

TD Newcrest London Energy Conference

January 2011



enerPLUS

Advisory

- This presentation contains certain forward-looking information and statements ("forward-looking information") within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends", "budget", "strategy" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this presentation contains forward-looking information pertaining to the following: Enerplus' strategy; the performance of Enerplus' assets and operations; future growth prospects, acquisitions and dispositions; future dividends to securityholders; capital and development expenditures and the timing and allocation thereof; the volumes and estimated value of Enerplus' oil and gas reserves and contingent resource volumes; the life of Enerplus' reserves; the volume and product mix of Enerplus' oil and gas production; future results from operations; future development and drilling locations and plans; the installation of infrastructure; receipt of regulatory approvals; commodity prices and foreign exchange rates; the amount of future asset retirement obligations; returns on Enerplus' capital program; Enerplus' tax position; and future costs, expenses and royalty rates.
- The forward-looking information contained in this presentation reflect several material factors and expectations and assumptions of Enerplus including, without limitation: that Enerplus will continue to conduct its operations in a manner consistent with past operations; the general continuance of current or, where applicable, assumed industry conditions; the continuance of existing (and in certain circumstances, the implementation of proposed) tax, royalty and regulatory regimes; the accuracy of the estimates of Enerplus' reserve and resource volumes; certain commodity price and other cost assumptions; the continued availability of adequate debt and/or equity financing and cash flow to fund its capital and operating requirements as needed; and the extent of its liabilities. Enerplus believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.
- The forward-looking information included in this presentation are not guarantees of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: changes in commodity prices; changes in the demand for or supply of Enerplus' products; unanticipated operating results or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in the development plans of Enerplus or by third party operators of Enerplus' properties, increased debt levels or debt service requirements; inaccurate estimation of Enerplus' oil and gas reserve and resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners; and certain other risks detailed from time to time in Enerplus' public disclosure documents (including, without limitation, those risks identified in Enerplus' Annual Information Form and Form 40-F described above).
- All financial figures are in Canadian dollars unless otherwise stated.
- Enerplus' financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). Canadian GAAP differs in some significant respects from U.S. GAAP and therefore this financial information may not be directly comparable to the financial information typically provided by U.S. companies. The principal differences as they may apply to Enerplus are summarized in Note 14 to Enerplus' audited consolidated financial statements for the year ended December 31, 2009. A complete copy of the audited financial statements and notes is available without charge from Enerplus.
- Our payout ratio is calculated as cash distributions/dividends divided by cash flow from operating activities. The term payout ratio does not have a standardized meaning as prescribed by GAAP and therefore may not be comparable with the calculation of a similar measure by other entities. This reflects the proportion of cash flow paid out to investors and not reinvested in the business.
- This presentation contains references to "Mcf" (thousand cubic feet of gas equivalent), "MMcfe" (million cubic feet of gas equivalent), "Bcfe" (billion cubic feet of gas equivalent) and "Tcfe" (trillion cubic feet of gas equivalent). Enerplus has adopted the standard of one barrel of oil to six thousand cubic feet of gas (1 bbl: 6 Mcf) when converting oil to Mcfe, MMcfe, Bcfe or Tcfe. Mcfes, MMcfe, Bcfe and Tcfe may be misleading, particularly if used in isolation. A conversion ratio of 1 bbl: 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Advisory

- Enerplus has adopted the standard of six thousand cubic feet of gas to one barrel of oil (6 Mcf: 1 bbl) when converting natural gas to BOEs, and one barrel of oil to six thousand cubic feet of gas (1 bbl: 6 Mcf) when converting oil to Mcfes, MMcfes, Bcfes and Tcfes. BOEs, Mcfes, MMcfes, Bcfes and Tcfes may be misleading, particularly if used in isolation. The foregoing conversion ratios are based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent a value equivalency at the wellhead. "MBOE" and "MMBOE" mean "thousand barrels of oil equivalent" and "million barrels of oil equivalent", respectively.
- Unless otherwise stated, all production volumes are stated on a gross basis, that is, our working interest production before the deduction of any royalty interest production.
- Unless otherwise specified, all reserves volumes in this presentation (and all information derived therefrom) are based on "company interest reserves" using forecast prices and costs. "Company interest reserves" consist of "gross reserves" (as defined in National Instrument 51-101 adopted by the Canadian securities regulators ("NI 51-101") plus Enerplus' royalty interests in reserves. "Company interest reserves" are not a measure defined in NI 51-101 and do not have a standardized meaning under NI 51-101. Accordingly, our company interest reserves may not be comparable to reserves presented or disclosed by other issuers. Our oil and gas reserves statement for the year ended December 31, 2009, which will include complete disclosure of our oil and gas reserves and other oil and gas information in accordance with NI 51-101, will be contained within our Annual Information Form for the year ended December 31, 2009 ("our AIF") which is available on our website at www.enerplus.com and on our SEDAR profile at www.sedar.com. Additionally, the Annual Information Form forms part of our Form 40-F that is filed with the U.S. Securities and Exchange Commission and is available on EDGAR at www.sec.gov. Readers are also urged to review the Management's Discussion & Analysis and financial statements filed on SEDAR and EDGAR concurrently with this presentation for more complete disclosure on our operations.
- This presentation contains estimates of "contingent resources". "Contingent resources" are not, and should not be confused with, oil and gas reserves. "Contingent resources" are defined in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") as "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage." There is no certainty that Enerplus will produce any portion of the volumes currently classified as contingent resources or that Enerplus will produce any portion of the volumes currently classified as contingent resources. The contingent resource estimates contained herein are presented as the "best estimate" of the quantity that will actually be recovered, effective as of December 31, 2009. A "best estimate" of contingent resources means that it is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate, and if probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate.
- For information regarding the primary contingencies which currently prevent the classification of Enerplus' disclosed contingent resources associated with its Marcellus shale gas and Fort Berthold assets as reserves and the positive and negative factors relevant to the contingent resource estimate, see Enerplus' material change report dated August 27, 2009, copies of which are available on SEDAR and EDGAR as described above.
- For additional information with respect to the presentation and disclosure of oil and gas reserves and resources, see "Presentation of Enerplus' Oil and Gas Reserves, Resources and Production" in the AIF.

