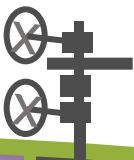


Denbury

Corporate Presentation

March 2012



NYSE: DNR

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, forecasted capital expenditures, dates of pipeline construction commencement and completion, drilling activity, acquisition and dispositions plans, development activities, timing of CO₂ injections and initial production response in tertiary flooding projects, estimated costs, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO₂ 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 CO₂ models, 2012 estimated production, 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”, “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.

A Different Kind of Oil Company



Leading CO₂ Enhanced Oil Recovery (EOR) Company in the U.S. with a Unique Profile

Scale

- ~\$10 billion enterprise value
- 67,234 BOE/d production (4Q11)
- Highest crude oil exposure in peer group⁽¹⁾

Performance

- 30% compound annual growth rate (CAGR) in EOR production over the last 12 years

Platform

- Infrastructure in place with secure CO₂ supply
- More than 1 billion barrels of potential oil reserves
- Experienced management team

Liquidity

- Projecting \$1.2 billion-to-\$1.4 billion of cash flow in 2012
- \$1.2 billion of credit facility availability at 12/31/11

Sustainable Growth

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

(1) Please reference slide 11 for more information.

Denbury at a Glance

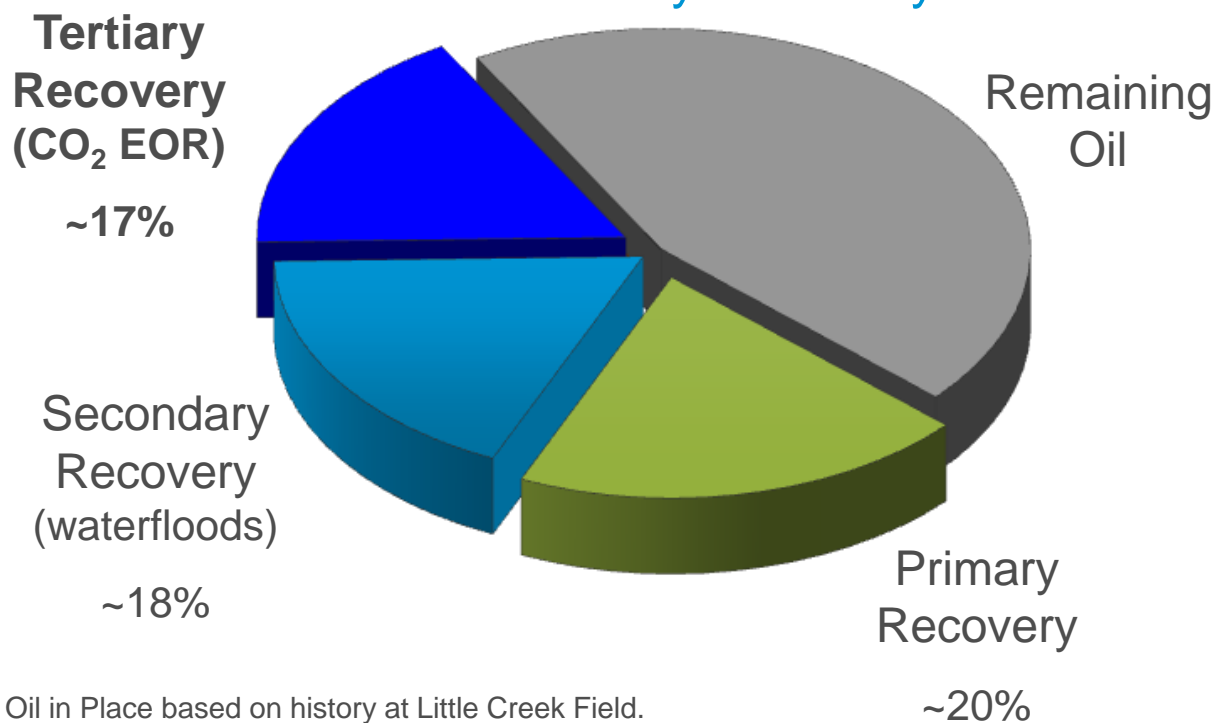


Total 3P Reserves (12/31/11)	~1.3 BBOE
% Oil Production (4Q11)	94%
Market Cap (2/29/12)	~\$7.9 billion
Total Net Debt (12/31/11)	\$2.7 billion
Total Production (4Q11)	67,234 BOE/d
Proved PV-10 (12/31/11) \$96.19 NYMEX Oil Price	\$10.6 billion
CO ₂ 3P Reserves (12/31/11)	~16 Tcf
CO ₂ Pipelines Controlled & Under Construction	~1,000 miles
Credit Facility Availability (12/31/11)	\$1.2 billion

What is CO₂ EOR & How Much Does It Recover?



EOR Delivers Almost as Much Production as Primary or Secondary Recovery⁽¹⁾



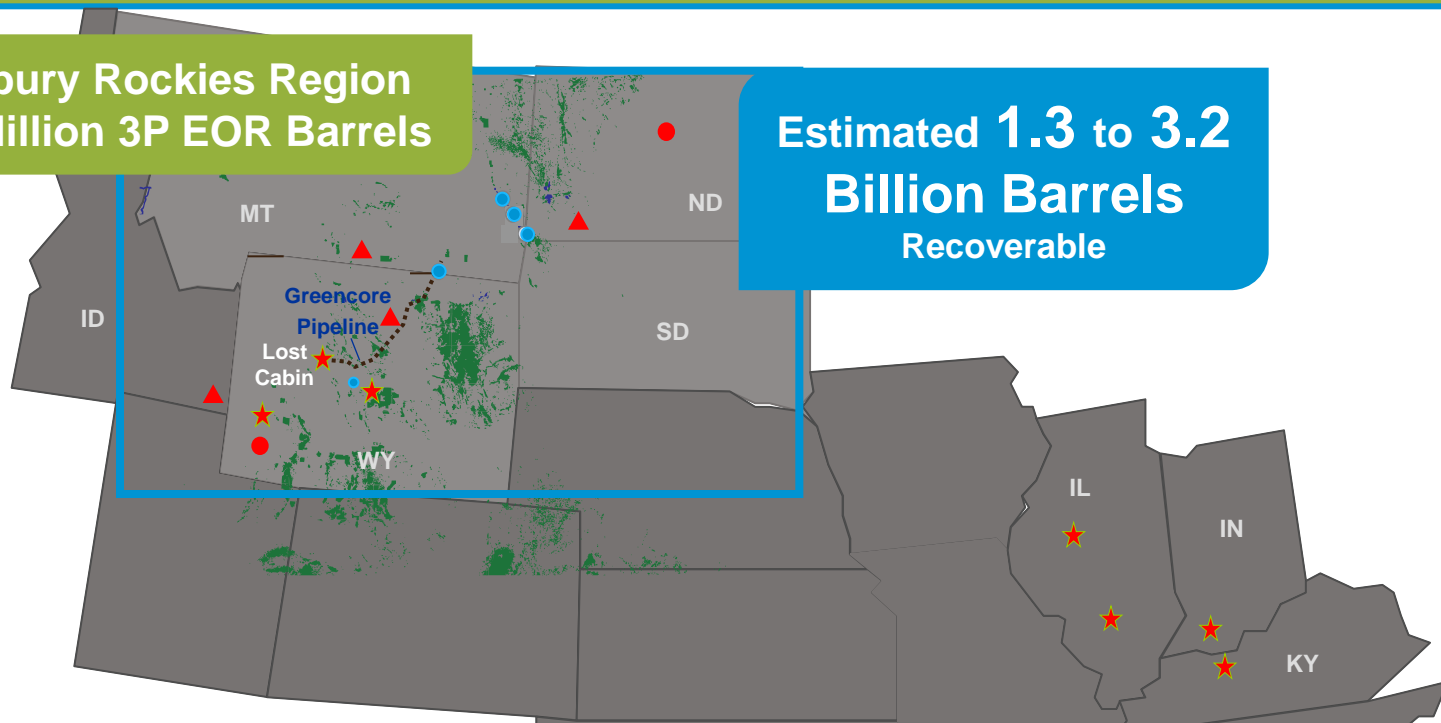
(1) Recovery of Original Oil in Place based on history at Little Creek Field.

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



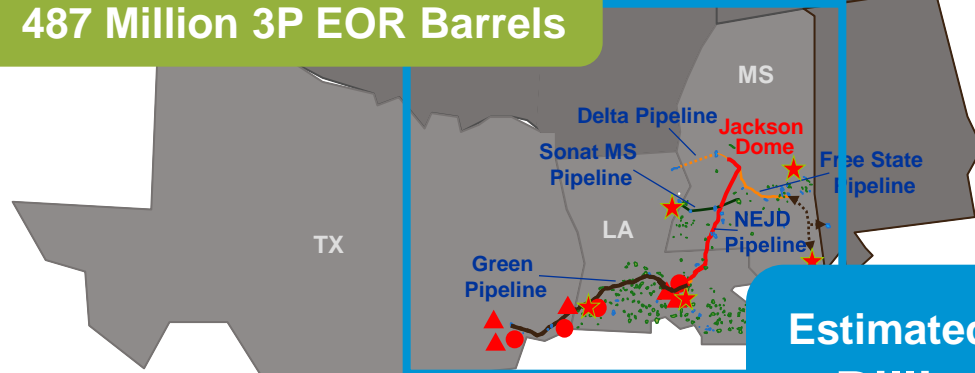
Denbury Rockies Region
233 Million 3P EOR Barrels

