

Howard Weil 40th Annual Energy Conference

Ralph Hill
Chief Executive Officer
March 28, 2012

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Reserves Disclaimer

The SEC requires oil and gas companies, in filings made with the SEC, to disclose proved reserves, which are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible — from a given date forward, from known reservoirs, under existing economic conditions, operating methods, and governmental regulations. The SEC permits the optional disclosure of probable and possible reserves. We have elected to use in this presentation “probable” reserves and “possible” reserves, excluding their valuation. The SEC defines “probable” reserves as “those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.” The SEC defines “possible” reserves as “those additional reserves that are less certain to be recovered than probable reserves.” The Company has applied these definitions in estimating probable and possible reserves. 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 reserves reporting guidelines. Investors are urged to consider closely the disclosure regarding our business that may be accessed through the SEC’s website at www.sec.gov.

The SEC’s rules prohibit us from filing resource estimates. Our resource estimations include estimates of hydrocarbon quantities for (i) new areas for which we do not have sufficient information to date to classify as proved, probable or even possible reserves, (ii) other areas to take into account the low level of certainty of recovery of the resources and (iii) uneconomic proved, probable or possible reserves. Resource estimates do not take into account the certainty of resource recovery and are therefore not indicative of the expected future recovery and should not be relied upon. Resource estimates might never be recovered and are contingent on exploration success, technical improvements in drilling access, commerciality and other factors.

Recent Highlights

- **Became stand-alone publicly traded exploration and production company**
 - December 31, 2011 – distribution date
 - January 3, 2012 – first date of regular way trading
 - S&P 500 company (NYSE ticker: WPX)
 - 197 MM shares outstanding

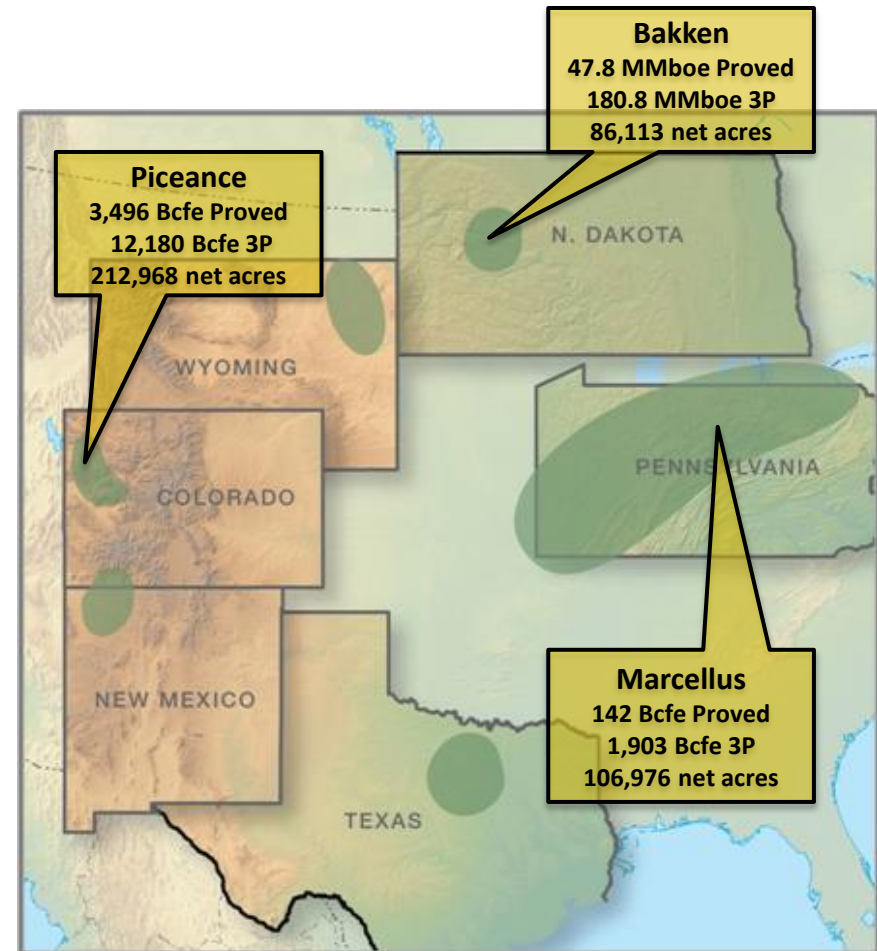
- **2011 highlights**
 - Record oil and NGL production 41 Mbbls/d, up 35%
 - Revenue from domestic oil and NGL sales rose 87%
 - Oil production up 65%
 - NGL production up 25%
 - Proved reserves 5.3 Tcfe, up 9%; 3P 18.5 Tcfe, up 7%
 - Adjusted EBITDAX for 2011, \$1.3 B

- **Well capitalized balance sheet built to withstand a low commodity price environment**
 - \$1.5 B in notes issued November 2011
 - Cash retained \$500 MM
 - \$1.5 B unsecured credit facility
 - ~95% of 2012 capital expected to be spent in our three core areas

Note: Adjusted EBITDAX is a non-GAAP measure. A reconciliation to relevant measures included in GAAP is provided in this presentation.

WPX Energy Is:

- **Geographically and product diverse**
 - Core areas: Bakken, Piceance and Marcellus
 - Rapidly changing commodity mix:
 - 2012 production – Oil and NGLs, 20%, Natural Gas, 80%
 - 46% of 2012 revenues from Oil and NGLs
- **Attractive asset base across a number of high growth areas**
 - Large-scale Piceance basin properties
 - High-growth opportunities in our Bakken and Marcellus positions
- **Proven technical leader in cost-efficient producer**
 - Leading cost structure in Piceance
 - Implementing Piceance efficiency model in the Bakken and Marcellus
- **Management team with broad, unconventional resource expertise**
 - 238 collective years of experience

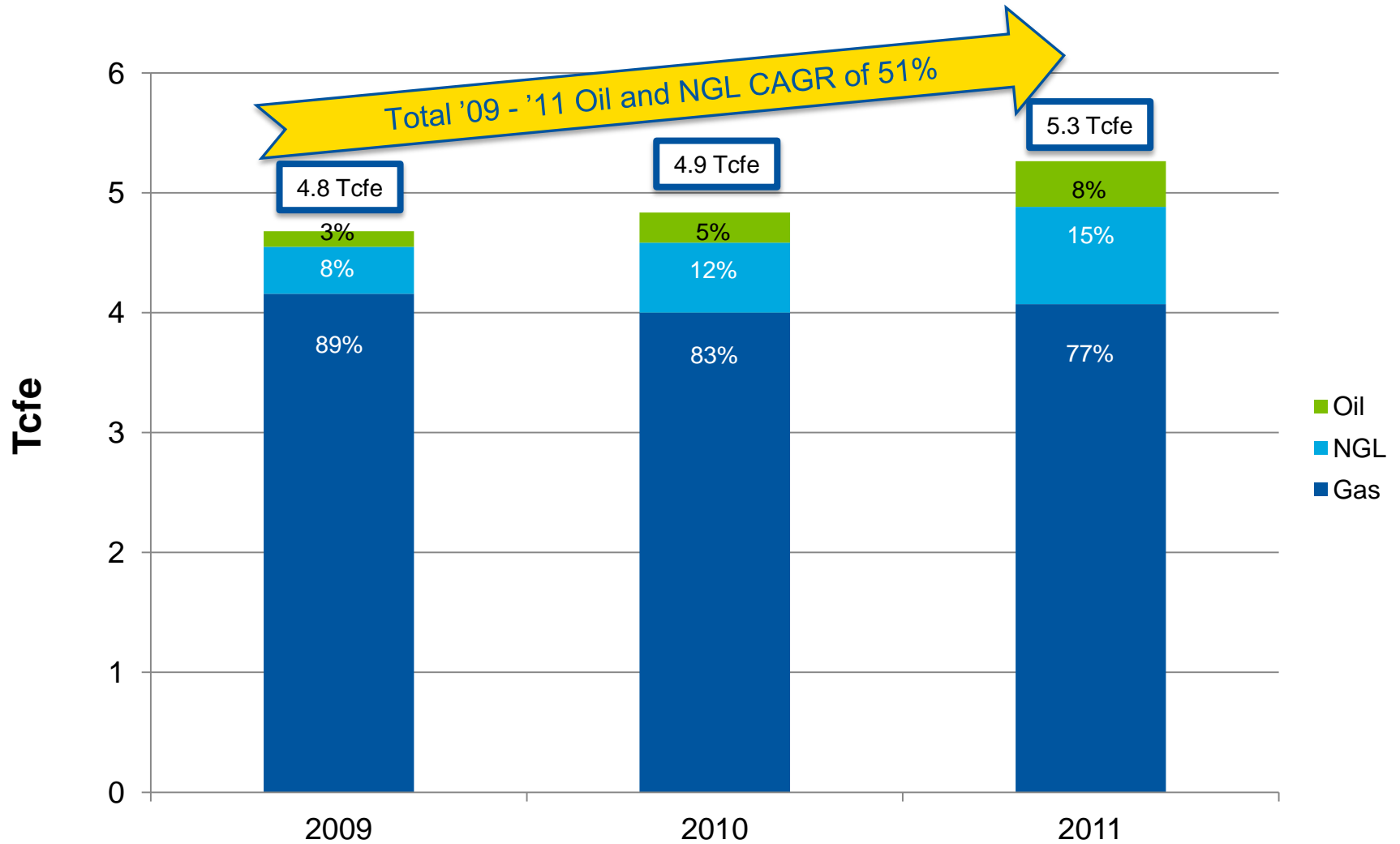


Note: Acreage, Proved and 3P numbers on the map are as of 12/31/11.