Enerplus Overview

- High-yielding North American energy producer
- Annual income and growth target of 10% - 15%
- Diversified asset base of high quality, low decline oil and gas assets complimented by growth assets in resource plays with superior economics - Bakken crude oil and Marcellus shale gas
- Cash flow from operations and strong financial position support capital reinvestment and monthly dividend
- Strong internal technical and commercial expertise



**Monthly
dividend
plus growth
potential**

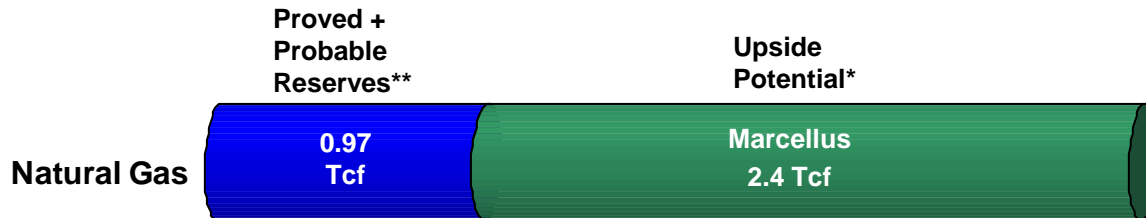
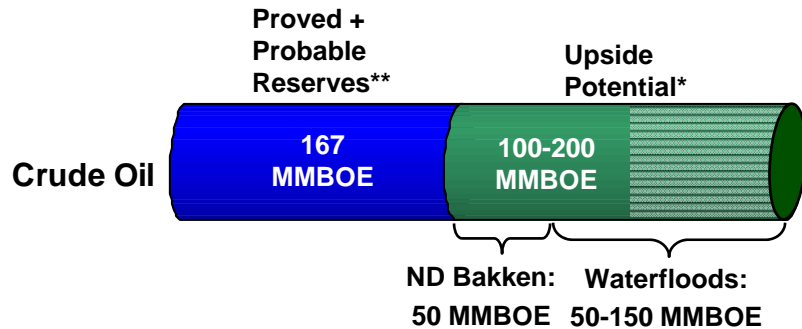
Repositioning Portfolio to add Unconventional Assets

**Over 475,000 net
new acres of
undeveloped land
added**

**Non-core
dispositions have
funded new
growth
acquisitions**

- New growth assets acquired with superior economics and ability to add meaningful production and reserves
 - Marcellus Shale Gas:
 - ~200,000 net acres in PA, WV and Maryland
 - Bakken Crude Oil:
 - +210,000 net acres in ND and SK
 - Deep Basin:
 - 65,000 net acres in Alberta & British Columbia
- Over 10,000 BOE/day of non-core conventional production sold, improving operating performance and funding acquisitions of new growth assets

Resource Potential within our Portfolio

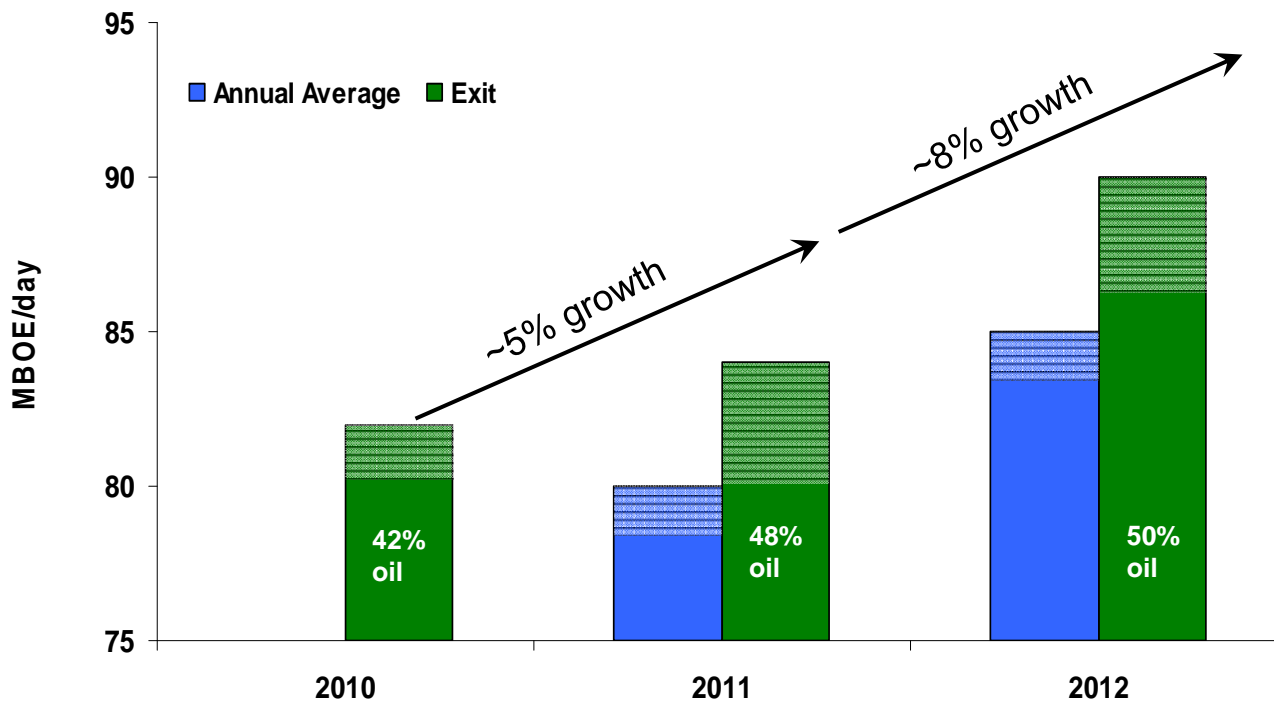


- Marcellus, North Dakota Bakken and waterflood assets could increase P+P reserves by nearly 3x if fully developed
- Does not reflect any potential resources in our Saskatchewan Bakken or Deep Basin lands

* Marcellus: internal and third party best estimate contingent resources. North Dakota Bakken: internal estimates of best estimate contingent resources and. Waterfloods: internal estimates of upside potential assuming increased ultimate recoverability from 27% to 30%-37%

** Reserves are as at December 31, 2009 and are adjusted to reflect impact of 2010 asset dispositions. Crude Oil 2P reserves also include expected 2P reserves additions at time of North Dakota Bakken acquisition

Production Growth Outlook



- Bakken production growth:
 - 25% of total by 2011
 - 30% of total by 2012
- Marcellus production growth:
 - 10% of total by 2011
 - 12% of total by 2012

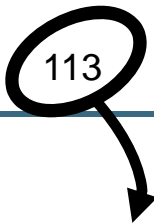
2011/2012 Strategy

- Capital spending focused on oil projects and increases by 25% to \$650 million
 - 85% of spending on Bakken, Waterfloods and Marcellus
 - Similar level of spending in 2012
- Production growth of 10 – 15% over next two years
- Crude oil volumes increase by 20% over next two years
 - Oil weighting increases from 42% to 50% of total volumes by end of 2012
- Cash flow expected to grow 15% by 2012
- Dividend maintained at \$0.18/share
- Balance sheet used to support plans

