

All Oil Companies Are Not Alike.

# A Different Kind of Oil Company



## Leading CO<sub>2</sub> Enhanced Oil Recovery (EOR) Company in the U.S. with a Unique Profile

### Scale

- ~\$9 billion enterprise value
- 71,532 BOE/d production (1Q12)
  - 8% Increase vs. 4Q11<sup>(1)</sup>
- Highest operating margins and capital efficiency in peer group<sup>(2)</sup>

### Performance

- 30% compound annual growth rate (CAGR) in EOR production over the last 12 years
- 2<sup>nd</sup> Largest CO<sub>2</sub> EOR Producer in North America

### Platform

- Infrastructure in place with secure CO<sub>2</sub> supply
- More than 1 billion barrels of potential oil reserves
- Experienced management team

### Liquidity

- ~\$1.2 billion of credit facility availability at 3/31/12
- Capital budget seeks to balance expenditures with free cash flow

### Sustainable Growth

- Sustainable EOR growth profile at 13-15% CAGR thru 2020
- ~200k acres in oil-rich Bakken play with growing production

(1) Adjusted for asset sales completed in 2012.

(2) Please reference slides 11 and 13 for more information

# Denbury at a Glance

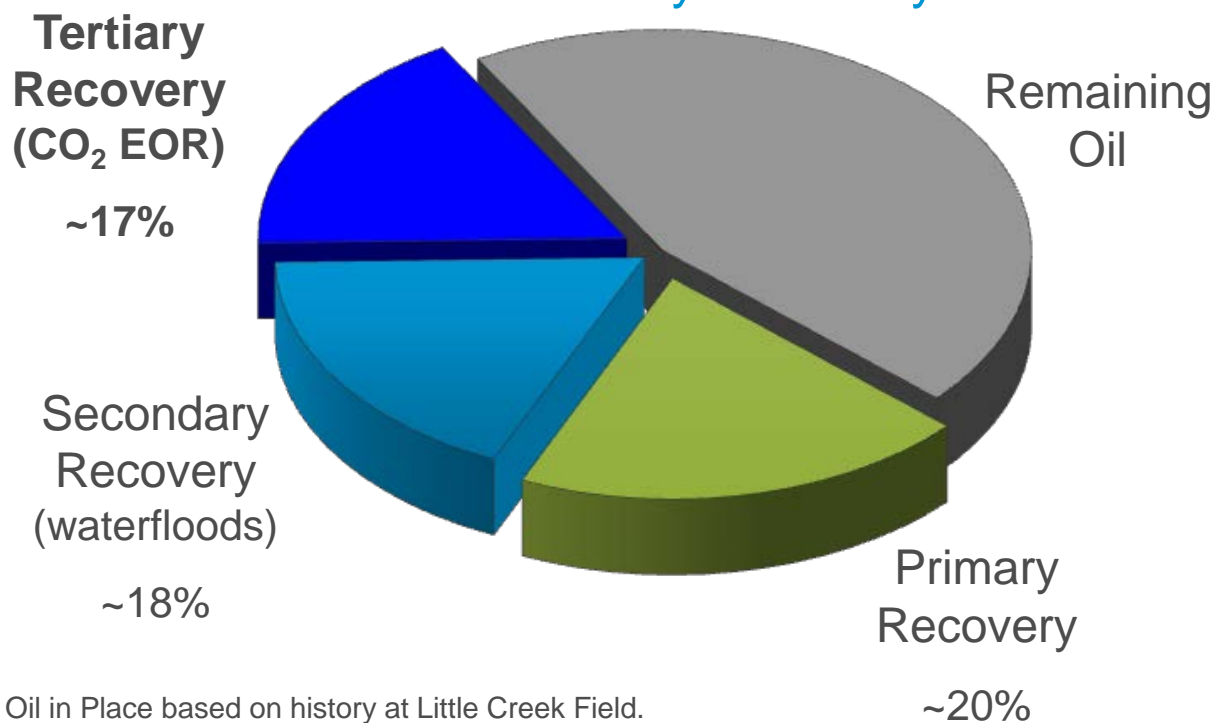


Total 3P Reserves (12/31/11)	~1.3 BBOE
% Oil Production (1Q12)	93%
Market Cap (5/31/12)	~\$5.9 billion
Total Net Debt (3/31/12)	\$2.5 billion
Total Daily Production (1Q12)	71,532 BOE/d
Proved PV-10 (12/31/11) \$96.19 NYMEX Oil Price	\$10.6 billion
CO <sub>2</sub> 3P Reserves (12/31/11)	~16 Tcf
CO <sub>2</sub> Pipelines Controlled & Under Construction	~1,000 miles
Credit Facility Availability (3/31/12)	~\$1.2 billion

# What is CO<sub>2</sub> EOR & How Much Does It Recover?



EOR Delivers Almost as Much Production as Primary or Secondary Recovery<sup>(1)</sup>



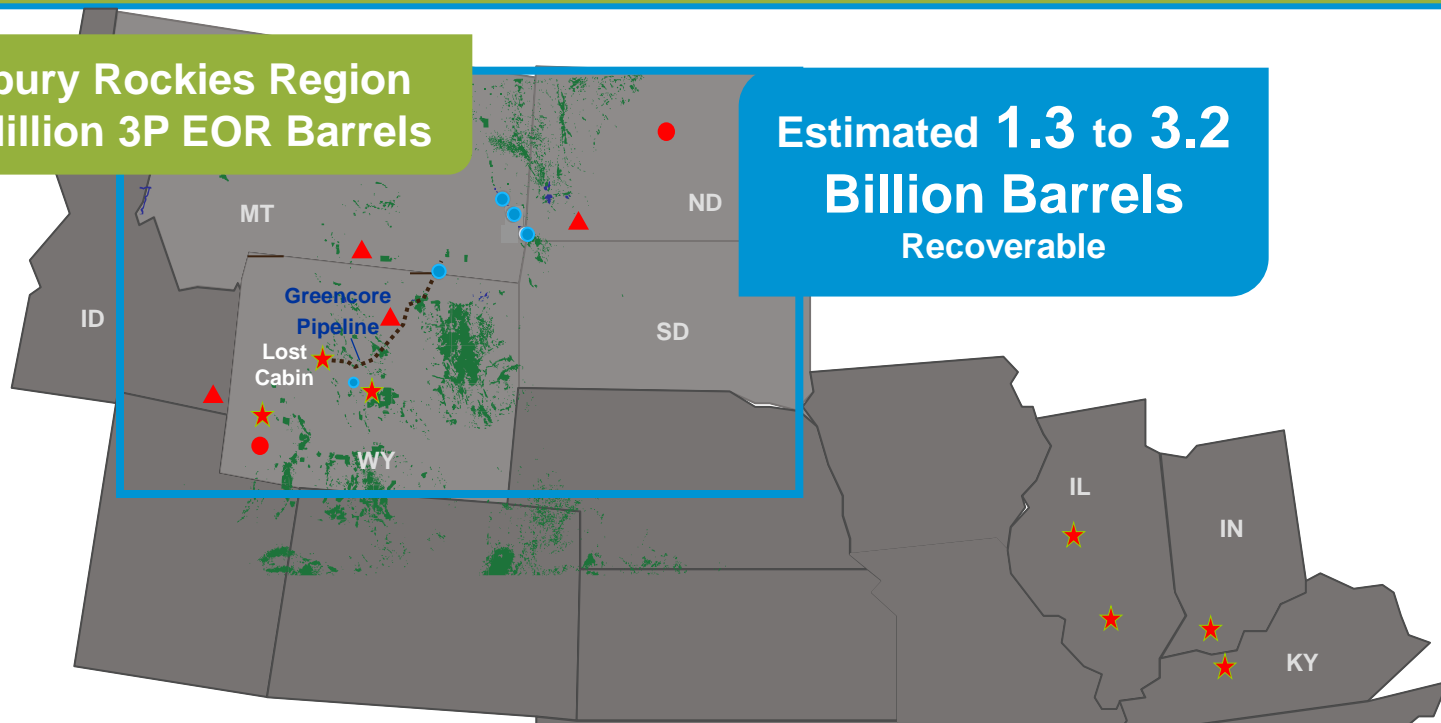
(1) Recovery of Original Oil in Place based on history at Little Creek Field.

# Our Two EOR Target Areas: Up to 10 Billion Barrels Recoverable with EOR



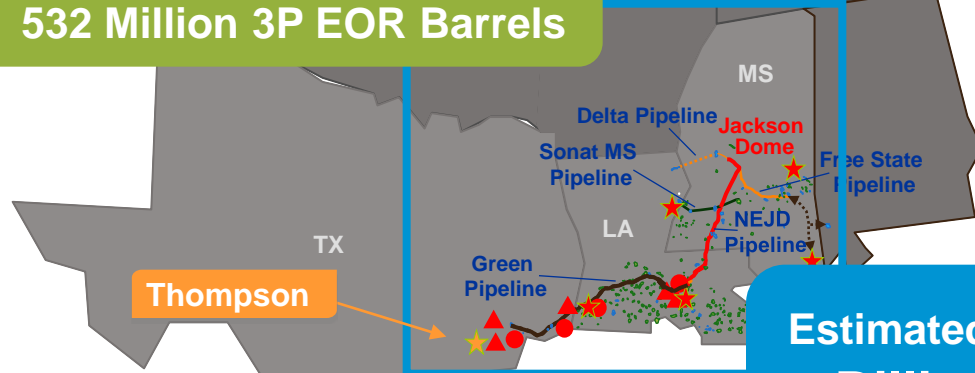
**Denbury Rockies Region**  
233 Million 3P EOR Barrels

**Estimated 1.3 to 3.2  
Billion Barrels  
Recoverable**



**Denbury Gulf Coast Region**  
532 Million 3P EOR Barrels

**Estimated 3.4 to 7.5  
Billion Barrels  
Recoverable**



- Existing CO<sub>2</sub> Pipelines
- ..... CO<sub>2</sub> Pipelines Under Development
- Denbury owned Rocky Mountain Fields With EOR Potential
- Existing Anthropogenic CO<sub>2</sub> Sources
- ▲ Proposed Coal to Gas or Liquids
- ★ Existing or Proposed CO<sub>2</sub> Source Owned or Contracted

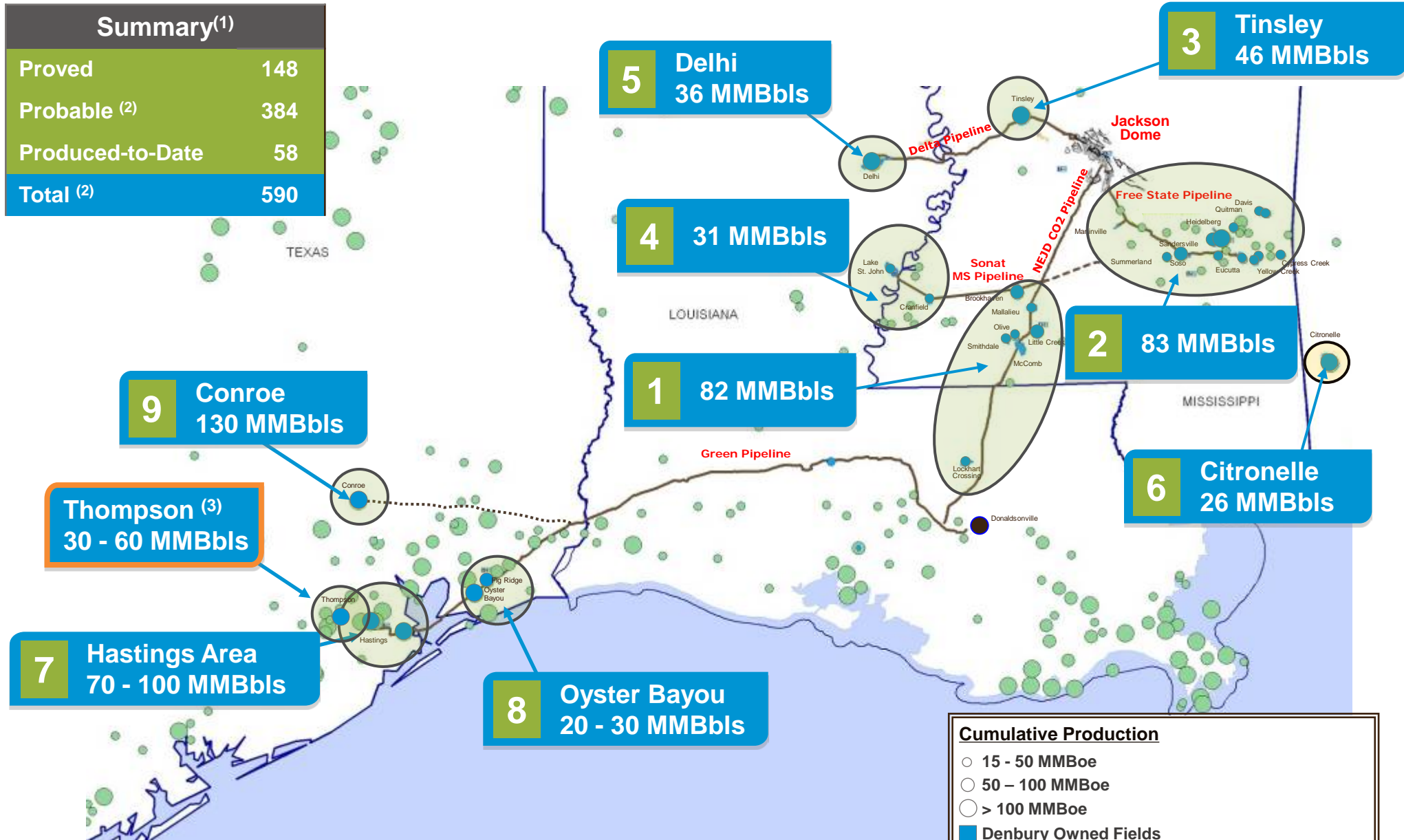
Source: DOE 2005 and 2006 reports.

Note: 3P total reserves as of 12/31/11, based on a variety of recovery factors, includes Thompson acquisition that closed in June 2012.