**Estimated 1.3 to 3.2
Billion Barrels
Recoverable**



Denbury Gulf Coast Region
487 Million 3P EOR Barrels

**Estimated 3.4 to 7.5
Billion Barrels
Recoverable**

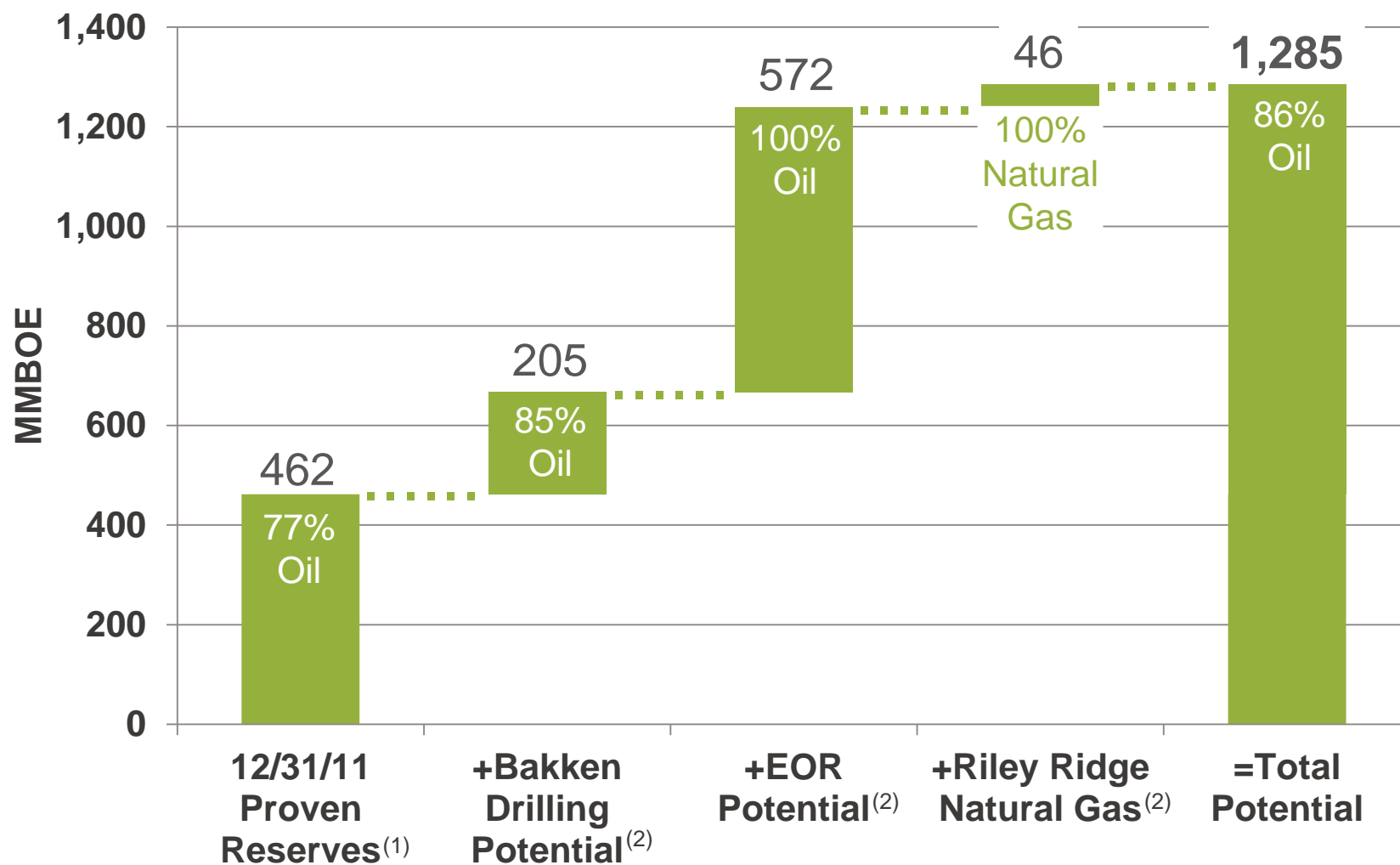


- Existing CO₂ Pipelines
- CO₂ Pipelines Under Development
- Denbury owned Rocky Mountain Fields With EOR Potential
- Existing Anthropogenic CO₂ Sources
- ▲ Proposed Coal to Gas or Liquids
- ★ Existing or Proposed CO₂ Source Owned or Contracted

Source: DOE 2005 and 2006 reports.

Note: 3P total reserves as of 12/31/11, based on a variety of recovery factors.

More than a Billion Barrels of Oil Potential

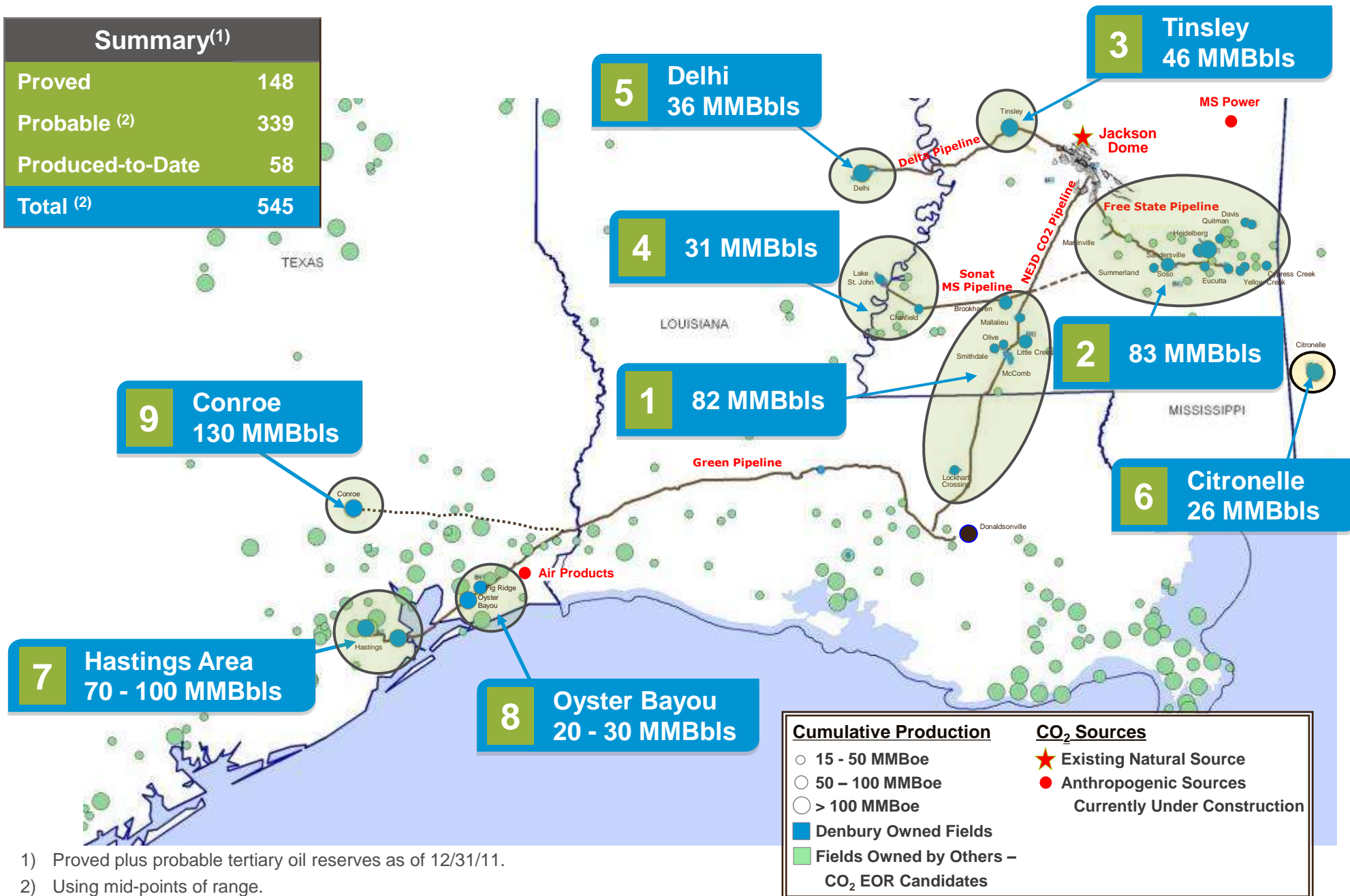


(1) Based on year-end 12/31/2011 SEC proved reserves
 (2) Estimates based on internal calculations, refer to slide 2

Gulf Coast Region: Control of CO₂ Sources & Pipeline Infrastructure Provides a Strategic Advantage



