OKLAHOMA CITY, Nov. 4, 2015 /PRNewswire/ -- Chesapeake Energy Corp. (NYSE:CHK) today reported financial and operational results for the 2015 third quarter. Highlights include:

- Production averaged approximately 667,000 boe per day, an increase of 3% year over year, adjusted for asset sales
- Adjusted net loss of $0.05 per fully diluted share and adjusted ebitda of $560 million
- 2015 total production guidance increased to 670 – 680 mboe per day
- 2015 production expense and general and administrative expense guidance lowered significantly
- 2015 capital guidance reduced to $3.4 – $3.9 billion

Doug Lawler, Chesapeake's Chief Executive Officer, commented, "The many actions that we have taken this quarter, including executing new gas gathering agreements, amending our revolving credit facility, reducing complexity and commitments and lowering our business costs, have significantly increased Chesapeake's ability to create additional value. Our focus on optimizing base production and continuing to generate efficiencies in the field drove a 3% increase in production compared to last year, adjusted for asset sales. In addition, the elimination of $200 million of annualized, controllable production and general and administrative expenses represents another step in our commitment to financial discipline."

Lawler continued, "We lowered our 2015 capital guidance to $3.4 to $3.9 billion and are prepared to execute on a significantly lower capital program in 2016. While the current price environment presents many challenges for our industry, we will continue focusing on our capital and operating cost efficiency, enhancing our cash flow and financial flexibility and optimizing our base production. The power of our people, the strength of our portfolio and our operational leadership will continue to create value for Chesapeake for the long term."

2015 Third Quarter Financial Results

For the 2015 third quarter, Chesapeake reported a net loss available to common stockholders of $4.695 billion, or $7.08 per fully diluted share, which compares to net income available to common stockholders of $169 million, or $0.26 per fully diluted share, in the 2014 third quarter. Items typically excluded by securities analysts in their earnings estimates reduced 2015 third quarter net income by approximately $4.612 billion on an after-tax basis and are presented on Page 12 of this release. The primary source of this reduction was a noncash impairment of the carrying value of Chesapeake's oil and natural gas properties largely resulting from significant decreases in the trailing 12-month average first-day-of-the-month oil and natural gas prices as of September 30, 2015, compared to June 30, 2015. Adjusting for this and other items, the 2015 third quarter net loss available to common stockholders was $83 million, or $0.05 per fully diluted share, which compares to adjusted net income available to common stockholders of $251 million, or $0.38 per fully diluted share, in the 2014 third quarter.

Adjusted ebitda was $560 million in the 2015 third quarter, compared to $1.236 billion in the 2014 third quarter. Operating cash flow was $476 million in the 2015 third quarter, compared to $1.293 billion in the 2014 third quarter. The year-over-year decreases in adjusted ebitda and operating cash flow were primarily the result of lower realized oil, natural gas and natural gas liquid (NGL) prices, partially offset by higher realized hedging gains and lower production expenses, general and administrative (G&A) expenses and production taxes.

Adjusted net income available to common stockholders, operating cash flow, ebitda and adjusted ebitda are non-GAAP financial measures. Reconciliations of these measures to comparable financial measures calculated in accordance with generally accepted accounting principles are provided on pages 12 – 17 of this release.

2015 Third Quarter Average Daily Production of 667,000 Boe Increased 3% Year Over Year, Adjusted for Asset Sales

Chesapeake's daily production for the 2015 third quarter averaged approximately 667,000 barrels of oil equivalent (boe), a year-over-year increase of 3% adjusted for asset sales. Average daily production in the 2015 third quarter consisted of approximately 114,100 barrels (bbls) of oil, 2.9 billion cubic feet (bcf) of natural gas and 76,200 bbls of NGL, which represent year-over-year increases of 4%, 2% and 7%, respectively, adjusted for asset sales. During the 2015 third quarter, the company had average curtailed production of approximately 51,000 boe per day. The company has increased its total 2015 production guidance to 670,000 – 680,000 boe per day, representing a 6% – 8% increase over 2014 results, adjusted for asset sales.

Capital Spending and Cost Overview

Chesapeake's 2015 third quarter drilling and completion capital expenditures decreased 41% sequentially to approximately $467 million, and capital expenditures for leasehold, geological and geophysical costs and other property, plant and equipment remained flat at approximately $57 million, for a total of approximately $524 million. Total 2015 third quarter capital expenditures of $623 million, including capitalized interest of $99 million, decreased 35% and 59% compared to 2015 second quarter and 2014 third quarter results, respectively, and are detailed in the table below. For 2015, the company has reduced its estimated total capital expenditures to $3.4 – $3.9 billion, compared to $3.5 – $4.0 billion as previously provided.

	[illegible]
Activity Comparison	[illegible]
Average operated rig count	[illegible]
Gross wells completed	[illegible]
Gross wells spud	[illegible]
Gross wells connected	[illegible]
Type of Cost ($ in millions)	
Drilling and completion costs	[illegible]
Leasehold, G&G and other PP&E	[illegible]
Subtotal capital spending	[illegible]
Capitalized interest	[illegible]
Total capital spending	[illegible]

Chesapeake's focus on cost discipline continued to generate reductions in production and G&A expenses. Production expenses during the 2015 third quarter were $4.09 per boe, while G&A expenses (including stock-based compensation) during the 2015 third quarter were $0.79 per boe. Combined production expenses and G&A expenses (including stock-based compensation) during the 2015 third quarter decreased 10% sequentially and 9% year over year.

A summary of the company's guidance for 2015 is provided in the Outlook dated November 4, 2015, beginning on Page 18.

