


EXCO EXCO Resources, Inc.

4th Quarter and Full Year 2007 Review

February 2008



Management Participants



Doug Miller	Chairman and CEO
Steve Smith	Vice Chairman and President
Doug Ramsey	Vice President and CFO
Hal Hickey	Vice President and COO
Mark Wilson	Vice President and CAO
Paul Rudnicki	Vice President

Forward Looking Statements



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

- our future financial and operating performance and results;
- our business strategy;
- market prices;
- our future commodity price risk management activities; and
- our plans and forecasts.

We have based these forward-looking statements on our current assumptions, expectations and projections about future events.

We use the words "may," "expect," "anticipate," "estimate," "believe," "continue," "intend," "plan," "budget" and other similar words to identify forward-looking statements. You should read statements that contain these words carefully because they discuss future expectations, contain projections of results of operations or of our financial condition and/or state other "forward-looking" information. We do not undertake any obligation to update or revise publicly any forward-looking statements, except as required by law. These statements also involve risks and uncertainties that could cause our actual results or financial condition to materially differ from our expectations in this presentation, including, but not limited to:

- fluctuations in prices of oil and natural gas;
- imports of foreign oil and natural gas, including liquefied natural gas;
- future capital requirements and availability of financing;
- estimates of reserves and economic assumptions used in connection with our acquisitions;
- geological concentration of our reserves;
- risks associated with drilling and operating wells;
- risks associated with operation of natural gas pipelines and gathering systems;
- discovery, acquisition, development and replacement of oil and natural gas reserves;
- cash flow and liquidity;
- impact of our private placement of preferred stock and the impact of dividends on our capital resources and liquidity;
- timing and amount of future production of oil and natural gas;
- availability of drilling and production equipment;
- marketing of oil and natural gas;
- developments in oil-producing and natural gas-producing countries;
- title to our properties;
- competition;
- litigation;
- general economic conditions, including costs associated with drilling and operation of our properties;
- governmental regulations;
- receipt of amounts owed to us by purchasers of our production and counterparties to our derivative financial instruments;
- deciding whether or not to enter into derivative financial instruments;
- events similar to those of September 11, 2001;
- actions of third party co-owners of interests in properties in which we also own an interest;
- fluctuations in interest rates; and
- our ability to effectively integrate companies and properties that we acquire.

Forward Looking Statements (continued)



We believe that it is important to communicate our expectations of future performance to our investors. However, events may occur in the future that we are unable to accurately predict, or over which we have no control. You are cautioned not to place undue reliance on a forward-looking statement. When considering our forward-looking statements, keep in mind the risk factors and other cautionary statements in this presentation, and the risk factors included in the Annual Reports on Form 10-K and our Quarterly Reports on Form 10-Q.

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for oil and natural gas. Declines in oil or natural gas prices may materially adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower oil or natural gas prices also may reduce the amount of oil or natural gas that we can produce economically. A decline in oil and/or natural gas prices could have a material adverse effect on the estimated value and estimated quantities of our oil and natural gas reserves, our ability to fund our operations and our financial condition, cash flow, results of operations and access to capital. Historically, oil and natural gas prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile.

The SEC has generally permitted oil and natural gas companies, in filings made with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. We use the terms “probable”, “possible”, “potential” or “unproved” to describe volumes of reserves potentially recoverable through additional drilling or recovery techniques that the SEC’s guidelines prohibit us from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being actually realized by the company. While we believe our calculations of unproved drillsites and estimation of unproved reserves have been appropriately risked and are reasonable, such calculations and estimates have not been reviewed by third party engineers or appraisers. Investors are urged to consider closely the disclosure in our Annual Report on Form 10-K for the year ended December 31, 2006 available on our website at www.excoresources.com under the Investor Relations tab or by calling us at 214-368-2084. Our Annual Report on Form 10-K for the year ended December 31, 2007 will be available on our website on or about February 29, 2008.

Financial Review

Steve Smith



2007 Corporate Highlights

- **Significant growth in all financial and operational metrics:**

	2006	2007
Adjusted EBITDA ⁽¹⁾ , millions	\$ 287	\$ 766
Cash flow from operations ⁽¹⁾⁽²⁾ , millions	\$ 206	\$ 614
Production, Mmcf/d	136	332
Proved Reserves, Tcfe	1.2	1.9