Summary ⁽¹⁾	
Proved	148
Probable ⁽²⁾	339
Produced-to-Date	58
Total ⁽²⁾	545



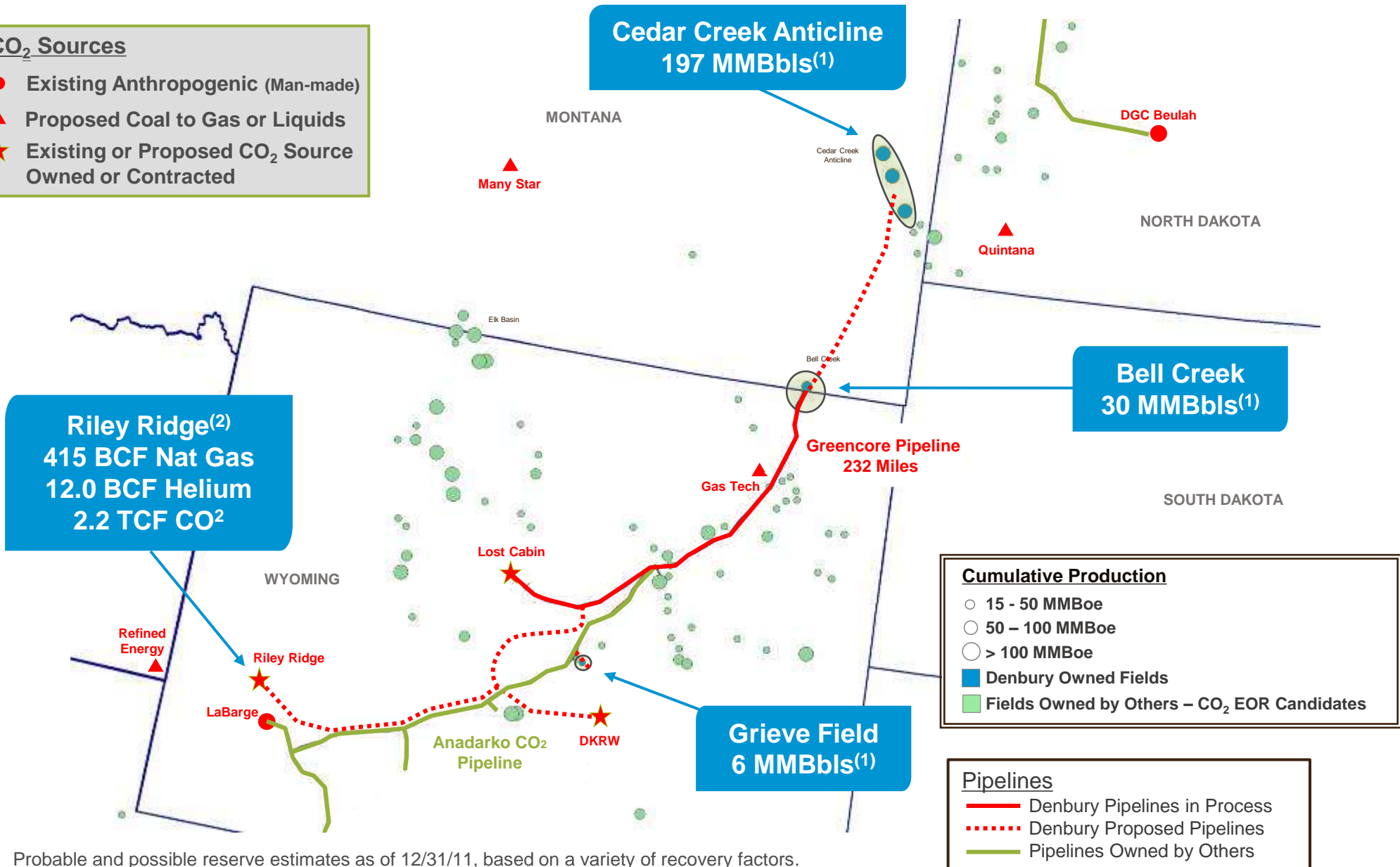
1) Proved plus probable tertiary oil reserves as of 12/31/11.

2) Using mid-points of range.

Rockies Region: Control of CO₂ Sources & Pipeline Infrastructure Provides a Strategic Advantage



- CO₂ Sources**
- Existing Anthropogenic (Man-made)
 - ▲ Proposed Coal to Gas or Liquids
 - ★ Existing or Proposed CO₂ Source Owned or Contracted



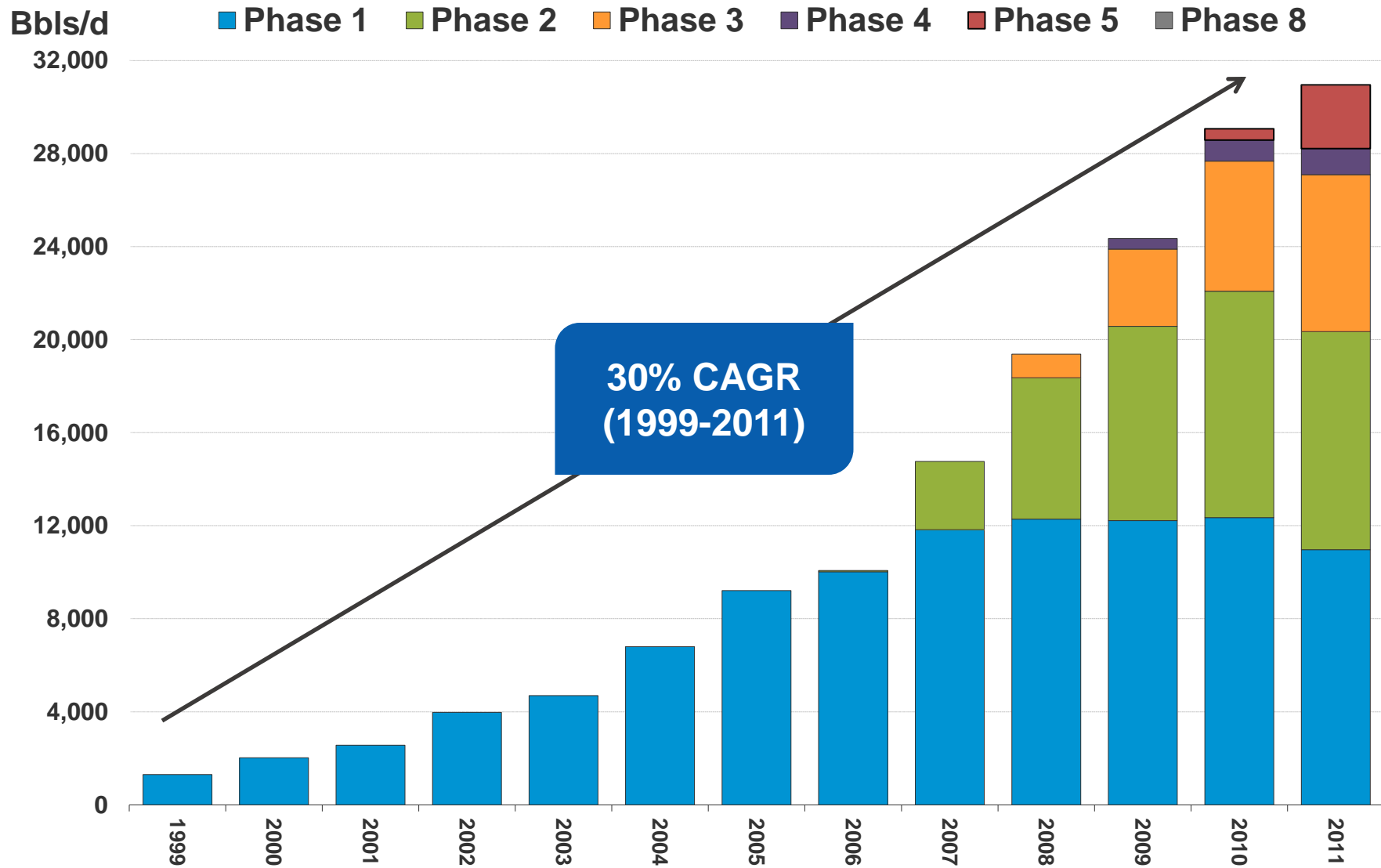
1) Probable and possible reserve estimates as of 12/31/11, based on a variety of recovery factors.
 2) Proved reserves as of 12/31/2011

- Cumulative Production**
- 15 - 50 MMBoe
 - 50 - 100 MMBoe
 - > 100 MMBoe
 - Denbury Owned Fields
 - Fields Owned by Others – CO₂ EOR Candidates
- Pipelines**
- Denbury Pipelines in Process
 - ⋯ Denbury Proposed Pipelines
 - Pipelines Owned by Others

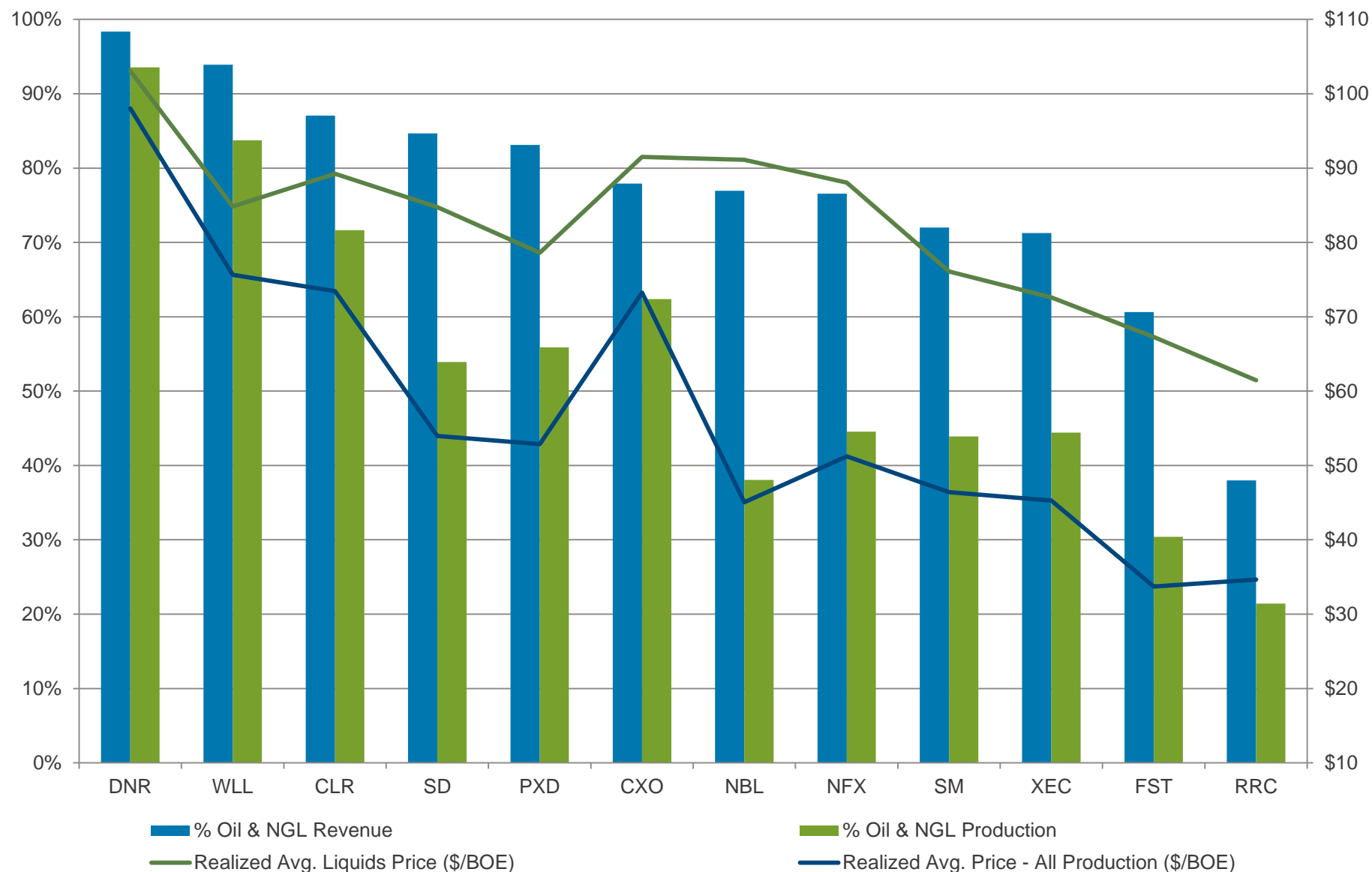
Proven Track Record



Net Daily Oil Production – Tertiary Operations (through 12/31/11)



Oiliest Assets in the Peer Group



(1) Data derived from company filings for 3 months ended 12/31/11.

