Memorial Resource Development Corp.
Form 425
June 27, 2016

Company Presentation
June 27, 2016
FILED BY RANGE RESOURCES CORPORATION PURSUANT TO RULE 425
UNDER THE SECURITIES ACT OF 1933 AND DEEMED FILED PURSUANT TO
RULE 14a-12 UNDER THE SECURITIES EXCHANGE ACT OF 1934
REGISTRATION NO. 333-211994
SUBJECT
COMPANY: MEMORIAL RESOURCE DEVELOPMENT CORP.

FILE NO. 001-36490

2

Forward-Looking Statements

This communication contains certain forward-looking statements within the meaning of federal securities laws, including w
Securities Litigation Reform Act of 1995 that are not limited to historical facts, but reflect Range s and MRD s current belief
such as may, will, could, should, expect, plan, project, intend, anticipate, believe, estimate,
expressions are intended to identify such forward-looking statements. The statements in this press release that are not historica
timetable for completing the proposed transaction, benefits and synergies of the proposed transaction, costs and other anticipat
combined company s plans, objectives, future opportunities for the combined company and products, future financial perform

regarding Range s and MRD s future expectations, beliefs, plans, objectives, financial conditions, assumptions or future even
looking statements within the meaning of the federal securities laws.

Furthermore, the statements relating to the proposed transaction are subject to numerous risks and uncertainties, many of whicl
cause actual results to differ materially from the results expressed or implied by the statements. These risks and uncertainties i
votes of Range s or MRD s shareholders; the timing to consummate the proposed transaction; satisfaction of the conditions to
that the closing of the proposed transaction otherwise does not occur; the risk that a regulatory approval that may be required f
subject to conditions that are not anticipated; the diversion of management time on transaction-related issues; the ultimate timi
Range and MRD; the effects of the business combination of Range and MRD, including the combined company s future finan
potential adverse reactions or changes to business relationships resulting from the announcement or completion of the propose
the proposed transaction and the ability of Range to realize such synergies and other benefits; expectations regarding regulator
settlements and investigations; and actions by third parties, including governmental agencies; changes in the demand for or pri
by weakness in the worldwide economy; consequences of audits and investigations by government agencies and legislative bo
proceedings by such agencies; compliance with environmental laws; changes in government regulations and regulatory require
exploration; compliance with laws related to income taxes and assumptions regarding the generation of future taxable income;
customers; delays or failures by
customers to make payments owed to us; impairment of oil and natural gas properties; structural changes in the oil and natural
maintaining a highly skilled workforce.

Range s and MRD s respective reports on Form 10-K for the year ended December 31, 2015, Form 10-Q for the quarter ende
other SEC filings discuss some of the important risk factors identified that may affect these factors and Range s and MRD s r
condition. Range and MRD undertake no obligation to revise or update publicly any forward-looking statements for any reaso
these forward-looking statements that speak only as of the date hereof.

The SEC permits oil and gas companies, in filings made with the SEC, to disclose proved reserves, which are estimates that ge
certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions as well as
Range has elected not to disclose the Company s probable and possible reserves in its filings with the SEC. Range uses certai
resource potential, "unproved resource potential" or "upside" or other descriptions of volumes of resources potentially recove
that may include probable and possible reserves as defined by the SEC's guidelines. Range has not attempted to distinguish pr
classifications. The SEC s rules prohibit us from including in filings with the SEC these broader classifications of reserves. T
estimates of proved, probable and possible reserves and accordingly are subject to substantially greater risk of actually being re
internal estimates of hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with
reviewed by independent engineers. Unproved resource potential does not constitute reserves within the meaning of the Societ
Management System and does not include proved reserves. Area wide unproven resource potential has not been fully risked b
recovery, refers to our management s estimates of hydrocarbon quantities that may be recovered from a well completed as a p
constitute or represent reserves within the meaning of the Society of Petroleum Engineer s Petroleum Resource Management
Actual quantities that may be recovered from Range's interests could differ substantially. Factors affecting ultimate recovery i
directly affected by the availability of capital, drilling and production costs, commodity prices, availability of drilling and com
transportation constraints, regulatory approvals, field spacing rules, recoveries of gas in place, length of horizontal laterals, act
and mechanical factors affecting recovery rates and other factors. Estimates of resource potential may change significantly as
data.