**Production
growth of
10 – 15%
over next
two years**

2011 Capital Outlook

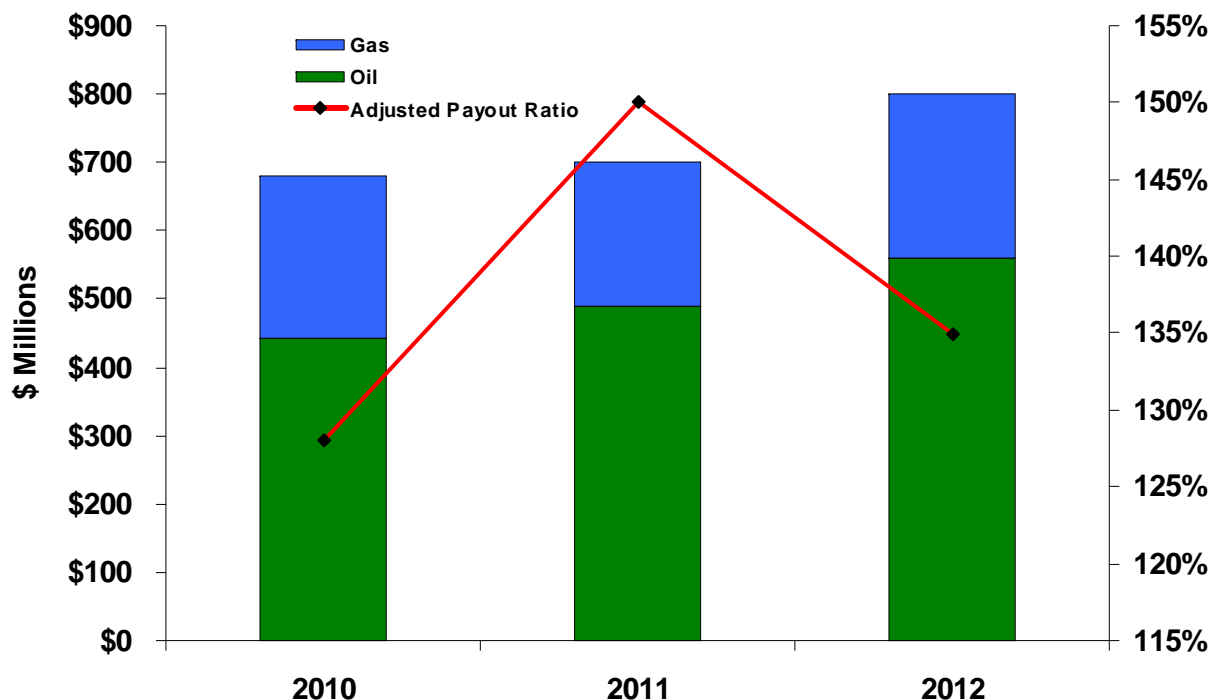
Resource Play	Capital (\$MM)	# of Net Wells	2010E Exit Production* (BOE/day)	2011E Exit Production* (BOE/day)	% Change Exit to Exit
Bakken/Tight Oil	300	48	13,000	18,000 – 21,000	50%
Waterfloods	110	26	14,500	13,500 – 15,000	-%
Marcellus Shale Gas	160	27	3,000	7,000 – 8,000	150%
Resource Play Total	\$570	101	30,500	38,500 – 44,000	35%
Company Total	\$650	113	~80,000	80,000 – 84,000	~5%



Over 90% are horizontal wells

Financial Outlook

Cash Flow Estimates



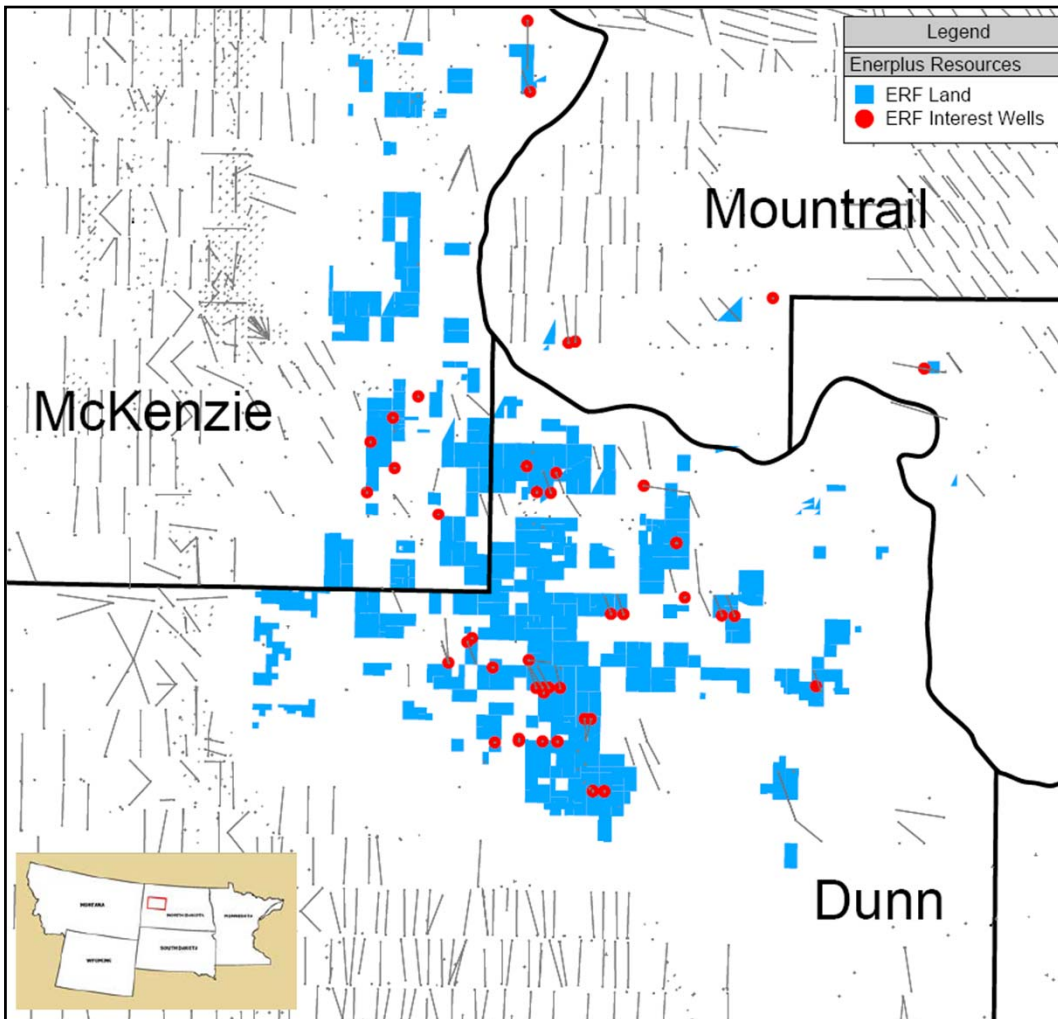
- 2011 and 2012 cash flow is 70% weighted to liquids, up from approximately 65% today
- Balance sheet supports growth plans through 2012
 - Debt/cash flow ratio increases from 1.3x at YE2010 to 2.0x at YE2012
 - Debt/cash flow and payout ratios decline as production from growth plays increase
 - Non-cash flow generating asset sales expected to help maintain financial flexibility

* Based upon the forward commodity prices (WTI US\$90/bbl, AECO \$4.15/Mcf, NYMEX Gas US\$4.70/MMBtu) and forecast costs as of December 8, 2010 including the impact of hedging