Compelling Economics⁽¹⁾



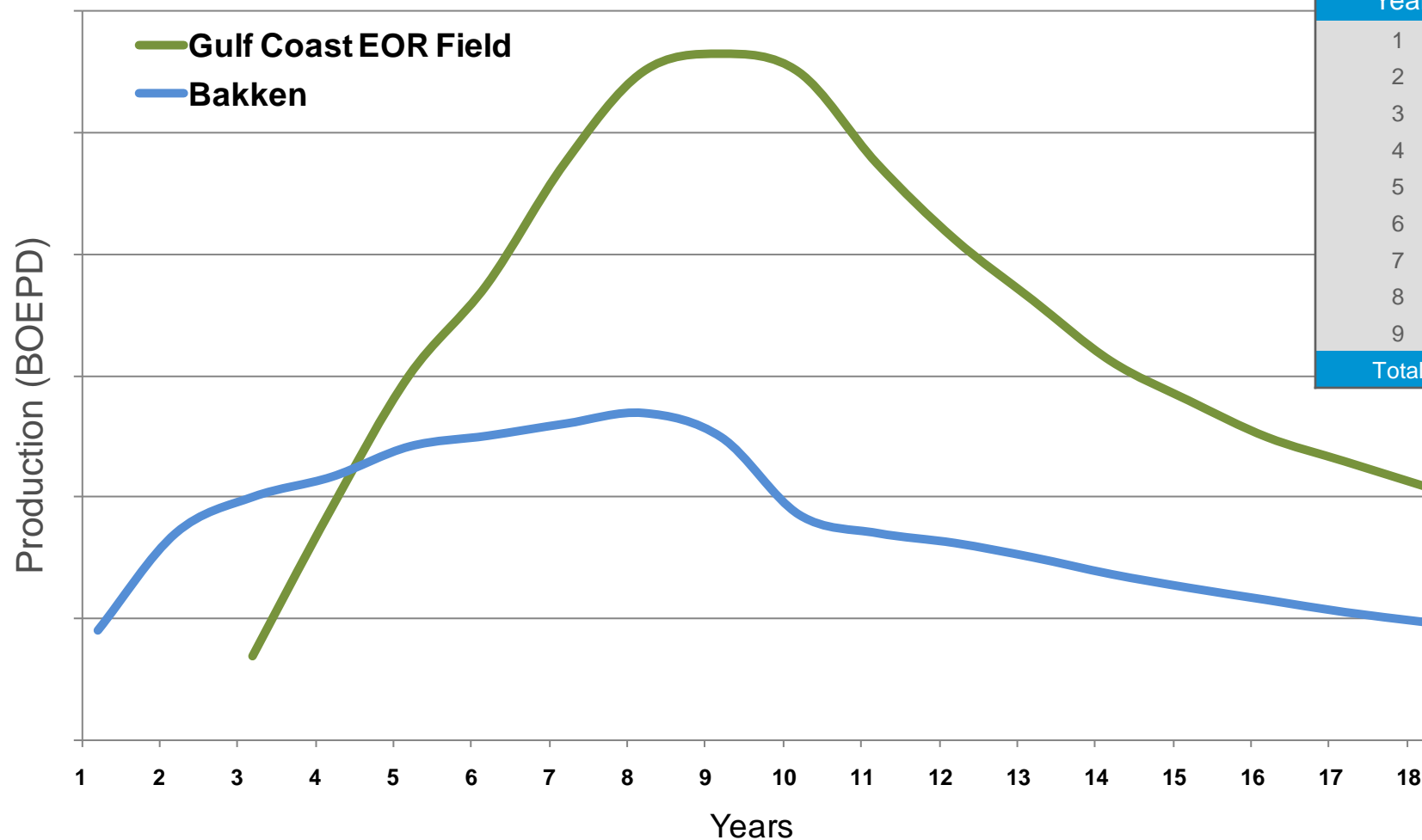
	EOR	Bakken
	Gulf Coast Model Averages	575,000 BOE / Well \$9.6 Million / Well 20% Royalty
NYMEX oil price	\$90.00	\$90.00
Finding & development cost:		
Field	9.00	21.00
Infrastructure	4.50	---
Total capital per BOE	\$13.50	\$21.00
Average operating cost over life	25.00	8.00
Average historic NYMEX differentials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

(1) Updated as of 12/31/11

Complementary Production Profiles



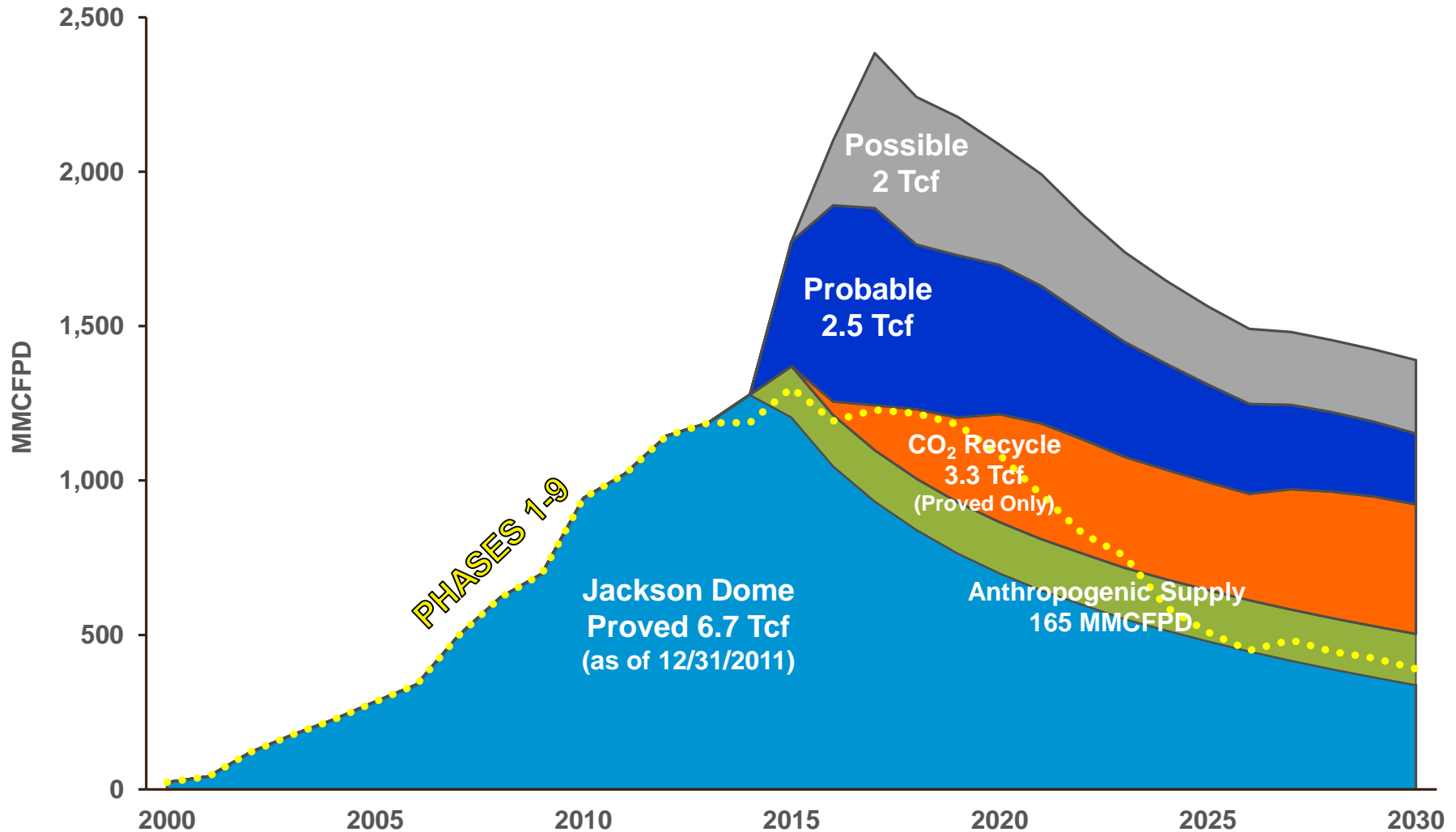
Projected Production Profile with Same Capital Spending



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
Total	\$555

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

Secure CO₂ Supply to Support Gulf Coast Growth



Note: CO₂ recycle assumed to be 50% of proved. Forecast based on internal management estimates. Actual results may vary. Phases 1-9 including industrial.