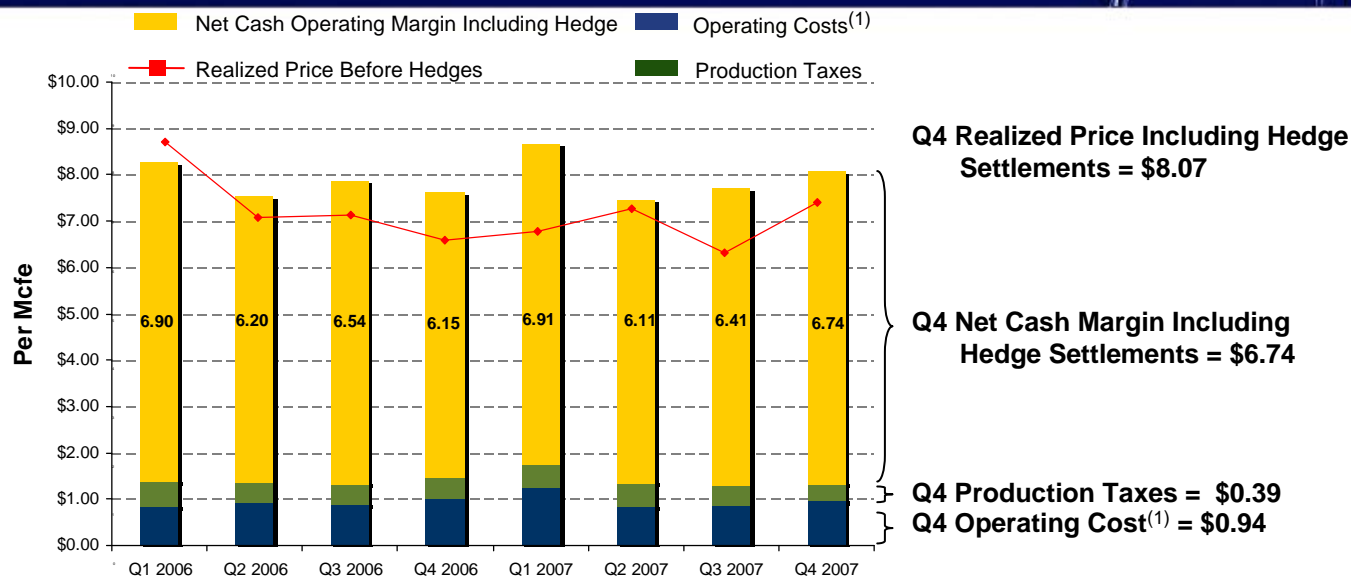
- **Significant growth in low-risk upside:**

	2006	2007
PUD, Prob, Poss Reserves, Tcfe	1.2	2.9
Drillable locations	5,100	10,000+

- **Identified 4.4 Tcfe of potential, including our original estimate of 2.6 Tcfe in the Marcellus Shale**
- **Total Marcellus Shale potential of our acreage, based on recent industry results, could significantly exceed our original estimates**
- **Closed nearly \$2.5 billion of acquisitions, while selling approximately \$500 million of properties**
- **Consolidated 2006 and 2007 acquisitions; hired over 300 new employees during 2007 to fully exploit our entire asset base**
- **Expect at least a 17% increase in average daily production between 2007 and 2008**

(1) Non-GAAP measures, please see tables on slides 24 to 26 for reconciliations to most comparable GAAP measures
 (2) Cash flow from operations before changes in working capital

Performance Highlights



Financial Highlights (in thousands)	Q4 2007		Full Year 2007	
	Amount	Per Share	Amount	Per Share
Adjusted Net Income Available to Common Stockholders ⁽²⁾	\$ 8,999	\$ 0.08	\$ (4,202)	\$ (0.04)
Adjusted EBITDA ⁽²⁾	\$ 227,489	\$ 1.07 ⁽⁴⁾	\$ 765,638	\$ 3.61 ⁽⁵⁾
Cash Flow From Operations ⁽²⁾⁽³⁾	\$ 198,352	\$ 0.94 ⁽⁴⁾	\$ 613,968	\$ 2.89 ⁽⁵⁾

Operational Highlights (dollars in thousands)		
Production – (Q4 2006/Q4 2007)	199 Mmcf/d	377 Mmcf/d
Midstream & Marketing – (Q4 2007 Throughput/Cashflow)	424 Mmcf/d	\$ 5,621

(1) Does not include non-cash stock based compensation costs of \$0.06 per Mcfe for Q4 2007

(2) Non-GAAP measures, please see tables on slides 24 to 26 for reconciliations to most comparable GAAP measures

(3) Cash flow from operations before changes in working capital

(4) Calculated using 106,532,360 fully diluted shares plus an additional 105,253,158 shares for conversion of the preferred stock

(5) Calculated using 106,983,614 fully diluted shares plus an additional 105,253,158 shares for conversion of the preferred stock

Year End Total Proved Reserves



Year-end 2007 SEC Proved Reserves ⁽¹⁾	1,865
Price Revisions to \$8 gas and \$60 oil ⁽²⁾	<u>37</u>
Year-end 2007 Proved Reserves	1,902

- Year-end reserves were 93% natural gas and 71% proved developed

	2007	3 Year
Reserve Replacement:		
All-in ⁽³⁾	781%	956%
Drill-bit only ⁽⁴⁾	159%	164%
Reserve Replacement Cost:		
All-in ⁽³⁾	\$ 2.96	\$ 2.44
Drill-bit only ⁽⁴⁾	\$ 2.31	\$ 2.18