Operational Results – Southern Division

Eagle Ford Shale (South Texas): Eagle Ford net production averaged approximately 108 thousand barrels of oil equivalent (mboe) per day (234 gross operated mboe per day) during the 2015 third quarter, an increase of 3% sequentially. Average completed well costs to date in 2015 are $5.3 million with an average completed lateral length of 6,000 feet and 21 frac stages, compared to the full-year 2014 average completed well cost of $5.9 million with an average completed lateral length of 5,850 feet and 18 frac stages. Chesapeake continues to realize significant efficiencies with longer laterals and larger completions in the area. Recent third quarter well results include the Rogers E-1H and Faith San Pedro F-4H wells, which had completed lateral lengths of 12,488 and 13,151 feet, respectively, and reached peak 24-hour production rates of 1,479 and 1,067 bbls of oil per day, respectively. These two long-lateral wells have an average field estimated completed well cost of $7.8 million each. The JEA Unit XIV LAS S 4H East Four Corners well was also completed in the third quarter using an enhanced design on a 4,611-foot completed lateral and reached a peak 24-hour rate of 1,311 bbls of oil per day. The field estimated completed well cost of this well is $4.8 million. The company placed 30 wells on production during the 2015 third quarter, compared to 89 wells in the 2014 third quarter. Chesapeake's operated rig count in the Eagle Ford averaged three rigs in the 2015 third quarter, and the company anticipates maintaining three operated rigs through the end of the year.

Haynesville Shale and Bossier Shales (Northwest Louisiana): Haynesville net production averaged approximately 636 million cubic feet of natural gas (mmcf) per day (1.03 gross operated bcf per day) during the 2015 third quarter, a decrease of 5% sequentially. Average completed well costs to date in 2015 are $7.7 million with an average completed lateral length of 5,000 feet and 14 frac stages, compared to the full-year 2014 average completed well cost of $8.4 million with an average completed lateral length of 4,900 feet and 14 frac stages. The company placed seven wells on production during the 2015 third quarter, compared to 14 wells in the 2014 third quarter. Operated rig count in the Haynesville averaged six rigs in the 2015 third quarter, and the company anticipates maintaining six operated rigs through the end of the year.

Mid-Continent: Mississippian Lime (Northern Oklahoma): Mississippian Lime net production averaged approximately 31 mboe per day (74 gross operated mboe per day) during the 2015 third quarter, a decrease of 1% sequentially. Average completed well costs to date in 2015 are $2.8 million with an average completed lateral length of 4,500 feet and nine frac stages, compared to the full-year 2014 average completed well cost of $3.0 million with an average completed lateral length of 4,450 feet and nine frac stages. During the 2015 third quarter, the company drilled a record lateral length of 9,395 feet in the JJJ 23-25-11 1H well, which is currently being completed. Chesapeake also drilled its first multi-lateral well in the Mississippian Lime. The Wilber 26-27-11 1H, which had dual laterals of 4,653 feet and 4,556 feet, is currently being completed. The company placed 13 wells on production during the 2015 third quarter, compared to 44 wells in the 2014 third quarter. Operated rig count in the Mississippian Lime averaged three rigs during the 2015 third quarter, and the company has released all operated rigs in the area through the end of the year.

Oklahoma STACK (Northwest and Central Oklahoma): The company has identified multiple stacked liquids-rich opportunities on its extensive Oklahoma STACK leasehold position, substantially all of which is held by production. During the 2015 third quarter, the company drilled its first two wells targeting the Meramec formation, and is currently drilling a third well, with encouraging results. The Rouce 4-17-10 1H, which has a completed lateral of 9,350 feet, was recently placed on production and has reached over 870 bbls of oil per day after three days. The Wittrock 16-16-9 1H has been drilled with a lateral length of 9,220 feet and is currently being completed. The Stangl 36-16-9 1H is currently drilling with a planned lateral length of 9,426 feet. The company intends to keep one operated rig in the STACK area through the end of the year.

Operational Results – Northern Division

Utica Shale (Eastern Ohio): Utica net production averaged approximately 106 mboe per day (183 gross operated mboe per day) during the 2015 third quarter, a decrease of 15% sequentially, as the company voluntarily curtailed approximately 20 net mboe per day during the quarter as a result of weak product pricing. During the 2015 fourth quarter, a new regional pipeline is expected to be placed in-service, allowing the company to move an additional 350 mmcf per day out of the basin and greater access to Gulf Coast pricing. Average completed well costs to date in 2015 are $7.7 million with an average completed lateral length of 7,900 feet and 40 frac stages, compared to the full-year 2014 average completed well cost of $7.2 million with an average completed lateral length of 6,200 feet and 29 frac stages. During the 2015 third quarter, the company drilled a new record lateral length in the Utica of 12,976 feet. Additionally, the average cycle time for Utica wells drilled in the third quarter was 9.9 days, with a record cycle time of 6.8 days. Operated rig count in the Utica averaged two rigs in the 2015 third quarter, and the company anticipates maintaining two operated rigs through the end of the year.

Marcellus Shale (Northern Pennsylvania): Marcellus net production averaged approximately 809 mmcf per day (1.77 gross operated bcf per day) during the 2015 third quarter, a decrease of 1% sequentially. Chesapeake has been voluntarily curtailing production from the area since the 2015 first quarter, primarily due to weak in-basin gas prices. The company anticipates maintaining Marcellus curtailments for the remainder of the year and actively managing its production through the winter months. Average completed well costs to date in 2015 are $6.4 million with an average completed lateral length of 6,800 feet and 29 frac stages, compared to the full-year 2014 average completed well cost of $7.5 million with an average completed lateral length of 6,000 feet and 27 frac stages. Recent third quarter well results include two tests of the Upper Marcellus formation located in Bradford County, Pennsylvania, which had completed lateral lengths of 5,600 feet and 4,800 feet, respectively, and reached peak 24-hour production rates of approximately 19,000 mcf per day and 17,000 mcf per day, respectively. The company believes that these successful completions in the Upper Marcellus could provide more than 1,000 potential new drilling locations. Operated rig count in the Marcellus averaged one rig in the 2015 third quarter, and the company anticipates maintaining one operated rig through the end of the year.

Powder River Basin (PRB) (Wyoming): PRB net production averaged approximately 21 mboe per day (31 gross operated mboe per day) during the 2015 third quarter, an increase of 5% sequentially. Average completed well costs to date in 2015 are $10.6 million with an average completed lateral length of 5,900 feet and 22 frac stages, compared to the full-year 2014 average completed well cost of $10.6 million with an average completed lateral length of 5,400 feet and 20 frac stages. Recent third quarter well results include the Barton 32-34-67 USA A 1H, which was placed on production in October with a completed lateral length of 9,500 feet and reached a peak 24-hour production rate of 1,500 boe per day (85% black oil) from the Niobrara formation. Operated rig count in the PRB averaged one rig in the 2015 third quarter, and the company has released all operated rigs in the area through the end of the year.

