

**EXCO** EXCO Resources, Inc.

# Second Quarter 2008 Review

August 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;
- exploratory risks, including our Marcellus and Huron shale plays in Appalachia and our Haynesville/Bossier shale play in East Texas/North Louisiana;
- 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;
- 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, 2007 available on our website at [www.excoresources.com](http://www.excoresources.com) under the Investor Relations tab or by calling us at 214-368-2084.

# Financial Review

Steve Smith



# Second Quarter 2008 Corporate Highlights

Significant growth in all financial and operational metrics



(In thousands, except per share and production)	Q2 2008		Q2 2007	
	Amount	Per Share	Amount	Per Share
Oil and natural gas revenues <sup>(1)(2)</sup>	\$ 338,271		\$ 268,182	
Adjusted net income (loss) available to common shareholders <sup>(2)</sup>	\$ 73,849	\$ 0.34 <sup>(4)</sup>	\$ (10,973)	\$ (0.11) <sup>(4)</sup>
Adjusted EBITDA <sup>(2)</sup>	\$ 262,921		\$ 209,352	
Cash flow from operations <sup>(2)(3)</sup>	\$ 231,875	\$ 1.07 <sup>(5)</sup>	\$ 175,255	\$ 0.83 <sup>(5)</sup>
Average daily production – Mmcfe/d	394		383	
Midstream income:				
Before intercompany eliminations	\$ 11,951		\$ 7,532	
After intercompany eliminations	\$ 4,132		\$ 1,072	

- Reported record adjusted EBITDA of \$263 million; over \$1.0 billion annualized run rate
- Enhanced shale acreage positions in Appalachia and East Texas/North Louisiana
- Drilled and tested shales across portfolio
- Continued expansion of midstream business

(1) Including cash settlements on derivative financial instruments

(2) Non-GAAP measures, please see tables on slides 27 to 32 for reconciliations to most comparable GAAP measures

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

(4) Computed using diluted shares of 216,290,220 for second quarter 2008 and 104,313,580 for second quarter 2007

(5) Computed using diluted shares of 216,290,220 for second quarter 2008 and 212,172,456 for second quarter 2007

