Second Quarter 2017 Review

Hal Hickey	Chief Executive Officer
Harold Jameson	Chief Operating Officer
Tyler Farquharson	Chief Financial Officer

August 9, 2017

Strategic Plan Update

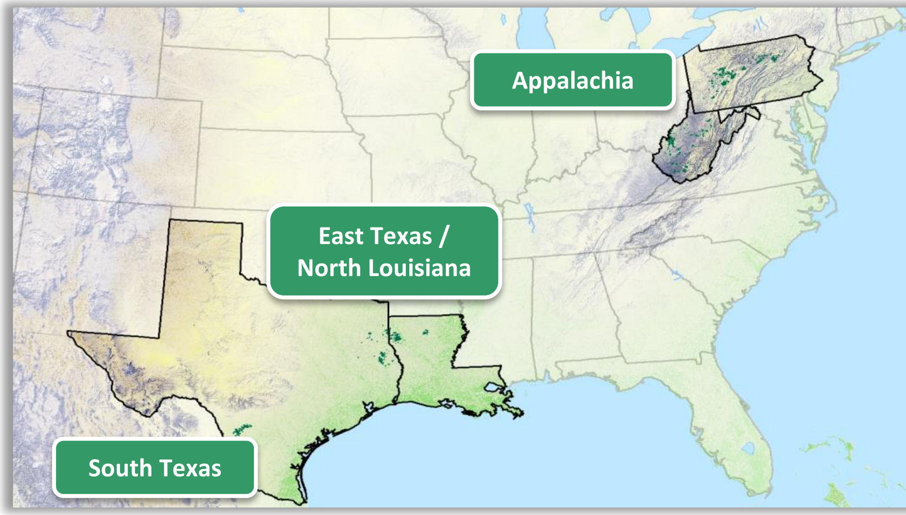
Focus Area	#	Improvement Plan	Update
Liability Management	1	Restructure balance sheet to enhance capital structure and extend structural liquidity	• Senior secured 1.5 lien notes and senior secured 1.75 lien term loans provide option, at EXCO's discretion, subject to certain limitations, to pay interest in cash, additional indebtedness, or common shares • Issued 2.7 million common shares to pay interest on the 1.75 Lien Term Loans in lieu of $23 million in cash • The ability to pay interest in common shares may be limited in the future due to the decline in the Company's share price • Liquidity was $170 million as of June 30, 2017; borrowed $50 million during the months of July and August • Evaluating restructuring options, which may include an in-court or out-of-court restructuring, focusing on establishing a sustainable capital structure that provides liquidity necessary to execute business plan
Operational Performance	2	Transform into lowest cost producer	• Adjusted general and administrative expenses, a non-GAAP measure, decreased 11% for second quarter 2017 compared to the same period in 2016 • Cost reduction efforts have resulted in a decrease in total employee headcount of approximately 36% since second quarter 2016 • Drilled 2^{nd} and 3^{rd} fastest Haynesville wells to date at 22 and 24 days • Extended lateral length wells provide improved cost per lateral foot metrics compared to standard well designs • Wells completed during 2017 have higher fracture intensity, utilizing 3,500 lbs of proppant per lateral foot and tighter cluster spacing
Capital Deployment	3	Optimize and reposition portfolio	• Continuing to execute disciplined capital allocation program to ensure the highest and best use of capital • Entered into definitive agreement to divest oil and natural gas properties in South Texas for $300 million, subject to closing conditions and adjustments; closing date of the divestiture was extended to August 15, 2017, subject to the satisfaction of certain conditions, which include terms that are acceptable to the buyer in its sole discretion • Acquired $19 million of core North Louisiana natural gas properties and undeveloped acreage • Maintain capital discipline despite increased service costs