In addition, our production forecasts and expectations for future periods are dependent upon many assumptions, including esti
the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drill
the disclosure in our most recent Annual Report on Form 10-K, available from our website at www.rangeresources.com or by
Worth, Texas 76102. You can also obtain this Form 10-K on the SEC s website at www.sec.gov or by calling the SEC at 1-8

3

Range s Keys for Success

High quality, large scale acreage position containing repeatable projects with good returns improving further as costs are reduced

Low cost structure with ability to continue driving costs down

Improving capital efficiency

New takeaway capacity projected to improve realizations for natural gas, NGLs and condensate

Shallow base decline rate, 19% in 1st year, allows a minimal level of capex to hold production flat, ~$300 million for 2017

Low-cost takeaway capacity with built-in flexibility

Strong 2016 hedges and ample liquidity with no near-term debt maturities

4
Driving Down Unit Costs
2011
2012
2013
2014
2015
2016E

DD&A
$1.69
$1.62
$1.44
$1.30
$1.14
$0.96
(2)
LOE
(1)
$0.60
$0.41
$0.36
$0.35
$0.26
$0.23
Prod. Taxes
$0.14
$0.15
$0.13
$0.10
$0.07
$0.06
G&A
(1)
$0.56
$0.46
$0.42
$0.35
$0.27
$0.24
Interest
$0.69
$0.61
$0.51
$0.40
$0.33
$0.29
Trans. &
Gathering
$0.62
$0.70
$0.75
$0.76
$0.78
Total
$4.30
$3.95
$3.61
$3.26

$2.85
$2.58
$0.00
(1)
Excludes non-cash stock compensation
(2)
1Q 2016 DD&A was $0.96
(3)
Includes additional NGL & natural gas firm transport agreements. Propane transport costs were previously netted against NGI
Incremental natural gas & NGL revenue, including additional ethane production, will more than offset the 2016 increase in trai
(4) Expected improvement in differentials as a result of additional transportation capacity
($0.25)
(4)
$1.05
(3)
$0.50
$1.00
$1.50
$2.00
$2.50
$3.00
$3.50
$4.00
$4.50

5

Near-Term Price Enhancements

Range will be able to utilize a full year of Spectra s Uniontown to Gas City project, which takes ~200 Mmcf per day of Range gas production from local Appalachia M2 to Midwest markets

Additional takeaway projects could strengthen local pricing differentials

Range is the only producer with capacity on the Mariner East project to Marcus Hook

20,000 barrels per day of ethane transportation to fulfill contract with INEOS

20,000 barrels per day of propane transportation with access to international propane markets

Range initiated a new marketing arrangement in 3Q15 which improved Marcellus condensate net realized prices
Natural Gas Differential
Natural Gas Differential
NGL (Natural Gas Liquids) Differential
NGL (Natural Gas Liquids) Differential
Condensate Differential
Condensate Differential
$0.00
Midpoint
Midpoint
Midpoint
$(0.62)
$(0.42)
$(0.70)
$(0.60)
$(0.50)
$(0.40)
$(0.30)
$(0.20)
$(0.10)
2015
2016E
RRC Marcellus NG Differential to NYMEX
18%
24%
0%
5%
10%
15%
20%
25%
30%
2015

2016E
RRC Corporate NGL Price as % of WTI
$(14.93)
$(13.50)
$(15.50)
$(15.00)
$(14.50)
$(14.00)
$(13.50)
$(13.00)
$(12.50)
2015
2016E
RRC Corporate Condensate Differential to WTI

6
Mariner East: Opening New Lanes
First
Ethane
Shipments

Faster
Propane

Loading
Combined
with
VLGC
Ships
A ship waits in the harbor as another ship is being loaded.

