MATTHEWS MILTON T
Form 4
March 08, 2002

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 4
STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP

[ ] Check this box if no longer subject to Section 16. Form 4 or Form 5 obligations may continue.

1. Name and Address of Reporting Person(s)
   Matthews Milton T
   100 Crystal A Drive

   Hershey, Pennsylvania 17033
2. Issuer Name and Ticker or Trading Symbol
   Hershey Foods Corporation (HSY)
3. I.R.S. Identification Number of Reporting Person, if an entity (Voluntary)

4. Statement for Month/Year
   02/02
5. If Amendment, Date of Original (Month/Year)
6. Relationship of Reporting Person(s) to Issuer (Check all applicable)
   [ ] Director [ ] 10% Owner
   [X] Officer (give title below) [ ] Other (specify below)
   V.P., Chief Customer Officer
7. Individual or Joint/Group Filing (Check Applicable Line)
   [X] Form filed by One Reporting Person
   [ ] Form filed by More than One Reporting Person

Table I Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1)Title of Security	2)Transaction Date (Month/Day/Year)	3.Transaction Code: Code	V	4.Securities Acquired(A) or Disposed of (D): Amount	A or D	Price
Common Stock (1)	02/04/02	M		6,400.0000	A	$24.18750
Common Stock	02/04/02	S		6,400.0000	D	$69.83000
Common Stock	02/11/02	A	V	278.0000	A	$70.38000
Common Stock	02/27/02	I	V	278.0000	D	$70.86000
Common Stock						
Common Stock						

Table II (PART 1) Derivative Securities Acquired, Disposed of, or Beneficially Owned (Columns 1 through 6)

1)Title of Derivative Security	2)Conversion or Exercise Price of Derivative Security	3)Transaction Date	4)Transaction Code: Code	V	5)Number of Derivative Securities Acquired (A) or Disposed of (D): A	D
Non-Qualified Stock Option	$24.18750	02/04/02	M			6,400.00

(right to buy) (1)

Table II (PART 2) Derivative Securities Acquired, Disposed of, or Beneficially Owned (Columns 1,3 and 7 through 11)

1)Title of Derivative Security	3)Transaction Date	7)Title and Amount of Underlying Securities Title	Amount or Number of Shares	8)Price of Derivative Security
-				
Non-Qualified Stock Option (right to buy) (1)	02/04/02	Common Stock	6,400.0000	$69.83000

SIGNATURE OF REPORTING PERSON
/S/ Matthews , Milton T
DATE March 8, 2002

Forfeited
(32,736
)

$
59.07

Non-vested at end of quarter
530,695

$
68.34

The fair value of the RSUs granted during the first nine months of 2014 was $19.6 million. These RSUs will vest 1/3rd on each of the next three anniversary dates of the grant. During the first nine months of 2014, the Company settled 250,601 RSUs that related to awards granted in previous years. The Company and the majority of grant participants mutually agreed to net share settle the awards to cover income and payroll tax withholdings as provided for in the plan document and award agreements. As a result, the Company issued 169,835 net shares of common stock. The remaining 80,766 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon delivery of the shares underlying those RSUs.

Performance Share Units Under the Equity Incentive Compensation Plan

The Company grants performance share units ("PSUs") as part of its equity compensation program. The number of shares of the Company's common stock issued to settle PSUs ranges from 0% to 200% of the number of PSUs awarded and is determined based on the Company's performance over a three-year measurement period. The performance criteria for the PSUs are based on a combination of the Company's annualized total shareholder return ("TSR") for the measurement period and the relative performance of the Company's TSR compared with the annualized

TSRs of a group of peer companies for the measurement period. Expense associated with PSUs is recognized as G&A expense and exploration expense over the vesting period of the award.

Total expense recorded for PSUs for the three months ended September 30, 2014, and 2013, was $4.8 million and $3.5 million, respectively, and $11.6 million and $13.2 million for the nine months ended September 30, 2014, and 2013, respectively. As of September 30, 2014, there was $24.7 million of total unrecognized compensation expense related to unvested PSU awards, which is being amortized through 2017.

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A summary of the status and activity of non-vested PSUs for the nine-month period ended September 30, 2014, is presented in the following table:

	PSUs [1]		Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	572,469		$66.07
Granted	202,404		$94.66
Vested	(115,784	)	$59.30
Forfeited	(129,491	)	$87.21
Non-vested at end of quarter	529,598		$73.31

(1) The number of awards assumes a one multiplier. The final number of shares of common stock issued may vary depending on the three-year performance multiplier, which ranges from zero to two.

The fair value of the PSUs granted during the first nine months of 2014 was $19.2 million. These PSUs will vest on the third anniversary of the date of the grant. During the first nine months of 2014, the Company settled PSUs that were granted in 2011, which earned a 0.55 times multiplier, by issuing a net 85,121 shares of the Company's common stock in accordance with the terms of the PSU awards. The Company and the majority of grant participants mutually agreed to net share settle the awards to cover income and payroll tax withholdings as provided for in the plan document and award agreements. As a result, the Company withheld 45,042 shares to satisfy income and payroll tax withholding obligations that occurred upon delivery of the shares underlying those PSUs.

Stock Option Grants Under the Equity Incentive Compensation Plan

A summary of activity associated with the Company's Stock Option Plan for the nine months ended September 30, 2014, is presented in the following table:

	Shares		Weighted-Average Exercise Price	Aggregate Intrinsic Value (in thousands)
Outstanding, at beginning of year	39,088		$20.87	$2,433
Exercised	(19,544	)	$20.87	$1,237
Forfeited	—		$—	$—
Outstanding, at end of quarter	19,544		$20.87	$1,117
Vested and exercisable, at end of quarter	19,544		$20.87	$1,117

As of September 30, 2014, there was no unrecognized compensation expense related to stock option awards.
Director Shares
During the nine months ended September 30, 2014 and 2013, the Company issued 27,677 and 28,169 shares, respectively, of its common stock to its non-employee directors, under the Company's Equity Incentive Compensation Plan. The Company recorded $196,000 of compensation expense related to these awards for the three months ended September 30, 2014, and no compensation expense related to these awards for the three months ended September 30, 2013. The Company recorded $1.4 million and $1.4 million of compensation expense related to these awards for the nine months ended September 30, 2014, and 2013, respectively.

All shares of common stock issued to the Company's non-employee directors are earned over the one-year service period following the date of grant, unless five years of service has been provided by the director, in which case that director's shares vest immediately.

Employee Stock Purchase Plan
Under the Company's Employee Stock Purchase Plan ("ESPP"), eligible employees may purchase shares of the Company's common stock through payroll deductions of up to 15 percent of eligible compensation, without accruing in excess of $25,000 in value from purchases for each calendar year. The purchase price of the stock is 85 percent of the lower of the fair market value of the stock on the first or last day of the purchase period, and shares issued under the ESPP have no restriction period. The ESPP is intended to qualify under Section 423 of the IRC. The Company had 1.2 million shares available for issuance under the ESPP as of September 30, 2014. The Company issued 35,249 and 44,437 shares under the ESPP during the first nine months of 2014 and 2013, respectively. The fair value of ESPP grants is measured at the date of grant using the Black-Scholes option-pricing model.
Net Profits Interest Bonus Plan

Cash payments made or accrued under the Company's Net Profits Interest Bonus Plan ("Net Profits Plan") that have been recorded as either G&A expense or exploration expense are presented in the table below:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
General and administrative expense	$2,487	$4,302	$7,451	$11,531
Exploration expense	162	329	644	1,026
Total	$2,649	$4,631	$8,095	$12,557

Additionally, the Company accrued or made cash payments under the Net Profits Plan of $8.3 million and $2.6 million for the nine months ended September 30, 2014, and 2013, respectively, as a result of divestiture proceeds. These cash payments are accounted for as a reduction in gain on divestiture activity included within the other operating revenues line in the accompanying statements of operations.

Note 8 - Pension Benefits

Pension Plans

The Company has a non-contributory pension plan covering substantially all employees who meet age and service requirements (the "Qualified Pension Plan"). The Company also has a supplemental non-contributory pension plan covering certain management employees (the "Nonqualified Pension Plan" and together with the Qualified Pension Plan, the "Pension Plans").

Components of Net Periodic Benefit Cost for the Pension Plans

The following table presents the components of the net periodic benefit cost for the Pension Plans:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Service cost	$1,584	$1,572	$4,752	$4,718
Interest cost	548	407	1,643	1,220
Expected return on plan assets that reduces periodic pension costs	(494)	(384)	(1,483)	(1,153)
Amortization of prior service costs	4	4	13	13
Amortization of net actuarial loss	172	306	516	917
Net periodic benefit cost	$1,814	$1,905	$5,441	$5,715

Prior service costs are amortized on a straight-line basis over the average remaining service period of active participants. Gains and losses in excess of 10 percent of the greater of the benefit obligation and the market-related value of assets are amortized over the average remaining service period of active participants.

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Contributions

The Company contributed $5.3 million to the Pension Plans during the nine month period ended September 30, 2014.

Note 9 - Earnings per Share

Basic net income per common share is calculated by dividing net income available to common stockholders by the basic weighted-average common shares outstanding for the respective period. The Company’s earnings per share calculations reflect the impact of any repurchases of shares of common stock made by the Company.

Diluted net income per common share is calculated by dividing adjusted net income by the diluted weighted-average common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for this calculation consist of in-the-money outstanding stock options, unvested RSUs, and contingent PSUs. The treasury stock method is used to measure the dilutive impact of unvested RSUs, contingent PSUs, and in-the-money stock options.

PSUs represent the right to receive, upon settlement of the PSUs after completion of the three-year performance period, a number of shares of the Company’s common stock that may range from 0% to 200% of the number of PSUs granted on the award date. The number of potentially dilutive shares related to PSUs is based on the number of shares, if any, that would be issuable at the end of the respective reporting period, assuming that date was the end of the contingency period applicable to such PSUs. For additional discussion on PSUs, please refer to Note 7 - Compensation Plans under the heading Performance Share Units Under the Equity Incentive Compensation Plan.

The following table sets forth the calculations of basic and diluted earnings per share:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands, except per share amounts)			
Net income	$208,938	$70,690	$334,325	$163,939
Basic weighted-average common shares outstanding	67,379	66,943	67,169	66,486
Add: dilutive effect of stock options, unvested RSUs, and contingent PSUs	1,051	1,310	1,089	1,483
Diluted weighted-average common shares outstanding	68,430	68,253	68,258	67,969
Basic net income per common share	$3.10	$1.06	$4.98	$2.47
Diluted net income per common share	$3.05	$1.04	$4.90	$2.41

Note 10 - Derivative Financial Instruments

Summary of Oil, Gas, and NGL Derivative Contracts in Place

The Company has entered into various commodity derivative contracts to mitigate a portion of its exposure to potentially adverse market changes in commodity prices and the associated impact on cash flows. All contracts are entered into for other-than-trading purposes. The Company’s derivative contracts include swap and costless collar arrangements for oil, gas, and NGLs.

As of September 30, 2014, the Company had commodity derivative contracts outstanding through the second quarter of 2018 for a total of 17.6 million Bbls of oil production, 164.1 million MMBtu of gas production, and 1.8 million Bbls of NGL production.

In a typical commodity swap agreement, if the agreed upon published third-party index price ("index price") is lower than the swap fixed price, the Company receives the difference between the index price and the agreed upon swap fixed price. If the index price is higher than the swap fixed price, the Company pays the difference. For collar agreements, the Company receives the difference between an index price and the floor price if the index price is below the floor price. The Company pays the difference between the ceiling price and the index price if the index price is above the ceiling price. No amounts are paid or received if the index price is between the floor and ceiling prices.