Key Financial and Operational Results

The table below summarizes Chesapeake's key financial and operational results during the 2015 third quarter, as compared to results in prior periods.

	Three Months Ended		
	09/30/15	06/30/15	09/30/14
Oil equivalent production (in mmboe)	61.3	63.9	66.8
Oil production (in mmbbls)	10.5	10.8	10.9
Average realized oil price ($/bbl)[a]	62.68	67.91	84.81
Oil as % of total production	17	17	16
Natural gas production (in bcf)	263.0	275.4	282.0
Average realized natural gas price ($/mcf)[a]	1.14	1.01	2.09
Natural gas as % of total production	72	72	71
NGL production (in mmbbls)	7.0	7.2	8.8
Average realized NGL price ($/bbl)[a]	(1.38)	1.90	22.95
NGL as % of total production	11	11	13
Production expenses ($/boe)	(4.09)	(4.32)	(4.47)
Production taxes ($/boe)	(0.42)	(0.52)	(0.94)
General and administrative costs ($/boe)[b]	(0.64)	(0.89)	(0.72)
Stock-based compensation ($/boe)	(0.15)	(0.19)	(0.18)
DD&A of natural gas and liquids properties ($/boe)	(7.95)	(9.39)	(10.31)
DD&A of other assets ($/boe)	(0.51)	(0.52)	(0.55)
Interest expense ($/boe)[a]	(1.41)	(1.12)	(0.16)
Marketing, gathering and compression net margin ($ in millions)[c]	58	209	(7)
Operating cash flow ($ in millions)[d]	476	572	1,293
Operating cash flow ($/boe)	7.76	8.95	19.37
Adjusted ebitda ($ in millions)[e]	560	600	1,236
Adjusted ebitda ($/boe)	9.12	9.37	18.52
Net income (loss) available to common stockholders ($ in millions)	(4,695)	(4,151)	169
Earnings (loss) per share – diluted ($)	(7.08)	(6.27)	0.26
Adjusted net income (loss) available to common stockholders ($ in millions)[f]	(83)	(126)	251
Adjusted earnings (loss) per share – diluted ($)	(0.05)	(0.11)	0.38

(a)	Includes the effects of realized gains (losses) from hedging, but excludes the effects of unrealized gains (losses) from hedging
(b)	Excludes expenses associated with stock-based compensation and restructuring and other termination costs.
(c)	Includes revenue, operating expenses and $70 million and $220 million of unrealized gains on supply contract derivatives for the three months ended September 30, 2015 and June 30, 2015, respectively. Excludes depreciation and amortization of othe assets.
(d)	Defined as cash flow provided by operating activities before changes in assets and liabilities.
(e)	Defined as net income before interest expense, income taxes and depreciation, depletion and amortization expense, as adjusted to remove the effects of certain items detailed on Pages 16 – 17.
(f)	Defined as net income available to common stockholders, as adjusted to remove the effects of certain items detailed on Page 12.

2015 Third Quarter Financial and Operational Results Conference Call Information

A conference call to discuss this release has been scheduled for Wednesday, November 4, 2015 at 9:00 am EST. The telephone number to access the conference call is 913-312-6690 or toll-free 888-600-4885. The passcode for the call is 4959206. We encourage those who would like to participate in the call to place calls between 8:50 and 9:00 am EST. For those unable to participate in the live conference call, a replay will be available for audio playback at 12:00 pm EST on Wednesday, November 4, 2015, and will run through 12:00 pm EST on Wednesday, November 18, 2015. The number to access the conference call replay is 719-457-0820 or toll-free 888-203-1112. The passcode for the replay is 4959206. The conference call will also be webcast live at www.chk.com in the "Investors" section of the company's website. The webcast of the conference will be available on the website for one year.

Chesapeake Energy Corp. (NYSE:CHK) is the second-largest producer of natural gas and the 12th largest producer of oil and natural gas liquids in the U.S. Headquartered in Oklahoma City, the company's operations are focused on discovering and developing its large and geographically diverse resource base of unconventional oil and natural gas assets onshore in the U.S. The company also owns substantial marketing and compression businesses. Further information is available at www.chk.com where Chesapeake routinely posts announcements, updates, events, investor information, presentations and news releases.

This news release and the accompanying Outlook include "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are statements other than statements of historical fact. They include statements that give our current expectations or forecasts of future events, production and well connection forecasts, estimates of operating costs, anticipated capital and operational efficiencies, planned development drilling and expected drilling cost reductions, general and administrative expenses, capital expenditures, the timing of anticipated noncore asset sales and proceeds to be received therefrom, projected cash flow and liquidity, our ability to enhance our cash flow and financial flexibility, plans and objectives for future operations (including our ability to optimize base production and execute gas gathering agreements), the ability of our employees, portfolio strength and operational leadership to create long-term value, and the assumptions on which such statements are based. Although we believe the expectations and forecasts reflected in the forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate or changed assumptions or by known or unknown risks and uncertainties.

Factors that could cause actual results to differ materially from expected results include those described under "Risk Factors" in Item 1A of our annual report on Form 10-K and any updates to those factors set forth in Chesapeake's subsequent quarterly reports on Form 10-Q or current reports on Form 8-K (available at http://www.chk.com/investors/sec-filings). These risk factors include the volatility of oil, natural gas and NGL prices; write-downs of our oil and natural gas carrying values due to declines in prices; the availability of operating cash flow and other funds to finance reserve replacement costs; our ability to replace reserves and sustain production; uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and projecting future rates of production and the amount and timing of development expenditures; our ability to generate profits or achieve targeted results in drilling and well operations; leasehold terms expiring before production can be established; commodity derivative activities resulting in lower prices realized on oil, natural gas and NGL sales; the need to secure derivative liabilities and the inability of counterparties to satisfy their obligations; adverse developments or losses from pending or future litigation and regulatory proceedings, including royalty claims; the limitations our level of indebtedness may have on our financial flexibility; charges incurred in response to market conditions and in connection with actions to reduce financial leverage and complexity; drilling and operating risks and resulting liabilities; effects of environmental protection laws and regulation on our business; legislative and regulatory initiatives further regulating hydraulic fracturing; our need to secure adequate supplies of water for our drilling operations and to dispose of or recycle the water used; federal and state tax proposals affecting our industry; potential OTC derivatives regulation limiting our ability to hedge against commodity price fluctuations; impacts of potential legislative and regulatory actions addressing climate change; competition in the oil and gas exploration and production industry; a deterioration in general economic, business or industry conditions; negative public perceptions of our industry; limited control over properties we do not operate; pipeline and gathering system capacity constraints and transportation interruptions;

cyber attacks adversely impacting our operations; and interruption in operations at our headquarters due to a catastrophic event.