Range is the only producer with
current capacity on Mariner East

Historic first shipments of ethane from
U.S. to Europe

Optionality of selling propane
internationally or in local markets

Expect uplift in ethane and propane
realizations in 2016 for Range
Ethane loading in progress

7
First VLGC Loading of Range Propane for Export

8
Regional Direction
Projected
Avg. 2016
Projected
Avg. 2017
Mmbtu/day
Transport

Cost
per Mmbtu
Mmbtu/day
Transport
Cost
per Mmbtu
Firm Transportation
Appalachia/Local
390,000
$ 0.20
325,000
$ 0.21
Gulf Coast
295,000
$ 0.30
510,000
$ 0.31
Midwest/Canada
285,000
$ 0.28
330,000
$ 0.30
Northeast
210,000
$ 0.59
210,000
$ 0.59
Total Gross Takeaway
Capacity
1,180,000
$ 0.31
1,375,000
$ 0.35
Total Net Takeaway
Capacity
980,000
$ 0.31
1,140,000
$ 0.35
Estimated Marcellus Differential
to NYMEX
($0.40)

($0.45)
($0.25)

($0.35)
Appalachia Gas Transportation Arrangements
Transportation Portfolio additions improve Range s differentials to NYMEX
Does

not
include
current
intermediary
pipeline
capacity
(gathering)
of
>650,000
Mmbtu/day
and
assumes
full
utilization.
Based
on
pipeline operator s anticipated project start dates.
(1) Based on expected utilization of capacity and forward pricing with differentials as of April 2016
(1)

9
Gas In Place (GIP) Analysis Shows Greatest Potential in SW PA
Note: Townships where Range holds ~2,000+ acres (as of January 2016) and estimated as prospective, are outlined green. GIP
Range estimates.
When
GIP
analysis
from

the Marcellus, Upper Devonian and Point Pleasant are combined, the largest stacked pay resource is located in SW PA where Range has concentrated its acreage position

10
SW/NE Pennsylvania Stacked Pays
Upper Devonian
335,000
180,000
515,000
335,000
290,000

625,000
-
400,000
400,000
670,000 870,000 1,540,000
Marcellus
Utica/Point
Pleasant
Wet
Acreage
Dry
Acreage
Total
Net
Acreage
(1)
(1) Excludes Northwest PA -
280,000 net acres, largely HBP
Stacked pays allow for multiple development opportunities

11
Over 180 Existing Pads Facilitate Future Development

124 pads with 5 or fewer
wells, 59 pads with 6 to 9
wells

Most pads designed to accommodate ~20 wells with the flexibility to drill Marcellus, Utica/Point Pleasant or Upper Devonian formations

Significant time and cost savings are realized
minimal permitting required
reuse of existing roads, surface facilities and gathering system

12
Range Marcellus
2016 Well Economic Summary
See appendix for complete assumptions and data on each area
SW Super-Rich
SW Wet
SW Dry
NE Dry

EUR
16.0 Bcfe
1,450 Mbbls & 7.3 Bcf
20.6 Bcfe
1,756 Mbbls & 10.1 Bcf
17.6 Bcf
14.1 Bcf
EUR/1,000 ft. lateral
2.4 Bcfe
3.0 Bcfe
2.5 Bcf
2.5 Bcf
EUR/stage
485 Mmcfe
589 Mmcfe
503 Mmcf
504 Mmcf
Well Cost
$5.9 MM
$5.8 MM
$5.2 MM
$2.9 MM
Cost/1,000
ft.
lateral
$881 K
$832 K
$743 K
$518 K
Stages
33
35
35
28
Lateral Length
6,660 ft.
6,970 ft.
7,000 ft.
5,660 ft.
IRR -
$3.00
26%
25%
54%
58%
Industry leading EUR/1,000 ft. and Cost/1,000 ft. in SW Appalachia

13
Appalachian Peers Well Cost Comparison
Average
Well Cost*
Average
Lateral Length
Cost
per

1,000 ft.
($000 s)
(feet)
(per 1,000
feet)
Range
$5,630
6,876
$819 K
Peer A
6,300
7,000
900
Peer B
8,500
9,000
944
Peer C
6,700
7,000
957
Peer D
7,350
7,500
980
Peer E
7,100
7,700
925
Peer Average
$7,195
7,640
$942 K
Peer group includes AR, COG, EQT, RICE, SWN. Peer data comes from most recent presentations.
* Costs should include surface facilities.