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The following tables summarize the approximate volumes and average contract prices of contracts the Company had in place as of September 30, 2014:

Oil Contracts

Oil Swaps

Contract Period	NYMEX WTI Volumes	Weighted-Average Contract Price
	(Bbls)	(per Bbl)
Fourth quarter 2014	2,016,000	$96.01
2015	5,741,000	$91.14
2016	5,570,000	$88.01
All oil swaps	13,327,000	

Oil Collars

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(Bbls)	(per Bbl)	(per Bbl)
Fourth quarter 2014	923,000	$85.00	$102.63
2015	3,366,000	$85.00	$94.25
All oil collars	4,289,000		

Gas Contracts

Gas Swaps

Contract Period	Volumes	Weighted-Average Contract Price
	(MMBtu)	(per MMBtu)
Fourth quarter 2014	22,014,000	$4.02
2015	57,943,000	$4.04
2016	37,472,000	$4.17
2017	23,430,000	$4.21
2018	10,200,000	$4.31
All gas swaps*	151,059,000	

*Gas swaps are comprised of IF El Paso Permian (4%), IF HSC (83%), IF NGPL TXOK (2%), IF NNG Ventura (2%), IF Enable East (8%), and IF CIG (1%).

Gas Collars

Contract Period	Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(MMBtu)	(per MMBtu)	(per MMBtu)
2015	13,002,000	$3.98	$4.30
All gas collars*	13,002,000		

*Gas collars are comprised of IF El Paso Permian (4%), IF HSC (80%), IF NNG Ventura (8%), and IF Enable East (8%).

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NGL Contracts

NGL Swaps

Contract Period	Volumes	Weighted-Average Contract Price
	(Bbls)	(per Bbl)
Fourth quarter 2014	980,000	$61.69
2015	781,000	$55.42
All NGL swaps*	1,761,000	

*NGL swaps are comprised of Oil Price Information System ("OPIS") Mont Belvieu LDH Propane (67%) and OPIS Mont Belvieu NON-LDH Natural Gasoline (33%).

Derivative Assets and Liabilities Fair Value

The Company's commodity derivatives are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities. The fair value of the commodity derivative contracts was a net asset of $50.9 million and net asset of $21.5 million as of September 30, 2014, and December 31, 2013, respectively.

The following tables detail the fair value of derivatives recorded in the accompanying balance sheets, by category:

	As of September 30, 2014			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity contracts	Current assets	$41,295	Current liabilities	$4,649
Commodity contracts	Noncurrent assets	22,510	Noncurrent liabilities	8,243
Derivatives not designated as hedging instruments		$63,805		$12,892

	As of December 31, 2013			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity contracts	Current assets	$21,559	Current liabilities	$26,380
Commodity contracts	Noncurrent assets	30,951	Noncurrent liabilities	4,640
Derivatives not designated as hedging instruments		$52,510		$31,020

Offsetting of Derivative Assets and Liabilities

As of September 30, 2014, and December 31, 2013, all derivative instruments held by the Company were subject to enforceable master netting arrangements by various financial institutions. In general, the terms of the Company's agreements provide for offsetting of amounts payable or receivable between it and the counterparty, at the election of both parties, for settlements that occur on the same date and in the same currency. The Company's agreements also provide that in the event of an early termination, the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. The Company’s accounting policy is to not offset these positions in its accompanying balance sheets.

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The following table provides a reconciliation between the gross assets and liabilities reflected on the accompanying balance sheets and the potential effects of master netting arrangements on the fair value of the Company's derivative contracts:

Offsetting of Derivative Assets and Liabilities	Derivative Assets As of September 30, 2014 (in thousands)	Derivative Assets As of December 31, 2013	Derivative Liabilities As of September 30, 2014	Derivative Liabilities As of December 31, 2013
Gross amounts presented in the accompanying balance sheets	$63,805	$52,510	$(12,892)	$(31,020)
Amounts not offset in the accompanying balance sheets	(12,744)	(30,652)	12,744	30,652
Net amounts	$51,061	$21,858	$(148)	$(368)

The following table summarizes the components of the derivative (gain) loss presented in the accompanying statements of operations:

	For the Three Months Ended September 30, 2014 (in thousands)	For the Three Months Ended September 30, 2013	For the Nine Months Ended September 30, 2014	For the Nine Months Ended September 30, 2013
Derivative cash settlement (gain) loss:				
Oil contracts	$517	$13,538	27,435	$13,786
Gas contracts	1,687	(11,019)	28,563	(18,752)
NGL contracts	(1,930)	(1,231)	6,896	(7,749)
Total derivative cash settlement (gain) loss[(1)]	274	1,288	62,894	(12,715)
Derivative (gain) loss:				
Oil contracts	(141,429)	30,488	(42,802)	8,233
Gas contracts	(43,039)	(2,264)	17,700	(12,462)
NGL contracts	(6,467)	10,421	(4,322)	2,259
Total derivative (gain) loss [(2)]	$(190,661)	$39,933	$33,470	$(14,685)

(1) Total derivative cash settlement (gain) loss is reported in the derivative cash settlement gain (loss) line item on the condensed consolidated statements of cash flows within net cash provided by operating activities.

(2) Total derivative (gain) loss is reported in the derivative (gain) loss line item on the condensed consolidated statements of cash flows within net cash provided by operating activities.

Credit Related Contingent Features

As of September 30, 2014, and through the filing date of this report, all of the Company's derivative counterparties were members of the Company's credit facility lender group. The Company's obligations under its derivative contracts are secured by liens on at least 75 percent of the Company's proved oil and gas properties.

Note 11 - Fair Value Measurements

The Company follows fair value measurement authoritative accounting guidance for all assets and liabilities measured at fair value. That authoritative accounting guidance defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Market or observable inputs are the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The fair value hierarchy for grouping these assets and liabilities is based on the significance level of the following inputs:

- Level 1 – quoted prices in active markets for identical assets or liabilities
- Level 2 – quoted prices in active markets for similar assets or liabilities, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations whose inputs are observable or whose significant value drivers are observable
- Level 3 – significant inputs to the valuation model are unobservable

The following is a listing of the Company’s assets and liabilities that are measured at fair value and their classification within the fair value hierarchy as of September 30, 2014:

	Level 1 (in thousands)	Level 2	Level 3
Assets:			
Derivatives [1]	$—	$63,805	$—
Proved oil and gas properties [2]	$—	$—	$9,443
Unproved oil and gas properties [2]	$—	$—	$43,252
Oil and gas properties held for sale [2]	$—	$—	$17,952
Liabilities:			
Derivatives [1]	$—	$12,892	$—
Net Profits Plan [1]	$—	$—	$41,705
Asset retirement obligation [2]	$—	$—	$923
Asset retirement obligation associated with oil and gas properties held for sale [2]	$—	$—	$452

[1] This represents a financial asset or liability that is measured at fair value on a recurring basis.
[2] This represents a non-financial asset or liability that is measured at fair value on a nonrecurring basis.

The following is a listing of the Company’s assets and liabilities that are measured at fair value and their classification within the fair value hierarchy as of December 31, 2013:

	Level 1 (in thousands)	Level 2	Level 3
Assets:			
Derivatives [1]	$—	$52,510	$—
Proved oil and gas properties [2]	$—	$—	$62,178
Unproved oil and gas properties [2]	$—	$—	$3,280
Oil and gas properties held for sale [2]	$—	$—	$650
Liabilities:			
Derivatives [1]	$—	$31,020	$—
Net Profits Plan [1]	$—	$—	$56,985

[1] This represents a financial asset or liability that is measured at fair value on a recurring basis.
[2] This represents a non-financial asset or liability that is measured at fair value on a nonrecurring basis.

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Both financial and non-financial assets and liabilities are categorized within the above fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. The following is a description of the valuation methodologies used by the Company as well as the general classification of such instruments pursuant to the above fair value hierarchy.

Derivatives

The Company uses Level 2 inputs to measure the fair value of oil, gas, and NGL commodity derivatives. Fair values are based upon interpolated data. The Company derives internal valuation estimates taking into consideration the counterparties’ credit ratings, the Company’s credit rating, and the time value of money. These valuations are then compared to the respective counterparties’ mark-to-market statements. These factors result in an estimated exit-price that management believes provides a reasonable and consistent methodology for valuing derivative instruments. The derivative instruments utilized by the Company are not considered by management to be complex, structured, or illiquid. The oil, gas, and NGL commodity derivative markets are highly active.

Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. However, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. The Company monitors the credit ratings of its counterparties and may require counterparties to post collateral if their ratings deteriorate. In some instances, the Company will attempt to novate the trade to a more stable counterparty.

Valuation adjustments are necessary to reflect the effect of the Company’s credit quality on the fair value of any liability position with a counterparty. This adjustment takes into account any credit enhancements, such as collateral margin that the Company may have posted with a counterparty, as well as any letters of credit between the parties. The methodology to determine this adjustment is consistent with how the Company evaluates counterparty credit risk, taking into account the Company’s credit rating, current credit facility margins, and any change in such margins since the last measurement date. All of the Company’s derivative counterparties are members of the Company’s credit facility lender group.

The methods described above may result in a fair value estimate that may not be indicative of net realizable value or may not be reflective of future fair values and cash flows. While the Company believes that the valuation methods utilized are appropriate and consistent with authoritative accounting guidance and with other marketplace participants, the Company recognizes that third parties may use different methodologies or assumptions to determine the fair value of certain financial instruments that could result in a different estimate of fair value at the reporting date.

Refer to Note 10 - Derivative Financial Instruments for more information regarding the Company’s derivative instruments.

Net Profits Plan

The Net Profits Plan is a standalone liability for which there is no available market price, principal market, or market participants. The inputs available for this instrument are unobservable and are therefore classified as Level 3 inputs. The Company employs the income approach, which converts expected future cash flow amounts to a single present value amount. This technique uses the estimate of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk to calculate the fair value. There is a direct correlation between realized oil, gas, and NGL commodity prices driving net cash flows and the Net Profits Plan liability. Generally, higher commodity prices result in a larger Net Profits Plan liability and lower commodity prices result in a smaller Net Profits Plan liability.

The Company records the estimated fair value of the long-term liability for estimated future payments under the Net Profits Plan based on the discounted value of estimated future payments associated with each individual pool. The calculation of this liability is a significant management estimate. A discount rate of 12 percent is used to calculate this liability and is intended to represent the Company's best estimate of the present value of expected future payments under the Net Profits Plan.

The Company's estimate of its liability is highly dependent on commodity prices, cost assumptions, discount rates, and overall market conditions. The Company regularly assesses the current market environment. The Net Profits Plan liability is determined using price assumptions of five one-year strip prices with the fifth year's pricing then carried out indefinitely. The average price is adjusted for realized price differentials and to include the effects of the forecasted production covered by derivatives contracts in the relevant periods. The non-cash expense associated with this significant management estimate is highly volatile from period to period due to fluctuations that occur in the oil, gas, and NGL commodity markets.

If the commodity prices used in the calculation changed by five percent, the liability recorded at September 30, 2014, would differ by approximately $4 million. A one percent increase or decrease in the discount rate would result in a change of approximately $2 million. Actual cash payments to be made to participants in future periods are dependent on realized actual production, realized commodity prices, and costs associated with the properties in each individual pool of the Net Profits Plan. Consequently, actual cash payments are inherently different from the amounts estimated.