In addition, disclosures concerning the estimated contribution of derivative contracts to our future results of operations are based upon market information as of a specific date. These market prices are subject to significant volatility. Our production forecasts are also dependent upon many assumptions, including estimates of production decline rates from existing wells and the outcome of future drilling activity. Expected asset sales may not be completed in the time frame anticipated or at all. We caution you not to place undue reliance on our forward-looking statements, which speak only as of the date of this news release, and we undertake no obligation to update any of the information provided in this release or the accompanying Outlook, except as required by applicable law.

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CHESAPEAKE ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

($ in millions, except per share data)

(unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
REVENUES:				
Oil, natural gas and NGL	$ 880	$ 2,341	$ 2,693	$ 5,812
Marketing, gathering and compression	2,013	3,362	5,993	9,543
Oilfield services	—	—	—	546
Total Revenues	2,893	5,703	8,686	15,901
OPERATING EXPENSES:				
Oil, natural gas and NGL production	251	298	826	868
Production taxes	25	62	87	185
Marketing, gathering and compression	1,955	3,369	5,751	9,515
Oilfield services	—	—	—	431
General and administrative	49	60	174	229
Restructuring and other termination costs	53	(14)	39	12
Provision for legal contingencies	—	100	359	100
Oil, natural gas and NGL depreciation, depletion and amortization	488	688	1,773	1,977
Depreciation and amortization of other assets	31	37	100	194
Impairment of oil and natural gas properties				

—

15,407

—

Impairments of fixed assets and other	79	15	167	75
Net (gains) losses on sales of fixed assets	(1)	(86)	3	(201)
Total Operating Expenses	8,346	4,529	24,686	13,385
INCOME (LOSS) FROM OPERATIONS	(5,453)	1,174	(16,000)	2,516
OTHER INCOME (EXPENSE):				
Interest expense	(88)	(17)	(210)	(82)
Losses on investments	(33)	(27)	(57)	(72)
Net gain on sales of investments	—	—	—	67
Losses on purchases of debt	—	—	—	(195)
Other income (expense)	(2)	(1)	3	12
Total Other Expense	(123)	(45)	(264)	(270)
INCOME (LOSS) BEFORE INCOME TAXES	(5,576)	1,129	(16,264)	2,246
INCOME TAX EXPENSE (BENEFIT):				
Current income taxes	—	2	(6)	10
Deferred income taxes	(937)	435	(3,808)	849
Total Income Tax Expense (Benefit)	(937)	437	(3,814)	859
NET INCOME (LOSS)	(4,639)	692	(12,450)	1,387
Net income attributable to noncontrolling interests	(13)	(30)	(50)	(110)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	(4,652)	662	(12,500)	1,277
Preferred stock dividends	(43)	(43)	(128)	(128)
Repurchase of preferred shares of CHK Utica	—	(447)	—	(447)
Earnings allocated to participating securities	—	(3)	—	(15)
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ (4,695)	$ 169	$ (12,628)	$ 687
EARNINGS (LOSS) PER COMMON SHARE:				
Basic	$ (7.08)	$ 0.26	$ (19.07)	$ 1.04
Diluted	$ (7.08)	$ 0.26	$ (19.07)	$ 1.04
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):				
Basic	663	660	662	659
Diluted	663	660	662	659

CHESAPEAKE ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

($ in millions)

(unaudited)

	September 30, 2015	December 31, 2014
Cash and cash equivalents	$ 1,759	$ 4,108
Other current assets	1,820	3,360
Total Current Assets	3,579	7,468
Property and equipment, (net)	16,959	32,515
Other assets	748	768
Total Assets	$ 21,286	$ 40,751
Current liabilities	$ 4,557	$ 5,863
Long-term debt, net of discounts	10,674	11,154
Other long-term liabilities	935	1,344
Deferred income tax liabilities	574	4,185
Total Liabilities	16,740	22,546
Preferred stock	3,062	3,062
Noncontrolling interests	264	1,302
Common stock and other stockholders' equity	1,220	13,841
Total Equity	4,546	18,205
Total Liabilities and Equity	$ 21,286	$ 40,751
Common Shares Outstanding (in millions)	663	663

CHESAPEAKE ENERGY CORPORATION

CAPITALIZATION

($ in millions)

(unaudited)

	September 30, 2015		December 31, 2014	
Total debt, net of unrestricted cash	$ 9,808		$ 7,427	
Preferred stock	3,062		3,062	
Noncontrolling interests[a]	264		1,302	
Common stock and other stockholders' equity	1,220		13,841	
Total	$ 14,354		$ 25,632	
Total net debt to capitalization ratio	68	%	29	%

[a] Includes third-party ownership as follows:

	September 30, 2015	December 31, 2014
Chesapeake Granite Wash Trust	$ 264	$ 287
CHK Cleveland Tonkawa, L.L.C. [1]	—	1,015
Total	$ 264	$ 1,302

[1] Repurchase of noncontrolling interest of CHK Cleveland Tonkawa occurred in August 2015.