Portfolio Transformation

	Core Area	Product Mix - Production	Product Mix - Reserves	Net Production	Reserves	3P Reserves
2009	Rockies focused	90% gas, 10% liquids	88% gas, 12% liquids	1,289 MMcfe Nat Gas 1,163 MMcf/d NGL 13.4 Mbbbl/d Oil 7.7 Mbbbl/d	4,759 Bcfe Nat Gas 4,190 Bcf NGL 66.0 MMbbl Oil 28.8 MMbbl	15.7 Tcfe
2011	Piceance, Bakken, Marcellus	83% gas, 17% NGL and crude oil	77% gas, 23% liquids	1,399 MMcfe Nat Gas 1,153 MMcf/d NGL 28.1 Mbbbl/d Oil 12.9 Mbbbl/d	5,265 Bcfe Nat Gas 4,073 Bcf NGL 135.3 MMbbl Oil 63.3 MMbbl	18.5 Tcfe

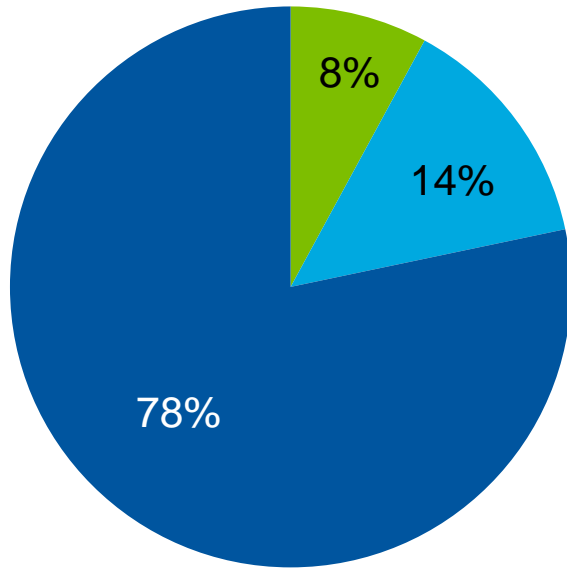
Proved Reserves Growth



3P Reserves

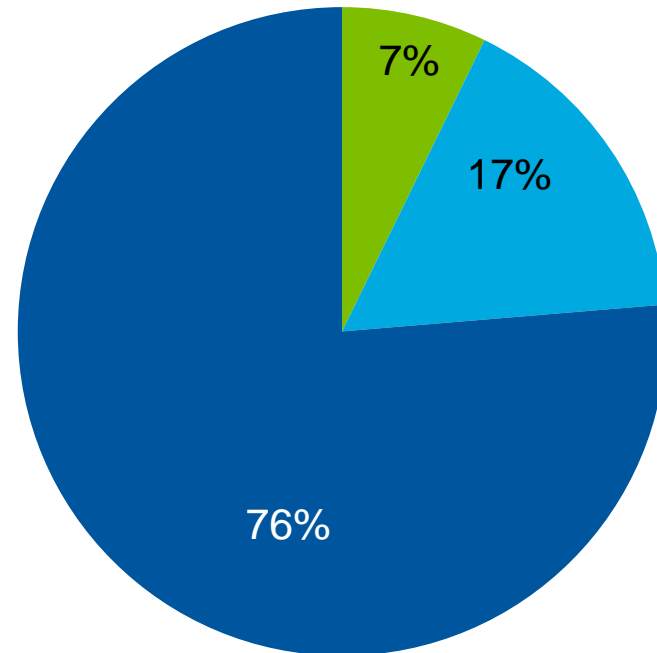
3P reserves 2010 vs. 2011 with 24% currently in oil and liquids-rich gas plays

Oil NGL Gas



2010
Total 3P reserves: 17.3 Tcfe

Oil NGL Gas

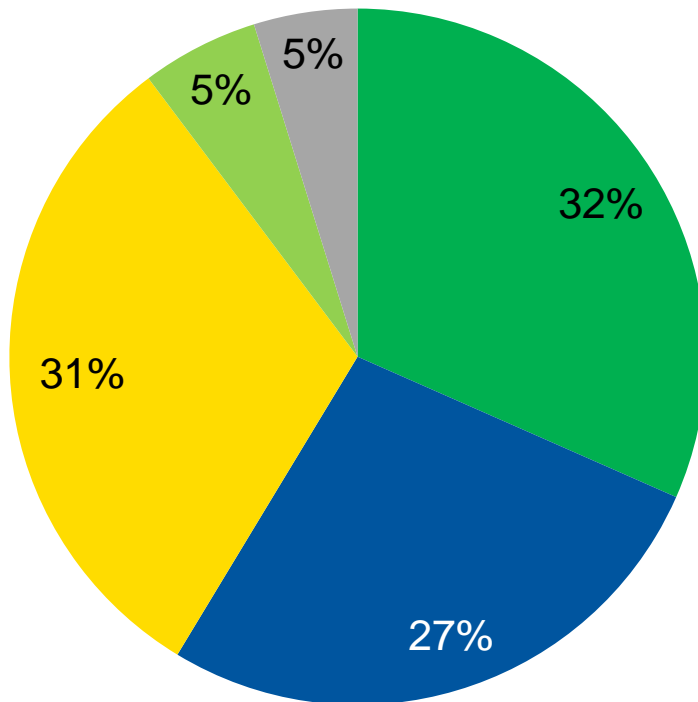


2011
Total 3P reserves: 18.5 Tcfe

2012 Capital Expenditures

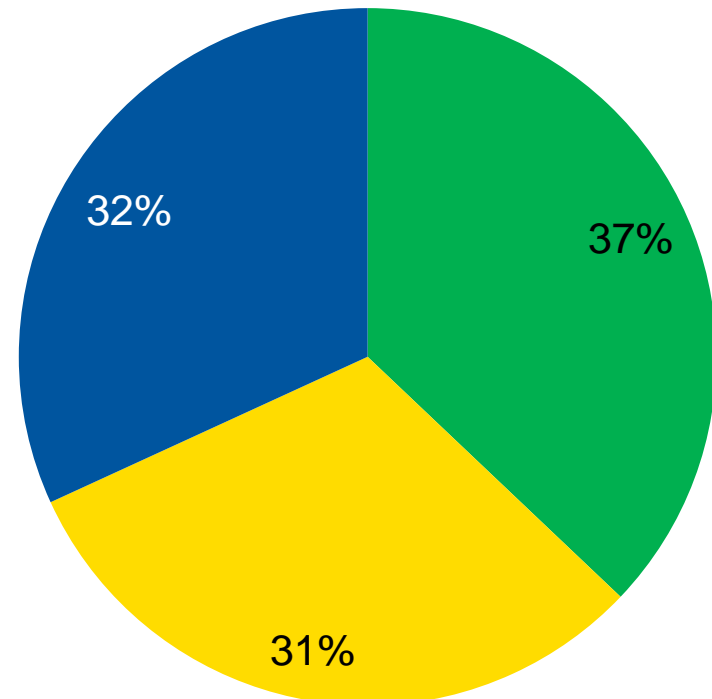
Total 2012 CapEx of \$1.2 B with 68% going to oil and liquids-rich plays

■ Bakken ■ Marcellus ■ Piceance ■ International ■ Other



BY AREA

■ Oil ■ Natural Gas + NGLs ■ Dry Gas



BY PRODUCT

Piceance



Continued Efficiency Gains in the Piceance

Improved Drilling Performance

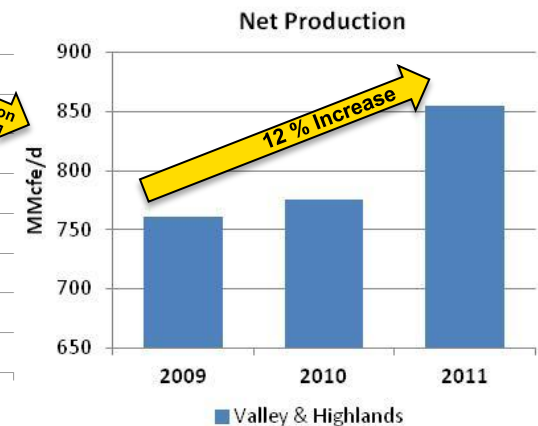
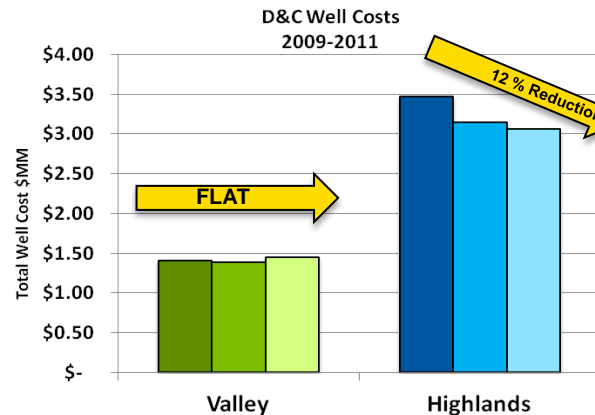
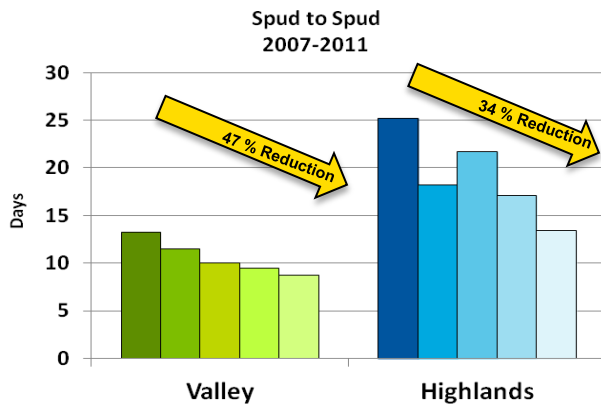
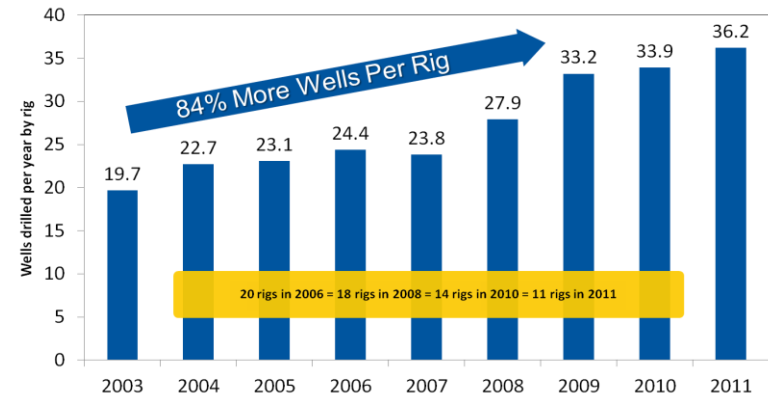
- Drilling more wells/rig
- Split rig design utilized in remote areas
- Faster drilling offsets cost increases

Record Production Achieved in 2011

- Operated production exceeds 900 MMcf/d
- Expanded water treatment capacity to 44,000 Bwp/d average
- NGL volumes increasing

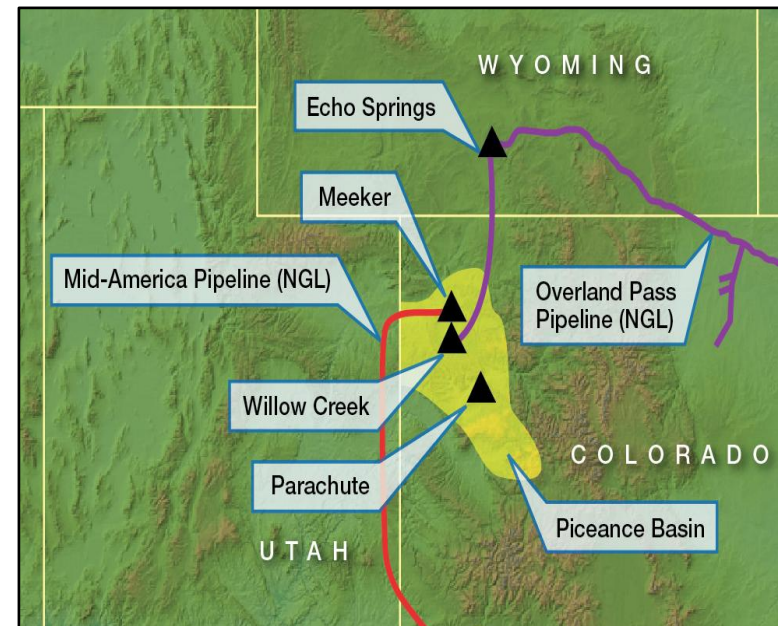
Mancos/Niobrara Initial Vertical Well Drilled

