All Oil Companies Are Not Alike.

Denbury

NYSE: DNR

8th Annual SECARB Stakeholders Briefing

March 2013

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, drilling activity, completion of acquisitions or reserves or future production attributable to them, development activities, timing of CO_2 injections and initial production response in tertiary flooding projects, estimated costs, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO_2 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, estimates of potential or recoverable reserves and anticipated production growth rates in our CO_2 models, or estimated production in 2013 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, 2012 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 original oil in place, 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.

Agenda

- Quick Denbury Review
- Why Anthropogenic?
- Anthropogenic Source Updates

Denbury at a Glance

		Pro forma[1]
Total 3P Reserves (12/31/12)	~1.1 BBOE	~1.2 BBOE
% Oil Production (4Q12)	93%	~94%[2]
Total Net Debt (12/31/12)[3]	$3.0 billion	~$3.1 billion
Total Daily Production – BOE/d (4Q12)	70,116	~73,450[2]
Proved PV-10 (12/31/12) $94.71 NYMEX Oil Price	$9.9 billion	$11.0 billion
Market Cap (1/31/13)	~$7 billion	
CO_2 Supply 3P Reserves (12/31/12)	~17 Tcf	
CO_2 Pipelines Controlled	~1,000 miles	
Credit Facility Availability (12/31/12)[4]	~$900 million	

(1) Pro forma for recently announced CCA acquisition expected to close near the end of 1Q 2013.

(2) Pro forma production removes 10,064 BOE/d of Bakken area production in 4Q12 and adds 11,000 BOE/d for recently announced CCA acquisition expected to close near the end of 1Q 2013 and 2,400 BOE/d to reflect a full quarter contribution from Hartzog Draw and Webster fields acquired on November 30, 2012.

(3) As of 12/31/12, we had ~ $700 million of borrowings outstanding under our $1.6 billion bank credit facility and our cash and cash equivalents totaled ~$100 million. At 12/31/12, ~$1.05 billion in restricted cash remained deposited with a qualified intermediary. Pro forma for expected deal and stock repurchases through 2/15/13.

(4) As of 12/31/12, we had ~$900 million of availability under our $1.6 billion bank credit facility and ~$100 million in unrestricted cash.

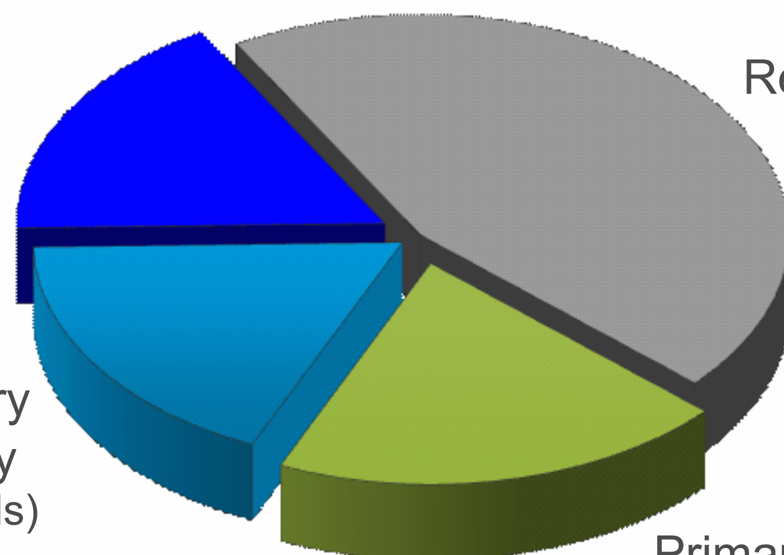
What is CO_2 EOR & How Much Oil Does It Recover?