- (1) As of December 31, 2007 SEC pricing of \$6.80 for natural gas and \$95.92 for oil without the effects of commodity derivatives and adjusted for historical differentials
- (2) From December 31, 2007 SEC pricing to \$8.00 natural gas and \$60.00 oil without the effects of commodity derivatives and adjusted for historical differentials. This price case is presented because it is used for internal planning purposes and financial guidance
- (3) All-in reserve replacement is calculated using extensions and discoveries, acquisitions and revisions. Total revisions were 79.8 Bcfe consisting of 139.3 Bcfe of negative performance revisions offset by positive revisions of 59.5 Bcfe due to price increases. Costs include drilling and development and acquisitions of proved properties
- (4) Drill-bit only reserve replacement is calculated using extensions and discoveries. Costs include drilling and development costs

Liquidity and Financial Position

(In thousands)	December 31, 2007	February 20, 2008
Cash	\$ 55,510	\$ 29,749
Bank debt (LIBOR + 125-150bps)	\$ 1,643,500	\$ 1,993,500
Senior notes (7 1/4%) ⁽¹⁾	<u>444,720</u>	<u>444,720</u>
Total debt	\$ 2,088,220	\$ 2,438,220
7% convertible preferred ⁽²⁾	\$ 2,000,000	
Common shareholders' equity	<u>1,115,742</u>	
Total capitalization	\$ 5,203,962	
Net debt to total capitalization	39%	
Borrowing base	\$ 2,200,000	\$ 2,475,000
Unused borrowing base ⁽³⁾	\$ 552,205	\$ 477,205

- Recently entered into \$700 million of interest rate swaps
 - Swapped at an average 2.66% LIBOR from February 2008 to February 2010

(1) Excludes unamortized bond premium

(2) Excludes \$7 million in offering costs

(3) Net of \$4.3 million in letters of credit at both December 31, 2007 and February 20, 2008

Current Hedge Position

As of December 31, 2007, including all trading activity through February 22, 2008

NYMEX Swaps	Gas Mmcf	Contract price per Mmcf	Oil Mbbls	Contract price per Bbl	Percent Hedged⁽¹⁾
Q1 2008	25,485	\$ 8.59	355	\$ 68.27	79%
Q2 2008	26,685	8.27	355	68.23	80%
Q3 2008	26,910	8.29	358	68.20	79%
Q4 2008	26,910	8.39	358	68.16	77%
2009	95,055	8.09	1,215	69.11	68%
2010	37,098	7.94	473	84.85	26%
2011	1,825	4.51	-	-	1%
2012	1,830	4.51	-	-	1%
2013	1,825	4.51	-	-	1%
Total	243,623	\$ 8.11	3,114	\$ 71.09	
Total of 262,307 Mmcf Hedged at \$8.38					

- Target hedging 65-80% of production volumes for 3-5 years
- Hedging program covers long term debt
- Only 14% of Proved Reserves hedged

(1) Based on 2008 production guidance

2008 Guidance

(\$ in thousands, except per unit amounts)	2008E	
	Low	High
<u>Production:</u>		
Oil – Mbbls	1,980	2,020
Gas - Mmcf	131,900	135,000
Mmcf	143,800	147,100
Per day - Mmcf	393	402
<u>Differentials to NYMEX:</u>		
Oil per Bbl	(\$3.75)	(\$3.50)
Gas per Mcf	93%	97%
Lease operating expense	\$129,100	\$141,100
Stock based compensation - LOE	\$4,640	\$6,540
Production tax rate	6.5%	7.5%
Interest income	\$1,000	\$2,000
Midstream income	\$34,600	\$36,600
Depletion rate per Mcfe	\$3.05	\$3.15
Depreciation rate per Mcfe	\$0.13	\$0.23
Asset retirement obligation	\$6,180	\$7,180
Cash G&A ⁽¹⁾	\$66,400	\$71,400
Non-cash stock comp	\$10,380	\$15,380
Interest expense	\$124,800	\$132,800
Tax rate	40%	40%
Cash tax rate	0%	0%
Preferred dividends	\$140,000	\$140,000
Adjusted EBITDA at Midpoint ⁽²⁾	\$933,600	

(1) Includes \$3.5 million to \$4.5 million of costs related to the withdrawal of the EXCO Partners IPO in Q1 2008