- IP = 1.5 MMcf/d (lower Niobrara)
- Plan to test 4 - 6 more intervals
- Horizontal test planned for 2012



Increasing Yields to Maximize Value

- **Willow Creek (65% of NGL volume)**
 - Long-term fee based contract
 - Mont Belvieu priced products via Overland Pass Pipeline
 - Volume dedication yields advantaged OPPL T&F rates
- **Enterprise – Meeker (35% of NGL volume)**
 - Long-term percent of proceeds contract
 - Mont Belvieu priced products via Mid American Pipeline
- **Cryo Capacity**
 - Willow Creek, 450 MMcf/d
 - Meeker, 200 MMcf/d (plus 50 - 100 Mcf of additional interruptible)
 - Echo Springs, 120 MMcf/d
 - Adding new Parachute, 350 MMcf/d (ISD 1Q-'14)
- **2013 Willow Creek Contract**
 - Fee for service arrangement retaining liquids
 - Tiered margin sharing up to 80%
 - Lower treating cost
 - Same contract terms for Parachute Cryo (ISD 1Q-'14)
 - **\$25 MM - \$35 MM EBITDAX improvement in 2012 if we were under the 2013 contract terms



Note: **EBITDAX improvement assumes \$99 WTI, \$3.00 NYMEX and a \$51 NGL Mount Belvieu price.

Bakken

Bakken Activity Highlights

- **Increased net production more than 300%**
 - Leading edge completion design
 - New sleeve technology
 - Ceramic proppant
 - Established strong well performance in area of development

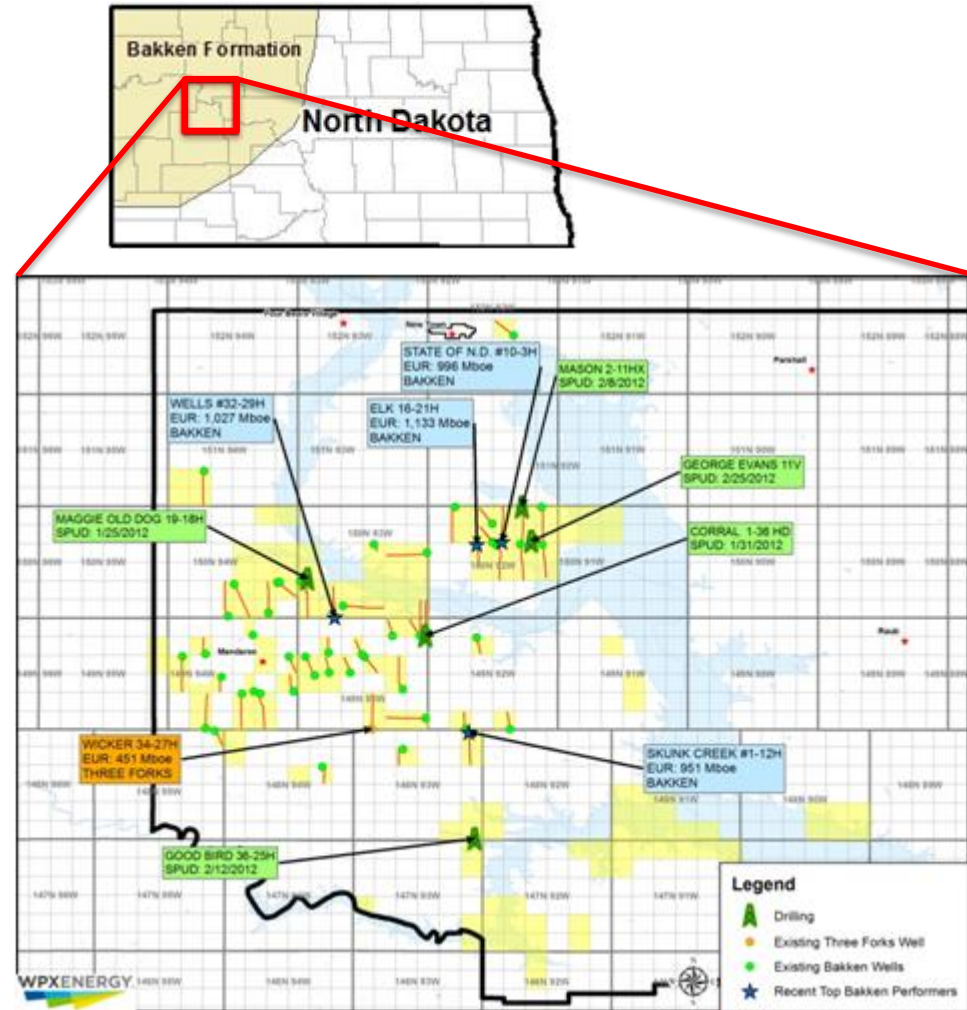
- **Bakken basis differential**
 - WTI expected to average -\$10 to -\$15 for 2012

- **Expanded to 5th rig in December 2011 (operated)**
 - 6th rig coming mid-year
 - All 6 rigs fit-for-purpose by year-end

- **Gathering system under construction**
 - Gather oil, gas and produced water
 - Deliver fresh water to location

- **Implemented full-time, 24-hour dedicated stimulation services**

- **Acresage 100% HBP by end of year**

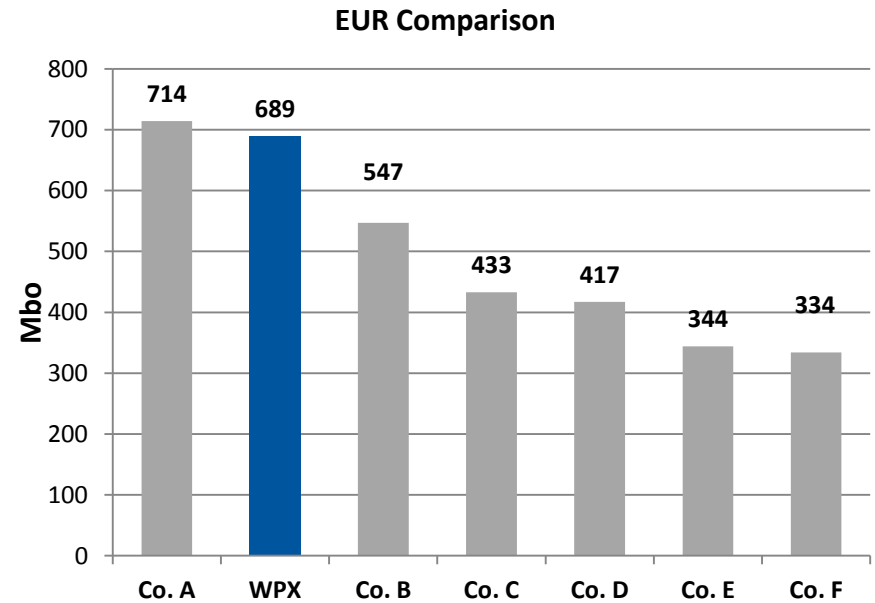
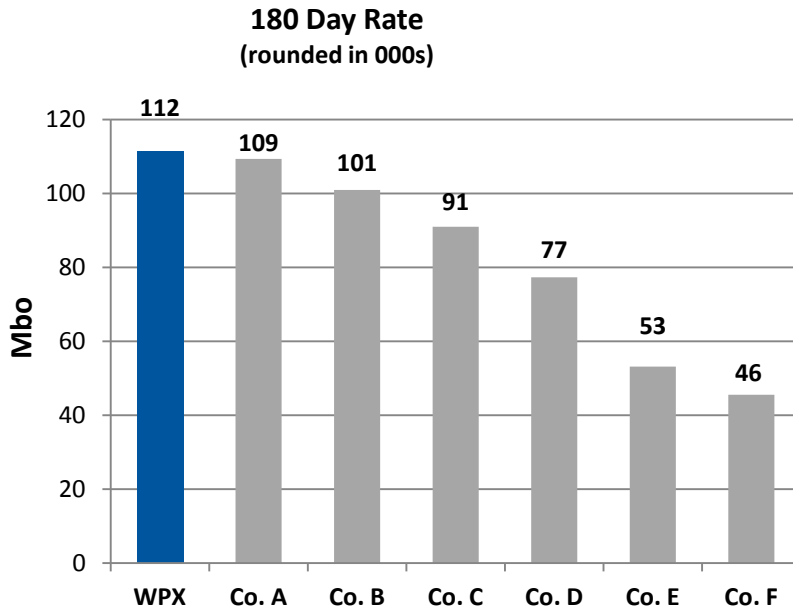


180 Day Rate / EUR Comparison

Middle Bakken, long laterals

Strong early production performance...

generates



Note: Rates and EURs are Mbo, not oil equivalent. Based on IHS data.