Secure CO_2 Supply

Transport via Pipeline

Inject into Oilfield

CO_2 EOR Delivers Almost as Much Production as
)



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

Estimated CO_2 EOR Peak Production Rates

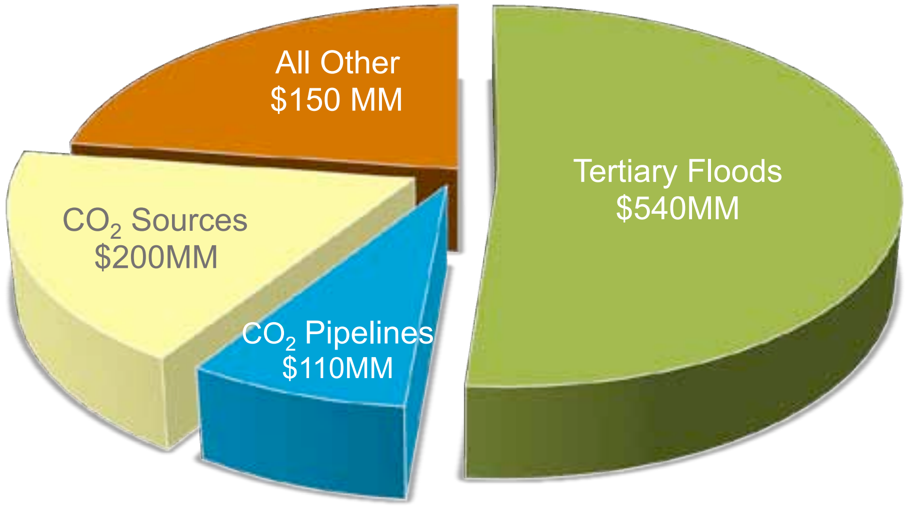
Operating Area	First Production	Estimated Peak Production Rate (Net MBOE/d)					Expected Peak Year	Produced to date[1] (MMBOE)	Proved Remaining[1] (MMBOE)	Potential Remaining[2] (MMBOE)
		< 5	5-10	10-15	15-20	> 20				
Mature Area	1999				●		2010	54	54	70
Tinsley	2008		●				2012-14	9	28	9
Heidelberg	2009		●				2018-20	3	35	6
Delhi	2010		●				2015-17	3	25	8
Oyster Bayou	2012	●					2015-17	<1	14	11
Hastings	2012				●		2018-20	1	45	24
Bell Creek	2013		●				2019-21	---	---	30
Webster	2015				●		2022-25	---	---	68
Hartzog Draw	2016		●				2021-23	---	---	25
Conroe	2017				●		2033-35	---	---	130
Cedar Creek Anticline[3]	2017					●	2023-27	---	---	200[3]
Thompson	2019			●			2025-27	---	---	45

Expected year of first tertiary production.

(1) Tertiary oil production and reserves as of 12/31/2012
(2) Based on internal estimates of reserve recovery, using mid-points of ranges.
(3) Does not include recently announced incremental CCA acquisition.

2013 Summary Guidance(1)

2013 Capital Budget – $1.0 Billion(2)



2013 Production Estimate

Operating area	2012 (BOE/d)	2013E (BOE/d)	2013E Growth
Tertiary Oil Fields	35,206	36,500-39,500	4-12%
Non-Tertiary Oil Fields	21,636	24,500	
CCA Acquisition(3)	---	7,700	
Total Estimated Production	**56,842**	**68,700-71,700**	**21-26%**

~$250 million remains under current stock repurchase authorization.

Stock re-purchased to date increases production per share ~9%(4)

We estimate the 2013 capital program(5) to be more than self-funded at ~low to mid $90's NYMEX WTI crude oil price, after the recently announced CCA acquisition closes.

(1) See slide 3 for full disclosure of forward-looking statements.

(2) Excludes capitalized exploration, capitalized interest and capitalized pre-production EOR startup costs, estimated at $125 million.

(3) Assumes recently announced CCA acquisition closes at the end of the first quarter of 2013. See slide 13 for more details.