# Gulf Coast Region: Control of CO<sub>2</sub> Sources & Pipeline Infrastructure Provides a Strategic Advantage



Summary <sup>(1)</sup>	
Proved	148
Probable <sup>(2)</sup>	384
Produced-to-Date	58
<b>Total <sup>(2)</sup></b>	<b>590</b>

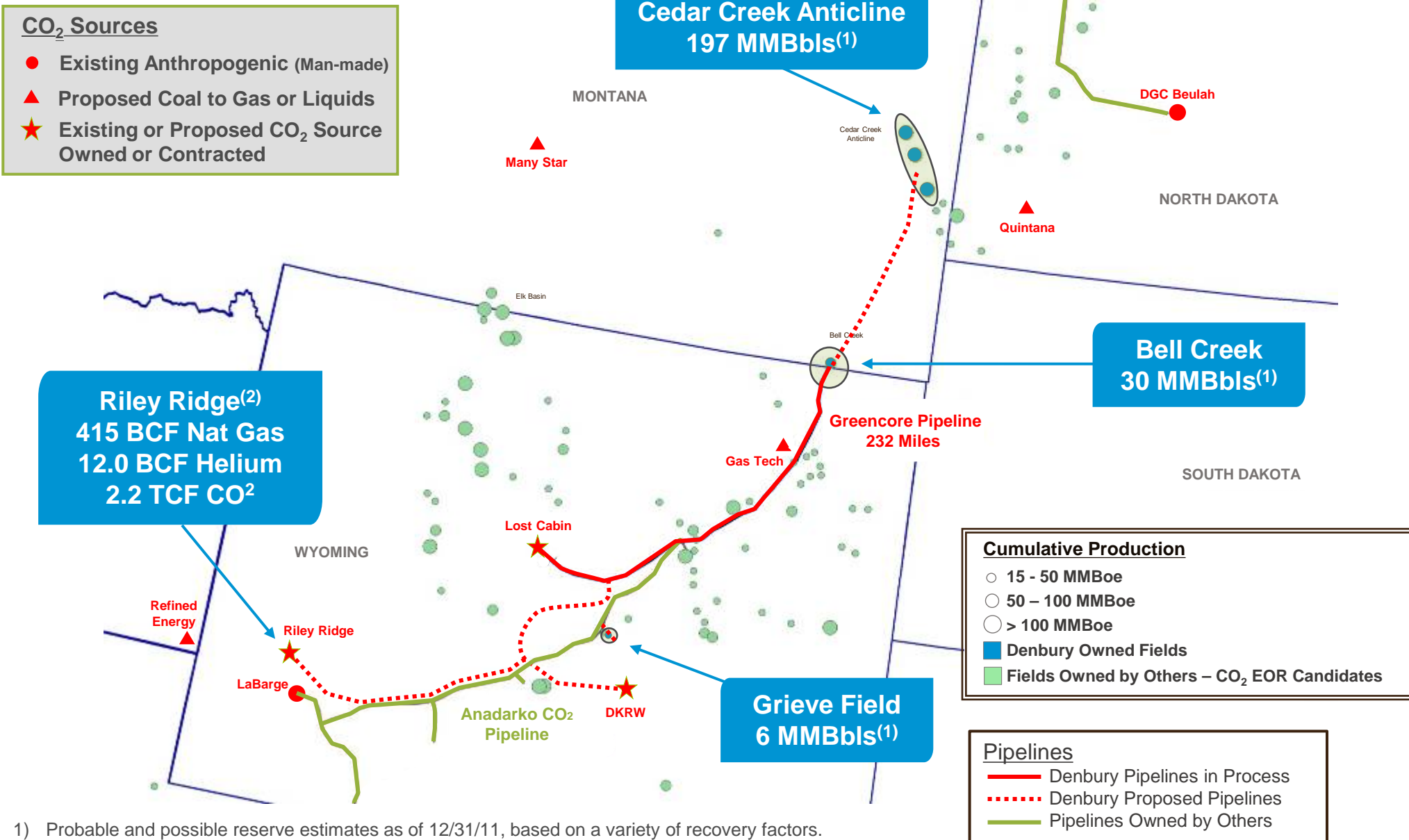


**Cumulative Production**

- 15 - 50 MMBoe
- 50 - 100 MMBoe
- > 100 MMBoe
- Denbury Owned Fields
- Fields Owned by Others - CO<sub>2</sub> EOR Candidates

1) Proved plus probable tertiary oil reserves as of 12/31/11, and includes Thompson acquisition that closed in June 2012.  
 2) Using mid-points of range.  
 3) Acquired June 2012.

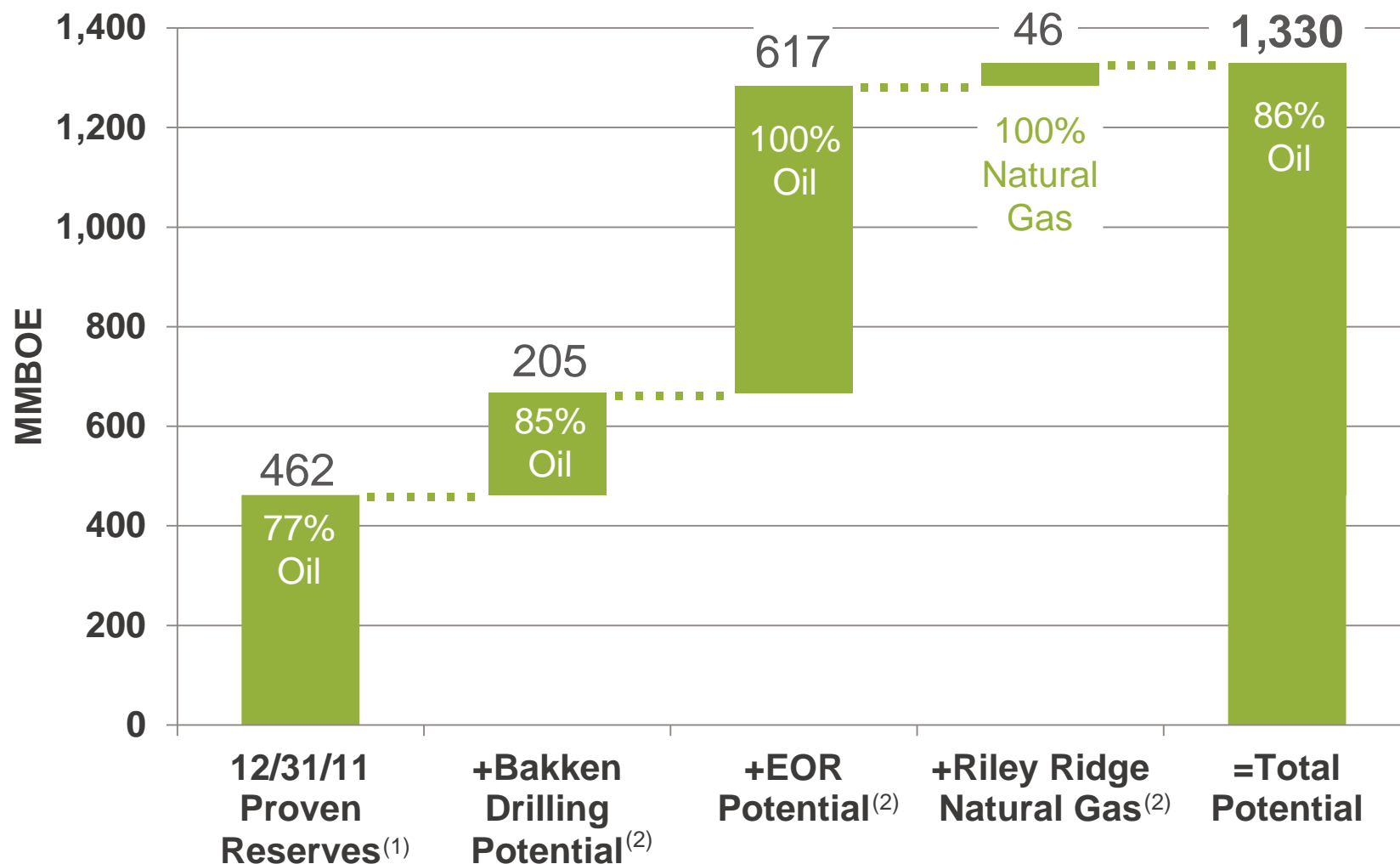
# Rocky Mountain Region: Control of CO<sub>2</sub> Sources & Pipeline Infrastructure Provides a Strategic Advantage



1) Probable and possible reserve estimates as of 12/31/11, based on a variety of recovery factors.

2) Proved reserves as of 12/31/11

# More than a Billion Barrels of Oil Potential



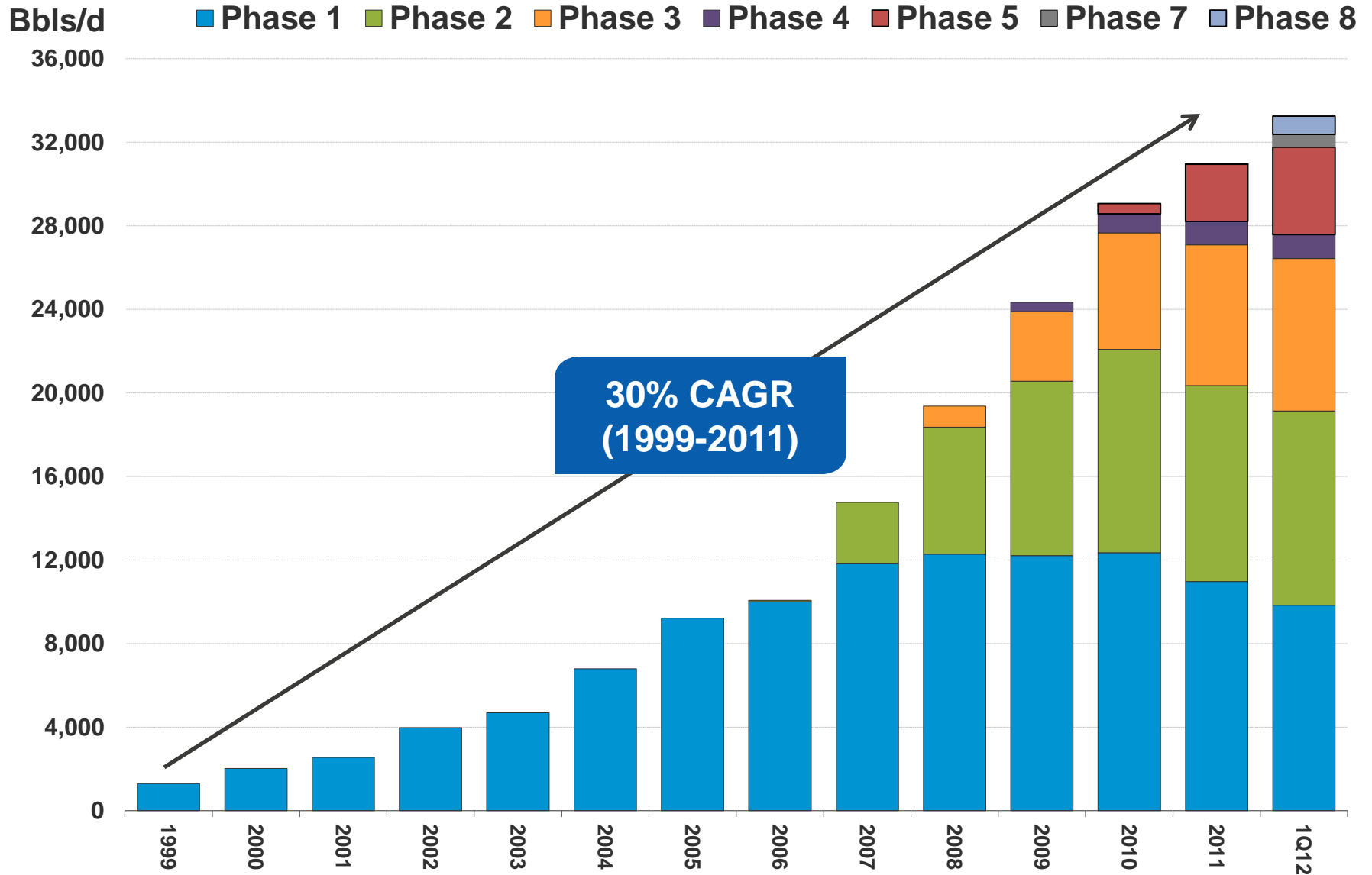
(1) Based on year-end 12/31/11 SEC proved reserves

(2) Estimates based on internal calculations, includes Thompson acquisition that closed in June 2012, refer to slide 27 for additional disclosures