No published market quotes exist on which to base the Company's estimate of fair value of its Net Profits Plan liability. As such, the recorded fair value is based entirely on management estimates that are described within this footnote. While some inputs to the Company's calculation of fair value on the Net Profits Plan's future payments are from published sources, others, such as the discount rate and the expected future cash flows, are derived from the Company's own calculations and estimates.

The following table reflects the activity for the Company's Net Profits Plan liability measured at fair value using Level 3 inputs:

	For the Nine Months Ended September 30, 2014 (in thousands)	
Beginning balance	$56,985	
Net increase in liability (1)	1,156	
Net settlements (1) (2)	(16,436	)
Transfers in (out) of Level 3	—	
Ending balance	$41,705	

(1) Net changes in the Company's Net Profits Plan liability are shown in the Change in Net Profits Plan liability line item of the accompanying statements of operations.

(2) Settlements represent cash payments made or accrued under the Net Profits Plan. The Company accrued or made cash payments under the Net Profits Plan of $8.3 million as a result of divestitures during the nine months ended September 30, 2014.

Long-term Debt

The following table reflects the fair value of the Senior Notes measured using Level 1 inputs based on quoted secondary market trading prices. The Senior Notes were not presented at fair value on the accompanying balance sheets as of September 30, 2014, or December 31, 2013, as they are recorded at historical value.

	As of September 30, 2014 (in thousands)	As of December 31, 2013
2019 Notes	$364,000	$374,290
2021 Notes	$371,875	$373,625
2023 Notes	$415,500	$422,000
2024 Notes	$492,500	$475,315

As of September 30, 2014, the Company had $390.0 million of floating-rate debt outstanding. The carrying value of the Company's credit facility approximates its fair value, as the applicable interest rates are floating and based on prevailing market rates.

Proved and Unproved Oil and Gas Properties

Proved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. The Company uses Level 3 inputs and the income valuation technique, which converts future amounts to a single present value amount, to measure the fair value of proved properties through an application of discount rates and price forecasts selected by the Company’s management. The calculation of the discount rate is based on the best information available and was estimated to be 12 percent as of September 30, 2014, and December 31, 2013. The Company believes that the discount rate is representative of current market conditions and takes into account estimates of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk. The prices for oil and gas are forecasted based on New York Mercantile Exchange (“NYMEX”) strip pricing, adjusted for basis differentials, for the first five years, after which a flat terminal price is used for each commodity stream. The prices for NGLs are forecasted using OPIS Mont Belvieu pricing, for as long as the market is actively trading, after which a flat terminal price is used. Future operating costs are also adjusted as deemed appropriate for these estimates. Proved properties classified as held for sale are valued using a market approach, based on an estimated selling price, as evidenced by the most current bid prices received from third parties. If an estimated selling price is not available, the Company utilizes the income valuation technique discussed above.

Unproved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. To measure the fair value of unproved properties, the Company uses a market approach, which takes into account the following significant assumptions: future development plans, risk weighted potential resource recovery, and estimated reserve values. Unproved properties classified as held for sale are valued using a market approach, based on an estimated selling price, as evidenced by the most current bid prices received from third parties. If an estimated selling price is not available, the Company estimates acreage value based on the price received for similar acreage in recent transactions by the Company or other market participants in the principal market.

The fair value measurements of assets acquired and liabilities assumed are measured on a nonrecurring basis on the acquisition date using an income valuation technique based on inputs that are not observable in the market and therefore represent Level 3 inputs. Significant inputs to the valuation of acquired oil and gas properties include estimates of: (i) reserves; (ii) production rates; (iii) future operating and development costs; (iv) future commodity prices, including price differentials; (v) future cash flows; and (vi) a market participant-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Company’s management at the time of the valuation and are subject to change. Refer to Note 3 - Acquisitions, Divestiture, and Assets Held for Sale for additional information on the fair value of assets acquired during the nine months ended September 30, 2014.

Asset Retirement Obligations

The Company utilizes the income valuation technique to determine the fair value of the asset retirement obligation liability at the point of inception by applying a credit-adjusted risk-free rate, which takes into account the Company’s credit risk, the time value of money, and the current economic state, to the undiscounted expected abandonment cash flows. Given the unobservable nature of the inputs, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs.

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This discussion and analysis contains forward-looking statements. Refer to Cautionary Information about Forward-Looking Statements at the end of this item for an explanation of these types of statements.

Overview of the Company, Highlights, and Outlook

General Overview

We are an independent energy company engaged in the acquisition, exploration, development, and production of oil, gas, and NGLs in onshore North America. Our assets include leading positions in the Eagle Ford shale and Bakken/Three Forks resource plays, oil-focused plays in the Powder River Basin and Permian Basin, and a position in an emerging play in East Texas. We have built a portfolio of onshore properties in the contiguous United States primarily through early entry into existing and emerging resource plays. This portfolio is comprised of properties with established production and reserves, prospective drilling opportunities, and unconventional resource prospects. We believe our strategy provides for stable and predictable production and reserves growth. By entering these plays early, we believe we can capture larger resource potential at a lower cost.

Our principal business strategy is to focus on the early capture of resource plays in order to create and then enhance value for our stockholders while maintaining a strong balance sheet. We strive to leverage industry-leading exploration and leasehold acquisition teams to quickly acquire and test new resource play concepts at a reasonable cost. Once we have identified potential value through these efforts, our goal is to develop such potential through top-tier operational and project execution, and as appropriate, high-grade our portfolio by selectively divesting assets. We regularly examine our portfolio for opportunities to improve the quality of our asset base in order to optimize our returns and preserve our financial strength.

In the third quarter of 2014, we had the following financial and operational results:

- Average net daily production for the three months ended September 30, 2014, was 43.5 MBbls of oil, 386.5 MMcf of gas, and 34.6 MBbls of NGLs, for a quarterly equivalent daily production rate of 142.5 MBOE, compared with 138.8 MBOE for the same period in 2013. Please see additional discussion below under Production Results.

- Net income for the three months ended September 30, 2014, was $208.9 million, or $3.05 per diluted share, compared to net income for the three months ended September 30, 2013, of $70.7 million, or $1.04 per diluted share. The increase in net income in the current period is largely driven by an increase in the fair value of commodity derivative contracts. Please refer to the Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2014, and 2013 below for additional discussion regarding the components of net income.

- Costs incurred for oil and gas property acquisitions and exploration and development activities for the three months ended September 30, 2014, totaled $1.0 billion. The majority of our drilling and completion costs incurred during this period were in our Eagle Ford shale and Bakken/Three Forks programs. Additionally, we acquired approximately $367.6 million of proved and unproved properties in our Gooseneck prospect area and the Powder River Basin during the third quarter of 2014. Total costs incurred for the same period in 2013 were $438.1 million. Please refer to Overview of Liquidity and Capital Resources below for additional discussion on how we expect to fund our capital program.

- Adjusted EBITDAX, a non-GAAP financial measure, for the three months ended September 30, 2014, was $406.2 million, compared to $410.4 million for the same period in 2013. Please refer to Non-GAAP Financial Measures below for additional discussion, including our definition of adjusted EBITDAX and reconciliations of our GAAP net income and net cash provided by operating activities to adjusted EBITDAX.

Oil, Gas, and NGL Prices

Our financial condition and the results of our operations are significantly affected by the prices we receive for our oil, gas, and NGL production, which can fluctuate dramatically. We sell the majority of our gas under contracts using first-of-the-month index pricing, which means gas produced in a given month is sold at the first-of-the-month price regardless of the spot price on the day the gas is produced. For assets where high BTU gas is sold at the wellhead, we also receive additional value for the higher energy content contained in the gas stream. Our NGL production is generally sold using contracts paying us a monthly average of the posted OPIS daily settlement prices, adjusted for processing, transportation, and location differentials. Our oil and condensate are sold using contracts paying us various industry posted prices, most commonly NYMEX West Texas Intermediate (“WTI”). We are paid the average of the daily settlement price for the respective posted prices for the period in which the product is sold, adjusted for quality, transportation, American Petroleum Institute (“API”) gravity, and location differentials. Substantially all of our oil production in our South Texas & Gulf Coast region is condensate. When we refer to realized oil, gas, and NGL prices below, the disclosed price represents the average price for the respective period, before the effects of derivative cash settlements, unless otherwise indicated.

The following table summarizes commodity price data, as well as the effects of derivative cash settlements as further discussed under the caption Derivative Activity below, for the second and third quarters of 2014, as well as the third quarter of 2013:

	For the Three Months Ended		
	September 30, 2014	June 30, 2014	September 30, 2013
Crude Oil (per Bbl):			
Average daily NYMEX price	$97.60	$103.06	$105.82
Realized price, before the effects of derivative cash settlements	$86.56	$91.78	$96.44
Effects of derivative cash settlements	$(0.12)	$(5.18)	$(3.66)
Natural Gas:			
Average daily NYMEX price (per MMBtu)	$3.94	$4.59	$3.55
Realized price, before the effects of derivatives cash settlements (per Mcf)	$4.49	$4.87	$3.81
Effects of derivative cash settlements (per Mcf)	$(0.05)	$(0.36)	$0.29
Natural Gas Liquids (per Bbl):			
Average daily OPIS price	$39.37	$41.21	$40.23
Realized price, before the effects of derivative cash settlements	$34.86	$35.61	$34.01
Effects of derivative cash settlements	$0.61	$(0.02)	$0.49

Note: Average OPIS prices per barrel of NGL, historical or strip, are based on a product mix of 37% Ethane, 32% Propane, 6% Isobutane, 11% Normal Butane, and 14% Natural Gasoline for all periods presented. This product mix represents the industry standard composite barrel and does not necessarily represent our product mix for NGL production. Realized prices reflect our actual product mix.

While quoted NYMEX oil and gas and OPIS NGL prices are generally used as a basis for comparison within our industry, the prices we receive are affected by quality, energy content, location, and transportation differentials for these products.

