



EXCO Resources, Inc.



# Investor Presentation and Financial Disclosure

July 2011



# Cautionary Note Concerning Forecasts Prepared by the Company's Management

EXCO Resources, Inc. (the "Company") does not as a matter of course prepare or make publicly available long-range forecasts or projections as to future value, reserve information, operating performance, production, earnings or other results due to the unpredictability of the underlying assumptions and estimates. However, in light of the letter from the Company's chairman and chief executive officer, Douglas H. Miller, to the Company's board of directors indicating an interest in acquiring all of the Company's outstanding shares of common stock not already owned by Mr. Miller for a cash price of \$20.50 per share (the "Proposed Transaction"), the Company prepared and provided certain forecasts and projections as to future value, reserve information, operating performance, production, earnings and other results that are included in this presentation (the "Forecasts") to potential investors in the Proposed Transaction and other persons interested in acquiring the Company in connection with their evaluation of the Proposed Transaction and the Company.

The Forecasts were necessarily based on a variety of assumptions and estimates. The assumptions and estimates underlying the Forecasts may not be realized and are inherently subject to significant business, economic and competitive uncertainties and contingencies, all of which are difficult to predict and many of which are beyond the Company's control. Although presented with numerical specificity, the Forecasts are not fact and reflect numerous assumptions and estimates as to future events made by the Company's management that the Company's management believed were reasonable at the time the Forecasts were prepared, including assumptions and estimates regarding factors such as industry performance and general business, economic, regulatory, market and financial conditions, as well as factors specific to the Company's businesses, such as oil and gas prices and success of production and drilling activities, all of which are difficult to predict and many of which are beyond the control of the Company's management. In addition, the Forecasts do not take into account any circumstances or events occurring after the date that they were prepared. Accordingly, there can be no assurance that the assumptions and estimates used to prepare the Forecasts will prove to be accurate, and actual results may materially differ from the Forecasts.

The inclusion of the summary of the material Forecasts in this presentation should not be regarded as an indication that the Company considered or considers the Forecasts to be a reliable prediction of future events, and the summary of the material Forecasts should not be relied upon as such. The Company is not making any representation regarding the information contained in the Forecasts and, except as may be required by applicable securities laws, does not intend to update or otherwise revise or reconcile the Forecasts to reflect circumstances existing after the date such Forecasts were generated or to reflect the occurrence of future events even in the event that any or all of the assumptions underlying the Forecasts are shown to be in error.

The Forecasts were prepared for internal use and not prepared with a view to public disclosure. The Forecasts were not prepared with a view towards compliance with the published guidelines of the Securities and Exchange Commission (the "SEC") or the guidelines established by the American Institute of Certified Public Accountants for preparation and presentation of prospective financial information. The Forecasts do not purport to present operations in accordance with U.S. generally accepted accounting principles ("GAAP"), and the Company's registered public accounting firm has not examined or otherwise applied procedures to the Forecasts.

Management believes that certain non-GAAP financial metrics are meaningful and useful to investors, analysts and/or rating agencies. Earnings before interest, taxes, depreciation, depletion and amortization, or "EBITDA" represents net income adjusted to exclude interest expense, income taxes and depreciation, depletion and amortization. "Adjusted EBITDA" represents EBITDA adjusted to exclude nonrecurring other operating items, accretion of discount on asset retirement obligations, non-cash changes in the fair value of derivatives, gains from early termination of derivatives, stock-based compensation and income or losses from equity method investments. 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 7.5% senior notes due September 15, 2018. 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 the computations. 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 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. With respect to any forward-looking EBITDA or Adjusted EBITDA information contained herein, we have not provided a quantitative reconciliation to the most comparable financial measure calculated in accordance with GAAP because such reconciliation is not available without unreasonable efforts.

The Forecasts are forward-looking statements. These statements involve certain risks and uncertainties that could cause actual results to differ materially from those in the Forecasts. There can be no assurance that any projected financial information will be, or are likely to be, realized, or that the assumptions on which they are based will prove to be, or are likely to be, correct. The Forecasts do not and should not be read to update, modify or affirm any prior financial guidance issued by the Company. Information on other important potential risks and uncertainties not discussed herein may be found in the Company's filings with the SEC, including its Annual Report on Form 10-K, as amended, for the year ended December 31, 2010 and its Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2011.

In light of the foregoing factors and the uncertainties inherent in the Forecasts, stockholders are cautioned not to place undue, if any, reliance on the Forecasts provided in this presentation.

# 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 use of derivative financial instruments; 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;
- continued disruption of credit and capital markets and the ability of financial institutions to honor their commitments;
- estimates of reserves and economic assumptions;
- geological concentration of our reserves;
- risks associated with drilling and operating wells;
- exploratory risks, including our Marcellus shale play in Appalachia and our Haynesville and Bossier shale plays 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;
- litigation;
- competition;
- general economic conditions, including costs associated with drilling and operation of our properties;
- 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 collectibility of amounts owed to us by purchasers of our production and counterparties to our derivative financial instruments;
- decisions whether or not to enter into derivative financial instruments;
- potential acts of terrorism;
- 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 our 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, the availability of capital from our revolving credit facility and liquidity from capital markets. 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.

Effective January 1, 2010, the SEC permits oil and gas companies, in their filings with the SEC, to disclose not only "proved" reserves (i.e., quantities of oil and gas that are estimated to be recoverable with a high degree of confidence), but also "probable" reserves (i.e., quantities of oil and gas that are as likely as not to be recovered) as well as "possible" reserves (i.e., additional quantities of oil and gas that might be recovered, but with a lower probability than probable reserves). In addition unless otherwise noted, certain proved reserve numbers and other reserve numbers provided herein are not SEC "case" numbers using flat commodity prices, but a management case price deck using escalating prices for a period of time. As noted above, statements of reserves are only estimates and may not correspond to the ultimate quantities of oil and gas recovered. Any reserve estimates provided in this presentation that are not specifically designated as being estimates of proved reserves may include estimated reserves not necessarily calculated in accordance with, or contemplated by, the SEC's latest reserve reporting guidelines. Investors are urged to consider closely the disclosure in our Annual Report on Form 10-K, as amended, for the fiscal year ended December 31, 2010 and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 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.

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## Corporate Overview

July 2011



## Snapshot

Continued growth during 2011

	12/31/2010	6/30/2011 E	12/31/2011 E
Net Production Exit Rate (Mmcfe/d)	385	513	600 - 650
Operated Rigs	25	27	28 - 29
Producing Operated Shale Wells	156	256	366
Employees	927	1,037	
Bank Borrowing Base (\$ in millions)	\$1,000	\$1,500	\$1,500 - \$1,800
Unused Borrowing Base + Cash (\$ in millions) <sup>(1)</sup>	\$341	\$853	\$500 - \$650

- ~33% production growth with relatively flat rig count
- Made three acquisitions totaling ~\$385 million consisting primarily of undrilled acreage and additional revenue interest in our core shale areas
- Continued financial flexibility with increased borrowing base

(1) The quarterly information in this release is preliminary and subject to revision. Final results will be provided in our Quarterly Report on form 10-Q for the three and six months ended June 30, 2011, which we currently plan to file with the Securities and Exchange Commission at the beginning of August 2011.

# Premier Asset Base with Outstanding People

High quality portfolio focused on shale resources

- **1.5 Tcfe** of SEC Year End 2010 Proved Reserves<sup>(1)</sup>
  - **1.6 Tcfe** using management price deck<sup>(2)</sup>
- **Current net production of 514 Mmcfe/d**<sup>(3)</sup>
- **Significant unproved upside**<sup>(2)</sup>
  - ~300,000 gross acres in ETX/NLA (~152,000 net); ~76,000 net acres with Haynesville/Bossier shale potential
  - ~847,000 gross acres in Appalachia (~379,000 net); ~140,000 net acres with Marcellus shale potential
  - Pursuing additional acquisition and leasing opportunities
- **Total reserve and resource base of 13.3 Tcfe**<sup>(2)(4)</sup>
- **Outstanding employees**
  - >1,000 employees
  - Experienced management team from various disciplines and backgrounds



(1) Year end 2010 SEC pricing of \$79.43 for oil and \$4.38 for natural gas. EXCO only reports proved reserves in SEC filings. Any reference to SEC reserves is to proved only.

(2) The reserves and resources and acreage estimates are pro forma for 50% of the Chief acquisition and another Appalachian acquisition, effective 12/31/10 using the management price deck shown below, adjusted for differentials and excluding hedge effects, unless otherwise noted

(3) Average production for the week ended 07/06/11, net of shut-in and curtailed volumes

(4) The shale portion of the Reserves and Resources Report was prepared by Haas Petroleum Engineering Services Inc. and accounts for 91% of the total. The non-shale portion of the Reserves and Resources Report was prepared by Lee Keeling and Associates and accounts for 9% of the total

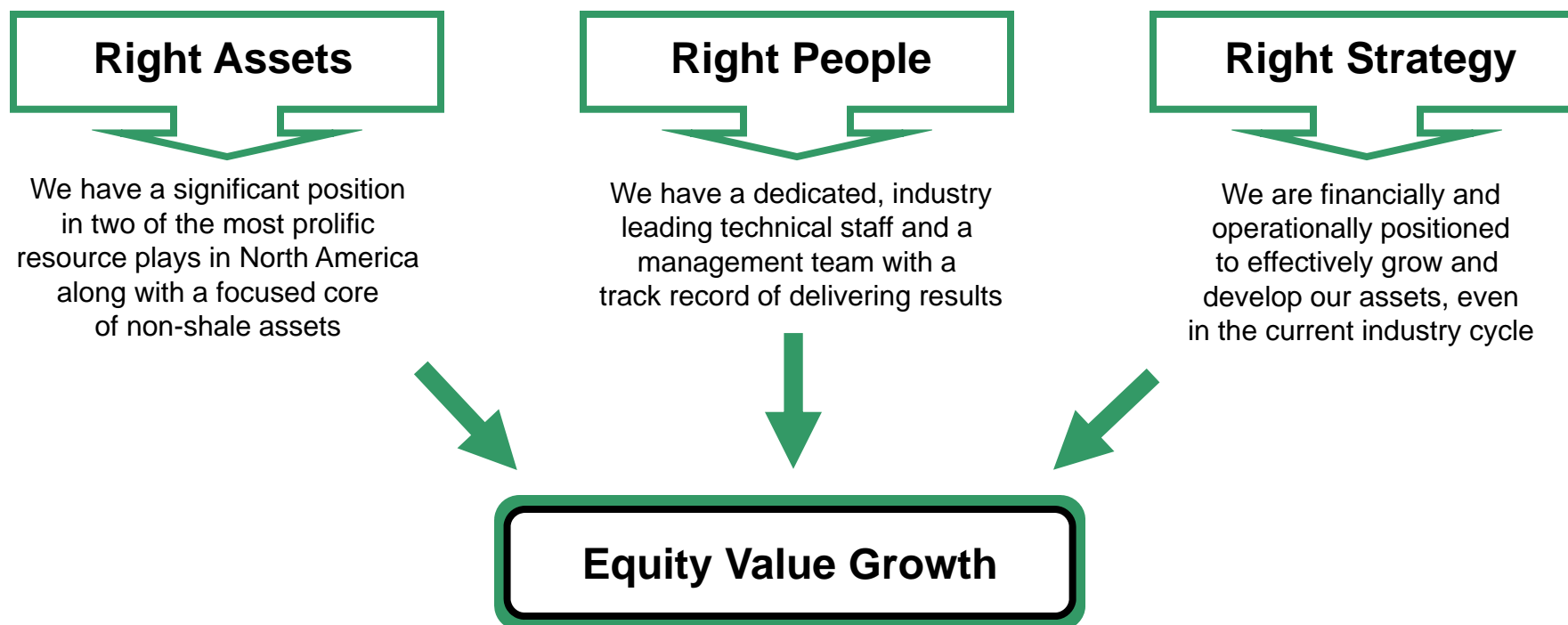
MGMT Price Deck	2011	2012	2013	2014	2015+
Oil - \$/Bbl	\$ 90.00	\$ 90.00	\$ 90.00	\$ 90.00	\$ 90.00
NG - \$/Mcf	\$ 4.50	\$ 5.00	\$ 5.25	\$ 5.50	\$ 6.00

## Unmatched Growth

Executing our plan delivers significant growth

<i>(\$'s in Millions)</i>	<b>2011E</b>	<b>2015 Target</b>
<b><u>Upstream</u></b>		
Production (Mmcfe/d)	501 - 534	1,023 - 1,142
EBITDA	\$650 - \$680	\$1,692 - \$1,943
Capital Expenditures	\$946 - \$1,006	\$1,000 - \$1,250
Net Debt	\$1,575 - \$1,675	\$0 - \$575
<b><u>Midstream (EXCO's 50% Share)</u></b>		
EBITDA	\$60 - \$70	\$205 - \$245
Capital Expenditures	\$145 - \$165	\$65 - \$85
Net Debt	\$225 - \$255	\$80 - \$110

## Keys to EXCO's Success



### Acquisition Strategy

- Focus on adding acreage and production in core areas to incorporate into development program
- Acreage additions enhance multi-year drilling inventory

### Drilling Strategy

- Grow production, cash flow, and reserves through the drill-bit
- Balance costs and risks to maximize value



EXCO Resources, Inc.



## Financial Summary & Updated Guidance

July 2011



## Corporate Highlights

(\$ in thousands)	Full Year 2010 Actuals	Q1 2011 Actuals	Guidance Midpoint
	Amount	Amount	Amount
Oil and natural gas revenues	\$ 515,226	\$ 161,228	\$ 206,500
Cash settlements of derivatives	\$ 217,455	\$ 26,935	\$ 23,200
Oil and natural gas revenues including derivatives	\$ 732,681	\$ 188,163	\$ 229,700
Adjusted EBITDA <sup>(1)</sup>	\$ 478,022	\$ 126,156	\$ 162,400
Cash flow from operations <sup>(1)(2)</sup>	\$ 433,877	\$ 113,287	\$ 149,500
Average daily production – Mmcfe/d	307	408	500

- Second quarter 2011 updated guidance for production of ~500 Mmcfe/d (net of ~23 Mmcfe/d of curtailed production related to TGGT incident, described further on page 35) increased **23%** from Q1 2011 production of 408 Mmcfe/d

(1) Non-GAAP measure, please see the Investor Relations section of our website ([www.excoresources.com](http://www.excoresources.com)) under the tab Non-GAAP reconciliations for Q1 reconciliation

(2) Cash flow from operations before changes in working capital, non-recurring other operating items, and including settlements of derivative financial instruments with a financing element

## Liquidity and Financial Position

\$ in thousands	3/31/2011	6/30/2011 <sup>(1)</sup>
Cash <sup>(2)</sup>	\$ 159,120	\$ 214,401
Bank debt (LIBOR + 1.5% to 2.5%)	589,000	851,500
Senior notes due 2018 (7 1/2%) <sup>(3)</sup>	750,000	750,000
Total debt	1,339,000	1,601,500
Net debt	\$ 1,179,880	\$ 1,387,099
Borrowing base <sup>(4)</sup>	\$ 1,500,000	\$ 1,500,000
Unused borrowing base <sup>(5)</sup>	\$ 895,500	\$ 639,000
<b>Unused borrowing base plus cash<sup>(2)(5)</sup></b>	<b>\$ 1,054,620</b>	<b>\$ 853,401</b>

- Redetermined borrowing base under credit facility; increased from \$1.0 billion to \$1.5 billion, effective April 1, 2011

(1) The June quarterly information in this release is preliminary and subject to revision. Final results will be provided in our Quarterly Report on form 10-Q for the three and six months ended June 30, 2011, which we currently plan to file with the Securities and Exchange Commission at the beginning of August 2011.