EXCO Overview: Three Concentrated Resource Positions

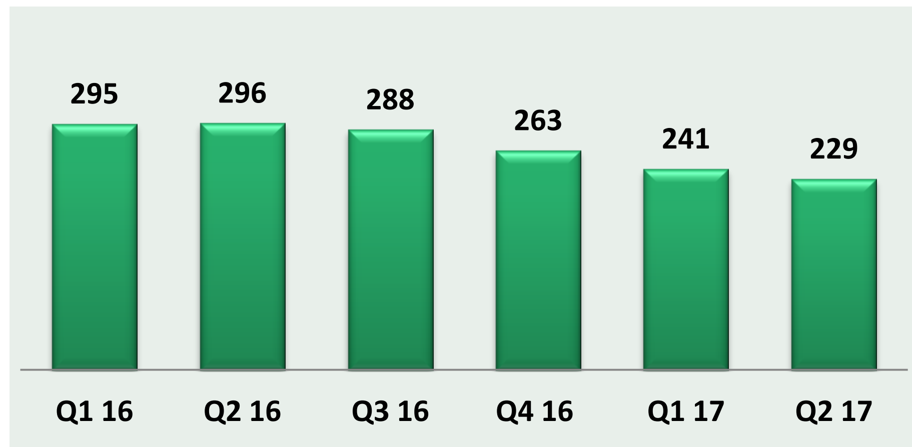
Operating Area Overview 1

East Texas and North Louisiana	
Net Acres/%HBP[1]	96,300/87%
Q2 '17 Operated Rigs	4
Q2 '17 Net Production (Mmcfe/d)	177
12/31/16 Proved Reserves (Bcfe)[2]	1,110
South Texas	
Net Acres/% HBP[1]	49,300/95%
Q2 '17 Operated Rigs	0
Q2 '17 Net Production (Boe/d)	3,700
12/31/16 Proved Reserves (Bcfe)[2]	155
Appalachia	
Net Acres/% HBP[1]	184,100/93%
Q2 '17 Operated Rigs	0
Q2 '17 Net Production (Mmcfe/d)	29
12/31/16 Proved Reserves (Bcfe)[2]	238
Total	
Net Acres/% HBP[1]	329,700/92%
Q2 '17 Operated Rigs	4
Q2 '17 Net Production (Mmcfe/d)	229
12/31/16 Proved Reserves (Bcfe)[2]	1,503

Core Basins 2



Net Production 16-17; Mmcfe/d 3



1. As of December 31, 2016
2. Proved reserves were based on December 30, 2016 NYMEX futures prices, in each case adjusted for geographical and historical differentials, and other assumptions used in the preparation of year end proved reserves. The NYMEX proved reserves disclosed differ from proved reserves that would be prepared based on the methodology prescribed by GAAP primarily due to the oil and natural gas prices and the development plans utilized in the classification of undeveloped locations. This measure should not be purported to be in accordance with GAAP nor is it indicative of the Company's proved reserves if they were prepared in accordance with GAAP

2017 Capital Budget

Capital Program Overview
17; Mixed Measures — 1

Category	Descriptions
Drilling	• Currently running 4 rigs • Drilling focused in NLA Haynesville for highest economic returns • Appraising Bossier shale in NLA
Completion	• 3,500 lb/ft completion design with higher fracture intensity on new wells • Program includes 4,500 to 10,000 ft laterals • Maintain capital discipline despite increased service costs
Non-Operated Activity	• Haynesville non-op activity is moving higher (8x 2016 level) • ETX appraisal will continue in 2017 through participation in certain wells in the Shelby area • Appraising Bossier shale in ETX
Land	• Land investment supports the 2017 drilling plans • Gain additional interests with non-consent election in certain wells

Capital Budget By Type
17; $MM — 2

Category	
Drilling and Completion[1]	138
Field Operations	2
Land	7
Corporate & Other[2]	11
Total	158

Drilling and Completion[3]
17; # — 3

Area	Gross Spuds	Net Spuds	Gross Completions	Net Completions
North LA	36	17.8	18	10.1

2017 program with 4 rigs focused on North LA to deliver highest returns in portfolio; spud 36 gross (17.8 net) EXCO operated wells

1. Includes $113 million of operated and $25 million of non-operated drilling and completion costs
2. Includes $5 million of capitalized interest and $4 million of capitalized general and administrative expenses
3. EXCO operated

High Quality Drilling Inventory

Drilling Inventory
Breakeven Price Required for 25% IRR ($/Mcf)[1]; Gross/Net Locations

1

Note: Breakeven figures are wellhead returns

Increases in service costs have recently eroded some of our wellhead returns, however, the inventory of high quality locations provides EXCO a multi-year drilling inventory