CHESAPEAKE ENERGY CORPORATION

SUPPLEMENTAL DATA – OIL, NATURAL GAS AND NGL PRODUCTION, SALES AND INTEREST EXPENSE

(unaudited)

	Three Months Ended September 30,		N S
	2015	2014	2
Net Production:			
Oil (mmbbl)	10.5	10.9	3
Natural gas (bcf)	263.0	282.0	8
NGL (mmbbl)	7.0	8.8	2
Oil equivalent (mmboe)	61.3	66.8	1

Oil, natural gas and NGL Sales ($ in millions):

Oil sales	$	43$4	1
Oil derivatives – realized gains (losses)[a]	224	(77)	6
Oil derivatives – unrealized gains (losses)[a]	(100)	456	(
Total Oil Sales	558	1,384	1
Natural gas sales	228	569	8
Natural gas derivatives – realized gains (losses)[a]	70	19	3
Natural gas derivatives – unrealized gains (losses)[a]	33	166	(
Total Natural Gas Sales	331	754	1
NGL sales	(9)	203	5
Total NGL Sales	(9)	203	5
Total Oil, Natural Gas and NGL Sales	$	88$0	2
Average Sales Price – excluding gains (losses) on derivatives:			
Oil ($ per bbl)	$	41$25	9
Natural gas ($ per mcf)	$	0.8$7	2
NGL ($ per bbl)	$	(1$38)	2
Oil equivalent ($ per boe)	$	10$63	2
Average Sales Price – including realized gains (losses) on derivatives:			
Oil ($ per bbl)	$	62$68	8
Natural gas ($ per mcf)	$	1.1$4	2
NGL ($ per bbl)	$	(1$38)	2
Oil equivalent ($ per boe)	$	15$45	2
Interest Expense ($ in millions):			
Interest[b]	$	88$	1
Derivatives – realized (gains) losses[c]	(2)	(4)	(
Derivatives – unrealized (gains) losses[c]	2	6	(
Total Interest Expense	$	88$	1

(a)	Realized gains and losses include the following items: (i) settlements of nondesignated derivatives related to current period production revenues, (ii) prior period settlements for option premiums and for early-terminated derivatives originally scheduled settle against current period production revenues, and (iii) gains and losses related to de-designated cash flow hedges original designated to settle against current period production revenues. Unrealized gains and losses include the change in fair value o open derivatives scheduled to settle against future period production revenues offset by amounts reclassified as realized gains and losses during the period. Although we no longer designate our derivatives as cash flow hedges for accounting purposes, we believe these definitions are useful to management and investors in determining the effectiveness of our price risk management program.
(b)	Net of amounts capitalized.
(c)	Realized (gains) losses include settlements related to the current period interest accrual and the effect of (gains) losses on ear termination trades. Unrealized (gains) losses include changes in the fair value of open interest rate derivatives offset by amounts reclassified to realized (gains) losses during the period.

CHESAPEAKE ENERGY CORPORATION

CONDENSED CONSOLIDATED CASH FLOW DATA

($ in millions)

(unaudited)

THREE MONTHS ENDED:	September 30, 2015	September 30, 2014
Beginning cash	$ 2,051	$ 1,462
Net cash provided by operating activities	318	1,184
Cash flows from investing activities:		
Drilling and completion costs[a]	(528)	(1,189)
Acquisitions of proved and unproved properties[b]	(141)	(667)
Proceeds from divestitures of proved and unproved properties	174	475
Additions to other property and equipment	(21)	(25)
Cash paid to purchase leased rigs and compressors	—	(52)
Proceeds from sales of other property and equipment	73	251
Additions to investments	(2)	(9)
Decrease in restricted cash	52	37
Other	—	(2)
Net cash used in investing activities	(393)	(1,181)
Net cash used in financing activities	(217)	(1,375)
Change in cash and cash equivalents	(292)	(1,372)
Ending cash	$ 1,759	$ 90

(a)	Includes capitalized interest of $3 million and $11 million for the three months ended September 30, 2015 and 2014, respectively.
(b)	Includes capitalized interest of $93 million and $135 million for the three months ended September 30, 2015 and 2014, respectively.

CHESAPEAKE ENERGY CORPORATION

CONDENSED CONSOLIDATED CASH FLOW DATA

($ in millions)

(unaudited)

NINE MONTHS ENDED:	September 30, 2015	September 30, 2014
Beginning cash	$ 4,108	$ 837
Net cash provided by operating activities	1,055	3,805
Cash flows from investing activities:		
Drilling and completion costs(a)	(2,696)	(3,185)
Acquisitions of proved and unproved properties(b)	(407)	(1,023)
Proceeds from divestitures of proved and unproved properties	188	723
Additions to other property and equipment	(114)	(201)
Cash paid to purchase leased rigs and compressors	—	(474)
Proceeds from sales of other property and equipment	80	964
Additions to investments	(8)	(14)
Proceeds from sales of investments	—	239
Decrease in restricted cash	52	37
Other	—	(4)
Net cash used in investing activities	(2,905)	(2,938)
Net cash used in financing activities	(499)	(1,614)
Change in cash and cash equivalents	(2,349)	(747)
Ending cash	$ 1,759	$ 90

(a)	Includes capitalized interest of $21 million and $40 million for the nine months ended September 30, 2015 and 2014, respectively.
(b)	Includes capitalized interest of $305 million and $433 million for the nine months ended September 30, 2015 and 2014, respectively.

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF ADJUSTED NET INCOME AVAILABLE TO COMMON STOCKHOLDERS

($ in millions, except per share data)

(unaudited)

THREE MONTHS ENDED:	September 30, 2015	June 30, 2015	September 30, 2014
Net income (loss) available to common stockholders	$ (4,695)	$ (4,151)	$ 169
Adjustments, net of tax:			
Unrealized (gains) losses on commodity derivatives	58	220	(384)
Unrealized gains on supply contract derivatives	(58)	(161)	—
Restructuring and other termination costs	44	(3)	(9)
Provision for legal contingencies	—	244	62
Impairment of oil and natural gas properties	4,506	3,666	—
Impairments of fixed assets and other	66	61	9
Net (gains) losses on sales of fixed assets	(1)	1	(54)
Repurchase of preferred shares of CHK Utica	—	—	447
Other	(3)	(3)	11
Adjusted net income (loss) available to common stockholders[a]	$ (83)	$ (126)	$ 251
Preferred stock dividends	43	43	43
Earnings allocated to participating securities	—	—	3
Total adjusted net income (loss) attributable to Chesapeake	$ (40)	$ (83)	$ 297
Weighted average fully diluted shares outstanding	777	777	776
(in millions)[b]			
Adjusted earnings (loss) per share assuming dilution[a]	$ (0.05)	$ (0.11)	$ 0.38