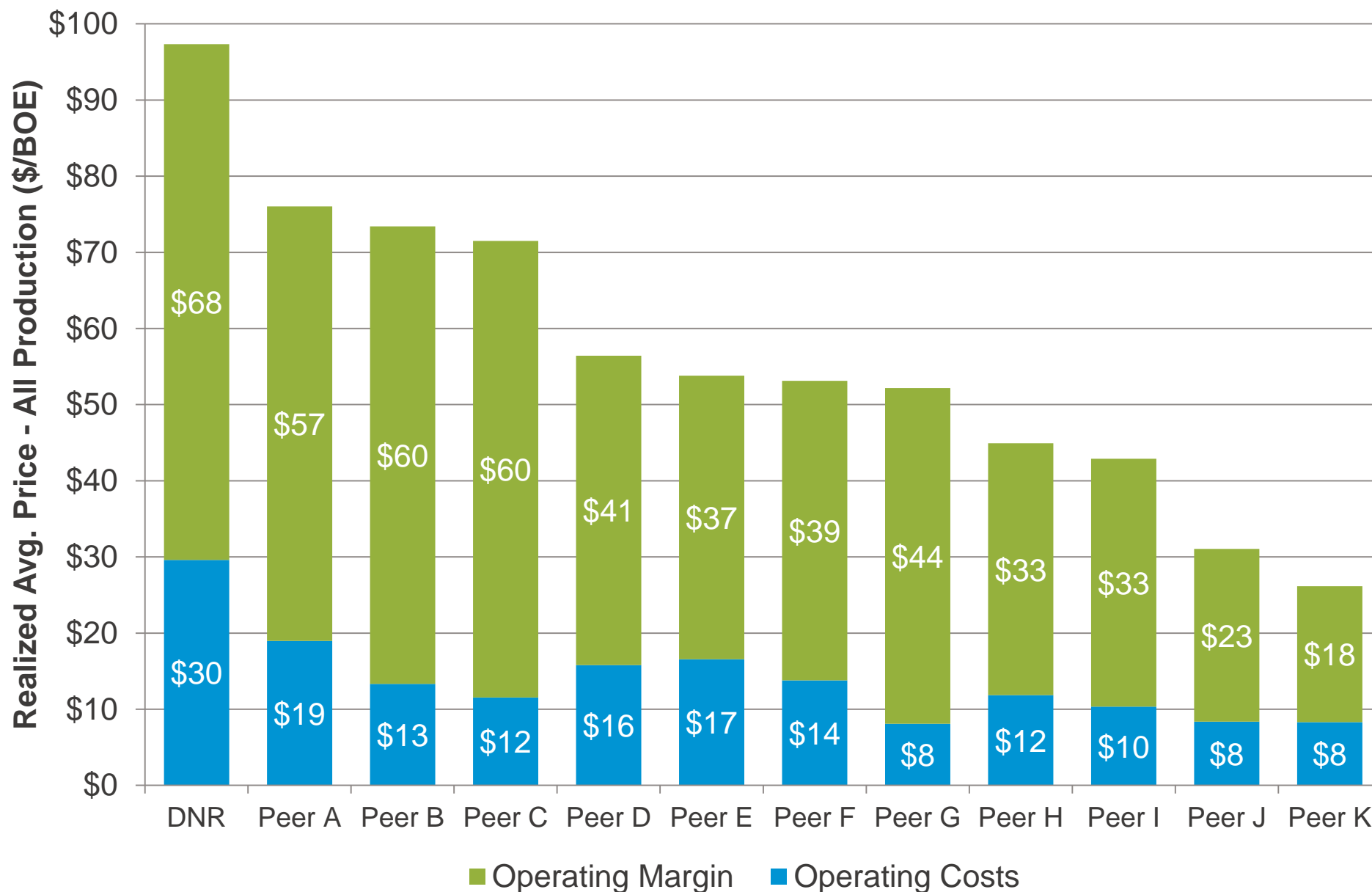
# Proven Track Record



## Net Daily Oil Production – Tertiary Operations (through 3/31/12)



# Highest Operating Margin in Peer Group<sup>(1)(2)</sup>



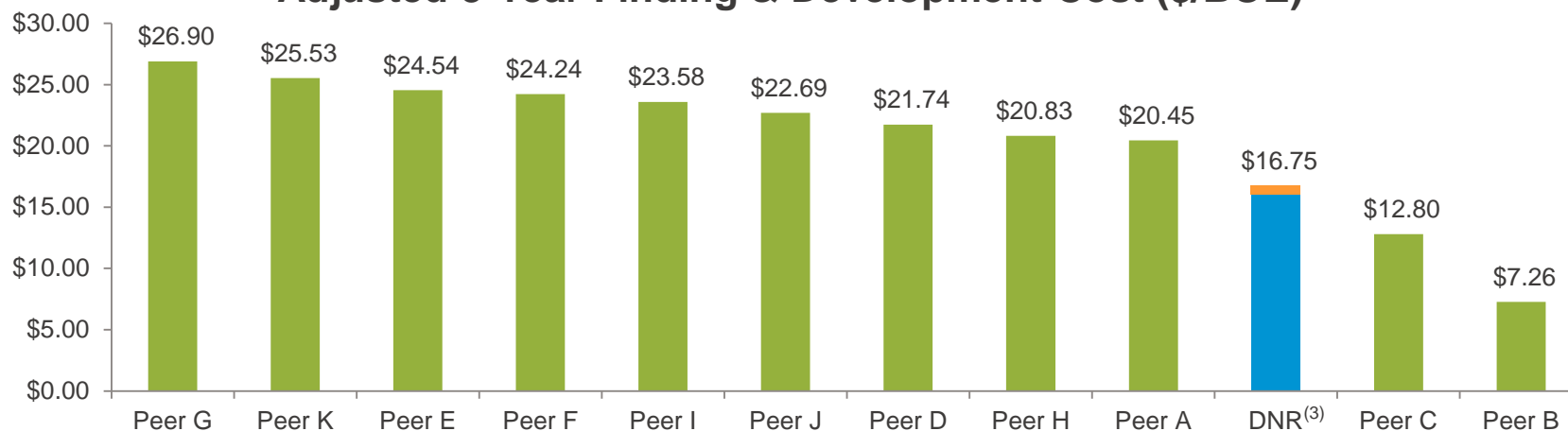
(1) Data derived from SEC filings, 3 months ended 3/31/12

(2) Peer Group includes CLR, CXO, FST, NBL, NFX, PXD, RRC, SD, SM, WLL, XEC

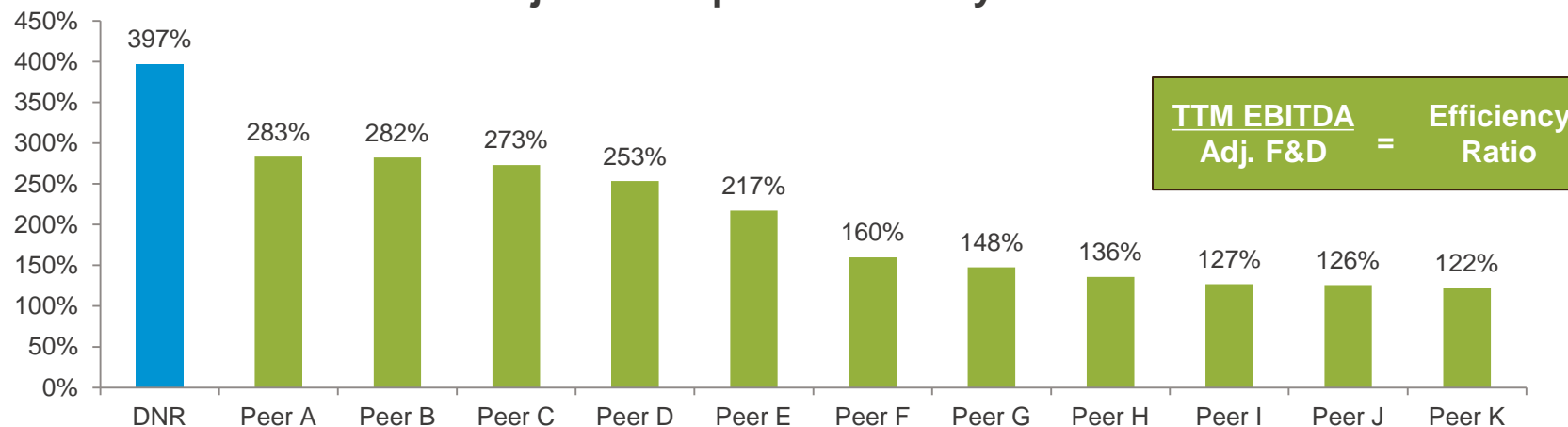
# Highest Capital Efficiency in Peer Group<sup>(1)</sup>



## Adjusted 3-Year Finding & Development Cost (\$/BOE)<sup>(2)</sup>



## Adjusted Capital Efficiency Ratio



(1) Peer Group includes CLR, CXO, FST, NBL, NFX, PXD, RRC, SD, SM, WLL, XEC

(2) Adjusted to include changes in future development costs and change in unevaluated properties.

(3) Includes 3 year average DD&A for CO<sub>2</sub> properties of \$0.83 per BOE

# Compelling Economics<sup>(1)</sup>



	<b>EOR</b>	<b>Bakken</b>
	<b>Gulf Coast Model Averages</b>	<b>575,000 BOE / Well \$9.6 Million / Well<sup>(2)</sup> 20% Royalty</b>
NYMEX oil price	\$90.00	\$90.00
Finding & development cost:		
Field	9.00	21.00
Infrastructure	4.50	---
<b>Total capital per BOE</b>	<b>\$13.50</b>	<b>\$21.00</b>
Average operating cost over life	25.00	8.00
Average historic NYMEX differentials	1.25	10.00
<b>Estimated gross margin</b>	<b>\$50.25</b>	<b>\$51.00</b>
<b>Estimated Internal Rate of Return</b>	<b>39%</b>	<b>27%</b>
<b>Return on investment</b>	<b>4.4</b>	<b>2.7</b>

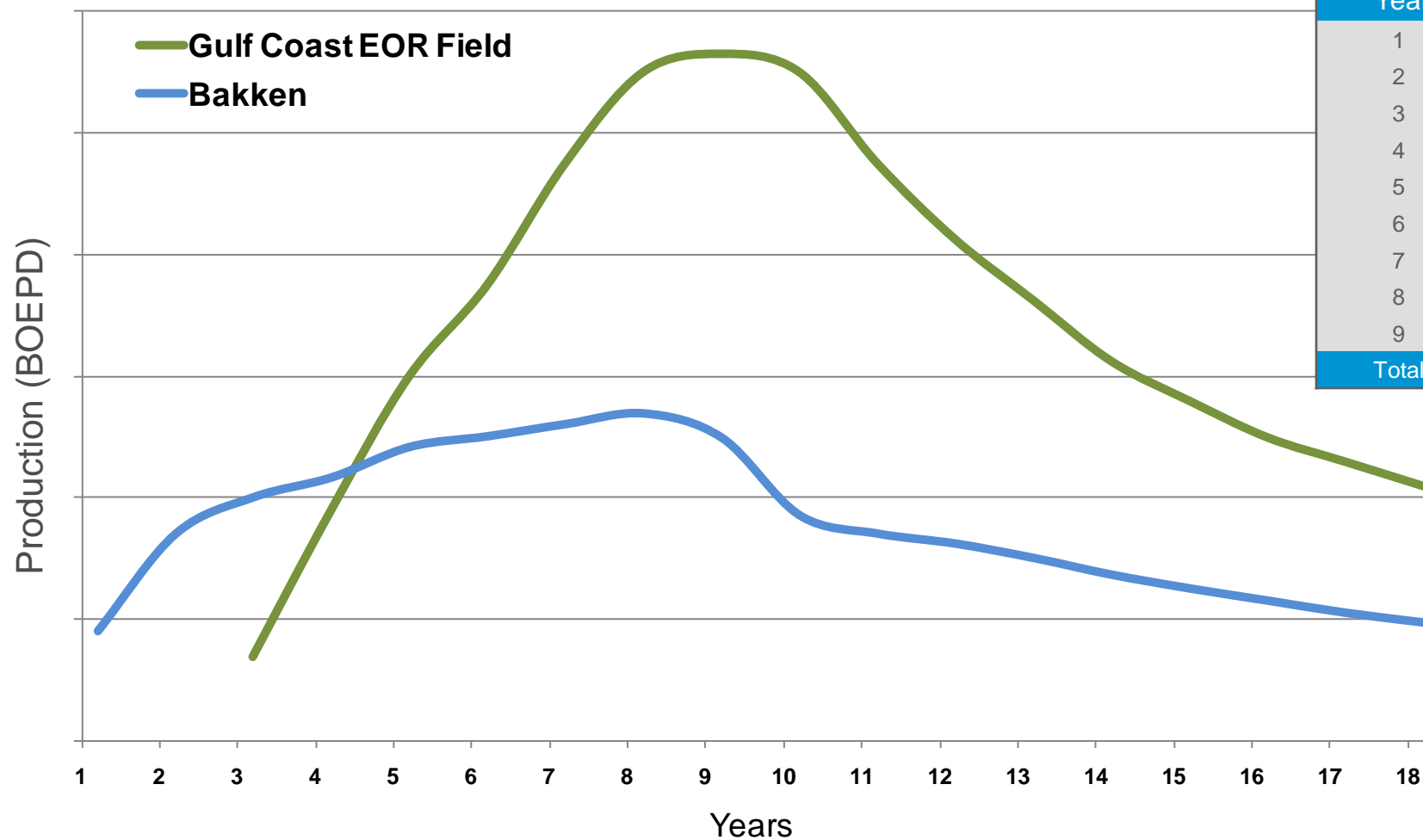
(1) Updated as of 12/31/11

(2) Cost target of long lateral well; Q1 actual cost averaged between \$10.5 to \$11.0 million

# Complementary Production Profiles



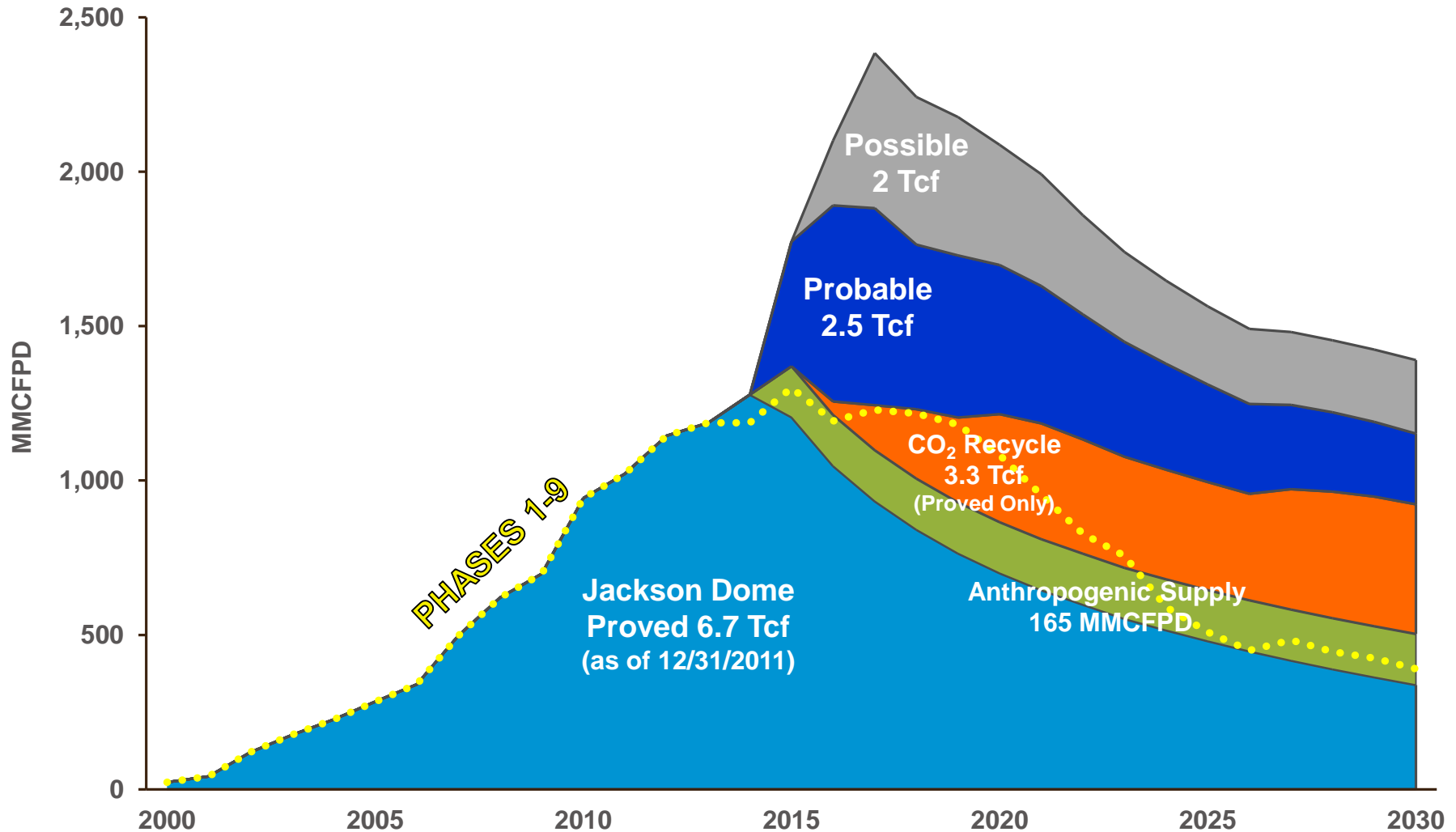
## Projected Production Profile with Same Capital Spending



Capital Spending per Year Based on EOR Spending Pattern	
Year	\$MM
1	83
2	83
3	60
4	60
5	68
6	52
7	52
8	52
9	45
<b>Total</b>	<b>\$555</b>

Note: Assumes 700 BOEPD initial 30 day rate for Bakken wells.