Crude Oil

Fort Berthold, North Dakota

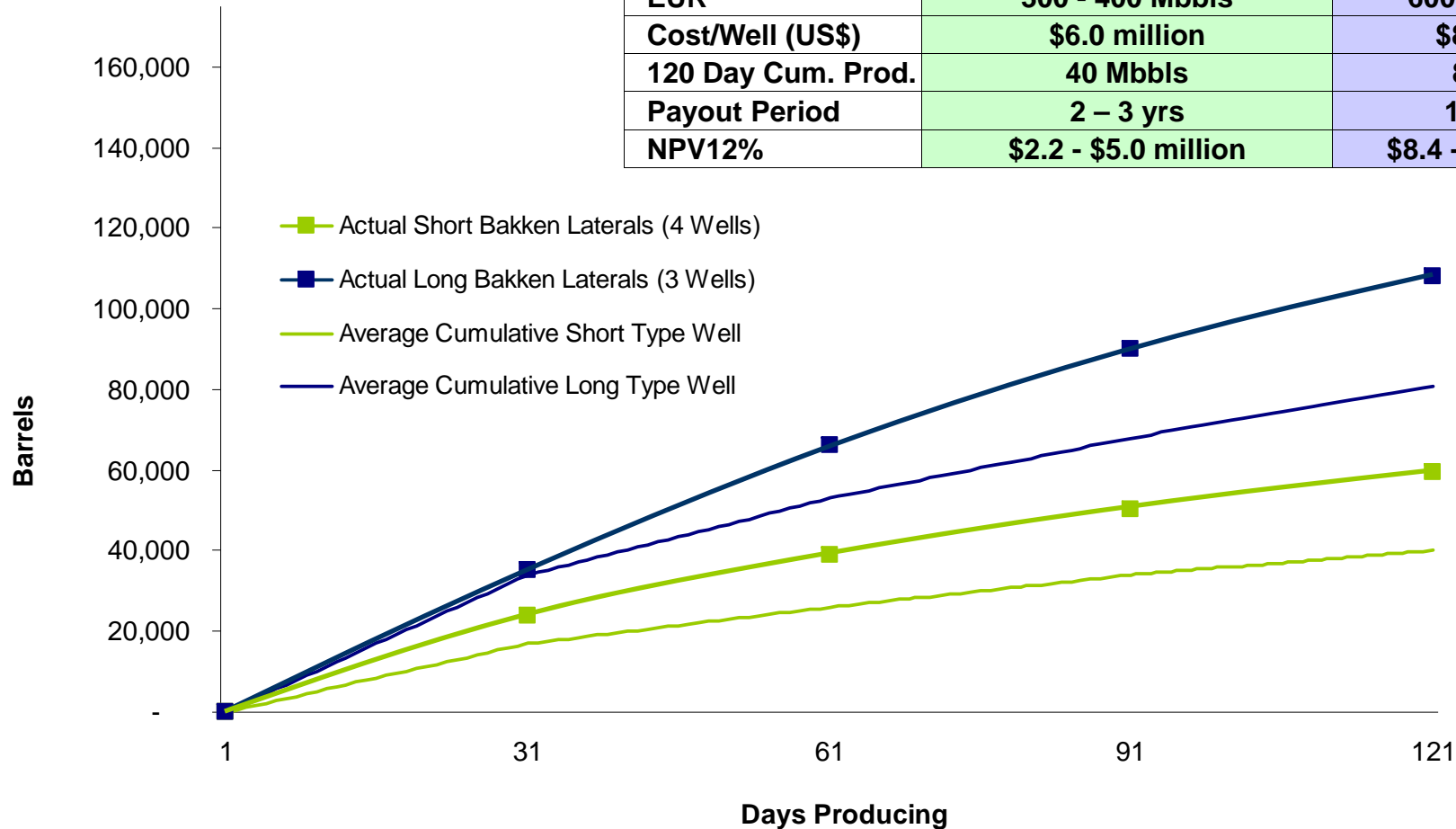


Key Facts	
Net Acreage	74,500
Current Production	~4,000 BOE/day
Internal Bakken Reserve Est.	18 million BOE
Internal Bakken Contingent Resource Est. (Best)	50 million BOE

- >90% operated & ~90% working interest
- 85% of land is prospective
- Long lease tenure
- Upside from Three Forks
- 2011 capital program - \$230 million


Fort Berthold Results

	Short Horizontals (~4,300 feet, 12 stage frac)	Long Horizontals (9,000 feet, 24 stage frac)
30 day IPs	550 - 650 bbls/day	1,100 - 1,200 bbls/day
EUR	300 - 400 Mbbls	600 - 800 Mbbls
Cost/Well (US\$)	\$6.0 million	\$8.0 million
120 Day Cum. Prod.	40 Mbbls	81 Mbbls
Payout Period	2 - 3 yrs	1 - 1.7 yrs
NPV12%	\$2.2 - \$5.0 million	\$8.4 - \$14.0 million



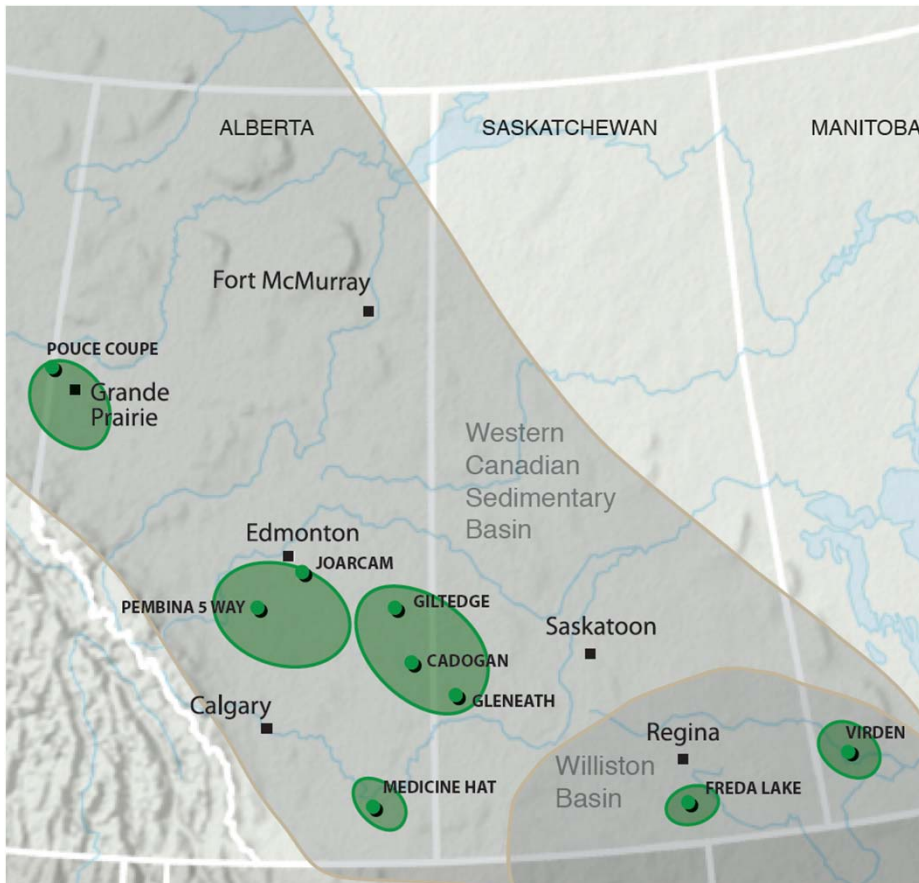
2011 North Dakota Bakken Plans

- 32 net operated wells, 75% long horizontal, Bakken and Three Forks
- 3 to 4 rigs working in the play
- Recently entered into agreements to secure rigs and access to frac services to help ensure timely execution of plans
- Expect to have mid-stream service agreements in place in mid 2011 to capture associated gas volumes
- 300 MBOE/day of new and expanded pipeline capacity proposed to address the takeaway shortfall
 - Evaluating securing additional capacity to address our production growth



