 – \$0.77
Production taxes (% of pre-derivative oil and gas revenue)	5.5%	5.5%
G&A – cash NPP (\$/MCFE)	\$0.08 – \$0.10	\$0.08 – \$0.10
G&A – other gas (\$/MCFE)	\$0.45 – \$0.48	\$0.41 – \$0.45
G&A – non-cash (\$/MCFE)	\$0.09 – \$0.11	\$0.09 – \$0.11
G&A Total (\$/MCFE)	\$0.62 – \$0.69	\$0.58 – \$0.66
DD&A (\$/MCFE)	\$3.35 – \$3.55	\$3.10 – \$3.30
Non-cash interest expense (\$MM)	\$3.7	\$6.6
Effective income tax rate range		37.2% – 37.7%
% of income tax that is current		–%

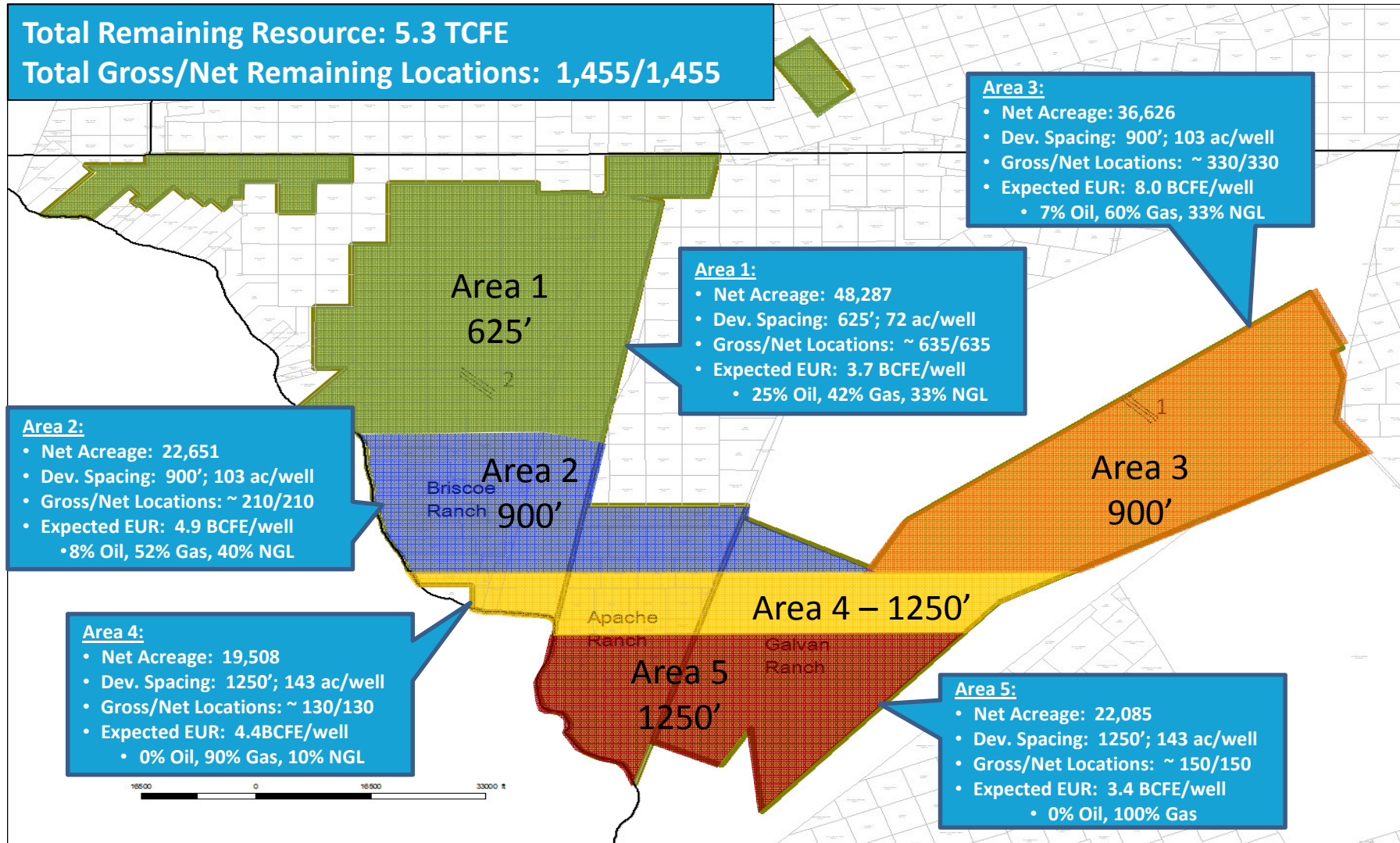
# Eagle Ford Takeaway Capacity Volumes\*



