

CORE STRENGTH

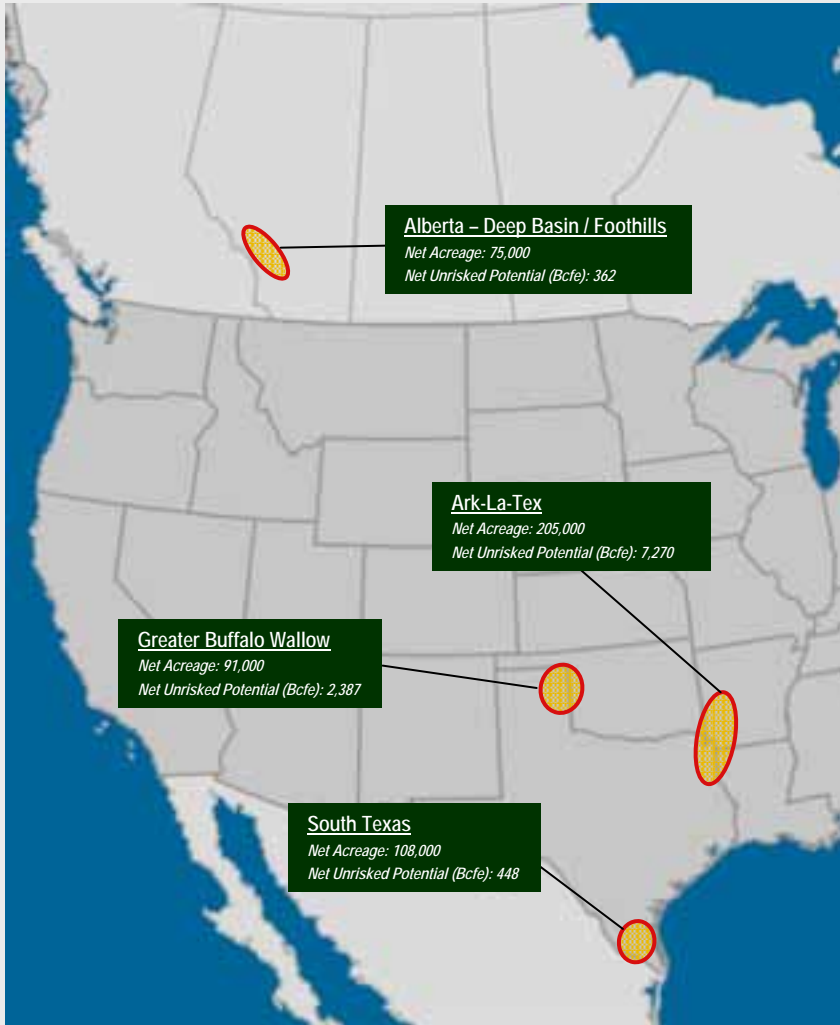


Corporate Update

August 10, 2009



Forest Oil – Snapshot



 Core Areas

Market Capitalization: <i>(8/6/09)</i>	\$1.9 Billion
Enterprise Value*	\$4.6 Billion
2008 Est. Proved Reserves: <i>(75% natural gas)</i>	2.7 Tcfe
R/P Ratio:	14.0 Years
Potential Locations**: <i>(Fully Developed)</i>	18,248
Net Unrisked Potential**:	17.8 Tcfe
2009 Production Guidance:	185-195 Bcfe



* Debt as of July 31, 2009

** As of 12/31/08; does not include estimated proved reserves or locations associated with estimated proved reserves



Excellent 2008 & Well Positioned For 2009

2008 Highlights

- Record estimated proved reserves of 2.7 Tcfe
- 18,248 locations with 17.8 Tcfe net unrisked potential
- 2008 net production rose 22% (17% organic) to 190 Bcfe
- All-sources reserve replacement of 549% with FD&A costs of \$2.61 per Mcfe*
- Organic reserve replacement of 281% with F&D costs of \$2.54 per Mcfe*
- Significant horizontal success in East Texas, Arkoma and Alberta

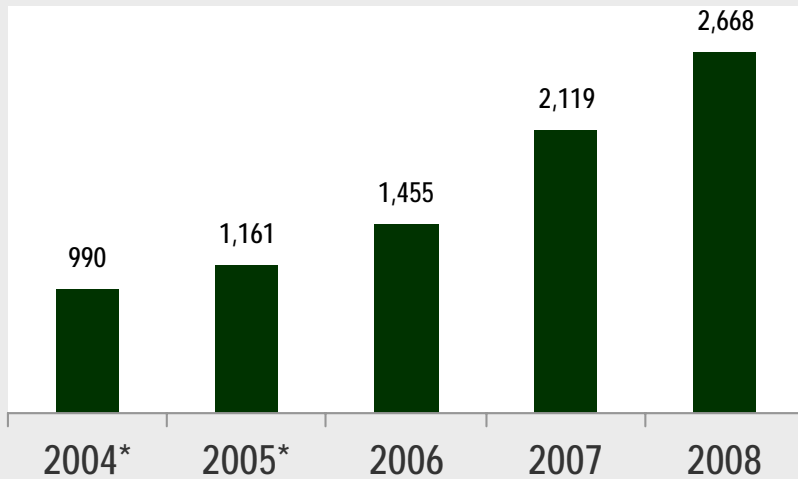
Well Positioned For 2009

- Strong balance sheet with approximately \$980 million of liquidity
- Attractive hedge positions – 60% – 65% of remaining 2009 natural gas production hedged
- One of the lowest cost structures in the industry
- “Free agent” on drilling costs
- 2009 capital plan designed to be below discretionary cash flow

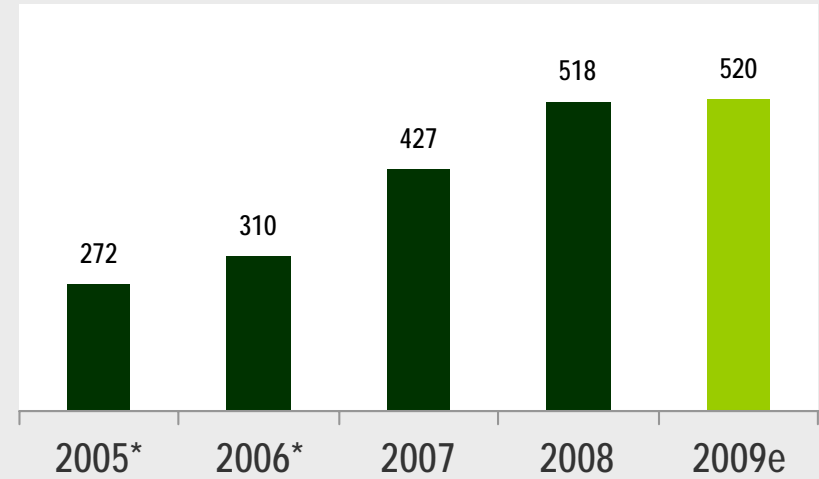


Key Statistics and Guidance

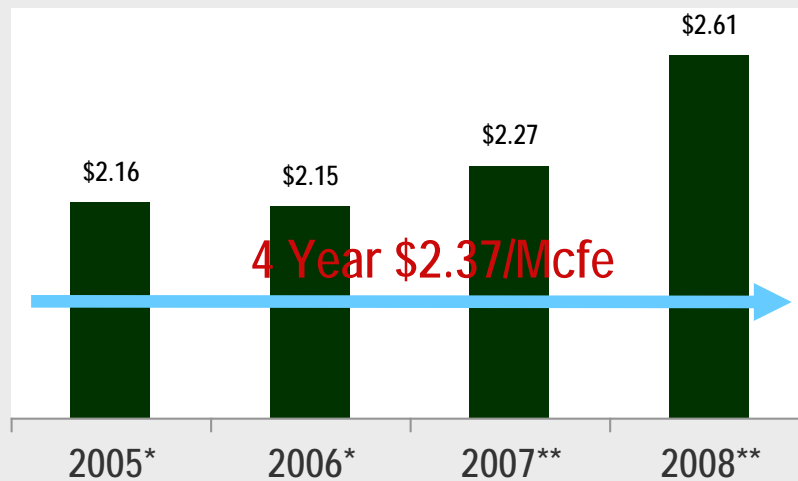
ESTIMATED PROVED RESERVES (Bcfe)



