Petroleum Development Corporation

2009 Analyst Day

March 19, 2009

NASDAQ:PETD

Disclaimer

The following information contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. These forward-looking statements are based on Management's current expectations and beliefs, as well as a number of assumptions concerning future events.

These statements are based on certain assumptions and analyses made by Management in light of its experience and its perception of historical trends, current conditions and expected future developments as well as other factors it believes are appropriate in the circumstances. However, whether actual results and developments will conform with Management's expectations and predictions is subject to a number of risks and uncertainties, general economic, market or business conditions; the opportunities (or lack thereof) that may be presented to and pursued by Petroleum Development Corporation; actions by competitors; changes in laws or regulations; and other factors, many of which are beyond the control of Petroleum Development Corporation.

You are cautioned not to put undue reliance on such forward-looking statements because actual results may vary materially from those expressed or implied, as more fully discussed in our safe harbor statements found in our SEC filings, including, without limitation, the discussion under the heading "Risk Factors" in the company's annual report on Form 10-K. All forward-looking statements are based on information available to Management on this date and Petroleum Development Corporation assumes no obligation to, and expressly disclaims any obligation to, update or revise any forward looking statements, whether as a result of new information, future events or otherwise.

The SEC permits oil and gas companies to disclose in their filings with the SEC only proved reserves, which are reserve 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. The Company uses in this presentation the terms "probable" and "possible" reserves, which SEC guidelines prohibit in filings of U.S. registrants. Probable reserves are unproved reserves that are more likely than not to be recoverable. Possible reserves are unproved reserves that are less likely to be recoverable than probable reserves. Estimates of probable and possible reserves which may potentially be recoverable through additional drilling or recovery techniques are by nature more uncertain than estimates of proved reserves and accordingly are subject to substantially greater risk of not actually being realized by the Company. In addition, the Company's production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

This material also contains certain non-GAAP financial measures as defined under the Securities and Exchange Commission rules.

2

Welcome

- Peter Schreck ,Vice President – Finance and Treasurer
- Introductions
  - Richard W. McCullough, Chairman and CEO
  - Gysle R. Shellum, Chief Financial Officer
  - Barton R. Brookman, Senior Vice President, Exploration and Production

See Slide 2 regarding Forward Looking Statements

Rick McCullough

Chairman & Chief Executive Officer

PDC History Snapshot

- NASDAQ:PETD
- Founded in 1969
- Market cap of $166.7 million at 3/16/09
- Operate in the Rockies, Appalachia and Michigan
- A leading producer in the Rocky Mountain region
- Reported record results in 2008 and exited the year with strong balance sheet metrics and liquidity
- Outstanding financial, technical and operating teams built in the past five years

See Slide 2 regarding Forward Looking Statements

5

2008 Fundamentals

	2008	2007	2006
Production (Bcfe)	38.7	28.0	17.0
Proved Reserves (Bcfe)	753	686	323
Realized Gas Prices (Mcfe)(1)	$8.66	$6.52	$6.91
Adj. EBITDA ($ millions)(2)	$192.5	$104.2	$80.3
Adj. Cash Flow from Operations ($ millions)(2)	$106.0-131.0	$95.6	$29.8
Adjusted Cash Flow from Operations, per diluted share (2)	$13.48	$6.44	$2.00
Stock Price(3)	$79.09 - $11.50	$61.91 - $35.73	$47.44 - $32.12

(1) Equivalent prices including oil sales, natural gas liquids and realized derivative gains and losses. Excludes non-realized derivative gains & losses
(2) See slides 66 and 67 for GAAP reconciliation of Adjusted EBITDA and Adjusted Cash Flow, respectively. Gain on leasehold sales excluded.
(3) Hi-low range, per year.

See Slide 2 regarding Forward Looking Statements

6

2009 Will Be Challenging

- 2008 – superior growth year
  - Production/Revenues
  - EBITDA/CASH FLOW
  - EPS/CFPS
- 2009 will be a challenging year
  - Valuable hedges - $153.5 MM MTM at 12/31/08
  - CAPEX reduced 50-60%, to $120 MM
  - Current strong liquidity position; will monitor it closely
  - Bank borrowing base redetermination in April
  - Substantial cost reduction/operational enhancement efforts underway

See Slide 2 regarding Forward Looking Statements

Cost Control and Operational Enhancements

- Implementing an internal strategic reassessment process
  - Measuring activities based on their contribution to shareholder value
  - Entire company involved
  - Will drive future decision making
- Review of all major elements of cost
- Basin by basin operational enhancement review
  - Costs; logistics; marketing

See Slide 2 regarding Forward Looking Statements

Bart Brookman

Senior V.P. Exploration & Production

9

2008 Operations Review

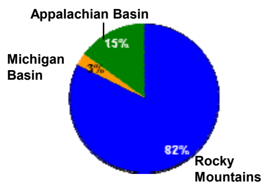
See Slide 2 regarding Forward Looking Statements

10

Core Operating Regions

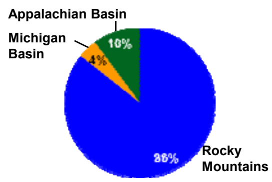
2008 Proved Reserves

753 Bcfe



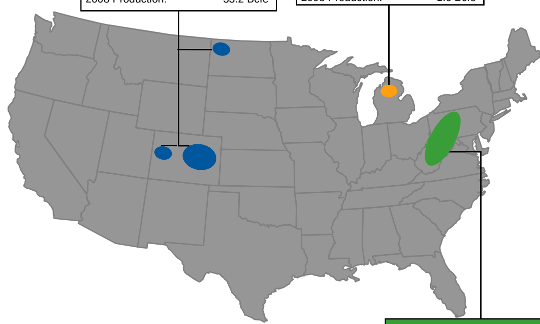
2008 Production

38.7 Bcfe



Rocky Mountains	
2007 Proved Reserves:	559 Bcfe
2007 Production:	23.5 Bcfe
2008 Proved Reserves:	620 Bcfe
2008 Production:	33.2 Bcfe