# Second Quarter 2008 Corporate Highlights

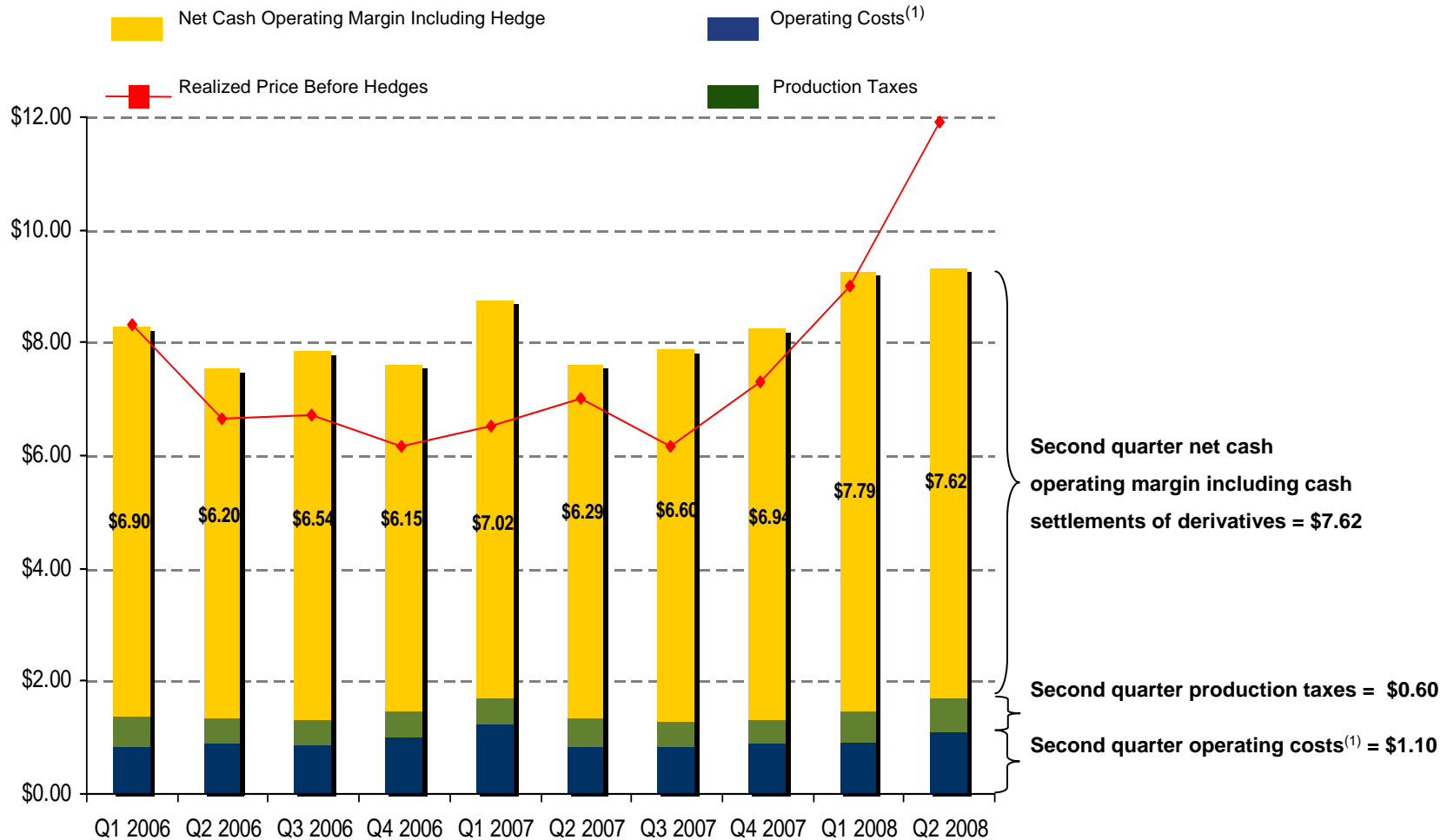
Exposed to three emerging shale plays



- **Haynesville Activity**
  - Increased our shale acreage through leasing and acquisitions
  - Averaged 200 feet of net pay in Harrison County, TX and Caddo and DeSoto Parishes, LA
  - Vertical test results of 0.8 – 2.8 Mmcf/d initial production rates
  - 1<sup>st</sup> horizontal spud planned for August 2008
- **Marcellus Activity**
  - Drilled and cased 1<sup>st</sup> horizontal well; 194 feet of net pay
  - Drilling 2<sup>nd</sup> well on same pad; plan to complete both wells in Q3
- **Huron Activity**
  - Drilled 1<sup>st</sup> horizontal well in Q2; spud 3 additional wells
  - Completions expected in Q3
- **Midstream Activity**
  - Major expansion in ETX nearing completion; well situated for future Haynesville production
  - Evaluating additional expansion opportunities as the play develops

# Performance Highlights

Stable operating cash margins in volatile price environment



(1) Does not include non-cash stock based compensation costs of \$0.03 per Mcfe for the second quarter 2008

# Second Quarter 2008

## Midstream segment results

(in thousands)	Midstream	Intercompany Eliminations	As Reported
Revenues:			
Third party	\$ 26,956		\$ 26,956
Intercompany	<u>12,618</u>	\$ (12,618)	<u>-</u>
Total revenue	39,574		26,956
Expenses:			
Operating expenses	22,824		22,824
Intercompany gas purchases	<u>4,799</u>	(4,799)	<u>-</u>
Total expenses	27,623		22,824
Segment profit	\$ 11,951	\$ (7,819) <sup>(1)</sup>	\$ 4,132

(1) Previously reported as decreases to gas revenue in our E&P segment

# Liquidity and Financial Position

(in thousands)	June 30, 2008	August 1, 2008
Cash	\$ 34,142	\$ 59,355
Bank debt (LIBOR + 125-175bps)	\$ 2,164,000	\$ 2,215,500
Senior unsecured term loan	-	300,000
Senior notes (7 1/4%) <sup>(1)</sup>	<u>444,720</u>	<u>444,720</u>
Total debt	\$ 2,608,720	\$ 2,960,220
7% convertible preferred <sup>(2)</sup>	\$ 2,000,000	-
Common shareholders' equity	<u>640,984</u>	<u>2,640,984</u>
Total capitalization	\$ 5,249,704	\$ 5,601,204
Net debt to total capitalization	49%	52%
Borrowing base	\$ 2,475,000	\$ 2,475,000
Unused borrowing base <sup>(3)</sup>	\$ 307,100	\$ 255,600

- Converted preferred stock into approximately 105 million shares of common stock on July 18, 2008, resulting in annual dividend savings of \$140 million

(1) Excludes unamortized bond premium  
(2) Excludes \$7.7 million in offering costs  
(3) Net of \$3.9 million in letters of credit at June 30, 2008 and August 1, 2008

# Hedge Position

As of June 30, 2008

<b>NYMEX Swaps</b>	<b>Gas Mmcf</b>	<b>Contract price per Mmcf</b>	<b>Oil Mbbls</b>	<b>Contract price per Bbl</b>	<b>Percent Hedged<sup>(1)</sup></b>
Q3 2008	26,900	8.29	358	68.20	79%
Q4 2008	26,910	8.39	358	68.16	77%
2009	100,530	8.18	1,215	69.11	71%
2010	40,748	8.03	473	84.85	29%
2011	9,125	7.97	-	-	6%
2012	1,830	4.51	-	-	1%
2013	1,825	4.51	-	-	1%
<b>Total</b>	<b>207,868</b>	<b>\$ 8.12</b>	<b>2,404</b>	<b>\$ 71.93</b>	
<b>Total of 222,292 Mmcfe Hedged at \$8.37</b>					

- Target hedging 65-80% of production volumes for 3-5 years
- Hedging program covers long term debt
- Only 12% of year end 2007 Proved Reserves hedged
- \$700 million of interest rate swaps at an average LIBOR rate of 2.66%