# Secure CO<sub>2</sub> Supply to Support Gulf Coast Growth



Note: CO<sub>2</sub> recycle assumed to be 50% of proved. Forecast based on internal management estimates. Actual results may vary. Phases 1-9 including industrial. Recently completed Thompson acquisition not included.

# Secure CO<sub>2</sub> Supply to Support Rocky Mountain Growth



## LaBarge Field

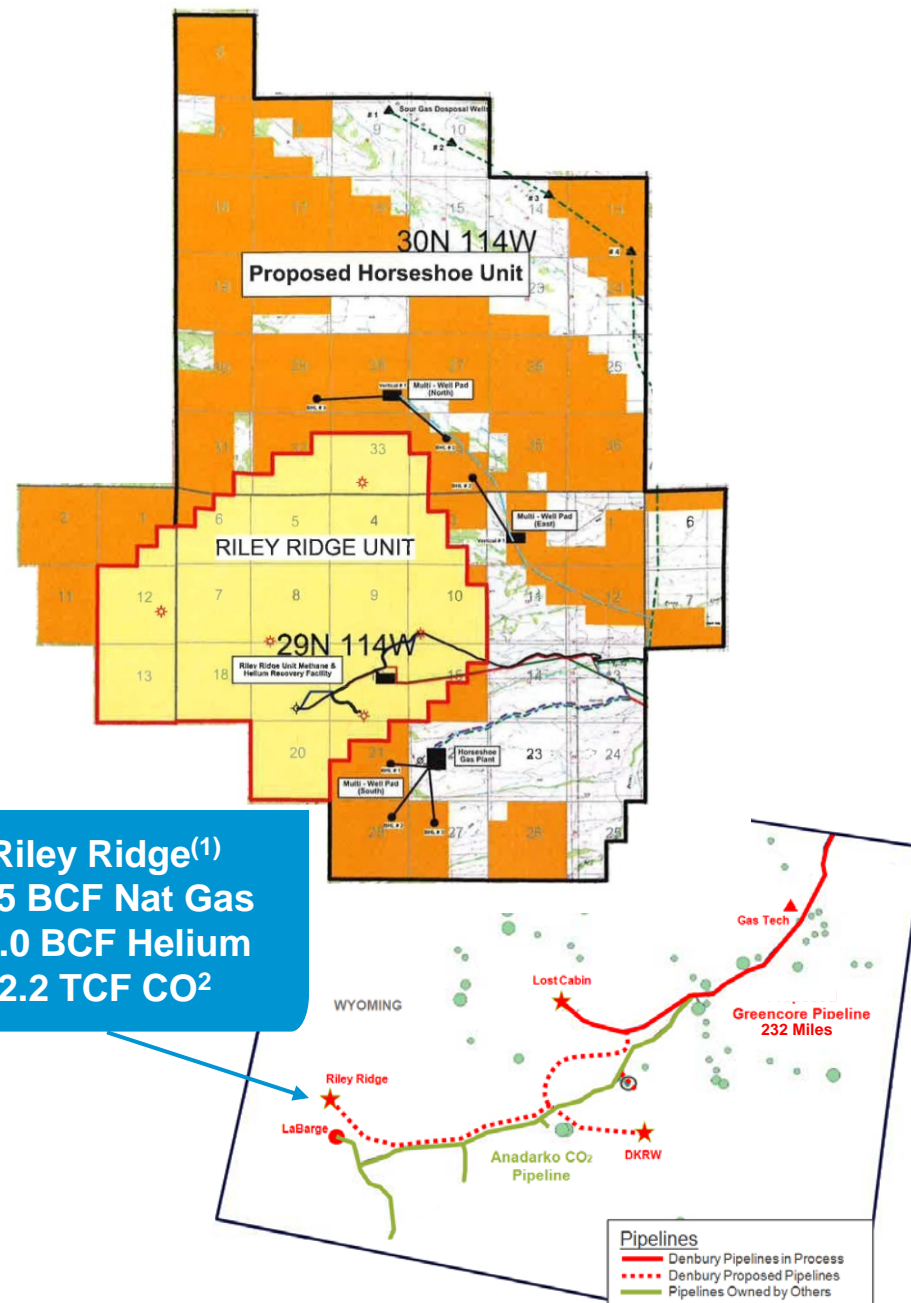
- Estimated Field Size: 750 Square Miles
- Estimated 100 TCF of CO<sub>2</sub> Recoverable

## Riley Ridge – Denbury Operated

- 100% WI in 9,700 acre Riley Ridge Federal Unit
- 33% WI in ~28,000 acre Horseshoe Unit



1) Proved reserves as of 12/31/2011



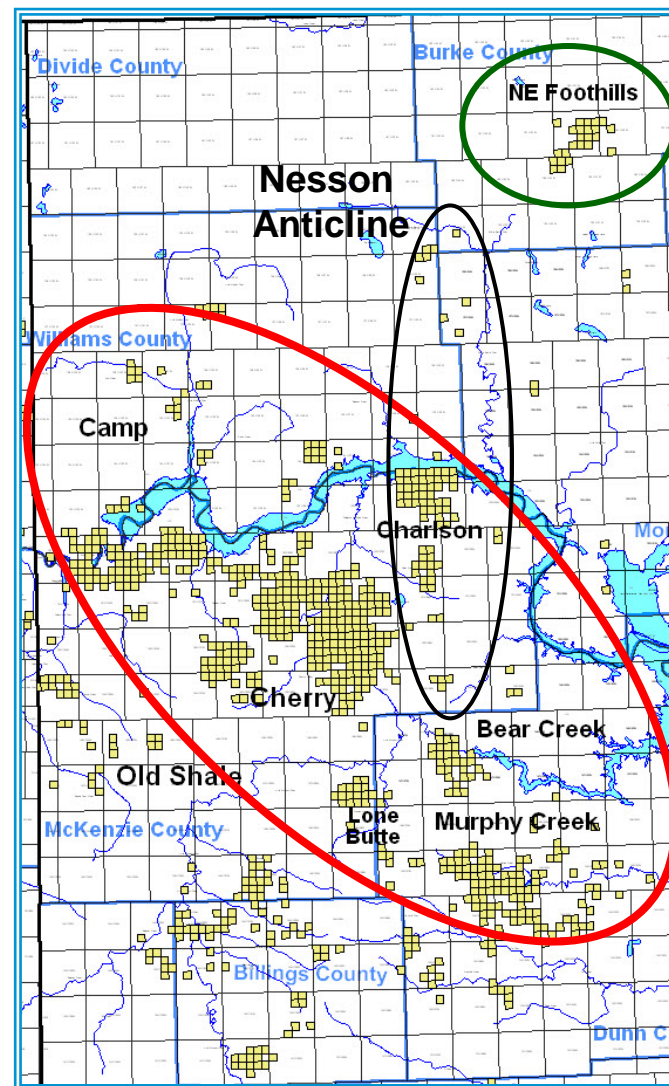
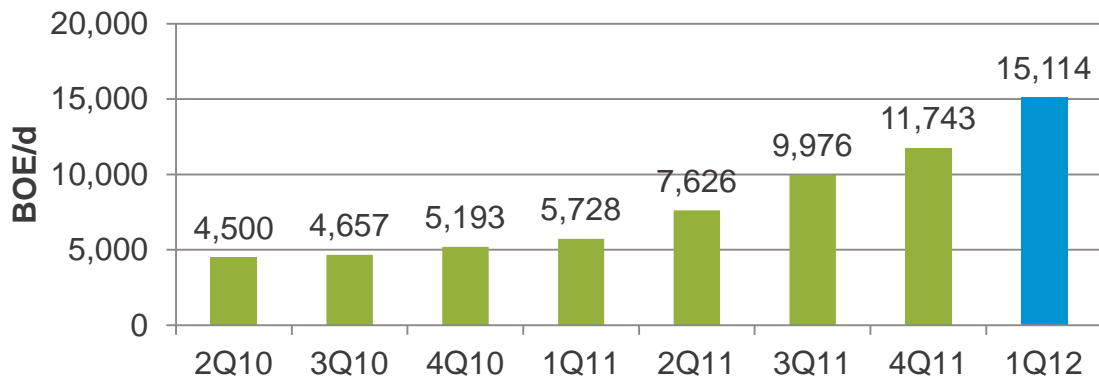
# Third Growth Platform (Bakken Area)



## Bakken Area

- ~200,000 net acres
- ~300 MMBOE of total potential
  - 93.9 MMBOE Proved as of 12/31/2011
- 2011 Production – 8,788 BOE/d
- 1Q12 Production – 15,114 BOE/d
  - 29% increase vs. 4Q11
- 2012E Production – 14,350-16,350 BOE/d

Net Bakken Production



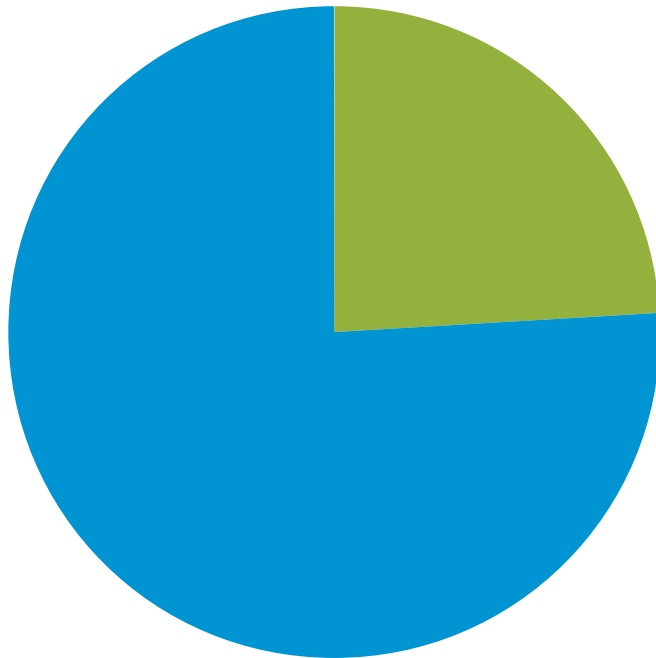
○ Denbury's Core Bakken Area     ○ Denbury's Extensional Bakken Areas  
● DNR Acreage