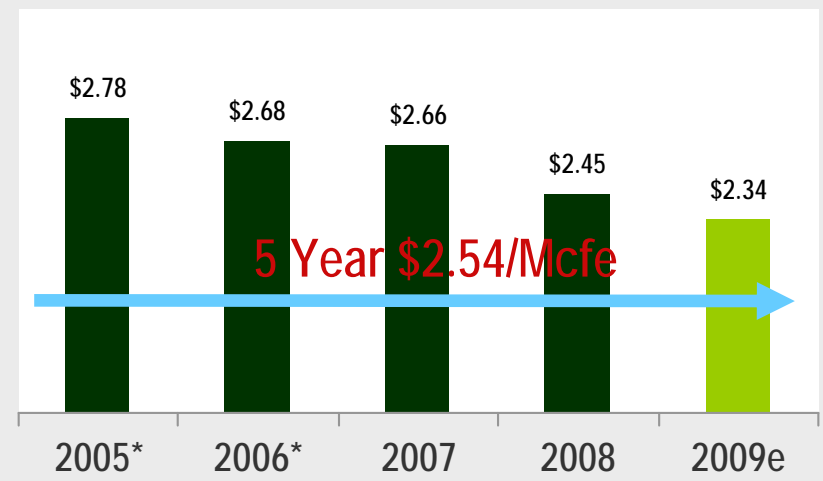
PRODUCTION (MMcfe/d)



FD&A COSTS (\$/Mcfe)



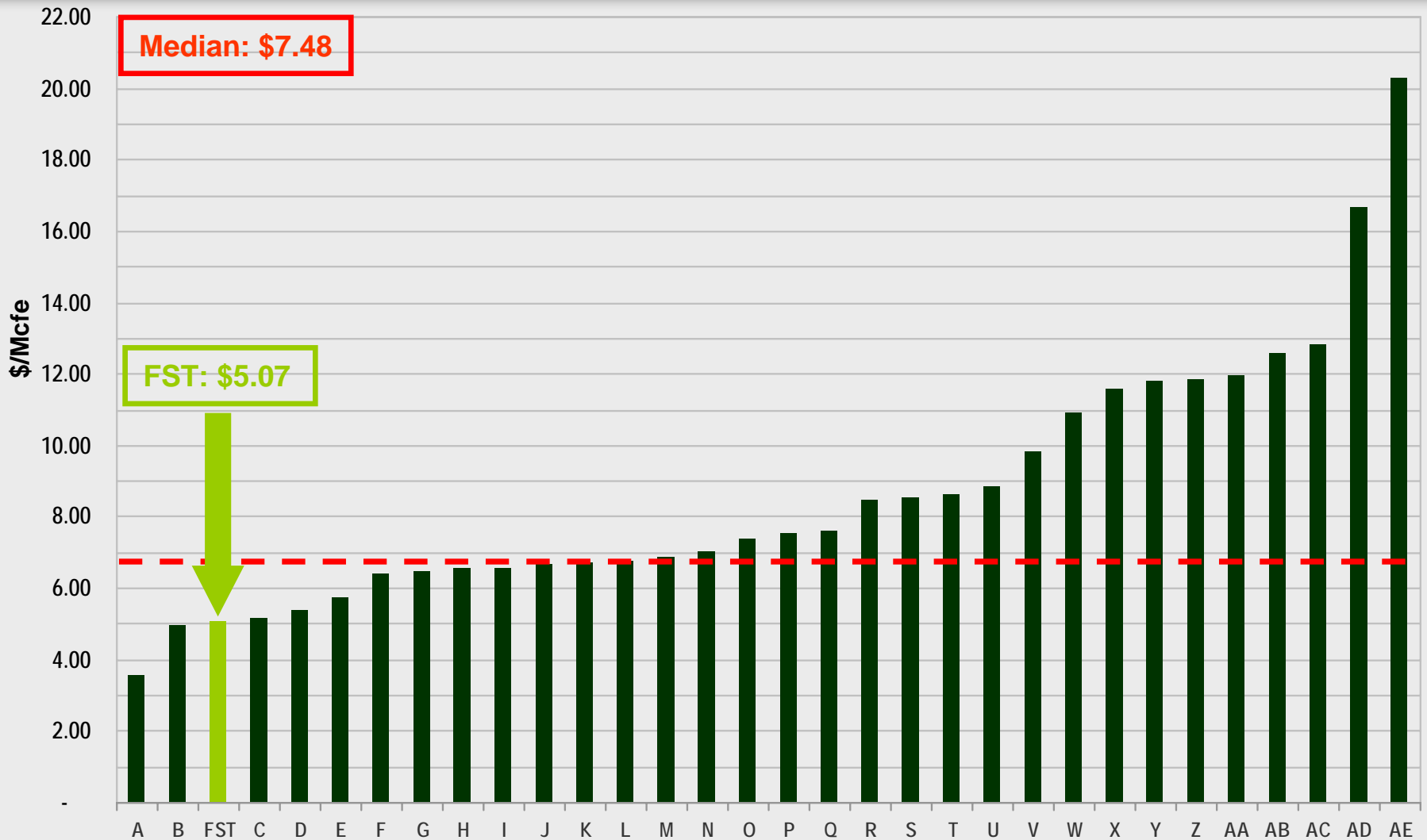
TOTAL CASH COSTS (\$/Mcfe)



* Pro forma for the spin-off of the Gulf of Mexico operations
** Does not include effects of Alaska properties during 2007 or reserve revisions