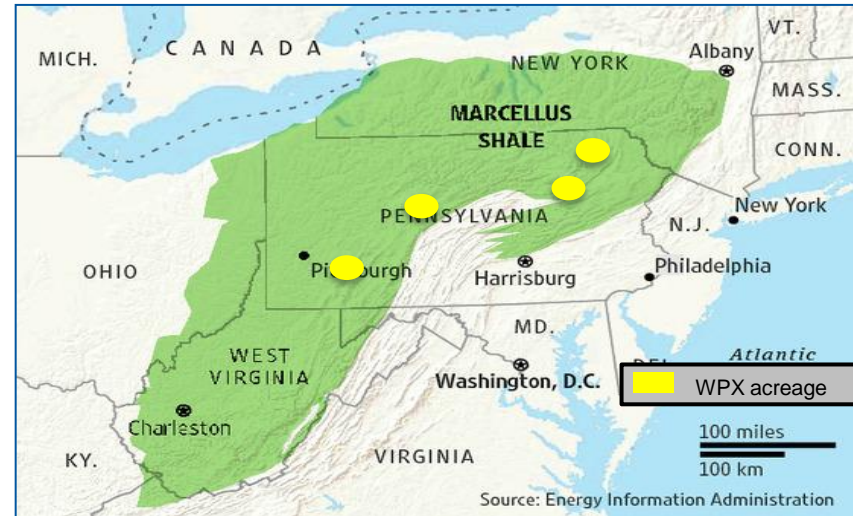
...Superior well results

Marcellus



Marcellus Operational Update

- Reduced drilling times 35% from 4Q 2010; average spud-to-rig release time of 18.3 days in 4Q 2011
- Drilled record lateral of 5,947' in Susquehanna County and 6,488' in Westmoreland County
- Dedicated frac crew in place. Second frac crew utilized last three months of 2011
- Gross production increased 81% from Q3 to Q4, and 287% from Jan. to Dec. 2011
- Best well in Susquehanna County produced at rates as high as 25 MM/d
- Average 30-day rate in Susquehanna County for the first 4 wells was approximately 7 MM/d flowing into high line pressures from 700 - 1100 psi; rates have been impacted by Laser start-up issues
- Recycling 100% of frac flowback and produced water



2011 Susquehanna County drilling program well counts

Wells Drilled	Fracture Stimulated	Placed in Service	Awaiting Completion
19	12	4	21

2011 Westmoreland County drilling program well counts

Wells Drilled	Fracture Stimulated	Placed in Service	Awaiting Completion
28	25	25	12

Susquehanna Transport & Gathering

Millennium Pipeline

- **Millennium Pipeline contract provides significant flow assurance, as well as access to diverse markets and pricing for Susquehanna County production including:**
 - TETCO M3
 - Dominion
 - Niagara (through connecting transport on Empire)
 - Leidy Hub (through connecting transport on National Fuel)
- **Transport contract allows for tiered capacity commitments to match Susquehanna production growth including:**
 - Current Transport of 140,000 dt/d based on a combination of Forward and Back Haul contracts that are renewable annually and semi-annually for up to ten (10) years
 - Additional Forward and Back Haul options increase Transport up to 400,000 dt/d to match production profile
- **Flexibility of transport contract allows for WPX to reduce demand charge exposure, if needed, to match production profile to a minimum obligation of 170,000 dt/d**

Laser Pipeline

- **Start-up issues with the Laser pipeline caused production to be shut-in for most of December in Susquehanna County**
- **Line pressures have continued to be erratic as Laser has been working to get its compressor station in New York lined out**
- **In field compression is not expected until late summer**

Apco



Our 69% Interest in Apco

■ ARGENTINA

Neuquen Basin

- Entre Lomas 96,000 net acres
- Bajada del Palo 59,000 net acres
- Agua Amarga 37,000 net acres
- Coiron Amargo 45,000 net acres
- Charco del Palenque 12,000 net acres
- Total 249,000 net acres
- Neuquen acreage located in Vaca Muerta Shale

Other

- Acambuco: 4,000 net acres
- TDF Concessions (Rio Cullen, Las Violetas, Angostura): 120,000 net acres
- Sur Rio Deseado Este: 58,000 net acres

■ COLOMBIA

- Llanos 32: 22,000 net acres
- Llanos 40: 82,000 net acres
- Turpial: 50,000 net acres

- All Apco's interests are non-operated
- Apco is funded by its internally generated cash flow – no domestic cash sent to Apco
- WPX owns ~20.3 million shares of Apco Oil and Gas International Inc (NASDAQ: APAGF)
- Ralph Hill is Apco's chairman and CEO

Reserve / Production Profile*

Proved Reserves (12/31/2011)

Gas (Bcf)	79.9
Oil (MMbbls)	<u>17.2</u>
Total Proved Reserves (Bcfe)	183.3

Production (FYE 12/31/2011)

Gas (Bcf)	8.7
Oil (MMbbls)	<u>2.2</u>
Total Production (Bcfe)	21.9

* Represents WPX interest at 69%

Apco Operational Update

■ 2012 1Q Update

- Development drilling progressing as planned; primarily in Entre Lomas and Bajada del Palo concessions
- Commence exploration drilling in Colombia in this quarter (Llanos 32)
- Actively investigating Vaca Muerta in Coirón Amargo

■ 2012 Operational Strategy

- Continue field development and conventional exploration in our existing properties
- Investigate Vaca Muerta, Molles and Lotena formations in core area in the Neuquén basin
 - Committed to drill 3 wells in the Tordillo/Vaca Muerta formation
- Secure concession extensions from the provinces of Río Negro and Tierra del Fuego
- Fulfill exploration commitments in Colombia



2012 Guidance

Dollars in millions, except production numbers

Capital expenditures	
Piceance	\$365
Bakken	\$370
Marcellus	\$315
International	\$65
Other	<u>\$50 - \$85</u>
Total	\$1,165 - \$1,200
Adjusted EBITDAX	\$1,200

Production	
Gas (MMcf/d)	1,160
Oil (Mbbl/d)	18
NGLs (Mbbl/d)	<u>30</u>
Equivalents (MMcfe/d)	1,450

Commodity price assumptions	
Oil Bbl - WTI	\$99.00
Natural gas – Henry Hub Mcf	\$3.00
NGL Bbl	\$51.00

Note: Adjusted EBITDAX is a non-GAAP measure. A reconciliation to relevant measures included in GAAP is provided in this presentation. Production volumes may not foot due to rounding. Oil price reflects only a domestic price.

Why WPX Is A Good Investment

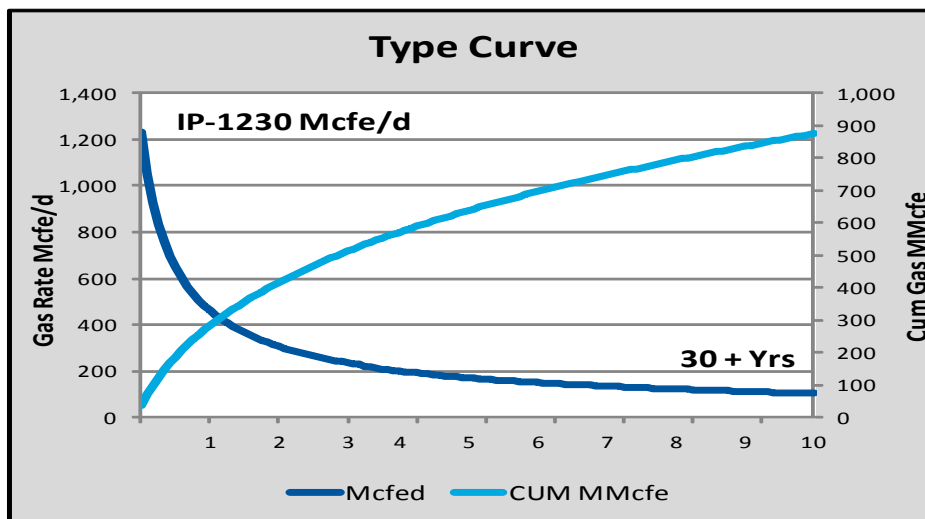
- **Economically attractive diversified asset base across a number of high growth areas**
 - Largest operator in the Piceance, substantial positions in the Bakken and the Marcellus
- **Proven technical leader and cost-efficient producer**
 - Leading cost structure in the Piceance, transferrable to the Bakken and Marcellus
- **Long-term double digit production growth capability for all products with existing asset base**
 - Oil/NGLs increasing 17%
 - Gas held flat, price improvement will provide ability to resume growth
- **Rapidly diversifying product mix to oil/NGLs**
 - Oil/NGLs represent 20% of production and 46% of revenues in 2012
- **Extensive drilling inventory**
 - 18.5 Tcfe 3P reserves with more than 18,000 gross locations
- **Significant operating flexibility**
 - 95% of 2012 capital spent in our three core areas
- **Substantial pro forma liquidity**
 - ~\$2 billion of liquidity at year-end 2011
- **Management team with broad unconventional resource expertise**
 - 238 collective years of experience

APPENDIX



Piceance Valley Basin Economics

Type Well Economics	
Gross Well Cost	\$1.43 MM
Gross Reserves	1,240 MMcfe
Working Interest	97%
Net Revenue Interest	81%
Net Liquids Contribution	\$.87/Mcf
Net Lifting Cost (LOE)	\$.25/Mcfe
Net Gathering/Transportation	\$.40/Mcfe
Net Production Tax	\$.24/Mcfe
Pre-tax IRR	
At \$3.62 (3 yr avg., Jan 13th Mkt price)	30%
At \$4.00 NYMEX - FLAT	31%
At \$5.00 NYMEX - FLAT	47%

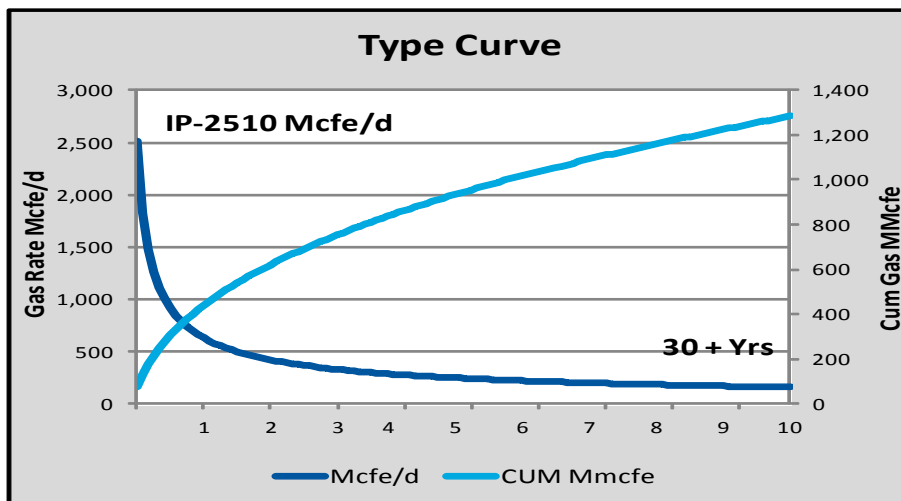


Basin Facts

- Net acreage: 102,277
- Gross 3P locations: 4,300
- Average rigs in 2012: 5.5
– 38 wells/rig/yr
- Spacing: 10 acre
- Liquids yield: 37 Bbls/MMcfe

Ryan Gulch Basin Economics

Type Well Economics	
Gross Well Cost	\$3.07 MM
Gross Reserves	1,881 MMcfe
Working Interest	52%
Net Revenue Interest	45%
Net Liquids Contribution	\$1.82/Mcf
Net Lifting Cost (LOE)	\$.44/Mcfe
Net Gathering/Transportation	\$.39/Mcfe
Net Production Tax	\$.30/Mcfe
Pre-tax IRR	
At \$3.62 (3 yr avg., Jan 13th Mkt price)	29%
At \$4.00 NYMEX - FLAT	28%
At \$5.00 NYMEX - FLAT	38%