Michigan Basin	
2007 Proved Reserves:	24 Bcfe
2007 Production:	1.7 Bcfe
2008 Proved Reserves:	20 Bcfe
2008 Production:	1.6 Bcfe



Appalachian Basin	
2007 Proved Reserves:	103 Bcfe
2007 Production:	2.7 Bcfe
2008 Proved Reserves:	113 Bcfe
2008 Production:	3.9 Bcfe

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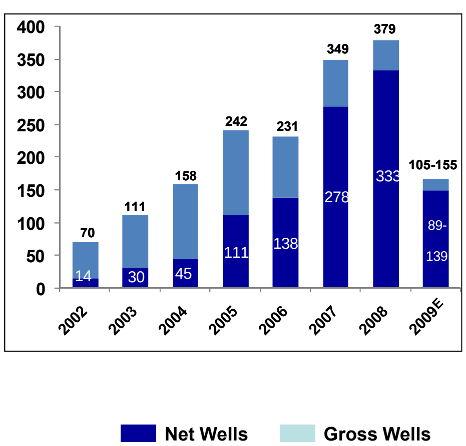
11

Operating Highlights

Historical Drilling



- **2008 Production increased 38% to 38.7 Bcfe**
- **2008 Proved reserves increased 10% to 753 Bcfe**

2008 Drilling Activity

Gross Wells Drilled	379
Net Wells Drilled	333
Development	357
Exploratory	22

Planned 2009 Drilling Activity

Gross Wells	105-155
Net Wells	89-139

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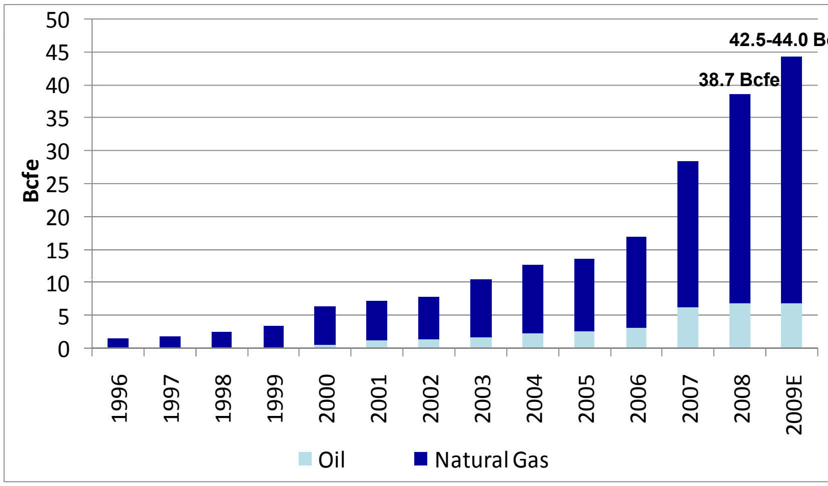
12

Net Production



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13

Production By Basin – Bcfe

Area	2007	2008	% Increase/ (Decrease)	2009E	% Increase/ (Decrease)
Eastern (App/MI)	4.4	5.5	25%	6.0	9%
Wattenberg	11.1	15.4	39%	15.4	0%
Piceance	8.2	12.5	52%	15.4 - 16.4*	23% - 31%
NECO	3.6	5.0	39%	5.3 - 5.8	6% - 16%
Other	0.6	0.3	-50%	0.4	33%
TOTAL	28.0	38.7	38%	42.5 - 44	10% - 14%

* Production assumes further drilling in the Piceance in 2009. No Piceance rigs are operating currently. If 2009 prices do not justify restarting the Piceance drilling program, the Company may deploy Piceance budgeted capital expenditures to other basins.

Bcfe = One billion cubic feet of natural gas equivalent.

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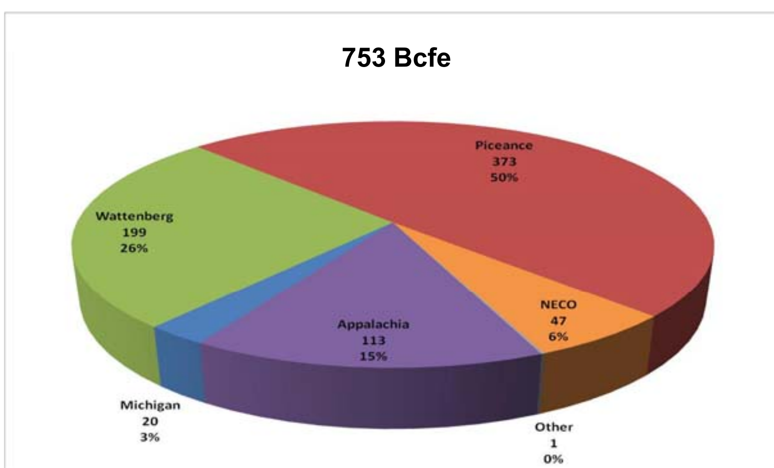
14

2008 Well Summary

Operating Area	YE2008 Gross Wells	2008 Gross Wells Drilled	2008 Net Wells Drilled	2009 Gross Wells Drilled
Grand Valley	285	62	54	0
Wattenberg	1,390	149	123	93
NECO	717	98	88	0 - 50
Appalachia	2,090	62	62	12
Michigan	210	2	2	0
Other	20	6	4	0
Total	4,712	379	333	105 - 155