(1) Based on 2008 production guidance

# Second Quarter 2008 Guidance vs. Actuals

(\$ in thousands, except per unit amounts)	Second Quarter 2008		
	Guidance <sup>(1)</sup>	Actual	Variance
<u>Production:</u>			
Oil – Mbbls	495	545	50
Gas – Mmcf	33,000	32,621	(379)
Mmcfe	35,950	35,891	(59)
Per day – Mmcfe	395	394	(1)
<u>Differentials to NYMEX:</u>			
Oil per Bbl	(\$3.63)	(\$2.91)	\$0.72
Gas per Mcf	99%	102%	3%
Lease operating expense	\$33,700	\$39,496	\$5,796
Stock based compensation - LOE	\$1,000	\$1,129	\$129
Gathering expense – per Mcfe	\$0.13	\$0.10	(\$0.03)
Production tax rate	7.0%	5.0%	(2.0%)
Other income	\$375	\$2,249	\$1,874
Midstream revenue	\$19,500	\$26,956	\$7,456
Midstream expense	\$18,250	\$22,824	\$4,574
Midstream income	\$1,250	\$4,132	\$2,882
Depletion rate per Mcfe	\$3.10	\$2.93	(\$0.17)
Depreciation rate per Mcfe	\$0.15	\$0.17	\$0.02
Asset retirement obligation	\$1,670	\$1,473	(\$197)
Cash G&A	\$16,200	\$17,102	\$902
Non-cash stock comp	\$2,570	\$2,555	(\$15)
Interest expense <sup>(2)</sup>	\$32,800	\$31,274	(\$1,526)
Tax rate	40%	36%	(4.0%)
Cash tax rate	0%	0%	-
Preferred dividends	\$35,000	\$35,000	\$0
Adjusted EBITDA	\$232,210	\$262,921	\$30,711

- (1) Second quarter 2008 midpoint guidance  
(2) Does not include impact of fair market adjustment on interest rate swaps of \$11,001

# 2008 Guidance

(\$ in thousands, except per unit amounts)	2008E <sup>(1)</sup>	
	Low	High
<u>Production:</u>		
Oil – Mbbls	2,062	2,082
Gas – Mmcf	132,170	133,970
Mmcf	144,582	146,482
Per day – Mmcf	395	400
<u>Differentials to NYMEX:</u>		
Oil per Bbl	(\$2.91)	(\$2.79)
Gas per Mcf	100.7%	102.2%
Lease operating expense	\$154,680	\$160,680
Stock based compensation - LOE	\$5,260	\$6,160
Gathering expense – per Mcfe	\$0.10	\$0.13
Production tax rate	5.7%	6.2%
Other income	\$4,180	\$4,680
Midstream revenue	\$74,850	\$84,850
Midstream expense	\$66,850	\$75,850
Midstream income	\$8,000	\$9,000
Depletion rate per Mcfe	\$3.00	\$3.05
Depreciation rate per Mcfe	\$0.16	\$0.21
Asset retirement obligation	\$5,880	\$6,380
Cash G&A	\$72,220	\$74,220
Non-cash stock comp	\$10,710	\$13,710
Interest expense <sup>(2)</sup>	\$155,260	\$159,260
Tax rate	40%	40%
Cash tax rate	0%	0%
Preferred dividends	\$77,000	\$77,000
Adjusted EBITDA at Midpoint <sup>(3)</sup>	\$990,300	

(1) 2008 guidance includes actual results for the first and second quarters of 2008

(2) Includes \$5.2 million of non-cash deferred financing cost amortization in Q3 and Q4 related to the senior unsecured term loan

(3) 2008 estimates based on NYMEX \$90 oil and \$9 natural gas for the third and fourth quarters

# Quarterly 2008 Guidance

(\$ in thousands, except per unit amounts)	3 <sup>rd</sup> Q 2008E		4 <sup>th</sup> Q 2008E	
	Low	High	Low	High
<u>Production:</u>				
Oil - Mbbls	500	510	510	520
Gas - Mmcf	33,300	34,200	34,200	35,100
Mmcfe	36,300	37,300	37,300	38,200
Per day - Mmcfe	395	405	405	415
<u>Differentials to NYMEX:</u>				
Oil per Bbl	(\$3.75)	(\$3.50)	(\$3.75)	(\$3.50)
Gas per Mcf	97%	100%	97%	100%
Lease operating expense	\$41,500	\$44,500	\$41,500	\$44,500
Stock based compensation – LOE	\$750	\$1,250	\$2,390	\$2,790
Gathering expense – per Mcfe	\$0.10	\$0.15	\$0.10	\$0.15
Production tax rate	6.0%	7.0%	6.0%	7.0%
Other income	\$250	\$500	\$250	\$500
Midstream revenue	\$20,000	\$25,000	\$20,000	\$25,000
Midstream expense	\$18,000	\$22,500	\$18,000	\$22,500
Midstream income	\$2,000	\$2,500	\$2,000	\$2,500
Depletion rate per Mcfe	\$3.05	\$3.15	\$3.05	\$3.15
Depreciation rate per Mcfe	\$0.15	\$0.25	\$0.15	\$0.25
Asset retirement obligation	\$1,545	\$1,795	\$1,545	\$1,795
Cash G&A	\$17,000	\$18,000	\$17,500	\$18,500
Non-cash stock comp	\$2,070	\$3,070	\$4,070	\$6,070
Interest expense <sup>(1)</sup>	\$45,300	\$47,300	\$46,300	\$48,300
Tax rate	40%	40%	40%	40%
Cash tax rate	0%	0%	0%	0%
Preferred dividends	\$7,000	\$7,000	\$0	\$0
Fully diluted shares outstanding <sup>(2)</sup>	216,000	217,000	216,000	217,000
Adjusted EBITDA at Midpoint <sup>(3)</sup>	\$231,500		\$241,900	