2008 All-In Costs

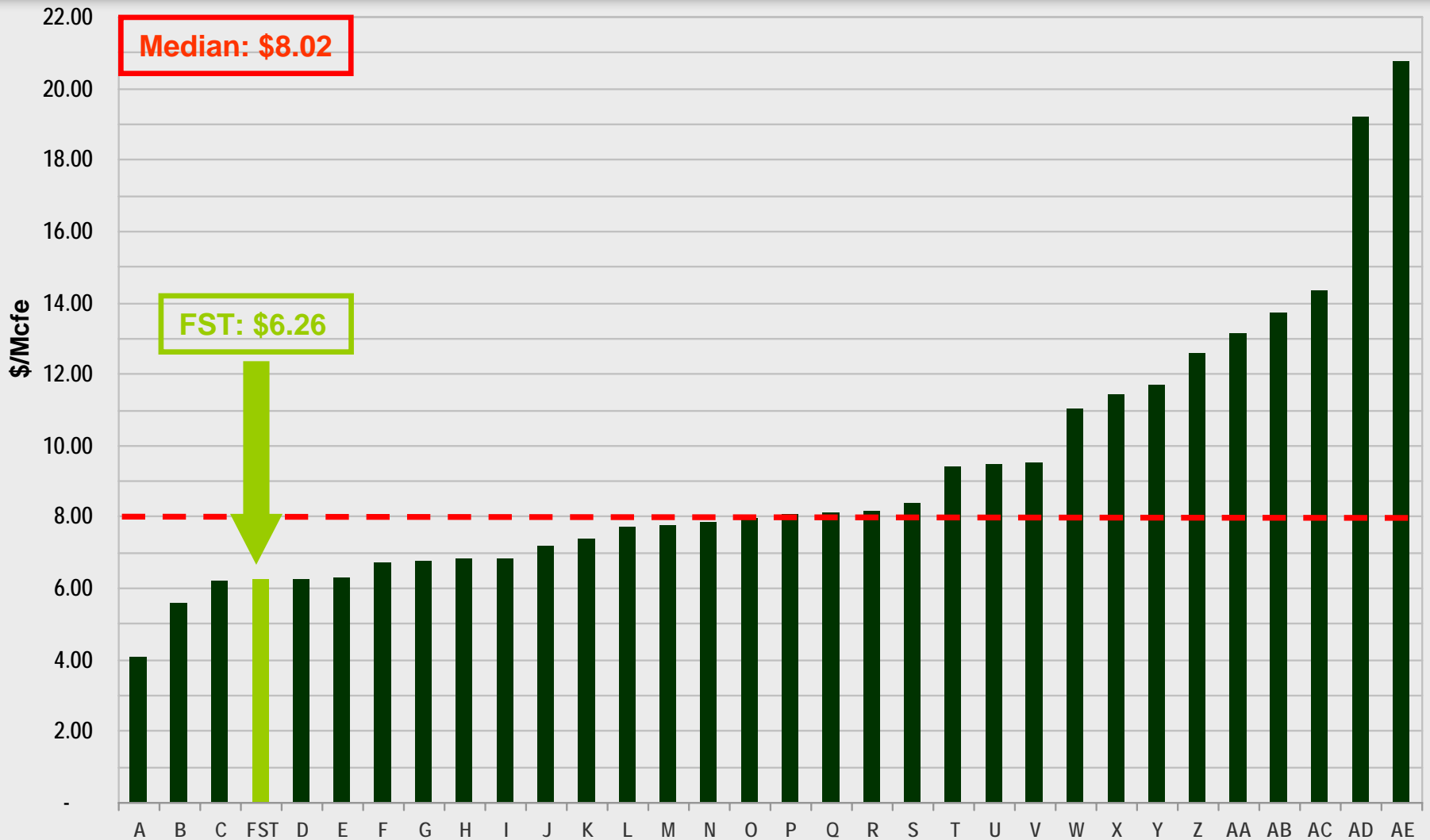


Source: Bank of America; all-in costs defined as production cost, G&A, interest cost and reserve replacement cost.

Companies Included: ATN, BEXP, BRY, Chaparral Energy, CHK, CRK, CWEI, DNR, DPTR, EAC, EP, EXXI, FST, HK, HLX, KWK, ME, MMR, NFX, PQ, PXD, PXP, RRC, SD, SFY, SGY, SWN, VQ, WLL, WTI, XCO AND XEC



2008 Breakeven Point

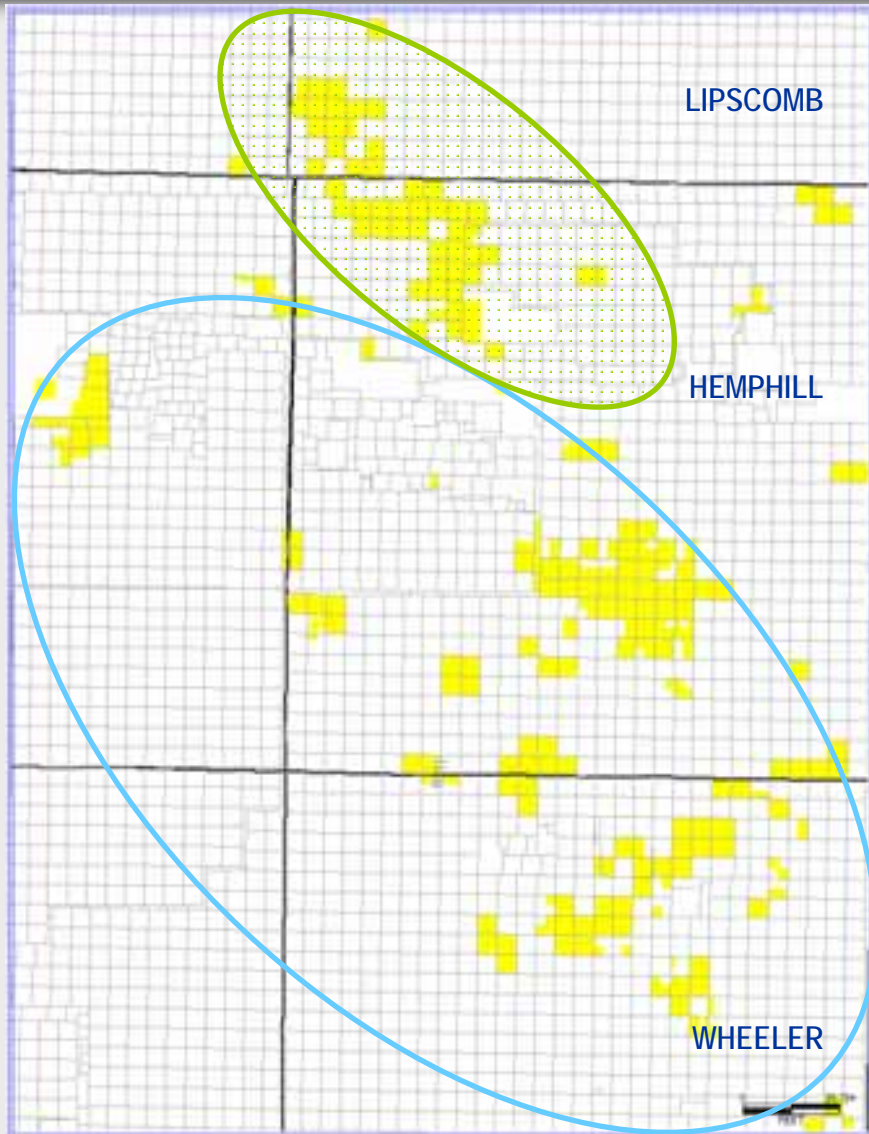


Source: Bank of America; breakeven point defined as all-in costs divided by company's NYMEX realization.

Companies Included: ATN, BEXP, BRY, Chaparral Energy, CHK, CRK, CWEI, DNR, DPTR, EAC, EP, EXXI, FST, HK, HLX, KWK, ME, MMR, NFX, PQ, PXD, PXP, RRC, SD, SFY, SGY, SWN, VQ, WLL, WTI, XCO AND XEC



Greater Buffalo Wallow Area



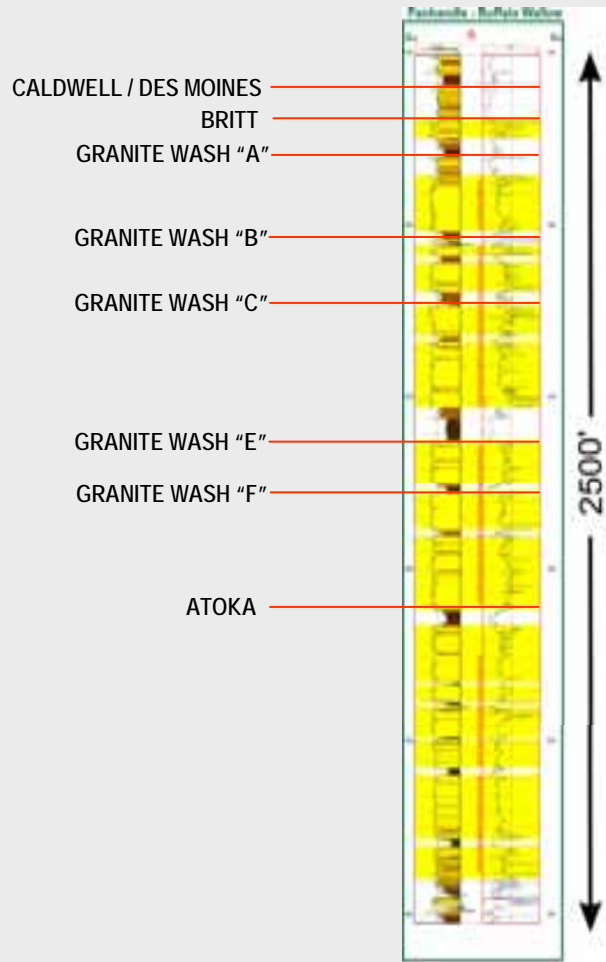
Greater Buffalo Wallow Area Attributes

- 120,000 gross acres (91,000 net) prospective for the Atoka, Cleveland, Douglas and Granite Wash
- Increased production 78% from 51 MMcfe/d in Q1 2008 to 91 MMcfe/d in Q1 2009 without horizontal drilling
- Horizontal potential in the Atoka, Morrow and Granite Wash
 - Completed first operated horizontal in the Granite Wash at an IP of 17 MMcfe/d
 - Participated in horizontal well with IP of 20 MMcfe/d +
 - Expect to run one rig for the remainder of 2009 and redesign development plan to focus on horizontal wells