We expect future prices for oil, gas, and NGLs to be volatile. In addition to supply and demand fundamentals, as a global commodity, the price of oil will continue to be impacted by real or perceived geopolitical risks in oil producing regions of the world, particularly the Middle East. The relative strength of the U.S. dollar compared to other currencies also could affect the price of oil. Concerns about lower forecasted levels of global economic growth combined with ample supply, particularly from producing countries in the Organization of Petroleum Exporting Countries (“OPEC”), have negatively impacted oil prices in recent weeks. The supply of NGLs in the United States is expected to continue to grow in the near term as a result of the number of industry participants targeting projects that produce these products. If demand does not keep pace with anticipated growth in NGL supply, prices could be negatively impacted. The prices of several NGL products correlate to the price of oil and accordingly are likely to directionally follow that market. Gas prices have been under sustained downward pressure due to high levels of supply in recent years, particularly in the Northeast United States. Longer term, we anticipate natural gas prices will remain near current levels. Changes to existing laws and regulations pertaining to the ability to export oil, gas, and NGLs also have the potential to impact the prices for these commodities. The following table summarizes 12-month strip prices for NYMEX WTI oil, NYMEX Henry Hub gas, and OPIS NGLs (same product mix as discussed under the table above) as of October 22, 2014, and September 30, 2014:

	As of October 22, 2014	As of September 30, 2014
NYMEX WTI oil (per Bbl)	$ 79.31	$ 88.68
NYMEX Henry Hub gas (per MMBtu)	$ 3.68	$ 4.01
OPIS NGLs (per Bbl)	$ 32.44	$ 37.75

Derivative Activity

We use financial derivative instruments as part of our financial risk management program. We have a financial risk management policy governing our use of derivatives. The amount of our production covered by derivatives is driven by the amount of debt on our balance sheet and the level of capital commitments and long-term obligations we have in place. With our current derivative contracts, we believe we have established a base cash flow stream for our future operations and have partially reduced our exposure to volatility in commodity prices. Our use of costless collars for a portion of our derivatives allows us to participate in some of the upward movements in oil, gas, and NGL prices while also setting a price floor for a portion of our production. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for additional information regarding our oil, gas, and NGL derivatives.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (“Dodd-Frank Act”) included provisions requiring over-the-counter derivative transactions to be cleared through clearinghouses and traded on exchanges. On July 10, 2012, the Commodity Futures Trading Commission (“CFTC”) and the SEC adopted final joint rules under Title VII of the Dodd-Frank Act, which define certain terms that determine what types of transactions will be subject to regulation under the Dodd-Frank Act swap rules. The issuance of these final rules also triggers compliance dates for a number of other final Dodd-Frank Act rules, including new rules proposed by the CFTC governing margin requirements for uncleared swaps entered into by non-bank swap entities, and new rules proposed by U.S. banking regulators regarding margin requirements for uncleared swaps entered into by bank swap entities. The ultimate effect of these new rules on our business and any additional regulations is currently uncertain. Under CFTC rules we believe our derivative activity qualifies for the non-financial, commercial end-user exception, which exempts derivatives intended to hedge or mitigate commercial risk entered into by entities predominantly engaged in non-financial activity from the mandatory swap clearing requirement. However, we are not certain whether the provisions of the final rules and regulations will exempt us from the requirements to post margin in connection with commodity price risk management activities. Final rules and regulations on major provisions of the legislation, such as new margin requirements, are to be established through regulatory rulemaking. Although we cannot predict the ultimate outcome of these rulemakings, new rules and regulations in this area may result in increased costs and cash collateral requirements for the types of derivative instruments we use to manage our financial risks related to volatility in oil, gas, and NGL commodity prices.

Third Quarter 2014 Highlights and Outlook for the Remainder of 2014

Operational Activities. During the third quarter of 2014, we operated between four and five drilling rigs supported by two frac spreads in our operated Eagle Ford shale program in South Texas. We primarily focused on pad drilling in the northern portion of our acreage position, where there is a higher liquids contribution to our product mix. This year, our development program has shifted to utilizing longer laterals and completions with higher sand loading. Early results from these enhanced completions suggest significantly improved well performance. In the third quarter, production declined due to required shut-ins of producing wells during offset well completions. We believe we have secured the requisite services, such as gas pipeline takeaway capacity and drilling and completion services, to support our current development plans.

In our outside operated Eagle Ford shale program, the operator began the third quarter of 2014 running nine drilling rigs and dropped two rigs during the quarter. The operator expects to run seven rigs for the remainder of 2014. During the second quarter of 2014, the remainder of our carry under our Acquisition and Development Agreement with Mitsui E&P Texas LP (“Mitsui”), an indirect subsidiary of Mitsui & Co., Ltd. (the “Acquisition and Development Agreement”), was expended. Accordingly, we accrued our full share of drilling and completion costs for this program in the third quarter of 2014.

We have an ongoing exploration program to acquire leasehold and test concepts in new plays. In 2014, we are evaluating an emerging new venture play in East Texas. We are currently constructing a gathering system to allow for longer-term production tests on wells that we have drilled and completed. We expect this system to be completed in the fourth quarter of 2014.

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In our Bakken/Three Forks program, we operated three drilling rigs during the third quarter of 2014 focusing on infill drilling of our Raven/Bear Den and Gooseneck prospects in the North Dakota portion of the Williston Basin. We are monitoring the results of various well and completion designs and down-spacing tests of both our operated and non-operated properties and testing the Bakken interval on our Gooseneck and Stateline acreage. During the third quarter of 2014, we completed our acquisition of additional Gooseneck assets and paid $325.2 million at closing, net of normal closing adjustments. We expect to increase rig activity in our Bakken/Three Forks program in the fourth quarter of 2014.

In our Powder River Basin program in Wyoming, we have been accelerating activity and expanding our acreage position through acquisitions from multiple sellers during the nine months ending September 30, 2014. We operated three drilling rigs during the third quarter, and we plan to add a fourth operated drilling rig in the fourth quarter of 2014.

In our Permian program, we operated two drilling rigs during the third quarter of 2014 focused on horizontal testing and development of the Wolfcamp B interval in our Sweetie Peck prospect. In our Buffalo prospect in Gaines and Dawson Counties, Texas, we are monitoring the results of a recently completed Wolfcamp D test well. In the fourth quarter of 2014, we plan to test the Lower Spraberry in both our Sweetie Peck and Buffalo prospects.

Please refer to Overview of Liquidity and Capital Resources below for additional discussion regarding how we intend to fund our 2014 capital program.

Production Results. The table below provides a regional breakdown of our production for the third quarter of 2014:

	South Texas & Gulf Coast	Rocky Mountain	Permian	Mid-Continent	Total [1]
Oil (MMBbl)	1.7	1.8	0.5	—	4.0
Gas (Bcf)	28.0	1.7	1.1	4.7	35.6
NGLs (MMBbl)	3.2	—	—	—	3.2
Equivalent (MMBOE)	9.5	2.1	0.7	0.8	13.1
Avg. daily equivalents (MBOE/d)	103.6	22.8	7.3	8.8	142.5
Relative percentage	73 %	16 %	5 %	6 %	100 %

[1] Totals may not add due to rounding.

Production increased for the three months ended September 30, 2014, compared to the same period in 2013, driven primarily by the continued development of our operated and non-operated Eagle Ford shale programs in our South Texas & Gulf Coast region. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2014, and 2013 below for additional discussion on production.

Rocky Mountain Acquisitions. In the third quarter of 2014, we closed multiple transactions to acquire proved and unproved properties in our Gooseneck prospect area and the Powder River Basin for a total of approximately $360.7 million. These acquisitions are subject to normal post-closing adjustments, which are expected to be completed during late 2014 and early 2015.

Subsequent Events. Subsequent to September 30, 2014, as a result of our regularly scheduled semi-annual borrowing base redetermination, the lending group increased our borrowing base under our credit facility from $2.2 billion to $2.4 billion with no change in the aggregate lender commitment amount of $1.3 billion. Additionally, we acquired proved and unproved properties in our Gooseneck prospect area for total cash consideration of $84.8 million. This acquisition is subject to normal post-closing adjustments.

First Nine Months of 2014 Highlights

Production Results. The table below provides a regional breakdown of our production for the first nine months of 2014:

	South Texas & Gulf Coast	Rocky Mountain	Permian	Mid-Continent	Total [(1)]
Oil (MMBbl)	5.0	5.1	1.4	—	11.6
Gas (Bcf)	86.7	4.7	3.2	14.4	109.1
NGLs (MMBbl)	9.1	—	—	0.1	9.2
Equivalent (MMBOE)	28.5	6.0	2.0	2.5	39.0
Avg. daily equivalents (MBOE/d)	104.5	21.8	7.2	9.2	142.7
Relative percentage	73 %	15 %	5 %	7 %	100 %

(1) Totals may not add due to rounding.

Please refer to Third Quarter 2014 Highlights and Outlook for the Remainder of 2014 above and Comparison of Financial Results and Trends Between the Nine Months Ended September 30, 2014, and 2013 below for additional discussion on production.

Costs Incurred in Oil and Gas Producing Activities. For the nine months ended September 30, 2014, we incurred $2.0 billion in costs related to oil and gas property acquisitions and exploration and development activities, including both capitalized and expensed amounts. This amount includes a combined $472.6 million of proved and unproved property acquisitions in the Gooseneck prospect area and the Powder River Basin. The majority of drilling and completion costs incurred during this period were in our Eagle Ford shale and Bakken/Three Forks programs. Please refer to Overview of Liquidity and Capital Resources below for additional discussion on how we expect to fund our capital program.

Rocky Mountain Divestiture. In the second quarter of 2014, we completed the divestiture of certain non-strategic assets in the Williston Basin for $50.2 million of total divestiture proceeds. The estimated net gain on this divestiture is $26.8 million. This divestiture is subject to normal post-closing adjustments, which are expected to be completed during the fourth quarter of 2014.

Financial Results of Operations and Additional Comparative Data

The tables below provide information regarding selected production and financial information. A detailed discussion follows.

	For the Three Months Ended September 30, 2014	June 30, 2014	March 31, 2014	December 31, 2013
	(in millions, except for production data)			
Production (MMBOE)	13.1	13.4	12.5	13.2
Oil, gas, and NGL production revenue	$617.2	$654.7	$623.1	$593.7
Lease operating expense	$66.5	$62.8	$57.0	$61.1
Transportation costs	$81.5	$83.0	$79.2	$75.0
Production taxes	$30.4	$31.8	$27.5	$26.7
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$183.3	$187.8	$177.2	$202.6
Exploration	$34.6	$24.3	$21.3	$21.8
General and administrative	$41.7	$38.1	$35.1	$48.0
Net income	$208.9	$59.8	$65.6	$7.0

Selected Performance Metrics:

	For the Three Months Ended September 30, 2014	June 30, 2014	March 31, 2014	December 31, 2013
Average net daily production equivalent (MBOE/d)	142.5	147.0	138.6	143.8
Lease operating expense (per BOE)	$5.07	$4.69	$4.58	$4.62
Transportation costs (per BOE)	$6.22	$6.20	$6.35	$5.67
Production taxes as a percent of oil, gas, and NGL production revenue	4.9 %	4.9 %	4.4 %	4.5 %
Depletion, depreciation, amortization, and asset retirement obligation liability accretion (per BOE)	$13.97	$14.03	$14.21	$15.31
General and administrative (per BOE)	$3.18	$2.85	$2.81	$3.63

Note: Amounts may not recalculate due to rounding.