(1) Includes \$5.2 million of non-cash deferred financing cost amortization in Q3 and Q4 related to the senior unsecured term loan

(2) Fully diluted shares outstanding includes 105,263,158 shares in the third and fourth quarters resulting from the conversion of preferred stock on July 18, 2008

(3) 2008 estimates based on NYMEX \$90 oil and \$9 natural gas for the third and fourth quarters

**EXCO** EXCO Resources, Inc.

# Operational Review

Hal Hickey



# Operational Highlights

## East Texas/North Louisiana

### Second Quarter 2008



- Haynesville/Bossier shale
  - Strategically drilling and completing to delineate the shale play, test fracturing technologies, and gather data for play development
  - Data collection and procedure optimization include extensive logging and coring programs, fracture stimulation and rate optimization for future horizontals, and optimization of flowback procedures
  - In final stages of testing individual Haynesville/Bossier zones in three vertical evaluation wells drilled in Caddo and DeSoto Parishes, LA and Harrison County, TX
  - Three wells have encouraging results
    - Average of approximately 200 feet of net pay
    - High porosities and total organic carbon indicating significant gas in place
    - IP rates have ranged from 800 to 2,800 Mcfe/d at flowing pressures between 1,000 and 3,200 psi
  - Added new build, 1,500 horsepower, top drive drilling rig for horizontal program; will spud first Haynesville horizontal in early August
  - Will add second new build horizontal drilling rig in Q4
  - Currently hold nearly 120,000 net acres with deep rights in the play and are actively acquiring additional acreage; 60% of acreage is held by shallow production

# Operational Highlights

## East Texas/North Louisiana

### Second Quarter 2008



- **Vernon**
  - Drilled and completed 6 wells during Q2 with average IP of more than 6 Mmcfe/d gross (4.1 Mmcfe/d net)
  - Expanded southern and western field limits and number of drilling locations; added 4<sup>th</sup> rig and plan to drill 31 wells during 2008
  - Reprocessing seismic as we evaluate an additional 35,000 net prospective acres in the Vernon area; will spud evaluation well in Q4 2008
  - Increasing oil country tubular goods and other costs have raised drilling well costs by approximately 10%
  
- **Shreveport Area**
  - Drilled and completed 28 wells in Q2, with IP average of slightly less than 1 Mmcfe/d
  - Expanding field limits; drilling with 5 rigs and plan to add 6<sup>th</sup> rig in October
  - Drilling several budgeted Cotton Valley wells to the deeper Haynesville to hold acreage and further define the play; as these wells are being completed in the Haynesville formation, some Cotton Valley completions are being deferred
  - Rig spud to release days down 20 - 30%; however, drilling and completion costs are increasing (recent drilling day rates up 20 - 30%)
  - Finalizing salt water disposal pipeline contract

# Operational Highlights

## East Texas/North Louisiana

### Second Quarter 2008



- Lifting costs have increased due to fuel, tubular/casing costs, and workover activity
  - Fuel up 40% or more, tubular/casing up 40 - 80% and workover activities up \$2.3 million versus Q1
- Acquisition
  - On July 15, closed \$244 million (after preliminary closing adjustments) asset acquisition in Gregg, Rusk and Upshur Counties, TX from private sellers
  - Assets include approximately 12 Mmcf per day of stabilized production, 11,000 gross acres (majority with deep rights), 109 Bcfe of proved reserves and more than 500 Cotton Valley, Travis Peak, and Rodessa locations, 92 of which are proved
  - The acquisition includes two wells penetrating the Haynesville/Bossier shale; we will drill into these zones during 2008 to further delineate the opportunities to exploit the shale
- Midstream
  - Throughput has increased from 460 Mmcf/d at year end 2007 to 535 Mmcf/d today
  - 57-mile, \$37.6 million expansion of our TGG pipeline continues; first phase on line in early May; overall expansion expected to be complete by late summer 2008, adding at least 100 Mmcf/d in total without compression. Added capacity with compression will exceed 200 Mmcf/d
  - Evaluating opportunities to support Haynesville/Bossier shale development

# Operation Highlights

Appalachia

Second Quarter 2008



- Production

- Set monthly production record of 61 Mmcfe/d in April 2008
- Production for the quarter was 59 Mmcfe/d
  - 13% increase over Q1 2008; 40% increase over Q2 2007
- Artificial Lift Enhancements in Central Pennsylvania
  - 150% average increase on 63 pump jacks; 50% average increase on 26 plunger lifts
  - Produced incremental 148 Mmcfe year-to-date

- Drilling

- Achieved 98% drilling success on 45 gross (41.4 net) wells
- Had 5 rigs drilling on June 30, 2008
  - 3 drilling conventional targets
  - 2 drilling shale targets
- Have 9 rigs drilling on August 1, 2008
  - 4 drilling conventional targets
  - 5 drilling shale/unconventional targets