# Strong Financial Position



- ~\$1.2 billion availability under credit facility on 3/31/12

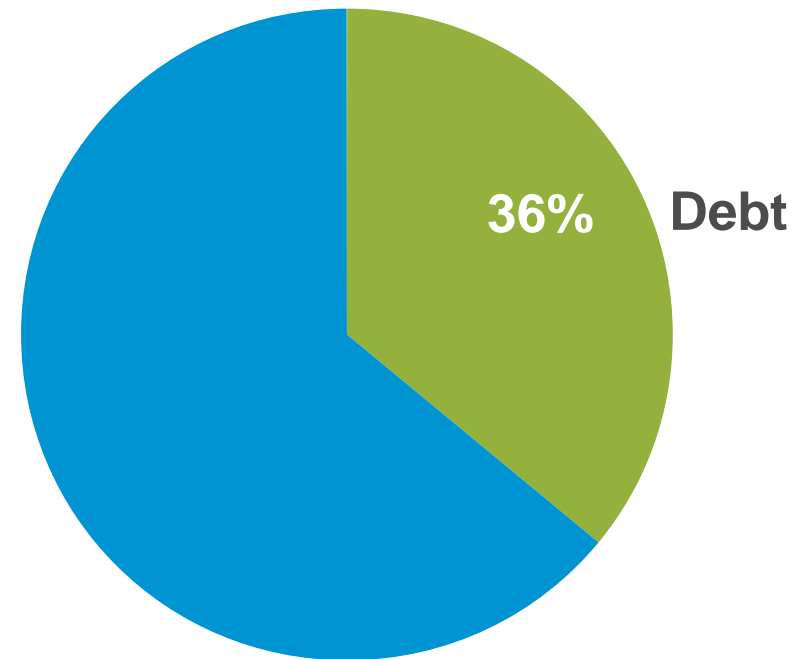
**Unused  
Credit  
Facility**



\$1.6 billion borrowing base

*Net of cash, revolver debt of ~\$225 million at 3/31/12*

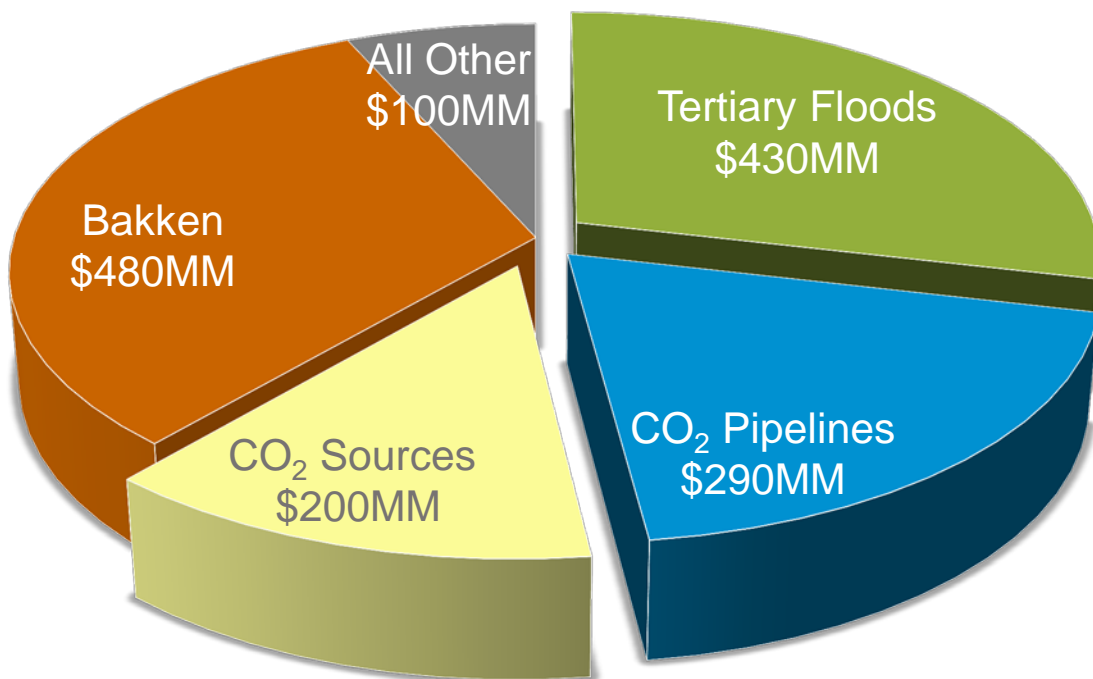
**Debt to Capitalization  
(3/31/12)**



+ (3/31/12) Cash – \$217 million



## 2012 Capital Budget – \$1.5 Billion<sup>(1)</sup>



## 2012 Production Estimate

Operating area	2011 (BOE/d)	1Q12 (BOE/d)	2012E (BOE/d)	2012E growth
Tertiary Oil Fields	30,959	33,257	33,000- 36,000	7-16%
Bakken	8,788	15,114	14,350- 16,350	63-86%
<b>Total Continuing Production<sup>(2)</sup></b>	<b>63,190</b>	<b>69,770</b>	<b>69,350- 74,350</b>	<b>10-18%</b>
<b>Total Production</b>	<b>65,660</b>	<b>71,532</b>	<b>69,775- 74,775</b>	<b>6-14%</b>

Production per share will grow an additional ~3.5% in 2012 as a result of stock re-purchased in 4Q11

Currently expect tertiary and total production to be in the upper half of their respective ranges.

(1) Excludes capitalized interest and capitalized EOR startup costs, estimated at \$60 million, also net of estimated \$75 million funded with equipment leases

(2) Excludes production associated with divested properties completed in 2012, reference slide 32 for additional details.

# Hedges Protect Against Downside in Near-Term<sup>(1)</sup>



Crude Oil <sup>(2)</sup>	2012		2013			
	2 <sup>nd</sup> Quarter	2 <sup>nd</sup> Half	1 <sup>st</sup> Quarter	2 <sup>nd</sup> Quarter	3 <sup>rd</sup> Quarter	4 <sup>th</sup> Quarter
Approximate production hedged <sup>(3)</sup>	~85%	~85%	~85%	~80%	~80%	~60%
Principal price support	\$70	\$80	\$70	\$75	\$75	\$80
Principal price ceilings	~\$119	~\$129	~\$110	~\$117	~\$122	~\$125

Natural Gas	2012
Approximate production hedged <sup>(3)</sup>	~45%
Principal price support (primarily swaps)	\$6.30-6.85

(1) Figures are general estimates and averages as of 5/29/12. Please see slide 43 and SEC documents for details of derivative contracts.

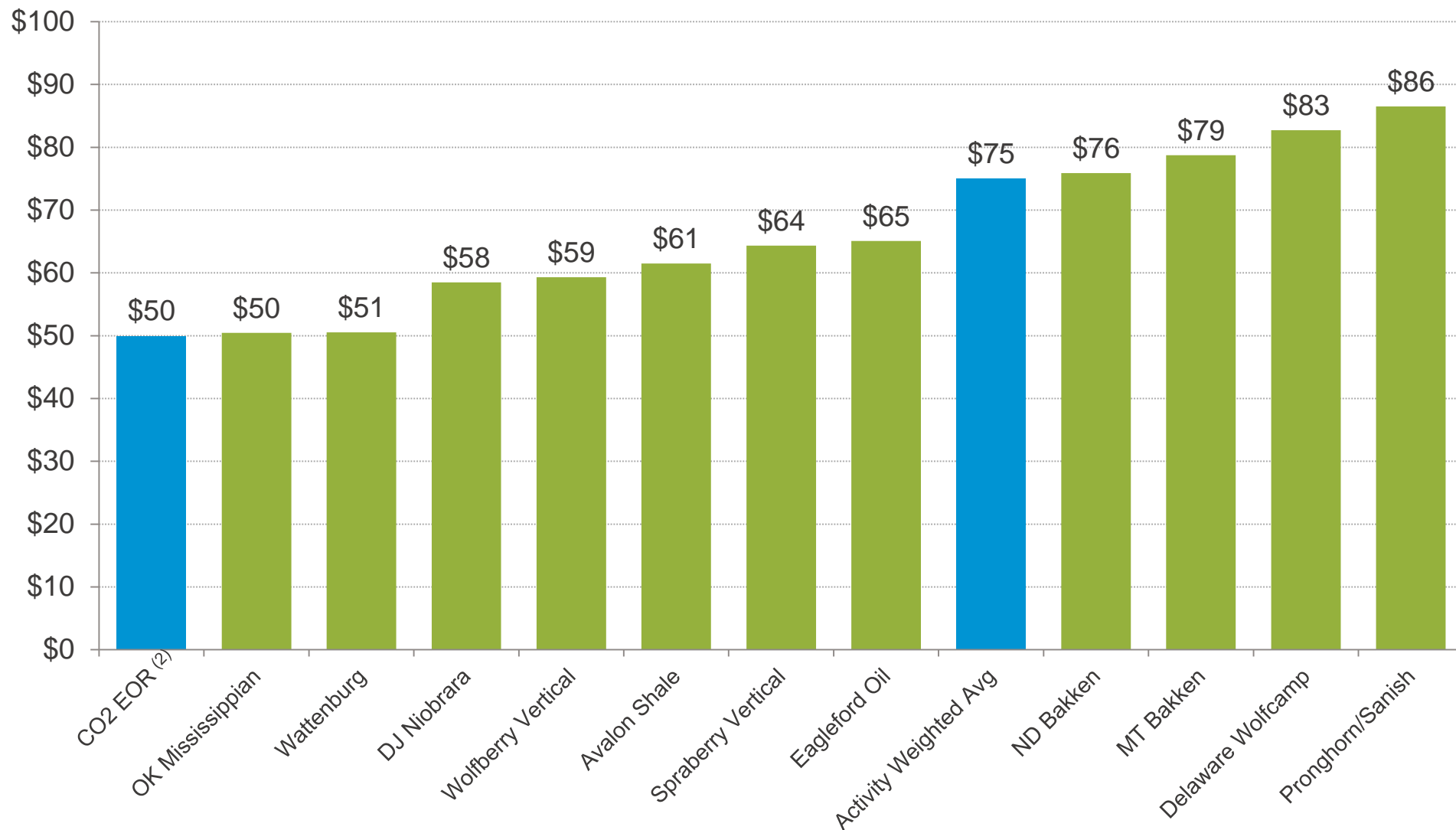
(2) All crude oil derivative contracts are based on West Texas Intermediate (WTI) NYMEX price basis.

(3) Approximate percentage which may differ from anticipated results.

# CO<sub>2</sub> EOR – Compelling Economics



## WTI Breakeven Price for a 15% After-Tax Rate of Return (\$ per Bbl)<sup>(1)</sup>



(1) Source: ISI Group report dated June 15, 2012. Defined as the threshold WTI oil price necessary to generate a 15% after-tax rate of return. Excludes acreage costs.

(2) Internal estimate for indicative large CO<sub>2</sub> EOR development project in the Gulf Coast Region.

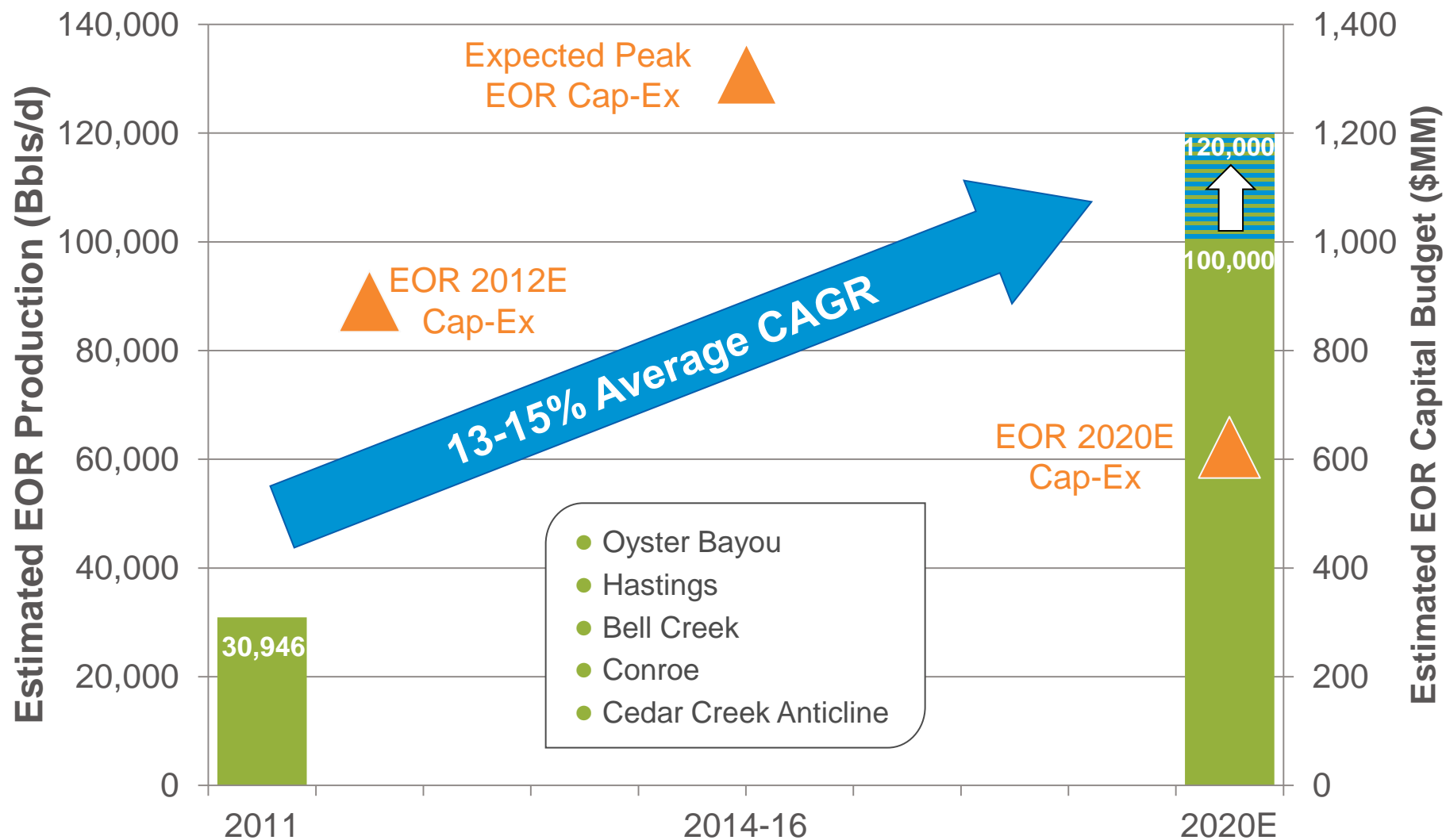
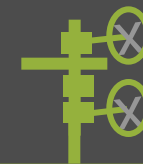


## Unique characteristics of CO<sub>2</sub> EOR provides significant capital flexibility

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- We attempt to balance development expenditures with free cash flow
- In contrast to shale plays, a reduction in EOR capital spending will not immediately impact EOR production growth
- Our newer EOR projects have many years of production growth with fairly low capital expenditures
- It is relatively easy to slow the development pace of EOR projects - most Rocky Mountain EOR infrastructure development could be delayed if necessary
- No lease expiration issues and limited capital commitments on EOR projects beyond 2012
- No near-term Bakken acreage expirations - three drilling rigs under contract through most of 2014