(2) Includes \$150.6 million and \$149.2 million of JV restricted cash at 3/31/2011 and 6/30/2011, respectively

(3) Excludes bond discount

(4) As of April 1, 2011, bank borrowing base was redetermined at \$1.5 billion

(5) Net of \$9.5 million in letters of credit at 6/30/2011 and \$15.5 million at 3/3/2011

## Summary of Indebtedness

- EXCO Resources Credit Agreement – due 4/30/16
  - \$851.5 million outstanding as of 6/30/11, \$1.5 billion borrowing base
  - Financial covenants:
    - Debt to EBITDAX (as defined in the agreement) maximum of 4.0 to 1.0
    - Current ratio (as defined in the agreement) minimum of 1.0 to 1.0
  
- EXCO Resources 7½ Senior Notes – due 9/15/18
  - \$750 million in principal outstanding as of 6/30/11
  - Limitation on Indebtedness
    - Coverage ratio (as defined in the indenture) maximum of 2.25 to 1.0
    - Credit facility not to exceed to greater of:
      - \$1.2 billion
      - 75% of ANCTA (as defined in the indenture), estimated \$1.9 billion limitation as of 12/31/10
    - Restricted payment basket estimated at \$560 million as of 12/31/10
  
- TGGT Credit Agreement – due 1/31/2016
  - Not guaranteed or secured by EXCO, not part of EXCO's consolidated debt
  - \$367.1 million outstanding as of 6/30/11, \$500 million revolving facility
  - Interest rate of LIBOR plus 200 -300 bps, depending on Debt to EBITDA ratio (as defined in the agreement)
  - Financial covenants:
    - Debt to EBITDAX (as defined in the agreement) maximum of 5.0 to 1.0
    - Interest coverage ratio (as defined in the agreement) minimum of 2.5 to 1.0

## Derivative Position

Includes all positions entered into through 6/30/2011

	NYMEX natural gas Mmcf	Contract price per Mcf	NYMEX oil Bbls	Contract price per Bbl	Equivalent Mmcf	Equivalent Mmcf/d	Contract price per Equivalent	% Hedged Forecast
Q1 2011	19,260	\$ 5.36	135,000	\$ 111.32	20,070	223	5.90	55%
Q2 2011	23,495	5.25	136,500	111.32	24,314	267	5.70	52%
Q3 2011	30,820	5.17	138,000	111.32	31,648	344	5.52	58%
Q4 2011	30,820	5.17	138,000	111.32	31,648	344	5.52	53%
2012	78,690	5.29	274,500	95.70	80,337	220	5.51	26%
2013	5,475	5.99	-	-	5,475	15	5.99	1%
Total	188,560	\$ 5.28	822,000	\$ 106.10	193,492		\$ 5.59	

- Positions entered into since the end of 2010:

NG Trades Added	Mmcf/d	Strike
2011	131	\$ 4.76
2012	140	\$ 5.10

- Bank Hedge Limitations (% of Total Proved)
  - Year 1: ~ 100%
  - Year 2: ~ 100%
  - Year 3: ~ 90%
  - Year 4: ~ 85%
  - Year 5: ~ 85%
- Target Hedge Levels (% of Expected)
  - Year 1: ~ 50%
  - Year 2: ~ 25%
  - Year 3: ~ 15%

## Second Quarter 2011 Original Guidance vs. Updated Guidance

Strong performance despite ~23 Mmcfe/d curtailment; expect higher EBITDA than original guidance

(dollars in thousands, except per unit amounts)	Second Quarter 2011			Second Quarter 2011			Impacts of TGGT Facility Incident
	Original Guidance at Q1 2011 Review: Low	High	Midpoint	Updated Guidance with Preliminary Q2 Results: Low	High	Midpoint	
<b>Production:</b>							
Oil - Mbbls	188	196	192	176	180	178	
Gas - Mmcf	43,920	45,692	44,806	44,262	44,602	44,432	
Mmcfe	45,045	46,865	45,955	45,318	45,682	45,500	
Mmcfe/d	495	515	505	498	502	500	Averaged 23 Mmcfe/d of curtailed net volumes Without impact of curtailed volumes, production would have exceeded High end of Original Guidance
<b>Differentials to NYMEX:</b>							
Oil per Bbl	\$ (4.00)	\$ (3.40)	\$ (3.70)	\$ (3.45)	\$ (3.35)	\$ (3.40)	
Gas per Mcf	96.0%	98.0%	97.0%	98.0%	99.0%	98.5%	
Lease operating expense	\$ 19,500	\$ 22,500	\$ 21,000	\$ 20,500	\$ 21,500	\$ 21,000	
Non-cash stock based compensation - LOE	\$ 50	\$ 250	\$ 150	\$ 50	\$ 70	\$ 60	
Gathering expense - per Mcfe	\$ 0.45	\$ 0.55	\$ 0.50	\$ 0.41	\$ 0.45	\$ 0.43	
Production tax rate	3.5%	4.5%	4.0%	2.8%	3.4%	3.1%	
Other income	\$ 250	\$ 500	\$ 375	\$ 1,750	\$ 2,250	\$ 2,000	
DD&A rate per Mcfe	\$ 1.85	\$ 1.95	\$ 1.90	\$ 1.85	\$ 1.91	\$ 1.88	
Asset retirement obligation	\$ 800	\$ 1,100	\$ 950	\$ 800	\$ 1,000	\$ 900	
Cash G&A	\$ 22,000	\$ 24,000	\$ 23,000	\$ 20,250	\$ 21,250	\$ 20,750	
Non-cash stock based compensation - G&A	\$ 2,000	\$ 3,000	\$ 2,500	\$ 2,000	\$ 2,800	\$ 2,400	
Interest expense - cash	\$ 11,000	\$ 13,000	\$ 12,000	\$ 11,500	\$ 12,500	\$ 12,000	
Interest expense - non-cash	\$ 1,600	\$ 1,900	\$ 1,750	\$ 1,600	\$ 1,900	\$ 1,750	
Equity income	\$ 9,000	\$ 12,000	\$ 10,500	\$ 3,000	\$ 4,000	\$ 3,500	Impairment charge of approximately \$6.0 - 7.5 MM
Income tax rate	40%	40%	40%	40%	40%	40%	
Income tax deferred	100%	100%	100%	100%	100%	100%	
CAPEX	\$ 246,100	\$ 266,100	\$ 256,100	\$ 246,100	\$ 266,100	\$ 256,100	
Fully diluted shares outstanding	216,000	218,000	217,000	217,000	218,000	217,500	
Adjusted EBITDA at Midpoint	\$153,400		\$ 153,400	\$164,000		\$ 164,000	
EXCO's share of TGGT's Adjusted EBITDA	\$ 14,000	\$ 17,000	\$ 15,500	\$ 14,000	\$ 15,000	\$ 14,500	Reduced treating fees and throughput lowered EBITDA by ~\$1.8 MM

# Quarterly 2011 Guidance

## Forecasting annual production growth in excess of 60% compared to full year 2010

- 25 – 30 Mmcf/d of curtailed volume in Q3 associated with the TGGT facility incident is expected to be offset by increased production

(dollars in thousands, except per unit amounts)	Q1 2011	Updated Q2 2011E		Q3 2011E		Q4 2011E		2011E	
	Actual	Low	High	Low	High	Low	High	Low	High
<b>Production:</b>									
Oil - Mbbls	193	176	180	194	202	199	207	762	782
Gas - Mmcf	35,525	44,262	44,602	48,059	52,611	50,326	57,638	178,172	190,376
Mmcf	36,683	45,318	45,682	49,220	53,820	51,520	58,880	182,741	195,065
Mmcf/d	408	498	502	535	585	560	640	501	534
<b>Differentials to NYMEX:</b>									
Oil per Bbl	\$ (4.09)	\$ (3.45)	\$ (3.35)	\$ (4.00)	\$ (3.40)	\$ (4.00)	\$ (3.40)	\$ (3.90)	\$ (3.56)
Gas per Mcf	98.4%	98.0%	99.0%	96.0%	98.0%	96.0%	98.0%	97.0%	98.3%
Lease operating expense	\$ 19,252	\$ 20,500	\$ 21,500	\$ 20,000	\$ 23,000	\$ 20,500	\$ 23,500	\$ 80,250	\$ 87,250
Non-cash stock based compensation - LOE	\$ 83	\$ 50	\$ 70	\$ 50	\$ 250	\$ 50	\$ 250	\$ 230	\$ 650
Gathering expense - per Mcfe	\$ 0.47	\$ 0.41	\$ 0.45	\$ 0.45	\$ 0.55	\$ 0.45	\$ 0.55	\$ 0.44	\$ 0.51
Production tax rate	3.5%	2.8%	3.4%	3.5%	4.5%	3.5%	4.5%	3.3%	4.1%
Other income <sup>(1)</sup>	\$ 968	\$ 1,750	\$ 2,250	\$ 250	\$ 500	\$ 250	\$ 500	\$ 3,220	\$ 4,220
DD&A rate per Mcfe	\$ 1.86	\$ 1.85	\$ 1.91	\$ 1.85	\$ 1.95	\$ 1.85	\$ 1.95	\$ 1.85	\$ 1.92
Asset retirement obligation	\$ 857	\$ 800	\$ 1,000	\$ 800	\$ 1,100	\$ 800	\$ 1,100	\$ 3,260	\$ 4,060
Cash G&A	\$ 20,838	\$ 20,250	\$ 21,250	\$ 23,000	\$ 25,000	\$ 23,000	\$ 25,000	\$ 87,090	\$ 92,090
Non-cash stock based compensation - G&A	\$ 2,585	\$ 2,000	\$ 2,800	\$ 2,000	\$ 3,000	\$ 4,000	\$ 5,000	\$ 10,590	\$ 13,390
Interest expense - cash	\$ 12,869	\$ 11,500	\$ 12,500	\$ 11,000	\$ 13,000	\$ 11,000	\$ 13,000	\$ 46,370	\$ 51,370
Interest expense - non-cash	\$ 1,947	\$ 1,600	\$ 1,900	\$ 1,600	\$ 1,900	\$ 1,600	\$ 1,900	\$ 6,750	\$ 7,650
Equity income	\$ 8,545	\$ 3,000	\$ 4,000	\$ 8,500	\$ 11,500	\$ 15,000	\$ 19,000	\$ 35,050	\$ 43,050
Income tax rate	40%	40%	40%	40%	40%	40%	40%	40%	40%
Income tax deferred	100%	100%	100%	100%	100%	100%	100%	100%	100%
CAPEX	\$ 245,611	\$ 246,100	\$ 266,100	\$ 231,500	\$ 251,500	\$ 223,000	\$ 243,000	\$ 946,210	\$ 1,006,210
Fully diluted shares outstanding	217,110	217,000	218,000	216,000	218,000	216,000	218,000	216,500	217,800
Adjusted EBITDA at Midpoint <sup>(2)(3)</sup>	\$126,156	\$164,000		\$178,400		\$197,800		\$666,400	
EXCO's share of TGGT's Adjusted EBITDA	\$ 12,292	\$ 14,000	\$ 15,000	\$ 14,000	\$ 17,000	\$ 20,000	\$ 24,000	\$ 60,292	\$ 68,292

(1) Excludes \$2,975K and 2,980K in non-recurring legal expenses and expenses associated with the potential going private transaction in Q1 and Q2, respectively

(2) Non-GAAP measure, please see the Investor Relations section of our website ([www.excoresources.com](http://www.excoresources.com)) under the tab Non-GAAP reconciliations

(3) 2011 estimates based on natural gas and oil NYMEX prices of \$4.32 for Q2, \$4.50 for Q3, \$4.75 for Q4, and \$102.56 for Q2, \$100.00 for Q3 – Q4, respectively



EXCO Resources, Inc.



## Net Asset Values

July 2011



## Net Asset Value Assumptions

- Based on Financial Modeling Report described on pages 45 – 59
- Report was “rolled-forward” to respective future dates
  - Unproved reserve and resource locations converted into forecasted Proved Developed Reserves in the year drilled
- Risked present values based on future cash flows as of each effective date
  - Based on management’s assessment of risk by area
- Assumes the following management price deck

MGMT Price Deck	2011	2012	2013	2014	2015+
Oil - \$/Bbl	\$ 90.00	\$ 90.00	\$ 90.00	\$ 90.00	\$ 90.00
NG - \$/Mcf	\$ 4.50	\$ 5.00	\$ 5.25	\$ 5.50	\$ 6.00

- Actual NYMEX forward curve as of July 5<sup>th</sup>, 2011

NYMEX Price Deck	2011	2012	2013	2014	2015+
Oil - \$/Bbl	\$ 98.30	\$ 101.42	\$ 102.39	\$ 101.96	\$ 101.34
NG - \$/Mcf	\$ 4.34	\$ 4.84	\$ 5.16	\$ 5.40	\$ 5.66

# Risked Net Asset Value<sup>(1)</sup>

## Management Price Deck

MGMT Price Deck	2011	2012	2013	2014	2015+
Oil - \$/Bbl	\$ 90.00	\$ 90.00	\$ 90.00	\$ 90.00	\$ 90.00
NG - \$/Mcf	\$ 4.50	\$ 5.00	\$ 5.25	\$ 5.50	\$ 6.00

In millions, except per share and per unit	12/31/2010 E Value	6/30/2011 E Value	12/31/2013 E Value	12/31/2015 E Value
Forecasted Proved Developed Reserves	\$ 1,787	\$ 2,220	\$ 5,647	\$ 7,682
Undeveloped Reserves and Resources				
Haynesville	1,456	1,525	492	387
Bossier	329	361	508	259
Marcellus	991	1,067	1,227	1,204
Non-Shale	163	161	110	130
Total Undeveloped Reserves and Resources	2,939	3,114	2,337	1,980
<b>Total of E&amp;P Assets</b>	<b>\$ 4,726</b>	<b>\$ 5,334</b>	<b>\$ 7,984</b>	<b>\$ 9,662</b>
TGGT Midstream	1,162	1,191	1,798	2,161
Appalachia Midstream	-	-	-	-
Working Capital	210	225	342	731
Hedges	112	73	-	-
Carry	157	98	-	-
Vernon Midstream	50	50	46	44
<b>Total Asset Value</b>	<b>\$ 6,417</b>	<b>\$ 6,971</b>	<b>\$ 10,170</b>	<b>\$ 12,598</b>
Less: Long-term Debt	1,407	1,602	1,312	750
<b>Equity Value</b>	<b>\$ 5,010</b>	<b>\$ 5,369</b>	<b>\$ 8,858</b>	<b>\$ 11,848</b>
Fully Diluted Shares	220	221	224	226
<b>NAV per Share</b>	<b>\$ 22.75</b>	<b>\$ 24.31</b>	<b>\$ 39.52</b>	<b>\$ 52.54</b>