14
Unhedged Recycle Ratio
Assumed 2017 Natural Gas price*:
~$3.00
Less: 2016 Expected Corp. differential
$0.42
2016 Expected All-in cash unit costs
$1.87

Adjusted Margin
~$0.71
Expected future development
Cost for PUD reserves
$0.40
Unhedged Recycle Ratio
1.8
Recycle Ratio: (Margin divided by F&D)
* Natural gas strip price as of 4/27/16

15
Liquidity and Leverage Outlook (Range pre-merger)

At March 31, 2016, Range had $1.7 billion liquidity under bank commitments, which is
currently
limited
to
$1.2

billion
by
senior
subordinated
note
indentures

$3 billion borrowing base and $2 billion commitment amount under $4 billion credit facility unanimously reaffirmed by bank group, next scheduled redetermination by May 1, 2017

No
note
maturities
until
2021

Bank
facility
subject
to
renewal
in
2019,
with
annual
redeterminations

Bradford County non-operated interest sold 3/28/16 for $110 million of proceeds

Signed agreement to sell 9,200 acres in the STACK play for ~$77 million

Solid, stable coverage on debt covenants

EBITDAX
to
interest

minimum
of
2.5x
(1Q
Actual
4.8x)

PV9
proved
reserves
value
to

debt

minimum
of
1.5x
(1Q
Actual
2.4x)

Hedges on 80% of 2016 production at ~$3.24

16
Range s Keys for Success

Assets, Team, Agreements & Strategy
Low cost structure with
ability to continue driving
costs lower

High-grading asset sales
lowered operating costs

Lower debt balances reduce
interest expense

Headcount reduced by 31% YoY
Improving capital
efficiency

Longer laterals; 2016 plan
average ~7,000 , 2017 plan est.
to average ~8,000

Improved targeting and
completions

Existing pad locations with
facilities and gathering

2017 maintenance capex
estimated at ~$300 million
Better realizations from
additional takeaway
capacity and sales
agreements

Unique marketing arrangements
coming on line

Ability to reach premium markets
and deliver products outside
Marcellus, including international
exports
Low-cost takeaway
capacity with built-in
flexibility

First-mover advantage allowed
Range to secure capacity on
low-cost expansion projects

Anticipated excess infrastructure
build-out and avoided
contracting for excessive firm
transport
Strong 2016 hedges and
ample liquidity

Approximately 80% hedged on

natural gas at ~$3.24 Mmbtu

At 3/31/16, only $31 million
drawn on $2 billion credit facility

2016 program expected to use
cash flow and asset sales,
preserving liquidity
High quality, large scale
acreage position
containing repeatable
projects with good
returns

Optionality and flexibility due to
quality of acreage position,
gathering system, available
locations on existing pads

Further improvements expected

17
Range Resources/Memorial Resource
Development Proposed Merger
Announced May 16, 2016
Closing
expected
late
3

rd
Qtr.
/
early
4
th
Qtr.
2016

18

Highlights of Merger

Core acreage positions in two of the most prolific high-quality natural gas plays in North America

Immediately cash flow accretive and credit enhancing

Combination of two low-cost gas producers with opportunities to drive costs lower, improve returns and increase cash flow

Complementary assets positioned near expanding natural gas and NGL demand centers

19
Transaction Details
Consideration

Range Resources (Range) merges with Memorial Resource Development (MRD) for 0.375 shares of Range per MRD share; All-stock transaction

Implied value of $15.75 per MRD share, a 17% premium based on closing prices as of May 13, 2016

Pro Forma Ownership and Corporate Governance

MRD shareholders will own ~31% of the combined company

MRD will have the right to nominate an independent director to a seat on Range s Board

Combined company will be led by current Range senior management team

Key Conditions and Timing

Range shareholder approval and MRD shareholder approval

Customary regulatory approvals

Closing expected late 3rd quarter or early 4th quarter of 2016

20
Immediately Accretive & Credit Enhancing
Annual Consensus
Metrics
*
Existing RRC
Pro
Forma

RRC
% Change

2016E Production
520 Bcfe
670 Bcfe
+29%

2016E Production per day
1,420 Mmcfe
1,830 Mmcfe
+29%

2016E Cash Flow
$375 Million
$780 Million
+108%

2016E Cash Flow per share
$2.24
$3.20
+43%

2016E Cash Margin per Mcfe
$0.72
$1.17
+62%

YE 2016E Debt to EBITDAX
4.8x
3.5x
+27%

YE 2016E Debt to Cap
50%
37%
+26%
* Using 5/13/16 Consensus estimates
Significant Enhancement to both
Cash Flow Per Share and Credit Metrics