(2) 2008 estimate based on NYMEX \$8.00 natural gas and \$60.00 oil

Quarterly 2008 Guidance

(\$ in thousands, except per unit amounts)	1 st Q 2008E		2 nd Q 2008E		3 rd Q 2008E		4 th Q 2008E	
	Low	High	Low	High	Low	High	Low	High
<u>Production:</u>								
Oil - Mbbls	480	490	490	500	500	510	510	520
Gas - Mmcf	31,800	32,300	32,600	33,400	33,300	34,200	34,200	35,100
Mmcfe	34,700	35,200	35,500	36,400	36,300	37,300	37,300	38,200
Per day - Mmcfe	381	387	390	400	395	405	405	415
<u>Differentials to NYMEX:</u>								
Oil per Bbl	(\$3.75)	(\$3.50)	(\$3.75)	(\$3.50)	(\$3.75)	(\$3.50)	(\$3.75)	(\$3.50)
Gas per Mcf	93%	97%	93%	97%	93%	97%	93%	97%
Lease operating expense	\$31,500	\$34,500	\$32,200	\$35,200	\$32,700	\$35,700	\$32,700	\$35,700
Stock based compensation – LOE	\$750	\$1,250	\$750	\$1,250	\$750	\$1,250	\$2,390	\$2,790
Production tax rate	6.5%	7.5%	6.5%	7.5%	6.5%	7.5%	6.5%	7.5%
Interest income	\$250	\$500	\$250	\$500	\$250	\$500	\$250	\$500
Midstream income	\$7,100	\$7,600	\$7,500	\$8,000	\$10,000	\$10,500	\$10,000	\$10,500
Depletion rate per Mcfe	\$3.05	\$3.15	\$3.05	\$3.15	\$3.05	\$3.15	\$3.05	\$3.15
Depreciation rate per Mcfe	\$0.10	\$0.20	\$0.10	\$0.20	\$0.15	\$0.25	\$0.15	\$0.25
Asset retirement obligation	\$1,545	\$1,795	\$1,545	\$1,795	\$1,545	\$1,795	\$1,545	\$1,795
Cash G&A ⁽¹⁾	\$18,600	\$20,600	\$15,700	\$16,700	\$15,800	\$16,800	\$16,300	\$17,300
Non-cash stock comp	\$2,170	\$3,170	\$2,070	\$3,070	\$2,070	\$3,070	\$4,070	\$6,070
Interest expense	\$29,400	\$31,400	\$31,800	\$33,800	\$31,800	\$33,800	\$31,800	\$33,800
Tax rate	40%	40%	40%	40%	40%	40%	40%	40%
Cash tax rate	0%	0%	0%	0%	0%	0%	0%	0%
Preferred dividends	\$35,000	\$35,000	\$35,000	\$35,000	\$35,000	\$35,000	\$35,000	\$35,000
Adjusted EBITDA at Midpoint ⁽²⁾	\$225,100		\$227,600		\$235,900		\$245,000	

(1) Includes \$3.5 million to \$4.5 million of costs related to the withdrawal of the EXCO Partners IPO in Q1 2008

(2) 2008 estimate based on NYMEX \$8.00 natural gas and \$60.00 oil

EXCO EXCO Resources, Inc.

Operational Review

Hal Hickey



Operational Highlights

4th Quarter 2007 and early 2008



- **East Texas / North Louisiana**

- Vernon
 - Drilled and completed 10 wells with average IP of 6.5 Mmcfe/d (gross)
 - Last completion had highest rate since EXCO acquisition – 10.3 Mmcfe/d (gross)
 - Expanded southern and western field limits, establishing additional drilling locations
- Holly / Caspiana
 - Five recent completions averaging in excess of 1.4 Mmcfe/d (gross)
- Gladewater
 - Two recent completions averaging in excess of 1.0 Mmcfe/d (gross)
- Overton
 - Two recent completions averaging in excess of 1.6 Mmcfe/d (gross)
- Overall, rig spud to release days down 20%; drill and complete costs down 10%

- **Midstream**

- Initiated 57-mile, \$37.6 million expansion of TGG pipeline to increase throughput by an incremental 100 Mmcfe/d

Operational Highlights

4th Quarter 2007 and early 2008



- **Permian**

- Sugg Ranch

- Increased rig count to three and increased net production from 19.7 on November 1, 2007 to 23.8 Mmcfe/d on February 5, 2008 (includes oil growth of 402 BOPD)
 - Expanding acreage position through leasing

- **Rockies**

- Drilled and logged Birdseye well in Wind River Basin, earning 3,400 gross acres thereby increasing prospect area to more than 7,400 gross acres and capturing 80+ additional drilling locations; will complete in Summer 2008
 - Completely exited Nebraska and Colorado (high cost, mature, limited upside assets)

- **Mid-Continent**

- Integrated significant acquisition in Golden Trend and Mocane Laverne, increasing area reserves by 200% and production by 120%
 - Drilled and completed our best well in Golden Trend since EXCO entered the area in October 2005; initial gross production rate was 3.7 Mmcfe/d