(a)	Adjusted net income and adjusted earnings per share assuming dilution are not measures of financial performance under accounting principles generally accepted in the United States (GAAP), and should not be considered as an alternative to net income available to common stockholders or diluted earnings per share. Adjusted net income available to common stockholders and adjusted earnings per share assuming dilution exclude certain items that management believes affect the comparability of operating results. The company believes these adjusted financial measures are a useful adjunct to earnings calculated in accordance with GAAP because:	
	(i)	Management uses adjusted net income available to common stockholders to evaluate the company's operational trends ar performance relative to other oil and natural gas producing companies.
	(ii)	Adjusted net income available to common stockholders is more comparable to earnings estimates provided by securities analysts.
	(iii)	Items excluded generally are one-time items or items whose timing or amount cannot be reasonably estimated. Accordingl any guidance provided by the company generally excludes information regarding these types of items.
(b)	Weighted average fully diluted shares outstanding include shares that were considered antidilutive for calculating earnings per share in accordance with GAAP.	

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF ADJUSTED NET INCOME AVAILABLE TO COMMON STOCKHOLDERS

($ in millions, except per share data)

(unaudited)

NINE MONTHS ENDED:	September 30, 2015	September 30, 2014
Net income (loss) available to common stockholders	$ (12,628)	$ 687
Adjustments, net of tax:		
Unrealized (gains) losses on commodity derivatives	486	(324)
Unrealized gains on supply contract derivatives	(222)	—
Restructuring and other termination costs	30	7
Provision for legal contingencies	275	62
Impairment of oil and natural gas properties	11,794	—
Impairments of fixed assets and other	128	46
Net (gains) losses on sales of fixed assets	2	(125)
Impairments of investments	—	3
Net gain on sales of investments	—	(42)
Losses on purchases of debt	—	121
Repurchase of preferred shares of CHK Utica	—	447
Tax rate adjustment	(17)	—
Other	(10)	5
Adjusted net income (loss) available to common stockholders[(a)]	$ (162)	$ 887
Preferred stock dividends	128	128
Earnings allocated to participating securities	—	15
Total adjusted net income (loss) attributable to Chesapeake	$ (34)	$ 1,030
Weighted average fully diluted shares outstanding (in millions)[(b)]	776	776
Adjusted earnings (loss) per share assuming dilution[(a)]	$ (0.04)	$ 1.33

(a)	Adjusted net income and adjusted earnings per share assuming dilution are not measures of financial performance under accounting principles generally accepted in the United States (GAAP), and should not be considered as an alternative to net income available to common stockholders or diluted earnings per share. Adjusted net income available to common stockholders and adjusted earnings per share assuming dilution exclude certain items that management believes affect the comparability of operating results. The company believes these adjusted financial measures are a useful adjunct to earnings calculated in accordance with GAAP because:
	(i) Management uses adjusted net income available to common stockholders to evaluate the company's operational trends ar performance relative to other oil and natural gas producing companies.
	(ii) Adjusted net income available to common stockholders is more comparable to earnings estimates provided by securities analysts.
	(iii) Items excluded generally are one-time items or items whose timing or amount cannot be reasonably estimated. According any guidance provided by the company generally excludes information regarding these types of items.
(b)	Weighted average fully diluted shares outstanding include shares that were considered antidilutive for calculating earnings per share in accordance with GAAP.

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF OPERATING CASH FLOW AND EBITDA

($ in millions)

(unaudited)

THREE MONTHS ENDED:	September 30, 2015	June 30, 2015	September 30, 2014
CASH PROVIDED BY OPERATING ACTIVITIES	$ 318	$ 314	$ 1,184
Changes in assets and liabilities	158	258	109
OPERATING CASH FLOW[(a)]	$ 476	$ 572	$ 1,293

THREE MONTHS ENDED:	September 30, 2015	June 30, 2015	September 30, 2014
NET INCOME (LOSS)	$ (4,639)	$ (4,090)	$ 692
Interest expense	88	71	17
Income tax expense (benefit)	(937)	(1,506)	437
Depreciation and amortization of other assets	31	34	37
Oil, natural gas and NGL depreciation, depletion and amortization	488	601	688
EBITDA[(b)]	$ (4,969)	$ (4,890)	$ 1,871

THREE MONTHS ENDED:	September 30, 2015	June 30, 2015	September 30, 2014
CASH PROVIDED BY OPERATING ACTIVITIES			

$

$

$

Changes in assets and liabilities	158	258	109
Interest expense, net of unrealized gains (losses) on derivatives	86	71	11
Gains (losses) on commodity derivatives, net	227	(48)	564
Gains on supply contract derivatives, net	70	220	—
Cash (receipts) payments on oil, natural gas and NGL derivative settlements, net	(223)	(223)	34
Stock-based compensation	(18)	(20)	(19)
Restructuring and other termination costs	(53)	4	42
Provision for legal contingencies	—	(334)	(100)
Impairment of oil and natural gas properties	(5,416)	(5,015)	—
Impairments of fixed assets and other	(78)	(79)	(15)
Net gains (losses) on sales of fixed assets	1	(1)	86
Losses on investments	(33)	(17)	(27)
Other items	(8)	(20)	2
EBITDA[b]	\$ (4,969)	\$ (4,890)	\$ 1,871

(a)	Operating cash flow represents net cash provided by operating activities before changes in assets and liabilities. Operating cash flow is presented because management believes it is a useful adjunct to net cash provided by operating activities under GAAP. Operating cash flow is widely accepted as a financial indicator of an oil and natural gas company's ability to generate cash that is used to internally fund exploration and development activities and to service debt. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investment recommendations of companies within the oi and natural gas exploration and production industry. Operating cash flow is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operating, investing or financing activities as an indicator of cash flows, or as a measure of liquidity.
(b)	Ebitda represents net income before interest expense, income taxes, and depreciation, depletion and amortization expense. Ebitda is presented as a supplemental financial measurement in the evaluation of our business. We believe that it provides additional information regarding our ability to meet our future debt service, capital expenditures and working capital requirements. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investme recommendations of companies. Ebitda is also a financial measurement that, with certain negotiated adjustments, is reported our lenders pursuant to our bank credit agreements and is used in the financial covenants in our bank credit agreements. Ebitda is not a measure of financial performance under GAAP. Accordingly, it should not be considered as a substitute for net income, income from operations or cash flow provided by operating activities prepared in accordance with GAAP.