(1) Forecasted reserves and resources on this page based on financial modeling report described on pages 45 – 59 of this presentation

# E&P Asset Value<sup>(1)</sup>

## Management Price Deck

MGMT Price Deck	2011	2012	2013	2014	2015+
Oil - \$/Bbl	\$ 90.00	\$ 90.00	\$ 90.00	\$ 90.00	\$ 90.00
NG - \$/Mcf	\$ 4.50	\$ 5.00	\$ 5.25	\$ 5.50	\$ 6.00

	12/31/2010 E Value	6/30/2011 E Value	12/31/2013 E Value	12/31/2015 E Value
<u>E&amp;P Asset Value (\$ in millions):</u>				
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<b>Total E&amp;P Asset Value</b>	<b>\$ 4,726</b>	<b>\$ 5,334</b>	<b>\$ 7,984</b>	<b>\$ 9,662</b>
<u>Net Unrisked Reserves and Resources (Bcfe):</u>				
Forecasted Proved Developed Reserves	946	1,083	2,327	3,221
Undeveloped Reserves and Resources				
Haynesville	3,113	2,944	1,629	1,327
Bossier	1,381	1,381	1,282	687
Marcellus	5,373	5,338	4,717	3,981
Non-Shale	239	229	172	99
Total Undeveloped Reserves and Resources	10,106	9,893	7,800	6,095
<b>Total Net Reserves</b>	<b>11,052</b>	<b>10,976</b>	<b>10,127</b>	<b>9,316</b>
<u>E&amp;P Asset Value per Mcfe:</u>				
Forecasted Proved Developed Reserves	\$ 1.89	\$ 2.05	\$ 2.43	\$ 2.38
Undeveloped Reserves and Resources				
Haynesville	0.47	0.52	0.30	0.29
Bossier	0.24	0.26	0.40	0.38
Marcellus	0.18	0.20	0.26	0.30
Non-Shale	0.68	0.70	0.64	1.31
Total Undeveloped Reserves and Resources	0.29	0.31	0.30	0.32
<b>E&amp;P Asset Value per Mcfe</b>	<b>\$ 0.43</b>	<b>\$ 0.49</b>	<b>\$ 0.79</b>	<b>\$ 1.04</b>

(1) Forecasted reserves and resources on this page based on financial modeling report described on pages 45 – 59 of this presentation



EXCO Resources, Inc.

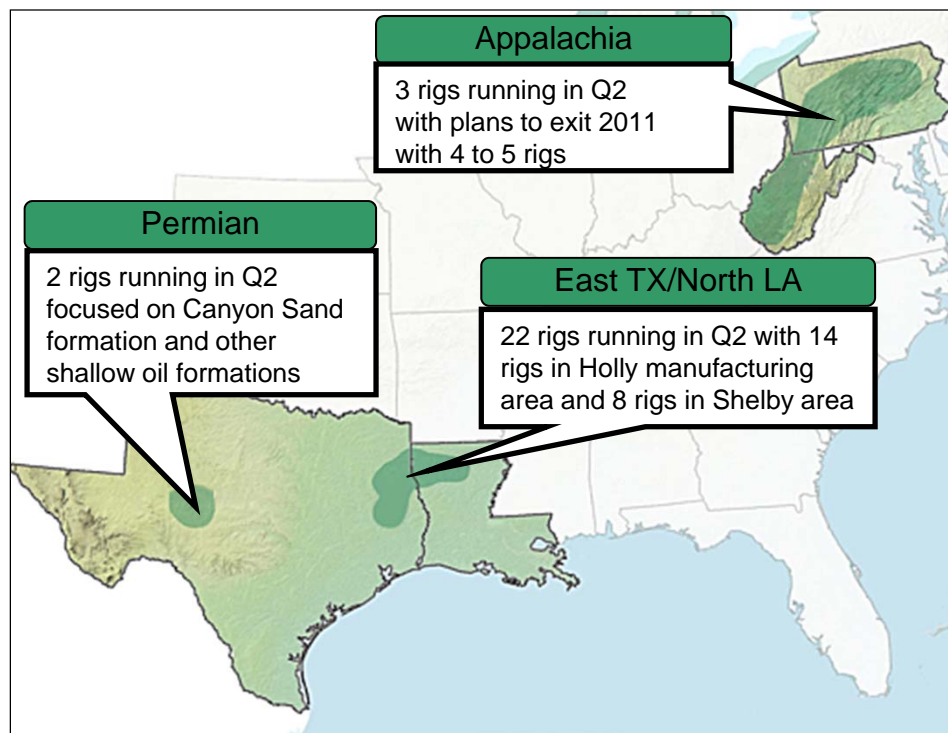


## Operations Update

July 2011



## Q2 2011 Operations Highlights



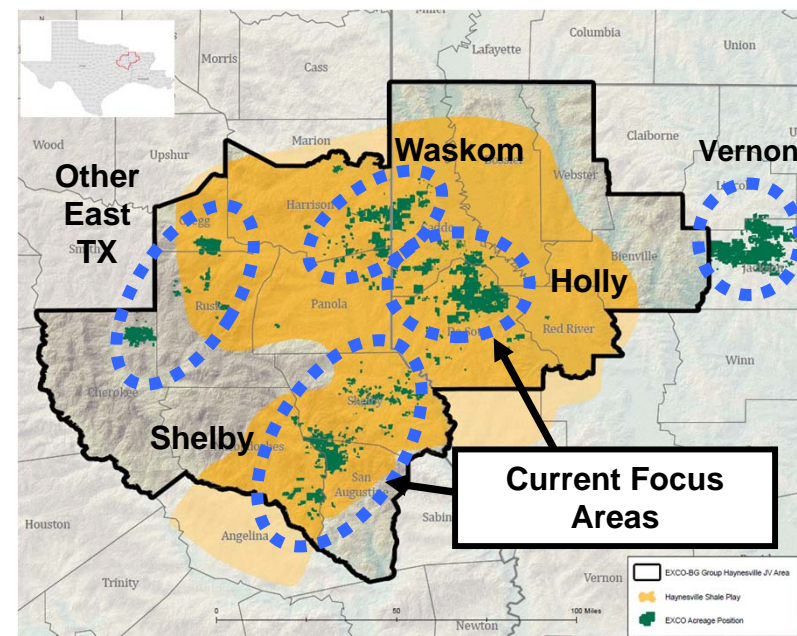
- Record net production volumes of ~500 Mmcf/d despite ~23 Mmcf/d curtailed during Q2 as a result of TGGT incident; exceeded 1 Bcfe/d of gross operated production in East Texas/North Louisiana
- 27 operated drilling rigs, inclusive of all divisions, with a 99% drilling success rate
- Continued success from manufacturing development program in our Holly area in North Louisiana; average IP rates of 18 Mmcf/d
- Outstanding results in the Highlander segment of our Shelby area in East Texas, with average IP rates >28 Mmcf/d
- Positioning Marcellus development program in northeast Pennsylvania; currently completing six wells on development acreage in northeast Pennsylvania and four wells in central Pennsylvania

	Q2 2011 Wells Completed (Gross)	Q2 2011 Wells Completed (Net)
Haynesville/Bossier	47	20.4
Marcellus	6	2.7
Permian	18	17.5
<b>Total</b>	<b>71</b>	<b>40.6</b>

## East Texas/North Louisiana

### Continued success in our core Haynesville/Bossier development areas

- Current operated shale production of 1.1 Bcf/d gross (347 Mmcf/d net); including OBO (operated by others), net production totals 372.5 Mmcf/d as of 7/6/11
  - ~23 Mmcf/d curtailed due to TGGT incident
- Currently have 222 operated and 123 OBO wells turned to sales
- Continuous improvement in drilling days and optimization of frac designs have helped costs remain relatively flat
  - Holly: 42.6 days spud to rig release; \$9.5 million average well cost
  - Shelby: 51.1 days spud to rig release; \$12.0 million average well cost
- Frac design optimization and faster completion cycle times have resulted in low completion inventory
  - Currently 12 wells waiting on completion
- Focus on water management has resulted in access to multiple water sources, including effluent water from local paper mill



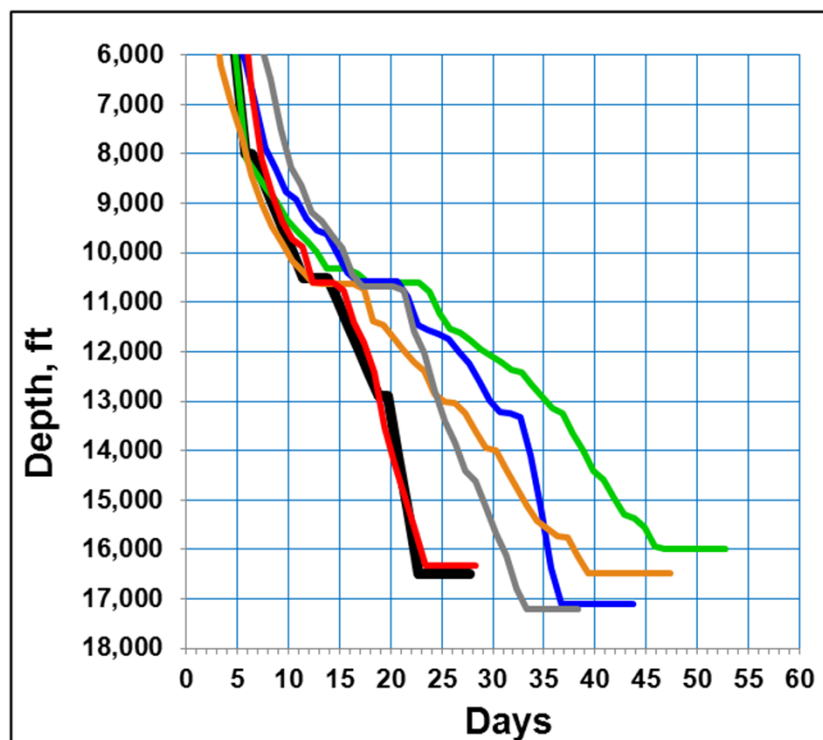
	Holly	Waskom	Shelby	Other East TX	Total	PV 10 (\$MM)
<b>Shale Reserves (Bcfe)<sup>(1)</sup></b>						
PD	199	2	26	-	228	\$ 563.5
PUD	485	-	11	-	496	529.3
<b>Total Proved</b>	<b>683</b>	<b>2</b>	<b>38</b>	<b>-</b>	<b>724</b>	<b>1,092.8</b>
Probable	244	-	45	-	289	434.7
Possible	314	-	151	-	464	644.1
<b>Total 3P</b>	<b>1,241</b>	<b>2</b>	<b>234</b>	<b>-</b>	<b>1,478</b>	<b>2,171.7</b>
Resources	1,302	493	2,911	-	4,706	4,236.6
<b>Grand Total</b>	<b>2,543</b>	<b>496</b>	<b>3,145</b>	<b>-</b>	<b>6,183</b>	<b>\$ 6,408.2</b>
Shale locations - gross	2,309	536	1,954	-	4,799	
Shale acres - net	23,000	14,000	24,000	15,000	76,000	
HBP%	95%	83%	25%	39%	60%	

(1) The reserves and resources and acreage estimates are pro forma for 50% of the Chief acquisition and another Appalachian acquisition, effective 12/31/10 using the management price deck, adjusted for differentials and excluding hedge effects

## East Texas/North Louisiana

### Drilling efficiencies gained with long-term contracts

#### Longest Contracted Flex Rig in EXCO's Fleet (2.9 years)

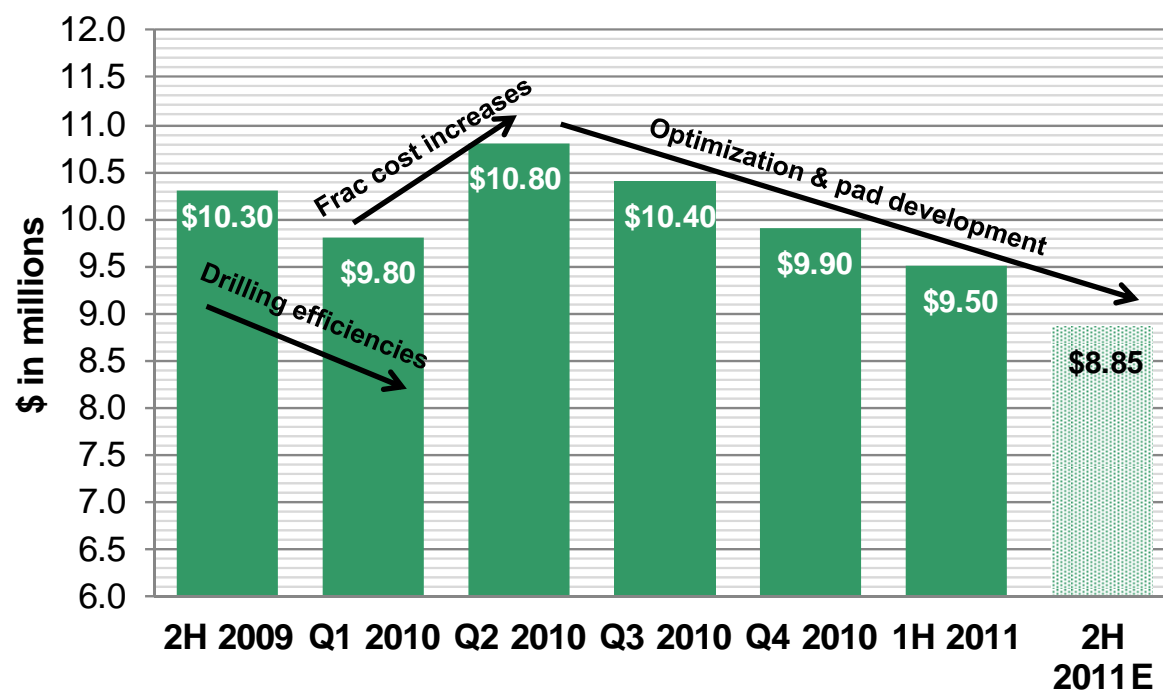


- **North Louisiana:**
  - As tracked by our bit contractors, EXCO has drilled the fastest lateral to date by any operator in the Haynesville
  - EXCO drilled its fastest well in 28 days, spud to rig release
  - On 11 wells, EXCO drilled the curve and entire lateral with one single bit run
  - In one well, EXCO drilled the surface to intermediate section with one bit run
- **Drilling Optimization Studies Ongoing:**
  - Reduction of non-productive time
  - Design specific equipment
  - Procuring firm pricing schedules
  - Re-design of locations to aid efficiency and costs

## East Texas/North Louisiana

### Cost saving initiatives

Implementing significant capital cost reduction in North LA



### Variable components of cost reduction:

- Drilling
  - Bit selection
  - Efficiencies
  - Reducing non productive time
- Completions
  - Proppant type/volumes
  - Horsepower
  - Equipment rentals
  - Perforation spacing

- Current North Louisiana well cost is \$9.35 million
- Targeting 2H 2011 well cost of \$8.85 million at current service cost levels
- Implementing similar efforts in East Texas