# Sustainable EOR Growth through 2020 (1)

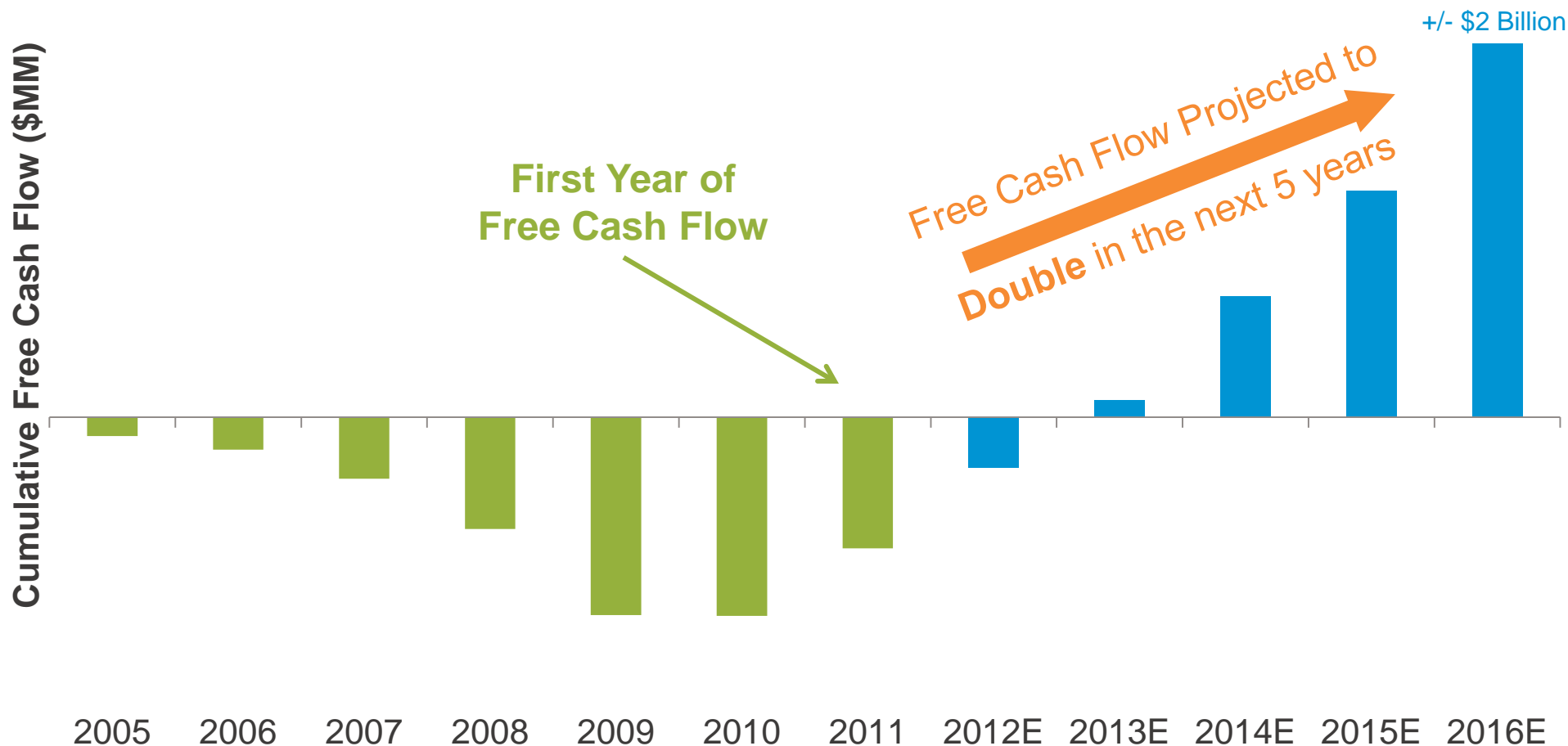


(1) 2012 and future forecasted capital expenditures and production may differ materially from actual results. See slide 27 for full disclosure.

# CO<sub>2</sub> EOR Generates Significant Free Cash Flow



## Cumulative Gulf Coast Tertiary Free Cash Flows<sup>(1)</sup>



(1) Calculated from actual historical operating cash flow (revenues less operating expenses) less capital expenditures and currently projected operating income and capital expenditures in 2012 and beyond using strip prices as of 5/4/2012. Includes Jackson Dome and Pipelines expenditures in Gulf Coast, does not include recently completed Thompson acquisition.

# Estimated EOR Peak Production Rates (as of 12/31/11)<sup>(1)</sup>



Operating Area	First Production	Estimated Peak Production Rate (Net MBOE/d)					Expected Peak Year	Produced to date <sup>(2)</sup> (MMBOE)	Proved Remaining (MMBOE)	2P&3P Remaining <sup>(3)</sup> (MMBOE)
		< 5	5-10	10-15	15-20	> 20				
Phase 1	1999						2010	36	35	11
Phase 2 (excl Heidelberg)	2006						2015-17	11	16	12
Oyster Bayou	2012						2012-13	0	---	25
Tinsley	2008						2013-14	6	31	9
Heidelberg	2009						2014-16	2	31	11
Delhi	2010						2015-17	1	27	8
Bell Creek	2013						2018-20	---	---	30
Cranfield	2009						2016-19	1	8	6
Lake Saint John	2016						2018-22	---	---	18
Hastings	2012						2021-25	---	---	75
Citronelle	Unscheduled						>2020	---	---	26
Conroe	2015						2022-26	---	---	130
Cedar Creek Anticline	2017						2023-27	---	---	197

## Expected year of first tertiary production.

- (1) Does not include recently completed Thompson acquisition, where first tertiary oil production is not anticipated prior to 2017.
- (2) Tertiary oil production only through 12/31/11
- (3) Based on internal estimates of reserve recovery

# IN SUMMARY: A Different Kind of Oil Company



## Leading CO<sub>2</sub> Enhanced Oil Recovery (EOR) Company in the U.S. with a Unique Profile

- Significant strategic advantage in CO<sub>2</sub> EOR
- Well defined and focused long-term growth strategy
- Highest operating margin and capital efficiency in peer group
- Substantial free cash flow generation from CO<sub>2</sub> EOR after up-front investment in infrastructure
- CO<sub>2</sub> EOR provides high degree of capital flexibility
- Track record of value creation in the Bakken
- Low stock price relative to net asset value





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# About Forward Looking Statements



The data contained in this presentation that are not historical facts are forward-looking statements that involve a number of risks and uncertainties. Such statements may relate to, among other things, preliminary first quarter 2012 production, forecasted capital expenditures, drilling activity, acquisition and dispositions plans, development activities, timing of CO<sub>2</sub> injections and initial production response in tertiary flooding projects, estimated costs, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO<sub>2</sub> reserves, helium reserves, potential reserves from tertiary operations, future hydrocarbon prices or assumptions, liquidity, cash flows, availability of capital, borrowing capacity, finding costs, rates of return, overall economics, net asset values, potential reserves and anticipated production growth rates in our CO<sub>2</sub> models, 2012 and future production and expenditure estimates, and availability and cost of equipment and services. These forward-looking statements are generally accompanied by words such as “estimated”, “preliminary”, “projected”, “potential”, “anticipated”, “forecasted” or other words that convey the uncertainty of future events or outcomes. These statements are based on management’s current plans and assumptions and are subject to a number of risks and uncertainties as further outlined in our most recent Form 10-K and Form 10-Q filed with the SEC. Therefore, the actual results may differ materially from the expectations, estimates or assumptions expressed in or implied by any forward-looking statement made by or on behalf of the Company.

Cautionary Note to U.S. Investors – Current SEC rules regarding oil and gas reserve information allow oil and gas companies to disclose in filings with the SEC not only proved reserves, but also probable and possible reserves that meet the SEC’s definitions of such terms. We disclose only proved reserves in our filings with the SEC. Denbury’s proved reserves as of December 31, 2011 were estimated by DeGolyer & MacNaughton, an independent petroleum engineering firm. In this presentation, we make reference to probable and possible reserves, some of which have been prepared by our independent engineers and some of which have been prepared by Denbury’s internal staff of engineers. In this presentation, we also refer to estimates of resource “potential” or other descriptions of volumes potentially recoverable, which in addition to reserves generally classifiable as probable and possible (2P and 3P reserves), include estimates of reserves that do not rise to the standards for possible reserves, and which SEC guidelines strictly prohibit us from including in filings with the SEC. These estimates, as well as the estimates of probable and possible reserves, are by their nature more speculative than estimates of proved reserves and are subject to greater uncertainties, and accordingly the likelihood of recovering those reserves is subject to substantially greater risk.

# Appendix



# CO<sub>2</sub> EOR is a Proven Process



## Significant CO<sub>2</sub> EOR Operators by Region

### Gulf Coast Region

- Denbury Resources

### Permian Basin Region

- Occidental
- Kinder Morgan
- Whiting

### Rockies Region

- Denbury Resources
- Anadarko

### Canada

- Cenovus
- Apache

## Significant CO<sub>2</sub> Suppliers by Region

### Gulf Coast Region

- Jackson Dome, MS (Denbury Resources)

### Permian Basin Region

- Bravo Dome, NM (Kinder Morgan, Occidental)
- McElmo Dome, CO (ExxonMobil, Kinder Morgan)
- Sheep Mountain, CO (ExxonMobil, Occidental)

### Rockies Region

- Riley Ridge, WY (Denbury Resources)
- LaBarge, WY (ExxonMobil)
- Lost Cabin, WY (ConocoPhillips)

### Canada

- Dakota Gasification – Anthropogenic (Cenovus, Apache)

## History of CO<sub>2</sub> EOR

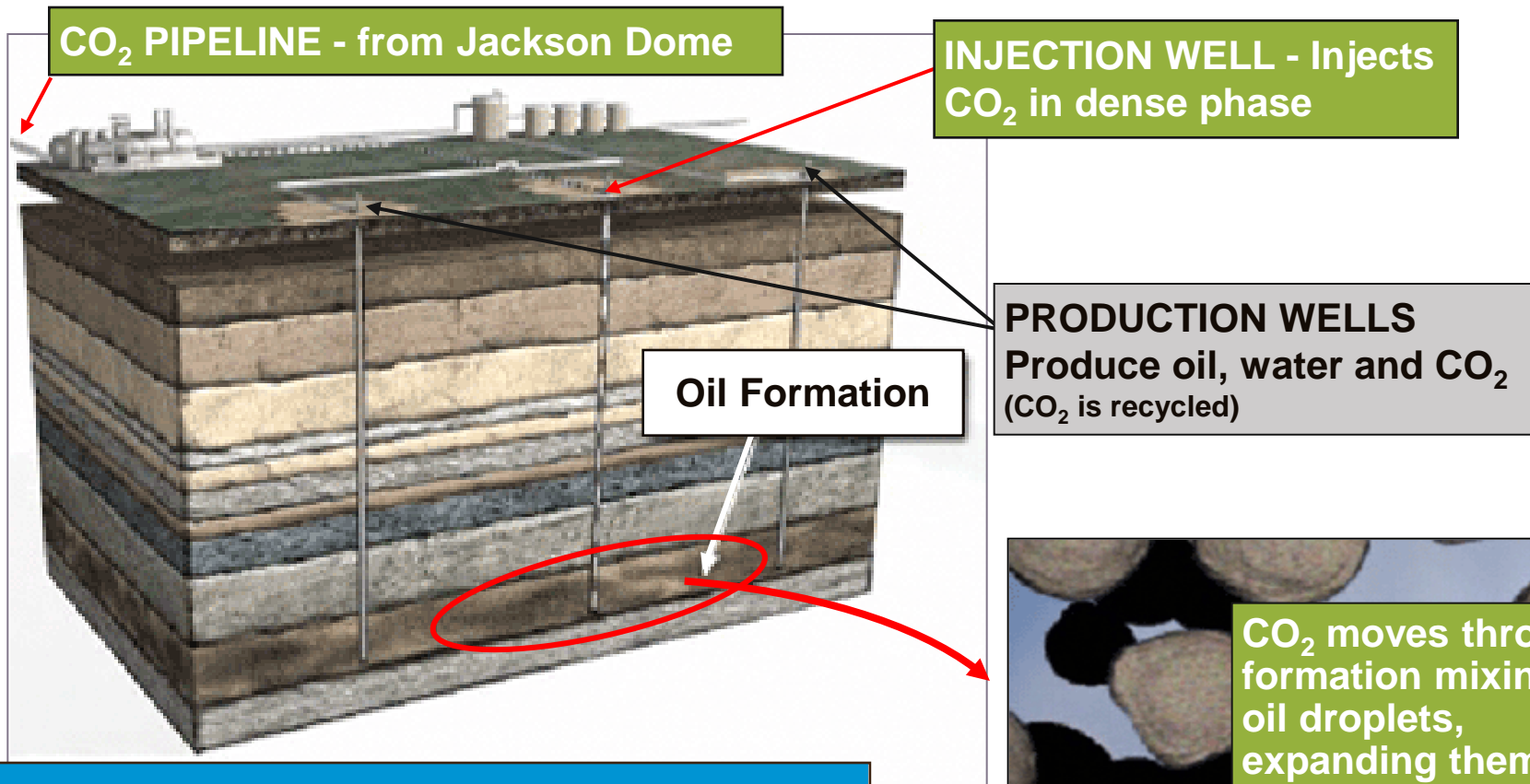
- 1910's-1970's – CO<sub>2</sub> Field Discoveries (Bravo Dome, McElmo Dome, Jackson Dome, Sheep Mountain)
- 1950's-1960's – Development & Testing
- 1972 – First Notable CO<sub>2</sub> EOR Flood in Permian Basin (SACROC)
- 1973 – First Notable CO<sub>2</sub> EOR Flood in Gulf Coast (Little Creek)
- 1986 – First Notable CO<sub>2</sub> EOR Flood in Rockies (Rangely)
- 2000 – First Anthropogenic CO<sub>2</sub> EOR Flood (Weyburn/Canada)

Denbury is the 2<sup>nd</sup> Largest CO<sub>2</sub> EOR Producer in North America<sup>(1)</sup>



(1) Based on net production interests from company filings for quarter ended 3/31/2012.