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF OPERATING CASH FLOW AND EBITDA

($ in millions)

(unaudited)

NINE MONTHS ENDED:	September 30, 2015	September 30, 2014
CASH PROVIDED BY OPERATING ACTIVITIES	$ 1,055	$ 3,805
Changes in assets and liabilities	877	348
OPERATING CASH FLOW[(a)]	$ 1,932	$ 4,153

NINE MONTHS ENDED:	September 30, 2015	September 30, 2014
NET INCOME (LOSS)	$ (12,450)	$ 1,387
Interest expense	210	82
Income tax expense (benefit)	(3,814)	859
Depreciation and amortization of other assets	100	194
Oil, natural gas and NGL depreciation, depletion and amortization	1,773	1,977
EBITDA[(b)]	$ (14,181)	$ 4,499

NINE MONTHS ENDED:	September 30, 2015	September 30, 2014
CASH PROVIDED BY OPERATING ACTIVITIES	$ 1,055	$ 3,805
Changes in assets and liabilities	877	348
Interest expense, net of unrealized gains (losses) on derivatives	218	123

Gains (losses) on commodity derivatives, net	340	(30)
Gains on supply contract derivatives, net	290	—
Cash (receipts) payments on oil, natural gas and NGL derivative settlements, net	(859)	352
Stock-based compensation	(61)	(59)
Restructuring and other termination costs	(39)	18
Provision for legal contingencies	(359)	(100)
Impairment of oil and natural gas properties	(15,407)	—
Impairments of fixed assets and other	(159)	(44)
Net gains (losses) on sales of fixed assets	(3)	201
Losses on investments	(57)	(72)
Net gain on sales of investments	—	67
Losses on purchases of debt	—	(61)
Other items	(17)	(49)
EBITDA(b)	$ (14,181)	$ 4,499

(a)	Operating cash flow represents net cash provided by operating activities before changes in assets and liabilities. Operating cash flow is presented because management believes it is a useful adjunct to net cash provided by operating activities under GAAP. Operating cash flow is widely accepted as a financial indicator of an oil and natural gas company's ability to generate cash that is used to internally fund exploration and development activities and to service debt. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investment recommendations of companies within the oi and natural gas exploration and production industry. Operating cash flow is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operating, investing or financing activities as an indicator of cash flows, or as a measure of liquidity.
(b)	Ebitda represents net income before interest expense, income taxes, and depreciation, depletion and amortization expense. Ebitda is presented as a supplemental financial measurement in the evaluation of our business. We believe that it provides additional information regarding our ability to meet our future debt service, capital expenditures and working capital requirements. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investme recommendations of companies. Ebitda is also a financial measurement that, with certain negotiated adjustments, is reported our lenders pursuant to our bank credit agreements and is used in the financial covenants in our bank credit agreements. Ebitda is not a measure of financial performance under GAAP. Accordingly, it should not be considered as a substitute for net income, income from operations or cash flow provided by operating activities prepared in accordance with GAAP.

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF ADJUSTED EBITDA

($ in millions)

(unaudited)

THREE MONTHS ENDED:	September 30, 2015	June 30, 2015	September 30, 2014
EBITDA	$ (4,969)	$ (4,890)	$ 1,871
Adjustments:			
Unrealized (gains) losses on oil, natural gas and NGL derivatives	67	301	(622)
Unrealized gains on supply contract derivatives	(70)	(220)	—
Restructuring and other termination costs	53	(4)	(14)
Provision for legal contingencies	—	334	100
Impairment of oil and natural gas properties	5,416	5,015	—
Impairments of fixed assets and other	79	84	15
Net (gains) losses on sales of fixed assets	(1)	1	(86)
Net income attributable to noncontrolling interests	(13)	(18)	(30)
Other	(2)	(3)	2
Adjusted EBITDA[(a)]	$ 560	$ 600	$ 1,236

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF ADJUSTED EBITDA

($ in millions)

(unaudited)

NINE MONTHS ENDED:	September 30, 2015	September 30, 2014
EBITDA	$ (14,181)	$ 4,499
Adjustments:		
Unrealized (gains) losses on oil, natural gas and NGL derivatives	642	(479)
Unrealized gains on supply contract derivatives	(290)	—
Restructuring and other termination costs	39	12
Provision for legal contingencies	359	100
Impairment of oil and natural gas properties	15,407	—
Impairments of fixed assets and other	167	75
Net (gains) losses on sales of fixed assets	3	(201)
Impairments of investments	—	5
Net gains on sales of investments	—	(67)
Losses on purchases of debt	—	195
Net income attributable to noncontrolling interests	(50)	(110)
Other	(9)	—
Adjusted EBITDA[a]	$ 2,087	$ 4,029

(a)	Adjusted ebitda excludes certain items that management believes affect the comparability of operating results. The company believes these non-GAAP financial measures are a useful adjunct to ebitda because:	
	(i)	Management uses adjusted ebitda to evaluate the company's operational trends and performance relative to other oil and natural gas producing companies.
	(ii)	Adjusted ebitda is more comparable to estimates provided by securities analysts.
	(iii)	Items excluded generally are one-time items or items whose timing or amount cannot be reasonably estimated. Accordingl any guidance provided by the company generally excludes information regarding these types of items.

Accordingly, adjusted EBITDA should not be considered as a substitute for net income, income from operations or cash flow provided by operating activities prepared in accordance with GAAP.

CHESAPEAKE ENERGY CORPORATION

MANAGEMENT'S OUTLOOK AS OF NOVEMBER 4, 2015

Chesapeake periodically provides management guidance on certain factors that affect the company's future financial performance. Changes from the company's August 5, 2015 Outlook are italicized bold below.