Operational Highlights

4th Quarter 2007 and early 2008



- **Appalachia**

- **Acquisitions**

- Closed \$16 million acquisition of 300 producing wells, 100+ drilling locations, 2 Mmcfe/d of production and 14.4 Bcfe of 3P reserves (12.4 proved) in Central Pennsylvania in November 2007
 - Closed \$388 million acquisition (contract price of \$395 million less customary closing adjustments of \$7 million) of 2,500 producing wells, 2,000 drilling locations and 16 Mmcfe/d of production in Pennsylvania, Ohio and West Virginia in February 2008. Acquired assets include 340 Bcfe of shallow 3P reserves (160 Bcfe proved), with 80% of the acquisition value situated among existing EXCO assets in Central Pennsylvania

- **Production**

- Set monthly production record of 46+ Mmcfe/d in January 2008
 - Installed 25 pump jacks on producing wells in Central Pennsylvania, uplifting production by an average 100+%

2008 Upside Evaluation and Development



- **Appalachia - Shale**
 - In the Marcellus shale, we hold 350,000+ net acres with 191,000+ net acres in the fairway of the play; our holdings could contain approximately 6 Tcfe of reserves⁽¹⁾, significantly above previous estimates
 - We have internal landmen and more than 30 contract brokers actively leasing in Pennsylvania
 - For Marcellus evaluation and development, we will drill four horizontal wells this year (all in Pennsylvania) and ten vertical wells (in both Pennsylvania and West Virginia), beginning in Q2
 - In West Virginia, we will drill a Huron shale horizontal well mid-year to begin evaluating our 120,000+ net acres
- **East Texas / North Louisiana - Cotton Valley and Vernon**
 - We will drill eight Cotton Valley horizontal wells during 2008, beginning in Q2
 - We are continuing leasing and evaluation of approximately 40,000 prospective Cotton Valley acres, with encouraging results
 - We are testing and expanding the southern and western Vernon Field limits, and evaluating an additional 65,000 net prospective acres in the Vernon area
- **Permian**
 - We are finalizing acquisition of 15,000+ net acres near Sugg Ranch and continuing to improve our drilling program, where we have reduced both cost and drilling time
- **Rockies**
 - Following encouraging results based on the logs of our Birdseye prospect, nine wells will be drilled in Wyoming's Wind River and Big Horn Basins during 2008 to continue evaluating our potential 1 Tcfe of unbooked upside
- **Midstream**
 - The TGG Pipeline expansion in East Texas to increase third party throughput by approximately 100 Mmcfe/d by Q4 2008 is well underway

(1) Based on drilling horizontal wells on 80 acre spacing with 2.5 Bcfe of reserves per well

Long Reserve Life and Multi-Year Project Inventory Across All Regions

As of December 31, 2007

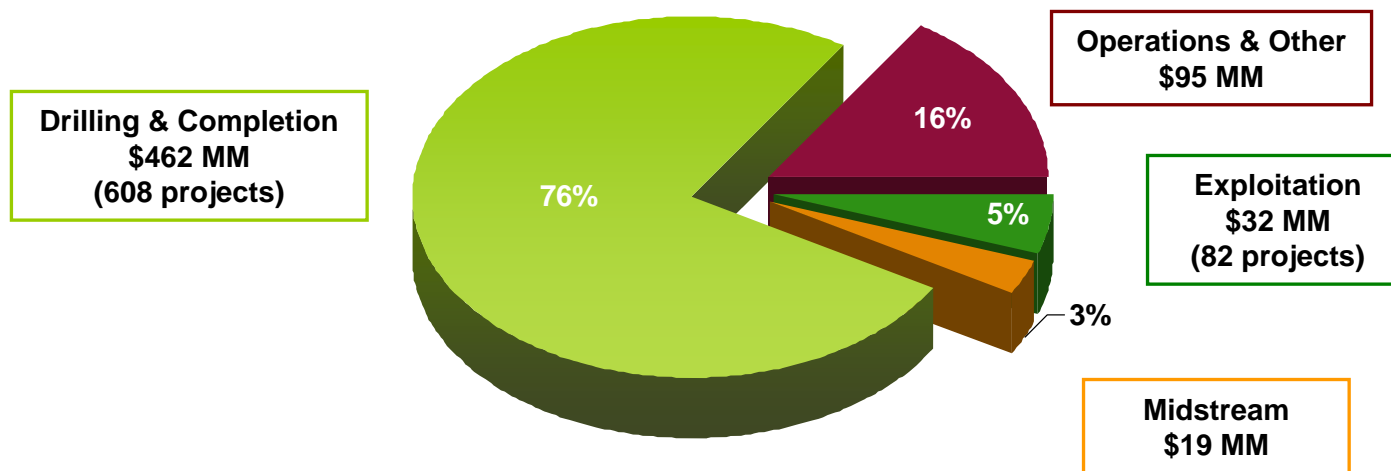
	East TX / North LA	Appalachia	Mid- Continent	Permian	Rockies	Total
Reserves & Well Summary:						
Proved Reserves ⁽¹⁾ (Bcfe)	1,005	425	316	144	12	1,902
Total Reserves⁽²⁾ (Bcfe)	2,333	819	468	339	233	4,192
Potential (Bcfe)	388	2,619	100	299	1,000	4,406
Total Reserves + Potential (Bcfe)	2,721	3,438	568	638	1,233	8,598
Production (Mmcfe/d)	243	44	62	26	2	377
Reserve Life ⁽³⁾ (Years)	11.3	26.5	14.0	15.2	16.4	13.8
Well Count ⁽⁴⁾ (Gross)	1,578	6,743	1,638	287	66	10,312
Well Count ⁽⁴⁾ (Net)	1,189	6,135	937	229	54	8,543
Acreage, Projects & Budget Summary:						
Gross / Net Acreage (Thousands)	329/278	863/815	379/222	72/50	148/132	1,790/1,498
Gross Drilling Locations (Total / 2008E)	2,466/139	6,154/247	548/57	684/156	150/9	10,002/608
Gross Exploitation Projects (Total / 2008E)	543/25	121/22	179/30	44/3	7/2	894/82
2008 Drilling and Development Budget ⁽⁵⁾ (Millions)	\$ 339	\$ 69	\$ 57	\$ 109	\$ 15	\$ 589
Rigs Drilling	13	3	1	4	1	22