See Slide 2 regarding Forward Looking Statements

YE2008 Reserves
Total Proved By Basin



See Slide 2 regarding Forward Looking Statements

YE2008 Proved Reserves

- Proved reserves improved 10% from 2007 levels
- PDPs improved 6% from 2007 levels
- Downward revisions of approximately 75 Bcfe due to reduced commodity pricing and increased costs
- Upward operational revisions were 41 Bcfe
- Extensions/additions were 139 Bcfe
- Reclassified PDNPs (Recompletions and Refracs) in Wattenberg to PUDs

Summary Reserve Data

	Proved Reserves (Bcfe)[1]				
Area	**2007 YE**	**2008 YE**	***% Growth***	***% Developed***	***% Natural Gas***
Rockies	**559**	**620**	***11%***	**38%**	**86%**
Appalachia	**103**	**113**	***10%***	**65%**	**100%**
Michigan	**24**	**20**	***(17)%***	**100%**	**99%**
Total	**686**	**753**	**10%**	**44%**	**88%**

(1) Independent reserve engineer's estimates

See Slide 2 regarding Forward Looking Statements

YE2008 Proved Reserves By Basin – Bcfe

	PDP		PDNP		PUD		Total Proved	
Area	**2007**	**2008**	**2007**	**2008**	**2007**	**2008**	**2007**	**2008**
Eastern (App/MI)	**83**	**73**	**22**	**21**	**22**	**39**	**127**	**133**
Wattenberg	**71**	**79**	**48**	**1**	**78**	**118**	**196**	**199**
Piceance	**84**	**107**	**8**	**6**	**202**	**260**	**294**	**373**
NECO	**43**	**40**	**8**	**3**	**16**	**5**	**67**	**47**
Other	**2**	**1**	**0**	**0**	**0**	**0**	**2**	**1**
TOTAL	**283**	**299**	**85**	**31**	**318**	**423**	**686**	**753**
% Total Proved	**41%**	**40%**	**12%**	**4%**	**46%**	**56%**	**100%**	**100%**

Bcfe = One billion cubic feet of natural gas equivalent.

See Slide 2 regarding Forward Looking Statements

YE2008 3P Reserves By Basin – Bcfe

Area	Total Proved 2007	Total Proved 2008	Proved + Probable 2007	Proved + Probable 2008	Proved + Probable + Possible 2007	Proved + Probable + Possible 2008
Eastern (App/MI)	127	133	127	146	127	156
Wattenberg	196	199	282	236	298	241
Piceance	294	373	444	485	499	538
NECO	67	47	94	57	119	74
Other	2	1	2	1	2	1
TOTAL	686	753	948	925	1,044	1,009

Bcfe = One billion cubic feet of natural gas equivalent.

See Slide 2 regarding Forward Looking Statements

F&D Costs

	2008	2007	2006	2005
Acquisition of Properties	(in millions)			
Proved Properties	$13.0	$257.3	$0.8	$1.6
Unproved Properties	—	13.7	11.9	16.9
Development Costs	257.9	194.0	114.5	68.6
Exploration Costs				
Exploratory Drilling	15.6	13.0	18.7	12.9
Geological & Geophysical	2.1	6.3	2.2	0.0
Total Costs Incurred	$288.7	$484.3	$148.1	$100.0
*Additions to Reserves (Bcfe)	107.4	396.3	66.9	80.3
F&D Cost ($/Mcfe)	2.69	1.22	2.21	1.25

* Additions to reserves = year-end proved reserves + production + dispositions to partnerships - beginning of year proved reserves.

See Slide 2 regarding Forward Looking Statements

Acreage Inventory

Area	Lease Gross Acres	PDC Net Acres	Net Developed Acres	Net Undeveloped Acres	State
Grand Valley	7,826	7,826	2,660	5,166	Colorado
Wattenberg	75,919	67,418	43,458	23,960	Colorado
NECO	141,654	112,474	19,276	93,198	Colorado/Kansas
Michigan	26,793	23,253	14,795	8,458	Michigan
New York	19,546	16,612	0	16,612	New York
North Dakota	75,132	51,094	4,767	46,327	North Dakota
Appalachian Basin	120,745	115,763	112,989	2,774	WV / PA
Wyoming	19,479	19,253	95	19,159	Wyoming
Texas Barnett	12,490	9,550	400	9,150	Texas
Total	499,584	423,244	198,440	224,804	
			PDC TOTAL NET	423,244	

See Slide 2 regarding Forward Looking Statements

2009 CAPEX

	2008	2009	%Change
Net Development Capital (MM$)	258	90 to 102	-65% to -60%
Exploration, Land, G&G (MM$)	18	5	-72%
Acquisitions	13	0	-100%
Miscellaneous Capital (MM$)	34	13	-62%
Total Net Capital (MM$)	$323	$108 to $120	-67% to -63%

See Slide 2 regarding Forward Looking Statements

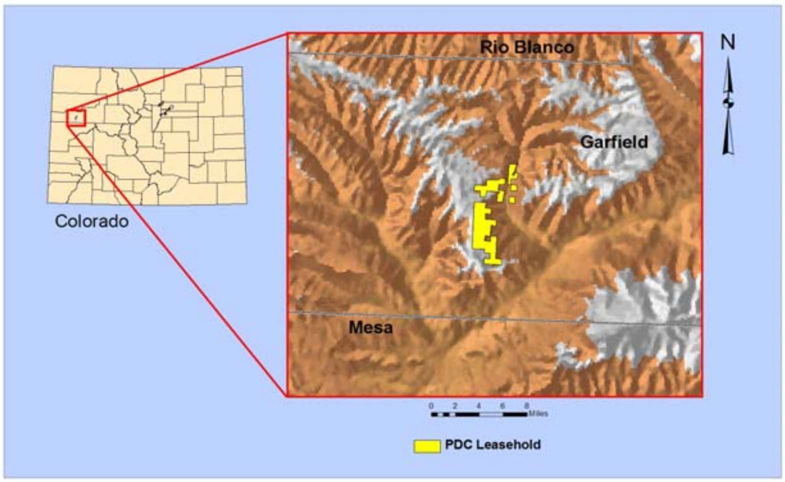
Operations Forecast
2008 vs. 2009

	2008	2009E	% Change
Total Net Production (Bcfe)	39	42.5 – 44	10% - 14%
Gross Exit Rate (MMcfe/d)	214	180 – 184	-16% to -14%
Net Exit Rate (MMcfe/d)	122	109 – 112	-11 to -8%
Net Development Capital (MM$)	$258	$90 - $102	-65% to -60%
Gross Number of Drilling Projects Gross	379	105 - 155	-72 to -59%
Gross Number of Other Projects	165	40	-76%