Secure CO₂ Supply to Support Rocky Mountain Growth



LaBarge Field

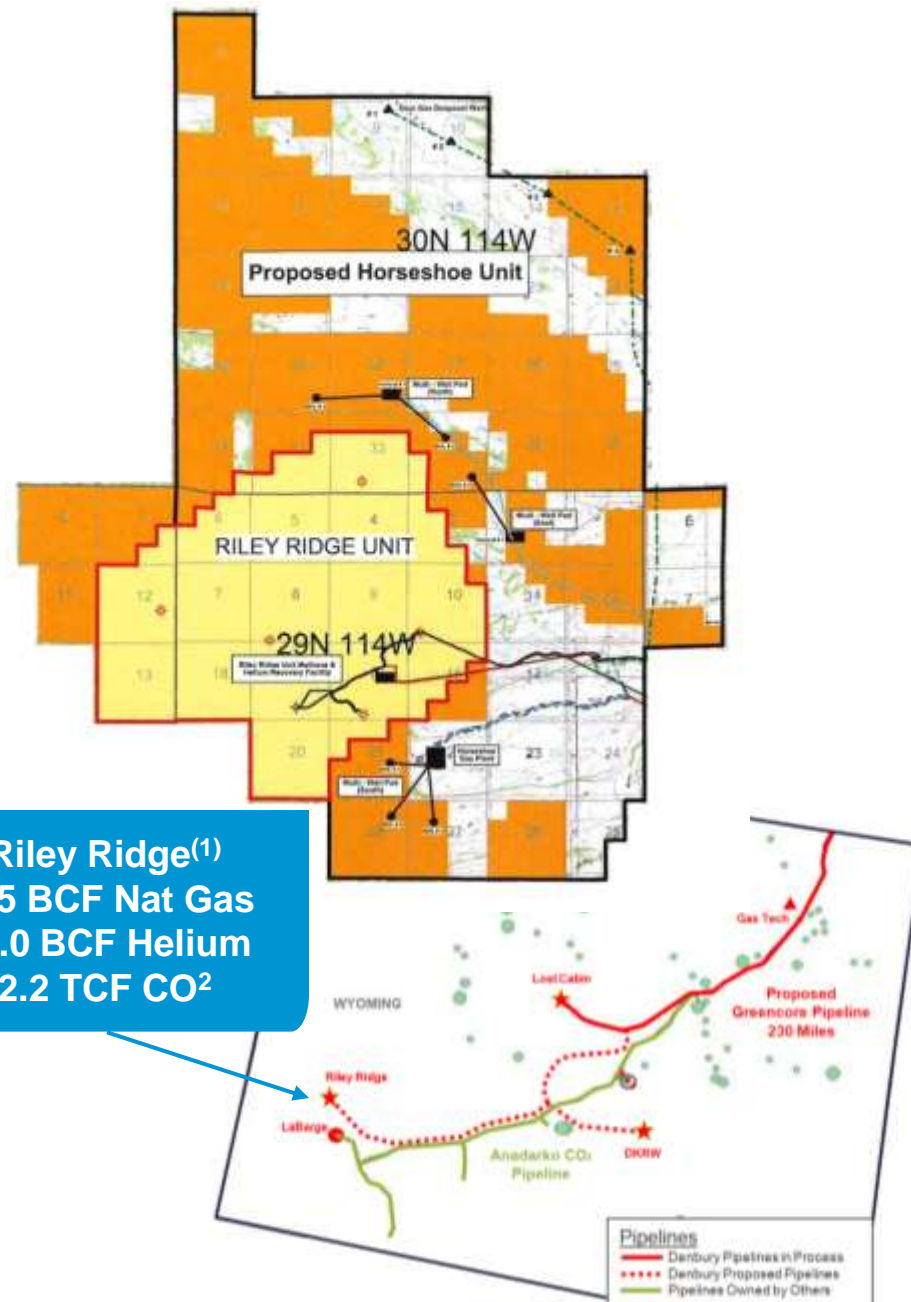
- Estimated Field Size: 750 Square Miles
- Estimated 100 TCF of CO₂ Recoverable

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



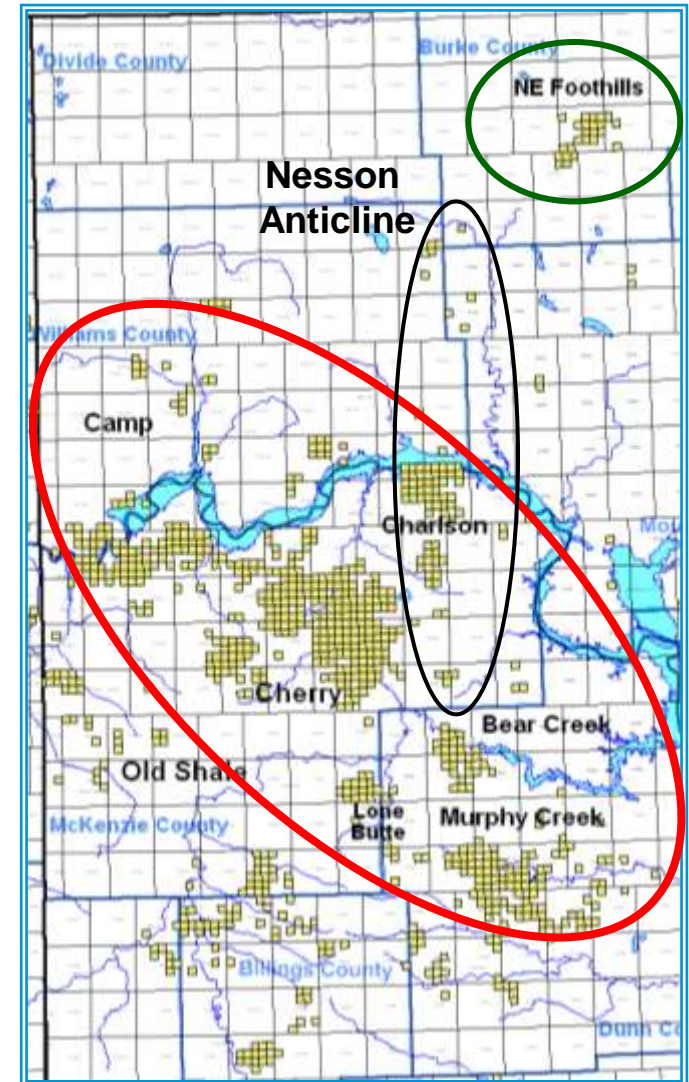
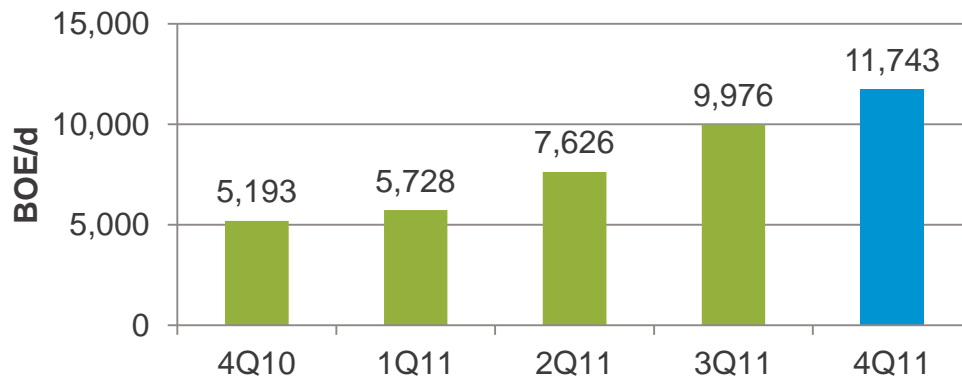
Third Growth Platform (Bakken Area)



Bakken Area

- ~200,000 net acres
- ~300 MMBOE of total potential
 - 93.9 MMBOE Proved as of 12/31/2011
- 4Q11 Production – 11,743 BOE/d
- 2011 Production – 8,788 BOE/d
- 2012E Production – 12,750-14,750 BOE/d

Net Bakken Production



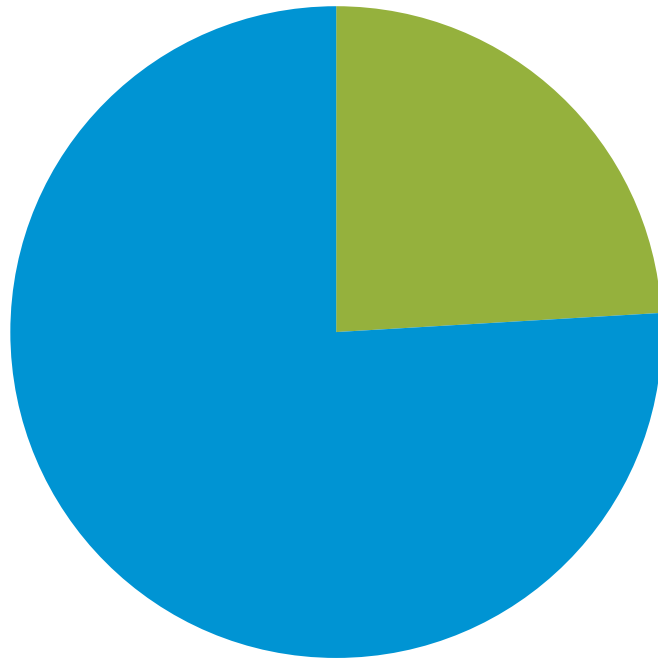
- Denbury's Core Bakken Area
- Denbury's Extensional Bakken Areas
- DNR Acreage