- (1) December 31, 2007 proved reserves with \$8 natural gas and \$60 oil pricing, adjusted for differentials and excluding hedge effects
(2) December 31, 2007 proved, probable and possible reserves with \$8 natural gas and \$60 oil pricing, adjusted for differentials and excluding hedge effects
(3) Reserve life based on proved reserves and annualized production
(4) We operate 9,273 of the 10,312 gross wells and 8,268 of the 8,543 net wells
(5) Includes drilling and completion, exploitation, operations and other capital; Midstream and IT capital not included

2008 Capital Budget and Drilling Schedule



- Our development budget totals \$608 million⁽¹⁾, but we will add \$50 - \$100 million for Marcellus shale leasing and drilling and development of our acquisition upside



2008 Capital Program

Area	Drilling & Completion (Net MM)	Gross Projects (#)	Exploitation (Net MM)	Gross Projects (#)	Operations & Other (Net MM)	Total 2008 Capital Budget (Net MM) ⁽²⁾
ETX / NLA	\$245	139	\$26	25	\$68	\$339
Appalachia	60	247	1	22	8	69
Mid-Continent	48	57	4	30	5	57
Permian	98	156	1	3	10	109
Rockies	11	9	-	2	4	15
Total	\$462	608	\$32	82	\$95	\$589

(1) Does not include \$18MM for IT and other

(2) Does not include \$18MM for IT and other and \$19MM for Midstream

Appendix



Operating Results

(In thousands)	4 th Quarter		Twelve Months		Period-to-Period Change			
	2006	2007	2006	2007	4 th Quarter		Twelve Months	
					Amount	Percent	Amount	Percent
<u>Revenues and other income:</u>								
Oil	\$ 16,778	\$ 41,391	\$ 57,043	\$ 117,073	\$ 24,613	147%	\$ 60,030	105%
Natural gas	104,368	214,860	298,737	728,987	110,492	106%	430,250	144%
Marketing and other Income	1,433	8,451	5,005	33,643	7,018	490%	28,638	572%
Cash settlement on derivatives	<u>18,273</u>	<u>23,460</u>	<u>29,423</u>	<u>108,413</u>	<u>5,187</u>	28%	<u>78,990</u>	268%
Total revenues	140,851	288,162	390,208	988,116	147,310	105%	597,908	153%
<u>Costs and expenses:</u>								
Operating costs – Cash	\$ 18,755	\$ 32,387	\$ 46,534	\$ 113,567	\$ 13,632	73%	\$ 67,033	144%
Operating costs – Non-cash ⁽¹⁾	-	2,094	-	3,591	2,094	-	3,591	-
Production taxes	<u>8,177</u>	<u>13,603</u>	<u>22,340</u>	<u>53,282</u>	<u>5,426</u>	66%	<u>30,942</u>	139%
Total production costs	26,932	48,084	68,874	170,440	21,152	79%	101,566	147%
General and administrative - Cash	16,273	14,683	34,674	55,629	(1,590)	(10)%	20,955	60%
General and administrative – Non-cash ⁽¹⁾	<u>4,105</u>	<u>3,811</u>	<u>6,532</u>	<u>9,041</u>	<u>(294)</u>	(7)%	<u>2,509</u>	38%
Total costs and expenses	47,310	66,578	110,080	235,110	19,268	41%	125,030	114%
Non-cash adjustments from above ⁽¹⁾	4,105	5,905	6,532	12,632	1,800	-	6,100	-
Adjusted EBITDA ⁽²⁾	\$ 97,647	\$ 227,489	\$ 286,660	\$ 765,638	\$ 129,842	133%	\$ 478,978	167%