# Operation Highlights

Appalachia

Second Quarter 2008



- Marcellus Shale

- Currently hold nearly 400,000 net acres with approximately 276,000 of our net acres in the fairway of the play
- Spud 2 horizontal Marcellus wells in Pennsylvania
  - Cored vertical section of the first horizontal
    - Thickness of nearly 200 feet
    - High porosities and total organic carbon indicating significant gas in place
    - Samples NOT “cherry-picked”  
i.e., reflect range of leaner grey shale to darker, richer black shale
- Completion of both Marcellus horizontals is expected during Q3 following TD of second well
- Spud and completed 3 vertical normal pressured Marcellus wells in West Virginia
  - Recovering stimulation fluids
  - Initial rates 70 – 100 Mcf per day

# Operation Highlights

Appalachia

Second Quarter 2008



- **Huron Shale**
  - Currently hold approximately 121,000 net acres in the Huron shale in West Virginia
  - Drilled 1 horizontal Huron well in Q2
    - Targeted a total thickness exceeding 550 feet with approximately 300 feet of organically rich Lower Huron
    - Numerous drilling breaks and gas shows along the 2,943 foot lateral qualitatively indicate high quality shale
    - Total measured depth of the well is 7,420 feet
  - Spud 3 additional wells
  - Expect to complete at least 2 Huron horizontal wells during Q3
  
- **Second Half 2008 Appalachia Shale Exploitation/Development Plans**
  - Drill 2 additional horizontal Marcellus wells
  - Drill 4 additional vertical Marcellus wells
  - Drill 7 additional horizontal Huron wells in West Virginia (have spud 3)
  - Contracted 2 new-build 1000-horsepower top-drive rigs for Q1 2009 delivery

# Operational Highlights

## Other Areas

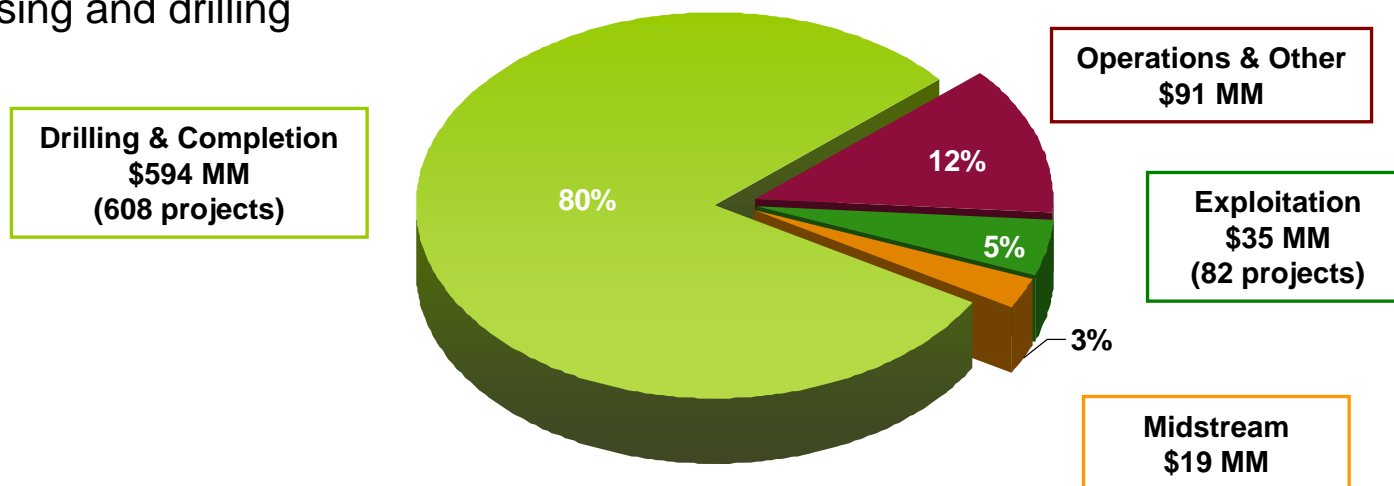
### Second Quarter 2008



- **Permian – Canyon Sand Field**
  - Drilled 31 gross (30.1 net) wells in Q2 with three operated rigs (100% success rate)
  - Plan to drill 124 gross (120 net) wells in 2008; have identified oil targets
  - Q2 2008 net production of 24 Mmcfe/d is up from less than 20 Mmcfe/d in November 2007, when EXCO took over operations
  - Negotiated a joint venture adding approximately 11,000 contiguous net acres
  - Leased additional 12,300 net acres contiguous to our existing acreage in Q2; now hold approximately 47,000 net acres in the area
  - Currently acquiring and evaluating 3-D seismic to identify additional opportunities
  
- **Rockies**
  - Plan to complete our previously drilled Birdseye prospect in the Wind River basin in September; completion delayed due to eagle nest in the area; substantial potential upside in region
  
- **Mid-Continent**
  - Drilled and completed 12 gross (7.3 net) wells in the Mid-Continent area achieving a 100% success rate; had three rigs running at end of Q2
  - Plan to drill 57 gross (33.0 net) wells in the Mid-Continent area during 2008

# 2008 Capital Budget and Drilling Schedule

- Our development budget totals \$943 million, which includes \$170 million for Marcellus/Huron shales leasing and drilling and \$90 million for Haynesville/Bossier shale leasing and drilling