\*Note: capacity figures assume 3 current firm commitment agreements (Regency, KM/CPNO, and ETC); conversion assumes 1.2 MMBTU/Mcf.

# Operated Eagle Ford Spacing and Type Curves

Total Remaining Resource: 5.3 TCFE  
 Total Gross/Net Remaining Locations: 1,455/1,455



\* Resource potential is based on expected-case EURs, which are different than EURs used for estimating prove reserves for SEC purposes. Net locations are based on current assumptions of development spacing and working interest percentages.

# Operated Eagle Ford – Resource Potential

	AREA 1		AREA 2		AREA 3		AREA 4		AREA 5	
Net Acreage	48,287		22,651		36,626		19,508		22,085	
Expected EUR/well	3.7 BCFE		4.9 BCFE		8.0 BCFE		4.4 BCFE		3.4 BCFE	
Development Spacing (ac/well)	72		103		103		143		143	
CWC /well (\$MM)	6.8		6.8		7.7		7.7		7.7	
	Gross/Net Count	Resource (BCFE)	Gross/Net Count	Resource (BCFE)	Gross/Net Count	Resource (BCFE)	Gross/Net Count	Resource (BCFE)	Gross/Net Count	Resource (BCFE)
PDP	40 / 38	61	9 / 9	25	26 / 26	94	3 / 3	10	6 / 6	7
PUD	<u>24 / 24</u>	<u>69</u>	<u>4 / 4</u>	<u>14</u>	<u>16 / 16</u>	<u>95</u>	<u>1 / 1</u>	<u>5</u>	<u>0 / 0</u>	<u>0</u>
Total Proved	64 / 62	131	13 / 13	39	42 / 42	189	4 / 4	15	6 / 6	7
Unproved	610 / 610	1,615	205 / 205	765	315 / 315	1,910	130 / 130	415	150 / 150	385
Drilling Locations*	634 / 634	1,684	209 / 209	779	331 / 331	2,005	131 / 131	420	150 / 150	385

\* Resource potential is based on expected-case EURs, which are different than EURs used for estimating prove reserves for SEC purposes. Net locations are based on current assumptions of development spacing and working interest percentages.



# Bakken/Three Forks Spacing and Type Curves

## Gooseneck - Three Forks:

- Net Acreage: 35,143
- Dev. Spacing: 320 acres/well
- Gross/Net Locations: ~189/95
- Expected EUR: ~365 MBOE/well
  - 100% Oil, 0% Gas
- Unrisked remaining resource potential: 28.4MMBOE