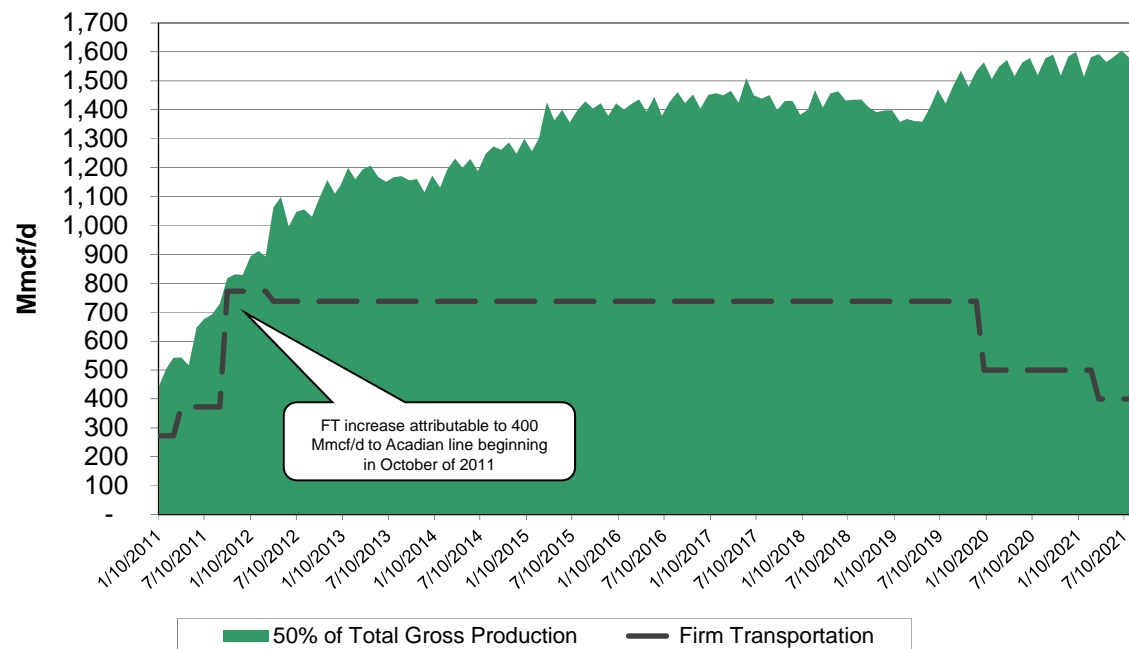
# Haynesville/Bossier

## Focus for 2011

- **Reduce Costs Without Sacrificing Well Performance:**
  - Continuous review of best practices
  - Faster drilling times
  - Optimize proppant mix
  - Improve consistency through standardized practices
  - Further optimize pad design for simultaneous operations (SIMOPS)
- **Improve EURs:**
  - Optimize cluster spacing and completion designs
  - Optimize choke management program
  - Enhance surveillance and technical analysis
  - Evaluate and test refrac opportunities
- **Optimize Downtime:**
  - Enhance scheduling to minimize well downtime (frac dates, tubing installs, batch treatments, pipeline access)
  - In-house, real-time monitoring of pipeline pressure, well site alarms, and ability to manage flow
- **Enhance EHS:**
  - Continuous review and implementation of best practices
  - Security and remote well monitoring
  - Further enhance EHS and SIMOPS policies and procedures into contractor work force
  - Continue to manage fracture stimulation and green house gas programs

## East TX / North LA Gas Marketing

### Current Firm Transportation Agreements



- Significant downstream takeaway agreements currently in place
- Potential to also move Shelby gas on Enterprise Acadian and/or ETC Tiger
- Current FT commitments are sufficient based on current marketing agreements and availability of interruptible capacity

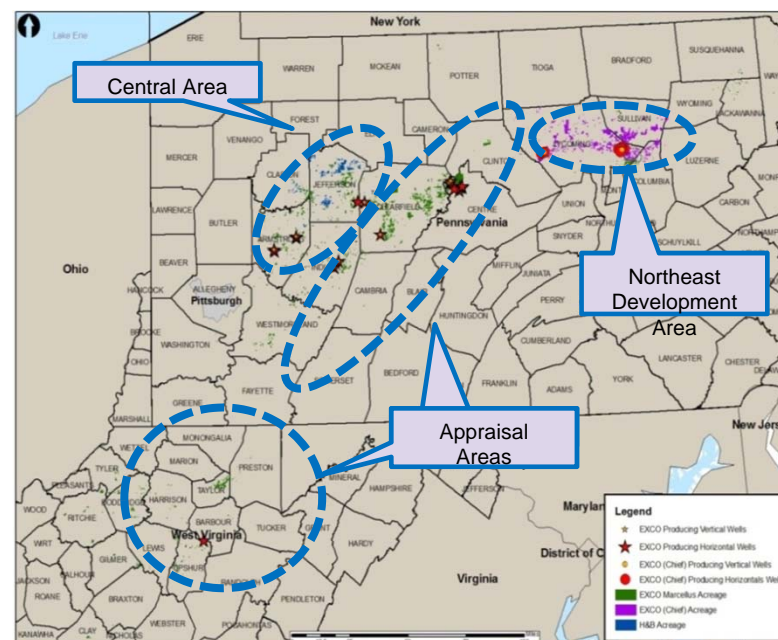
#### EXCO Holly Area Firm Transportation Agreements

Pipeline	Rate/ Mcf	FT Mmcf/d	Start	End
Crosstex	\$ 0.16	35.0	Feb-07	Mar-12
Regency	0.30	237.5	Feb-10	Jan-20
ETC Tiger	0.36	100.0	Dec-10	Nov-20
Enterprise Acadian	0.33	400.0	Oct-11	Sep-21
<b>Total FT</b>	<b>\$ 0.31</b>	<b>772.5</b>		

# Appalachia – Significant Resource Potential

## Current development focused on Northeast Area

- 847,000 gross acres (379,000 net) with ~140,000 net acres with Marcellus shale potential
  - Significant held by production position
- Currently operating 3 rigs with plans to add 1-2 additional rigs by year-end 2011
- Drilling days continue to improve; average days to drill horizontal section reduced from an average of 25 days in Q2 2010 to 15 days now, with average lateral length of ~3,800 feet
- Completing 6 wells in the Northeast Development Area and 4 wells in the Central Area
  - Northeast Development Area well completed in early 2011 had 10.6 Mmcf/d IP from lateral of 4,168 feet
- Q2 2011 appraisal program resulted in IP's ranging from 1.9 Mmcf/d to 5.1 Mmcf/d, with lateral lengths averaging 3,604 feet
  - Best Q2 2011 IP of 5.1 Mmcf/d came from shortest lateral of 3,206 feet



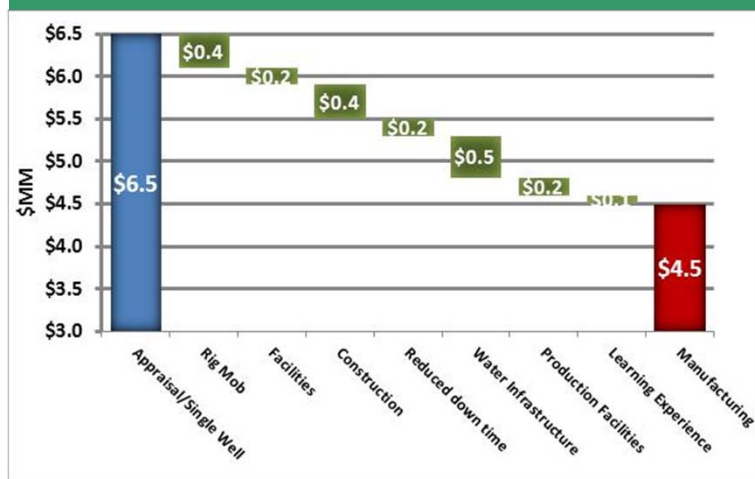
	Central Development	Northeast Development	Appraisal	Total	PV 10 (\$MM)
<u>Shale Reserves (Bcfe)<sup>(1)</sup></u>					
PD	5	18	3	26	\$ 185
PUD	1	16	-	18	33
<b>Total Proved</b>	<b>6</b>	<b>34</b>	<b>3</b>	<b>43</b>	<b>218</b>
Probable	5	35	-	40	69
Possible	2	99	-	102	146
<b>Total 3P</b>	<b>14</b>	<b>168</b>	<b>3</b>	<b>185</b>	<b>434</b>
Resources	1,585	915	3,235	5,735	4,685
<b>Grand Total</b>	<b>1,598</b>	<b>1,083</b>	<b>3,238</b>	<b>5,920</b>	<b>\$ 5,119</b>
Shale locations - gross	973	934	2,634	4,541	
Approx shale acres - net	55,000	35,000	50,000	140,000	
HBP%				56%	

(1) The reserves and resources and acreage estimates are pro forma for 50% of the Chief acquisition and another Appalachian acquisition, effective 12/31/10 using the management price deck, adjusted for differentials and excluding hedge effects

# Marcellus Capital

Shift to development program will result in lower costs

## Cost Reduction Initiatives



### Contractor Resources and Management

- Build local workforce and service points
- Keep crews and expertise intact

### People and Technology

- Strong technical professionals
- Experience in shale development plays
- Staff well connected and well respected in industry
- Securing resources for future development at competitive costs

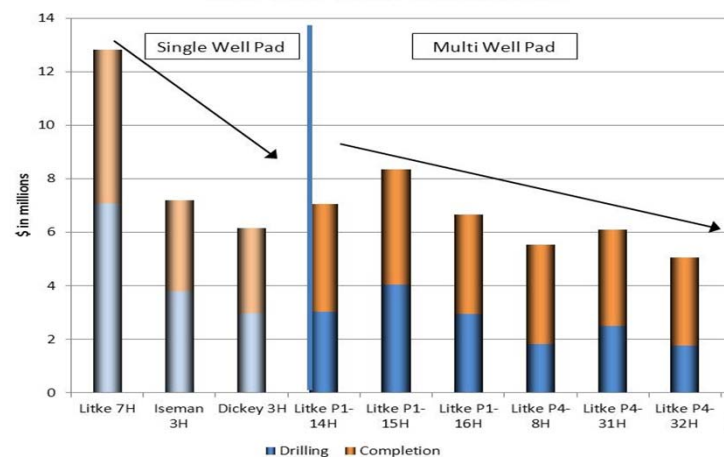
### Infrastructure

- Water transportation systems
- Local service points for contractors
- Roads
- Impoundments
- Central gas gathering and collection facilities

### Shift from Single Well/Appraisal to Pad Development

- Multi well pad efficiencies
- High cost drivers shared between wells
  - Roads and locations
  - Water management systems
  - Equipment mobilization and demobilization
  - Well site facilities

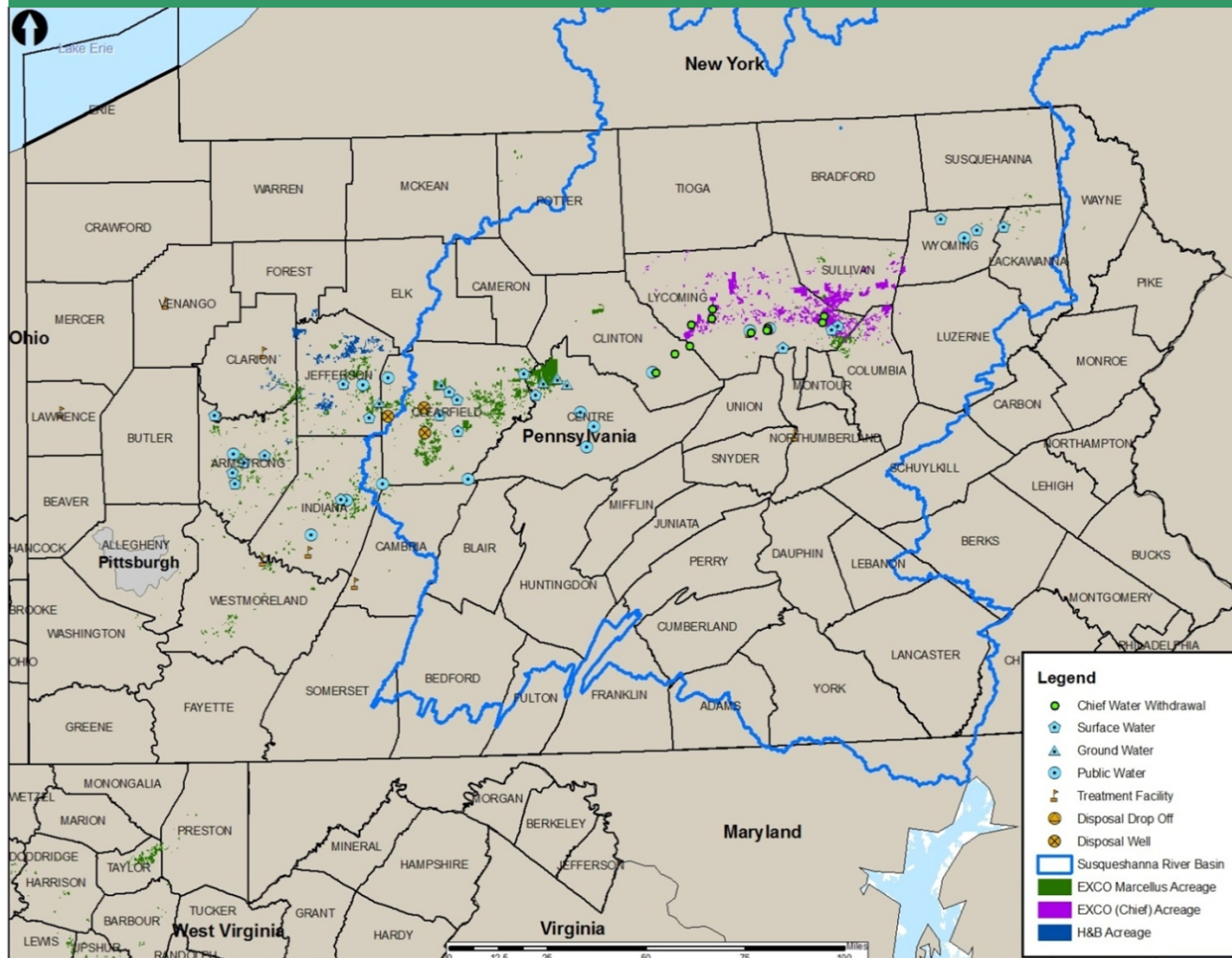
## Actual Total Well Cost



# Appalachia Water Procurement & Disposal

## Recycled more than 90% of frac water in 2011

### Marcellus Water Procurement & Disposal



- Water management staff of eight employees
- 18 MMgpd of water available from 31 surface sources and public supplies
- Current storage capacity of 60 million gallons and growing
- EXCO operates two of the eight disposal wells in PA
- Five water treatment facilities
- Currently testing new technologies for water treatment