21
Marketing and Operational Efficiencies
Marketing

MRD s position gives Range a
presence in the Gulf Coast in advance
of additional transportation availability
out of Appalachia

Opportunities to optimize Range s transportation portfolio

Creates an expanding and improved Range customer base in or near multiple demand areas
Operational

Modified drilling and targeting techniques

Capital cost reductions through leveraging service provider relationships and reducing drilling or completion times

Overhead efficiencies
Marcellus
Terryville
Existing infrastructure connects the two acreage positions

22
Appendix

23
Sustained Growth with Improving Capital Efficiency
* 2016 production estimated at midpoint of guidance with capital budget of $495 million
$ Capex per incremental mcfe Production
Production (Mmcfepd)
Range has one of the most capital efficient spending programs in the sector
1,500
1,250

1,000
750
500
250
0
2011
2012
2013
2014
2015
2016E*
$30
$25
$20
$15
$10
$5
$-

24
Cost & Efficiency Improvements
SW
Pennsylvania
-
1,000
2,000
3,000

4,000
5,000
6,000
7,000
8,000
2012
2013
2014
2015
2016 E
Average Lateral Length
'
'
'
'
'
'
'
'
$-
$500
$1,000
$1,500
$2,000
$2,500
2012
2013
2014
2015
2016 E
Well Cost / Lateral Length
$-
$200
$400
$600
$800
$1,000
$1,200
2012
2013
2014
2015
2016 E
Drilling Cost / Lateral Length
(includes vertical)
$-
$200
$400
$600
$800

$1,000
$1,200
$1,400
2012
2013
2014
2015
2016 E
Completion Cost / Lateral Length

25
Source
Bentek, Jefferies as of April 2016
Monthly
Y/Y
%
Growth

Total
US
Dry
Gas
U.S. Natural Gas Production Growth has Slowed Considerably
December 2015 marked the first Y/Y supply decrease since February 2010
December 2015 marked the first Y/Y supply decrease since February 2010
12.0%
10.0%
8.0%
6.0%
4.0%
2.0%
0.0%
-2.0%

26

Track Record of Impressive Reserve Replacement at Low Cost

(1)

Includes performance and price revisions, excludes SEC required PUD removal due to 5-year rule

(2)

From all sources, including price, performance and SEC required PUD removal due to 5-year rule

(3)

Percentages shown are compounded annual growth rate

	2011	2012	2013	2014	2015	3-Year Average	5-Year Average
Reserve Replacement							
All sources excluding PUD removals (1)	849%	680%	745%	793%	436%	638%	669%
All sources (2)	849%	680%	636%	649%	207%	469%	546%
Finding Costs							
Drill bit only without acreage (1)	$0.76	$0.76	$0.47	$0.44	$0.37	$0.43	$0.53
Drill bit only with acreage (1)	$0.89	$0.86	$0.52	$0.51	$0.40	$0.48	$0.60

All sources
excluding PUD removals
(2)
$0.89
$0.86
$0.52
$0.54
$0.40
$0.50
$0.61
All sources
(2)
$0.89
$0.76
$0.61
$0.67
$0.84
$0.68
$0.75
26

27
$0.00
$0.25
$0.50
$0.75
$1.00
$1.25
$1.50

$1.75
$2.00
$2.25
$2.50
Range
Peer 1
Peer 2
Peer 3
Peer 4
Peer 5
Peer 6
Peer 7
Adds + perform + price rev into D & C
Adds + all adjustments into total cost
Peers included
Antero, Cabot, Consol, EQT, Gulfport, Rice & Southwestern
N
e
g
a
t
i
v
e
A
d
d
i
t
i
o
n
s
N
e
g
a
t
i
v
e
A
d
d
i
t
i
o
n
s

N
e
g
a
t
i
v
e
A
d
d
i
t
i
o
n
s
N
e
g
a
t
i
v
e
A
d
d
i
t
i
o
n
s
Appalachia Producer s 2015 F & D Costs
Core Acreage Has Big Impact on Value of Reserves