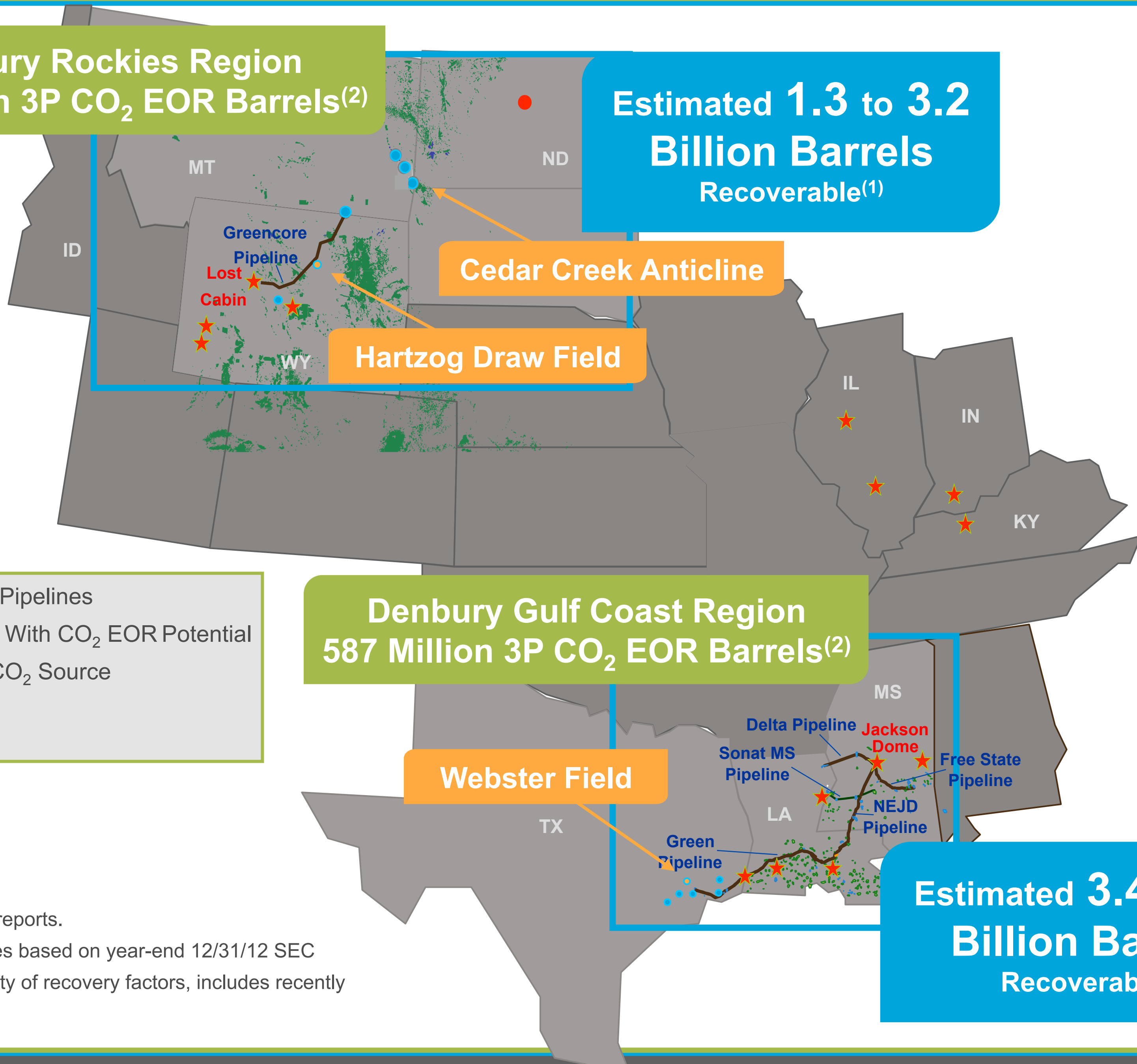
(4) Total stock purchased since October 2011 is ~34.6 million shares at about $15 per share, as of 2/20/13.

(5) Including capitalized exploration, capitalized interest and capitalized pre-production EOR startup costs, estimated at $125 million.

Our Two CO_2 EOR Target Areas: Up to 10 Billion Barrels Recoverable with CO_2 EOR

Denbury Rockies Region
331 Million 3P CO_2 EOR Barrels[(2)]

Estimated 1.3 to 3.2 Billion Barrels Recoverable[(1)]



Denbury Gulf Coast Region
587 Million 3P CO_2 EOR Barrels[(2)]

Estimated 3.4 to 7.5 Billion Barrels Recoverable[(1)]

- Existing Denbury CO_2 Pipelines
- Denbury owned Fields With CO_2 EOR Potential
- Existing or Proposed CO_2 Source Owned or Contracted
- Other CO_2 Sources

(1) Source: DOE 2005 and 2006 reports.