Geologic Zones in Greater Buffalo Wallow Area

Type Log – Vertical Nomenclature

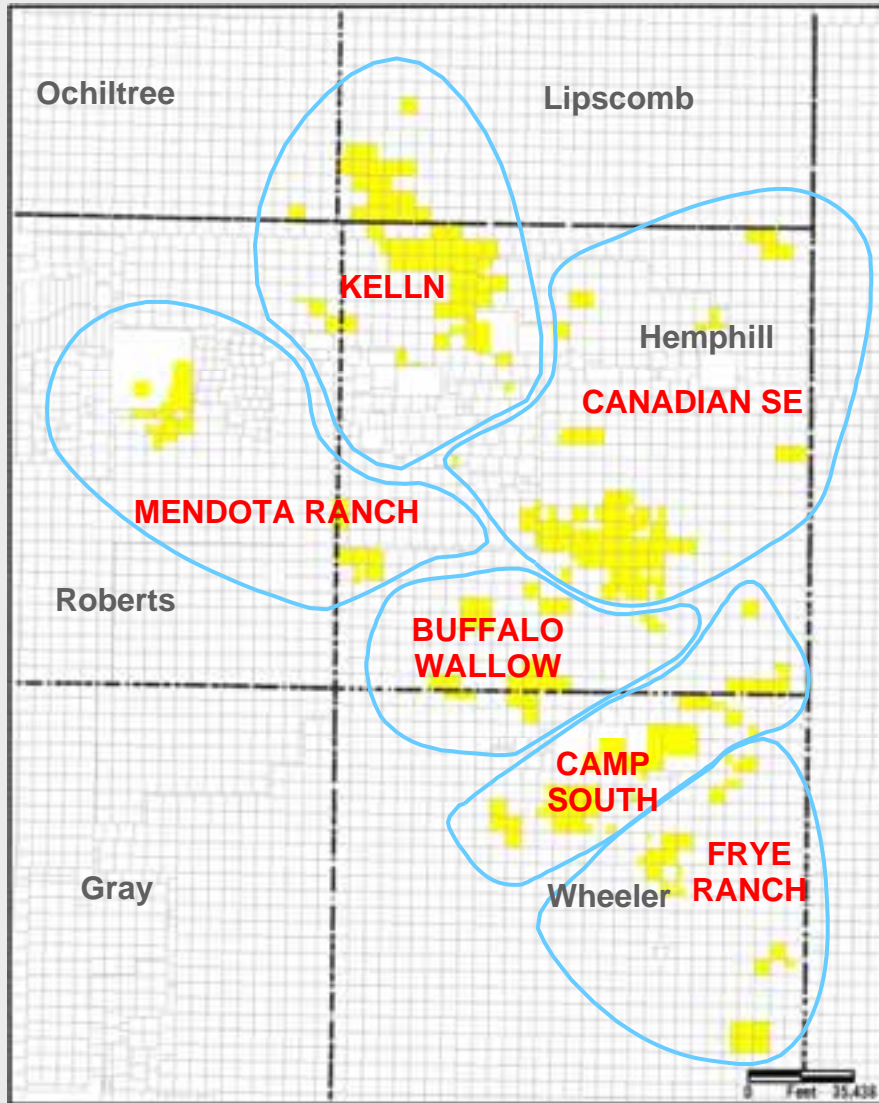


Basic Play Facts

- Trend was established by mountain front orogeny running northwest to southeast
- Mountain front became the source of deposition as erosion of the mountains with granitic sediments deposited in lobes, or fingers, coming off the mountains
- Moderate porosity, low permeabilities
- Depths of play range from 13,000' to 17,000' and the total thickness of this deposition ranges from 1,500' to 3,500'
- Amount of pay varies depending on acreage position
- Other potential objectives in the Morrow, Douglas, Cleveland, Novi Lime, St. Louis Lime and Tonkawa



Forest Oil's Nomenclature



Area Nomenclature

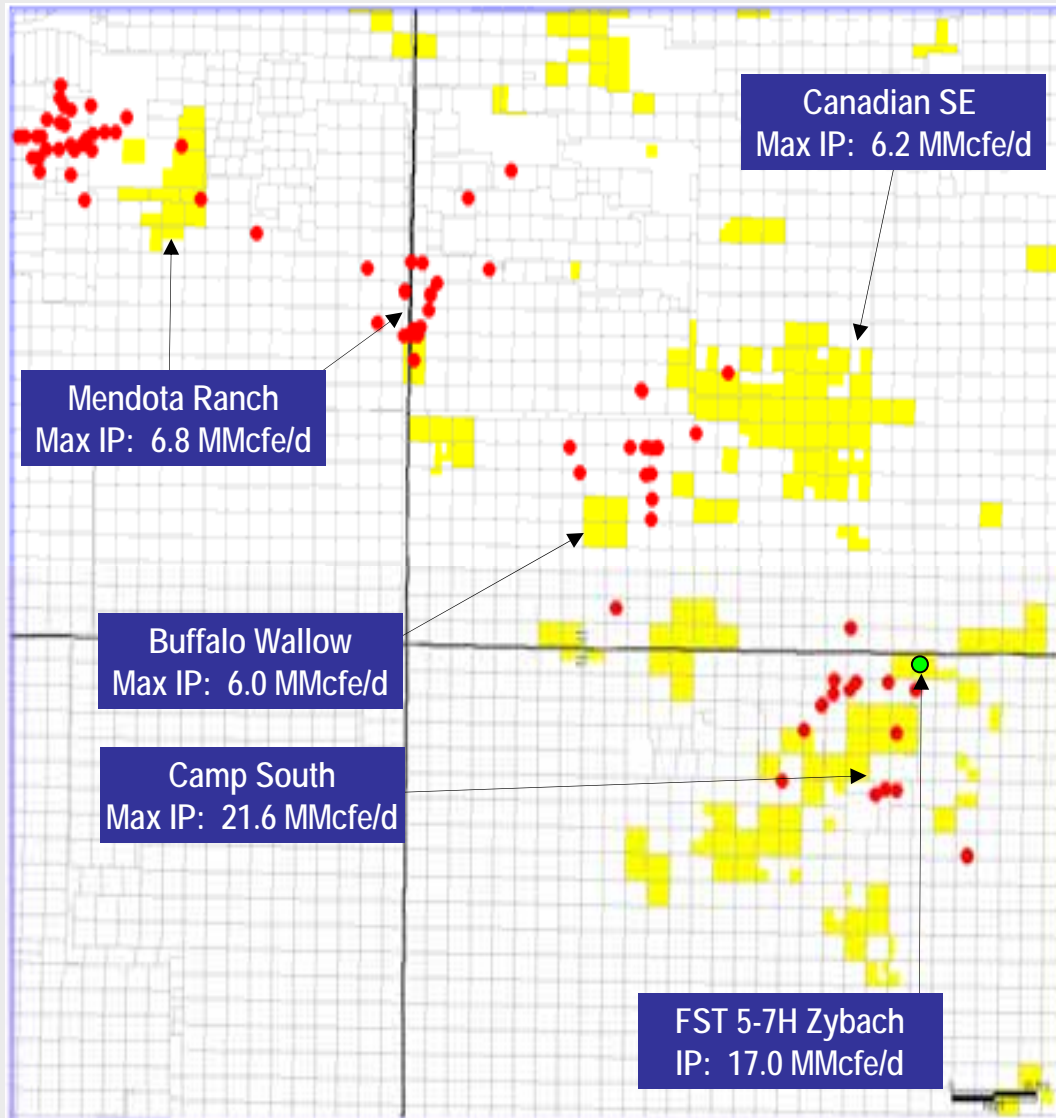
- Different Nomenclature...Same Play
- Transition to horizontal drilling involved minimal vertical drilling to secure sections allowing for optimal horizontal development
- Acreage accumulated through grass roots leasing, farm outs and acquisitions
- Frac mapping was performed to allow for more efficient spacing and less interference between wells
- Frac data, well bore, and other data have been incorporated and mapped over our acreage yielding best development