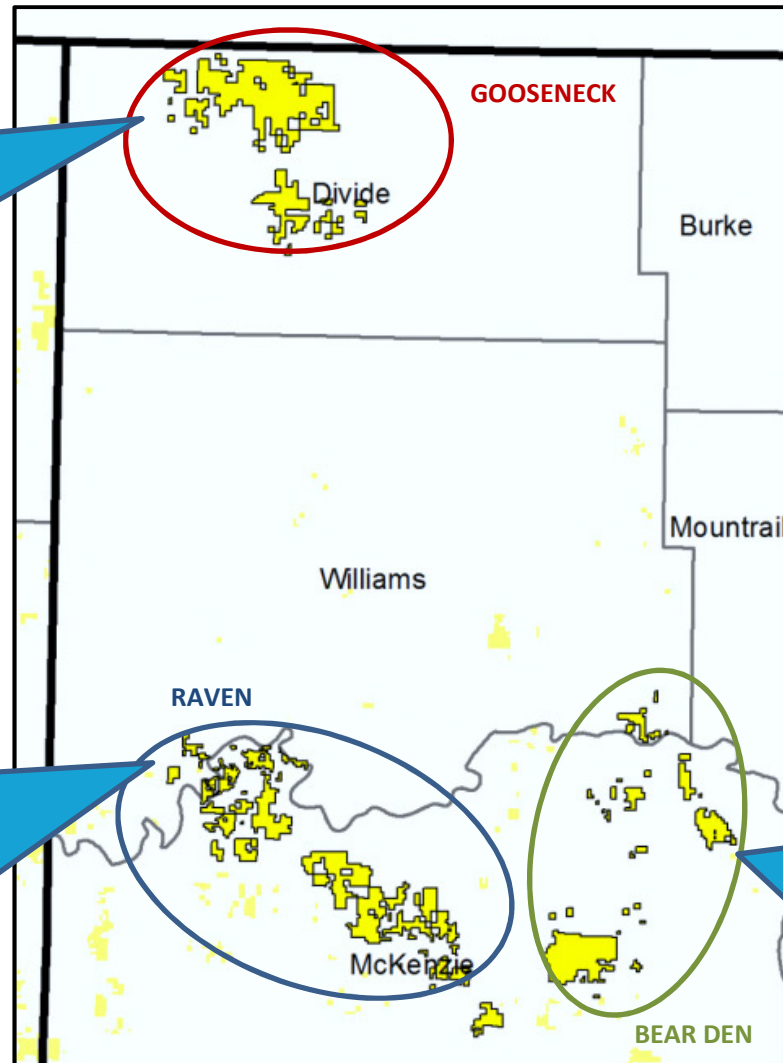
**Total Remaining Resource:**  
~140 MMBOE  
**Total Gross/Net Remaining Locations:** 1,260/375

## Raven – Bakken/Three Forks:

- Net Acreage: 36,534
- Dev. Spacing: 320 acres/well
- Gross/Net Locations:
  - Bakken: ~344/99
  - Three Forks: ~459/114
- Expected EUR:
  - Bakken: ~500 MBOE/well
  - 84% Oil, 16% Gas
  - Three Forks ~400MBOE/well
  - 84% Oil, 16% Gas
- Unrisked remaining resource potential: 80.4 MMBOE

## Bear Den – Bakken/Three Forks:

- Net Acreage: 15,281
- Dev. Spacing: 320 – 427 acres/well
- Gross/Net Locations:
  - Bakken: ~114/31
  - Three Forks: ~156/35
- Expected EUR:
  - Bakken: ~550 MBOE/well
  - 77% Oil, 23% Gas
  - Three Forks ~450MBOE/well
  - 77% Oil, 23% Gas
- Unrisked remaining resource potential: 30.3 MMBOE



\* Resource potential is based on expected-case EURs, which are different than EURs used for estimating prove reserves for SEC purposes. Net locations are based on current assumptions of development spacing and working interest percentages.