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A three-month and nine-month overview of selected production and financial information, including trends:

	For the Three Months Ended September 30,		Amount Change Between Periods	Percent Change Between Periods	For the Nine Months Ended September 30,		Amount Change Between Periods	Percent Change Between Periods
	2014	2013			2014	2013		
Net production volumes [(1)]								
Oil (MMBbl)	4.0	3.8	0.2	5 %	11.6	10.2	1.4	13 %
Gas (Bcf)	35.6	38.5	(2.9)	(8)%	109.1	109.9	(0.8)	(1)%
NGLs (MMBbl)	3.2	2.5	0.7	26 %	9.2	6.6	2.6	40 %
Equivalent (MMBOE)	13.1	12.8	0.3	3 %	39.0	35.1	3.9	11 %
Average net daily production [(1)]								
Oil (MBbl per day)	43.5	41.6	1.9	5 %	42.3	37.3	5.0	13 %
Gas (MMcf per day)	386.5	418.1	(31.6)	(8)%	399.5	402.4	(2.9)	(1)%
NGLs (MBbl per day)	34.6	27.5	7.1	26 %	33.8	24.2	9.6	40 %
Equivalent (MBOE per day)	142.5	138.8	3.7	3 %	142.7	128.6	14.1	11 %
Oil, gas, & NGL production revenue (in millions)								
Oil production revenue	$346.5	$368.9	$ (22.4)	(6)%	$1,029.1	$946.6	$ 82.5	9 %
Gas production revenue	159.6	146.7	12.9	9 %	530.1	429.3	100.8	23 %
NGL production revenue	111.1	86.2	24.9	29 %	335.8	230.0	105.8	46 %
Total	$617.2	$601.8	$ 15.4	3 %	$1,895.0	$1,605.9	$ 289.1	18 %
Oil, gas, & NGL production expense (in millions)								
Lease operating expense	$66.5	$61.0	$ 5.5	9 %	$186.3	$171.9	$ 14.4	8 %
Transportation costs	81.5	68.8	12.7	18 %	243.7	183.2	60.5	33 %
Production taxes	30.4	29.1	1.3	4 %	89.7	79.2	10.5	13 %
Total	$178.4	$158.9	$ 19.5	12 %	$519.7	$434.3	$ 85.4	20 %
Realized price								
Oil (per Bbl)	$86.56	$96.44	$ (9.88)	(10)%	$89.08	$92.93	$ (3.85)	(4)%
Gas (per Mcf)	$4.49	$3.81	$ 0.68	18 %	$4.86	$3.91	$ 0.95	24 %
NGLs (per Bbl)	$34.86	$34.01	$ 0.85	2 %	$36.34	$34.77	$ 1.57	5 %
Per BOE	$47.06	$47.13	$ (0.07)	— %	$48.63	$45.74	$ 2.89	6 %
Per BOE Data [(1)]								
Production costs:								
Lease operating expense	$5.07	$4.77	$ 0.30	6 %	$4.78	$4.89	$ (0.11)	(2)%
Transportation costs	$6.22	$5.38	$ 0.84	16 %	$6.25	$5.22	$ 1.03	20 %
Production taxes	$2.32	$2.29	$ 0.03	1 %	$2.30	$2.26	$ 0.04	2 %
General and administrative	$3.18	$2.66	$ 0.52	20 %	$2.95	$2.89	$ 0.06	2 %
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$13.97	$15.33	$ (1.36)	(9)%	$14.07	$17.67	$ (3.60)	(20)%
Derivative cash settlement [(2)]	$(0.02)	$(0.14)	$ 0.12	(86)%	$(1.61)	$0.31	$ (1.92)	(619)%
Earnings per share information								
Basic net income per common share	$3.10	$1.06	$ 2.04	192 %	$4.98	$2.47	$ 2.51	102 %
Diluted net income per common share	$3.05	$1.04	$ 2.01	193 %	$4.90	$2.41	$ 2.49	103 %
Basic weighted-average common shares outstanding (in thousands)	67,379	66,943	436	1 %	67,169	66,486	683	1 %

Diluted weighted-average common shares outstanding (in thousands)	68,430	68,253	177	—	%	68,258	67,969	289	—	%

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(1) Amount and percentage changes may not recalculate due to rounding.
(2) We discontinued hedge accounting on January 1, 2011. As a result, fair values at December 31, 2010, were frozen in AOCL and were reclassified into earnings as the original derivative transactions settled, the last of which settled in the third quarter of 2013. For the three and nine months ended September 30, 2013, derivative cash settlements are included within the other operating revenues and derivative (gain) loss line items in the accompanying statements of operations. All derivative cash settlements for the three and nine months ended September 30, 2014, are included within the derivative (gain) loss line item only.

We present per BOE information because we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe may require additional analysis. Average daily reported production for the three and nine months ended September 30, 2014, increased three percent and 11 percent, respectively, compared with the same periods in 2013, driven primarily by the development of our Eagle Ford shale assets. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2014, and 2013 and Comparison of Financial Results and Trends Between the Nine Months Ended September 30, 2014, and 2013 below for additional discussion on changes in our production mix in 2014.

Changes in production volumes, revenues, and costs reflect the cyclical and highly volatile nature of our industry. Our realized price on a per BOE basis for the three months ended September 30, 2014, was slightly lower than the same period in 2013. Our realized price on a per BOE basis increased six percent for the nine months ended September 30, 2014, compared to the same period in 2013, primarily due to higher natural gas prices.

Lease operating expense ("LOE") on a per BOE basis for the three months ended September 30, 2014, increased six percent compared to the same period in 2013, whereas for the nine months ended September 30, 2014, LOE on a per BOE basis decreased two percent compared to the same period in 2013. Our LOE is comprised of recurring LOE, workover expense, and ad valorem tax expense. Absolute LOE increased nine percent and eight percent for the three and nine months ended September 30, 2014, respectively, compared to the same periods in 2013, driven primarily by increased recurring LOE and workover activity in our Rocky Mountain region and higher ad valorem tax expense in our South Texas & Gulf Coast region. Production volumes were lower in the third quarter of 2014 as compared to the second quarter of 2014 due to well shut-ins in the Eagle Ford for offset completions and weather-related delays in the Williston Basin. As such, volumes did not increase at the same rate as in previous quarters. This, along with increased workover activity in the Rocky Mountain region resulted in an increase in LOE on a per BOE basis for the three months ended September 30, 2014. Throughout the first half of 2014, production grew at a faster rate than absolute LOE resulting in a slight decrease in LOE on a per BOE basis for the nine months ended September 30, 2014. We experience volatility in our LOE as a result of seasonality in workover expense and the impact industry activity has on service provider costs. Overall, we expect absolute LOE to increase as a result of continued development and the recent acquisitions of properties in our Rocky Mountain region during the third quarter of 2014. We expect Company-wide production to increase at a faster rate than absolute LOE resulting in a slight decrease in LOE per BOE for the remainder of 2014.

Transportation costs on a per BOE basis for the three and nine months ended September 30, 2014, increased 16 percent and 20 percent, respectively, compared to the same periods in 2013. Our Eagle Ford shale program has meaningfully higher transportation expense per unit of production compared to our other regions. Ongoing development of the Eagle Ford shale has resulted in production from these assets becoming a larger portion of our total production, thereby increasing company-wide transportation expense per BOE over time. Included in transportation costs in our Eagle Ford shale program are charges for compression and fuel, which can fluctuate with the price of natural gas. We anticipate that we will recognize fluctuations in our per unit Eagle Ford shale transportation rate over time; however, we also anticipate company-wide transportation costs on a per BOE basis will increase as Eagle Ford shale production continues to grow and constitutes a larger portion of our total production mix.

Production taxes on a per BOE basis for the three and nine months ended September 30, 2014, increased one percent and two percent, respectively, compared to the same periods in 2013. We generally expect absolute production tax expense to trend with oil, gas, and NGL production revenue. Product mix, the location of production, and incentives to encourage oil and gas development can all impact or change the amount of production tax we recognize.

G&A expense on a per BOE basis for the three and nine months ended September 30, 2014, increased 20 percent and two percent, respectively, compared to the same periods in 2013. Absolute G&A expense increased between these two periods due to an increase in employee headcount. A portion of our G&A expense is linked to our profitability and cash flow, which are driven in large part by the realized commodity prices that we receive for our production. The Net

Profits Plan and a portion of our short-term incentive compensation correlate with net cash flows and therefore are subject to variability. Additionally, because production decreased from the second quarter of 2014 to the third quarter of 2014, G&A expense on a per BOE basis increased. Generally, we expect G&A expense on a per BOE basis to decrease as we anticipate production going forward will increase at a faster rate than absolute G&A expense.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion (“DD&A”) expense on a per BOE basis for the three and nine months ended September 30, 2014, decreased nine percent and 20 percent, respectively, compared to the same periods in 2013. Our DD&A rate can fluctuate as a result of impairments, planned and closed divestitures, and changes in the mix of our production and the underlying proved reserve volumes. Our DD&A rate has decreased as assets with lower finding and development costs have become a larger portion of our total production mix. Our finding and development costs have benefited from a general decrease in well costs and an increase in recoveries per well, as well as from our outside operated Eagle Ford shale program, where we have added reserves with minimal associated costs due to our carry with Mitsui under our Acquisition and Development Agreement. This carry was exhausted during the second quarter of 2014.

Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2014, and 2013 and Comparison of Financial Results and Trends Between the Nine Months Ended September 30, 2014, and 2013 below for additional discussion on operating expenses.
Please refer to Note 9 - Earnings per Share in Part I, Item 1 of this report for additional discussion on the types of shares included in our basic and diluted net income per common share calculations.

Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2014, and 2013

Oil, gas, and NGL production revenue and costs. The following table presents the regional changes in our production, and oil, gas, and NGL production revenue and costs between the three months ended September 30, 2014, and 2013:

	Average Net Daily Production Added (Lost) (MBOE/d)	Oil, Gas, & NGL Production Revenue Added (Lost) (in millions)	Production Costs Increase (Decrease) (in millions)
South Texas & Gulf Coast	14.6	$65.5	$20.7
Rocky Mountain	1.6	(5.2)	5.7
Permian	0.4	(4.3)	(2.8)
Mid-Continent	(12.9)	(40.6)	(4.1)
Total	3.7	$15.4	$19.5

In our South Texas & Gulf Coast region, average net daily production increased 16 percent between the two periods as a result of drilling activity in our Eagle Ford shale program. This significant production growth in our Eagle Ford shale program exceeded the production decrease in our Mid-Continent region resulting from our Anadarko Basin asset divestiture in December 2013.

A three percent increase in equivalent production with relatively consistent realized prices on a per BOE basis resulted in a three percent increase in oil, gas, and NGL production revenue between the two periods. Please refer to A three-month and nine-month overview of selected production and financial information, including trends above for realized prices received before the effects of derivative cash settlements for the three months ended September 30, 2014, and 2013. Based on current levels of activity, we expect production volumes to continue to increase. We expect our realized prices to trend with commodity prices.

Other operating revenues. Gains and losses on divestiture activity are recorded to other operating revenues. We recorded a loss on divestiture activity of $5.4 million and $6.2 million for the three months ended September 30, 2014, and 2013, respectively, due largely to the write-down to fair value of certain assets held for sale. Other operating revenues also includes marketed gas system revenues, which decreased $10.5 million between the three months ended September 30, 2014, and 2013. The decrease occurred as a result of our Anadarko Basin divestiture in December 2013, which reduced marketed gas volumes and the overall significance of marketed gas system revenues and expenses.

Oil, gas, and NGL production expense. Total production costs increased 12 percent for the three months ended September 30, 2014, compared with the same period of 2013, as a result of a three percent increase in net equivalent production volumes as well as an overall increase in transportation costs in our South Texas & Gulf Coast region. Please refer to A three-month and nine-month overview of selected production and financial information, including trends above for discussion of production costs on a per BOE basis.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A expense decreased six percent for the three-month period ended September 30, 2014, compared with the same period in 2013. Please refer to A three-month and nine-month overview of selected production and financial information, including trends above for discussion of DD&A on a per BOE basis, as our lower DD&A rate for the three months ended September 30, 2014, has resulted in decreased absolute DD&A expense compared to the same period in 2013.

Exploration. The components of exploration expense are summarized as follows:

	For the Three Months Ended September 30,	
	2014	2013
	(in millions)	
Geological and geophysical expenses	$1.4	$0.9
Exploratory dry hole expense	16.3	—
Overhead and other expenses	16.9	15.4
Total	$34.6	$16.3

Exploration expense for the three months ended September 30, 2014, increased 112 percent compared to the same period in 2013 as a result of an exploratory dry hole during the three months ended September 30, 2014. An exploratory project resulting in non-commercial quantities of oil, gas, or NGLs is deemed an exploratory dry hole and impacts the amount of exploration expense we record. We have an active exploration program, which can result in periodic dry hole expense.