2008 Capital Program

Area	Gross Wells (#)	Drilling & Completion (Net \$ MM)	Exploitation (Net \$ MM)	Land (Net \$ MM)	Operations & Other (Net \$ MM)	Total 2008 Capital Budget (Net \$ MM) <sup>(1)</sup>
<b>EXT/NLA</b>						
Cotton Valley	141	\$297	\$26	\$10	\$58	\$391
Haynesville/Bossier Shale	20	32	-	54	4	90
<b>Appalachia</b>						
Conventional	229	54	4	1	14	73
Marcellus/Huron Shale	20	54	-	116	-	170
<b>Mid-Continent</b>	57	48	4	-	5	57
<b>Permian</b>	137	98	1	3	7	109
<b>Rockies</b>	4	11	-	1	3	15
<b>Total</b>	<b>608</b>	<b>\$594</b>	<b>\$35</b>	<b>\$185</b>	<b>\$91</b>	<b>\$905</b>

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

# Appendix



# Operating Results

(in thousands)	Three months ended June 30,			Six months ended June 30,		
	2008	2007	% Change	2008	2007	% Change
<b>Revenues and other income:</b>						
Oil	\$ 65,982	\$ 26,057	153%	\$ 114,998	\$ 41,162	179%
Natural gas	362,669	235,495	54%	638,596	340,749	87%
Midstream	26,956	5,211	417%	34,848	9,757	257%
Cash settlement on derivative instruments	(90,380)	6,630	(1463)%	(87,364)	38,702	(326)%
Other income	<u>2,249</u>	<u>1,883</u>	<u>19%</u>	<u>3,676</u>	<u>5,162</u>	<u>(29)%</u>
Adjusted revenues <sup>(1)</sup>	367,476	275,276	33%	704,754	435,532	62%
<b>Costs and expenses:</b>						
Operating costs – Cash	\$ 39,496	\$ 29,280	35%	\$ 71,676	\$ 50,831	41%
Operating costs – Non-cash <sup>(2)</sup>	1,129	767	47%	2,120	767	176%
Production taxes	<u>21,433</u>	<u>16,999</u>	<u>26%</u>	<u>40,743</u>	<u>25,375</u>	<u>61%</u>
Production costs	62,058	47,046	32%	114,539	76,973	49%
Midstream operating expenses	22,824	4,139	451%	30,851	7,103	334%
Gathering and transportation costs	3,700	2,303	61%	6,831	3,275	109%
General and administrative – Cash	17,102	13,203	30%	37,716	25,467	48%
General and administrative – Non-cash <sup>(2)</sup>	<u>2,555</u>	<u>1,787</u>	<u>43%</u>	<u>4,568</u>	<u>3,698</u>	<u>24%</u>
Operating and production expenses	108,239	68,478	58%	194,505	116,516	67%
Depreciation, depletion and amortization	111,281	105,148	6%	220,498	156,472	41%
Accretion of discount on asset retirement obligations	1,473	1,267	16%	2,789	2,210	26%
Interest	<u>20,273</u>	<u>33,543</u>	<u>(40)%</u>	<u>56,293</u>	<u>110,252</u>	<u>(49)%</u>
Total costs and expenses	241,266	208,436	16%	474,085	385,450	23%
Non-cash adjustments and interest from above	136,711	142,512		286,268	273,399	
Adjusted EBITDA <sup>(1)</sup>	\$ 262,921	\$ 209,352	26%	\$ 516,937	\$ 323,481	60%

(1) Non-GAAP measure; please see table on slides 27 - 32 for reconciliation to most comparable GAAP measure

(2) Stock based compensation

# Unit Operating Statistics

	Three months ended June 30,		% Change	Six months ended June 30,		% Change
	2008	2007		2008	2007	
<u>Production volumes:</u>						
Oil – Mbbbls	545	426	28%	1,053	701	50%
Gas – Mmcf	32,621	32,320	1%	64,670	47,983	35%
Total - Mmcf	35,891	34,876	3%	70,988	52,189	36%
<u>Realized pricing<sup>(1)</sup>:</u>						
Oil per Bbl	\$ 121.07	\$ 61.17	98%	\$ 109.21	\$ 58.72	86%
Gas per Mcf	11.12	7.29	53%	9.87	7.10	39%
Per Mcfe	11.94	7.50	59%	10.62	7.32	45%
<u>Production costs per Mcfe:</u>						
Operating costs <sup>(2)</sup>	\$ 1.10	\$ 0.84	31%	\$ 1.01	\$ 0.97	4%
Production taxes	<u>0.60</u>	<u>0.49</u>	22%	<u>0.57</u>	<u>0.49</u>	16%
Total production costs	\$ 1.70	\$ 1.33	28%	\$ 1.58	\$ 1.46	8%
Gathering and transportation costs	\$ 0.10	\$ 0.07	43%	\$ 0.10	\$ 0.06	67%
Cash operating margin	\$ 10.14	\$ 6.10	66%	\$ 8.94	\$ 5.80	54%
Effects of cash settlements on derivatives	<u>(2.52)</u>	<u>0.19</u>	(1426)%	<u>(1.23)</u>	<u>0.74</u>	(266)%
Net cash operating margin	\$ 7.62	\$ 6.29	21%	\$ 7.71	\$ 6.54	18%