# Bakken/Three Forks – Resource Potential

	Gooseneck – Three Forks		Raven – Bakken		Raven – Three Forks		Bear Den – Bakken		Bear Den – Three Forks	
Net Acreage	35,143		36,534*		36,534*		15,281*		15,281*	
Expected EUR/well	365 MBOE		498 MBOE		409 MBOE		554 MBOE		447 MBOE	
Development Spacing (ac/well)	320		320		320		320 - 427		320 - 427	
CWC (\$MM/well)	6.9		9.1		9.1		9.1		9.1	
	Gross/Net Count	Resource (MMBOE)	Gross/Net Count	Resource (MMBOE)	Gross/Net Count	Resource (MMBOE)	Gross/Net Count	Resource (MMBOE)	Gross/Net Count	Resource (MMBOE)
PDP	20 / 15	3.6	54 / 16	4.0	2 / 1	0.0	44 / 10	2.1	35 / 6	1.2
PUD	<u>19 / 14</u>	<u>3.8</u>	<u>54 / 16</u>	<u>7.5</u>	<u>1 / 0</u>	<u>0.2</u>	<u>23 / 6</u>	<u>1.9</u>	<u>7 / 1</u>	<u>0.9</u>
Total Proved	39 / 29	7.5	108 / 32	11.4	3 / 1	0.2	67 / 16	4.0	42 / 7	2.1
Unproved	170 / 80	25	290 / 85	35	455 / 115	40	90 / 25	15	150 / 35	15
Drilling Locations **	189 / 94	28.8	344 / 101	42.5	456 / 115	40.2	113 / 31	16.9	157 / 36	15.9

\*Note: Acreage figures for Bakken and Three Forks plays in the Raven and Bear Den prospects provide the amount of acreage that is prospective for each respective interval.

\*\* Resource potential is based on expected-case EURs, which are different than EURs used for estimating prove reserves for SEC purposes. Net locations are based on current assumptions of development spacing and working interest percentages.



# 2011 Proved Reserves

Proved oil and gas reserve quantities						
	For the Year Ended					
	December 31, 2011					
	Oil or Condensate	Gas	NGL	Equivalents	Proved Developed	Proved Undeveloped
	(MMBbl)	(Bcf)	(MMBbl)	(BCFE)	(BCFE)	(BCFE)
<b>Total proved reserves</b>						
Beginning of year	57.4	640.0	-	984.5	687.3	297.2
Revisions of previous estimate	(0.9)	(76.7)	15.6	11.5	36.5	(25.0)
Discoveries and extensions	26.9	223.5	17.8	491.3	303.8	187.5
Infill reserves in an existing proved field	2.8	14.8	0.5	34.7	20.1	14.6
Purchases of minerals in place	-	-	-	-	-	-
Sales of reserves	(6.4)	(37.3)	(2.9)	(93.1)	(68.6)	(24.5)
Production	(8.1)	(100.3)	(3.5)	(169.7)	(169.7)	-
Conversions				-	34.6	(34.6)
End of year	71.7	664.0	27.5	1259.2	844.0	415.2
<b>PV-10 value (in millions)</b>				\$3,461.2	\$2,836.3	\$624.9
<b>Proved developed reserves</b>						
Beginning of year	46.0	411.0	-	687.3		
End of year	50.3	451.2	15.2	844.0		

# Adjusted Net Income Reconciliation

## Reconciliation of net income (GAAP) to adjusted net income (Non-GAAP):

(in thousands, except per share data)

### Reported Net Income (GAAP)

### Adjustments net of tax: (1)

Change in Net Profits Plan liability

Unrealized derivative (gain) loss

Gain on divestiture activity

Impairments of proved properties

Abandonment and impairment of unproved properties

DD&A adjustment for Marcellus shale

### Adjusted net income (Non-GAAP) (2)

### Diluted net income per common share

As Reported (GAAP)

Adjusted (Non-GAAP) (3)

### Average number of shares outstanding

As Reported (GAAP)

Adjusted (Non-GAAP) (3)

## For the Three Months Ended December 31,

	2011	2010
	\$ (120,711)	\$ 37,139
	(475)	(2,956)
	28,380	8,249
	15,666	(14,660)
	106,911	3,889
	1,913	(1,912)
	9,245	-
	\$ 40,929	\$ 29,749
	\$ (1.89)	\$ 0.57
	\$ 0.60	\$ 0.46
	64,024	64,919
	67,653	64,919

(1) For the three and twelve-month periods ended December 31, 2011, adjustments are shown net of tax and are calculated using an effective tax rate of 37.3%, which approximates the Company's statutory tax rate adjusted for ordinary permanent differences. For the three and twelve-month periods ended December 30, 2010, adjustments are shown net of tax using the effective income tax rate as calculated by dividing the income tax expense by income before income taxes as shown on the consolidated statement of operations for the respective period.