(1) Stock based compensation

(2) Non-GAAP measure - please see tables on slides 24 to 26 for reconciliation to most comparable GAAP measure

Unit Operating Statistics

(In thousands)	4 th Quarter		Twelve Months		Period-to-Period Change			
					4 th Quarter		Twelve Months	
	2006	2007	2006	2007	Amount	Percent	Amount	Percent
<u>Production volumes:</u>								
Oil – Mbbls	304	469	916	1,645	165	54%	729	80%
Gas – Mmcf	16,486	31,828	44,123	111,419	15,342	93%	67,296	153%
Total - Mmcf	18,310	34,642	49,619	121,289	16,332	89%	71,670	144%
<u>Realized pricing⁽¹⁾:</u>								
Oil per Bbl	\$ 55.19	\$ 88.25	\$ 62.27	\$ 71.17	\$ 33.06	60%	\$ 8.90	14%
Gas per Mcf	6.33	6.75	6.77	6.54	0.42	7%	(0.23)	(3)%
Per Mcfe	6.62	7.40	7.17	6.98	0.78	12%	(0.19)	(3)%
<u>Production costs per Mcfe:</u>								
Operating costs ⁽²⁾	\$ 1.02	\$ 0.94	\$ 0.94	\$ 0.94	\$ (0.08)	(8)%	\$ 0.00	0%
Production taxes	0.45	0.39	0.45	0.44	(0.06)	(13)%	(0.01)	(2)%
Total production costs	1.47	1.33	1.39	1.38	(0.14)	(10)%	(0.01)	(1)%
Cash operating margin	\$ 5.15	\$ 6.07	\$ 5.78	\$ 5.60	\$ 0.92	18%	\$ (0.18)	(3)%
Effects of cash settlements on derivatives	1.00	0.67	0.59	0.89	(0.33)	(33)%	0.30	51%
Net cash operating margin	6.15	6.74	6.37	6.49	0.59	10%	0.12	2%

(1) Does not include the effects of derivative financial instruments

(2) Does not include stock based compensation which would have increased operating costs per Mcfe by \$0.06 and \$0.03 for Q4 2007 and for the full year 2007

Year End 2007 Reserve Detail

(Dollars in thousands, except per Mcfe)	Cost	Reserves (Mmcf)	Per Mcfe
Development and exploration costs	\$ 446,675	193,062	\$ 2.31
Proved property acquisition	2,356,354	833,567	2.83
Subtotal	2,803,029	1,026,629	2.73
Revisions – price	-	59,550	-
Revisions – performance	-	(139,325)	-
Subtotal	2,803,029	946,854	2.96
Unproved property acquisition	117,893	-	-
Lease acquisitions and other	21,415	-	-
Subtotal	2,942,337	946,854	3.11
Capitalized asset retirement	5,127	-	-
Total	\$ 2,947,464	946,854	\$ 3.11

	Oil (Mbbbls)	Natural Gas (Mmcf)	Equivalent (Mmcf) ⁽¹⁾
December 31, 2006	16,155	1,126,602	1,223,532
Purchase of reserves in place	10,500	770,567	833,567
New discoveries and extensions	2,469	178,248	193,062
Revisions of previous estimates	(188)	(78,647)	(79,775) ⁽²⁾
Production	(1,645)	(111,419)	(121,289)
Sales of reserves in place	(6,361)	(145,801)	(183,967)
December 31, 2007	20,930	1,739,550	1,865,130

(1) Mcfe - One thousand cubic feet equivalent calculated by converting one Bbl of oil to six Mcf of natural gas

(2) Performance revisions were 139,325 Mmcf offset by 59,550 Mmcf of positive price revisions

Non-GAAP Reconciliations

Consolidated Cash Flows From Operations

(Unaudited in thousands)	Three months ended December 31, 2006	Three months ended December 31, 2007	Year ended December 31, 2006	Year ended December 31, 2007
Cash flow from operations, GAAP	\$ 54,765	\$ 197,531	\$ 227,659	\$ 577,829
Net change in working capital	(476)	821	(21,226)	36,139
Cash flow from operations before changes in working capital, non-GAAP measure ⁽¹⁾	\$ 54,289	\$ 198,352	\$ 206,433	\$ 613,968

- (1) Operating cash flow before working capital changes is presented because management believes it is a useful financial indicator for companies in our industry. This non-GAAP disclosure is widely accepted as a measure of an oil and natural gas company's ability to provide cash used to fund development and acquisition activities and service debt or pay dividends. Operating cash flow is not a measure of financial performance pursuant to GAAP and should not be used as an alternative to cash flows from operating, investing, or financing activities.