Granite Wash Horizontal Fairway

Overview

- 21 horizontal wells drilled by industry in the field to date with an average IP of 6.6 MMcfe/d
- Forest has participated in 8 wells (40%) with average IP of 8.0 MMcfe/d
- Forest's first operated horizontal IP of 17 MMcfe/d
- Forest has initially estimated 170 potential horizontal locations on large undeveloped acreage position with additional Atoka potential
- Expected drill and complete cost of \$5.5 million



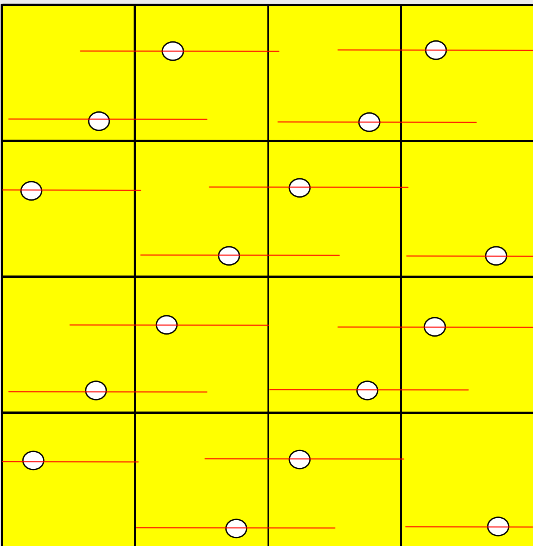


Texas Panhandle: Horizontal vs. Vertical Development

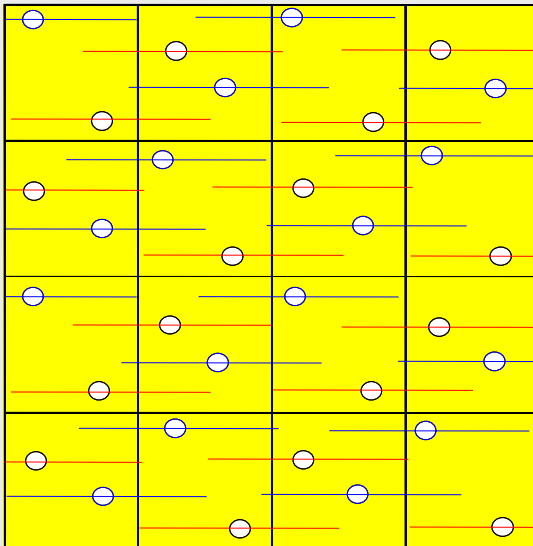
Horizontal Drilling – Most Efficient Development

Scenario	# of Wells	EUR/Well (Bcfe)	EUR/Sec (Bcfe)	D&C (\$MM)	Dev Cost/Sec (\$MM)	F&D (\$/Mcfe)
40-Acre Vertical	16	1.5	23.2	\$2.3	\$36.9	\$1.59
20-Acre Vertical	32	1.5	46.5	\$2.3	\$73.8	\$1.59
Granite Wash Horizontal	3	6.5	19.6	\$5.5	\$16.6	\$.85
Atoka Horizontal	3	6.8	20.3	\$9.9	\$29.7	\$1.46
Twin Horizontal	6		39.9		\$46.3	\$1.16
20-Acre vs. Twin	(26)		(6.6)		(\$27.5)	(\$4.17)