	Year Ending 12/31/2015
Adjusted Production Growth[a]	6% – 8%
Absolute Production	
Liquids - mbbls	67.5 – 69.5
Oil - mbbls	41.5 – 42.5
NGL[b] - mbbls	26.0 – 27.0
Natural gas - bcf	1,060 – 1,070
Total absolute production - mmboe	244 – 249
Absolute daily rate - mboe	670 – 680
Estimated Realized Hedging Effects[c] (based on 10/31/15 strip prices):	
Oil - $/bbl	$20.80
Natural gas - $/mcf	$0.41
Estimated Basis/Gathering/Marketing/Transportation Differentials to NYMEX Prices:	
Oil - $/bbl	$6.00 – 8.00
Natural gas - $/mcf	$1.65 – 1.85
NGL - $/bbl	$48.00 – 50.00
Fourth quarter minimum volume commitment (MVC) estimate ($ in millions)	($160) – (180)
Operating Costs per Boe of Projected Production:	
Production expense	$4.25 – 4.50
Production taxes	$0.45 – 0.55
General and administrative[d]	$0.75 – 0.85
Stock-based compensation (noncash)	$0.15 – 0.20
DD&A of natural gas and liquids assets	$8.00 – 9.00
Depreciation of other assets	$0.50 – 0.60
Interest expense[e]	$1.20 – 1.30
Other ($ millions):	
Marketing, gathering and compression net margin[f]	($40 – 60)
Net income attributable to noncontrolling interests and other[g]	($60 – 65)
Book Tax Rate	20% – 30%
Capital Expenditures ($ in millions)[h]	$3,000 – 3,500
Capitalized Interest ($ in millions)	$425
Total Capital Expenditures ($ in millions)	$3,425 – 3,925

(a)	Based on 2014 production of 618 mboe per day adjusted for 2014 sales and the sale of the Cleveland Tonkawa asset in 2015.
(b)	Assumes ethane recovery in the Utica to fulfill Chesapeake's pipeline commitments, no ethane recovery in the Powder River Basin and partial ethane recovery in the Mid-Continent and Eagle Ford.
(c)	Includes expected settlements for commodity derivatives adjusted for option premiums. For derivatives closed early, settlements are reflected in the period of original contract expiration.
(d)	Excludes expenses associated with stock-based compensation.
(e)	Excludes unrealized gains (losses) on interest rate derivatives.
(f)	Includes revenue and operating expenses. Excludes depreciation and amortization of other assets and unrealized gains (losses) on supply contract derivatives.
(g)	Net income attributable to noncontrolling interests of Chesapeake Granite Wash Trust and, prior to its repurchase in the 2015 third quarter, CHK Cleveland Tonkawa, L.L.C.
(h)	Includes capital expenditures for drilling and completion, leasehold, geological and geophysical costs and other property and plant and equipment.

Oil and Natural Gas Hedging Activities

Chesapeake enters into oil and natural gas derivative transactions in order to mitigate a portion of its exposure to adverse changes in market prices. Please see the quarterly reports on Form 10-Q and annual reports on Form 10-K filed by Chesapeake with the SEC for detailed information about derivative instruments the company uses, its quarter-end derivative positions and accounting for oil and natural gas derivatives.

As of October 31, 2015, the company had downside protection, through open swaps, on approximately 38% of its projected 2015 fourth quarter oil production at an average price of $86.89 per bbl. In addition, the company had downside price protection under three-way collar arrangements on approximately 11% of its projected 2015 fourth quarter oil production based on an average bought put NYMEX price of $90 per bbl and exposure below an average sold put NYMEX price of $80 per bbl. The company had downside price protection, through open swaps, on approximately 20% of the company's projected 2015 fourth quarter natural gas production at an average price of $3.94 per mcf. In addition, the company had downside price protection under three-way collar arrangements on approximately 14% of its projected 2015 fourth quarter natural gas production based on an average bought put NYMEX price of $4.17 per mcf and exposure below an average sold put NYMEX price of $3.38 per mcf. On three-way collars, if the actual price at settlement is below the sold put, the company's gain will be the difference between the bought put and the sold put.

The company's crude oil hedging positions as of October 31, 2015 were as follows:

Open Crude Oil Swaps; Gains from Closed

Crude Oil Trades and Call Option Premiums

	Open Swaps (mbbls)	Avg. NYMEX Price of Open Swaps	Total Gains from Closed Trades and Premiums for Call Options ($ in millions)	
Q4 2015	3,634	$ 86.89	$	63
2016 (a)	12,078	52.13	38	
Total 2017 – 2022	—	$ —	$	78

(a)	Certain hedging arrangements include a sold option to extend at an average price of $53.67 per bbl covering 2.9 mmbbls in 2016.

Crude Oil Three-Way Collars

	Open Collars (mbbls)	Avg. NYMEX Sold Put Price		Avg. NYMEX Bought Put Price		Avg. NYMEX Sold Call Price	
Q4 2015	1,104	$	80.00	$	90.00	$	98.94

Crude Oil Net Written Call Options

	Call Options (mbbls)	Avg. NYMEX Strike Price	
Q4 2015	1,868	$	85.31
2016	10,951	96.23	
2017	5,293	$	83.50

Crude Oil Basis Protection Swaps

	Volume (mbbls)	Avg. NYMEX plus	
Q4 2015	2,361	$	3.14

The company's natural gas hedging positions as of October 31, 2015 were as follows:

Open Natural Gas Swaps; Gains (Losses) from Closed
Natural Gas Trades and Call Option Premiums

	Open Swaps (bcf)	Avg. NYMEX Price of Open Swaps	Total Losses from Closed Trades and Premiums for Call Options ($ in millions)
Q4 2015	52	$ 3.94	$ (31)
2016	283	3.18	(109)
Total 2017 – 2022	—	$ —	$ (78)

Natural Gas Three-Way Collars

	Open Collars (bcf)	Avg. NYMEX Sold Put Price	Avg. NYMEX Bought Put Price	Avg. NYMEX Sold Call Price
Q4 2015	36	$ 3.38	$ 4.17	$ 4.37

Natural Gas Net Written Call Options

	Call Options (bcf)	Avg. NYMEX Strike Price
2016	79	$ 8.48
Total 2017 – 2020	114	$ 10.92

Natural Gas Basis Protection Swaps

	Volume	Avg. NYMEX plus/(minus)	
	(bcf)		
Q4 2015	18	$	0.37
2016	33	0.17	
Total 2017 - 2022	24	$	(0.48)

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