(2) Adjusted net income excludes certain items that the Company believes affect the comparability of operating results. Items excluded generally are non-recurring items or are items whose timing and/or amount cannot be reasonably estimated. These items include non-cash adjustments and impairments such as the change in the Net Profits Plan liability, unrealized derivative (gain) loss, impairment of proved properties, abandonment and impairment of unproved properties, and gain on divestiture activity. The non-GAAP measure of adjusted net income is presented because management believes it provides useful additional information to investors for analysis of SM Energy's fundamental business on a recurring basis. In addition, management believes that adjusted net income is widely used by professional research analysts and others in the valuation, comparison, and investment recommendations of companies in the oil and gas exploration and production industry, and many investors use the published research of industry research analysts in making investment decisions. Adjusted net income should not be considered in isolation or as a substitute for net income, income from operations, cash provided by operating activities or other income, profitability, cash flow, or liquidity measures prepared under GAAP. Because adjusted net income excludes some, but not all, items that affect net income and may vary among companies, the adjusted net income amounts presented may not be comparable to similarly titled measures of other companies.

(3) Adjusted net income per diluted share assumes income for the period and is calculated using potentially dilutive securities related to unvested restricted stock units, in-the-money outstanding options to purchase the Company's common stock, contingent Performance Share Units, and shares into which the 3.50% Senior Convertible Notes may be converted, as calculated for accounting purposes using the treasury stock method as applied to the Company's net share settlement option for the notes. On a GAAP basis, these items were not treated as dilutive securities in the fourth quarter of 2011 as the Company reported a GAAP loss for the quarter.

# Operating Cash Flow Reconciliation

(in thousands)

Reconciliation of net cash provided by operating activities (GAAP) to Operating cash flow (non-GAAP):	For the Three Months Ended December 31,	
	2011	2010
Net cash provided by operating activities (GAAP)	\$ 270,785	\$ 78,737
Changes in current assets and liabilities	(13,492)	78,605
Exploration	19,950	21,027
Less: Exploratory dry hole expense	(228)	--
Less: Stock-based compensation expense included in exploration	(1,869)	(1,952)
Operating cash flow (Non-GAAP) <sup>(1)</sup>	\$ 275,146	\$ 176,417

(1) Operating cash flow is computed as net cash provided by operating activities adjusted for changes in current assets and liabilities and exploration, less exploratory dry hole expense, and stock-based compensation expense included in exploration. The non-GAAP measure of operating cash flow is presented because management believes that it provides useful additional information to investors for analysis of SM Energy's ability to internally generate funds for exploration, development, acquisitions, and to service debt. In addition, operating cash flow is widely used by professional research analysts and others in the valuation, comparison, and investment recommendations of companies in the oil and gas exploration and production industry, and many investors use the published research of industry research analysts in making investment decisions. Operating cash flow should not be considered in isolation or as a substitute for net income, income from operations, net cash provided by operating activities or other income, profitability, cash flow, or liquidity measures prepared under GAAP. Because operating cash flow excludes some, but not all items that affect net income and net cash provided by operating activities and may vary among companies, the operating cash flow amounts presented may not be comparable to similarly titled measures of other companies. See the consolidated statements of cash flows included in our annual report for the year ended December 31, 2011 for more detailed cash flow information.

# Summarized Oil Derivative Position\*

## Oil Swaps - NYMEX Equivalent

	<u>Bbls</u>		<u>\$/Bbl</u>
2012			
Q1	569,200	\$	84.15
Q2	524,200	\$	84.19
Q3	489,400	\$	83.87
Q4	462,600	\$	87.08
<b>2012 Total</b>	<b>2,045,400</b>		
2013			
Q1	200,300	\$	87.75
Q2	272,600	\$	86.67
Q3	75,300	\$	91.80
Q4	68,000	\$	91.83
<b>2013 Total</b>	<b>616,200</b>		
2014			
Q1	61,600	\$	91.82
Q2	599,000	\$	91.71
Q3	0		
Q4	0		
<b>2014 Total</b>	<b>660,600</b>		
<b>Grand Total</b>	<b>3,322,200</b>		