# CO<sub>2</sub> Operations: Oil Recovery Process



**Model for Oil Recovery Using CO<sub>2</sub> is +/- 17% of Original Oil in Place (Based on Little Creek)**

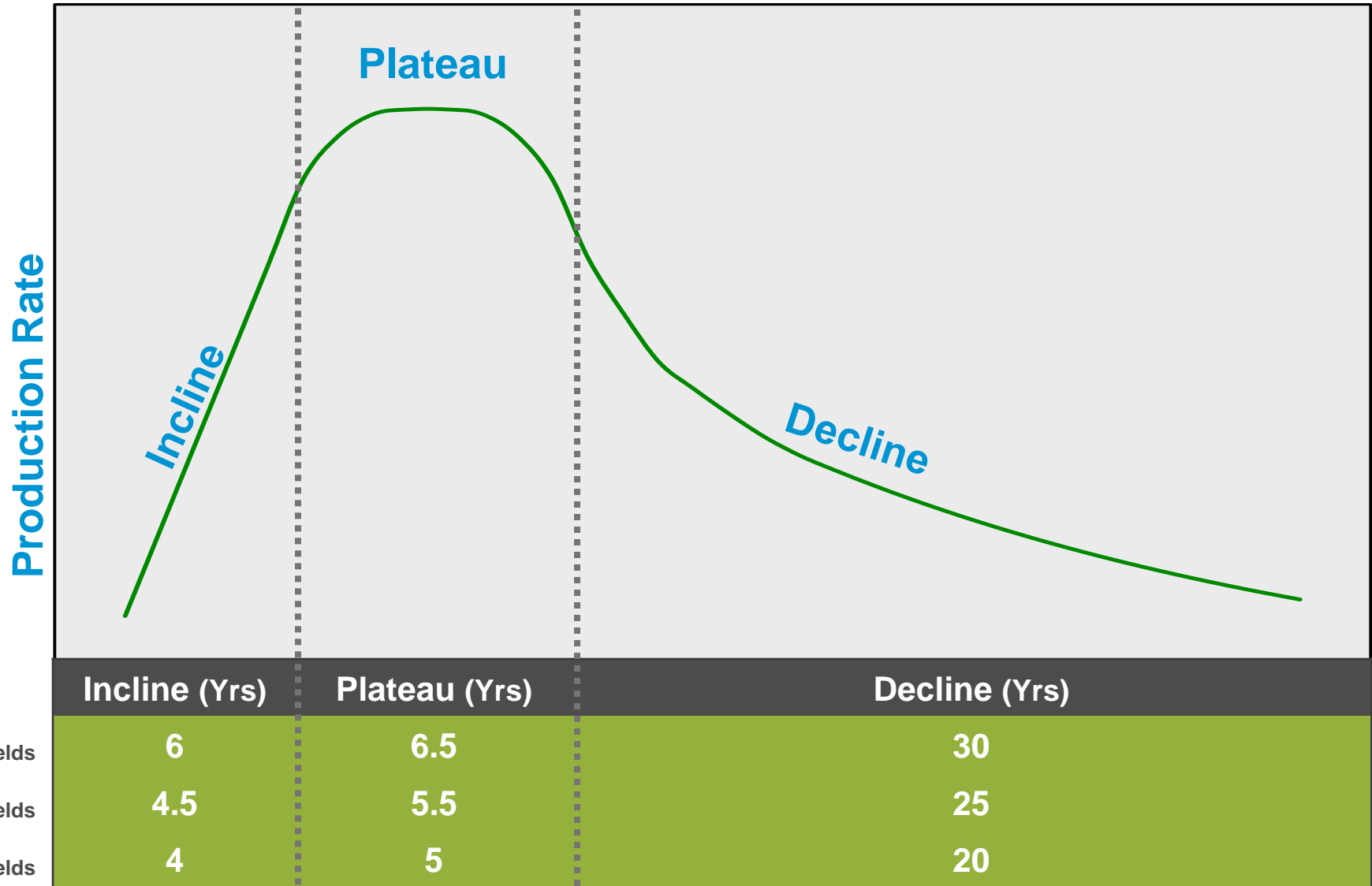
**Primary recovery = +/- 20%**

**Secondary recovery (waterfloods) = +/- 18%**

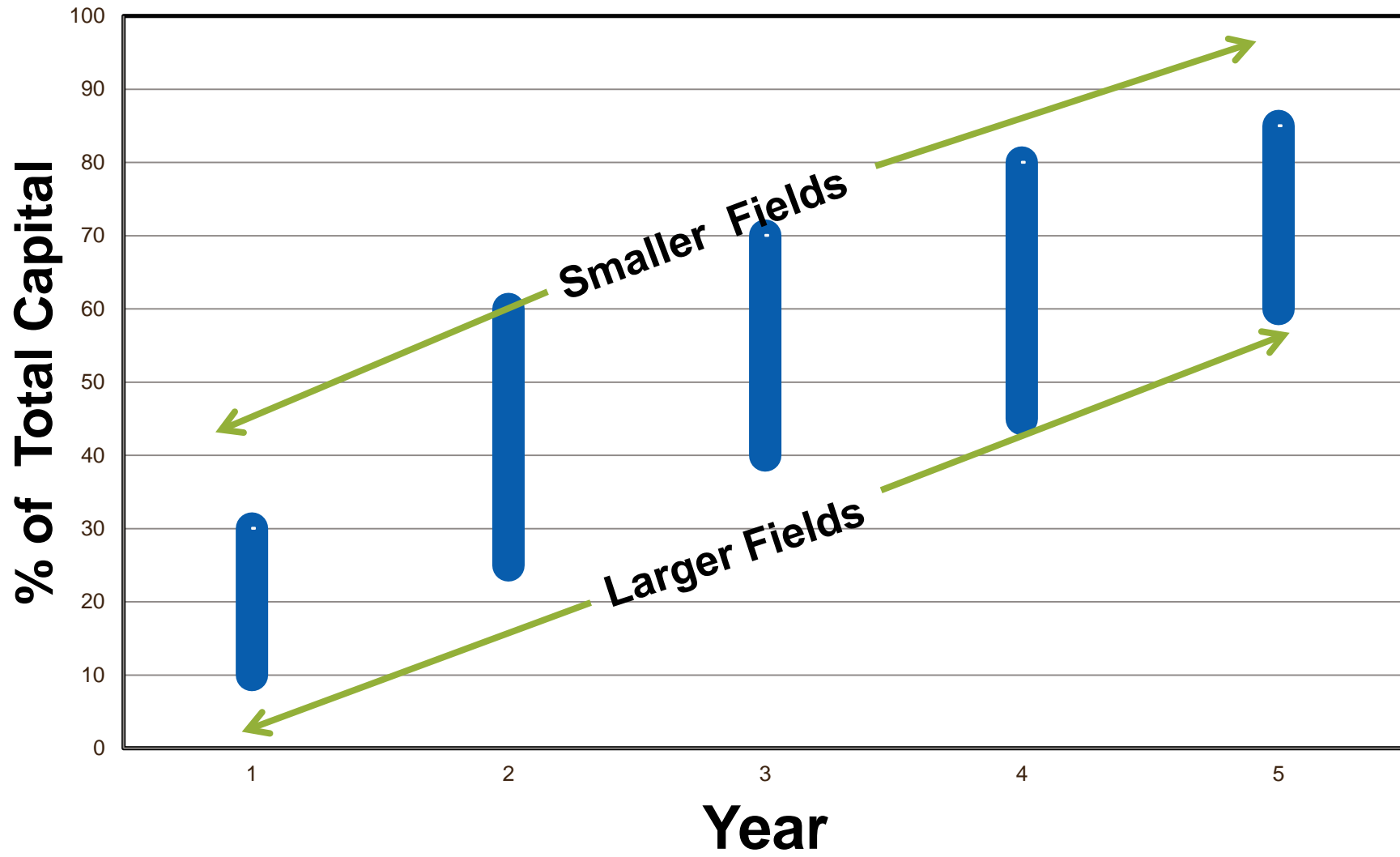
**Tertiary (CO<sub>2</sub>) = +/- 17%**



# CO<sub>2</sub> EOR Generalized Type Curve



# Capital Spending Range for CO<sub>2</sub> Floods



# Production by Area (BOE/d)



Operating area	1Q11	2Q11	3Q11	4Q11	2011	1Q12 <sup>(1)</sup>	2012E <sup>(1),(2)</sup>
Tertiary Oil Fields	30,825	30,771	31,091	31,144	30,959	33,257	33,000 - 36,000
Mississippi	5,930	5,642	5,636	4,746	5,486	4,573	4,450
Texas	4,371	4,202	4,096	3,868	4,133	3,674	4,650
Louisiana	511	454	47	141	287	191	150
Alabama & Other	1,020	1,079	1,064	1,031	1,049	1,090	950
Cedar Creek Anticline	9,163	8,925	8,930	8,858	8,968	8,496	8,300
Bakken	5,728	7,626	9,976	11,743	8,788	15,114	14,350- 16,350
Other Rockies	3,503	3,629	3,578	3,373	3,520	3,375	3,500
<b>Total Continuing Production</b>	<b>61,051</b>	<b>62,328</b>	<b>64,418</b>	<b>64,904</b>	<b>63,190</b>	<b>69,770</b>	<b>69,350- 74,350</b>
Gulf Coast Non-Core Properties	1,918	1,901	1,732	1,677	1,805	1,054	250
Paradox Basin Properties	635	690	680	653	665	708	175
<b>Total Production</b>	<b>63,604</b>	<b>64,919</b>	<b>66,830</b>	<b>67,234</b>	<b>65,660</b>	<b>71,532</b>	<b>69,775 – 74,775</b>
							<b>~90% Oil</b>

(1) In February and April 2012, we sold non-core Gulf Coast and Paradox Basin assets in separate transactions for combined net proceeds of \$213 million. The combined average annual production from with these assets in 2012 was estimated at 2,050 BOE/d. Due to their contribution to our production during the period we owned them in 2012, the sale reduced our 2012 average annual production estimates by 1,625 BOE/d.

(2) In June 2012 we acquired Thompson field for \$360 million, before working capital adjustments. Expected average production from the assets for the remainder of 2012 is estimated at 2,000 BOE/d. The acquisition increased our 2012 average annual production estimates by 1,150 BOE/d as the acquired assets will only contribute to our production for approximately seven months in 2012.

# Tertiary Production by Field



Field	Average Daily Production (BOE/d)				
	1Q11	2Q11	3Q11	4Q11	1Q12
<b>Phase 1</b>					
Brookhaven	3,664	3,213	3,030	3,121	3,014
Little Creek Area	1,637	1,636	1,533	1,445	1,216
Mallalieu Area	2,925	2,646	2,620	2,587	2,585
McComb Area	2,161	1,983	2,005	1,843	1,746
Lockhart Crossing	1,653	1,560	1,346	1,304	1,284
<b>Phase 2</b>					
Martinville	500	416	453	481	551
Eucutta	3,247	3,114	2,985	3,139	3,090
Soso	2,582	2,317	2,331	2,162	2,063
Heidelberg	3,374	3,548	3,141	3,728	3,583
<b>Phase 3</b>					
Tinsley	6,567	6,990	7,075	6,338	7,297
<b>Phase 4</b>					
Cranfield	991	1,085	1,214	1,200	1,152
<b>Phase 5</b>					
Delhi	1,524	2,263	3,358	3,778	4,181
<b>Phase 7</b>					
Hastings	---	---	---	---	618
<b>Phase 8</b>					
Oyster Bayou	---	---	---	18	877
<b>Total Tertiary Production</b>	<b>30,825</b>	<b>30,771</b>	<b>31,091</b>	<b>31,144</b>	<b>33,257</b>

# Analysis of Tertiary Operating Costs



	Correlation w/Oil	1Q10 \$/BOE	2Q10 \$/BOE	3Q10 \$/BOE	4Q10 \$/BOE	1Q11 \$/BOE	2Q11 \$/BOE	3Q11 \$/BOE	4Q11 \$/BOE	1Q12 \$/BOE
CO <sub>2</sub> Costs	Direct	\$4.50	\$4.73	\$4.52	\$5.38	\$5.39	\$5.43	\$4.87	\$4.53	\$5.76
Power & Fuel	Partially	6.12	5.82	6.03	5.76	6.12	6.17	6.24	6.71	\$6.71
Labor & Overhead	None	3.58	3.50	3.70	3.43	3.94	3.77	3.85	3.90	\$4.59
Equipment Rental	None	2.13	2.02	1.93	1.79	2.20	1.52	2.28	2.38	\$2.30
Chemicals	Partially	1.41	1.41	1.73	1.67	1.62	1.44	1.80	1.67	\$1.63
Workovers	Partially	2.97	1.62	2.78	2.36	3.75	2.53	3.44	2.68	\$3.43
Other	None	1.21	1.56	1.68	1.34	1.91	2.01	2.43	1.72	\$2.32
<b>Total</b>		<b>\$21.92</b>	<b>\$20.66</b>	<b>\$22.37</b>	<b>\$21.73</b>	<b>\$24.93</b>	<b>\$22.87</b>	<b>\$24.91</b>	<b>\$23.59</b>	<b>\$26.74</b>
<b>NYMEX Oil Price</b>		<b>\$78.61</b>	<b>\$78.12</b>	<b>\$76.10</b>	<b>\$85.16</b>	<b>\$94.26</b>	<b>\$102.58</b>	<b>\$89.60</b>	<b>\$93.93</b>	<b>\$102.87</b>

Beginning in November 2011, Ad Valorem Taxes and any other production taxes that had previously been recorded as a part of LOE are no longer in LOE. These taxes are now reflected in the "Taxes other than income" category. To maintain comparability, all prior period LOE in this analysis have been restated to reflect these changes.

# Potential Carbon Gasification Projects



- Denbury purchase contracts (contingent on plants being completed)
  - Initial production expected +/- 4 years after construction begins (not before 2015)

Gulf Coast Sources (\$0.29 to \$0.44/Mcf @ \$60 Oil)		MMCFD
Mississippi Power <sup>(4)</sup> (2014)	<i>Currently Under Construction</i>	+/- 115
Air Products (Port Arthur, TX) <sup>(4)</sup> (Q1 2013)		50
Lake Charles Cogeneration LLC <sup>(3)</sup>		190 – 240
Mississippi Gasification (SNG) <sup>(1)</sup> <sup>(2)</sup> <sup>(3)</sup>		170 – 225

Midwest Sources (\$0.20/Mcf @ \$60 Oil)		MMCFD
Indiana Gasification (SNG) <sup>(1)</sup> <sup>(2)</sup>		230 – 300
Power Holdings of Illinois (SNG) <sup>(1)</sup>		250 – 300
Christian County Generation/Tenaska of Illinois (SNG) <sup>(1)</sup> <sup>(2)</sup> <sup>(5)</sup>		170 – 225
Cash Creek Kentucky (SNG) <sup>(1)</sup>		190 – 210

(1) Requires additional supplies and additional pipeline.

(2) In term sheet negotiation phase under the U.S. Department of Energy Loan Guarantee Program.