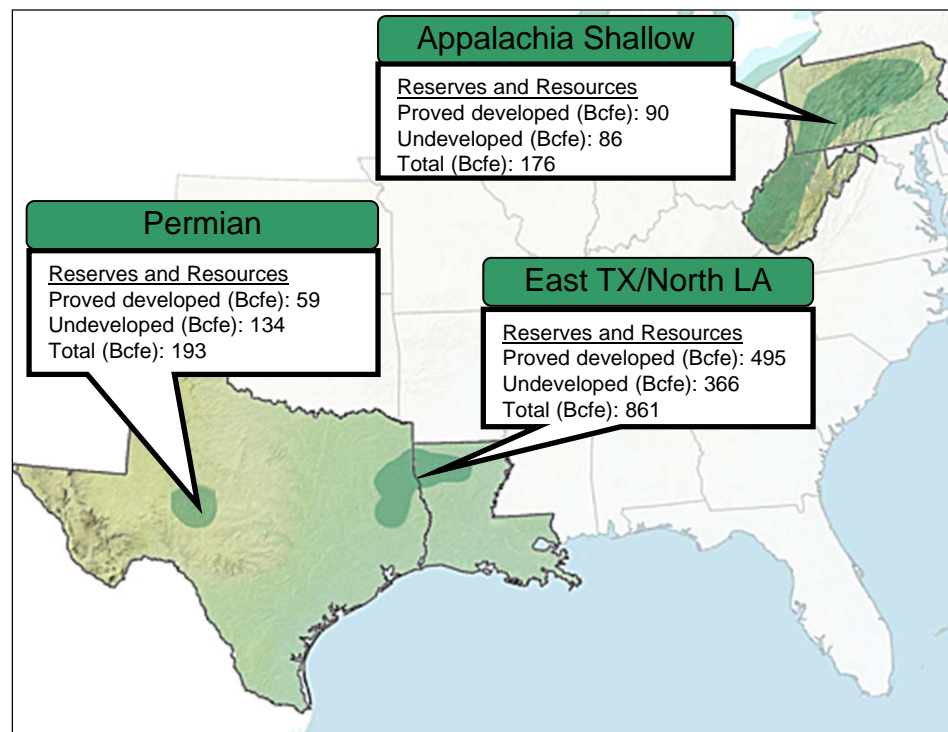
# Marcellus

## Focus for 2011

- **Development in the Northeast Area**
- **Continue to improve technical understanding of the Marcellus shale play**
  - Pennsylvania production data available
  - Competitor data trades
  - In-house operational results and experience
- **Identify best rock**
  - Significant existing acreage within best rock areas
    - Two rig development program underway
  - Additional acreage in areas of low industry activity
    - One rig appraisal program underway (opportunity for first mover)
  - Acreage in lower performing areas
    - Analyzing data to determine upside potential (majority HBP, no time constraints)
- **Accelerate appraisal and portfolio optimization**
  - Prioritized acreage to rapidly move into gas manufacturing mode in proven areas
  - Maximize take away from existing infrastructure; leverage commercial and TGGT expertise

## Non-shale “Conventional” Assets

>1.2 Tcf of reserves and resources potential<sup>(1)</sup>



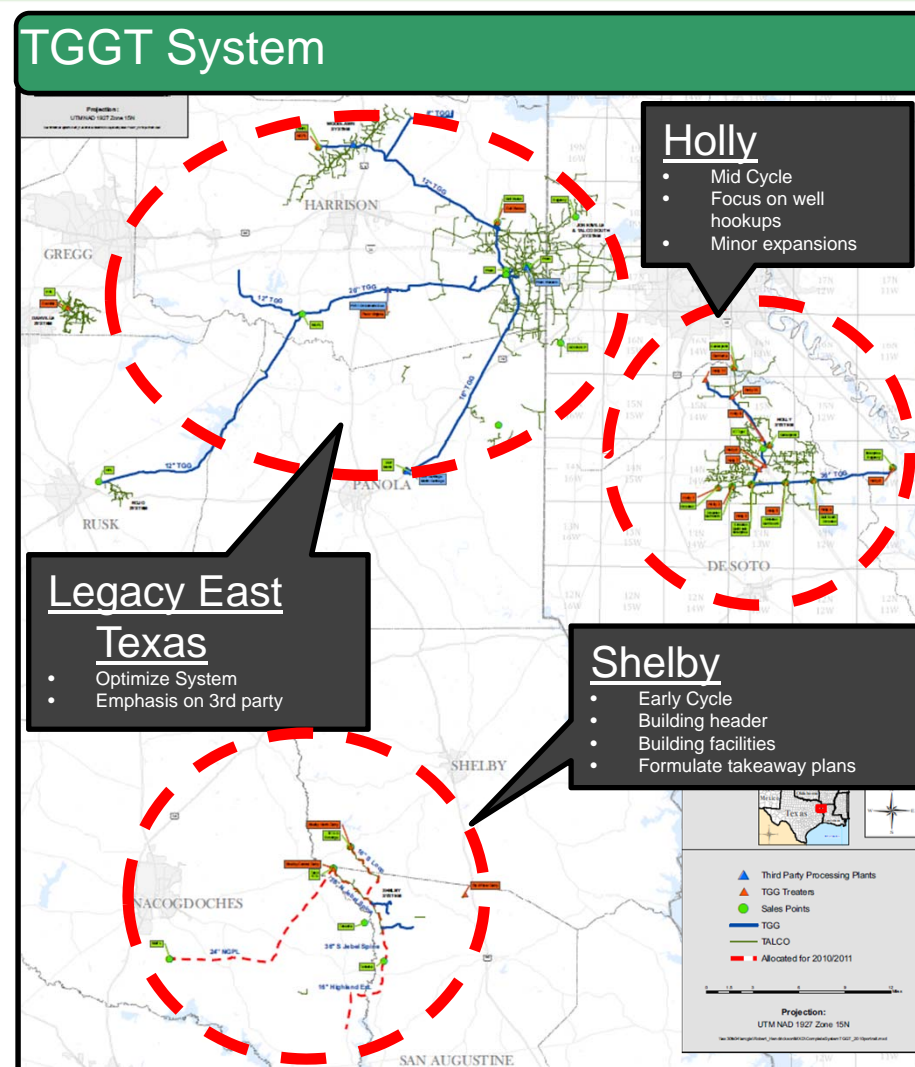
- Conventional assets represent ~25% of our net production
  - Permian: 20.7 Mmcfe/d (45% oil)
  - Appalachia shallow: 15.8 Mmcfe/d
  - East Texas/North Louisiana: 88.9 Mmcfe/d
- Development strategy
  - Operating two drilling rigs in our Permian area, production results in cash margins >\$10.00 per Mcfe
  - Operations focused on cost management; recompletion and workover programs used to manage production declines
  - Assets provide large operational footprint in our shale development areas
  - Production provides cash flow and, particularly in the shale areas, assists in holding other horizons

(1) The reserves and resources estimates are pro forma for 50% of the Chief acquisition and another Appalachian acquisition, effective 12/31/10 using the management price deck, adjusted for differentials and excluding hedge effects

# TGGT

Throughput exceeds 1.5 Bcf/d

- Average Q2 throughput set a record, exceeding 1.4 Bcf/d
  - Holly: 893 Mmcf/d
  - Shelby: 162 Mmcf/d
  - Legacy East Texas: 364 Mmcf/d
- Throughput is now approximately the same level as prior to the facility incident of May 28, 2011
- As of Q3, we have limited treating capabilities at major facilities in the Holly area, reducing amine treating revenue on majority of Holly throughput until late Q3 2011
- Anticipate having temporary treating units and certain permanent facilities operational by late Q3 to provide full treating capacity in Holly
- Infrastructure and pipeline projects continue in Shelby to meet the growing throughput volumes



## TGGT May 28, 2011 Treating Facility Incident Red River Parish, Louisiana

- The function of the damaged facility is to treat ~450 Mmcf/d of natural gas to pipeline quality
- Failure of a vessel occurred, resulting in ongoing shutdown of this facility and certain similar units of like design
- Internal and external investigation teams are evaluating the incident
- We are taking steps to restart the facilities:
  - Leasing temporary amine units; expect treatment to resume in late Q3 2011
  - Plan to restart undamaged units in late Q3 2011
  - Plan to restart damaged unit in January 2012
- With the leased units and restart of undamaged units, we expect full treating capacity in late Q3 2011
- Estimated Impacts to Operating Results:

<b>TGGT: \$ in thousands</b>	<b>Q2 E</b>	<b>Q3 E</b>	<b>Q4 E<sup>(1)</sup></b>	<b>Full Yr 11 E</b>
Revenue Impact	\$ (3,500)	\$ (5,900)	\$ 2,600	\$ (6,800)
Operating Expense Impact	(140)	(5,600)	(750)	(6,490)
Total Adjusted EBITDA Impact	\$ (3,640)	\$ (11,500)	\$ 1,850	\$ (13,290)

- In addition, expect \$12 - \$15 million of non-cash impairment charges
- Estimated impact to EXCO's 50% equity income in TGGT based on midpoint

<b>\$ in thousands</b>	<b>Q2 E</b>	<b>Q3 E</b>	<b>Q4 E<sup>(1)</sup></b>	<b>Full Yr 11 E</b>
Equity Income Impact	\$ (8,570)	\$ (5,750)	\$ 925	\$ (13,395)

(1) The Revenue Impact and the Equity Income impact increases are due to the additional treating rate that will be charged during the period the units are leased, which is projected to begin in late Q3 2011.

# 2011 Capital Budget and Development Strategy

## E&P budget totals \$976 million<sup>(1)</sup>

- **Haynesville development is our main activity as a result of**

- Performance as we are exceeding economic hurdles in core areas, even in low commodity price environment
- Existing infrastructure and access to multiple markets
- Readily available field services
- The opportunity to secure additional “bolt-on” acreage
- Recognized leading industry position in the play

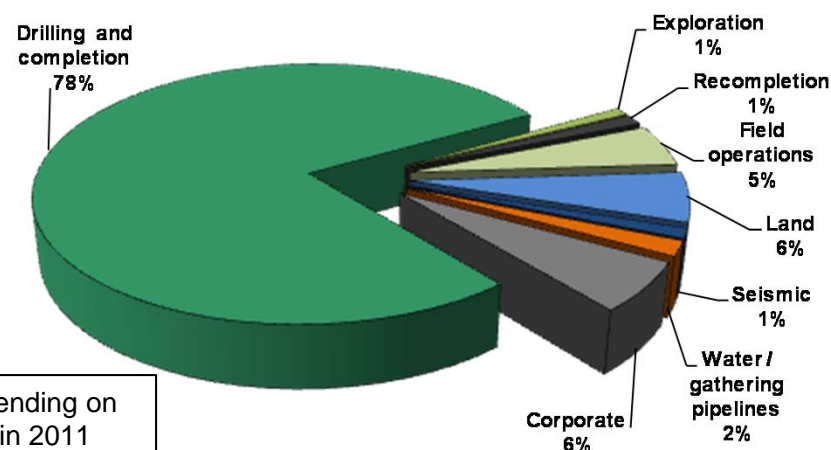
- **Marcellus development is progressing**

- Technical understanding of the Marcellus shale play is rapidly improving
- Size and breadth of the play demands additional analysis to identify core areas
- Large amount of HBP acreage allows time for deliberate pace of development
- Improving regulatory environment
- Implementing appraisal/development plan
- Infrastructure development required

- **Permian development ongoing**

- Superior returns driven by oil and liquids content
- Good infrastructure and market access
- Minimal overhead

### 2011 Capital Budget by Category



>85% spending on shales in 2011

(\$ in millions)	ETX/NLA JV	Vernon	Appalachia	Permian	Corporate	2011 Total
Drilling and completion	\$ 683.0	\$ -	\$ 28.4	\$ 48.0	\$ -	\$ 759.4
Exploration	-	-	9.5	-	-	9.5
Recompletion	4.1	6.8	-	1.4	-	12.3
Field operations	22.1	10.8	13.5	3.1	-	49.5
Land	29.8	2.8	25.0	0.9	-	58.5
Seismic	2.4	2.6	6.4	-	-	11.4
Water pipelines & gas gathering	15.6	1.8	-	-	-	17.4
Corporate	-	-	-	-	58.2	58.2
<b>Total E&amp;P capital</b>	<b>\$ 757.0</b>	<b>\$ 24.8</b>	<b>\$ 82.8</b>	<b>\$ 53.4</b>	<b>\$ 58.2</b>	<b>\$ 976.2</b>

(1) \$976 million E&P CAPEX does not include midstream CAPEX of \$212 million net to EXCO (\$119 million related to TGGT and \$93 million related to Appalachia midstream). TGGT midstream projects to be internally funded by credit facility at TGGT. In addition, expect to receive \$73 million of acreage reimbursements from BG Group.



EXCO Resources, Inc.



## Reserves and Resources Update

July 2011



## EXCO Reserves and Resources

Strong historical performance and future potential

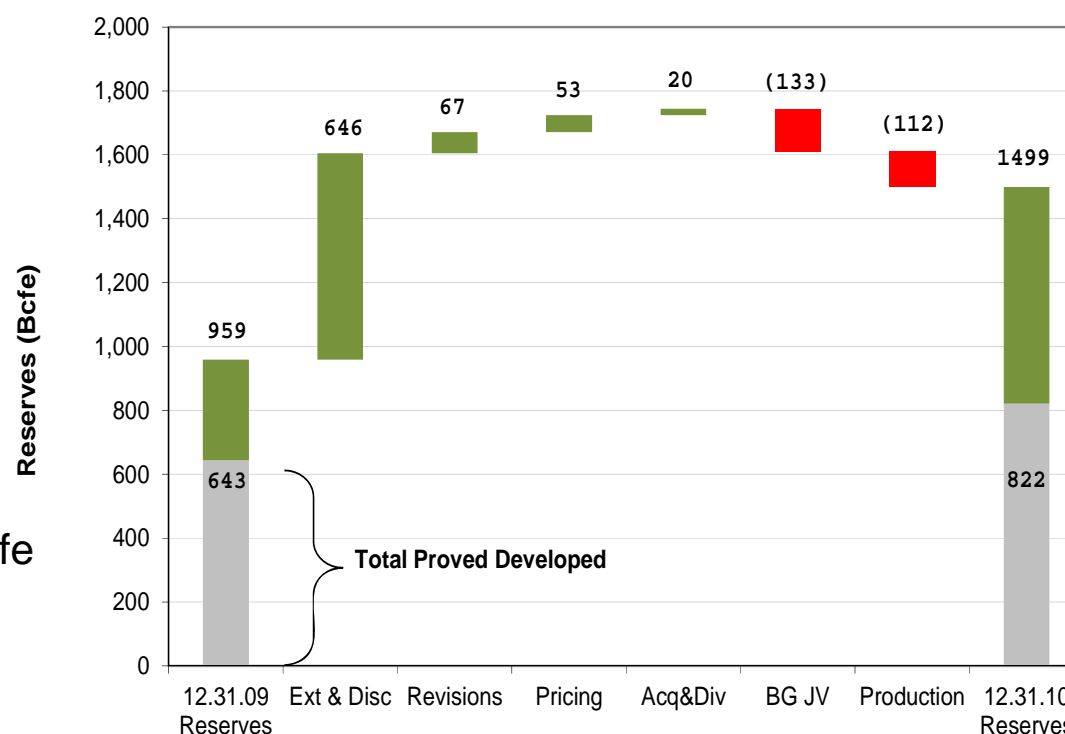
- **Strong performance since the end of 2008**
  - Added 0.9 Tcfe in extensions and discoveries, spending ~\$640 million or \$0.73/mcfe
  - Added over 10 Tcfe of shale reserves and resources
  - Appraised and began development of Haynesville and Marcellus shale plays, which now provide ~75% of EXCO's current production
- **High quality reserves and resources**
  - Increased Proved Reserves in 2010 by 56%, mainly from Haynesville Shale, while realizing 576% production replacement ratio
  - High-graded locations by reclassifying stale PUDs and removing lowest value locations
  - 72% of PUD reserves in the Haynesville shale, with the majority in the core DeSoto area
  - 97% of our reserves and resources are in two of the highest value shale plays and are supported with audited/signed reserve reports
  - ~36% of gross operated wells expected to be turned to sales this year were booked in the Contingent Resource category at the beginning of this year; limited wells and offset production prevented us from booking these locations as reserves