## Oil Collars - NYMEX Equivalent

	<u>Bbls</u>	<u>Ceiling</u>	<u>Floor</u>
		<u>\$/Bbl</u>	<u>\$/Bbl</u>
2012			
Q1	714,600	\$ 112.65	\$ 80.39
Q2	742,900	\$ 112.89	\$ 80.78
Q3	637,900	\$ 112.53	\$ 80.35
Q4	566,200	\$ 112.28	\$ 80.03
<b>2012 Total</b>	<b>2,661,600</b>		
2013			
Q1	754,900	\$ 107.36	\$ 79.87
Q2	619,900	\$ 109.08	\$ 76.65
Q3	764,800	\$ 107.98	\$ 74.89
Q4	726,600	\$ 116.09	\$ 81.02
<b>2013 Total</b>	<b>2,866,200</b>		
2014			
Q1	694,400	\$ 115.07	\$ 80.97
Q2	123,100	\$ 111.00	\$ 85.00
Q3	692,000	\$ 104.00	\$ 85.00
Q4	665,000	\$ 104.00	\$ 85.00
<b>2014 Total</b>	<b>2,174,500</b>		
<b>Grand Total</b>	<b>7,702,300</b>		

# Summarized Gas Derivative Position\*

## Natural Gas Swaps - NYMEX Equivalent

	<u>MMBTU</u>	<u>\$/MMBTU</u>
2012		
Q1	7,930,000	\$ 5.25
Q2	7,140,000	\$ 4.91
Q3	6,510,000	\$ 5.10
Q4	8,424,000	\$ 4.70
<b>2012 Total</b>	<b>30,004,000</b>	
2013		
Q1	6,317,000	\$ 4.87
Q2	5,101,000	\$ 4.40
Q3	4,708,000	\$ 4.56
Q4	4,383,000	\$ 4.74
<b>2013 Total</b>	<b>20,509,000</b>	
2014		
Q1	4,099,000	\$ 5.13
Q2	1,108,000	\$ 3.94
Q3	5,006,000	\$ 4.03
Q4	4,741,000	\$ 4.14
<b>2014 Total</b>	<b>14,954,000</b>	
<b>Grand Total</b>	<b>65,467,000</b>	

## Natural Gas Collars - NYMEX Equivalent

	<u>MMBTU</u>	<u>Ceiling \$/MMBTU</u>	<u>Floor \$/MMBTU</u>
2012			
Q1	-		
Q2	-		
Q3	-		
Q4	-		
<b>2012 Total</b>	<b>-</b>		
2013			
Q1	1,330,000	\$ 5.59	\$ 4.52
Q2	1,910,000	\$ 5.44	\$ 4.51
Q3	1,770,000	\$ 5.45	\$ 4.52
Q4	1,640,000	\$ 5.45	\$ 4.53
<b>2013 Total</b>	<b>6,650,000</b>		
2014			
Q1	1,540,000	\$ 5.72	\$ 4.54
Q2	4,194,000	\$ 5.42	\$ 4.51
Q3	-		
Q4	-		
<b>2014 Total</b>	<b>5,734,000</b>		
<b>Grand Total</b>	<b>12,384,000</b>		

# Summarized NGL Derivative Position\*

## Natural Gas Liquid Swaps - Mont. Belvieu

	<u>Bbls</u>		<u>\$/Bbl</u>
2012			
Q1	410,000	\$	51.52
Q2	387,000	\$	52.68
Q3	346,000	\$	53.83
Q4	316,000	\$	53.28
<b>2012 Total</b>	<b>1,459,000</b>		
2013			
Q1	84,000	\$	44.95
Q2			
Q3			
Q4			
<b>2013 Total</b>	<b>84,000</b>		
2014			
Q1	0		
Q2	0		
Q3	0		
Q4	0		
<b>2014 Total</b>	<b>0</b>		
<b>Grand Total</b>	<b>1,543,000</b>		