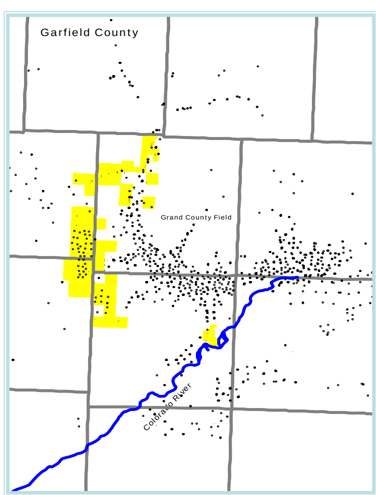
Three Region Focus

- Rocky Mountains
  - Grand Valley Field – Piceance Basin
  - Wattenberg Field – DJ Basin
  - NECO – DJ Basin
- Appalachian Basin
- Michigan Basin

Grand Valley Field



Grand Valley Field



- Gross operated wells at year end 285
- Undeveloped acreage 5,166
- 449 undeveloped 10 acre locations
- 359 PDC, 90 PDC and Partners (18 net PDC) <u>377 total net PDC</u>
- Number of net remaining locations
  - PUD 232
  - Probable 100
  - Possible 45

Key Economics Parameters Grand Valley Field

• Reserves per well*	1.5 Bcfe
• IP rate*	982 Mcfed
• Gross Cost Per Well	$2.5 MM
• Working Interest	84%
• Net Revenue Interest	70%
• Operation Cost/Well/Month	$3,400
• Well Life*	40 Years

*** Mesa type curve**

2009 Proposed Development Grand Valley Field

	2008	2009	% Change
Total Net Production (Bcfe)	12.5	16.1	29%
Net Exit Rate (MMcfe/d)	42.8	38.3	-11%
Total Net Capital (MM$)	$110.7	$33.7	-70%
Drilling Projects, Gross (Net)	62 (54)	0 (0)	-100%

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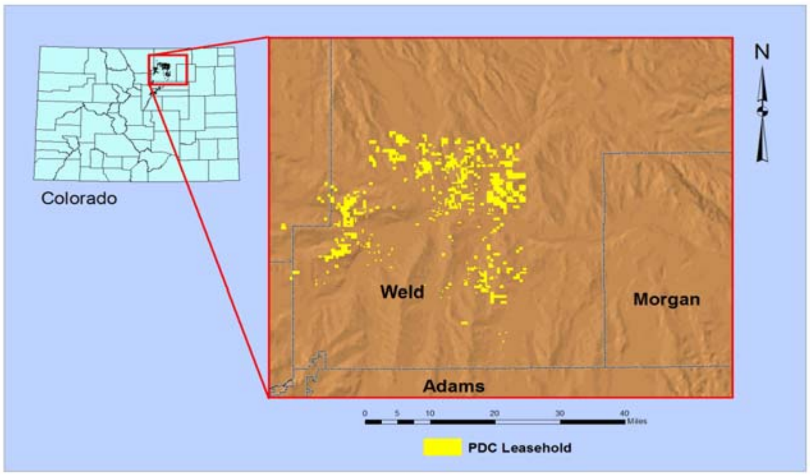
Wattenberg Field



See Slide 2 regarding Forward Looking Statements

29

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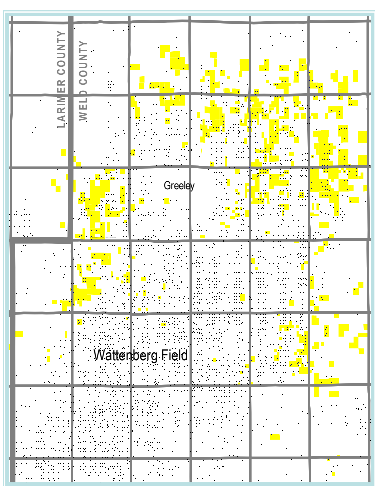
Wattenberg Field



- Gross Operated wells at year end 1,321
- Undeveloped acreage 23,960
- Undeveloped locations 1,566
- 754 PDC, 393 PDC and Partners (145 Net PDC) 899 total net PDC
- Number of net remaining locations 899
  - PUD 383
  - Probable 392
  - Possible 124

See Slide 2 regarding Forward Looking Statements

30

Key Economics Parameters
Wattenberg Field – Codell/Niobrara

• Reserves per well*	0.275 Bcfe
• IP rate*	140 Mcfd, 17 Bbl/d
• Gross Cost Per Well	$625K
• Working Interest	84%
• Net Revenue Interest	67%
• Operation Cost/Well/Month	$900
• Well Life*	30 Years

*67W Codell/Niobrara type curve

See Slide 2 regarding Forward Looking Statements

2009 Proposed Development
Wattenberg Field

	2008	2009	% Change
Total Net Production (Bcfe)	15.4	15.4	0%
Net Exit Rate (MMcfe/d)	47.1	43.2	-8%
Total Net Capital (MM$)	$107.2	$53.1	-50%
Drilling Projects, Gross (Net)	149 (123)	93 (72)	-38% (-41%)
Other Projects, Gross (Net)	106 (102)	0 (0)	-100%