Strong Financial Position



- \$1.2 billion availability under credit facility on 12/31/11

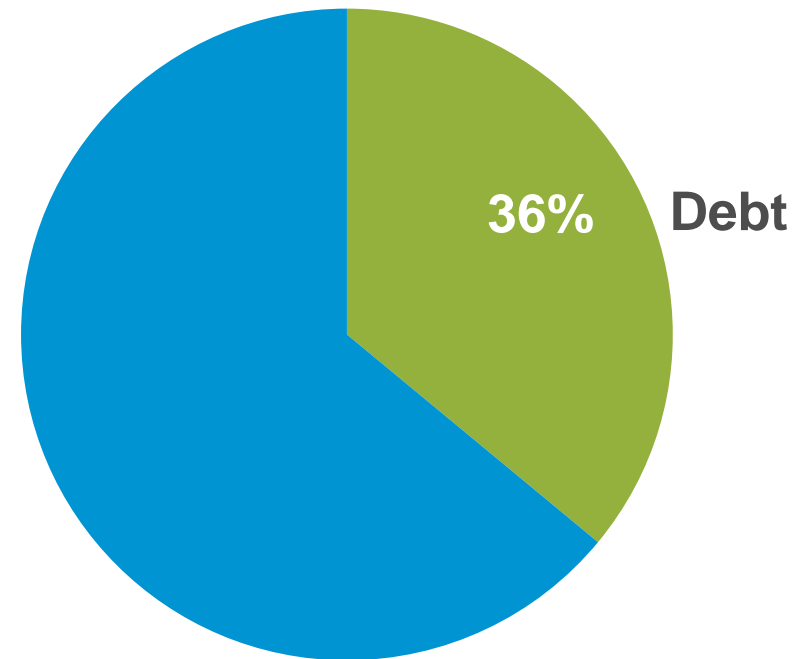
**Unused
Credit
Facility**



\$1.6 billion borrowing base

Estimated Net debt of ~\$366 million at 12/31/11

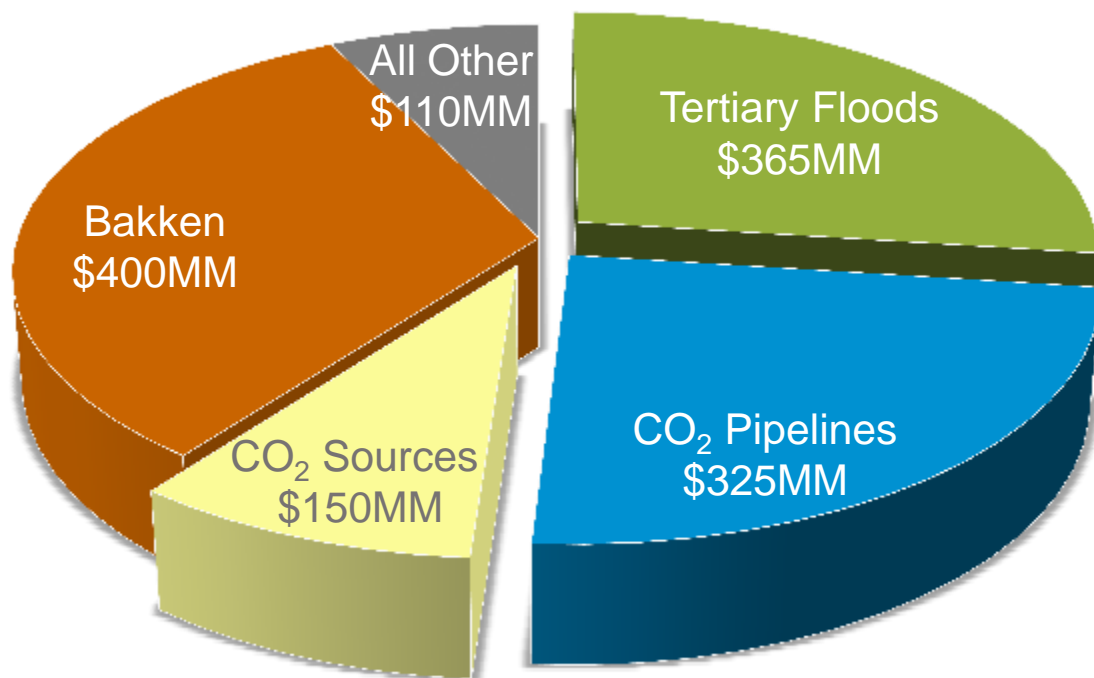
Debt to Capitalization (12/31/11)



+ (12/31/11) Cash – \$19 million



2012 Capital Budget – \$1.35 Billion⁽¹⁾



2012 Production Estimate

Operating area	2011 (BOEPD)	2012E (BOEPD)	2012E growth
Tertiary Oil Fields	30,959	33,000- 36,000	7-16%
Bakken	8,788	12,750- 14,750	44-67%
Total Production	65,660	70,250- 75,250	7-15%

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

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

Sources & Uses



2012E Sources of Cash	(\$MM)
Estimated Cash flow from operations @ \$90-95 NYMEX oil	\$1,200 - 1,400 ⁽¹⁾
Estimated Asset sales ⁽²⁾	150 - 300
Total Estimated Sources	\$1,350 - 1,700

2012E Uses of Cash	(\$MM)
Capital budget	\$1,350
Estimated Capitalized interest & tertiary start-up costs	60
Assumed stock repurchases (2011 and 2012) ⁽³⁾	250
Total Estimated Uses	\$1,660

2012E Cash flow (deficit)/excess	(\$310) - \$40
---	-----------------------

(1) Based on projections in early November 2011, assuming a range of production outcomes within our production guidance and a range of positive price differentials from those realized in 2011.

(2) In 1Q12, we sold properties for \$155 million, and VNR units for net proceeds of ~\$84 million. Currently marketing non-operated interest in Greater Aneth Field.

(3) ~14 million shares purchased through 12/31/11 for approximately \$195 million.

Hedges Protect Against Downside in Near-Term⁽¹⁾



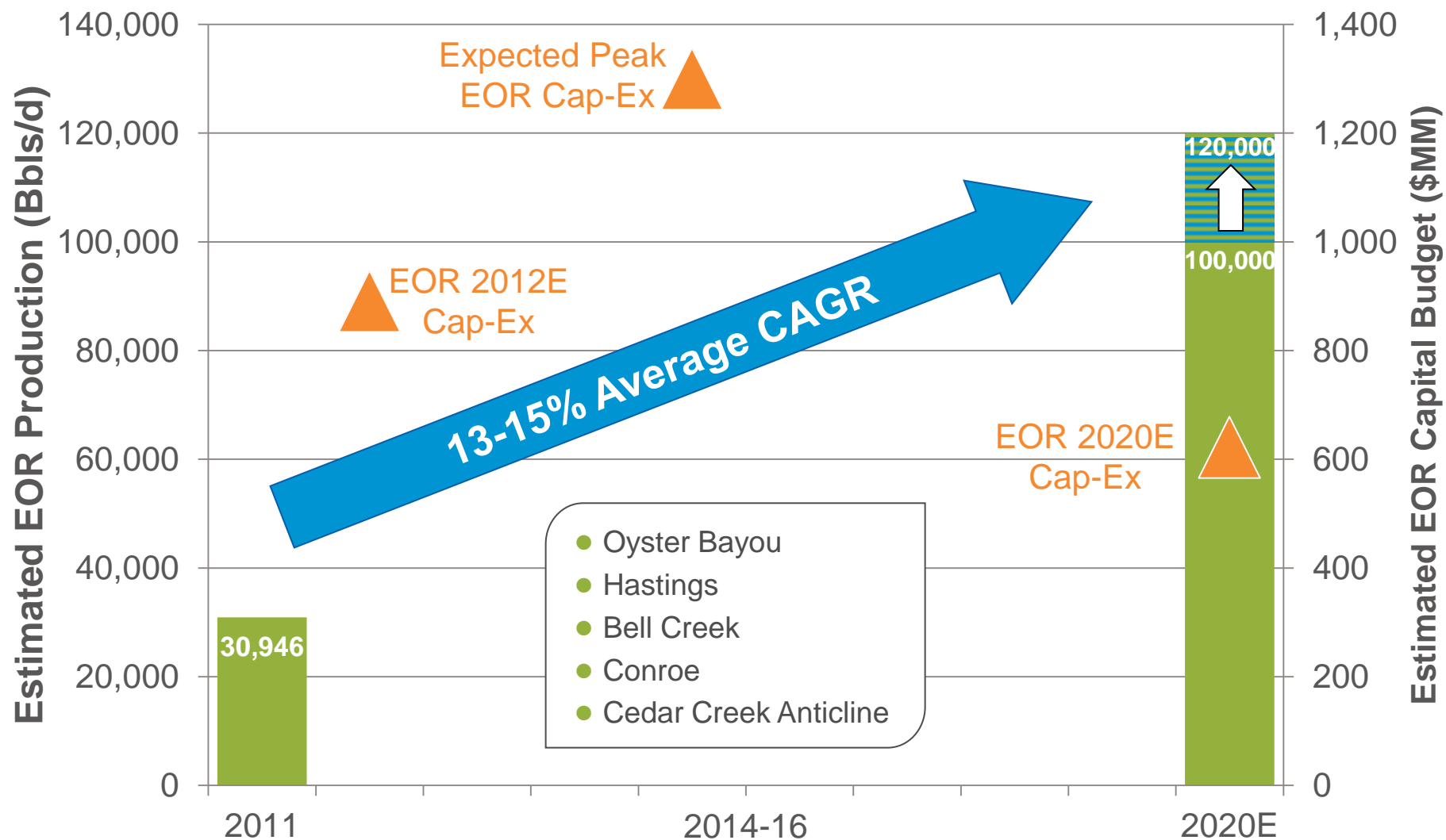
Crude Oil	2012			2013		
	1st Quarter	2nd Quarter	2nd Half	1st Quarter	2nd Quarter	3rd Quarter
Approximate production hedged ⁽²⁾	~85%	~85%	~85%	~85%	~80%	~70%
Principal price support	\$70	\$70	\$80	\$70	\$75	\$75
Principal price ceilings	~\$107	~\$119	~\$129	~\$110	~\$117	~\$121

Natural Gas	2012
Approximate production hedged ⁽²⁾	~45%
Principal price support (primarily swaps)	\$6.50-6.65

(1) Figures are general estimates and averages as of 2/1/12. Please see SEC documents for details of derivative contracts.

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

Sustainable EOR Growth through 2020 (1)



(1) 2012 and future forecasted capital expenditures and production may differ materially from actual results. See slide 2 for full disclosure.