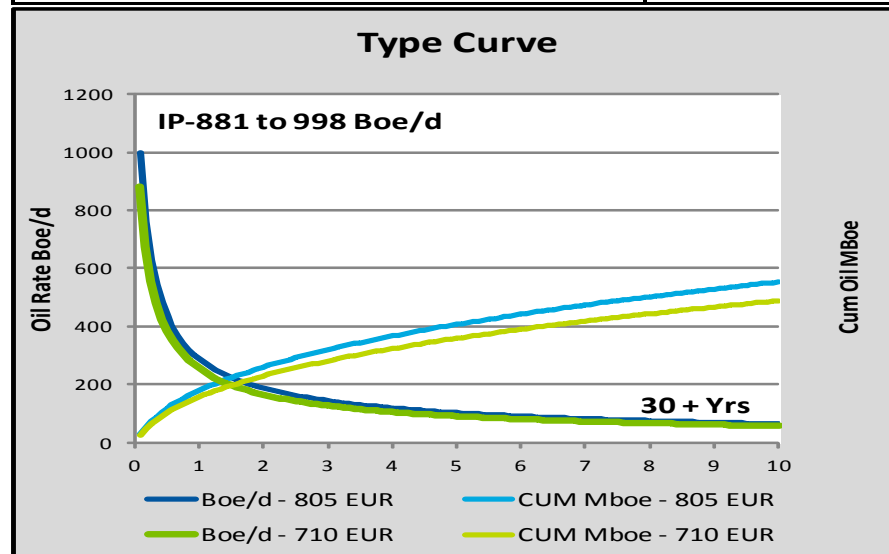


Basin Facts

- Net acreage: 34,918
- Gross 3P locations: 4,611
- Average rigs in 2012: 1.2
– 25 wells/rig/yr
- Spacing: 20 acre
- Liquids yield: 58 Bbls/MMcfe

Bakken Basin Economics

Type Well Economics	
Gross Well Cost	\$10.5 MM
Gross Reserves	710 - 805 Mboe
Working Interest	81%
Net Revenue Interest	64%
Net Liquids Contribution	\$5.10/Bbl
Net Lifting Cost (LOE)	\$6.41/Bbl
Net Gathering/Transportation	\$3.51/Bbl
Net Production Tax	\$9.68/Bbl
Pre-tax IRR	
At \$80.00 WTI - FLAT	27% to 35%
At \$95.00 WTI - FLAT	44% to 52%
At \$100.00 WTI - FLAT	49% to 59%



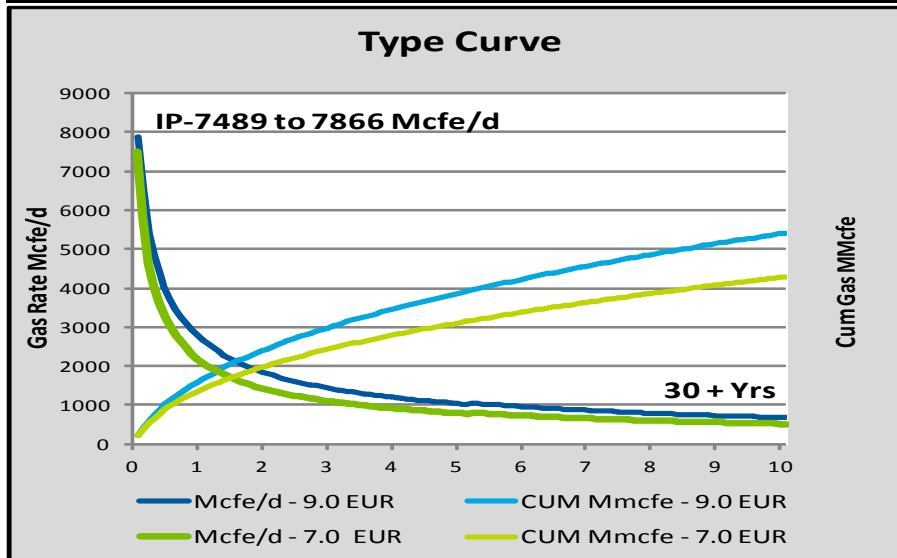
Basin Facts

- **Net acreage:** 86,113
- **Gross 3P locations:** 574*
- **Average rigs in 2012:** 5.6
 - Currently drilling single well pads
 - Will average 10 wells/rig/yr when multi well pad drilling begins later this year
- **Spacing:** 640 / 1,280 acre
- **Lateral length:** 9,200'
- **Frac Stages:** 30 (ceramic mix)

*Gross 3P locations decreased due to land trades. Well type represents Middle Bakken well.

Marcellus Susquehanna Basin Economics

Type Well Economics	
Gross Well Cost	\$6.0 to \$8.0 MM
Gross Reserves	7.0 to 9.0 Bcfe
Working Interest	86%
Net Revenue Interest	73%
Net Liquids Contribution	\$.00/Mcf
Net Lifting Cost (LOE)	\$.24/Mcfe
Net Gathering/Transportation	\$.40/Mcfe
Net Production Tax	\$.00/Mcfe
Pre-tax IRR	
At \$3.62 (3 yr avg., Jan 13th Mkt price)	21% to 23%
At \$4.00 NYMEX - FLAT	23% to 26%
At \$5.00 NYMEX - FLAT	39% to 46%



Basin Facts

- ***Net acreage: 106,976**
- ***Gross 3P locations: 574**
- **Average rigs in 2012: 2.9**
– 16 wells/rig/yr
- **Spacing: 500' to 1000'**
- **Lateral length: 4,300' - 4700'**
- **Frac Stages: 15 - 22**

* Represents total Marcellus position

2012 Hedges and Hedging Strategy

- Use of a combination of hedging instruments: fixed price swaps, basis swaps, costless collars and swaptions
- Hedge percentages
 - Natural gas = 55%
 - Crude oil = 78% protected, 82% capped
 - Natural gas liquids = 12%
- Decision to no longer apply hedge accounting on a perspective basis allows WPX Energy to be nimble with hedging decisions

As of 2/14/2012	2012
NG fixed price at the basin	
Volume (Bbtu/d)	508
Weighted average price (\$/MMBtu)	\$5.06
NGL swaps	
Volume (Bbl/d)	3,661
Weighted average price (\$/gallon)	\$1.21
Weighted average price (\$/Bbl)	\$50.74
Crude oil	
Crude oil swaps	
Volume (Bbl/d)	7,503
Weighted average price (\$/Bbl)	\$97.79
Crude oil collars	
Volume (Bbl/d)	2,000
Weighted average collar price (\$/Bbl)	\$85.00 - 106.30
Crude oil swaptions	
Volume (Bbl/d)	503
Weighted average price (\$/Bbl)	\$108.00
Crude oil hedge volumes (Bbl/d)	10,006
Protected	9,503
Capped	503
NGL hedge volumes (Bbl/d)	3,661
Natural gas hedge volumes (Bbtu/d)	508

WPX 2012 Liquidity Guidance

- **All capacity under \$1.5 billion, 5-year revolver is available at year-end**
 - General corporate borrowing facility
 - Facility became effective November 1
- **At 12/31/11, \$292 million outstanding under bilateral LC facilities**
- **Maintain a conservative capital structure to promote production growth and resource development**
 - Raised \$1.5 billion of bonds in November
 - Under levered compared to peers
- **Maintain adequate liquidity to preserve operational flexibility**
 - ~\$2 billion of liquidity at 12/31/2011
 - Goal is to maintain a minimum of \$1 billion liquidity
- **Utilize financial strength to assess growth opportunities**

<i>Liquidity (millions)</i>	
Cash and cash equivalents	\$526
Less:	
Apco Oil and Gas	\$38
Margins held	\$7
	<u>(\$45)</u>
Available unrestricted cash	\$481
Available revolver capacity	\$1,500
Unrestricted liquidity @ 12/31/11	\$1,981
Cash flow from Operations	\$1,100
Capital	(\$1,200)
Anticipated LCs issued*	(\$355) - (\$405)
Projected liquidity @ 12/31/2012	\$1,476 - 1,526

*LCs are currently issued under bilateral, uncommitted agreements

4th Quarter and Full-Year Results

<i>Dollars in millions, except production numbers</i>	4Q		Full Year	
	2011	2010	2011	2010
Daily Production				
Gas (MMcf/d)	1,163	1,137	1,153	1,096
Oil (Mbb/d)	15	8	13	8
NGLs (Mbb/d)	28	25	28	23
Equivalent (MMcfe/d)	1,420	1,337	1,399	1,277
Adjusted EBITDAX	\$340	\$322	\$1,330	\$1,329
Adjusted Net Income from Continuing Operations	\$20	\$18	\$67	\$151
Capital Expenditures				
Piceance	176	171	712	626
Bakken	85	950	263	950
Marcellus	120	84	264	805
International/other	103	141	333	424
Total	\$484	\$1,346	\$1,572	\$2,805

Note: Adjusted EBITDAX is a non-GAAP measure. A reconciliation to relevant measures included in GAAP is provided in this presentation. 2010 CapEx includes Bakken and Susquehanna acreage acquisitions of ~\$1.7B.

2012 Tax Guidance

Tax Rates	2011 1st Qtr	2011 2nd Qtr	2011 3rd Qtr	2011 Year-to-Date
Provision (benefit) at statutory rate	\$4 35%	\$19 35%	\$29 35%	(\$146) 35%
Increases (decreases) in taxes resulting from:				
State income taxes (net of federal benefit)	- 0%	1 1%	1 1%	\$ 441
Effective state income tax rate change (net of federal benefit)	- 0%	- 0%	- 0%	85
Foreign operations - net	(1) -11%	(2) -3%	(1) -1%	- 0%
Other - net	- 0%	1 1%	- 0%	- 0%
Provision (benefit) for income taxes	3 24%	19 34%	29 35%	(145) 35%

Rates below are based on income from continuing operations before income taxes	2011	2012
Full-year effective tax rate guidance	24 - 35%	34 - 36%