Adjusted Net Income

(In thousands, except per share)	Three months ended December 31, 2007		Year ended December 31, 2007	
	Amount	Per Share ⁽¹⁾	Amount	Per Share ⁽²⁾
Net Income (loss), GAAP	\$ (1,995)		\$ 49,656	
Adjustments (after tax):				
Non-cash mark-to-market losses on derivative financial instruments, after taxes	45,994		48,882	
Non-cash income tax valuation allowance ⁽³⁾	-		11,000	
Nonrecurring financing costs, after taxes ⁽³⁾	-		19,228	
Total adjustments	45,994		79,110	
Adjusted net income ⁽⁴⁾	\$ 43,999		\$ 128,766	
Net loss available to common shareholders, GAAP	\$ (36,995)	\$ (0.35)	\$ (83,312)	\$ (0.80)
Adjustments shown above	45,994	0.43	79,110	0.76
Adjusted net income (loss) available to common shareholders ⁽⁴⁾	\$ 8,999	\$ 0.08	\$ (4,202)	\$ (0.04)

- (1) Based on 106,532,360 diluted shares

- (2) Based on 106,983,614 shares for adjusted net income and 104,364,092 shares for adjusted net loss

- (3) Income taxes for the year ended December 31, 2007 include \$11.0 million of non-cash expense valuation allowance attributable to the substitution of current net operating losses for foreign tax credits previously utilized in connection with the sale of our Canadian subsidiary in 2005. This substitution resulted in a cash refund of approximately \$6.0 million during the fourth quarter of 2007. The valuation allowance was required due to the lack of current foreign operations.

- (4) Management is disclosing the non-GAAP measures of adjusted net income and adjusted net income available to common shareholders because it quantifies the financial impact of non-cash gains or losses resulting from derivative financial instruments and certain items management believes affect the comparability of our results of operations which are included in GAAP net income measures.

Non-GAAP Reconciliations



EBITDA and adjusted EBITDA reconciliations

(Unaudited, in thousands)	Three months ended December 31, 2006	Three months ended December 31, 2007	Year ended December 31, 2006	Year ended December 31, 2007
Net income (loss)	\$ (966)	\$ (1,995)	\$ 138,954	\$ 49,656
Interest expense	43,586	34,575	84,871	181,350
Income tax expense	216	1,253	89,401	60,096
Depreciation, depletion and amortization	<u>54,393</u>	<u>109,623</u>	<u>135,722</u>	<u>375,420</u>
EBITDA⁽¹⁾	97,229	143,456	448,948	666,522
Accretion of discount on asset retirement obligations	936	1,344	2,014	4,878
Non-cash change in fair value of derivative financial instruments	(4,623)	76,785	(169,241)	81,606
Stock based compensation expense	4,105	5,904	6,532	12,632
Equity in net income of TXOK Acquisition, Inc.	-	-	<u>(1,593)</u>	-
Adjusted EBITDA⁽¹⁾	\$ 97,647	\$ 227,489	\$ 286,660	\$ 765,638
Interest expense	(43,586)	(34,575)	(84,871)	(181,350)
Income tax expense (benefit)	(216)	(1,253)	(89,401)	(60,096)
Amortization of deferred financing costs, premium on 7¼% senior notes due 2011 and discount on long-term debt	228	(468)	4,733	10,332
Deferred income taxes	216	1,253	89,401	66,171
Gain on sale of other assets	-	(288)	(89)	(941)
Settlements of derivative financial instruments with a financing element	-	6,194	-	14,214
Changes in operating assets and liabilities	<u>476</u>	<u>(821)</u>	<u>21,226</u>	<u>(36,139)</u>
Net cash provided by operating activities	\$ 54,765	\$ 197,531	\$ 227,659	\$ 577,829
Statement of cash flow data:				
Cash flow provided by (used in):				
Operating activities	\$ 54,765	\$ 197,531	\$ 227,659	\$ 577,829
Investing activities	(1,265,231)	(367,885)	(1,791,517)	(2,396,437)
Financing activities	1,210,597	79,067	1,359,727	1,851,296

Non-GAAP Reconciliations



- (1) Earnings before interest, taxes, depreciation, depletion and amortization, or “EBITDA” represents net income adjusted to exclude interest expense, income taxes, 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 derivatives, stock-based compensation expense and equity in net income of TXOK Acquisition, Inc. We have presented EBITDA and Adjusted EBITDA because they are a widely used measure by investors, analysts and rating agencies for valuations, peer comparisons and investment recommendations. In addition, these measures are used in covenant calculations required under our credit agreement and the indenture governing our 7 1/4 % senior notes, and compliance with the liquidity and debt incurrence covenants included in these agreements is considered material to us. Our 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 our computations as compared to those of others. EBITDA and Adjusted EBITDA are measures that are not prescribed by generally accepted accounting principles, or 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 a company’s operating, investing and financing activities. As such, we encourage investors not to use these measures as substitutes for the determination of net income, net cash provided by operating activities or other similar GAAP measures.