**Production
grows from
4,000 bbls/day to
+20,000 BOE/day
over next 4 years**

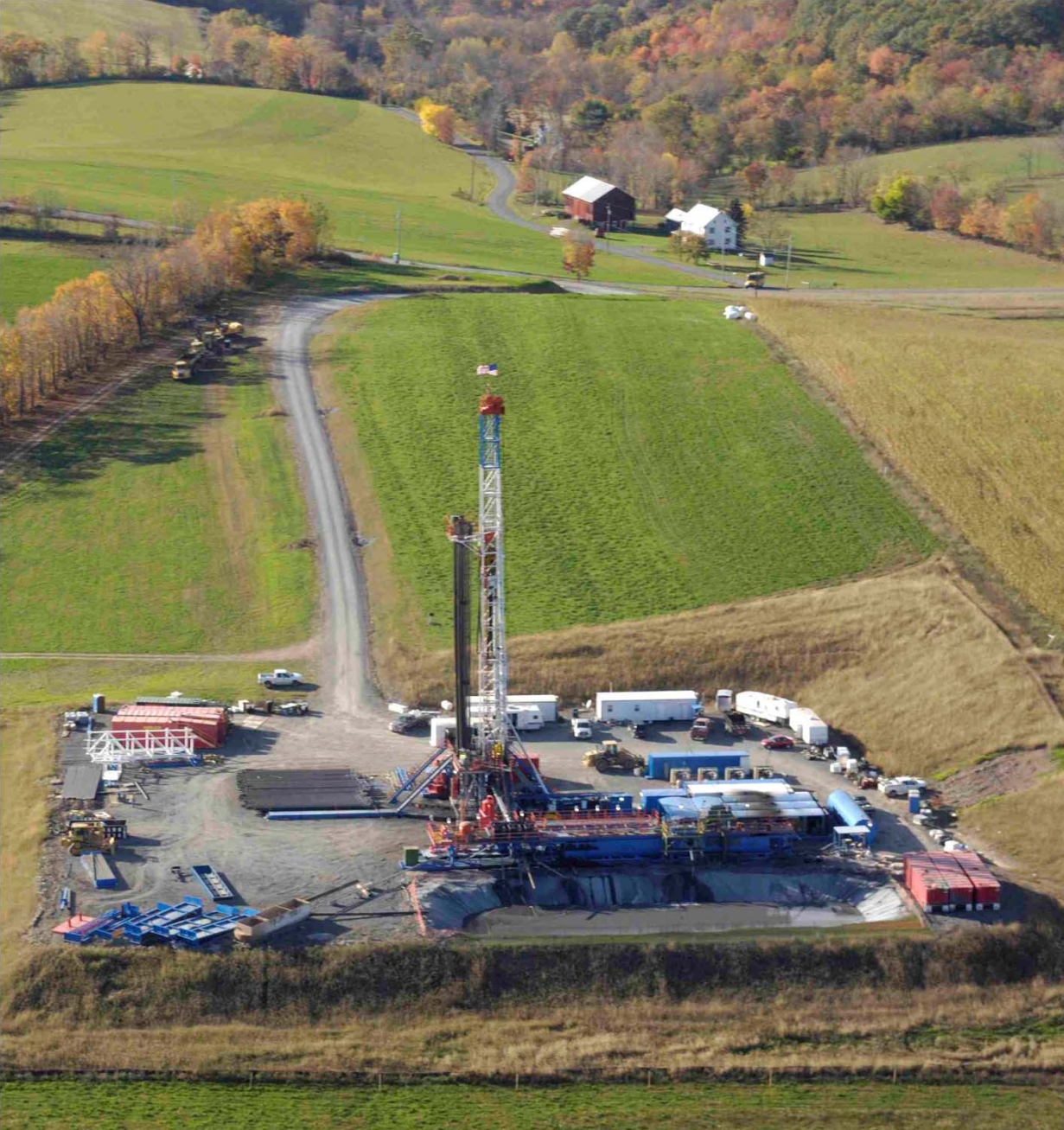
Waterfloods Overview



Key Facts

P+P Reserves (2009 adj. for dispositions)	83.1 million barrels
2011E Annual Production	13.5 – 15.0 MBOE/day
2011 Capital Budget	\$110 million

- Mature, cash generating assets in various plays such as the Glauconitic, Viking, Cardium and Ratcliffe
- Free cash flow supports dividend and growth strategy
- ~18% of total production
- Low decline of ~16% with average oil quality of 30° API
- Significant OOIP
 - 22% recovered to date
 - Reserves booked to 27% (12/31/2009)
- Drilling & EOR upside could improve recoverability to 30-37% and add 50 – 150 million barrels
- 2011 plans: Drill 26 production/injection wells and initiate polymer pilots at two properties
- Expect to maintain production at ~14,000 BOE/day