## YE 2009<sup>(1)</sup> to YE 2010<sup>(2)</sup> Total Proved Reserves Reconciliation

Extensions & discoveries of 646 Bcfe; 576% production replacement and positive revisions

- Extensions & Discoveries – 646 Bcfe
  - 615 Bcfe – ETX-NLA
- Revisions – 120 Bcfe
  - 53 Bcfe – Price
  - 92 Bcfe – Vernon Performance
  - (25) Bcfe – Stale PUDs
- Acquisitions/Divestitures – 20 Bcfe
- Appalachia JV Divestiture – (133) Bcfe
- Production – (112) Bcfe

EXCO YE2009 YE2010 Proved Reserve Adjustments

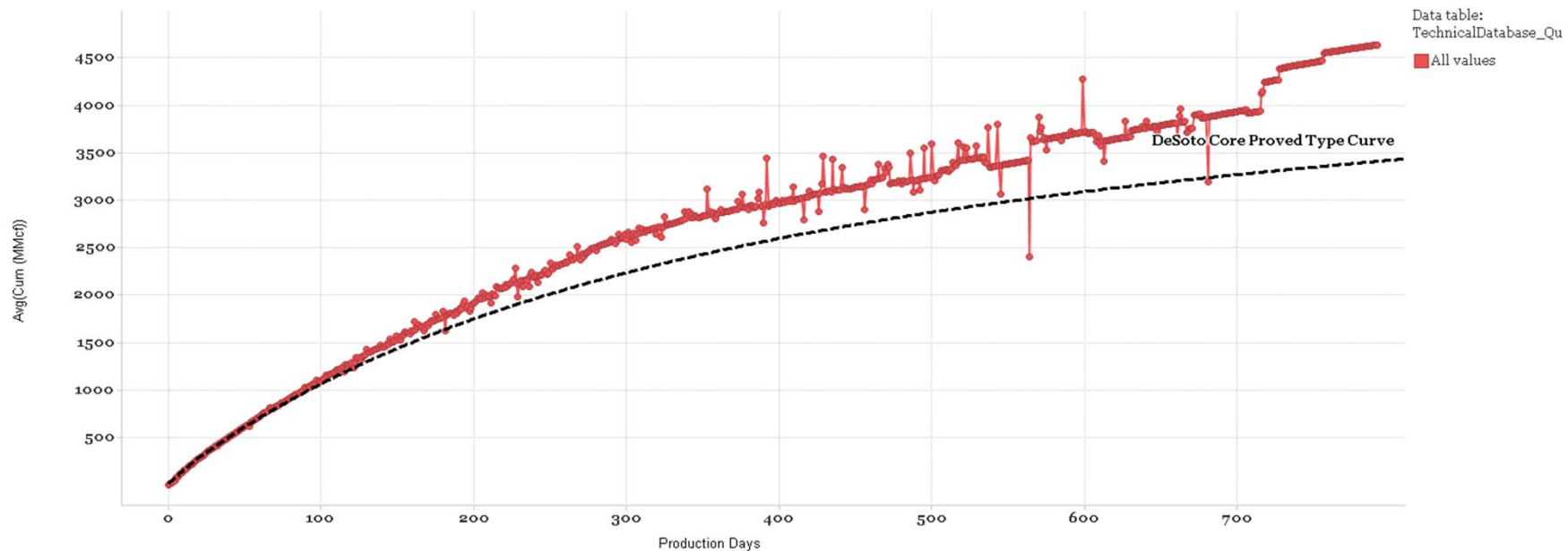


(1) Based on YE 2009 SEC reserve estimate pricing of \$ \$3.87 per Mcf for natural gas and \$61.18 per Bbl for crude oil

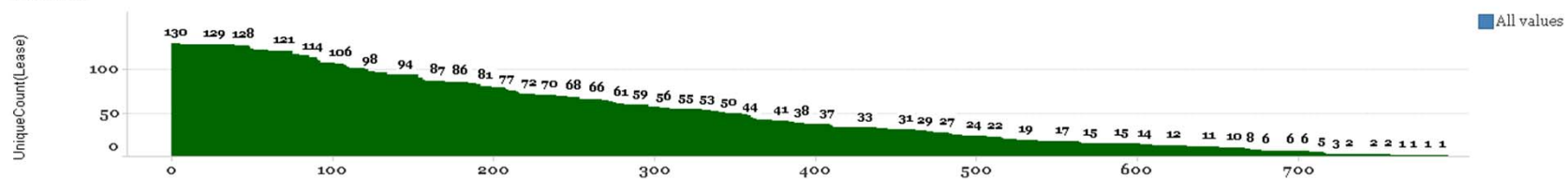
(2) Based on YE 2010 SEC reserve estimate pricing of \$4.38 per Mcf for natural gas and \$79.43 per Bbl for crude oil

# DeSoto Area Performance

Operated well performance exceeding year end 2010 proved type curve



Bar Chart



DeSoto Core Haynesville	Cumulative Production									
	30 Days	Wells	60 Days	Wells	90 Days	Wells	180 Days	Wells	365 Days	Wells
EXCO Operated	402,396	129	729,268	121	1,016,945	112	1,833,629	111	2,875,617	42
All Wells	394,421	163	721,521	155	1,014,115	143	1,794,530	136	2,840,708	60
Type Curve	397,797	-	709,164	-	983,438	-	1,637,235	-	2,471,779	-

NOTE: "All wells" in table above represent all wells for which daily data is available through ownership, data trades or other agreements, as of 6/8/2011.

## Reserves and Resources Report effective 12/31/10

### Assumptions

- Proved Reserves based on year end 2010 SEC proved reserve report
  - Operating expenses adjusted to expected levels
  - Drilling and completion costs adjusted to expected levels
  - Price deck assumes management deck shown below:

MGMT Price Deck	2011	2012	2013	2014	2015+
Oil - \$/Bbl	\$ 90.00	\$ 90.00	\$ 90.00	\$ 90.00	\$ 90.00
NG - \$/Mcf	\$ 4.50	\$ 5.00	\$ 5.25	\$ 5.50	\$ 6.00

- Proved and non-proved locations audited by outside engineering firms
- Added in year to date acquisitions pro forma for an effective date of 12/31/10
- The following table summarizes the average estimated ultimate recovery (EUR) and gross locations for our shale plays by category as utilized in this report:

	Haynesville		Bossier		Marcellus	
	Gross Loc.	Avg. EUR	Gross Loc.	Avg. EUR	Gross Loc.	Avg. EUR
Proved Undeveloped	497	6.2	-	-	15	6.8
Probable	230	7.5	-	-	32	7.3
Possible	366	8.3	-	-	87	7.5
Contingent Resources	1,942	7.4	1,764	7.4	4,407	5.1
Average of drilling locations	3,035	7.3	1,764	7.4	4,541	5.1

- Only includes drilling locations that achieve economic hurdle rate of 10% rate of return

# Reserves and Resources Report effective 12/31/10<sup>(1)</sup>

## Reconciliation to year end 2010 SEC Report

Reserves and Resources Report Detail	Net Oil (Mbbbl)	Net Gas (Mmcf)	Net Gas Equiv (Mmcfe)
1PDP	4,364	744,886	771,072
2PNP	52	43,936	44,245
3PBP	368	79,589	81,796
<b>Total Proved Developed</b>	<b>4,784</b>	<b>868,411</b>	<b>897,113</b>
4PUD	2,871	664,685	681,909
<b>Total Proved</b>	<b>7,655</b>	<b>1,533,096</b>	<b>1,579,022</b>
Probable	1,788	442,080	452,805
Possible	703	730,597	734,815
Contingent	8,360	10,515,746	10,565,905
<b>Grand Total</b>	<b>18,506</b>	<b>13,221,519</b>	<b>13,332,547</b>

Reconciliation to SEC Proved Reserves Report	Net Oil (Mbbbl)	Net Gas (Mmcf)	Net Gas Equiv (Mmcfe)
1PDP	4,216	675,585	700,882
2PNP	50	40,400	40,701
3PBP	366	77,792	79,989
<b>Total Proved Developed</b>	<b>4,632</b>	<b>793,777</b>	<b>821,572</b>
4PUD	2,725	661,176	677,529
<b>Total Proved (SEC Report 12/31/10)</b>	<b>7,357</b>	<b>1,454,953</b>	<b>1,499,101</b>
<b>Variance due to Mgmt. pricing and Appalachia acquisitions</b>	<b>298</b>	<b>78,143</b>	<b>79,921</b>
<b>Total Proved (Reserves and Resources Report 12/31/10)</b>	<b>7,655</b>	<b>1,533,096</b>	<b>1,579,022</b>

(1) The reserves and resources estimates are pro forma for 50% of the Chief acquisition and another Appalachian acquisition, effective 12/31/10 using the management price deck, adjusted for differentials and excluding hedge effects

# Reserves and Resources Report effective 12/31/10<sup>(1)</sup>

## Shale/non-shale by area

Net Bcfe	Non-Shale				Shale			Grand Total
	ETX-NLA	Permian	Appalachia	Total	ETX-NLA	Appalachia	Total	
1PDP	415	59	87	560	187	23	211	771
2PNP	33	-	1	34	7	3	10	44
3PBP	47	-	2	49	33	-	33	82
4PUD	106	40	23	169	496	18	514	683
<b>Total Proved</b>	<b>601</b>	<b>99</b>	<b>113</b>	<b>812</b>	<b>724</b>	<b>44</b>	<b>769</b>	<b>1,581</b>
<b>Probable</b>	76	20	28	124	289	40	329	452
<b>Possible</b>	138	12	19	169	464	102	566	734
<b>Contingent</b>	46	62	17	125	4,706	5,735	10,441	10,566
<b>Grand Total</b>	<b>861</b>	<b>193</b>	<b>176</b>	<b>1,229</b>	<b>6,183</b>	<b>5,920</b>	<b>12,103</b>	<b>13,333</b>

PV-10 (\$ in millions)	Non-Shale				Shale			Grand Total
	ETX-NLA	Permian	Appalachia	Total	ETX-NLA	Appalachia	Total	
1PDP	\$ 608	\$ 218	\$ 126	\$ 952	\$ 482	\$ 49	\$ 531	\$ 1,483
2PNP	43	3	2	48	19	7	26	74
3PBP	71	2	1	74	62	-	62	136
4PUD	38	100	10	148	529	23	552	700
<b>Total Proved</b>	<b>760</b>	<b>323</b>	<b>139</b>	<b>1,222</b>	<b>1,092</b>	<b>79</b>	<b>1,171</b>	<b>2,393</b>
<b>Probable</b>	9	59	13	81	435	56	491	572
<b>Possible</b>	15	24	6	45	644	140	784	829
<b>Contingent</b>	4	138	4	146	4,237	4,681	8,918	9,064
<b>Grand Total</b>	<b>\$ 788</b>	<b>\$ 544</b>	<b>\$ 162</b>	<b>\$ 1,494</b>	<b>\$ 6,408</b>	<b>\$ 4,956</b>	<b>\$ 11,364</b>	<b>\$ 12,858</b>

<b>Gross Locations</b>	<b>365</b>	<b>638</b>	<b>1,991</b>	<b>2,994</b>	<b>4,799</b>	<b>4,541</b>	<b>9,340</b>	<b>12,334</b>
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(1) The reserves and resources estimates are pro forma for 50% of the Chief acquisition and another Appalachian acquisition, effective 12/31/10 using the management price deck, adjusted for differentials and excluding hedge effects



EXCO Resources, Inc.



## Financial Models

July 2011



# Financial Modeling Report effective 7/1/11

## Assumptions

- Based on unrisks Financial Modeling Report
  - Effective 7/1/11
  - Operating, drilling and completion cost assumptions are the same as the Reserves and Resources Report
  - Added additional North Louisiana royalty acquisition
  - Updated type curves based additional performance data and selected the most likely type curve for each area regardless of original reserve or resource category
  - Type curves are based on EXCO's determination of most likely type curves

EUR Comparison	Haynesville	Bossier	Marcellus
Reserves and Resources Report	7.3	7.4	5.1
Financial Modeling Report	7.1	7.7	5.8

- The average Haynesville EUR is 0.2 Bcf lower due to a reduction of the possible and contingent resource type curves, offset by an increase in the proved undeveloped type curve
- The average Bossier EUR is 0.3 Bcf higher due to increased expectations in the Shelby area
- The average Marcellus EUR is 0.7 Bcf higher due to increased expectations in the Northeast area

- Projections are based on the following management price deck, adjusted for basin differentials:

MGMT Price Deck	2011	2012	2013	2014	2015+
Oil - \$/Bbl	\$ 90.00	\$ 90.00	\$ 90.00	\$ 90.00	\$ 90.00
NG - \$/Mcf	\$ 4.50	\$ 5.00	\$ 5.25	\$ 5.50	\$ 6.00

- Includes actuals through April 2011
- Assumes 20% rate of return hurdle rate for drilling projects
- Downtime factors by region through 2015 for offset frac and other operational factors; no downtime post 2015:

Holly	7.5%
Shelby	5.0%
Waskom	7.5%
ETXNLA JV Conventional	3.5%

- Forecast adjusted to include additional capital charges not included in the Financial Modeling Report including workover, seismic, and other corporate capital

# Financial Modeling Report effective 7/1/11<sup>(1)</sup>

## Reconciliation to Reserves and Resources Report

	Net Oil (Mbbbl)	Net Gas (Mmcf)	Net Gas Equiv (Mmcfe)
1PDP	4,773	897,573	926,210
2PNP	51	42,388	42,696
3PBP	368	73,480	75,687
<b>Total Proved Developed</b>	<b>5,192</b>	<b>1,013,440</b>	<b>1,044,593</b>
Undeveloped Reserves and Resources <sup>(2)</sup>	12,301	11,020,281	11,094,088
<b>Grand Total</b>	<b>17,493</b>	<b>12,033,721</b>	<b>12,138,681</b>

	Net Gas Equiv (Mmcfe)
Reserves and Resources Report effective 12/31/10	13,332,549
<u>Adjustments:</u>	
Production	(82,224)
Type curve adjustments	(1,111,644)
Total adjustments to 12/31/10 report	(1,193,868)
Financial Modeling Report effective 7/1/11	12,138,681