28
Range: Low-Cost, Large Scale
Source: Wood Mackenzie
February 2016
0.00
0.50
1.00
1.50

2.00
2.50
3.00
3.50
4.00
4.50
5.00
5.50
0
20
40
60
80
100
120
140
160
Remaining net risked resource (tcfe)
Range - Southwest Rich
EQT - Southwest Rich
EQT - WV Rich
Southwestern - Rich Gas Core
CONSOL - Southwest Rich
Noble - Southwest Rich
Rice - Greene
Antero - WV Rich
Range - Pittsburgh
Rex - Pittsburgh
Magnum Hunter - WV Rich
CONSOL - Allegheny Mountains
Noble - Allegheny Mountains
Range - Rich Gas Core
Range - Greene
Chevron - Greene
ExxonMobil - Pittsburgh
Antero - WV Dry
EXCO - Pittsburgh
CONSOL - Rich Gas Core
CONSOL - WV Rich
Rice - Southwest Rich
AEP - WV Rich
EQT - WV Dry
Chevron - Rich Gas Core
Southwestern - WV Rich
CONSOL - WV Dry
Chevron - Allegheny Mountains
ExxonMobil - WV Dry
EQT - Allegheny Mountains
Noble - WV Rich
Southwestern - WV Dry

Noble - WV Dry
Chevron - Pittsburgh
Wood Mackenzie 2016 Henry
Hub price forecast
(US$2.60/mcf)
140 tcfe in the Southwest
Marcellus alone
Range has lowest breakeven price in the SW
Marcellus per Wood Mackenzie
Range has lowest breakeven price in the SW
Marcellus per Wood Mackenzie

29
SW PA Super-Rich Area Marcellus Projected 2016 Well Economics

Southwestern
PA

(High
Btu

case)

110,000 Net Acres

EUR
/
1,000
ft.

2.40
Bcfe

EUR
16.0 Bcfe
(226 Mbbls condensate, 1,224 Mbbls NGLs & 7.3 Bcf gas)

Drill
and
Complete
Capital

$5.87
MM
($881 K per 1,000 ft.)

Average
Lateral
Length

6,660
ft.

F&D
$0.44/mcfe
NYMEX
Gas Price
ROR
Strip -
22%
$3.00 -
26%
Estimated
Cumulative Recovery
for 2016 Production Forecast
Condensate
(Mbbls)
Residue
(Mmcf)
NGL w/
Ethane

(Mbbls)
1 Year
48
661
111
2 Years
73
1,142
192
3 Years
92
1,555
261
5 Years
120
2,246
378
10 Years
161
3,517
591
20 Years
195
5,157
867
EUR
226
7,279
1,224

Price includes current and expected differentials less gathering, transportation and processing costs

For flat pricing, oil price assumed to be $40/bbl for 2016, $50/bbl for 2017 then $65/bbl to life with no escalation

NGL is average price including ethane with escalation

Ethane price tied to ethane contracts plus same comparable escalation

Strip dated 12/31/15 with 10-year average $52.14/bbl and $3.25/mcf

30
Southwest PA -
Super-Rich Area 2016 Turn in Line Forecast
Improvements Between Years
EUR
(Bcfe)
Well Costs
($ MM)

Lateral
Lengths (ft.)
2015 Type Curve -
TIL
12.9
$5.9
5,367
2016 Type Curve -
TIL
16.0
$5.9
6,660
System designed to maximize project economics

31
Southwest PA
Super-Rich Marcellus
All comparisons based on Turned in Line (TIL) wells for each year
2,000
2,500
3,000
3,500

4,000
4,500
5,000
5,500
6,000
6,500
7,000
2014
2015
2016
Horizontal Length (TIL)
5
10
15
20
25
30
35
2014
2015
2016
Average Number of Stages
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
2014
2015
2016
EUR per 1,000 ft.
0.0
5.0
10.0
15.0
20.0
2014
2015
2016
EUR by Year
Gas
NGLs
Condensate

32
SW PA Wet Area Marcellus Projected 2016 Well Economics

Southwestern PA
(Wet Gas case)

225,000 Net Acres

EUR / 1,000 ft.
2.95 Bcfe

EUR
20.6 Bcfe
(56 Mbbls
condensate, 1,700 Mbbls
NGLs & 10.1 Bcf
gas)

Drill and Complete Capital
$5.8 MM
($832 K per 1,000 ft.)