Natural Gas

Marcellus Overview

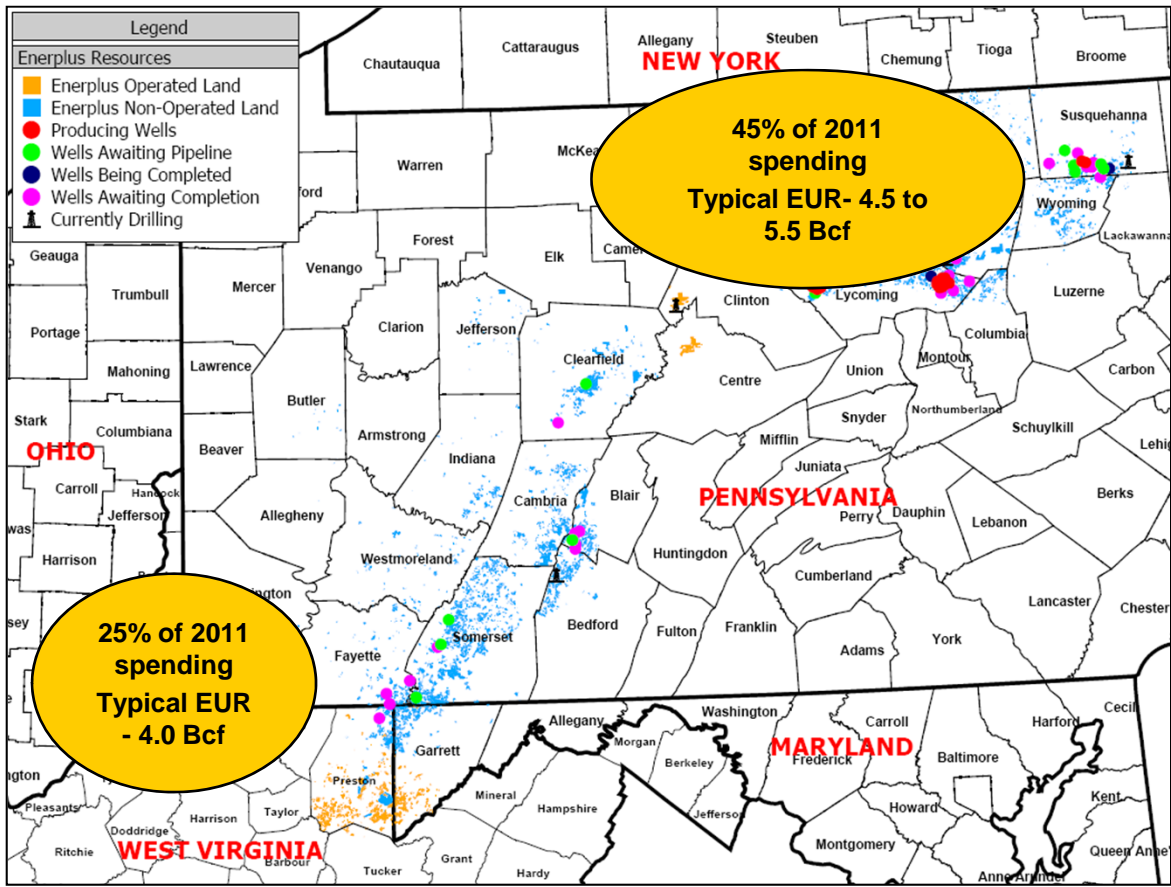
**Production
growth of over
150 MMcf/day
over next 4 yrs**

**Over 2.4 Tcfe of
natural gas
potential***

- Entry into one of the most economic and largest shale gas plays in North America
- ~ 200,000 net acres
 - 70,000 net operated acres with an average working interest of 90%
 - Average 23% non-operated working interest in approximately 565,000 gross acres (approximately 128,500 net acres) primarily in Pennsylvania and West Virginia with Chief Oil & Gas
- Non-operated Marcellus position alone has the potential to triple our proved plus probable natural gas reserves

*excluding operated land in W. Virginia & Maryland

Marcellus Shale Gas

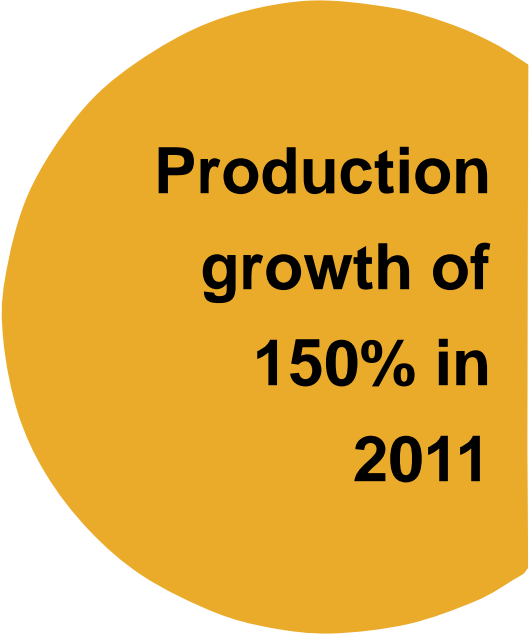


Key Facts	
Original Gas in Place	13 to 15 Tcfe
Booked P+P Reserves (YE09)	24.9 Bcfe
Contingent Resource "Best Estimate"	2.4 Tcfe
Land Utilization	55%
EUR/well	3.5 – 6.0 Bcfe
Well Costs	\$4.5 – \$6.0 MM
Well Density	4 - 8 wells/section
2011 Capital	\$160 million