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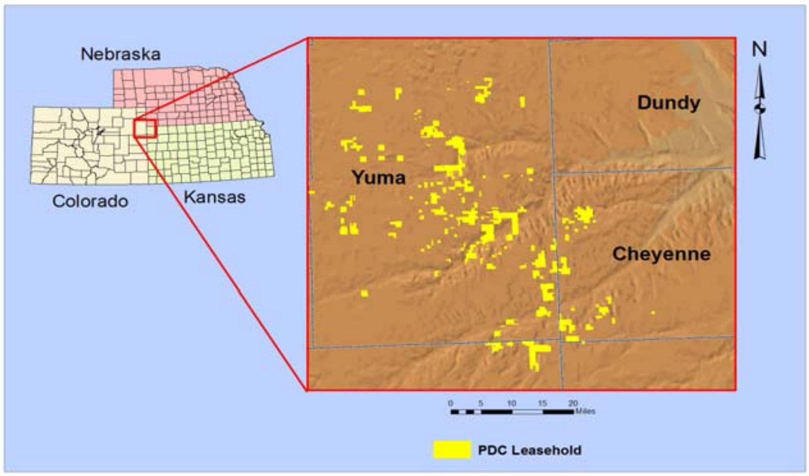
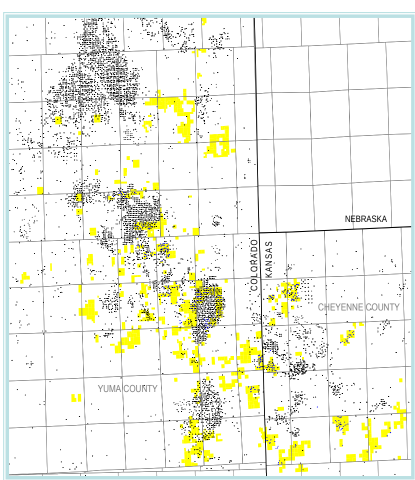
NECO Area



NECO Area



Gross operated wells at year end	500
Undeveloped acreage	93,198
Undeveloped locations	289
No Partnerships	
Number of Remaining Net Locations	271
• PUD	45
• Probable	74
• Possible	152

Key Economics Parameters NECO Area

• Reserves per well*	0.188 Bcfe
• IP rate*	93 Mcfd
• Gross Cost Per Well	$240K
• Working Interest	94%
• Net Revenue Interest	77%
• Operation Cost Well/Month	$920
• Well Life*	25 Years

***Shallow Niobrara type curve**

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35

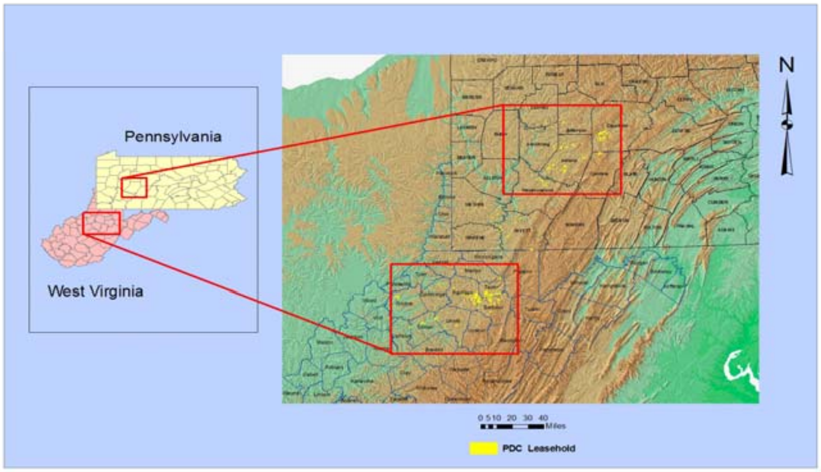
2009 Proposed Development NECO Area

	2008	2009E	% Change
Total Net Production (Bcfe)	**5.0**	**5.3 to 5.8**	**6% to 16%**
Net Exit Rate (MMcfe/d)	**14.9**	**14.2 to 17.2**	**-5% to 15%**
Total Net Capital (MM$)	**$18.1**	**$0 to $12.0**	**-100% to -34%**
Drilling Projects, Gross	**98**	**0 to 50**	**-100% to -49%**

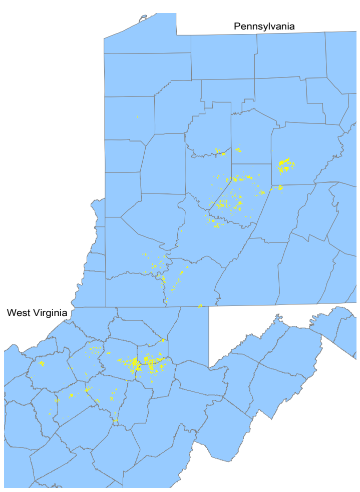
See Slide 2 regarding Forward Looking Statements

36

Appalachian Operating Area



Appalachian Basin



- Gross operated wells at year end 2,114
- Undeveloped acreage 2,774
- Undeveloped locations (No Partnerships) 547
- Number of remaining locations
  - PUD 375
  - Probable 94
  - Possible 76

Key Economics Parameters Appalachian Basin

• Reserves per well*	0.185 Bcfe
• IP rate*	115 Mcfd
• Gross Cost Per Well	$300K
• Working Interest	100%
• Net Revenue Interest	85%
• Operation Cost Well/Month	$345
• Well Life*	51 Years