Lateral Length
6,970 ft.

F&D
$0.34/mcfe

Price includes current and expected differentials less gathering, transportation and processing costs

For flat pricing, oil price assumed to be $40/bbl for 2016, $50/bbl for 2017 then $65/bbl to life with no escalation

NGL is average price including ethane with escalation

Ethane price tied to ethane contracts plus same comparable escalation

Strip dated 12/31/15 with 10-year average $52.14/bbl and $3.25/mcf
NYMEX
Gas Price
ROR
Strip -
20%
$3.00 -
25%
Estimated
Cumulative Recovery
for 2016 Production Forecast
Condensate
(Mbbls)
Residue

(Mmcf)
NGL w/
Ethane
(Mbbls)
1 Year
20
1,211
204
2 Years
30
2,014
339
3 Years
36
2,665
449
5 Years
44
3,694
622
10 Years
51
5,470
921
20 Years
55
7,654
1,289
EUR
56
10,100
1,700

33
Southwest PA -
Wet Area 2016 Turn in Line Forecast
Improvements Between Years
EUR
(Bcfe)
Well Costs
($ MM)

Lateral
Lengths (ft.)
2015 Type Curve
-
TIL
17.6
$5.9
5,955
2016 Type Curve -
TIL
20.6
$5.8
6,970
System designed to maximize project economics

34
Southwest PA
Wet Marcellus
34
2,000
3,000
4,000
5,000

6,000
7,000
8,000
2014
2015
2016
Horizontal Length (TIL)
5
10
15
20
25
30
35
40
2014
2015
2016
Average Number of Stages
1.0
1.5
2.0
2.5
3.0
3.5
2014
2015
2016
EUR per 1,000 ft.
0.0
5.0
10.0
15.0
20.0
25.0
2014
2015
2016
EUR by Year
Gas
NGLs
Condensate
All comparisons based on Turned in Line (TIL) wells for each year

35

Southwestern PA
(Dry Gas case)

180,000 Net Acres

EUR / 1,000 ft.

2.52 Bcf

EUR
17.6 Bcf

Drill and Complete Capital $5.2 MM
($743 K per 1,000 ft.)

Average Lateral Length
7,000 ft.

F&D
$0.36/mcf
NYMEX
Gas Price
ROR
Strip -
41%
$3.00 -
54%
Estimated
Cumulative Recovery
for 2016 Production Forecast
Residue
(Mmcf)
1 Year
3,039
2 Years
4,674
3 Years
5,866
5 Years
7,609
10 Years
10,392
20 Years
13,633
EUR
17,641

Price includes current and
expected differentials less
gathering and transportation
costs

Strip dated 12/31/15 with 10-year
average $52.14/bbl and $3.25/mcf
SW PA Dry Area Marcellus Projected 2016 Well Economics
Based on Washington County well data

36
SW PA
Dry Area 2016 Turn in Line Forecast
Improvements Between Years
EUR
(Bcf)
Well Costs
($ MM)

Lateral
Lengths (ft.)
2015 Type Curve -
TIL
17.1
$6.0
6,798
2016 Type
Curve -
TIL
17.6
$5.2
7,000
System designed to maximize project economics
Based on Washington County well data

37
Southwest PA
Dry Marcellus
37
Based on Washington County well data
2,000
3,000
4,000

5,000
6,000
7,000
8,000
2014
2015
2016
Horizontal Length (TIL)
5
10
15
20
25
30
35
40
2014
2015
2016
Average Number of Stages
1.0
1.5
2.0
2.5
3.0
2014
2015
2016
EUR per 1,000 ft.
0.0
5.0
10.0
15.0
20.0
2014
2015
2016
EUR by Year
All comparisons based on Turned in Line (TIL) wells for each year

38
Utica Wells
Wellhead Pressure vs. Cumulative Production
Early Time Production Data (Including Flowback/Test Data)
Normalized Gas Cum (Mcf/1000 ft.)
RRC DMC Properties well one of the best in the Utica
~25 Mmcfd
~30 Mmcfd