- Expect to grow net production by 150% to 45 MMcf/day in 2011

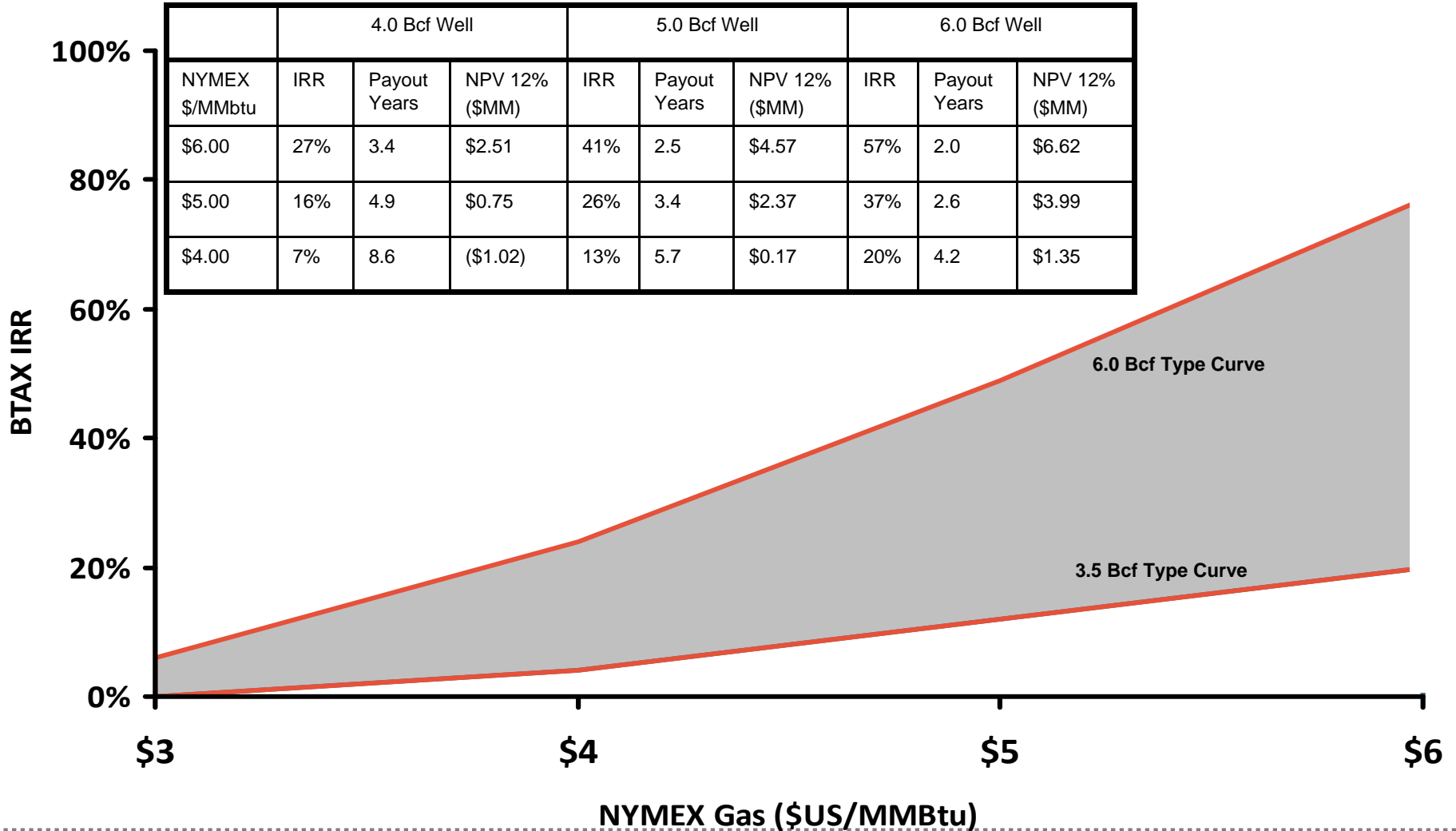
2011 Plans

- Results over past 18 months have either met or exceeded expectations
- 150 gross wells planned (22.4 net), 8 – 10 rigs running
- Expect to complete ~121 gross wells with 94 new gross wells on stream by the end of the year
- Capital breakdown:
 - 25% directed to liquids rich gas in SW PA and NW West Virginia
 - 30% directed to delineation activity to preserve lease positions and identify future potential
 - 45% of capital directed to development drilling in areas with EUR's of 4.5 to 5.5 Bcf
- Plan to drill 4 net operated wells



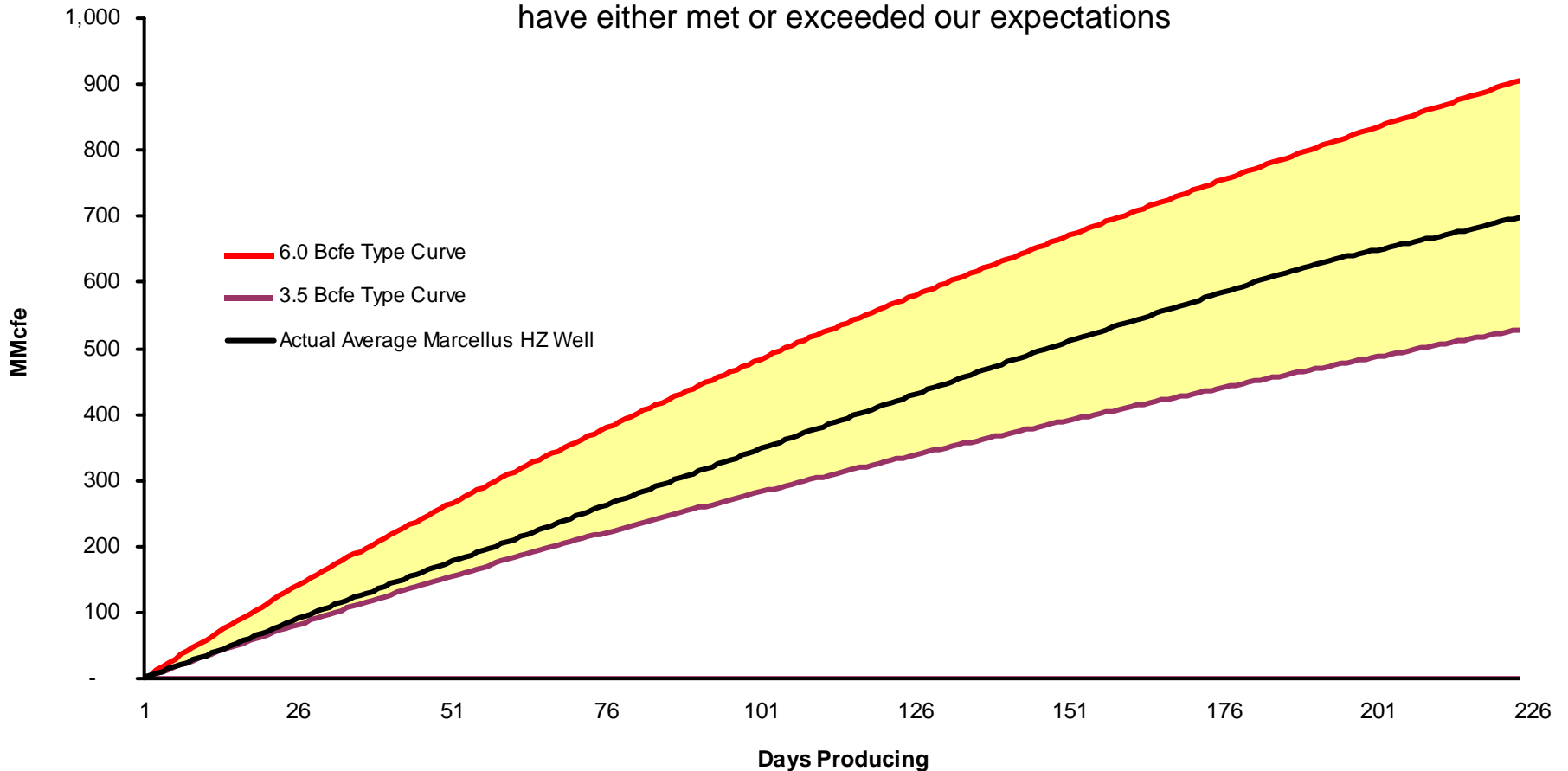
**Production
growth of
150% in
2011**

Potential in the Marcellus



Marcellus Performance – Cumulative Production

Type curve estimates have been increased as well results have either met or exceeded our expectations



Executing on our Strategy

- Enerplus is well positioned in our transition toward a growth and income business
- Significant progress has been made in acquiring early stage resource plays
 - ~475,000 net acres of prospective undeveloped land in the Marcellus, Bakken/tight oil and Deep Basin tight gas plays
- Production growth of 10 – 15% over next two years
- Cash flow from existing portfolio with strong balance sheet will support growth and dividend plans
- Current focus on executing development programs

Supplemental Information



enerPLUS

Corporate Profile

• Trading Symbol (TSX/NYSE)	ERF
• Market Capitalization ⁽¹⁾	\$5.6 billion
• Enterprise Value ⁽²⁾	\$6.3 billion
• Average Daily Trading Value (Dec 2010)	\$30 million
• Average Daily Production (Q3/2010)	82,869 BOE/day
– Gas Weighting	57%
• Long-Term Debt /Trailing 12-Month Cash Flow Ratio ⁽³⁾	0.9x
• Current Monthly Cash Dividend	\$0.18/share
• Current Annualized Yield	6.8%


⁽¹⁾ Market Cap. at January 5, 2011 – based upon 178,118,000 shares outstanding at September 30, 2010

⁽²⁾ Market Cap. at January 5, 2011 plus outstanding debt (*net of cash*) at September 30, 2010