Impairment of proved properties. We recorded no impairment of proved properties for the three months ended September 30, 2014. We recorded a $5.9 million impairment of proved properties in the third quarter of 2013, related to our decision to no longer pursue the development of certain underperforming assets. We expect impairments of proved properties to be more likely to occur in periods of low commodity prices.

Abandonment and impairment of unproved properties. We recorded $15.5 million of abandonment and impairment of unproved properties expense for the three months ended September 30, 2014, related to acreage we no longer intended to develop as a result of unsuccessful exploratory activities. For the same period in 2013, we recorded $3.8 million of expense related to acreage we no longer intended to develop. We expect our abandonment and impairment of unproved properties expense to fluctuate with the timing of lease expirations and unsuccessful exploratory activities.

General and administrative. G&A expense increased 23 percent for the three months ended September 30, 2014, compared with the same period of 2013. The increase is due to an increase in employee headcount, which increased base and equity compensation, benefits, and general corporate office expenses incurred. Please refer to A three-month and nine-month overview of selected production and financial information, including trends above for discussion of G&A expense on a per BOE basis.

Change in Net Profits Plan liability. This non-cash item generally relates to the change in the estimated value of the associated noncurrent liability between reporting periods. For the three months ended September 30, 2014, we recorded a non-cash benefit of $6.4 million. For the same period in 2013, we recorded a non-cash expense of $940,000. The change in our liability is subject to estimation and may change from period to period based on assumptions used for production rates, reserve quantities, commodity pricing, discount rates, and production costs. We expect the change in our Net Profits Plan liability to correlate with fluctuations in commodity prices. Payments made to participants as a result of divestitures and ongoing operations also impact the change in the Net Profits Plan liability.

Derivative (gain) loss. We recognized a derivative gain of $190.7 million for the three-month period ended September 30, 2014, which is comprised of a $274,000 loss on cash settlements and a $190.9 million increase in the fair value of commodity derivative contracts during the period. This compares to a loss of $39.9 million for the same period in 2013, which is comprised of a $38.6 million decrease in the fair value of commodity derivative contracts and a $1.3 million loss on cash settlements during the period. The decrease in commodity strip prices, particularly oil, during the three months ended September 30, 2014, resulted in a significant increase in the net derivative asset position as of quarter-end. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for additional information.

Other operating expenses. This line item includes marketed gas system expense, which decreased $9.5 million for the three months ended September 30, 2014, compared to the same period in 2013. This decrease occurred as a result of our Anadarko Basin divestiture in December 2013, which reduced marketed gas system volumes and the overall significance of marketed gas system revenues and expenses. Additionally, during the three months ended September 30, 2013, other operating expenses included $3.6 million of expense related to an agreed clarification concerning royalty payment provisions of various leases on certain South Texas & Gulf Coast acreage.

Income tax expense. We recorded income tax expense of $124.7 million for the three-month period ended September 30, 2014, compared to expense of $42.3 million for the same period in 2013, resulting in effective tax rates of 37.4 percent and 37.5 percent, respectively.

Comparison of Financial Results and Trends Between the Nine Months Ended September 30, 2014, and 2013

Oil, gas, and NGL production revenue and costs. The following table presents the regional changes in our production, and oil, gas, and NGL production revenue and costs between the nine months ended September 30, 2014, and 2013:

	Average Net Daily Production Added (Lost) (MBOE/d)	Oil, Gas, & NGL Production Revenue Added (Lost) (in millions)	Production Costs Increase (Decrease) (in millions)
South Texas & Gulf Coast	23.7	$328.0	$75.6
Rocky Mountain	2.0	40.1	21.3
Permian	0.9	16.0	—
Mid-Continent	(12.5)	(95.0)	(11.5)
Total	14.1	$289.1	$85.4

In our South Texas & Gulf Coast region, average net daily production increased 29 percent between the two periods as a result of drilling activity in our Eagle Ford shale program. Average daily production increased 10 percent in our Rocky Mountain region as a result of drilling activity in our Bakken/Three Forks program. This significant production growth in our Eagle Ford shale and Bakken/Three Forks programs exceeded the production decrease in our Mid-Continent region resulting from our Anadarko Basin asset divestiture in December 2013.

An 11 percent increase in production on a BOE basis combined with a six percent increase in the realized price per BOE resulted in an 18 percent increase in oil, gas, and NGL production revenue between the two periods.

Other operating revenues. Gains and losses on divestiture activity are recorded to other operating revenues. The gain realized on the sale of properties in our Rocky Mountain region during the second quarter of 2014 was mostly offset by losses recorded on assets classified as held for sale in the second and third quarters of 2014. Please refer to Third Quarter 2014 Highlights and Outlook for the Remainder of 2014 above for further discussion of the gain recorded on our divestiture of assets in our Rocky Mountain region. Other operating revenues also includes marketed gas system revenues, which decreased $30.8 million for the nine months ended September 30, 2014, compared to the same period in 2013. This decrease occurred as a result of our Anadarko Basin divestiture in December 2013. This divestiture reduced marketed gas volumes and the overall significance of marketed gas system revenues and expenses. Partially offsetting this decrease was a $10.7 million gain recorded in the second quarter of 2014 related to our settlement with Endeavour.

Oil, gas, and NGL production expense. Total production costs increased 20 percent for the nine months ended September 30, 2014, compared with the same period of 2013, as a result of an 11 percent increase in net equivalent production volumes as well as an overall increase in transportation costs in our South Texas & Gulf Coast region. Please refer to the caption A three-month and nine-month overview of selected production and financial information, including trends above for discussion of production costs on a per BOE basis.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A expense decreased 12 percent to $548.3 million for the nine-month period ended September 30, 2014, compared with $620.2 million for the same period in 2013. Please refer to A three-month and nine-month overview of selected production and financial information, including trends above for discussion of DD&A on a per BOE basis, as our lower DD&A rate for the nine months ended September 30, 2014, has resulted in decreased absolute DD&A expense compared to the same period in 2013.

Exploration. The components of exploration expense are summarized as follows:

	For the Nine Months Ended September 30,	
	2014	2013
	(in millions)	
Geological and geophysical expenses	$7.2	$3.2
Exploratory dry hole expense	22.8	5.9
Overhead and other expenses	50.2	43.2
Total	$80.2	$52.3

Exploration expense for the nine months ended September 30, 2014, increased 53 percent compared to the same period in 2013 due to an exploratory dry hole being expensed in each of the second and third quarters of 2014. During the first quarter of 2014, we performed a seismic study, which increased geological and geophysical ("G&G") expenses. We have also experienced an overall increase in exploration overhead. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2014, and 2013 above for additional discussion of exploration expense.

Impairment of proved properties. We recorded no impairment of proved properties expense for the nine months ended September 30, 2014, compared to $61.7 million for the same period in 2013. In addition to the explanation under Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2014, and 2013, above, we recorded a $21.2 million impairment of proved properties in the first quarter of 2013 related to Olmos interval, dry gas assets in our South Texas & Gulf Coast region as a result of commencing a plugging and abandonment program. We also recorded a $34.6 million impairment of proved properties in the second quarter of 2013 related to our decision to no longer pursue the development of certain underperforming assets.

Abandonment and impairment of unproved properties. For the nine months ended September 30, 2014, and 2013, we recorded abandonment and impairment of unproved properties expense of $18.5 million and $8.5 million, respectively, related to acreage we no longer intended to develop. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2014, and 2013 above for additional discussion.

General and administrative. G&A expense increased 13 percent to $114.9 million for the nine months ended September 30, 2014, compared with $101.6 million for the same period of 2013, as a result of increased employee headcount, which increased base and equity compensation, benefits, and general corporate office expenses incurred. Please refer to A three-month and nine-month overview of selected production and financial information, including trends above for additional discussion of G&A on a per BOE basis.

Change in Net Profits Plan liability. For the nine months ended September 30, 2014, and 2013, we recorded a non-cash benefit of $15.3 million and $6.4 million, respectively. The increase in the benefit between these two periods is mostly due to payments made as a result of the divestiture of properties in our Rocky Mountain region during the second quarter of 2014. Please refer to Comparison of Financial Results and Trends Between the Three Months Ended September 30, 2014, and 2013 above for additional discussion.

Derivative (gain) loss. We recognized a derivative loss of $33.5 million for the nine-month period ended September 30, 2014, which is comprised of a $62.9 million loss on cash settlements and a $29.4 million increase in the fair value of commodity derivative contracts during the period. This compares to a gain of $14.7 million for the same period in 2013, which consists of a $12.7 million gain on cash settlements and a $2.0 million increase in the fair value of commodity derivative contracts during the period. The loss on derivative cash settlements during the nine months ended September 30, 2014, is partially offset by the decline in oil commodity strip pricing during the period resulting in an increase in the fair value of derivative contracts. The derivative gain for the nine months ended September 30, 2013, is driven by favorable cash settlements on gas contracts. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for additional information.

Other operating expenses. This line item includes marketed gas system expense, which decreased $28.3 million in the first nine months of 2014 compared to the same period in 2013. This decrease occurred as a result of our Anadarko

Basin divestiture in December 2013, reducing marketed gas system volumes and the overall significance of marketed gas system revenues and expenses. Additionally, during the nine months ended September 30, 2013, other operating expenses included $17.8 million of expense related to an agreed clarification concerning royalty payment provisions of various leases on certain South Texas & Gulf Coast acreage.

Income tax expense. We recorded income tax expense of $199.7 million for the nine-month period ended September 30, 2014, compared to expense of $98.9 million for the same period in 2013, resulting in effective tax rates of 37.4 percent and 37.6 percent, respectively. The decrease in the rate is partially attributable to the Anadarko Basin divestiture that closed at the end of 2013. The sale of assets in a higher rate state caused a decrease in the composition of our blended state tax rate for future years. However, state cash taxes are higher as a result of the estimated Texas margin tax.

Overview of Liquidity and Capital Resources

We believe we have sufficient liquidity and capital resources to execute our business plan for the foreseeable future. We continue to manage the duration and level of our drilling and completion service commitments in order to provide flexibility to reduce activity and capital expenditures in periods of prolonged commodity price decline.

Sources of Cash

We currently expect our remaining 2014 capital program to be funded by cash flows from operations and proceeds from 2014 divestitures, supplemented by borrowings under our credit facility. Although we anticipate cash flow from these sources will be sufficient to fund our remaining expected 2014 capital program, we may also elect to access the capital markets, depending on prevailing market conditions, as well as divest of additional non-strategic oil and gas properties to provide additional sources of funding. From time to time, we may enter into carrying cost funding and sharing arrangements with third parties for particular exploration and/or development programs. All of our sources of liquidity can be impacted by the general condition of the broader economy and by fluctuations in commodity prices, operating costs, and volumes produced, all of which affect us and our industry. We have no control over the market prices for oil, gas, or NGLs, although we are able to influence the amount of our realized revenues from our oil, gas, and NGL sales through the use of derivative contracts as part of our commodity price risk management program. Historically, decreases in commodity prices have limited our industry's access to capital markets. The borrowing base under our credit facility could be reduced as a result of lower commodity prices, divestitures of proved properties, or newly issued debt.

In late 2011, we consummated our Acquisition and Development Agreement with Mitsui, pursuant to which Mitsui funded, or carried, 90 percent of certain drilling and completion costs attributable to our remaining interest in our non-operated Eagle Ford shale acreage until $680.0 million was expended on our behalf. The remaining carry was utilized during the second quarter of 2014, at which point we became responsible for funding our share of drilling and completion costs.