(1) Using the management price deck shown below

Management Price Deck	2011	2012	2013	2014	2015+
Gas	\$ 4.50	\$ 5.00	\$ 5.25	\$ 5.50	\$ 6.00
Oil	\$ 90.00	\$ 90.00	\$ 90.00	\$ 90.00	\$ 90.00

(2) Undeveloped locations assume most likely type curve for each area

# Financial Modeling Report effective 7/1/11<sup>(1)</sup>

## Shale/non-shale by area

Net Bcfe	Non-Shale				Shale			Grand Total
	ETX-NLA	Permian	Appalachia	Total	ETX-NLA	Appalachia	Total	
1PDP	392	64	84	540	322	64	386	926
2PNP	32	0	1	34	5	4	9	43
3PBP	47	0	2	49	27	-	27	76
<b>Total Proved Developed</b>	<b>471</b>	<b>65</b>	<b>87</b>	<b>623</b>	<b>354</b>	<b>68</b>	<b>422</b>	<b>1,045</b>
Undeveloped Reserves and Resources <sup>(2)</sup>	359	119	86	565	4,763	5,766	10,529	11,094
<b>Grand Total</b>	<b>831</b>	<b>184</b>	<b>173</b>	<b>1,188</b>	<b>5,117</b>	<b>5,834</b>	<b>10,951</b>	<b>12,139</b>
PV-10 (\$ in millions)	Non-Shale				Shale			Grand Total
	ETX-NLA	Permian	Appalachia	Total	ETX-NLA	Appalachia	Total	
1PDP	\$ 581	\$ 245	\$ 124	\$ 950	\$ 845	\$ 140	\$ 984	\$ 1,935
2PNP	48	3	2	53	14	8	22	74
3PBP	75	2	2	78	73	-	73	152
<b>Total Proved Developed</b>	<b>704</b>	<b>250</b>	<b>127</b>	<b>1,081</b>	<b>932</b>	<b>147</b>	<b>1,079</b>	<b>2,161</b>
Undeveloped Reserves and Resources <sup>(2)</sup>	66	276	35	377	4,363	4,876	9,240	9,617
<b>Grand Total</b>	<b>\$ 770</b>	<b>\$ 526</b>	<b>\$ 162</b>	<b>\$ 1,458</b>	<b>\$ 5,295</b>	<b>\$ 5,024</b>	<b>\$ 10,319</b>	<b>\$ 11,777</b>
<b>Gross Locations with &gt; 20% IRR</b>	<b>26</b>	<b>210</b>	<b>521</b>	<b>757</b>	<b>3,778</b>	<b>3,805</b>	<b>7,583</b>	<b>8,340</b>

(1) Using the management price deck shown below

Management Price Deck	2011	2012	2013	2014	2015+
Gas	\$ 4.50	\$ 5.00	\$ 5.25	\$ 5.50	\$ 6.00
Oil	\$ 90.00	\$ 90.00	\$ 90.00	\$ 90.00	\$ 90.00

(2) Undeveloped locations assume most likely type curve for each area

## Development Plan Summary

Net Wells Turned to Sales					
<u>Operated</u>	2011 E	2012 E	2013 E	2014 E	2015 E
Haynesville	65.1	56.8	49.1	32.4	24.1
Bossier	-	-	7.3	24.1	39.8
Marcellus	12.0	34.3	51.0	60.2	74.4
<u>OBO</u>					
Haynesville/Bossier	5.0	20.3	20.2	10.9	14.1

Gross Well Cost (\$ in thousands)					
<u>Operated</u>	2011 E	2012 E	2013 E	2014 E	2015 E
Haynesville	\$ 9,348	\$ 9,222	\$ 8,981	\$ 8,600	\$ 8,184
Bossier			\$ 10,650	\$ 10,650	\$ 10,650
Marcellus	\$ 5,697	\$ 5,187	\$ 4,753	\$ 4,656	\$ 4,478
<u>OBO</u>					
Haynesville/Bossier	\$ 9,501	\$ 9,222	\$ 9,140	\$ 9,317	\$ 9,614

Average Royalty %					
<u>Operated</u>	2011 E	2012 E	2013 E	2014 E	2015 E
Haynesville	21%	21%	23%	24%	20%
Bossier			25%	25%	25%
Marcellus	18%	18%	17%	17%	17%
<u>OBO</u>					
Haynesville/Bossier	17%	25%	27%	26%	25%

- Development plan scheduled to drill highest PV areas first
- Well costs reductions assume current service cost levels; reductions are a result of drilling and completion efficiencies and savings associated with pad development

Forecasted Reserve Range <sup>(1)</sup>	2011E	2012E	2013E
Forecasted Proved Developed Reserves (Tcfe)	0.9 - 1.0	1.1 - 1.2	1.1 - 1.4
Forecasted Proved Reserves (Tcfe)	1.7 - 2.0	1.8 - 2.1	2.0 - 2.7

(1) Forecasted reserves and resources on this page based on financial modeling report described on pages 45 – 59 of this presentation

## Development Plan Economics and 2011E Operating Margin by Area

	Gross well cost (\$M)	Gross EUR (Mmcf)	Royalty %	Net EUR (Mmcf)	F&D	IRR% <sup>(1)</sup>
Haynesville	\$ 9,000	7,100	23%	5,467	\$ 1.65	61%
Bossier	\$ 9,200	7,700	25%	5,775	\$ 1.59	42%
Marcellus	\$ 4,500	5,800	18%	4,756	\$ 0.95	67%
Permian	\$ 690	454	25%	341	\$ 2.03	95%

2011 E	Total			Total			Permian	Vernon	EXCO Total
	Haynesville	Cotton Valley	ETX/NLA JV	Marcellus	Shallow	Appalachia JV			
NYMEX	\$ 4.50	\$ 4.50	\$ 4.50	\$ 4.50	\$ 4.50	\$ 4.50	\$ 4.50	\$ 4.50	\$ 4.50
% Differential	93%	106%	94%	106%	108%	107%	248%	98%	101%
<b>Realized price</b>	<b>\$ 4.18</b>	<b>\$ 4.78</b>	<b>\$ 4.22</b>	<b>\$ 4.77</b>	<b>\$ 4.86</b>	<b>\$ 4.80</b>	<b>\$ 11.14</b>	<b>\$ 4.39</b>	<b>\$ 4.56</b>
Direct LOE <sup>(2)</sup>	\$ 0.09	\$ 1.48	\$ 0.18	\$ 0.25	\$ 1.63	\$ 0.64	\$ 0.93	\$ 0.75	\$ 0.32
Gathering	0.50	0.50	0.51	0.79	-	0.57	-	0.40	0.48
Production tax	0.06	0.36	0.08	0.00	0.18	0.05	0.96	0.39	0.15
<b>Total expense</b>	<b>\$ 0.65</b>	<b>\$ 2.35</b>	<b>\$ 0.76</b>	<b>\$ 1.04</b>	<b>\$ 1.80</b>	<b>\$ 1.26</b>	<b>\$ 1.89</b>	<b>\$ 1.54</b>	<b>\$ 0.95</b>
<b>Operating margin</b>	<b>\$ 3.53</b>	<b>\$ 2.43</b>	<b>\$ 3.45</b>	<b>\$ 3.73</b>	<b>\$ 3.06</b>	<b>\$ 3.54</b>	<b>\$ 9.25</b>	<b>\$ 2.85</b>	<b>\$ 3.61</b>

- 2011 forecasted natural gas realized price differential 97.9% of NYMEX
- 2011 forecasted oil realized price differential (\$4.17) of NYMEX

(1) Based on management price deck shown below  
(2) Excludes overhead and non-recurring workover expense

Management Price Deck	2011	2012	2013	2014	2015+
Gas	\$ 4.50	\$ 5.00	\$ 5.25	\$ 5.50	\$ 6.00
Oil	\$ 90.00	\$ 90.00	\$ 90.00	\$ 90.00	\$ 90.00

# Financial Model Summary

## Upstream:

	2011 E	2012 E	2013 E	2014 E	2015 E
Average Rigs:					
Haynesville/Bossier	22	27	27	27	27
Marcellus	4	8	11	13	16
Permian	2	2	2	2	-
Total	28	37	40	42	43
Production (Mmcfe/d)	527	833	1,028	1,050	1,142
<i>\$ in millions</i>					
EBITDA	\$ 679	\$ 1,169	\$ 1,515	\$ 1,623	\$ 1,943
CAPEX	\$ 1,002	\$ 911	\$ 1,019	\$ 1,033	\$ 1,133
Net Debt/(Cash)	\$ 1,585	\$ 1,414	\$ 1,001	\$ 417	\$ (139)
Secured debt capacity (projected)	\$ 1,500	\$ 2,300	\$ 3,000	\$ 3,200	\$ 3,900
Potential liquidity	\$ 564	\$ 1,616	\$ 2,728	\$ 3,512	\$ 4,772

## Midstream (100% to the JVs):

	2011 E	2012 E	2013 E	2014 E	2015 E
Throughput (Mmcf/d):					
TGGT	1,489	2,268	2,741	2,698	2,685
Appalachia	33	128	264	396	473
Total	1,521	2,396	3,005	3,094	3,158
<i>\$ in millions</i>					
EBITDA	\$ 137	\$ 275	\$ 375	\$ 435	\$ 450
CAPEX	\$ 307	\$ 203	\$ 472	\$ 337	\$ 147
Net Debt	\$ 479	\$ 435	\$ 530	\$ 462	\$ 188

**Note:** EXCO owns a 50% equity interest in Midstream entities

# Upstream Summary Forecast

	2011 E	2012 E	2013 E	2014 E	2015 E	Total
Oil - Mbbls	836	833	820	770	614	3,874
Natural gas - Mmcf	187,384	299,221	370,267	378,638	413,258	1,648,768
Equivalent - Mmcf	192,402	304,219	375,188	383,257	416,943	1,672,009
Per day production- Mmcf/d	527	833	1,028	1,050	1,142	
<b>Summary cash flow (\$ 000's)</b>						
Oil and natural gas revenue	\$ 877,965	\$ 1,514,683	\$ 1,947,216	\$ 2,089,235	\$ 2,459,296	\$ 8,888,395
Hedge settlements	91,587	22,660	4,038	-	-	118,284
Total revenue	969,551	1,537,343	1,951,254	2,089,235	2,459,296	9,006,679
Lease operating expense	78,891	81,873	93,468	98,530	110,532	463,294
Production taxes	28,637	36,686	42,523	49,118	58,725	215,689
Gathering expenses	92,861	153,394	196,612	207,228	227,189	877,284
General and administrative	89,610	96,331	103,556	111,323	119,672	520,493
Total operating expense	289,999	368,285	436,158	466,198	516,118	2,076,759
Adjusted EBITDA	\$ 679,552	\$ 1,169,058	\$ 1,515,096	\$ 1,623,036	\$ 1,943,177	\$ 6,929,920
Cash interest expense	48,379	47,761	41,801	31,283	27,131	196,354
Cash taxes	-	-	-	-	184,664	184,664
Dividends	8,548	-	-	-	-	8,548
Discretionary cash flow	\$ 622,625	\$ 1,121,298	\$ 1,473,296	\$ 1,591,753	\$ 1,731,382	\$ 6,540,353
Drilling and completion capital	822,488	871,547	981,946	1,013,873	1,114,185	4,804,038
Field and other capital	179,137	39,000	37,000	19,000	19,000	293,137
Total capital	1,001,625	910,547	1,018,946	1,032,873	1,133,185	5,097,176
Free cash flow	\$ (379,000)	\$ 210,750	\$ 454,350	\$ 558,881	\$ 598,197	\$ 1,443,178
<b>Assumed NYMEX</b>						
Oil (\$/Bbl)	\$ 92.70	\$ 90.00	\$ 90.00	\$ 90.00	\$ 90.00	
Natural gas (\$/Mcf)	\$ 4.38	\$ 5.00	\$ 5.25	\$ 5.50	\$ 6.00	
<b>Per unit metrics (\$/Mcf)</b>						
Revenue	\$ 4.56	\$ 4.98	\$ 5.19	\$ 5.45	\$ 5.90	\$ 5.32
Hedge settlements	0.48	0.07	0.01	-	-	0.07
Lease operating expense	0.41	0.27	0.25	0.26	0.27	0.28
Production taxes	0.15	0.12	0.11	0.13	0.14	0.13
Gathering expenses	0.48	0.50	0.52	0.54	0.54	0.52
General and administrative	0.47	0.32	0.28	0.29	0.29	0.31
Operating margin	\$ 3.53	\$ 3.84	\$ 4.04	\$ 4.23	\$ 4.66	\$ 4.14
Net back (% of NYMEX)	81%	77%	77%	77%	78%	
<b>Summary liquidity (\$ 000's)</b>						
Cash	\$ 244,743	\$ 244,743	\$ 244,743	\$ 312,054	\$ 871,548	
Bank	\$ 1,080,529	\$ 929,181	\$ 516,725	\$ -	\$ -	
Senior Notes	750,000	750,000	750,000	750,000	750,000	
Total debt	\$ 1,830,529	\$ 1,679,181	\$ 1,266,725	\$ 750,000	\$ 750,000	
Secured debt capacity (projected)	\$ 1,400,000	\$ 2,300,000	\$ 3,000,000	\$ 3,200,000	\$ 3,900,000	
Potential liquidity	\$ 564,214	\$ 1,615,562	\$ 2,728,018	\$ 3,512,054	\$ 4,771,548	

# Upstream Income Statement

\$ in thousands	2011 E	2012 E	2013 E	2014 E	2015 E	Total
Oil - Mbbls	836	833	820	770	614	3,874
Natural gas - Mmcf	187,384	299,221	370,267	378,638	413,258	1,648,768
Equivalent - Mmcf	192,402	304,219	375,188	383,257	416,943	1,672,009
Per day - Mmcf/d	527	833	1,028	1,050	1,142	
<u>Revenues</u>						
Oil	\$ 74,046	\$ 71,834	\$ 70,726	\$ 66,385	\$ 52,961	\$ 335,952
Natural gas	803,918	1,442,849	1,876,490	2,022,849	2,406,335	8,552,442
Oil and natural gas hedge settlements	91,587	22,660	4,038	-	-	118,284
Total revenues	969,551	1,537,343	1,951,254	2,089,235	2,459,296	9,006,679
<u>Cost and expenses</u>						
Lease operating expense	78,891	81,873	93,468	98,530	110,532	463,294
Production taxes	28,637	36,686	42,523	49,118	58,725	215,689
Gathering expenses	92,861	153,394	196,612	207,228	227,189	877,284
Depreciation, depletion and amortization	341,743	532,383	656,579	670,700	729,650	2,931,054
Accretion of asset retirement obligations	3,409	3,360	3,360	3,360	3,360	16,849
Stock based compensation	10,726	10,800	10,800	10,800	10,800	53,926
General and administrative	89,610	96,331	103,556	111,323	119,672	520,493
Other - non-cash	-	-	-	-	-	-
Other - cash	2,376	-	-	-	-	2,376
Operating costs and expenses	648,253	914,828	1,106,896	1,151,058	1,259,929	5,080,964
Operating income	321,298	622,516	844,358	938,176	1,199,367	3,925,715
<u>Other income (expense)</u>						
Interest	(90,668)	(92,658)	(86,698)	(71,029)	(65,160)	(406,213)
Capitalized interest	33,658	34,800	34,800	34,800	34,800	172,858
Change in FMV on derivatives	(54,611)	-	-	-	-	(54,611)
Equity income in subsidiaries	42,079	111,692	154,226	178,410	184,834	671,242
Other	227	-	-	-	-	227
Income before income taxes	251,983	676,349	946,685	1,080,358	1,353,842	4,309,217
<u>Income tax expense (benefit)</u>						
Current	-	-	-	-	184,664	184,664
Deferred	-	-	348,930	432,143	356,872	1,137,945
Income (loss) available to common shareholders	\$ 251,983	\$ 676,349	\$ 597,755	\$ 648,215	\$ 812,305	\$ 2,986,607
Adjusted EBITDA	\$ 677,176	\$ 1,169,058	\$ 1,515,096	\$ 1,623,036	\$ 1,943,177	\$ 6,927,544