Domestic Price Realization

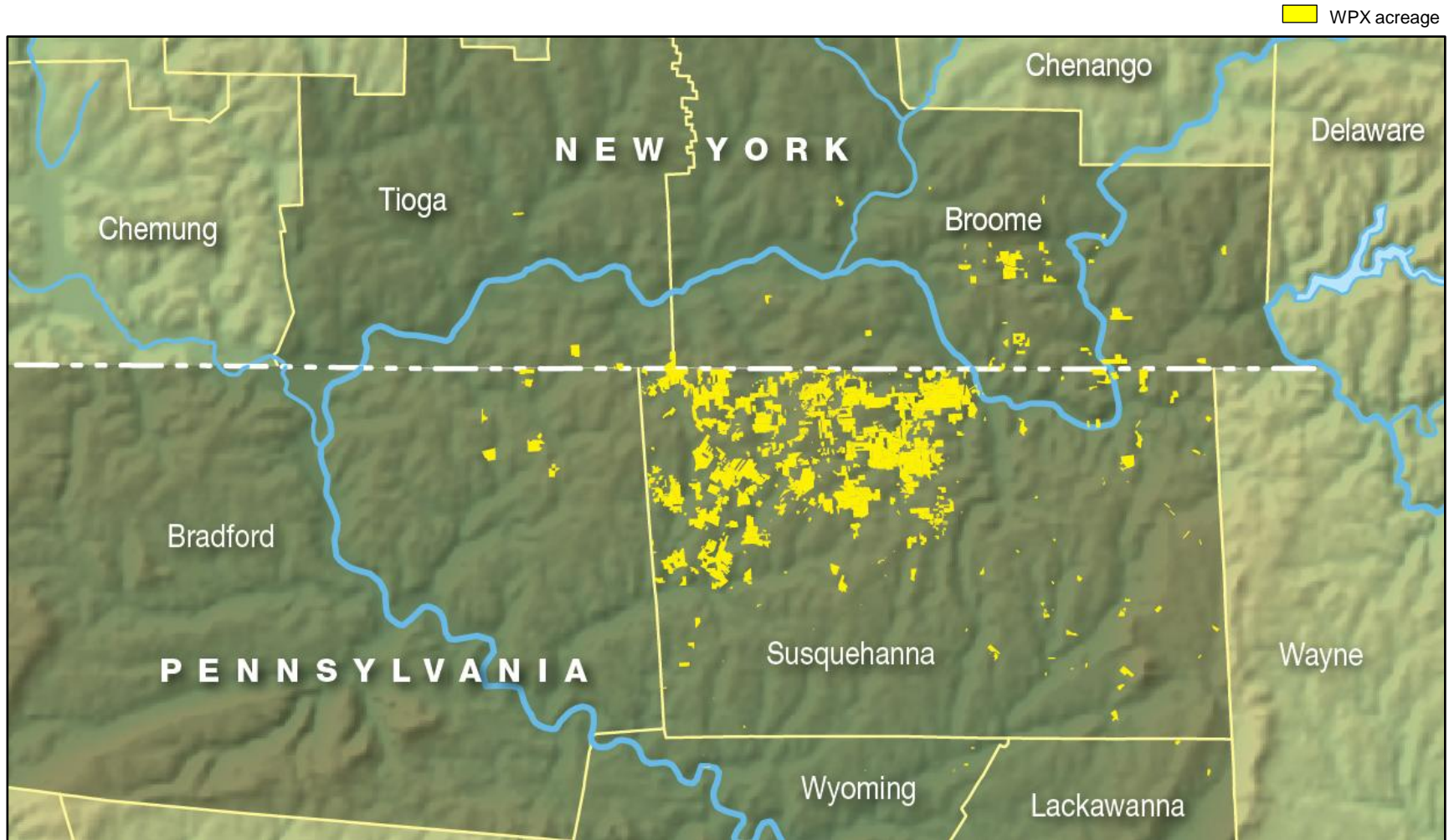
	Gas (\$/Mcf)				NGL (\$/Bbl)				OIL (\$/Bbl)			
	Q1 '11	Q2 '11	Q3 '11	Q4 '11	Q1 '11	Q2 '11	Q3 '11	Q4 '11	Q1 '11	Q2 '11	Q3 '11	Q4 '11
Price Point	\$4.10	\$4.31	\$4.19	\$3.55	\$47.81	\$53.75	\$53.07	\$52.63	\$90.63	\$104.02	\$92.43	\$90.27
Price Deduct	(0.49)	(0.56)	(0.62)	(0.41)	(12.77)	(12.59)	(10.61)	(10.88)	(3.26)	(12.11)	(9.50)	(10.04)
Hedge Impact	0.77	0.67	0.67	1.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net Price	\$4.38	\$4.42	\$4.23	\$4.19	\$35.04	\$41.16	\$42.46	\$41.75	\$86.73	\$88.89	\$86.14	\$81.51

Note: Price Point of Oil and Natural Gas is the average daily closing price over the quarter, WTI and NYMEX respectively. NGLs are the average daily Mount Belvieu price over the quarter. Price deducts include basis differential, main/line fuel , transport, fuel shrinkage and prior period adjustments.

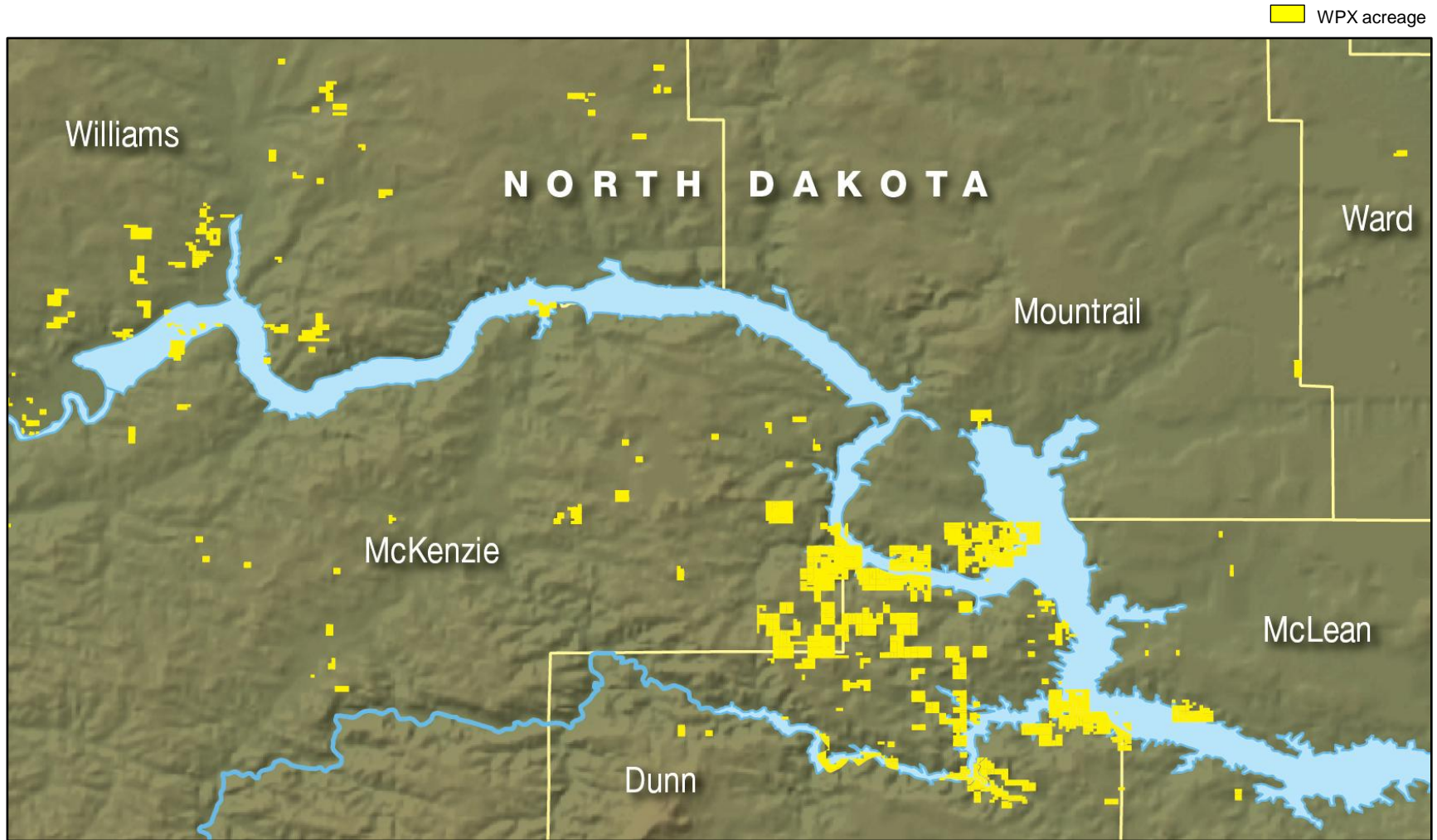
2010-11 Daily Production

	2010					2011				
	Q1	Q2	Q3	Q4	Total	Q1	Q2	Q3	Q4	Total
Domestic Production										
Oil (Mbb/d)	2	2	2	3	2	4	8	8	9	7
NGLs (Mbb/d)	20	23	21	24	22	27	28	28	28	28
Gas (MMcf/d)	1,052	1,054	1,080	1,118	1,076	1,091	1,115	1,182	1,143	1,133
MMcfe/d	1,184	1,204	1,221	1,281	1,223	1,279	1,329	1,398	1,362	1,342
International Production										
Oil (Mbb/d)	5	6	5	6	5	5	6	6	6	6
NGLs (Mbb/d)	0	0	0	0	0	0	1	1	0	1
Gas (MMcf/d)	19	19	20	20	19	20	21	19	21	20
MMcfe/d	53	56	53	56	55	55	58	57	58	57
Total Production										
Oil (Mbb/d)	7	8	8	8	8	10	14	14	15	13
NGLs (Mbb/d)	21	23	22	25	23	27	28	28	28	28
Gas (MMcf/d)	1,071	1,074	1,100	1,137	1,096	1,111	1,137	1,201	1,163	1,153
MMcfe/d	1,237	1,260	1,274	1,337	1,277	1,333	1,387	1,455	1,420	1,399