Proposals to reform the IRC, which include eliminating or reducing current tax deductions for intangible drilling costs, depreciation of equipment acquisition costs, the domestic production activities deduction, and percentage depletion, continue to circulate. We expect that future legislation modifying or eliminating these deductions would reduce net operating cash flows over time, thereby reducing funding available for our exploration and development capital programs, as well as funding available to our peers in the industry. If enacted at some point in the future, these funding reductions could have a significant adverse effect on drilling in the United States for a number of years.

Credit Facility

During the second quarter of 2013, we and our lenders entered into a Fifth Amended and Restated Credit Agreement. The credit facility has a maximum loan amount of $2.5 billion, current aggregate lender commitments of $1.3 billion, and a maturity date of April 12, 2018. The borrowing base under the credit facility as of the filing date of this report is $2.4 billion and is subject to regular semi-annual redeterminations. We believe the current commitment amount is sufficient to meet our anticipated liquidity and operating needs. No individual bank participating in our credit facility represents more than 10 percent of the lending commitments under the credit facility. Borrowings under our credit facility are secured by mortgages on at least 75 percent of our proved oil and gas properties. Please refer to Note 5 - Long-term Debt in Part I, Item 1 of this report for additional discussion as well as the presentation of the outstanding balance, total amount of letters of credit, and available borrowing capacity under our credit facility as of October 22, 2014, September 30, 2014, and December 31, 2013.

We are subject to customary covenants under our credit facility, including limitations on dividend payments and requirements to maintain certain financial ratios, which include debt to adjusted EBITDAX, as defined by our credit agreement as the ratio of debt to 12-month trailing adjusted EBITDAX, of less than 4.0, and an adjusted current ratio, as defined by our credit agreement, of no less than 1.0. As of September 30, 2014, and as of the filing date of this report, we are in compliance with all covenants under our credit facility.

Operating cash flow and cash received from the divestiture of properties were sufficient in meeting our capital expenditure needs through the first half of 2014. During the third quarter of 2014, we began to draw upon our credit facility, primarily to fund acquisitions of oil and gas properties. Our daily weighted-average credit facility balance was $41.7 million and $14.1 million for the three and nine months ended September 30, 2014, respectively. Our daily weighted-average credit facility balance was $72.8 million and $239.2 million for the three and nine months ended September 30, 2013, respectively. Our daily weighted-average credit facility balance was lower throughout 2014 as a result of proceeds received from property divestitures in the fourth quarter of 2013. Cash flows provided by our operating activities, proceeds received from divestitures of properties, and the amount of our capital expenditures all impact the amount we have borrowed under our credit facility.

Weighted-Average Interest Rates

Our calculated weighted-average interest rates include paid and accrued interest, cash fees on the unused portion of the credit facility's aggregate commitment amount, letter of credit fees, and the non-cash amortization of deferred financing costs. Our calculated weighted-average borrowing rates include paid and accrued interest only.

The following table presents our weighted-average interest rates and our weighted-average borrowing rates for the three and nine months ended September 30, 2014, and 2013:

	For the Three Months Ended September 30,				For the Nine Months Ended September 30,			
	2014		2013		2014		2013	
Weighted-average interest rate	6.6	%	6.5	%	6.7	%	6.2	%
Weighted-average borrowing rate	5.9	%	5.9	%	6.0	%	5.6	%

Our weighted-average interest rates and weighted average borrowing rates in 2013 and 2014 have been impacted by the issuance of the 2024 Notes in the second quarter of 2013. This event, as well as the divestiture of properties, including our Anadarko Basin divestiture in December 2013, impacted the average balance on our revolving credit facility and the fees paid on the unused portion of our aggregate commitment.

Uses of Cash

We use cash for the acquisition, exploration, and development of oil and gas properties and for the payment of operating and G&A costs, income taxes, dividends, and debt obligations, including interest. Expenditures for the exploration and development of oil and gas properties are the primary use of our capital resources. In the first nine months of 2014, we spent $1.8 billion for exploration and development capital activities and proved and unproved oil and gas property acquisitions. This amount differs from the cost incurred amount, which is accrual-based and includes asset retirement obligation, G&G, and exploration overhead amounts.

The amount and allocation of future capital expenditures will depend upon a number of factors, including the number and size of available acquisition and drilling opportunities, our ability to assimilate acquisitions and execute our drilling program, and our cash flows from operating, investing, and financing activities. In addition, the impact of oil, gas, and NGL prices on investment opportunities, the availability of capital, and the timing and results of our operated and non-operated development and exploratory activities may lead to changes in funding requirements for future development. We periodically review our capital expenditure budget to assess changes in current and projected cash flows, acquisition and divestiture activities, debt requirements, and other factors.

We may from time to time repurchase certain amounts of our outstanding debt securities for cash and/or through exchanges for other securities. Such repurchases or exchanges may be made in open market transactions, privately negotiated transactions, or otherwise. Any such repurchases or exchanges will depend on prevailing market conditions, our liquidity requirements, contractual restrictions, compliance with securities laws, and other factors. The amounts involved in any such transaction may be material.

As of the filing date of this report, we could repurchase up to 3,072,184 shares of our common stock under our stock repurchase program, subject to the approval of our Board of Directors. Shares may be repurchased from time to time in the open market, or in privately negotiated transactions, subject to market conditions and other factors, including certain provisions of our credit facility, the indentures governing our Senior Notes, compliance with securities laws, and the terms and provisions of our stock repurchase program. Our Board of Directors reviews this program as part of the allocation of our capital. We currently do not plan to repurchase any shares in 2014.

The following table presents changes in cash flows between the nine months ended September 30, 2014, and 2013. The analysis following the table should be read in conjunction with our condensed consolidated statements of cash flows in Part I, Item 1 of this report.

	For the Nine Months Ended September 30,		Amount Change Between Periods	Percent Change Between Periods
	2014	2013		
	(in millions)			
Net cash provided by operating activities	$1,075.1	$1,000.9	$74.2	7 %
Net cash used in investing activities	$(1,736.0)	$(1,166.4)	$(569.6)	49 %
Net cash provided by financing activities	$378.9	$159.8	$219.1	137 %

Analysis of Cash Flow Changes Between the Nine Months Ended September 30, 2014, and 2013

Operating activities. Cash received from oil, gas, and NGL production revenues, net of transportation costs and production taxes, and including derivative cash settlements, increased $182.2 million, or 14 percent, to $1.5 billion for the first nine months of 2014, compared to the same period in 2013. This increase was due to an increase in production volumes and an increase in our realized equivalent price, including the effects of derivative cash settlements. Cash paid for LOE increased $4.2 million to $170.6 million for the first nine months of 2014, compared to the same period in 2013, due to increased production and increased workover activity in our Rocky Mountain region, as well as the timing of cash payments. Cash paid for interest, net of capitalized interest, during the first nine months of 2014 increased $19.3 million compared to the same period in 2013, due to the first interest payment on our 2024 Notes being made in the first quarter of 2014. Additionally, cash bonuses paid in 2014 for the 2013 performance year were $41.7 million compared to $16.0 million paid in 2013 for the 2012 performance year.

Investing activities. Capital expenditures for the first nine months of 2014 increased 18 percent compared with the same period in 2013 due to increased spending in our Eagle Ford shale and Bakken/Three Forks programs. Acquisitions of proved and unproved properties increased $397.3 million as a result of property acquisitions in our Gooseneck prospect area and Powder River Basin in the second and third quarters of 2014.

Financing activities. We had net borrowings under our credit facility of $390.0 million during the nine months ended September 30, 2014, and net repayments of $312.0 million during the same period in 2013.

Interest Rate Risk and Commodity Price Risk

Our credit agreement allows us to fix the interest rate for all or a portion of the principal balance of our revolving credit facility for a period up to six months; however, our borrowings are generally made with interest rates fixed for one month. Therefore, to the extent we do not repay the principal, our borrowings are rolled over and the interest rate is reset based on the current LIBOR or Alternate Base Rate (“ABR”) as applicable. As a result, changes in interest rates can impact results of operations and cash flows. Changes in interest rates do not impact the amount of interest we pay on our fixed-rate Senior Notes, but can impact their fair market values. As of September 30, 2014, we had $1.6 billion of fixed-rate debt outstanding. Please refer to Note 11 - Fair Value Measurements in Part I, Item 1 of this report for additional discussion on the fair value of our Senior Notes. As of September 30, 2014, we had $390.0 million of floating-rate debt outstanding. The carrying amount of our floating rate debt at September 30, 2014, approximates its fair value.

The prices we receive for our oil, gas, and NGL production heavily impact our revenue, overall profitability, access to capital, and future rate of production growth. Oil, gas, and NGL prices are subject to wide fluctuations in response to changes in supply and demand. Historically, the markets for oil, gas, and NGLs have been volatile, and these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control.

We enter into commodity derivative contracts in order to reduce the impact of fluctuations in commodity prices. Please refer to Note 10 - Derivative Financial Instruments in Part I, Item 1 of this report for information about our oil, gas, and NGL derivative contracts.

There has been no material change to the interest rate risk analysis or oil and gas price sensitivity analysis previously disclosed. Please refer to Interest Rate Risk and Commodity Price Risk in Management's Discussion and Analysis of Financial Condition and Results of Operations in Part II, Item 7 of our 2013 Form 10-K for further discussion.

Off-Balance Sheet Arrangements

We have not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. We evaluate our transactions to determine if any variable interest entities exist. If we determine that we are the primary beneficiary of a variable interest entity, that entity is consolidated into our consolidated financial statements.

Critical Accounting Policies and Estimates

Please refer to the corresponding section in Part II, Item 7 of our 2013 Form 10-K and to the footnote disclosures included in Part I, Item 1 of this report for a discussion of our accounting policies and estimates.

New Accounting Pronouncements

Please refer to Note 2 - Basis of Presentation, Significant Accounting Policies, and Recently Issued Accounting Standards under Part I, Item 1 of this report for new accounting matters.