~18 Mmcfd
~12 Mmcfd
~20 Mmcfd
*TVD (total vertical depth) With an average pressure gradient of .85 to .95
for these wells, greater TVD equals higher cost and higher pressure
13,200 TVD*
13,400 TVD*
11,850 TVD*
9,206 TVD*

39
Utica/Point Pleasant Update

1
st
well
estimated

to
have
15
Bcf
EUR, or 2.8 Bcf per 1,000 lateral
foot

2
nd
well
completed
with
higher
sand concentration and brought
online in Q3 2015 with choke
management at 13 Mmcf per day

2
nd
well
EUR
appears
to
be
greater than the first well

3
rd
well
appears
to
be
one
of
the
best dry gas Utica wells in the
basin

400,000 net acres in SW PA
prospective
Note: Townships where Range holds ~2,000+ or more acres are
shown outlined above (as January 2016)

40
Cost & Efficiency Improvements
Northern Marcellus
'
'
'
'
'

'
'
'
'

Normalized Production Results of Marcellus Tighter Spacing Projects

Tighter spaced wells turned to sales in 2009 and 2010

Average lateral length of these wells is 2,861 feet

Well performance not reflective of improved targeting and completion designs

500 foot spaced wells produced 77% of 1,000 foot spaced wells through the life of the current production

Tighter spaced wells turned to sales in 2009 and 2010

Average lateral length of these wells is 2,861 feet

Well performance not reflective of improved targeting and completion designs

500 foot spaced wells produced 77% of 1,000 foot spaced wells through the life of the current production
41

Targeting/Down Spacing Test Results Encouraging

Optimized targeting
shows a ~53% increase in
cumulative production
after 600 days

Normalized well costs

were $850,000 less than
original wells

No detrimental
production impact seen
on the original wells
Represents New Optimized
Completion Method
42

43
43
Returning to Existing Pads
SW Wet
Avg EUR/1000 ft.: 3.6+ Bcfe

Ability to target our best areas with 3.6+ Bcfe/1,000 ft.

New wells have EURs 22% higher than the average wet well

Significant cost savings
Drilled
wells -
2015
Future
Locations
Additional 5 wells
Drilled
wells -
2010

44
44
Returning to Existing Pads
SW Dry
Additional 3 wells
Avg EUR/1000 ft.: 3.0+ Bcfe

Ability to target our best areas with 3.0+ Bcfe/1,000 ft.

New wells have EURs 20% higher than the average dry well

Significant cost savings
Drilled
wells -
2015
Drilled
wells -
2014
Future
Locations

45
Gas In Place (GIP)
Marcellus Shale
Note: Townships where Range holds ~2,000+ acres (as of January 2016) and estimated as prospective, are outlined green. GIP
Range estimates.

GIP is a function of pressure,
temperature, thermal

maturity, porosity, hydrocarbon saturation and net thickness

Two core areas have been developed in the Marcellus

Condensate and NGLs are in gaseous form in the reservoir

46

Gas In Place (GIP)

Point Pleasant

Bold, outlined portion represents
the area of the highest pressure
gradients in the Point Pleasant

Note: Townships where Range holds ~2,000+ acres (as of January 2016) and estimated as prospective, are outlined green. GIP
Range estimates.

47

Gas In Place (GIP)

Upper Devonian Shale

The greatest GIP in the Upper Devonian is found in SW PA

A significant portion of the GIP

in the Upper Devonian is located
in the wet gas window
Note: Townships where Range holds ~2,000+ acres (as of January 2016) and estimated as prospective, are outlined green. GIF
Range estimates.

48
Macro Section

49
Significant
Natural
Gas
Demand
Growth
Projected

Beginning
in
2016
LONG TERM US NATURAL GAS DEMAND ROADMAP (BCF/D)
2016
2017
2018
2019
2020
Cumulative
2015-2020
LNG Exports
Sabine Pass
1.2
1.2
0.7
3.1
Freeport
0.5
1.0
1.5
Cove Point
0.8
0.8
Cameron
1.2
0.6
1.8
Corpus Christi