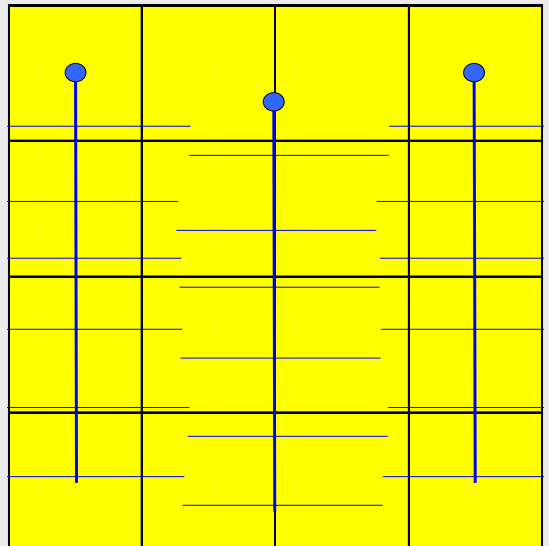
40 Acre Spacing



20 Acre Spacing



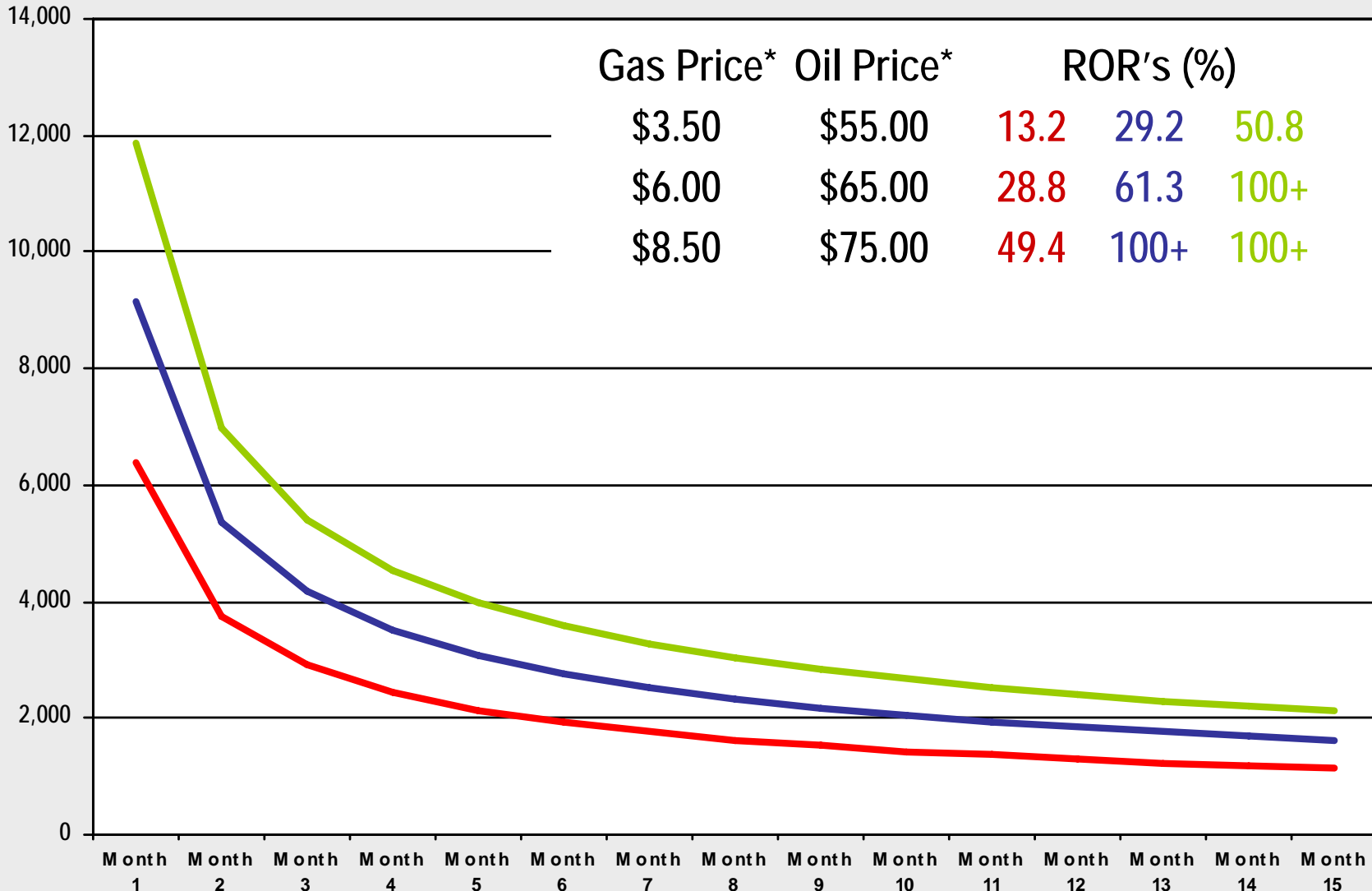
Horizontal Development





Granite Wash Economics & Type Curve

Mcf/d



Gas Price*	Oil Price*	ROR's (%)		
\$3.50	\$55.00	13.2	29.2	50.8
\$6.00	\$65.00	28.8	61.3	100+
\$8.50	\$75.00	49.4	100+	100+

* NYMEX price

— Upside Case — Median Case — Downside Case

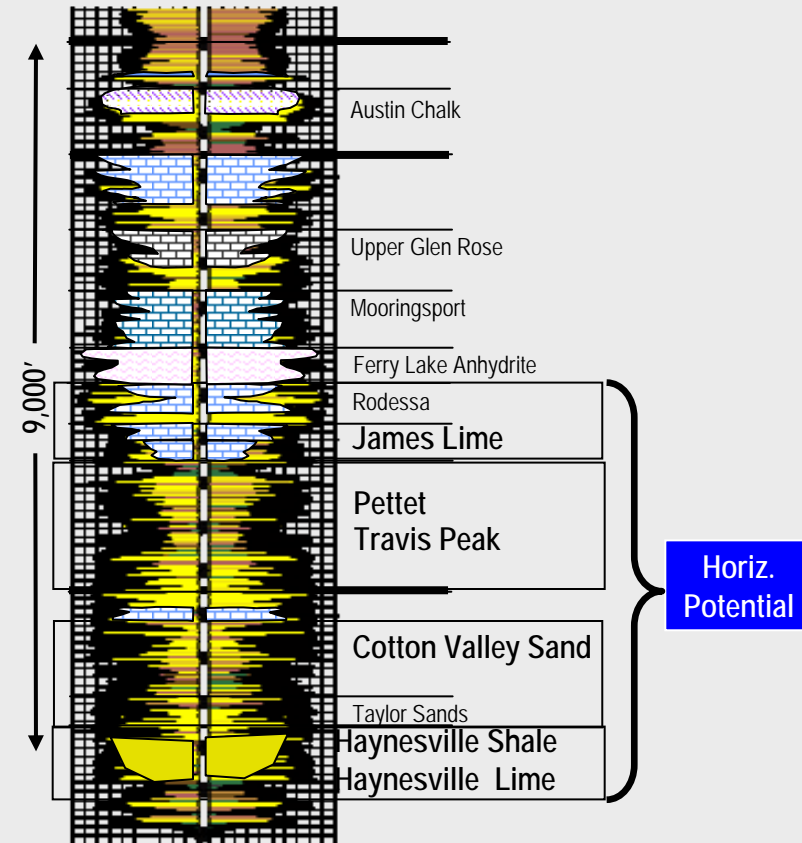


East Texas/North Louisiana Potential

Forest's "Core Strengths" in Resource Plays

- Low cost of entry provides superior economics
- Up front integration of data before horizontal drilling includes cores samples
- Mechanical success on horizontal completions
- Cost and extraction efficiencies as play expands

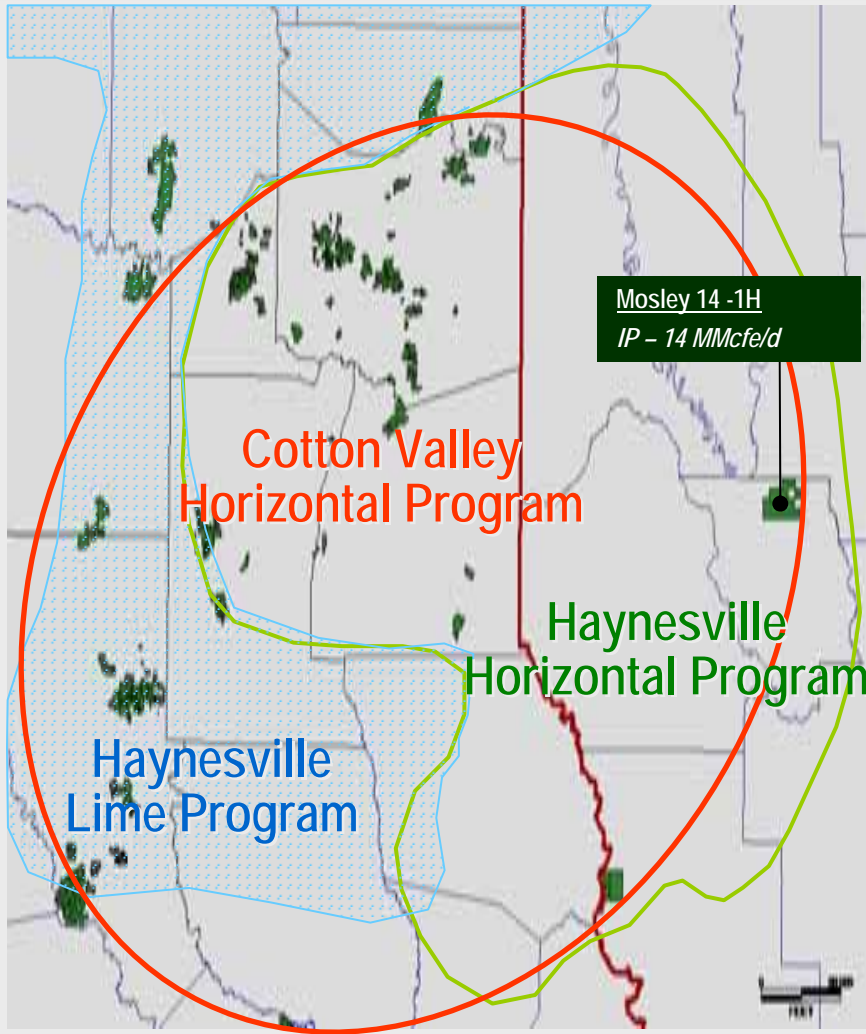
E. Texas/N. Louisiana Geologic Zones



“Acreage In East Texas/North Louisiana Provides Multiple Production Horizons”