Non-GAAP Financial Measures

Adjusted EBITDAX represents income before interest expense, other non-operating income or expense, income taxes, depreciation, depletion, amortization, and accretion expense, exploration expense, property impairments, non-cash stock compensation expense, derivative gains and losses net of cash settlements, change in the Net Profits Plan liability, and gains and losses on divestitures. Adjusted EBITDAX excludes certain items that we believe affect the comparability of operating results and can exclude items that are generally one-time in nature or whose timing and/or amount cannot be reasonably estimated. Adjusted EBITDAX is a non-GAAP measure that is presented because we believe that it provides useful additional information to investors and analysts, as a performance measure, for analysis of our ability to internally generate funds for exploration, development, acquisitions, and to service debt. We are also subject to a financial covenant under our credit facility based on our debt to adjusted EBITDAX ratio. In addition, adjusted EBITDAX 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 EBITDAX should not be considered in isolation or as a substitute for net income, income from operations, net cash provided by operating activities, or profitability or liquidity measures prepared under GAAP. Because adjusted EBITDAX excludes some, but not all items that affect net income and may vary among companies, the adjusted EBITDAX amounts presented may not be comparable to similar metrics of other companies. The following table provides reconciliations of our net income and net cash provided by operating activities to adjusted EBITDAX for the periods presented:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Net income (GAAP)	$208,938	$70,690	$334,325	$163,939
Interest expense	22,621	24,488	70,851	65,170
Other non-operating (income) expense, net	672	(28)	2,493	(64)
Income tax expense	124,748	42,334	199,660	98,921
Depreciation, depletion, amortization, and asset retirement obligation liability accretion	183,259	195,792	548,255	620,232
Exploration [(1)]	32,155	14,176	74,696	45,783
Impairment of proved properties	—	5,935	—	61,706
Abandonment and impairment of unproved properties	15,522	3,818	18,487	8,459
Stock-based compensation expense	10,227	7,427	24,568	25,495
Derivative (gain) loss	(190,661)	39,933	33,470	(14,685)
Derivative cash settlement gain (loss)	(274)	(1,288)	(62,894)	12,715
Change in Net Profits Plan liability	(6,399)	940	(15,280)	(6,423)
(Gain) loss on divestiture activity [(2)]	5,432	6,216	(52)	510
Adjusted EBITDAX (Non-GAAP)	406,240	410,433	1,228,579	1,081,758
Interest expense	(22,621)	(24,488)	(70,851)	(65,170)
Other non-operating income (expense), net	(672)	28	(2,493)	64
Income tax expense	(124,748)	(42,334)	(199,660)	(98,921)
Exploration [(1)]	(32,155)	(14,176)	(74,696)	(45,783)
Exploratory dry hole expense	16,385	(8)	22,844	5,878
Amortization of deferred financing costs	1,479	1,474	4,433	3,914
Deferred income taxes	124,269	42,380	198,180	98,619
Plugging and abandonment	(2,974)	(3,707)	(6,193)	(7,453)
Changes in current assets and liabilities	(7,127)	37,752	(22,087)	25,034
Other, net	1,893	(2,840)	(2,934)	2,929
Net cash provided by operating activities (GAAP)	$359,969	$404,514	$1,075,122	$1,000,869

[1] Stock-based compensation expense is a component of exploration expense and general and administrative expense on the accompanying statements of operations. Therefore, the exploration line items shown in the reconciliation above will vary from the amount shown on the accompanying statements of operations because of the component of stock-based compensation expense recorded to exploration.
[2] (Gain) loss on divestiture activity is included within the other operating revenues line item in the accompanying statements of operations.

Cautionary Information about Forward-Looking Statements

This report contains "forward-looking statements" within the meaning of Section 27A of the Securities Act and Section 21E of the Securities Exchange Act of 1934 (the "Exchange Act"). All statements, other than statements of historical facts, included in this report that address activities, events, or developments with respect to our financial condition, results of operations, or economic performance that we expect, believe, or anticipate will or may occur in the future, or that address plans and objectives of management for future operations, are forward-looking statements. The words "anticipate," "assume," "believe," "budget," "estimate," "expect," "forecast," "intend," "plan," "project," "will," and similar ex intended to identify forward-looking statements. Forward-looking statements appear in a number of places in this report, and include statements about such matters as:

- the amount and nature of future capital expenditures and the availability of liquidity and capital resources to fund capital expenditures;
- the drilling of wells and other exploration and development activities and plans, as well as possible future acquisitions;
- the possible divestiture or farm-down of, or joint venture relating to, certain properties;
- proved reserve estimates and the estimates of both future net revenues and the present value of future net revenues associated with those proved reserve estimates;
- pending acquisitions of oil and gas assets;
- future oil, gas, and NGL production estimates;
- our outlook on future oil, gas, and NGL prices, well costs, and service costs;
- cash flows, anticipated liquidity, and the future repayment of debt;
- business strategies and other plans and objectives for future operations, including plans for expansion and growth of operations or to defer capital investment, and our outlook on our future financial condition or results of operations; and
- other similar matters such as those discussed in the Management's Discussion and Analysis of Financial Condition and Results of Operations section of this report.

Our forward-looking statements are based on assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, expected future developments, and other factors that we believe are appropriate under the circumstances. These statements are subject to a number of known and unknown risks and uncertainties, which may cause our actual results and performance to be materially different from any future results or performance expressed or implied by the forward-looking statements. Some of these risks are described under Risk Factors in Item 1A of our 2013 Form 10-K, and include such factors as:

- the volatility of oil, gas, and NGL prices, and the effect it may have on our profitability, financial condition, cash flows, access to capital, and ability to grow production volumes and/or proved reserves;
- weakness in economic conditions and uncertainty in financial markets;
- our ability to replace reserves in order to sustain production;
- our ability to raise the substantial amount of capital that is required to develop and/or replace our reserves;
- our ability to compete against competitors that have greater financial, technical, and human resources;
- our ability to attract and retain key personnel;
- the imprecise estimations of our actual quantities and present value of proved oil, gas, and NGL reserves;
- the uncertainty in evaluating recoverable reserves and estimating expected benefits or liabilities;

- the possibility that exploration and development drilling may not result in commercially producible reserves;
- our limited control over activities on non-operated properties;
- our reliance on the skill and expertise of third-party service providers on our operated properties;
- the possibility that title to properties in which we have an interest may be defective;
- the possibility that our planned drilling in existing or emerging resource plays using some of the latest available horizontal drilling and completion techniques is subject to drilling and completion risks and may not meet our expectations for reserves or production;
- the uncertainties associated with divestitures, joint ventures, farm-downs, farm-outs, and similar transactions with respect to certain assets, including whether such transactions will be consummated or completed in the form or timing and for the value that we anticipate;
- the uncertainties associated with enhanced recovery methods;
- our commodity derivative contracts may result in financial losses or may limit the prices that we receive for oil, gas, and NGL sales;
- the inability of one or more of our service providers, customers, or contractual counterparties to meet their obligations;
- our ability to deliver necessary quantities of oil, gas, or NGLs to contractual counterparties;
- price declines or unsuccessful exploration efforts resulting in write-downs of our asset carrying values;
- the impact that lower oil, gas, or NGL prices could have on the amount we are able to borrow under our credit facility;
- the possibility that our amount of debt may limit our ability to obtain financing for acquisitions, make us more vulnerable to adverse economic conditions, and make it more difficult for us to make payments on our debt;
- the possibility that covenants in our debt agreements may limit our discretion in the operation of our business, prohibit us from engaging in beneficial transactions, or lead to the accelerated payment of our debt;
- operating and environmental risks and hazards that could result in substantial losses;
- the impact of seasonal weather conditions and lease stipulations on our ability to conduct drilling activities;
- our ability to acquire adequate supplies of water and dispose of or recycle water we use at a reasonable cost in accordance with environmental and other applicable rules;
- complex laws and regulations, including environmental regulations, that result in substantial costs and other risks;
- the availability and capacity of gathering, transportation, processing, and/or refining facilities;
- our ability to sell and/or receive market prices for our oil, gas, and NGLs;
- new technologies may cause our current exploration and drilling methods to become obsolete;
- the possibility of security threats, including terrorist attacks and cybersecurity breaches, against, or otherwise impacting, our facilities and systems; and
- litigation, environmental matters, the potential impact of legislation and government regulations, and the use of management estimates regarding such matters.

We caution you that forward-looking statements are not guarantees of future performance and that actual results or performance may be materially different from those expressed or implied in the forward-looking statements. The forward-looking statements in this report speak as of the filing date of this report. Although we may from time to time voluntarily update our prior forward-looking statements, we disclaim any commitment to do so except as required by securities laws.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by this item is provided under Interest Rate Risk and Commodity Price Risk in Item 2 above and is incorporated herein by reference. Please also refer to the information under Interest Rate Risk and Commodity Price Risk in Management's Discussion and Analysis of Financial Condition and Results of Operations in Part II, Item 7 of our 2013 Form 10-K.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures that are designed to reasonably ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized, and reported within the time periods specified in the SEC’s rules and forms, and to reasonably ensure that such information is accumulated and communicated to our management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosure.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) (“Disclosure Controls”) will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls will be modified as systems change and conditions warrant.

An evaluation of the effectiveness of the design and operation of our Disclosure Controls was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our Disclosure Controls are effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting

There have been no changes during the third quarter of 2014 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Except as noted in Part II, Item 1 of the Quarterly Report on Form 10-Q for the quarter ended June 30, 2014, there have been no other material changes to the legal proceedings as previously disclosed in our 2013 Form 10-K, under Part I, Item 3. See Note 6 - Commitments and Contingencies, in Part I, Item 1 of this report, for additional discussion.

ITEM 1A. RISK FACTORS

There have been no material changes to the risk factors as previously disclosed in our 2013 Form 10-K.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

(c) The following table provides information about purchases by the Company or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Exchange Act) during the fiscal quarter ended September 30, 2014, of shares of the Company's common stock, which is the sole class of equity securities registered by the Company pursuant to Section 12 of the Exchange Act:

PURCHASES OF EQUITY SECURITIES BY ISSUER
AND AFFILIATED PURCHASERS

	(a)	(b)	(c)	(d)
Period	Total Number of Shares Purchased [(1)]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Number of Shares that May Yet Be Purchased Under the Program [(2)]
07/01/14 - 07/31/14	124,698	$84.15	—	3,072,184
08/01/14 - 08/31/14	212	78.70	—	3,072,184
09/01/14 - 09/30/14	32	86.53	—	3,072,184
Total:	124,942	$84.14	—	3,072,184

(1) All shares purchased in the third quarter of 2014 were to offset tax withholding obligations that occurred upon the delivery of outstanding shares underlying RSUs and PSUs delivered under the terms of grants under our Equity Incentive Compensation Plan.

(2) In July 2006, our Board of Directors approved an increase in the number of shares that may be repurchased under the original August 1998 authorization to up to 6,000,000 shares as of the effective date of the resolution. Accordingly, as of the date of this filing, we may repurchase up to 3,072,184 shares of common stock on a prospective basis, subject to the approval of our Board of Directors. The shares may be repurchased from time to time in open market transactions or privately negotiated transactions, subject to market conditions and other factors, including certain provisions of our credit facility, the indentures governing our Senior Notes and compliance with securities laws. Stock repurchases may be funded with existing cash balances, internal cash flow, or borrowings under our credit facility. The stock repurchase program may be suspended or discontinued at any time.

Our payment of cash dividends to our stockholders is subject to covenants under the terms of our credit facility that limit our annual dividend payments to no more than $50.0 million per year. We are also subject to certain covenants under our Senior Notes that restrict certain payments, including dividends; provided, however, that the first $6.5 million of dividends paid each year are not restricted by these covenants. We do not anticipate that these restrictions will limit our payment of dividends at our current rate for the foreseeable future if declared by our Board of Directors.

ITEM 6. EXHIBITS

The following exhibits are filed or furnished with or incorporated by reference into this report:

Exhibit	Description
2.1*†	Purchase Agreement dated July 29, 2014, between Baytex Energy USA LLC and SM Energy Company
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes - Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes - Oxley Act of 2002
32.1**	Certification pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes - Oxley Act of 2002
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document

*	Filed with this report.
**	Furnished with this report.
†	Confidential Treatment has been requested with respect to portions of the exhibit. Such portions have been redacted and filed separately with the SEC.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

	SM ENERGY COMPANY
October 29, 2014	By: /s/ ANTHONY J. BEST Anthony J. Best Chief Executive Officer (Principal Executive Officer)
October 29, 2014	By: /s/ A. WADE PURSELL A. Wade Pursell Executive Vice President and Chief Financial Officer (Principal Financial Officer)
October 29, 2014	By: /s/ MARK T. SOLOMON Mark T. Solomon Vice President - Controller and Assistant Secretary (Principal Accounting Officer)

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