1. Breakeven figures are wellhead returns

Financial and Operational Results

Factors	Unit	Quarter-to-Date					Year-to-Date		
		2Q 17	1Q 17		2Q 16		2Q 17	2Q 16	
		Actual	Actual	% Change	Actual	% Change	Actual	Actual	% Change
Rig Count	#	4	1	300	1	300	3	1	200
Gross/Net Wells Drilled	#	11/4.8	4/3.5	37	1/0.9	433	15/8.3	6/5.2	60
Gross/Net Wells Turned to Sales	#	4/3.5	0/0.0	100	3/2.5	40	4/3.5	11/6.1	(43)
Production									
Oil	Mbbl	303	331	(8)	447	(32)	634	997	(36)
Natural Gas	Bcf	19.1	19.7	(3)	24.3	(21)	38.8	47.8	(19)
Total	Bcfe	20.9	21.7	(4)	27.0	(23)	42.6	53.8	(21)
Total Daily	Mmcfe/d	229	241	(5)	296	(23)	235	296	(21)
Realized Price Differentials									
Oil	$/Bbl	(1.41)	(2.91)	(52)	(5.04)	(72)	(2.19)	(5.15)	(57)
Natural Gas	$/Mcf	(0.56)	(0.63)	(11)	(0.46)	22	(0.59)	(0.50)	18
Financial Results									
Lease Operating Expense	$/Mcfe	0.39	0.39	-	0.28	39	0.39	0.32	22
Production Taxes	$/Mcfe	0.16	0.16	-	0.18	(11)	0.16	0.18	(11)
Gathering and Transportation	$/Mcfe	1.30	1.26	3	0.99	31	1.28	0.96	33
General and Administrative[1]	$MM	7	7	-	8	(13)	13	15	(13)
Cash Interest Expense[2]	$MM	3	15	(80)	17	(82)	18	35	(49)
Adj. EBITDA[3]	$MM	18	18	-	23	(22)	37	44	(16)
Capital Expenditures	$MM	40	18	122	19	111	58	56	4

1. Excludes equity based compensation. General and Administrative is a non-GAAP measure. See appendix for definition and reconciliation
2. Cash interest expenses exclude interest paid or accrued in-kind, the amortization of debt issuance costs, discount on notes and capitalized interest. In addition, cash payments under the second lien term loan ("Exchange Term Loan") and a portion of the 1.75 Lien Term Loans are not considered interest expense per FASB ASC 470-60, Troubled Debt Restructuring by Debtors ("ASC 470-60") and are excluded from the cash interest expenses amounts shown
3. Adjusted EBITDA is a non-GAAP measure. See appendix for definition and reconciliation

Actuals to Guidance Comparison

Factors	Unit	Three Months Ended				
		2Q 17	2Q 17 Guidance[3]		3Q 17 Guidance[3]	
		Actual	Low	High	Low	High
Wells Spud (Gross/Net)	#	11/4.8	11/3.9		11/5.3	
Wells Turned to Sales (Gross/Net)	#	4/3.5	4/3.5		0/0.0	
Production						
Oil	Mbbl	303	200	220	175	195
Natural Gas	Bcf	19.1	18.4	19.2	19.2	20.0
Total	Bcfe	20.9	19.6	20.5	20.2	21.2
Total Daily	Mmcfe/d	229	215	225	220	230
Realized Price Differentials						
Oil	$/Bbl	(1.41)	(3.00)	(4.00)	(2.00)	(3.00)
Natural Gas	$/Mcf	(0.56)	(0.50)	(0.60)	(0.55)	(0.65)
Financial Results						
Lease Operating Expense	$/Mcfe	0.39	0.35	0.40	0.35	0.40
Production Taxes	$/Mcfe	0.16	0.15	0.20	0.15	0.20
Gathering and Transportation	$/Mcfe	1.30	1.25	1.30	1.25	1.30
General and Administrative[1]	$MM	7	6	7	7	8
Cash Interest Expense[2]	$MM	3	12	16	3	5

1. **Excludes equity based compensation. General and Administrative is a non-GAAP measure. See appendix for definition and reconciliation**
2. Interest expenses exclude interest paid or accrued in-kind, the amortization of debt issuance costs, discount on notes and capitalized interest. In addition, cash payments under the Exchange Term Loan and a portion of the 1.75 Lien Term Loans are not considered interest expense per FASB ASC 470-60 and are excluded from the cash interest expenses amounts shown
3. Assumes South Texas divestiture occurring on June 1, 2017 for 2Q and September 1, 2017 for 3Q