⁽³⁾ Using outstanding debt and Cash Flow from Operations at September 30, 2010

Corporate Conversion

- Unitholder and court approvals obtained and conversion to a dividend paying corporation effective January 1, 2011
- Intend to maintain dividend at \$0.18/share/month based upon current commodity prices and capital spending plans
- Will continue to pay monthly dividend post conversion
- No change to name or ticker symbols (elimination of .un on TSX)
- No acceleration or vesting of any compensation awards to employees or Directors



**No Canadian
cash taxes
expected for 3-5
years**

Progress on Portfolio Transition – 2009/2010

Acquisitions	Net Acreage	Cost (\$ Million)
Marcellus Non-Operated Acreage	128,500 acres	\$448
Marcellus Operated Acreage	70,200 acres	\$185
North Dakota Bakken	74,500 acres	\$618
Saskatchewan Bakken	140,000 acres	\$176
Deep Basin	65,000 acres	\$40
Total	478,200 acres	\$1,467

Dispositions	Production	Proceeds (\$ Million)
Non-Core Conventional Assets ⁽¹⁾	~10,500 BOE/day	~\$600
Kirby Oil Sands	-	\$405
Total Proceeds		~\$1,005

2010 Year to Date Operating Performance

	Cal 2010 Guidance*	YTD Sept 30, 2010
Annual Average Production (MBOE/day)	83 – 84	84.2
Natural Gas	58%	58%
Exit Rate Production (MBOE/day)	80 – 82	N/A
Natural Gas	55%	
Capital Spending (\$MM)	\$515	\$314
Operating Costs (\$/BOE)	\$10.20	\$10.02
Distributions Paid (\$MM)	-	\$288
Annual Adjusted Payout Ratio	128%	108%
Debt/Cash Flow Ratio at Year-End	1.1x	0.9x

- Production volumes on track with expectations, post divestment activity
- Sold 6,000 BOE/day YTD
- Operating costs declining
- 60% of capital spending on oil projects
- Significant production increases in Bakken and Marcellus

* adjusted for divestments

Hedging Strategy

- Protect a portion of cash flow to support capital spending, economics of our acquisitions and income distribution
- Provide downside protection and retain upside price increases
- Typically hedging forward 2 years
- Combination of instruments utilized - puts, calls, swaps
- Not hedging in current natural gas price environment

2011 Hedge Positions:

56% of crude oil production hedged at US\$87.10/bbl
32% of natural gas production hedged at effective price of
\$6.14/Mcf through March 2011

2012 Hedge Positions:

7% of crude oil production hedged at US\$90.29/bbl

Waterfloods 2011 Capital Program Highlights

Property	Crude Quality (API)	2011 Capital Spending	Activity
Freda Lake Ratcliffe	31°	\$26 million	drill 9 hz wells, injector conversions
Medicine Hat Glauc C Unit	11-18°	\$21 million	drill 7 wells, facility upgrades, prepare for EOR pilot
Virden/Daly	34°	\$16 million	Drill 7 hz wells, also recompletions and facility work
Pembina 5-Way	39°	\$9 million	drill 2 hz, complete another 4 hz, also injector conversions, well stimulation, maintenance
Gleneath	37°	\$9 million	drill 6 hz, some maintenance & optimization
Giltedge	14-20°	\$9 million	complete 5 wells drilled Dec 2010, EOR pilot startup Q1, waterflood optimization work

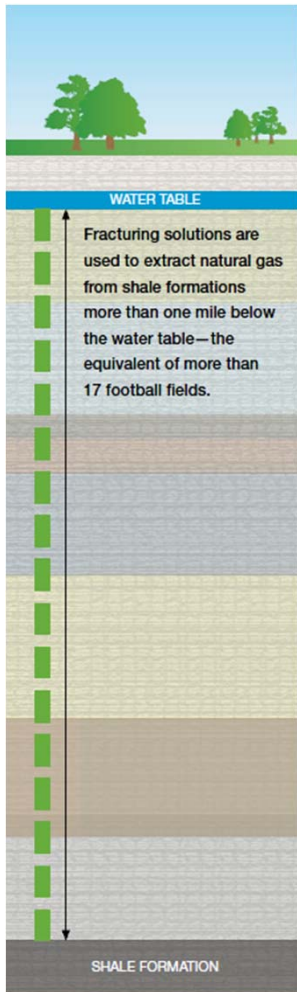
Marcellus Drilling Activity

Gross Wells Drilled (at Dec 10, 2010)	Horizontal	Vertical	Total
Producing	35	7	42
Partially Drilled*	2	1	3
Waiting on Completion	33	6	39
Waiting on Pipeline	9	6	15
Total Gross Wells	79	20	99

* Vertical portion of well drilled, awaiting horizontal extension

- Planned drilling activity in 9 counties in PA, Marshall and Preston counties in West Virginia, and Garrett county in Maryland
- Non-op drilling will focus mostly on retaining leases. Operated activity will be primarily delineation work to better identify the resource.
- Majority of producing wells in Bradford, Lycoming and Susquehanna Counties in PA (>80% of current production) and Marshall County in WV

Marcellus Environmental Concerns



- Freshwater aquifers range in depth from 80 to 500 feet below surface
- Drilling depth in the Marcellus ranges from 4,500 feet to over 7,500 feet across the play
- Drilling and completion techniques are designed to minimize contamination risks:
 - Surface casing set and cemented to approximately 900 feet below surface
 - Intermediate casing set and cemented to 2,400 feet below surface
- Surface containment system being used
 - Poly liner covering well site
 - Isolates spills from fracture process
 - Flowback/water storage pits double lined with 2 layers of 40 ml. plastic liner
 - Greatly reduces off-pad migration potential

\$1 Billion Credit Facility

Canadian Imperial Bank of Commerce	\$145
Royal Bank of Canada	\$120
Bank of Montreal	\$120
Bank of Nova Scotia	\$110
Toronto Dominion Bank	\$100
National Bank of Canada	\$85
Alberta Treasury Branches	\$50
Total Canadian	\$730
HSBC Bank	\$85
Citibank N.A.	\$85
Union Bank of California	\$50
Sumitomo Mitsui Bank	\$50
Total Foreign	\$270

Analyst Coverage

Research Firm	Analyst	Rating
Bank of America	Andrew Fairbanks	Sell
BMO Capital Markets	Gordon Tait	Hold
CIBC World Markets	Jeremy Kaliei	Sell
Canaccord Capital	Kyle Preston	Hold
Citigroup	Richard Roy	Buy
Dundee Securities Corp.	Travis Wood	Buy
FirstEnergy Capital Corp.	Jill Angevine	Buy
Macquarie Capital Markets	Cristina Lopez	Hold
National Bank Financial	n/a	Under Review
Odlum Brown Limited	Mark Barclay	Buy
Peters & Co. Limited	Kam Sandhar	Hold
Raymond James	Kristopher Zack	Hold
RBC Dominion Securities	Fergal Kelly	Hold
Scotia Capital	Patrick Bryden	Sell
TD Newcrest	Roger Serin	Buy
UBS	Matt Donohue	Hold

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