*Harrison County Devonian Shale Type Curve

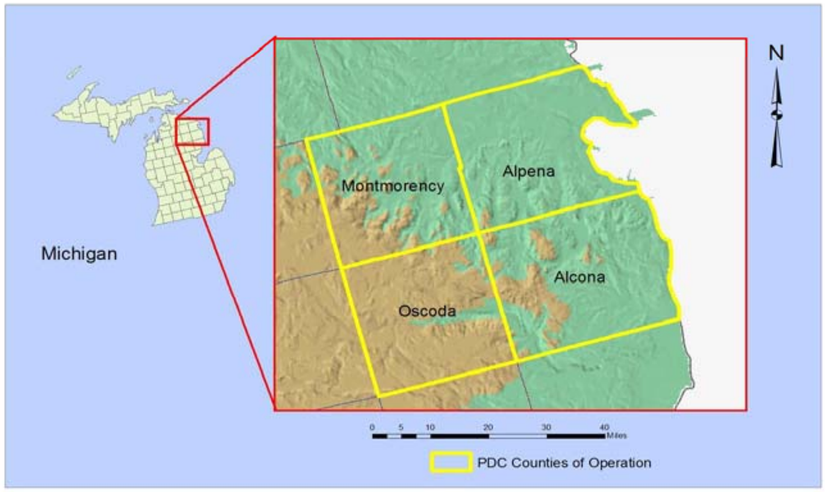
See Slide 2 regarding Forward Looking Statements 39

2009 Proposed Development Appalachian Basin

	2008	2009	% Change
Total Net Production (Bcfe)	3.9	4.4	13%
Net Exit Rate (MMcfe/d)	11.7	11.7	0%
Total Net Capital (MM$)	$18	$7.1	-61%
Drilling Projects, Gross (Net)	62 (62)	12 (12)	-81%
Other Projects, Gross (Net)	21 (21)	40 (40)	90%

See Slide 2 regarding Forward Looking Statements 40

Michigan



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Michigan

Gross operated wells at year end	210
Undeveloped acreage	8,458
Undeveloped locations	0

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2009 Proposed Development Michigan Basin

	2008	2009	% Change
Total Net Production (Bcfe)	1.6	1.5	-6%
Net Exit Rate (MMcfe/d)	4.4	4.1	-7%
Total Net Capital (MM$)	$0.2	$0	-100%
Drilling Projects, Gross (Net)	0 (0)	0 (0)	0%

Other Operating Areas

- North Dakota
  - 51,094 acres Burke County
  - Exploration drilling in 2009
- Barnett
  - 9,550 acres Erath County
  - No planned activity 2009

2009 Operations Guidance

- 42.5–44 Bcfe total production
- Capex of $108 - $120 MM
- 105 - 155 wells
- Significant Capex slowdown
- Focus on drilling costs/LOE reductions
- Capex expected to be in line with anticipted cash flow
- Flexibility to adjust Capex to respond to market conditions

Marcellus Shale Highlights

- Two vertical wells completed and on line
  - Initial rates from 376 Mcfd to 232 Mcfd
- One vertical well completed and on flow back
- One vertical well waiting on completion
- Typical shale analysis being conducted
  - Two cores currently being evaluated
  - Shale indicators have provided positive feedback
    - Electric logs
    - Gas analysis
    - Early core data

Future Plans
Marcellus Shale

- Drill five additional vertical tests
  - Evaluate greater geographic area
  - Test completion types
  - Continue to establish shale quality
- Determine proper location for horizontal test
- Establish midstream and downstream strategy for full development

See Slide 2 regarding Forward Looking Statements 47

2009 Cost Management

	Capital		Lease Operating Expense	
	Projected Cost Reduction Per Well by July 2009	Projected % Savings by July 2009	Projected Cost Savings Per Month by July 2009	Projected % Savings Per Month by July 2009
Piceance	$590,000	22	$176,000	15
Wattenberg	168,000	20	210,000	14
NECO	51,000	21	62,000	13
East	37,050	9	98,000	10

See Slide 2 regarding Forward Looking Statements 48

Takeaways

- PDC's inventory is low risk, predictable reserve projects
  - 2009 Capex is dramatically reduced
    - Lower natural gas prices
    - Capital cost increases 2005 – 2008
    - Capital market environment
- PDC has built an exceptional technical/geoscience team over the past several years
  - Prepared for increased activity on existing assets
  - Apply organizational strength to possible acquisitions
- 2009 Capex will be reduced with intensified focus on:
  - Capital cost improvements
  - Production engineering / production optimization
  - LOE improvements
- Marcellus shale provides production / reserve opportunity
  - Define opportunity in 2009
  - Partial to full implementation in 2010
- PDC is proactively managing operations as the market fluctuates
  - Rockies rig count is dramatically reduced
  - Costs are improving very quickly
  - PDC is maintaining full operational flexibility
  - Every project is evaluated as market fluctuates

See Slide 2 regarding Forward Looking Statements

49

Gysle Shellum

Chief Financial Officer

50

2008 Summary Financial Results

($ in millions, except for per share data)

	Year Ended December 31,	
	2008	2007*
Income from operations	$202.3	$60.8
Net income	$113.3	$33.2
Diluted earnings (per share)	$7.63	$2.24
Production (Bcfe)	38.7	28.0
Realized gas prices (per Mcfe) (1)	$8.66	$6.52
Unrealized hedging gains	$118.4	($4.4)

(1) Equivalent prices including oil sales, natural gas liquids and realized derivative gains and losses. Excludes non-realized derivative gains & losses

* 2007 data includes a $33 million gain on leasehold sales.