Haynesville Shale and Lime



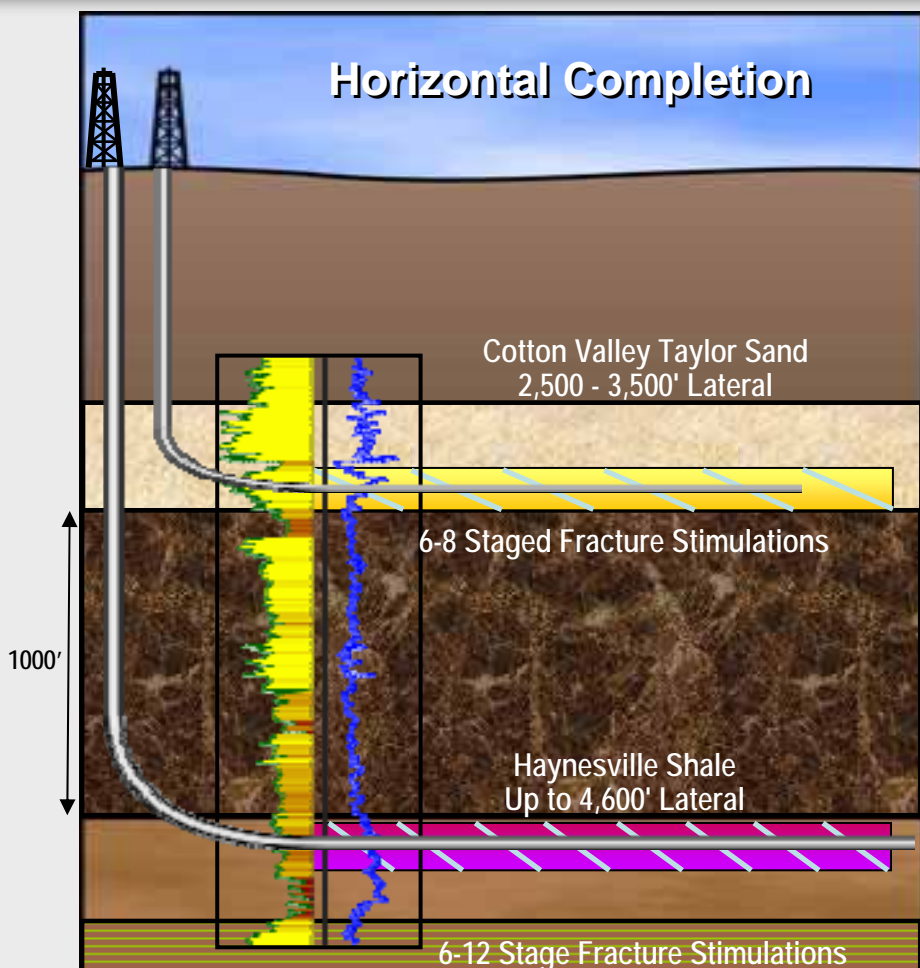
East Texas/North Louisiana

- 140,000 gross acres (127,000 net) prospective for Haynesville Play
- Shallow and deep rights on majority of acreage
- 14 vertical Haynesville tests completed
- Louisiana: Horizontal IP's of 20 MMcfe/d and 14 MMcfe/d (100% WI)
- Texas: Three horizontal IP's of 5 MMcfe/d
- 2009 Haynesville program
 - 2 rig program drilling 10 – 12 operated wells
 - Participation in 2 – 3 non-operated wells
- Currently drilling deeper Haynesville Lime well



Horizontal Drilling – Another Core Strength

Horizontal Completion



Horizontal Success

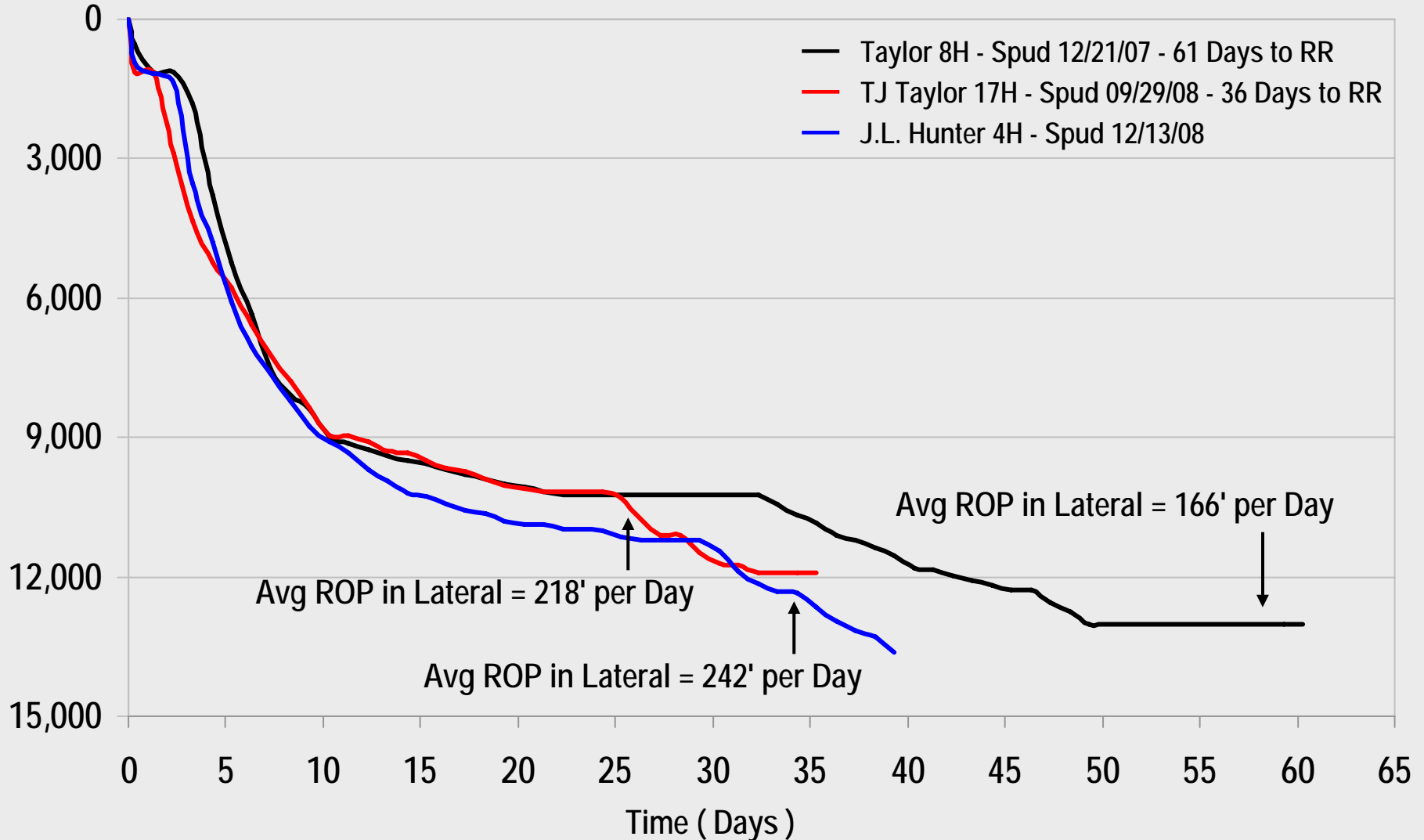
- Focused horizontally in both the Cotton Valley Taylor Sands and the Haynesville Shale and Lime
- Reduced cost on horizontal Cotton Valley wells from \$6.3 million to \$4.8 million with average IP rates in excess of 5 MMcfe/d
- Haynesville Shale horizontals targeted at a \$7.3 million average

“We Intend To Extract Efficiencies Through Cost Control And Technology”



E. Texas/N. Louisiana Horizontal Drilling Efficiencies

Measured Depth (Feet)





2009 Observations

Capital Plan

- E&D spending designed to be within discretionary cash flow
- Protect lease expirations and non-consent penalties
- Horizontal drilling is favored economically versus vertical
- Utilize Lantern rigs
- Prioritize “FOCUS” projects to reduce production expense – recompletions/workovers
- Take advantage of declining service costs in 2009