Appendix

Hedge Positions

Factors	Unit	Six Months Ended 12/31/17		Twelve Months Ended 12/31/18	
		Volume	Price	Volume	Price
Natural Gas					
Fixed Price Swaps - Henry Hub	Bbtu, $/Mmbtu	18,400	3.05	3,650	3.15
Collars - Henry Hub	Bbtu	5,520			
Sold Call Options	$/Mmbtu		3.28		
Purchased Put Options	$/Mmbtu		2.87		
Oil					
Fixed Price Swaps - WTI	Mbbl, $/Bbl	92	50.00	-	-
Percent Hedged[1]					
Natural Gas	%	78		8	
Oil	%	16		-	

1. Percent hedged based on PDP production forecast

Single Well Economics – Internal Type Curves

		Unit	NLA DeSoto Core	NLA Caddo X-Unit Lateral	NLA Caddo Standard Lateral	NLA Bossier X-Unit Lateral	ETX Shelby HSVL	ETX Highlander HSVL	ETX Highlander BSSR
1	Target Lateral Length	Ft	4,500	7,500	4,500	7,500	7,500	6,500	6,500
2	Gross Locations	#	17	45	24	167	63	57	65
3	Net Locations	#	6	11	10	84	25	13	17
4	WI	%	37	24	42	50	39	23	26
5	NRI	%	29	19	32	39	31	18	20
6	Spacing	Acres	136	227	136	227	241	221	223
	Type Curve								
7	IP	Mcf/d	14,000	17,600	13,200	10,900	9,300	11,500	9,500
8	Phase I – Duration Month	Month	16	16	16	12	12	18	16
9	Phase I – B Factor	x	0	0	0	0	0	0	0
10	Phase I – Initial Decline	%	50	40	52	41	22	22	22
11	Phase II – Duration Month	Month	10	10	10	14	15	54	56
12	Phase II – B Factor	x	0.6	0.6	0.6	0.6	0.6	0.6	0.6
13	Phase II – Initial Decline	%	51	52	51	37	42	42	41
14	Phase III – Duration Month	Month	16	16	16	16	9	24	24
15	Phase III – B Factor	x	1	1	1	1	1	1	1
16	Phase III – Initial Decline	%	42	42	42	37	39	25	25
17	Phase IV – Initial Decline	%	32	32	32	26	36	22	22
18	Terminal Decline	%	6	6	6	6	6	6	6
19	Wellhead EUR	Bcf	9.9	14.9	8.9	12	11.3	14.1	11.7
20	EUR per 1,000' (lateral length)	Bcf	2.2	1.98	1.98	1.6	1.5	2.2	1.8
21	D&C	$MM	7.7	10.6	7.7	12.8	10.6	11.1	10.7
22	LOE Fixed	$/month	1,770	1,770	1,770	1,770	3,034	2,690	2,690
23	Variable/Gathering Expense	$/mcf	.05/.47	.05/.47	.05/.47	.06/.47	0.08/0.29	0.06/0.31	0.06/0.31
	Single Well Returns								
24	PV10 (8/8ths)[1]	$MM	4.4	7.3	3.2	0.4	2.5	5.8	3.1
25	IRR[1]	%	54	59	40	12	21	37	24
26	Breakeven Flat Price (25%)	$/MMBTU	2.52	2.42	2.70	3.58	3.10	2.66	3.08
27	PV/I, Disc[1]	X	1.57	1.69	1.42	1.03	1.24	1.52	1.29