See Slide 2 regarding Forward Looking Statements

2008 Summary Financial Results

($ in millions, except for per share data)

	Year Ended December 31,	
	2008	2007
O&G Revenues	$321.9	$175.2
O&G Production & Well Operating Costs	$78.2	$49.3
O&G Operating Margin(1)	$243.7	$125.9
Adjusted Net Income(2)	$44.6	$37.5
Adjusted Cash Flow from Operations(2)	$200.1	$95.6
Adjusted Cash Flow from Operations (per share) (2)	$13.48	$6.44
DD&A	$104.6	$70.8
G&A	$37.7	$31.0

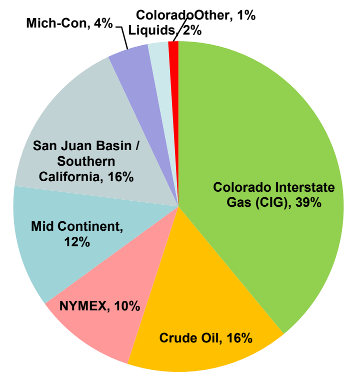
(1) O&G operating margin is defined as O&G sales less O&G production and well operations costs.
(2) See slides 66 - 68 for GAAP reconciliation of Adjusted EBITDA, Adjusted Cash Flow and Adjusted Net Income, respectively.

See Slide 2 regarding Forward Looking Statements

Petroleum Development Corporation

Energy Market Exposure

Percentage of Mcfe Sold by Market
(for Twelve Months Ended December 31, 2008)



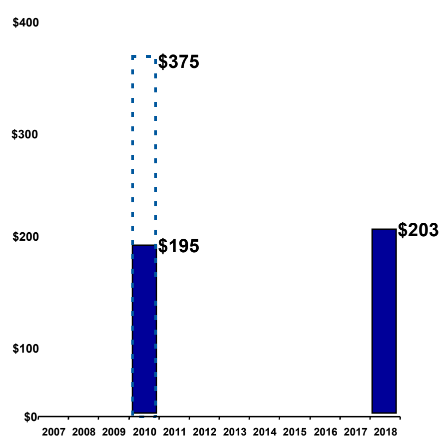
See Slide 2 regarding Forward Looking Statements

Petroleum Development Corporation

Debt Maturity Schedule

($ in millions)

- $375 million revolver matures November 4, 2010
- Maturity schedule reflects:
  - Mitigation of liquidity risk
  - Diversification of funding sources
- As of December 31, 2008:
  - $195 MM drawn balance
  - $51 MM cash balance
  - $231MM available liquidity
- April 2009 borrowing base redetermination



See Slide 2 regarding Forward Looking Statements

CAPEX Spending & Production Growth

	2008	2007	2006
CAPEX Total ($MM)	$323	$239	$147
CAPEX Developmental ($MM)	$258	$194	$115
Organic Production Growth(1)	38%	32%	20%
Total Production Growth(1)	38%	65%	24%

(1) Internal estimate.

2009 Guidance

2009 Assumptions(1)

- Reserves, production and capital expenditures per the internal operational plan
- Production taxes and direct operating costs determined on a field-by-field basis
- SG&A flat with 2008
- DD&A based on field-by-field depreciation analysis

(1) The Company does not intend to update these estimates during the year.

2009 Assumptions(1), cont'd.

- Revolver interest rate at pricing grid plus LIBOR spread
- $203 MM Senior Notes interest yield of 12.25%
- 2009 commodity pricing based on high and low NYMEX Gas/Oil cases
- Differentials (NYMEX Gas/Oil) determined on field by field basis, averaged 21% / 12% for gas and oil, respectively
- 50% of exploration expenditures expensed. No production or reserve impacts from exploration activities

Derivative Positions

(as of March 16, 2009, in MMBtu)

- PDC's implemented hedge positions provide stable, predictable cash flows[(1)]

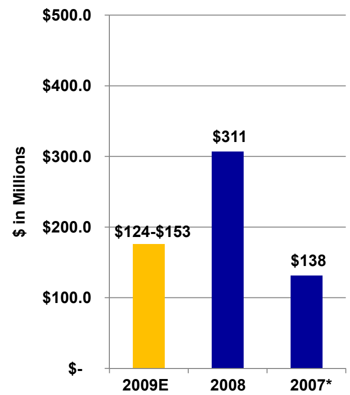
			Floors		Ceilings		Swaps	
Index	**Begin**	**End**	**Quantity (000's)**	**$ Price**	**Quantity (000's)**	**$ Price**	**Quantity (000's)**	**$ Price**
CIG	Jan-09	Mar-11	13,798	6.08	13,798	9.62	13,050	6.14
CIG - Basis	Apr-10	Dec-13					23,168	(1.88)
NYMEX – Gas	Jan-09	Mar-12	4,719	7.88	4,719	13.78	6,781	8.37
PEPL – Gas	Jan-09	Mar-11	3,730	6.56	3,730	11.08	2,110	8.50
NYMEX – Oil [(1)]	Jan-09	Dec-10					6,390	15.27

1) Conversion factor for oil: 1 barrel = 6.0 MMBtu.

2009 Earnings Guidance

	Low	High
Total E&P Revenue	$233	$274
Production Taxes	10	13
Operating Expenses	61	61
G&A	34	38
EBITDAX	$128	$162
Exploration Expense	5	5
DD&A	108	108
Net Interest Expense	34	33
Taxes	(5)	4
Net Income	($14)	$12
Stock-based Compensation	5	5
DD&A	108	108
Exploratory / Dry Hole Cost	5	6
Other	1	(4)
Cash Flows from Operations	$105	$127
OP CFPS	$7.06	$8.54

Adjusted EBITDA



- EBITDA represents Net Income + Interest Expense + Income Taxes + Depreciation, Depletion and Amortization
- 2008's EBITDA reflects higher prices of 30% and higher production of 38% vs. 2007
- 2009's EBITDA reflects higher production offset by lower prices vs. 2008

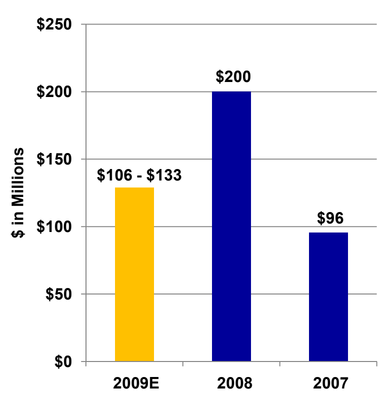
*2007 includes a gain on sale of leaseholds of $33 MM. 2008 includes an unrealized derivative gain of $118 MM.