Financially Flexible

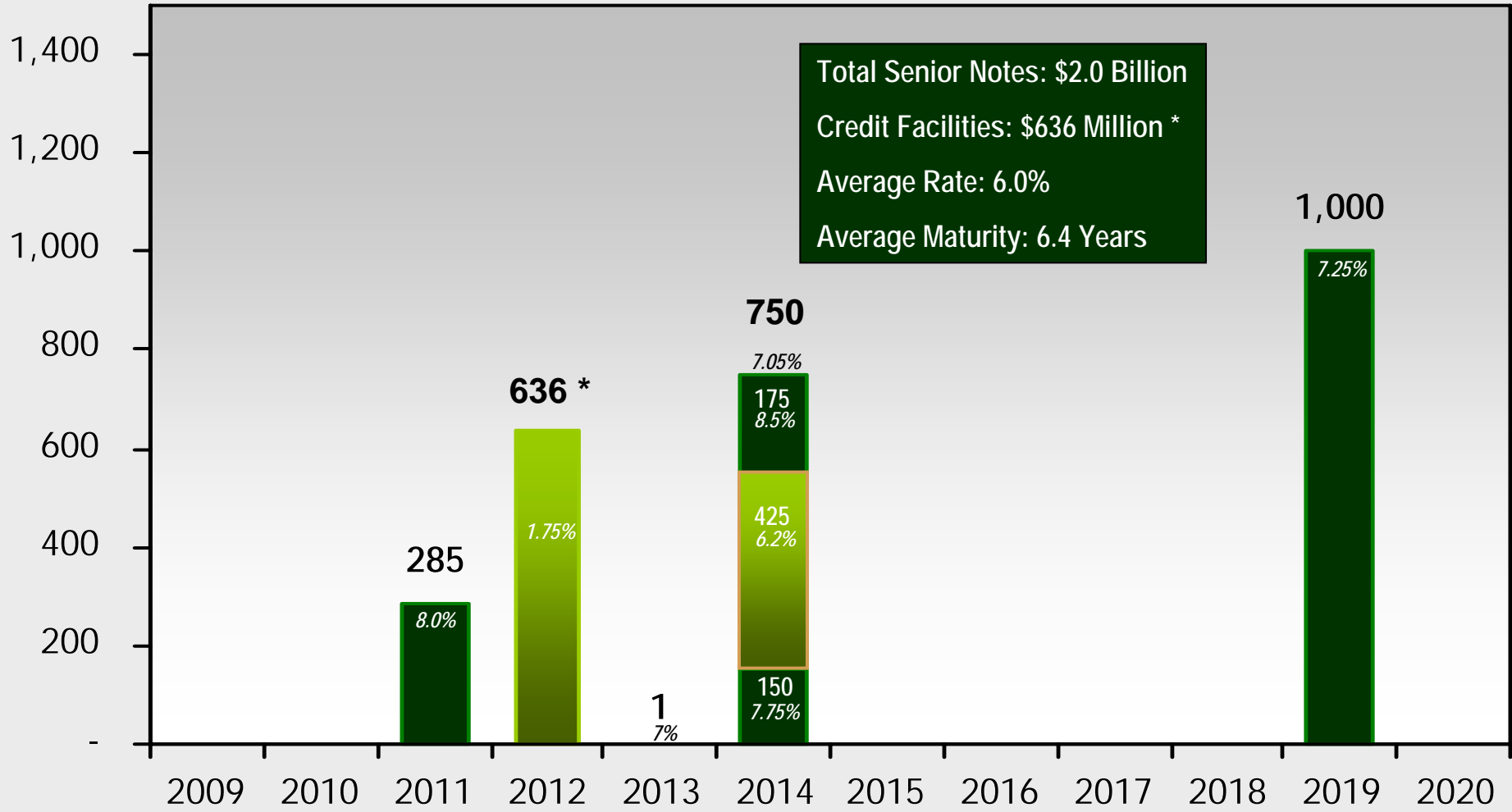
- Staggered long term debt maturity schedule
- Approximately \$980 million in liquidity under \$1.62 billion credit facilities
- 60% – 65% of remaining 2009 natural gas production hedged at \$7.53/MMBtu floor
- 30% – 35% of 2009 oil production hedged at \$69.01/Bbl
- 160 BBtu/d of 2010 natural gas production hedged at \$6.34/MMBtu



Debt Maturity Profile

(\$MM)

6/30/09



Note: LIBOR assumption at 50 bps



Floating



Fixed

* As of July 31, 2009



Hedge Portfolio – NYMEX Hedges

Hedging Price Risk

	Apr-Dec 2009	Weighted Price Floor/Ceiling	2010	Weighted Price Floor/Ceiling
Natural Gas Swaps				
Contract Volumes (BBtu/d)	193.4 [*]		160.0	
Weighted Average Price (\$ per MMBtu)	7.58		6.34	
Natural Gas Collars				
Contract Volumes (BBtu/d)	40.0		-	
Weighted Average Ceiling Price (\$ per MMBtu)	9.76		-	
Weighted Average Floor Price (\$ per MMBtu)	7.31		-	
		\$7.53 - \$7.95		\$6.34 – \$6.34
Oil Swaps				
Contract Volumes (MBbl/d)	4.5		1.5	
Weighted Average Price (\$ per Bbl)	69.01		72.95	
Oil Collars				
Contract Volumes (MBbl/d)	-		-	
Weighted Average Ceiling Price (\$ per Bbl)	-		-	
Weighted Average Floor Price (\$ per Bbl)	-		-	

* 10.0 Bbtu/d of natural gas swaps are subject to a written put of \$6.00 per MMBtu

\$69.01

\$72.95

- 200 + Bbtu/d of basis hedged at (\$.71) per MMBtu in 2009 (60 Bbtu/d hedged in Mid-Con at (\$1.04))



Summary

- Portfolio management has created substantial North American gas resource plays
- 18,248 fully developed locations provide over 17.8 Tcfe of additional net unrisks potential with a large HBP component
- Built to withstand adverse environments; liquidity, cash flow and asset base are strong
- High quality assets, substantial liquidity, low cost structure and substantial upside in asset portfolio

“Forest Has A High Quality Asset Base And Is Levered Operationally And Financially To Natural Gas”



Cautionary Statements

Forward Looking Statements – This presentation includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, that address activities that Forest assumes, plans, expects, believes, projects, estimates or anticipates (and other similar expressions) will, should or may occur in the future are forward-looking statements. The forward-looking statements provided in this press release are based on management's current belief, based on currently available information, as to the outcome and timing of future events. Forest cautions that its future natural gas and liquids production, revenues, cash flows, liquidity, plans for future operations, expenses, outlook for oil and natural gas prices, timing of capital expenditures, and other forward-looking statements are subject to all of the risks and uncertainties normally incident to the exploration for and development and production and sale of oil and gas.

These risks include, but are not limited to, oil and natural gas price volatility, Forest's access to cash flows and other sources of liquidity to fund its capital expenditures, its level of indebtedness, its ability to replace production, the impact of the current financial crisis on Forest's business and financial condition, a lack of availability of goods and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating future oil and gas production or reserves, economic conditions and other risks as described in reports that Forest files with the Securities and Exchange Commission (SEC), including its Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, and Current Reports on Form 8-K. Also, the financial results of Forest's foreign operations are subject to currency exchange rate risks. Any of these factors could cause Forest's actual results and plans to differ materially from those in the forward-looking statements.

Reserves – The Securities and Exchange Commission permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves, which are estimates that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Forest uses the terms "probable" and "possible" reserves, resource "potential" or "upside" or other descriptions of volumes of reserves or resources potentially recoverable through additional drilling or recovery techniques that the SEC's guidelines strictly prohibit Forest 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 Forest. Resource potential refers to Forest's internal estimates of hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques. Resource potential does not constitute reserves within the meaning of the Society of Petroleum Engineer's Petroleum Resource Management System and does not include any proved reserves. Area wide unrisked resource potential has not been risked by Forest's management. Actual quantities that may be ultimately recovered from Forest's interests will differ substantially. Factors affecting ultimate recovery include the scope of Forest's ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals and other factors; and actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of resource potential may change significantly as development of our resource plays provides additional data. Investors are urged to consider closely the disclosures in Forest's Annual Report on Form 10-K for fiscal year ended December 31, 2008 and Forest's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, copies of which are available for free from Forest by writing Forest at 707 17th Street, Suite 3600, Denver, CO 80202, Attention: Investor Relations, or by calling Investor Relations at 303-812-1400, or visiting Forest's website at www.forestoil.com.