1. Economics based on flat $3.00 per MMBtu

Non-GAAP Measures and Reconciliations

Consolidated EBITDA and Adjusted EBITDA Reconciliations

(in thousands)	Three Months Ended June 30, 2017	Three Months Ended March 31, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Net income (loss)	$ 120,750	$ 8,193	$ (111,347)	$ 128,943	$ (241,495)
Interest expense	22,480	19,952	17,932	42,432	37,189
Income tax expense	1,027	1,028	747	2,055	747
Depletion, depreciation and amortization	11,622	11,508	19,084	23,130	48,085
EBITDA (1)	$ 155,879	$ 40,681	$ (73,584)	$ 196,560	$ (155,474)
Accretion of discount on asset retirement obligations	215	212	769	427	1,681
Impairment of oil and natural gas properties	—	—	26,214	—	160,813
Other items impacting comparability	300	—	24,296	300	24,698
(Gain) loss on restructuring and extinguishment of debt	108	6,272	(16,839)	6,380	(61,953)
Equity (income) loss	(338)	(317)	91	(655)	8,001
(Gain) loss on derivative financial instruments - commodity derivatives	(6,541)	(15,533)	36,432	(22,074)	19,841
Cash receipts (payments) of commodity derivative financial instruments	(1,099)	(4,459)	16,598	(5,558)	33,388
Gain on derivative financial instruments - common share warrants	(122,295)	(6,004)	—	(128,299)	—
Equity-based compensation	(7,959)	(2,382)	9,328	(10,341)	13,141
Adjusted EBITDA (1)	$ 18,270	$ 18,470	$ 23,305	$ 36,740	$ 44,136
Interest expense	(22,480)	(19,952)	(17,932)	(42,432)	(37,189)
Current income tax expense	—	—	—	—	—
Amortization of deferred financing costs and discount	7,035	4,402	1,878	11,437	4,999
Paid in-kind interest expense	15,914	—	—	15,914	—
Other operating items impacting comparability and non-operating items	(18)	(21)	875	(39)	453
Changes in working capital	9,684	2,297	9,818	11,981	33,526
Net cash provided by operating activities	$ 28,405	$ 5,196	$ 17,944	$ 33,601	$ 45,925

1. Earnings before interest, taxes, depreciation, depletion and amortization ("EBITDA") represents net income (loss) adjusted to exclude interest expense, income taxes and depreciation, depletion and amortization. "Adjusted EBITDA" represents EBITDA adjusted to exclude accretion of discount on asset retirement obligations, non-cash changes in the fair value of derivative financial instruments, non-cash impairments of assets, equity-based compensation, income or losses from equity investments and other operating items impacting comparability.

   EXCO has presented EBITDA and Adjusted EBITDA because they are measures widely used by investors, analysts and rating agencies for valuations, peer comparisons and investment recommendations. In addition, similar measures are used in covenant calculations required under the Credit Agreement, the indenture governing the 1.5 Lien Notes, the indenture governing the 2018 Notes, the indenture governing the senior unsecured notes due April 15, 2022 ("2022 Notes") and the term loan credit agreement governing the 1.75 Lien Term Loans. Compliance with the liquidity and debt incurrence covenants included in these agreements is considered material to the Company. EXCO's computations of EBITDA and Adjusted EBITDA may differ from computations of similarly titled measures of other companies due to differences in the inclusion or exclusion of items in the Company's computations as compared to those of others. EBITDA and Adjusted EBITDA are measures that are not prescribed by GAAP. EBITDA and Adjusted EBITDA specifically exclude changes in working capital, capital expenditures and other items that are set forth on a cash flow statement presentation of the Company's operating, investing and financing activities. As such, investors are encouraged not to use these measures as substitutes for the determination of net income, net cash provided by operating activities or other similar GAAP measures. The calculation of EBITDA and Adjusted EBITDA as presented herein differ in certain respects from the calculation of comparable measures in the Credit Agreement, the indentures and the term loan credit agreement.

Adjusted General and Administrative Expenses Reconciliations

(in thousands)	Three Months Ended June 30, 2017	Three Months Ended March 31, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
General and administrative, GAAP	$ (1,394)	$ 4,415	$ 16,983	$ 3,021	$ 27,880
Less: Equity-based compensation	7,959	2,382	(9,328)	10,341	(13,141)
Less: Restructuring and severance costs	(208)	(775)	(501)	(983)	988
Adjusted general and administrative, non-GAAP measure	$ 6,357	$ 6,022	$ 7,154	$ 12,379	$ 15,727

1. The Company believes this non-GAAP measure is used by investors, analysts and management for valuations, peer comparisons and other recommendations. The exclusion of equity-based compensation is important to users that are evaluating the impact of the Company's cash-based general and administrative costs on its credit metrics and ability to service its indebtedness. In addition, the exclusion of cash-based costs, such as restructuring and severance, assists in the comparability between periods and similar measures are used in debt covenant calculations required under certain of the Company's debt agreements. Restructuring costs include legal and advisory costs incurred in connection with the Company's strategic initiative focused on restructuring its balance sheet and gathering and transportation contracts, and severance costs relate primarily to the Company's reductions in workforce.

Forward Looking Statements

This presentation contains forward-looking statements, as defined in Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. These forward-looking statements relate to, among other things, the following:

- future financial and operating performance and results;
- business strategy;
- market prices;
- future use of derivative financial instruments; and
- plans and forecasts.