Estimated EOR Peak Production Rates (as of 12/31/11)



Operating Area	First Production	Estimated Peak Production Rate (Net MBOE/d)					Expected Peak Year	Produced to date ⁽¹⁾ (MMBOE)	Proved Remaining (MMBOE)	2P&3P Remaining ⁽²⁾ (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) Tertiary oil production only through 12/31/11
- (2) Based on internal estimates of reserve recovery

IN SUMMARY: A Different Kind of Oil Company



Leading CO₂ Enhanced Oil Recovery (EOR) Company in the U.S. with a Unique Profile

- Significant strategic advantage in CO₂ EOR
- Large additional crude oil growth platform in the Bakken
- CO₂ EOR is a repeatable and sustainable process
- CO₂ EOR is highly profitable at current oil prices
- The spending and production profile for CO₂ EOR is much different than a shale play
- CO₂ EOR is a lower risk play (dealing with fields with millions of barrels of historical production)
- There are different inflation factors with CO₂ EOR operations





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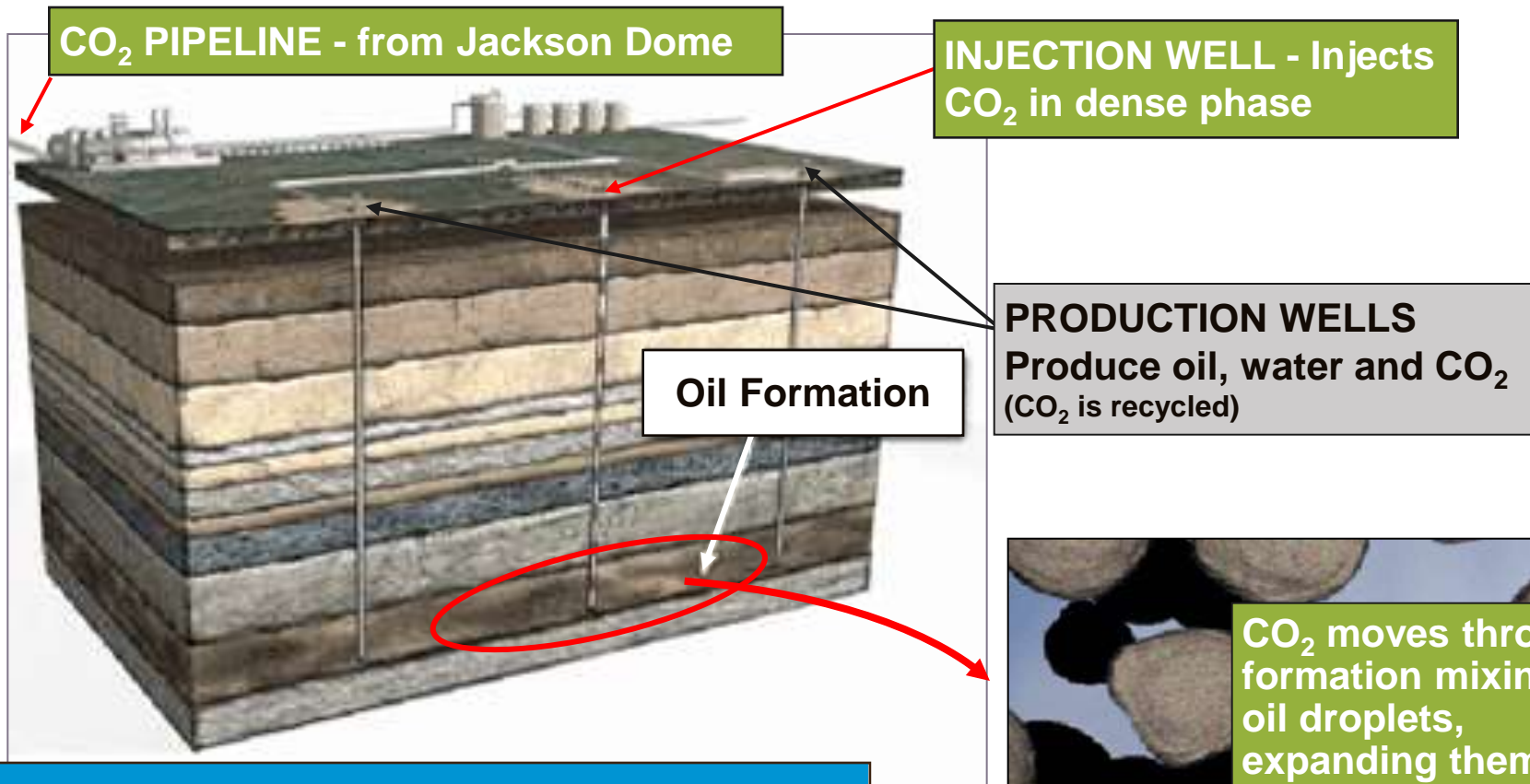
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Appendix



CO₂ Operations: Oil Recovery Process



Model for Oil Recovery Using CO₂ is +/- 17% of Original Oil in Place (Based on Little Creek)

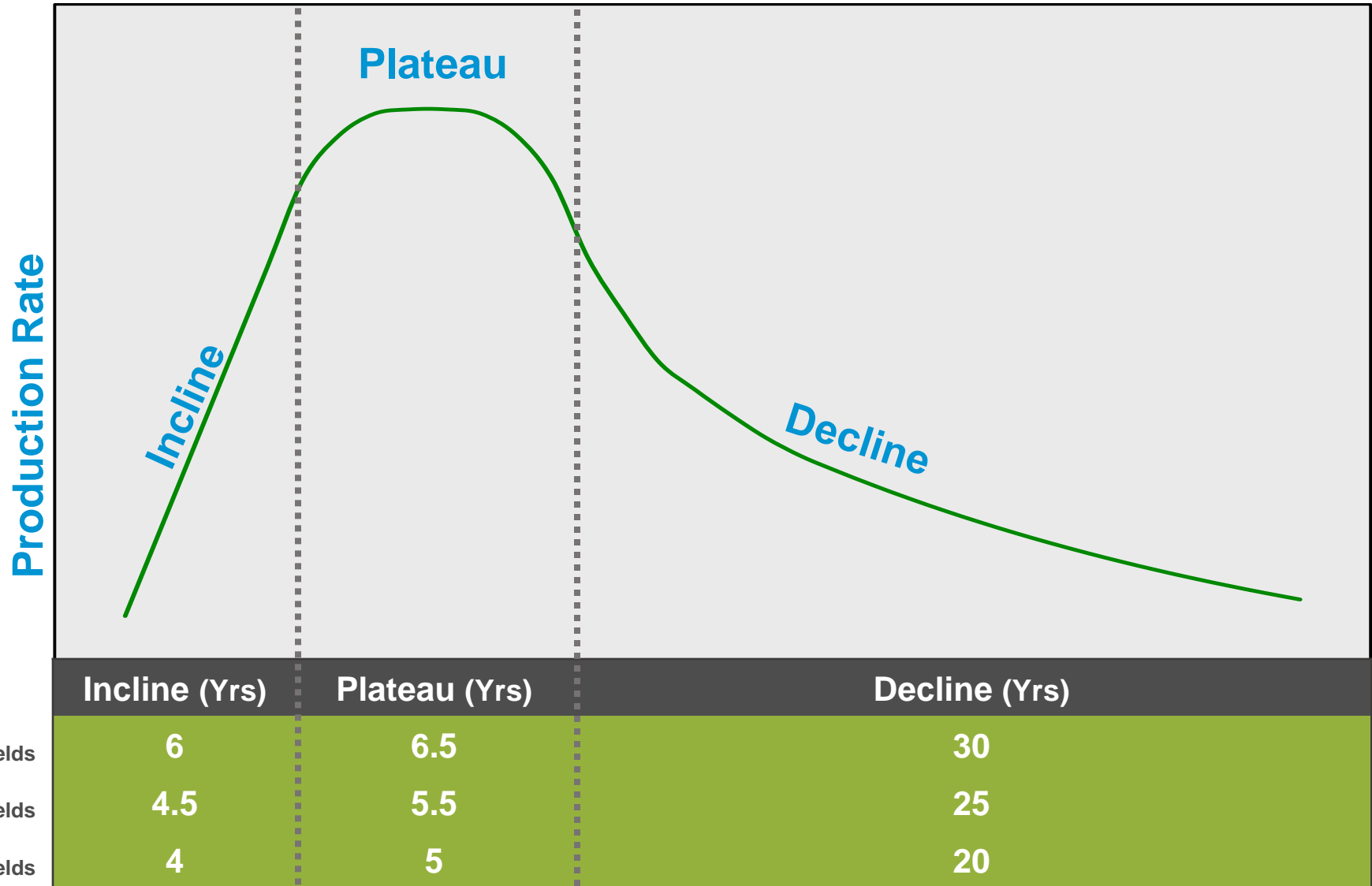
Primary recovery = +/- 20%

Secondary recovery (waterfloods) = +/- 18%

Tertiary (CO₂) = +/- 17%



CO₂ EOR Generalized Type Curve



Production by Area (BOE/d)



Operating area	Pro forma 2010 ⁽¹⁾	1Q11	2Q11	3Q11	4Q11	2011 ⁽²⁾	2012E ⁽²⁾
Tertiary Oil Fields	29,062	30,825	30,771	31,091	31,144	30,959	33,000 - 36,000
Mississippi – Non-CO ₂ Floods	8,012	7,586	7,333	7,193	6,264	7,090	5,700
Texas	4,941	4,371	4,202	4,096	3,868	4,133	3,500
Onshore Louisiana	709	767	659	214	294	482	300
Alabama & Other	1,049	1,026	1,084	1,072	1,037	1,055	950
Cedar Creek Anticline	9,728	9,163	8,925	8,930	8,858	8,968	8,300
Bakken	4,480	5,728	7,626	9,976	11,743	8,788	12,750 - 14,750
Other Rockies	4,577	4,138	4,319	4,258	4,026	4,185	5,750
Total Continuing Production	62,558	63,604	64,919	66,830	67,234	65,660	70,250 - 75,250
Disposed Legacy Encore Properties	9,852	---	---	---	---	---	---
Disposed ENP Properties	8,767	---	---	---	---	---	---
Total Production	81,177	63,604	64,919	66,830	67,234	65,660	70,250 - 75,250
							~90% Oil

(1) Represents pro forma production assuming we had reported Encore production for the period prior to the merger between 1/1/10 and 3/8/10.

