This presentation contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 ("Securities Act") and Section 21E of the Securities Exchange Act of 1934 ("Exchange Act") regarding PDC Energy’s ("PDC" or the "Company") business, financial condition, results of operations and prospects. All statements other than statements of historical facts included in and incorporated by reference into this report are "forward-looking statements" within the meaning of the safe harbor provisions of the United States ("U.S.") Private Securities Litigation Reform Act of 1995. Words such as expects, anticipates, intends, plans, believes, seeks, estimates, outlook, and similar expressions or variations of such words are intended to identify forward-looking statements herein. These statements relate to, among other things: estimated natural gas, natural gas liquids ("NGLs") and crude oil reserves; future production (including the components of such production), expenses, cash flows, margins; rates of return; liquidity; prices, debt levels, earnings, EBITDAX, EBITDA and reserves; anticipated capital projects, expenditures and opportunities, including drilling locations and downspacing potential; future exploration and development activities; availability of additional midstream facilities and services and timing of that availability; availability of sufficient funding for PDC’s capital program and sources of that funding; potential for infrastructure projects to improve the Company’s NGL pricing; PDC’s compliance with debt covenants; the future effect of contracts, policies and procedures PDC believes to be customary; effectiveness of the Company’s derivative program in providing a degree of price stability; closing of, and expected proceeds from, PDC’s pending Colorado asset disposition; and the Company’s future strategies, plans and objectives.

The above statements are not the exclusive means of identifying forward-looking statements herein. Although forward-looking statements contained in this presentation reflect PDC’s good faith judgment, such statements can only be based on facts and factors currently known to the Company. Consequently, forward-looking statements are inherently subject to risks and uncertainties, including known and unknown risks and uncertainties incidental to the exploration for, and the acquisition, development, production and marketing of natural gas, NGLs and crude oil, and actual outcomes may differ materially from the results and outcomes discussed in the forward-looking statements.

Estimates of non-proved reserves are subject to significantly greater risk of not being produced than proved reserves. Initial and test results from a well are not necessarily indicative of the well’s long-term performance.

Further, PDC urges you to carefully review and consider the cautionary statements and disclosures, specifically those under Item 1A, Risk Factors, made in the Company’s Annual Report on Form 10-K for the year ended December 31, 2012 and PDC’s other filings with the U.S. Securities and Exchange Commission ("SEC") for further information on risks and uncertainties that could affect the Company’s business, financial condition, results of operations and cash flows. PDC cautions you not to place undue reliance on forward-looking statements, which speak only as of the date of this presentation. PDC undertakes no obligation to update any forward-looking statements in order to reflect any event or circumstance occurring after the date of this report or currently unknown facts or conditions or the occurrence of unanticipated events. All forward-looking statements are qualified in their entirety by this cautionary statement.
Introduction

• This presentation is targeting the smaller Wattenberg Operator that is just getting started or considering horizontal development plans in the future.

• Though PDC Energy is the third largest producer and lease holder in the Wattenberg with 99,000 net acres\(^{(1)}\) and over 2,500 producing wells, we are a “small-cap” company with different challenges than our “larger cap” colleagues.

• One advantage PDC had making the transition to Niobrara horizontal development was a technical team experienced in the Bakken Shale dating back to 2005 and then later in the Barnett Shale.

• In addition to the Wattenberg Field, PDC is actively drilling horizontal wells in the Marcellus and Utica Shales and has no plans of drilling any vertical wells this year.

\(^{(1)}\) Pro-forma for Non-core Colorado asset divestiture
Project Considerations & Initiation

Financial Considerations

- Why should you drill horizontal wells in Wattenberg
  - Greater returns/higher profitability
    - IRR of 40% – 140%\(^{(1)}\)
  - Typical EURs from 300 to 500 MBoe
  - Strong repeatable results

- Challenges associated with horizontal development
  - High outlay of cost per well if something goes wrong
  - Multi well pad production delays
  - Potential impact to existing vertical well production

- Capital constraints
  - Six times more expensive than Niobrara/Codell vertical wells with AFE’s ranging from $4MM to $5MM for a 4,000’ lateral length well
  - More difficult to fund a continuous drilling program which could impact efficiencies
  - Delays in delineating acreage potential