The Company based these forward-looking statements on current assumptions, expectations and projections about future events.

The Company uses the words “may,” “expect,” “anticipate,” “estimate,” “believe,” “continue,” “intend,” “plan,” “potential,” "project," “budget” and other similar words to identify forward-looking statements. The statements that contain these words should be read carefully because they discuss future expectations, contain projections of results of operations or financial condition and/or state other “forward-looking” information. The Company does not undertake any obligation to update or revise any forward-looking statements, except as required by applicable securities laws. These statements also involve risks and uncertainties that could cause actual results or financial condition to materially differ from expectations in this presentation, including, but not limited to:

- our ability to continue as a going concern;
- cash flow and Liquidity;
- our ability and decisions to pay interest on the 1.5 Lien Notes and 1.75 Lien Term Loans in cash, common shares or additional indebtedness;
- future capital requirements and availability of financing, including limitations on our ability to incur certain types of indebtedness under our debt agreements and to refinance or replace existing debt obligations as they mature;
- our ability to meet our current and future debt service obligations, including our upcoming 2018 debt maturities;
- our ability to maintain compliance with our debt covenants;
- fluctuations in the prices of oil and natural gas;
- the availability of oil and natural gas;
- disruption of credit and capital markets and the ability of financial institutions to honor their commitments;
- estimates of reserves and economic assumptions, including estimates related to acquisitions and dispositions of oil and natural gas properties;
- geological concentration of our reserves;
- risks associated with drilling and operating wells;
- exploratory risks, including those related to our activities in shale formations;
- discovery, acquisition, development and replacement of oil and natural gas reserves;
- outcome of divestitures of non-core assets, including the potential sale of our assets in the South Texas region;
- our ability to enter into transactions as a result of our credit rating, including commodity derivatives with financial institutions and services with vendors;
- timing and amount of future production of oil and natural gas;
- availability of drilling and production equipment;
- availability of water, sand and other materials for drilling and completion activities;
- marketing of oil and natural gas;
- political and economic conditions and events in oil-producing and natural gas-producing countries;
- title to our properties;
- litigation;
- competition;
- our ability to attract and retain key personnel;
- general economic conditions, including costs associated with drilling and operations of our properties;
- our ability to comply with the listing requirements of, and maintain the listing of our common shares on, the New York Stock Exchange;
- environmental or other governmental regulations, including legislation to reduce emissions of greenhouse gases legislation of derivative financial instruments, regulation of hydraulic fracture stimulation and elimination of income tax incentives available to our industry;
- receipt and collectability of amounts owed to us by purchasers of our production and counterparties to our commodity derivative financial instruments;
- decisions whether or not to enter into commodity derivative financial instruments;
- potential acts of terrorism;
- our ability to manage joint ventures with third parties, including the resolution of any material disagreements and our partners’ ability to satisfy obligations under these arrangements;
- actions of third party co-owners of interests in properties in which we also own an interest;
- fluctuations in interest rates;
- our ability to effectively integrate companies and properties that we acquire; and
- our ability to execute our business strategies and other corporate actions.

It is important to communicate expectations of future performance to investors. However, events may occur in the future that EXCO is unable to accurately predict, or over which EXCO has no control. Users of the financial statements are cautioned not to place undue reliance on any forward-looking statements. When considering EXCO's forward-looking statements, investors are urged to read the cautionary statements and the risk factors included in EXCO's Annual Report on Form 10-K for the year ended December 31, 2016, filed with the Securities and Exchange Commission ("SEC") on March 16, 2017 and its other periodic filings with the SEC.

Any number of factors could cause actual results to differ materially from those in EXCO's forward-looking statements, including, but not limited to, the volatility of oil and natural gas prices, future capital requirements and the availability of capital and financing, uncertainties about reserve estimates, the outcome of future drilling activity, environmental risks and regulatory changes. Revenues, operating results and financial condition substantially depend on prevailing prices for oil and natural gas and the availability of capital from our credit agreement. Declines in oil or natural gas prices may have a material adverse effect on financial condition, liquidity, results of operations, the amount of oil or natural gas that we can produce economically and the ability to fund operations. Historically, oil and natural gas prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile. EXCO undertakes no obligation to publicly update or revise any forward-looking statements.