(2) In February 2012, Denbury sold certain non-core Gulf Coast assets for \$155 million. The production associated with these assets in 2011 was 1,806 BOE/d and was estimated at 1,400 BOE/d for 2012.

Analysis of Tertiary Operating Costs



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

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.

Reclassified Quarterly Income Statement



Income Statement (In thousands)	Q1 2011	Q2 2011	Q3 2011	Q4 2011	2011
Revenues and other income:					
Oil, natural gas, and related product sales	\$506,192	\$591,099	\$565,523	\$606,337	\$2,269,151
CO ₂ sales and transportation fees	4,924	5,343	6,541	5,903	22,711
Interest income and other income	3,049	4,955	4,441	5,017	17,462
Total revenues and other income	514,165	601,397	576,505	617,257	2,309,324
Expenses:					
Lease Operating Expenses	123,797	126,085	133,285	124,230	507,397
Marketing Expense	5,303	6,270	6,416	8,058	26,047
CO ₂ discovery and operating expenses	1,946	1,694	1,250	9,369	14,258
Taxes other than income	32,483	39,632	36,180	39,239	147,534
General and administrative	42,319	28,708	26,613	27,884	125,525
Interest, net	48,777	42,249	37,617	35,717	164,360
Depletion, depreciation, and amortization	93,594	103,495	101,978	110,129	409,196
Derivatives expense (income)	170,750	(172,904)	(210,154)	159,811	(52,497)
Loss on early extinguishment of debt	15,783	348	-	-	16,131
Transaction and other costs related to the Encore Merger	2,359	2,018	-	-	4,377
Impairment of assets	-	-	-	22,951	22,951
Total expenses	537,111	177,595	133,185	537,388	1,385,279
Income (loss) before income taxes	(22,946)	423,802	443,320	79,869	924,045
Income tax provision (benefit)					
Current income taxes	(848)	12,028	(5,331)	2,400	8,249
Deferred income taxes	(7,908)	152,528	172,981	24,862	342,463
Net income (loss) attributable to Denbury stockholders	\$(14,190)	\$259,246	\$275,671	\$52,607	\$573,333

Note: Beginning in November 2011, AVT 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 and lifting cost numbers in this report 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 ⁽⁴⁾ (2014)	<i>Currently Under Construction</i>	+/- 115
Air Products (Port Arthur, TX) ⁽⁴⁾ (Q1 2013)		50
Lake Charles Cogeneration LLC ⁽³⁾		190 – 240
Mississippi Gasification (SNG) ⁽¹⁾ ⁽²⁾ ⁽³⁾		170 – 225
Faustina (Donaldsonville, LA)		100 – 225

Midwest Sources (\$0.20/Mcf @ \$60 Oil)		MMCFD
Indiana Gasification (SNG) ⁽¹⁾ ⁽²⁾		230 – 300
Power Holdings of Illinois (SNG) ⁽¹⁾		250 – 300
Christian County Generation/Tenaska of Illinois (SNG) ⁽¹⁾ ⁽²⁾ ⁽⁵⁾		170 – 225
Cash Creek Kentucky (SNG) ⁽¹⁾		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 CO₂



Rocky Mountain Purchase Contracts		MMCFD
COP Lost Cabin (Central Wyoming) (Q1 2013)	<i>Currently Under Construction</i>	+/- 50
XOM LaBarge (SW Wyoming) ⁽¹⁾ (Q3 2012)		+/- 50
DKRW Medicine Bow (SE Wyoming) ⁽²⁾ (+/- 2016)		+/- 100
Rocky Mountain CO ₂ Ownership		MMCFD
Riley Ridge Unit - LaBarge (SW Wyoming) (2016)		+/- 200⁽⁴⁾
Rocky Mountain Potential Sources		MMCFD
GasTech (NE Wyoming)		+/- 115
Quintana South Heart Project (SW North Dakota)		+/- 100
Dakota Gasification (SW North Dakota) ⁽³⁾		+/- 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 ⁽¹⁾	30-Day Avg. ⁽²⁾ (BOE/d)	60-Day Avg. ⁽²⁾ (BOE/d)	90-Day Avg. ⁽²⁾ (BOE/d)	Unit Acres	Frac Stages	W. I.	IP Date
Loomer 34-4 NWH	Cherry	Bakken	2,574	674	467	508	640	16	57%	7/15/11
Lee 34-31 NWH	Cherry	Bakken	2,004	644	638	583	1,280	24	79%	7/22/11
Wolff 13-24 NEH	Cherry	Bakken	2,414	738	638	532	1,280	26	63%	8/14/11
Sorenson 34-32 NWH	Cherry	Bakken	1,681	750	697	597	1,280	32	52%	8/16/11
Swenson 41-33 SEH	Charlson	Bakken	2,189	724	637	567	640	20	44%	8/21/11
McCoy 44-32 NWH	Cherry	Bakken	2,322	921	742	630	1,280	26	85%	9/3/11
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 SHE	Cherry	Bakken	1,850	26 ⁽³⁾	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

(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.

Most Recent Operated Bakken Well Activity



Completed Well	Area	Formation	IP ⁽¹⁾	30-Day Avg. ⁽²⁾ (BOE/d)	60-Day Avg. ⁽²⁾ (BOE/d)	90-Day Avg. ⁽²⁾ (BOE/d)	Unit Acres	Frac Stages	W. I.	IP Date
Loomer 21-4 SWH	Cherry	Bakken	1,689	549	547	N/A	1,280	26	72%	11/23/11
Satter 31-1 SWH	Cherry	TFS	1,715	587	606	N/A	1,280	26	84%	11/30/11
Sorenson 31-28 SWH	Cherry	Bakken	1,614	38 ⁽³⁾	348	N/A	1,280	26	68%	12/2011
Bergem 44-28 NWH	Cherry	Bakken	1,170	327	333	N/A	1,280	20	55%	12/2011
Loomer 24-34 NEH	Cherry	Bakken	1,689	30	47	190 ⁽⁴⁾	1,280	26	49%	12/2011
Serrahn 41-6 SWH	Cherry	Bakken	2,035	N/A	N/A	N/A	1,280	26	75%	1/13/12
Stepanek 31-17 SWH	Camp	Bakken	835	N/A	N/A	N/A	1,280	26	59%	1/10/12
Jore 34-22 NWH	Cherry	Bakken	2,060	N/A	N/A	N/A	1,280	26	48%	1/15/12
Satter 24-35 NEH	Cherry	Bakken	1,393	N/A	N/A	N/A	1,280	26	91%	1/21/12
Satter 24-35 SHE	Cherry	Bakken	2,015	N/A	N/A	N/A	1,280	26	91%	1/24/12
Roan 24-23 NEH	Cherry	Bakken	Flowing	N/A	N/A	N/A	1,280	26	43%	1/28/12

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

(2) Date from first significant production

(3) Clean out issues. Waiting to finish completion

(4) Pad issues. Last 30 average, 464 BOE/d.

Most Recent Operated Bakken Well Activity



Completing	Area	Formation	Frac Date	30-Day Avg.	Unit Acreage	Frac Stages	W. I.
Erickson 41-25 NWH	Cherry	Bakken	Feb 2012	N/A	1,280	26	46%
Erickson 41-25 SWH	Cherry	Bakken	Feb 2012	N/A	1,280	26	40%
Olson 34-19 NWH	Cherry	Bakken	March 2012	N/A	1,280	26	79%
Olson 34-19 SWH	Cherry	Bakken	March 2012	N/A	1,280	26	63%
Johnson 24-31 NEH	Cherry	Bakken	Feb 2012	N/A	1,280	26	98%
Nelson 24-11 NEH	Cherry	Bakken	Feb 2012	N/A	1,280	26	67%
Iverson 34-19 NWH	Cherry	Bakken	March 2012	N/A	1,280	26	69%

Drilling	Area	Formation	Spud Date	Frac Date	Acreage	Frac Stages	W. I.
Rink 12-4 SEH	Cherry	TFS	1/26/2012	4/2012	1,280	26	83%
Johnson 43-27 NWH	Murphy Creek	TFS	1/10/2012	4/2012	1,280	26	67%
Johnson 43-27 NEH	Murphy Creek	TFS	1/11/2012	4/2012	640	12	42%
Lund 44-8 NEH	Cherry	Bakken	1/17/2012	4/2012	1,280	26	74%
Johnsrud 21-13 SEH	Cherry	TFS	2/1/2012	4/2012	1,280	26	81%
Lundin 11-13 SEH	Cherry	Bakken	1/16/2012	4/2012	1,280	26	87%

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
Total				202

Encore Acquisition was Highly Profitable



Purchase price:	(Billions)
Equity	\$2.8
Debt assumed	1.0
Total value	\$3.8 ⁽¹⁾

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

Capital Structure



(\$MM)	12/31/11
Cash	\$19
Bank credit facility	385
9.500% Sr. Sub Notes due 2016	237
9.750% Sr. Sub Notes due 2016	408
8.250% Sr. Sub Notes due 2020	996
6.375% Sr. Sub Notes due 2021	400
Other Encore Sr. Sub Notes	4
Genesis pipeline financings / other	240
Total long-term debt	\$2,670
Equity	4,806
Total capitalization	\$7,476
2011 Adjusted cash flow from operations (1)	\$1,360
Debt to 2011 Adjusted cash flow from operations	2.0x
Debt to total capitalization	36%

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