\(^{(1)}\) Flat Pricing: $90 NYMEX Oil, $3.50 NYMEX Gas
• Drill site considerations
  – Larger pad size to accommodate drilling equipment, number of wells to be drilled, water needs for completion operations (5 to 10 acres)
  – Tank battery & production equipment location
    • Have ready during flowback operations
    • Balancing utilization of pad with other activities
  – Lease road design to accommodate increase in traffic

• Well design and layout
  – A limited acreage position could determine layout
  – Lateral length and orientation
    • Optimal length – point of diminishing returns
    • Rig and equipment limitations
    • Orientation
  – Target formation – Niobrara A, B, C or Codell
    • What zones are present in the target area
    • What are the communication & drainage considerations
    • Faulting influences during drilling & completions
Project Considerations & Initiation

• Down spacing impact to vertical well production
  – Communication from horizontal frac
  – Impact on the present value of the well
  – Vertical wellbore integrity
  – Impact on horizontal reserves

• Increase in Land and Lease activity
  – Larger drilling units
    • 320 acre drilling unit versus 20 for vertical wells
    • Increased number of working interest partners
    • Additional notifications
  – Larger drilling pad
    • Crop considerations & damages
  – More work related to JOA’s, JIB’s and Non-Op’s
Drilling Considerations

• Rig type
  – Fit for purpose or conventional
    • Rig availability may dictate
    • Conventional rigs work fine/modifications

• Mud system
  – Water base mud
  – Reaming
  – Polymer beads
  – Closed loop with no reserve pit

• Steering
  – Gyro offset vertical wells
  – Beware of faulting influences
    • Staying in zone bigger issue with Codell
  – Good communication with mudloggers, directional personnel and geology team
Conventional drilling rig operating at 9 days spud to TD; ~13 days spud to spud
Potential Drilling Issue

Staying in Zone

Stages 2-4 in Carlile

Lost gas

4/15/2013 9
Completion Considerations

- Casing design – consider premium grade tubular & connections

- Packer & sleeves versus plug and perf
  - PDC has done both with similar results

- Frac design
  - Fluid type
    - X-link gel, slick water
  - Number of stages: 200’ to 250’ intervals
  - Stage size
    - Fluid type, number of stages, formation parameters

4 ½” heel section
Completion Considerations

- Contingent on spacing, complete all wells on multi well pad before flowing back & producing wells

- Water logistics
  - Availability & access to a water supply
  - Water volume needed
    - 60,000 to 80,000 bbls per well
    - 240,000 to 320,000 bbls – 4 well pad
  - Tanks/large capacity pools/lined earthen pits
    - Tanks need more room, more trucking, but more secure
    - Pools can develop leaks, higher cost, but use less room per barrel
    - Pits need permits, fresh water only, may not work in agriculture fields, but could be feasible in a centralized water facility

- Flowback
  - Large capacity 3-phase separators
  - Flowback crews 24/7 during the short term
  - 24 hour oil recovery; plan oil trucks accordingly
R & D Considerations

- Capex impacts
- 3D seismic
- Micro-seismic Fracture Mapping
- Horizontal well logging
- Frac fluid tracer chemicals
- Production logging

Image Log in horizontal wellbore showing faults and micro-seismic fracture mapping 3-well pad
Ideally, the minimum number of wells drilled within a spacing unit to efficiently and economically drain the reservoir.

Number of wells needed is dependent on:
- Permeability
- Porosity
- Thickness
- Extent
- Frac size
- Acreage position

Two trains of thought on how many wells:
- Cash flow
- Economics
Down Spacing

• Micro-seismic fracture mapping & reservoir modeling
  – Help determine height and width of frac stages
  – Micro-seismic shows possible room for down spacing
  – Reservoir modeling to understand drainage area

3-well pad on a 320 acre unit
Tracer & Ion Concentrations vs. Time

The Completions Diagnostics Company ProTechnics
Down Spacing

- 8 wells per 320 acres
- Alternating Codell & Niobrara
- Laterals about 335’ apart
- Using tracers & fracture mapping