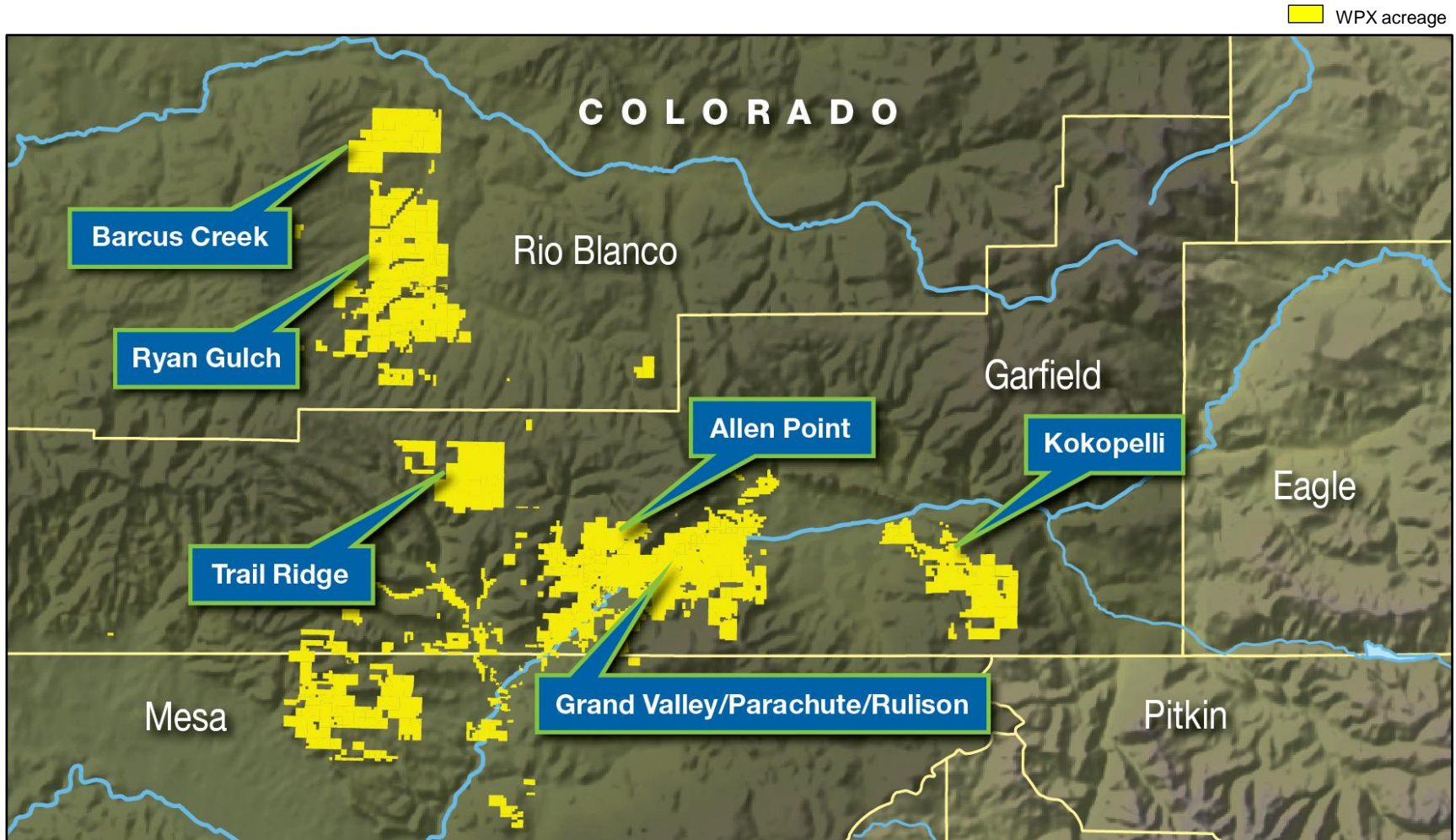
Northeast Pennsylvania – Susquehanna



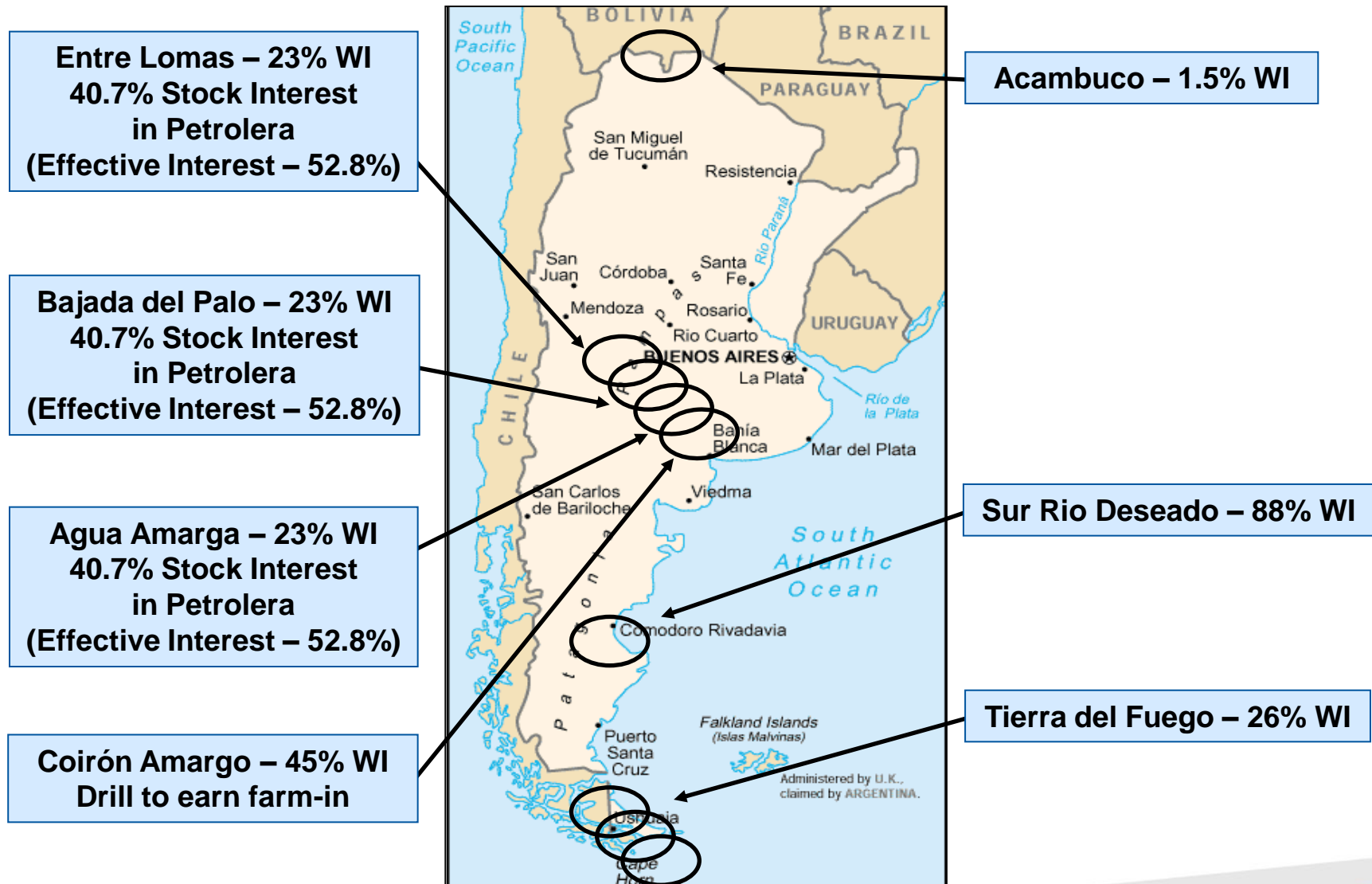
Williston Basin



Piceance Basin



Argentina Asset Map



Non-GAAP



WPX Non-GAAP Disclaimer

This presentation may include certain financial measures, including adjusted EBITDAX (earnings before interest, taxes, depreciation, depletion, amortization and exploration expenses), adjusted segment profit, adjusted earnings and adjusted per share measures that are non-GAAP financial measures as defined under the rules of the Securities and Exchange Commission. These non-GAAP financial measures exclude items of income or loss that the company characterizes as unrepresentative of its ongoing operations and reflect mark-to-market adjustments for certain hedges and other derivatives in Exploration & Production. These measures provide investors meaningful insight into the company's results from ongoing operations and better reflect results on a basis that is more consistent with derivative portfolio cash flows. The mark-to-market adjustments reverse forward unrealized mark-to-market gains or losses from derivatives and add realized gains or losses from derivatives for which mark-to-market income has been previously recognized, with the effect that the resulting adjusted segment profit is presented as if mark-to-market accounting had never been applied to these derivatives. The measure is limited by the fact that it does not reflect potential unrealized future losses or gains on derivative contracts. However, management compensates for this limitation since derivative assets and liabilities do reflect unrealized gains and losses of derivative contracts. Overall, management believes the mark-to-market adjustments provide an alternative measure that more closely matches realized cash flows for these derivatives but does not substitute for actual cash flows.

This presentation is accompanied by a reconciliation of these non-GAAP financial measures to their nearest GAAP financial measures. Management uses these financial measures because they are widely accepted financial indicators used by investors to compare a company's performance. In addition, management believes that these measures provide investors an enhanced perspective of the operating performance of the company and aid investor understanding. These non-GAAP financial measures should not be considered in isolation or as substitutes for a measure of performance prepared in accordance with United States generally accepted accounting principles.

2011-12 Adjusted EBITDAX Reconciliation

<i>Dollars in millions</i>	Year Ended Dec. 31, 2011	Pro Forma Year Ended Dec. 31, 2012
Adjusted EBITDAX		
Reconciliation to Net Income (Loss):		
Net Income (Loss)	\$ (292)	\$ 78
Interest Expense	117	115
Provision (Benefit) for Income Taxes	(145)	(18)
Depreciation, Depletion and Amortization	949	971
Exploration Expenses	134	86
EBITDAX	763	1,232
Impairments of Goodwill, producing properties and cost of acquired unproved reserves	547	-
(Income) loss from discontinued operations	20	-
Adjusted EBITDAX	\$ 1,330	\$ 1,232

Reconciliation – Adjusted Net Income from Continuing Operations

(Unaudited)



<i>Dollars in millions, except per share amounts</i>	2010					2011				
	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	Year	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	Year
Income (loss) from continuing operations attributable to WPX Energy, Inc. available to common stockholders	\$ 81	\$ 30	\$ (1,412)	\$ 18	\$ (1,283)	\$ 5	\$ 25	\$ 17	\$ (329)	\$ (282)
Income (loss) from continuing operations – diluted earnings per share	\$ 0.41	\$ 0.15	\$ (7.16)	\$ 0.09	\$ (6.51)	\$ 0.03	\$ 0.13	\$ 0.09	\$ (1.67)	\$ (1.43)
Adjustments:										
Impairments	\$ -	\$ -	\$ 1,681	\$ -	\$ 1,681	\$ -	\$ -	\$ -	\$ 547	\$ 547
Total adjustments	\$ -	\$ -	\$ 1,681	\$ -	\$ 1,681	\$ -	\$ -	\$ -	\$ 547	\$ 547
Less tax effect for above items	\$ -	\$ -	\$ (247)	\$ -	\$ (247)	\$ -	\$ -	\$ -	\$ (198)	\$ (198)
Adjusted income from continuing operations available to common stockholders	\$ 81	\$ 30	\$ 22	\$ 18	\$ 151	\$ 5	\$ 25	\$ 17	\$ 20	\$ 67
Adjusted diluted earnings per common share	\$ 0.41	\$ 0.15	\$ 0.11	\$ 0.09	\$ 0.77	\$ 0.03	\$ 0.13	\$ 0.09	\$ 0.10	\$ 0.34
Weighted-average shares – diluted – millions (1)	197.1	197.1	197.1	197.1	197.1	197.1	197.1	197.1	197.1	197.1

(1) For comparative purposes and to provide a more meaningful calculation for weighted average shares, we have assumed the amount of common stock issued at Dec. 31, 2011, to be outstanding for all periods presented.