(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 \$0.03 for the three and six months ended June 30, 2008 and \$0.02 for the three and six months ended June 30, 2007

# Non-GAAP Reconciliations

## Revenues and Adjusted Revenues

(in thousands)	Three months ended June 30,		Six months ended June 30,	
	2008	2007	2008	2007
Oil and natural gas revenues, before derivative financial instruments	\$ 428,651	\$ 261,552	\$ 753,594	\$ 381,911
Cash settlements on derivative financial instruments	<u>(90,380)</u>	<u>6,630</u>	<u>(87,364)</u>	<u>38,702</u>
Subtotal, revenues including cash settlements on derivative financial instruments	338,271	268,182	666,230	420,613
Non-cash gain (loss) on oil and natural gas derivative financial instruments	<u>(572,273)</u>	<u>71,267</u>	<u>(916,483)</u>	<u>(56,824)</u>
Oil and natural gas revenues	(234,002)	339,449	(250,253)	363,789
Midstream revenues	26,956	5,211	34,848	9,757
Other income	<u>2,249</u>	<u>1,883</u>	<u>3,676</u>	<u>5,162</u>
Total revenues other income, GAAP	(204,797)	346,543	(211,729)	378,708
Elimination of non-cash oil and natural gas derivative financial instruments activity included in GAAP revenues	<u>572,273</u>	<u>(71,267)</u>	<u>916,483</u>	<u>56,824</u>
Adjusted revenues <sup>(1)</sup>	\$ 367,476	\$ 275,276	\$ 704,754	\$ 435,532

- (1) EXCO does not designate its derivatives as hedges. As a result, unrealized gains or losses in the fair market value of our derivatives are recognized as a component of current revenues. Adjusted revenues are not a measure of revenues in accordance with GAAP. Management believes that adjusted revenue is a meaningful measure to investors and rating agencies as it presents the combination of actual revenues before the impact of oil and natural gas derivatives in accordance with GAAP, combined with the actual cash receipts or settlements arising from the oil and natural gas derivative program. Adjusted revenues specifically exclude the non-cash unrealized gains or losses from derivative activities as the non-cash impact of the changes in the fair value of derivatives does not impact our current liquidity and cash flows used to fund our operations, execute our capital program and make acquisitions.

# Non-GAAP Reconciliations

## Cash Flow From Operations

(in thousands)	Three months ended June 30,		Six months ended June 30,	
	2008	2007	2008	2007
Cash flow from operations, GAAP	\$ 312,724	\$ 136,575	\$ 512,234	\$ 169,126
Net change in working capital	(8,283)	42,358	3,773	57,697
Settlements of derivative financial instruments with a financing element	<u>(72,566)</u>	<u>(3,678)</u>	<u>(62,099)</u>	<u>(3,678)</u>
Cash flow from operations before changes in working capital, non-GAAP measure <sup>(1)</sup>	\$ 231,875	\$ 175,255	\$ 453,908	\$ 223,145

- (1) Cash flow from operations before working capital changes and adjustments for settlements of derivative financial instruments with a financing element 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. We have also elected to exclude the adjustment for derivative financial instruments with a financing element as this adjustment simply reclassifies settlements from operating cash flows to financing activities. Management believes these settlements should be included in this non-GAAP measure to conform with the intended measure of our ability to provide cash to fund operations and development activities.

# Non-GAAP Reconciliations

## Adjusted Net Income

(in thousands, except per share)	Three months ended June 30, 2008		Three months ended June 30, 2007		Six months ended June 30, 2008		Six months ended June 30, 2007	
	Amount	Per Share	Amount	Per Share	Amount	Per Share	Amount	Per Share
Net income (loss), GAAP	\$ (262,914)		\$ 82,886		\$ (425,753)		\$ (4,811)	
Adjustments:								
Non-cash mark-to-market (gains) losses on oil and natural gas derivative financial instruments, before taxes	572,273		(71,267)		916,483		56,824	
Non-cash mark-to-market (gains) losses on interest rate derivative financial instruments, before taxes	(11,001)		-		(7,370)		-	
Nonrecurring financing costs, before taxes <sup>(1)</sup>	-		-		-		32,100	
Income taxes on adjustments <sup>(2)</sup>	<u>(224,509)</u>		<u>28,507</u>		<u>(363,645)</u>		<u>(35,570)</u>	
Total adjustments, net of taxes	<u>336,763</u>		<u>(42,760)</u>		<u>545,468</u>		<u>53,354</u>	
Adjusted net income	\$ 73,849		\$ 40,126		\$ 119,715		\$ 48,543	
Net income (loss) available to common shareholders, GAAP <sup>(3)</sup>	\$ (297,914)	\$ (2.83)	\$ 31,787	\$ 0.30	\$ (495,753)	\$(4.72)	\$ (57,046)	\$(0.55)
Adjustments shown above <sup>(3)</sup>	336,763	3.20	(42,760)	(0.41)	545,468	5.20	53,354	0.51
Dilution attributable to stock options <sup>(4)</sup>	-	<u>(0.02)</u>	-	<u>n/a</u>	-	<u>(0.03)</u>	-	<u>n/a</u>
Adjusted net income (loss) available to common shareholders	\$ 38,849	\$ 0.35	\$ (10,973)	\$(0.11)	\$ 49,715	\$ 0.45	\$ (3,692)	\$(0.04)
Benefit of preferred dividends due to assumed conversion <sup>(5)</sup>	\$ 35,000	-	n/a	-	n/a	-	n/a	-
Adjusted net income (loss) available to common shareholders	<u>38,849</u>	-	<u>(10,973)</u>	-	<u>49,715</u>	-	<u>(3,692)</u>	-
Adjusted net income (loss) for diluted earnings per share <sup>(5)</sup>	\$ 73,849	\$ 0.34	\$ (10,973)	\$(0.11)	\$ 49,715	\$ 0.45	\$ (3,692)	\$(0.04)
<u>Common stock and equivalents used for earnings per share (EPS):</u>								
Weighted average common shares outstanding		105,253		104,313		104,968		104,258
Dilutive stock options		<u>5,774</u>		<u>n/a</u>		<u>4,351</u>		<u>n/a</u>
Shares used to compute EPS for adjusted net income (loss) available to common shareholders		111,027		104,313		109,319		104,258
Dilutive preferred stock		<u>105,263</u>		<u>n/a</u>		<u>n/a</u>		<u>n/a</u>
Shares used to compute diluted EPS for adjusted net income (loss) available to common shareholders		216,290		104,313		109,319		104,258