Note: See slide 68 for GAAP reconciliation.

See Slide 2 regarding Forward Looking Statements

61

Adjusted Cash Flow from Operations



- Adjusted cash flow from operations represents cash flow from operations before impact of working capital.

Note: See slide 67 for GAAP reconciliation.

See Slide 2 regarding Forward Looking Statements

62

Costs Related to Oil and Gas Drilling (per Mcfe)

	2009E	2008	2007
Average lifting costs	$0.98	$1.07	$0.90
DD&A (O&G properties only)	$2.44	$2.51	$2.37

See Slide 2 regarding Forward Looking Statements

2009 Guidance Qualitative Comments

- Strong financial position
  - Conservative relative debt metrics support opportunistic growth strategy
  - Strong relative liquidity position
- Existing reserve base provides significant growth potential
  - Predictable low-risk production profile
- Realized prices will have greatest impact on results

See Slide 2 regarding Forward Looking Statements

2008 Financial Results

APPENDIX

Adjusted EBITDA Reconciliation

($ in millions)

	2009E		2008	2007
	Low	High		
Net income	($14.0)	$12.0	$113.3	$33.2
Gain on sale of leaseholds	-	-	-	(33.3)
Unrealized derivative (gain) loss	-	-	(118.4)	4.4
Interest, net	34.0	33.0	27.5	6.6
Income taxes	(5.0)	4.0	61.5	21.0
Depreciation	108.0	108.0	104.6	70.8
Other	1.0	(4.0)	4.0	1.5
EBITDA	124.0	153.0	192.5	104.2

See Slide 2 regarding Forward Looking Statements

Adjusted Cash Flow Reconciliation

($ in millions)

	2009E	2008	2007
Net Cash provided by Operating Activities	$105.0 - $127.0	$139.1	$60.3
Changes in Assets & Liabilities Related to Operations	$1.0 - $6.0	61.0	35.3
Adjusted Cash Flow from Operations	$106.0 - $133.0	$200.1	$95.6

See Slide 2 regarding Forward Looking Statements

Adjusted Net Income Reconciliation

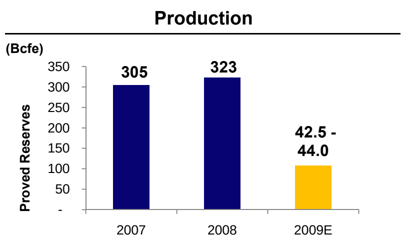
($ in millions)

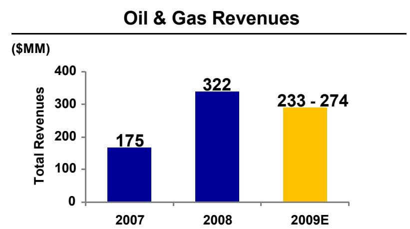
	2009E	2008	2007
Net income	$(14) to $12	$113.3	$33.2
Unrealized derivative (gain) loss	-	(118.4)	4.4
Tax effect[1]	-	45.7	(1.6)
Other	-	4.0	1.5
Adjusted net income	$(14) to $12	$44.6	$37.5

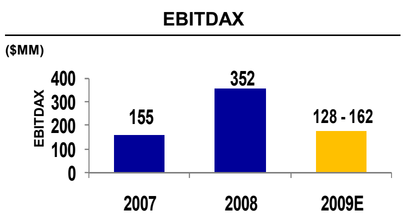
(1) Tax rate exclusive of discrete items.

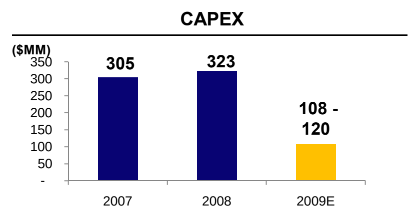
See Slide 2 regarding Forward Looking Statements

2007-2009E Financial Metrics



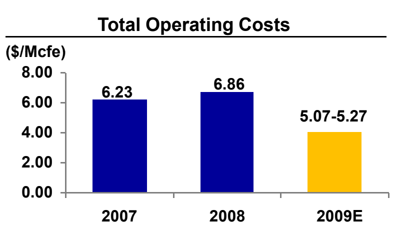


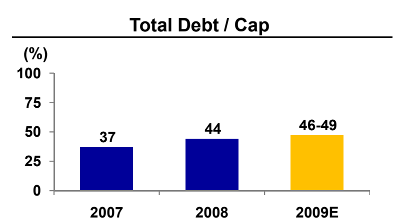


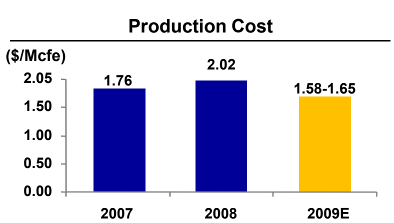


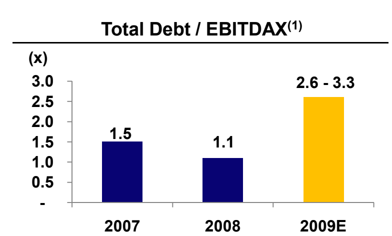
See Slide 2 regarding Forward Looking Statements

2007-2009E Operating & Credit Metrics









(1) Earnings before interest, taxes, depreciation, depletion and amortization and exploration expense

See Slide 2 regarding Forward Looking Statements

Petroleum Development Corporation

2009 Analyst Day

March 19, 2009

NASDAQ:PETD