Consolidated EBITDAX Reconciliation

(Unaudited)

Dollars in millions	2010					2011				
	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	Year	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	Year
Revenues:										
Product revenues										
Natural gas sales	\$ 490	\$ 427	\$ 454	\$ 441	\$ 1,812	\$ 434	\$ 453	\$ 464	\$ 444	\$ 1,795
Natural gas liquid sales	71	68	61	85	285	86	105	110	107	408
Oil and condensate sales	26	32	31	39	128	52	84	86	93	315
Total product revenues	587	527	546	565	2,225	572	642	660	644	2,518
	556	366	435	385	1,742	408	337	347	336	1,428
	9	-	16	2	27	2	6	12	9	29
	12	11	9	8	40	2	5	3	3	13
Total revenues	1,164	904	1,006	960	4,034	984	990	1,022	992	3,988
Costs and expenses:										
Lease and facility operating expense	66	66	75	79	286	70	70	78	77	295
Gathering, processing and transportation	72	73	71	110	326	115	125	132	127	499
Taxes other than income	40	33	36	16	125	31	45	33	31	140
Gas management, including charges for unutilized pipeline capacity	558	376	451	386	1,771	417	345	360	351	1,473
Exploration	8	10	27	28	73	13	20	74	27	134
Depreciation, depletion and amortization	216	217	222	220	875	216	236	251	246	949
Impairment of producing properties and costs of acquired unproved reserves	-	-	678	-	678	-	-	-	547	547
Goodwill impairment	-	-	1,003	-	1,003	-	-	-	-	-
General and administrative	61	61	61	70	253	70	65	73	77	285
Other - net	-	3	(9)	(13)	(19)	3	2	(1)	(3)	1
Total costs and expenses	1,021	839	2,615	896	5,371	935	908	1,000	1,480	4,323
Operating income (loss)	143	65	(1,609)	64	(1,337)	49	82	22	(488)	(335)
Interest expense	(25)	(25)	(38)	(36)	(124)	(49)	(48)	-	(20)	(117)
Interest capitalized	4	4	4	4	16	4	4	-	1	9
Investment income and other	5	6	4	6	21	6	6	7	7	26
Income (loss) from continuing operations before income taxes	\$ 127	\$ 50	\$ (1,639)	\$ 38	\$ (1,424)	\$ 10	\$ 44	\$ 29	\$ (500)	\$ (417)
Provision (benefit) for income taxes	\$ 44	\$ 18	\$ (229)	\$ 18	\$ (149)	\$ 3	\$ 16	\$ 10	\$ (174)	\$ (145)
Income (loss) from continuing operations	\$ 83	\$ 32	\$ (1,410)	\$ 20	\$ (1,275)	\$ 7	\$ 28	\$ 19	\$ (326)	\$ (272)
Loss from discontinued operations	\$ -	\$ (1)	\$ (1)	\$ (6)	\$ (8)	\$ (8)	\$ -	\$ (3)	\$ (9)	\$ (20)
Net income (loss)	\$ 83	\$ 31	\$ (1,411)	\$ 14	\$ (1,283)	\$ (1)	\$ 28	\$ 16	\$ (335)	\$ (292)
Less: Net income attributable to noncontrolling interests	\$ 2	\$ 2	\$ 2	\$ 2	\$ 8	\$ 2	\$ 3	\$ 2	\$ 3	\$ 10
Net income (loss) attributable to WPX Energy	\$ 81	\$ 29	\$ (1,413)	\$ 12	\$ (1,291)	\$ (3)	\$ 25	\$ 14	\$ (338)	\$ (302)
Adjusted EBITDAX										
Net income (loss)	\$ 83	\$ 31	\$ (1,411)	\$ 14	\$ (1,283)	\$ (1)	\$ 28	\$ 16	\$ (335)	\$ (292)
Interest expense	25	25	38	36	124	49	48	-	20	117
Provision (benefit) for income taxes	44	18	(229)	18	(149)	3	16	10	(174)	(145)
Depreciation, depletion and amortization	216	217	222	220	875	216	236	251	246	949
Exploration expenses	8	10	27	28	73	13	20	74	27	134
EBITDAX	376	301	(1,353)	316	(360)	280	348	351	(216)	763
Impairments of goodwill, producing properties and cost of acquired unproved reserves	-	-	1,681	-	1,681	-	-	-	547	547
Loss from discontinued operations	-	1	1	6	8	8	-	3	9	20
Adjusted EBITDAX	\$ 376	\$ 302	\$ 329	\$ 322	\$ 1,329	\$ 288	\$ 348	\$ 354	\$ 340	\$ 1,330

Domestic Income Statement

Dollars in millions	2010					2011				
	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	Year	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	Year
Revenues:										
Product revenues										
Natural gas sales	\$ 486	\$ 424	\$ 451	\$ 436	\$ 1,797	\$ 430	\$ 449	\$ 460	\$ 440	\$ 1,779
Natural gas liquid sales	70	67	60	85	282	85	104	109	106	404
Oil and condensate sales	11	14	13	19	57	34	64	64	67	229
Total product revenues	567	505	524	540	2,136	549	617	633	613	2,412
Gas management	556	366	435	385	1,742	408	337	347	336	1,428
Hedge ineffectiveness and mark to market gains and losses	9	-	16	2	27	2	6	12	9	29
Other	12	11	9	8	40	1	4	2	2	9
Total revenues	1,144	882	984	935	3,945	960	964	994	960	3,878
Costs and expenses:										
Lease and facility operating expense	63	61	70	73	267	65	64	71	68	268
Gathering, processing and transportation	72	73	71	110	326	115	125	132	127	499
Taxes other than income	37	29	32	11	109	28	39	27	25	119
Gas management, including charges for unutilized pipeline capacity	558	376	451	386	1,771	417	345	360	351	1,473
Exploration	4	8	27	28	67	12	19	74	26	131
Depreciation, depletion and amortization	212	213	218	215	858	211	231	245	240	927
Impairment of producing properties and costs of acquired unproved reserves	-	-	678	-	678	-	-	-	547	547
Goodwill impairment	-	-	1,003	-	1,003	-	-	-	-	-
General and administrative, including Williams	59	59	58	68	244	67	63	70	73	273
Other - net	-	3	(9)	(13)	(19)	2	2	(2)	(4)	(2)
Total costs and expenses	1,005	822	2,599	878	5,304	917	888	977	1,453	4,235
Operating income (loss)	139	60	(1,615)	57	(1,359)	43	76	17	(493)	(357)
Interest expense	(25)	(25)	(38)	(36)	(124)	(49)	(48)	-	(20)	(117)
Interest capitalized	4	4	4	4	16	4	4	-	1	9
Investment income and other	1	1	1	1	4	1	2	2	1	6
Income (loss) from continuing operations before income taxes	\$ 119	\$ 40	\$ (1,648)	\$ 26	\$ (1,463)	\$ (1)	\$ 34	\$ 19	\$ (511)	\$ (459)
Summary of Production Volumes (1)										
Natural gas (MMcf)	94,641	95,954	99,358	102,822	392,775	98,185	101,481	108,734	105,120	413,520
Natural gas liquids (MMbbls)	1,813	2,058	1,945	2,240	8,056	2,426	2,527	2,567	2,539	10,059
Oil (MMbbls)	167	204	222	264	857	392	720	743	822	2,677
Combined equivalent volumes (MMcfe) (2)	106,523	109,526	112,357	117,847	446,253	115,089	120,963	128,591	125,285	489,926
(1) Excludes production from our Arkoma Basin operations, which are reported as discontinued operations and comprised less than one percent of our total production.										
(2) Amounts for 2010 have been recalculated using a conversion ratio for our NGLs of 6 to 1 as these were previously reported in natural gas volumes.										
Realized average price per unit, including the impact of hedges (1)										
Natural gas (per MMcf)	5.14	4.42	4.54	4.24	4.57	4.38	4.42	4.23	4.19	4.30
Natural gas liquids (per Bbl)	38.61	32.56	30.85	37.95	35.02	35.04	41.16	42.46	41.75	40.17
Oil (per Bbl)	65.87	68.63	58.56	71.97	66.32	86.73	88.89	86.14	81.51	85.38
(1) Excludes our Arkoma Basin operations, which are reported as discontinued operations.										
Expenses per MMcfe (1)										
Lease and facility operating expense	0.59	0.56	0.62	0.62	0.60	0.56	0.53	0.55	0.54	0.55
Gathering, processing and transportation	0.68	0.67	0.63	0.93	0.73	1.00	1.03	1.03	1.01	1.02
Taxes other than income	0.35	0.26	0.28	0.09	0.24	0.24	0.32	0.21	0.20	0.24
Depreciation, depletion and amortization	1.99	1.94	1.94	1.82	1.92	1.83	1.91	1.91	1.92	1.89
General and administrative	0.55	0.54	0.52	0.58	0.55	0.58	0.52	0.54	0.58	0.56
(1) Excludes our Arkoma Basin operations, which were classified as held for sale and reported as discontinued operations.										

International Income Statement

(Unaudited)

Dollars in millions	2010					2011				
	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	Year	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	Year
Revenues:										
Product revenues:										
Natural gas sales	\$ 4	\$ 3	\$ 3	\$ 5	\$ 15	\$ 4	\$ 4	\$ 4	\$ 4	\$ 16
Natural gas liquid sales	1	1	1	-	3	1	1	1	1	4
Oil and condensate sales	15	18	18	20	71	18	20	22	26	86
Total product revenues	20	22	22	25	89	23	25	27	31	106
Gas management	-	-	-	-	-	-	-	-	-	-
Hedge ineffectiveness and mark to market gains and losses	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	1	1	1	1	4
Total revenues	20	22	22	25	89	24	26	28	32	110
Costs and expenses:										
Lease and facility operating expense	3	5	5	6	19	5	6	7	9	27
Gathering, processing and transportation	-	-	-	-	-	-	-	-	-	-
Taxes other than income	3	4	4	5	16	3	6	6	6	21
Gas management (including charges for unutilized pipeline capacity)	-	-	-	-	-	-	-	-	-	-
Exploration	4	2	-	-	6	1	1	-	1	3
Depreciation, depletion and amortization	4	4	4	5	17	5	5	6	6	22
Impairment of producing properties and costs of acquired unproved reserves	-	-	-	-	-	-	-	-	-	-
Goodwill impairment	-	-	-	-	-	-	-	-	-	-
General and administrative	2	2	3	2	9	3	2	3	4	12
Other - net	-	-	-	-	-	1	-	1	1	3
Total costs and expenses	16	17	16	18	67	18	20	23	27	88
Operating income (loss)	4	5	6	7	22	6	6	5	5	22
Interest expense	-	-	-	-	-	-	-	-	-	-
Interest capitalized	-	-	-	-	-	-	-	-	-	-
Investment income and other	4	5	3	5	17	5	4	5	6	20
Income (loss) from continuing operations before income taxes	\$ 8	\$ 10	\$ 9	\$ 12	\$ 39	\$ 11	\$ 10	\$ 10	\$ 11	\$ 42
Summary of Production Volumes										
Total (MMcfe) (1) (2)	4,773	5,116	4,895	5,155	19,940	4,926	5,280	5,231	5,373	20,810
(1) Converted using 6 to 1 conversion rate for NGL and Oil										
(2) Reflects approximately 69 percent of Apco's production.										