# Non-GAAP Reconciliations

- (1) Interest expense for the six months ended June 30, 2007 includes one time charges of \$32.1 million incurred during the first quarter 2007. Expenses associated with the payoff of the EXCO Operating Company, LP Senior Term Credit Agreement included a \$13.0 million redemption premium, a \$9.2 million write-off of deferred financing costs, and a \$3.0 million write-off of unamortized original issue discount. In addition, \$6.9 million of commitment fees were expensed in connection with other debt arrangements that were terminated in the first quarter of 2007. Interest expense for the three and six months ended June 30, 2008 includes decreases to interest expense of \$11.0 million and \$7.4 million, respectively, a result of non-cash gains resulting from interest rate swaps entered into during the first quarter 2008
- (2) The assumed income tax rate is 40% for all periods
- (3) Per share amounts are based on weighted average number of common shares outstanding
- (4) Represents dilution per share attributable to common stock equivalents from in-the-money stock options for periods with adjusted net income available to common shareholders
- (5) Preferred stock was dilutive to adjusted net income for the three months ended June 30, 2008. Therefore, the assumed conversion of preferred stock and related dividend savings are included in the diluted earnings per share computation. Diluted income per share for the six months ended June 30, 2008 is computed using the weighted average common stock and dilutive stock options. The assumed conversion of preferred stock is not included in the diluted per share computation as those shares are antidilutive for the six month period ended June 30, 2008. The three and six months ended June 30, 2007 per share losses are computed using only the weighted average common stock outstanding as the stock options and assumed conversion of preferred stock are antidilutive.

# Non-GAAP Reconciliations



## EBITDA and adjusted EBITDA reconciliations

(unaudited, in thousands)	Three months ended June 30,		Six months ended June 30,	
	2008	2007	2008	2007
Net income (loss)	\$ (262,914)	\$ 82,886	\$ (425,753)	\$ (4,811)
Interest expense	20,273	33,543	56,293	110,252
Income tax expense (benefit)	(183,149)	55,221	(260,061)	(1,931)
Depreciation, depletion and amortization	111,281	105,148	220,498	156,472
<b>EBITDA<sup>(1)</sup></b>	<b>(314,509)</b>	<b>276,798</b>	<b>(409,023)</b>	<b>259,982</b>
Accretion of discount on asset retirement obligations	1,473	1,267	2,789	2,210
Non-cash change in fair value of derivative financial instruments	572,273	(71,267)	916,483	56,824
Stock based compensation expense	3,684	2,554	6,688	4,465
<b>Adjusted EBITDA<sup>(1)</sup></b>	<b>\$ 262,921</b>	<b>\$ 209,352</b>	<b>\$ 516,937</b>	<b>\$ 323,481</b>
Interest expense <sup>(2)</sup>	(31,274)	(33,543)	(63,663)	(110,252)
Income tax benefit (expense)	183,149	(55,221)	260,061	1,931
Amortization of deferred financing costs, premium on 7¼% senior notes due 2011 and discount on long-term debt	411	561	817	9,916
Deferred income taxes	(183,332)	54,106	(260,244)	(1,931)
Changes in operating assets and liabilities and other	8,283	(42,358)	(3,773)	(57,697)
Settlements of derivative financial instruments with a financing element	72,566	3,678	62,099	3,678
<b>Net cash provided by operating activities</b>	<b>\$ 312,724</b>	<b>\$ 136,575</b>	<b>\$ 512,234</b>	<b>\$ 169,126</b>
Statement of cash flow data:				
Cash flow provided by (used in):				
Operating activities <sup>(2)</sup>	\$ 312,724	\$ 136,575	\$ 512,234	\$ 169,126
Investing activities	(329,289)	(571,310)	(934,158)	(1,972,666)
Financing activities	41,594	318,338	400,556	1,833,999

# 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 and stock-based compensation. 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 agreements and the indenture governing our 7 1/4 % senior notes. 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.
- (2) Excludes non-cash change in fair value of interest rate swaps included in GAAP interest expense