(3) Denbury and Producer selected for DOE Grant FOA-0000015 (grant dollars, not loan guarantees).

(4) Under Construction

(5) Contingent on having pipeline capacity.

# Rockies Anthropogenic CO<sub>2</sub>



Rocky Mountain Purchase Contracts		MMCFD
COP Lost Cabin (Central Wyoming) (Q1 2013)	<i>Currently Under Construction</i>	+/- 50
XOM LaBarge (SW Wyoming) <sup>(1)</sup> (Q3 2012)		+/- 50
DKRW Medicine Bow (SE Wyoming) <sup>(2)</sup> (+/- 2016)		+/- 100
Rocky Mountain CO <sub>2</sub> Ownership		MMCFD
<b>Riley Ridge Unit - LaBarge (SW Wyoming) (2016)</b>		<b>+/- 130<sup>(4)</sup></b>
Rocky Mountain Potential Sources		MMCFD
GasTech (NE Wyoming)		+/- 115
Quintana South Heart Project (SW North Dakota)		+/- 100
Dakota Gasification (SW North Dakota) <sup>(3)</sup>		+/- 250

(1) Grieve Field Contract – Potential for more XOM supply.

(2) In term sheet negotiation phase under the U.S. Department of Energy Loan Guarantee Program.

(3) Includes volumes currently under contract by third parties

(4) Initial capacity, potential to increase to +/- 600 MMCFD by 2021

# Most Recent Operated Bakken Well Activity



Completed Well	Area	Formation	IP <sup>(1)</sup>	30-Day Avg. <sup>(2)</sup> (BOE/d)	60-Day Avg. <sup>(2)</sup> (BOE/d)	90-Day Avg. <sup>(2)</sup> (BOE/d)	Unit Acres	Frac Stages	W. I.	IP Date
Charlson 34-12	Charlson	Bakken	1,441	524	538	477	640	15	58%	10/1/11
Rolfson 21-16 SEH	Cherry	Bakken	2,340	576	638	650	1,280	26	69%	10/17/11
Loomer 24-34 SEH	Cherry	Bakken	1,850	26 <sup>(3)</sup>	362	459	1,280	26	59%	10/20/11
Rolfson 11-16 NEH	Cherry	Bakken	2,694	683	667	663	1,280	25	66%	10/26/11
Loomer 21-4 SWH	Cherry	Bakken	1,689	549	647	632	1,280	26	72%	11/23/11
Satter 31-1 SWH	Cherry	TFS	1,715	587	606	570	1,280	26	84%	11/30/11
Sorenson 31-28 SWH	Cherry	Bakken	1,614	38 <sup>(4)</sup>	348	456	1,280	26	68%	12/2011
Bergem 44-28 NWH	Cherry	Bakken	1,170	327	333	290	1,280	20	55%	12/2011
Loomer 24-34 NEH	Cherry	Bakken	1,689	30	47	190 <sup>(5)</sup>	1,280	26	49%	12/2011
Serrahn 41-6 SWH	Cherry	Bakken	2,035	815	608	623	1,280	26	75%	1/13/12
Stepanek 31-17 SWH	Camp	Bakken	835	532	464	389	1,280	26	59%	1/10/12
Jore 34-22 NWH	Cherry	Bakken	2,060	816	721	679	1,280	26	48%	1/15/12
Satter 24-35 NEH	Cherry	Bakken	1,393	852	738	663	1,280	26	91%	1/21/12

(1) Consecutive 24-hour test in BOE/d.

(2) Date from first significant production.

(3) Dual Pad. Waiting on NEH clean-out to open up.

(4) CO Issues. Waiting to finish Completion.

(5) Pad issues. Last 30 Avg 464 BOE/d.

# Most Recent Operated Bakken Well Activity



Completed Well	Area	Formation	IP <sup>(1)</sup>	30-Day Avg. <sup>(2)</sup> (BOE/d)	60-Day Avg. <sup>(2)</sup> (BOE/d)	90-Day Avg. <sup>(2)</sup> (BOE/d)	Unit Acres	Frac Stages	W. I.	IP Date
Satter 24-35 SEH	Cherry	Bakken	2,015	892	851	809	1,280	26	91%	1/24/12
Roen 24-23 NEH	Camp	Bakken	1,039	370	360	325	1,280	26	43%	2/13/12
Erickson 41-25 NWH	Camp	Bakken	1,153	337	359	N/A	1,280	26	42%	2/26/12
Erickson 41-25 SWH	Camp	Bakken	1,170	155 <sup>(3)</sup>	202	N/A	1,280	15	40%	3/6/12
Nelson 24-11 NEH	Cherry	Bakken	2,178	988	N/A	N/A	1,280	26	81%	3/9/12
Johnson 24-31 NEH	Cherry	Bakken	2,091	808	648	N/A	1,280	26	98%	3/10/12
Iverson 34-19 NWH	Camp	Bakken	809	N/A	N/A	N/A	1,280	26	69%	4/3/2012
Johnsrud 21-13 SEH <sup>(4)</sup>	Cherry	TFS	928	260	N/A	N/A	1,280	26	87%	3/30/2012

(1) Consecutive 24-hour test in BOE/d.

(2) Date from first significant production.

(3) Dual Pad. Impacted due to waiting on NWH clean-out.

(4) Completion Issues – partially stimulated.

# Most Recent Operated Bakken Well Activity



Completed Well	Area	Formation	IP <sup>(1)</sup>	30-Day Avg. <sup>(2)</sup> (BOE/d)	60-Day Avg. <sup>(2)</sup> (BOE/d)	90-Day Avg. <sup>(2)</sup> (BOE/d)	Unit Acres	Frac Stages	W. I.	IP Date
Lundin 11-13 SEH	Cherry	Bakken	2,663	N/A	N/A	N/A	1,280	26	87%	4/10/2012
Rink 12-4 SEH	Cherry	TFS	2,097	N/A	N/A	N/A	1,280	22	83%	4/23/2012
Johnson 43-27 NWH	Murphy Creek	TFS	Flowing <sup>(3)</sup>	N/A	N/A	N/A	1,280	22	81%	
Johnson 43-27 NEH	Murphy Creek	TFS	Flowing <sup>(3)</sup>	N/A	N/A	N/A	1,280	14	51%	

(1) Consecutive 24-hour test in BOE/d.

(2) Date from first significant production.

(3) Unloading completion fluid. No IP to date.

# Most Recent Operated Bakken Well Activity



Completing	Area	Formation	Frac Date	30-Day Avg.	Unit Acreage	Frac Stages	W. I.
Olson 34-19 NWH <sup>(1)</sup>	Cherry	Bakken	May 2012	N/A	1,280	24	79%
Olson 34-19 SWH <sup>(1)</sup>	Cherry	Bakken	Shut in	N/A	1,280	22	63%
Lund 44-8 NH	Cherry	Bakken	May 2012	N/A	1,280	26	74%
Lund 44-8 SH	Cherry	Bakken	May 2012	N/A	640	16	94%
Tobacco Garden 41-18 SH	Cherry	Bakken	May 2012	N/A	1,280	26	61%
Lundin 41-14 SWH	Cherry	TFS	May 2012	N/A	1,280	22	78%
Lundin 11-4 SH	Cherry	TFS	June 2012	N/A	640	16	66%

Drilling	Area	Formation	Spud Date	Frac Date	Acreage	Frac Stages	W. I.
Grimestad 34-33 NEH	Charlson	TFS	5/13/2012	7/2012	640	16	44%
James 41-3SH	Camp	TFS	4/20/2012	Non-op After Drill	1,280	22	24%
Amundson 44-22 NWH	Cherry	TFS	3/29/2012	6/2012	1,280	22	100%
Tobacco Garden 31-29NEH	Cherry	Bakken	3/31/2012	6/2012	1,280	22	66%
Tobacco Garden 31-29 SEH	Cherry	TFS	4/2/2012	6/2012	1,280	22	61%
Lund 26-18SH	Cherry	TFS	4/23/2012	7/2012	1,280	22	80%

(1) Dual Pad. Completion Issue on 34-19 NWH.

# Bakken Area Production Zones



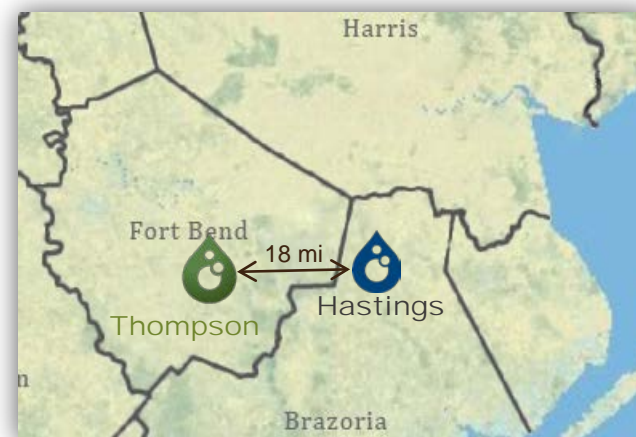
Area	Productive Zone		Estimated Wells/DSU	Approx. Net Acreage
	MB	TFS		(1,000's)
Charlson	✓	✓	6	15
Murphy Creek	✓	✓	6	18
Bear Creek	✓	✓	6	10
Cherry	✓	✓	6	66
Lone Butte	✓	✓	6	9
Camp/Indian Hills	✓	?	6	16
NE Foothills	✓	?	3	10
Old Shale Play	✓	✓	6	46
Montana & Other Areas	✓	?	3	12
<b>Total</b>				<b>202</b>

# Thompson Field, Fort Bend County, Texas



## Thompson Field

- Acquired in June 2012 for \$360 million cash, excluding working capital adjustments, and a production payment
- Denbury is the operator with a nearly 100% working interest and 84.7% net revenue interest
- Original oil in place of ~650 MMBbls, with zones initially targeted for CO<sub>2</sub> flood estimated to have ~300 MMBbls of OOIP
- Potential tertiary oil reserves between 30-60 MMBbls (based on recovery factor from other Gulf Coast CO<sub>2</sub> floods)
- Requires ~18 mile pipeline extension to Green Pipeline
- Estimated 2012 development costs ~\$12 million
- Estimated average production for remainder of 2012 of 2,000 net BOPD
- Estimated 17 MMBbls of conventional potential reserves



# Encore Acquisition was Highly Profitable



Purchase price:	(Billions)
Equity	\$2.8
Debt assumed	1.0
<b>Total value</b>	<b>\$3.8</b> <sup>(1)</sup>

Value: (Estimated values at \$79.43/Bbl – 12/31/10 SEC Pricing)	
Proved reserves at 12/31/10	\$2.0 <sup>(2)</sup>
Proceeds from sold properties	1.5
Net cash flow from 3/9/10 to 12/31/10	0.3
<b>Total</b>	<b>\$3.8</b>
<b>Additional potential:</b>	
Bakken potential	(253 MMBOE) <sup>(3)</sup>
EOR potential	(227 MMBOE)

(1) Excludes consolidated ENP debt and minority interest in ENP.

(2) Excludes sold properties, and ENP reserves.

(3) Current 3P estimates less 12/31/2010 reserves.

# Crude Oil & Natural Gas Hedge Detail



## 2012 Crude Oil Hedges (BOPD) <sup>(1)</sup>

Instrument	Volume	Average <sup>(2)</sup>		Ceiling		
		Price	Floor	Ceiling	Low	High
Q2 Collars	26,000		70.00	113.26	110.00	115.00
	18,000		70.00	119.78	118.85	120.90
	9,000		70.00	136.63	136.00	137.50
	625		65.00			
Swap	625	81.04				
H2 Collars	12,000		80.00	124.54	123.00	125.62
	24,000		80.00	127.70	126.25	129.35
	14,000		80.00	131.04	130.00	132.75
	3,000		80.00	140.13	139.10	140.65
	Put	625		65.00		
Swap	625	81.04				

## 2012 Natural Gas (MCFD)

Instrument	Volume	Average <sup>(2)</sup>		
		Price	Low	High
FY12 Swaps	7,000	6.31	6.30	6.35
	11,000	6.62	6.60	6.65
	2,000	6.82	6.80	6.85

## 2013 Crude Oil Hedges (BOPD) <sup>(1)</sup>

Instrument	Volume	Average <sup>(2)</sup>		Ceiling		
		Price	Floor	Ceiling	Low	High
Q1 Collars	12,000		70.00	106.07	104.50	107.40
	28,000		70.00	110.34	109.00	112.00
	11,000		70.00	112.82	112.50	113.00
	4,000		70.00	116.00	115.00	117.00
Q2 Collars	24,000		75.00	115.11	115.00	115.90
	18,000		75.00	116.99	116.50	118.00
	8,000		75.00	122.18	121.00	124.20
Q3 Collars	20,000		75.00	120.04	119.50	120.78
	26,000		75.00	122.11	121.00	123.80
	4,000		75.00	132.93	132.75	133.10
Q4 Collars	8,000		80.00	120.00	120.00	120.00
	18,000		80.00	126.63	126.00	127.50
	12,000		80.00	121.10	121.00	121.50

(1) All crude oil derivative contracts are based on West Texas Intermediate (WTI) NYMEX price basis.

(2) Averages are volume weighted

# Capital Structure



(\$MM)	3/31/12
<b>Cash</b>	<b>\$217</b>
Bank credit facility (Borrowing base of \$1.6 billion, matures May 2016)	445
9.750% Sr. Sub Notes due 2016 (Callable March 2013 at 104.875% of par)	410
9.500% Sr. Sub Notes due 2016 (Callable May 2013 at 104.75% of par)	236
8.250% Sr. Sub Notes due 2020 (Callable February 2015 at 104.125% of par)	996
6.375% Sr. Sub Notes due 2021 (Callable August 2016 at 103.18% of par)	400
Other Encore Sr. Sub Notes	4
Genesis pipeline financings / other	255
<b>Total long-term debt</b>	<b>\$2,746</b>
Equity	4,928
<b>Total capitalization</b>	<b>\$7,674</b>
1Q12 Annualized Adjusted cash flow from operations <sup>(1)</sup>	\$1,408
Debt to 1Q12 Annualized Adjusted cash flow from operations	1.9x
<b>Debt to total capitalization</b>	<b>36%</b>

(1) A non-GAAP measure, please visit our website for a full reconciliation.