# Upstream Cash Flow Statement

\$ in thousands	2011 E	2012 E	2013 E	2014 E	2015 E	Total
<b>Operating activities</b>						
Net income (loss)	\$ 251,983	\$ 676,349	\$ 597,755	\$ 648,215	\$ 812,305	\$ 2,986,607
Adjustments to reconcile net income operating activities						
Income from equity investment in subsidiaries	(42,079)	(111,692)	(154,226)	(178,410)	(184,834)	(671,242)
Depreciation, depletion and amortization	341,743	532,383	656,579	670,700	729,650	2,931,054
Accretion of asset retirement obligations	3,409	3,360	3,360	3,360	3,360	16,849
Stock based compensation	10,726	10,800	10,800	10,800	10,800	53,926
Deferred income taxes	-	-	348,930	432,143	356,872	1,137,945
Amortization of deferred financing costs	8,974	10,098	10,098	4,946	3,228	37,344
Fair market adjustment on derivatives	54,611	-	-	-	-	54,611
Other	-	-	-	-	-	-
Cash flow before changes in working capital	629,367	1,121,298	1,473,296	1,591,753	1,731,382	6,547,095
Accounts receivable	(69,282)	(66,511)	(38,855)	(17,614)	(57,487)	(249,750)
Accounts payable	(48,607)	7,110	(3,040)	42,770	18,784	17,017
	(671)	-	-	-	-	(671)
Net cash provided by (used in) operating activities	510,806	1,061,896	1,431,401	1,616,909	1,692,679	6,313,691
<b>Investing activities</b>						
Additions to oil and natural gas properties - acquisitions	(259,724)	-	-	-	-	(259,724)
Additions to oil and natural gas properties - development	(818,599)	(871,547)	(981,946)	(1,013,873)	(1,114,185)	(4,800,149)
Additions to gathering systems, facilities and other office	(128,085)	(39,000)	(37,000)	(19,000)	(19,000)	(242,085)
Investment in TGGT Holdings, Inc. & App Midstream	114,800	-	-	-	-	114,800
Proceeds from sale of assets	405,952	-	-	-	-	405,952
Restricted cash	(8,026)	-	-	-	-	(8,026)
Other	(6,339)	-	-	-	-	(6,339)
Net cash provided by (used in) investing activities	(700,021)	(910,547)	(1,018,946)	(1,032,873)	(1,133,185)	(4,795,571)
<b>Financing activities</b>						
Proceeds / (payments) on bank credit facility	231,529	(151,349)	(412,455)	(516,725)	-	(849,000)
Proceeds / (payments) on sub debt	-	-	-	-	-	-
Issuance of stock	8,315	-	-	-	-	8,315
Deferred financing costs	(11,312)	-	-	-	-	(11,312)
Dividends	(8,548)	-	-	-	-	(8,548)
Other	-	-	-	-	-	-
Net cash provided by (used in) financing activities	219,984	(151,349)	(412,455)	(516,725)	-	(860,545)
Net increase (decrease) in cash	30,770	-	-	67,311	559,494	657,575
Effect of exchange rate changes on cash	-	-	-	-	-	-
Cash at beginning of period	44,230	75,000	75,000	75,000	142,311	44,230
Cash at end of period	\$ 75,000	\$ 75,000	\$ 75,000	\$ 142,311	\$ 701,805	\$ 701,805

# Upstream Balance Sheet

\$ in thousands	2011 E	2012 E	2013 E	2014 E	2015 E
<b>Assets</b>					
<b>Current assets</b>					
Cash	\$ 75,000	\$ 75,000	\$ 75,000	\$ 142,311	\$ 701,805
Restricted cash	169,743	169,743	169,743	169,743	169,743
Accounts receivable	282,995	349,507	388,362	405,976	463,463
Inventory	7,112	7,112	7,112	7,112	7,112
Derivative financial instruments	26,657	4,033	-	-	-
Other	18,628	18,628	18,628	18,628	18,628
Total current assets	580,135	624,023	658,845	743,770	1,360,751
<b>Oil and natural gas properties</b>					
Unproved oil and natural gas properties	733,897	733,897	733,897	733,897	733,897
Proved oil and natural gas properties	3,535,989	4,436,037	5,446,482	6,477,355	7,608,539
Allowance for depreciation, depletion and amortization	(1,636,572)	(2,152,154)	(2,791,933)	(3,445,833)	(4,158,683)
Oil and natural gas properties, net	2,633,315	3,017,779	3,388,446	3,765,419	4,183,753
Gas gathering assets, net	137,222	133,822	130,422	122,022	113,622
Office and field equipment, net	51,936	49,036	44,136	37,736	31,336
Deferred financing costs	34,312	25,605	16,899	13,345	11,508
Derivative financial instruments	-	-	-	-	-
Goodwill	218,256	218,256	218,256	218,256	218,256
Investment in subsidiaries	308,650	420,342	574,568	752,978	937,813
Other	6,666	6,666	6,666	6,666	6,666
	-	-	-	-	-
Total assets	\$ 3,970,492	\$ 4,495,530	\$ 5,038,239	\$ 5,660,193	\$ 6,863,706
<b>Liabilities and stockholders' equity</b>					
<b>Current liabilities</b>					
Accounts payable	\$ 289,164	\$ 296,273	\$ 293,234	\$ 336,004	\$ 354,788
Oil and natural gas derivatives	-	-	-	-	-
Other	2	2	2	2	2
Total current liabilities	289,166	296,275	293,236	336,006	354,790
<b>Long-term debt</b>					
Senior notes	1,080,529	929,181	516,725	-	-
Deferred income taxes	740,541	741,932	743,324	744,715	746,107
Derivative financial instruments	-	-	348,930	781,073	1,137,945
Asset retirement obligations	-	-	-	-	-
Other	56,214	59,574	62,934	66,294	69,654
	6,698	6,698	6,698	6,698	6,698
<b>Stockholders' equity</b>					
Common stock	214	214	214	214	214
Additional paid in capital	3,172,523	3,183,323	3,194,123	3,204,923	3,215,723
Retained earnings	(1,311,373)	(635,023)	(37,268)	610,947	1,423,251
Dividends	(48,889)	(48,889)	(48,889)	(48,889)	(48,889)
Accumulated other comprehensive income	(7,655)	(30,279)	(34,312)	(34,312)	(34,312)
Other	(7,479)	(7,479)	(7,479)	(7,479)	(7,479)
Total stockholders' equity	1,797,342	2,461,867	3,066,389	3,725,404	4,548,508
Total liabilities and stockholders' equity	\$ 3,970,489	\$ 4,495,527	\$ 5,038,236	\$ 5,660,189	\$ 6,863,703

# Summary Midstream Financial Projections

## Assumptions

- Based on unrisksed Financial Modeling Report effective 7/1/11

- Projections based on management price deck:

MGMT Price Deck	2011	2012	2013	2014	2015+
Oil - \$/Bbl	\$ 90.00	\$ 90.00	\$ 90.00	\$ 90.00	\$ 90.00
NG - \$/Mcf	\$ 4.50	\$ 5.00	\$ 5.25	\$ 5.50	\$ 6.00

- Includes actual financial results through May 2011
- Throughput forecasts are 100% joint venture gross operated production volumes except in Legacy East Texas area where third party operated volumes were included
- Throughput forecasts were based on the upstream development program specific to each area
- Downtime factors by region through 2015 for offset frac and other operational factors; no downtime post 2015:

Holly	7.5%
Shelby	5.0%
Waskom	7.5%
ETXNLA JV Conventional	3.5%

## Midstream Summary Income Statement

Midstream Financials are 100% to the JVs, EXCO owns 50% of JVs

### TGGT & Appalachia Midstream

#### Income Statement

(\$ in millions)

	2011 E	2012 E	2013 E	2014 E	2015 E
Revenue:					
TGGT	\$ 213.1	\$ 334.5	\$ 389.3	\$ 416.8	\$ 414.4
Appalachia	9.5	37.5	77.0	115.5	138.1
Total Revenue	222.6	371.9	466.3	532.3	552.5
Expense:					
TGGT	81.8	79.0	81.7	85.2	88.9
Appalachia	3.7	6.1	9.4	11.9	13.8
Total Operating Expense	85.5	85.1	91.1	97.1	102.7
EBITDA	137.1	286.9	375.3	435.2	449.8
TGGT: Texas Margin Tax	1.3	1.7	1.9	2.1	2.1
Interest Expense	10.5	13.4	12.7	13.0	9.8
Capital:					
TGGT	259.1	112.7	200.2	64.3	60.8
Appalachia	48.0	90.2	271.8	272.2	85.8
Total Capital	307.0	202.9	472.0	336.5	146.6
Free Cash Flow <sup>(1)</sup>	\$ (181.1)	\$ 69.5	\$ (110.8)	\$ 84.3	\$ 291.9

(1) Free Cash Flow excludes non-cash deferred interest expense.

## Midstream Summary Balance Sheet

Midstream Financials are 100% to the JVs, EXCO owns 50% of JVs

### TGGT & Appalachia Midstream

#### Balance Sheet

(\$ in millions)

	As of December 31,				
	2011 E	2012 E	2013 E	2014 E	2015 E
Cash & cash equivalents	\$ 10.0	\$ 10.0	\$ 10.0	\$ 10.0	\$ 10.0
Accounts receivable	28.2	35.5	43.6	49.3	51.4
Inventory	3.6	3.6	3.6	3.6	3.6
Other	0.1	0.1	0.1	0.1	0.1
<b>Current Assets</b>	<b>41.9</b>	<b>49.2</b>	<b>57.3</b>	<b>63.0</b>	<b>65.1</b>
Gas gathering assets-net	1,118.6	1,285.1	1,705.0	1,978.1	2,056.5
Deferred financing costs	2.8	2.2	1.6	1.0	0.4
Office & field equipment, net	10.7	10.7	10.7	10.7	10.7
<b>Total Assets</b>	<b>\$ 1,174.1</b>	<b>\$ 1,347.2</b>	<b>\$ 1,774.5</b>	<b>\$ 2,052.8</b>	<b>\$ 2,132.7</b>
Accounts payable	\$ 34.1	\$ 28.6	\$ 51.8	\$ 41.2	\$ 26.3
Accrued interest payable	1.3	1.1	1.0	1.0	0.8
Other	2.5	2.5	2.5	2.5	2.5
<b>Current Liabilities</b>	<b>37.8</b>	<b>32.2</b>	<b>55.3</b>	<b>44.8</b>	<b>29.6</b>
Long term liabilities	3.6	3.6	3.6	3.6	3.6
Long term debt	489.2	444.6	540.4	472.4	197.8
Additional paid-in capital	529.4	529.4	529.4	529.4	529.4
Retained earnings	114.1	337.4	645.9	1,002.7	1,372.4
<b>Total Stockholders' Equity</b>	<b>643.4</b>	<b>866.8</b>	<b>1,175.3</b>	<b>1,532.1</b>	<b>1,901.8</b>
<b>Total Liabilities &amp; Stockholders' Equity</b>	<b>\$ 1,174.1</b>	<b>\$ 1,347.2</b>	<b>\$ 1,774.5</b>	<b>\$ 2,052.8</b>	<b>\$ 2,132.7</b>

## Midstream Summary Cash Flow

Midstream Financials are 100% to the JVs, EXCO owns 50% of JVs

### TGGT & Appalachia Midstream

#### Cash Flow Statement

(\$ in millions)

	2011 E	2012 E	2013 E	2014 E	2015 E
<b>Operating Activities:</b>					
Net Income	\$ 84.0	\$ 223.4	\$ 308.5	\$ 356.8	\$ 369.7
Depreciation & Amortization	28.3	36.4	52.1	63.4	68.3
Cash Flow before Changes in Working Capital	112.3	259.8	360.6	420.2	437.9
Decrease (Increase) in:					
Accounts receivable	8.7	(7.2)	(8.1)	(5.7)	(2.1)
Accounts & Accrued interest payable	(13.5)	(5.7)	23.1	(10.5)	(15.2)
Cash Provided (Used In) Operating Activities	107.5	246.9	375.6	403.9	420.6
<b>Investing Activities:</b>					
Capital Expenditures	(370.8)	(202.9)	(472.0)	(336.5)	(146.6)
Cash Provided (Used in) Investing Activities	(370.8)	(202.9)	(472.0)	(336.5)	(146.6)
<b>Financing Activities:</b>					
Deferred Financing Costs	(2.8)	0.6	0.6	0.6	0.6
Borrowings or (Repayments under facility)	489.2	(44.6)	95.8	(68.0)	(274.6)
Cash Provided (Used in) Financing Activities	486.4	(44.0)	96.4	(67.4)	(274.0)
Net Increase (Decrease) in Cash & Cash Equivalents	(13.3)	-	-	-	-
Cash & cash equivalents, beginning of period	23.4	10.2	10.2	10.2	10.2
Cash & cash equivalents, end of period	\$ 10.2	\$ 10.2	\$ 10.2	\$ 10.2	\$ 10.2

## Midstream Summary Throughput and Capital Summary

Midstream Financials are 100% to the JVs, EXCO owns 50% of JVs

Midstream Throughput (Mmcf/d)	2011 E	2012 E	2013 E	2014 E	2015 E
TGGT	1,488.9	2,268.1	2,741.0	2,698.1	2,684.9
Appalachia	32.6	128.4	263.8	395.7	473.0
<b>Consolidated Throughput</b>	<b>1,521.5</b>	<b>2,396.5</b>	<b>3,004.8</b>	<b>3,093.7</b>	<b>3,157.9</b>

TGGT Capital by Category	2011 E	2012 E	2013 E	2014 E	2015 E
Well Hookups	\$ 39.4	\$ 58.4	\$ 62.1	\$ 56.5	\$ 42.2
Field Infrastructure & Facilities	163.7	47.6	62.6	3.6	13.6
Transportation Pipelines	43.5	0.5	71.5	0.5	0.5
Miscellaneous/Other	12.5	6.2	4.0	3.7	4.5
<b>Total Capital</b>	<b>\$ 259.1</b>	<b>\$ 112.7</b>	<b>\$ 200.2</b>	<b>\$ 64.3</b>	<b>\$ 60.8</b>