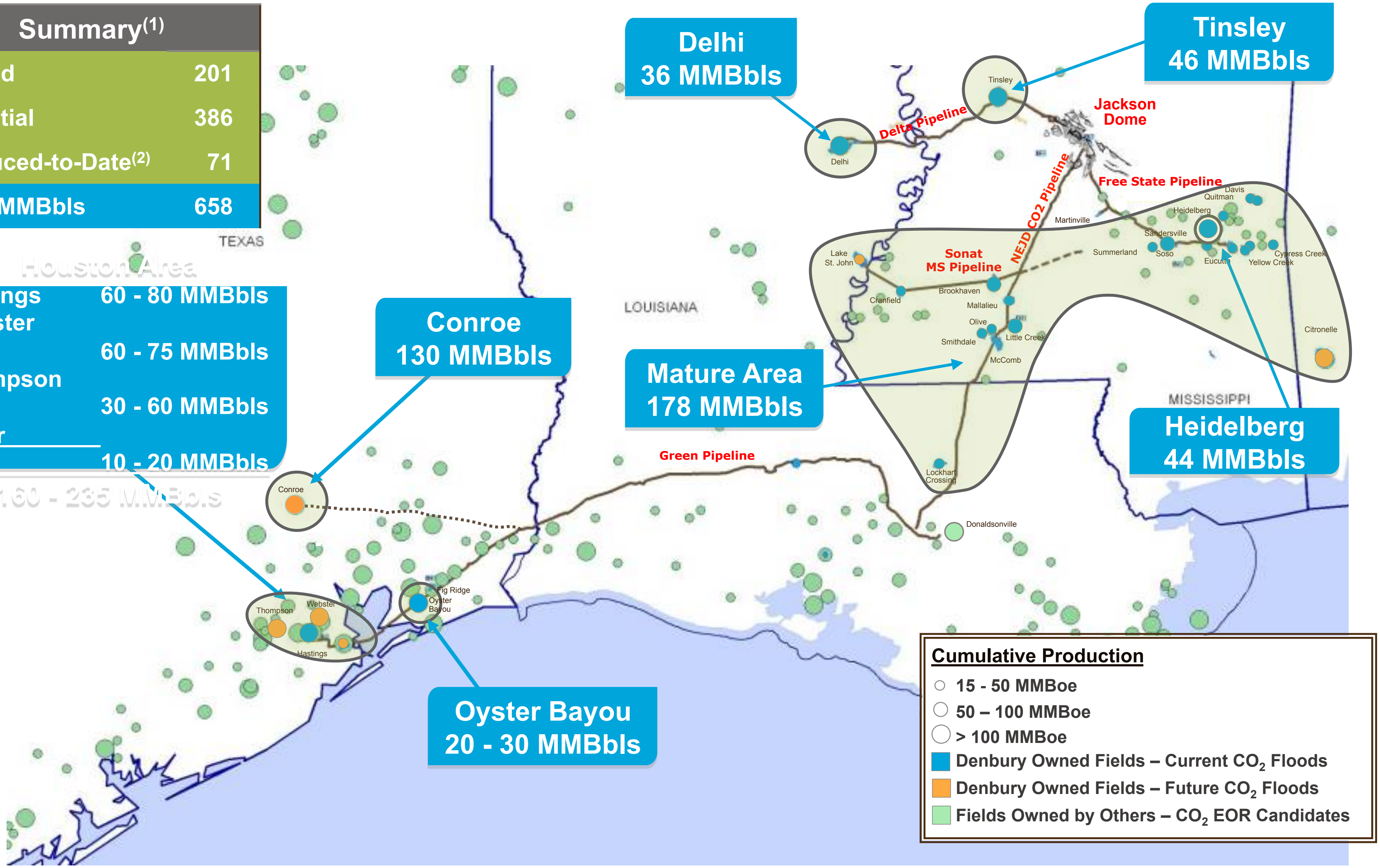
(2) 3P tertiary oil reserve estimates based on year-end 12/31/12 SEC proved reserves, based on a variety of recovery factors, includes recently announced CCA area acquisition.

CO_2 EOR in Gulf Coast Region:
Control of CO_2 Sources & Pipeline Infrastructure Provides a Strategic Advantage

Summary[1]	
Proved	201
Potential	386
Produced-to-Date[2]	71
Total MMBbls	658

Houston Area

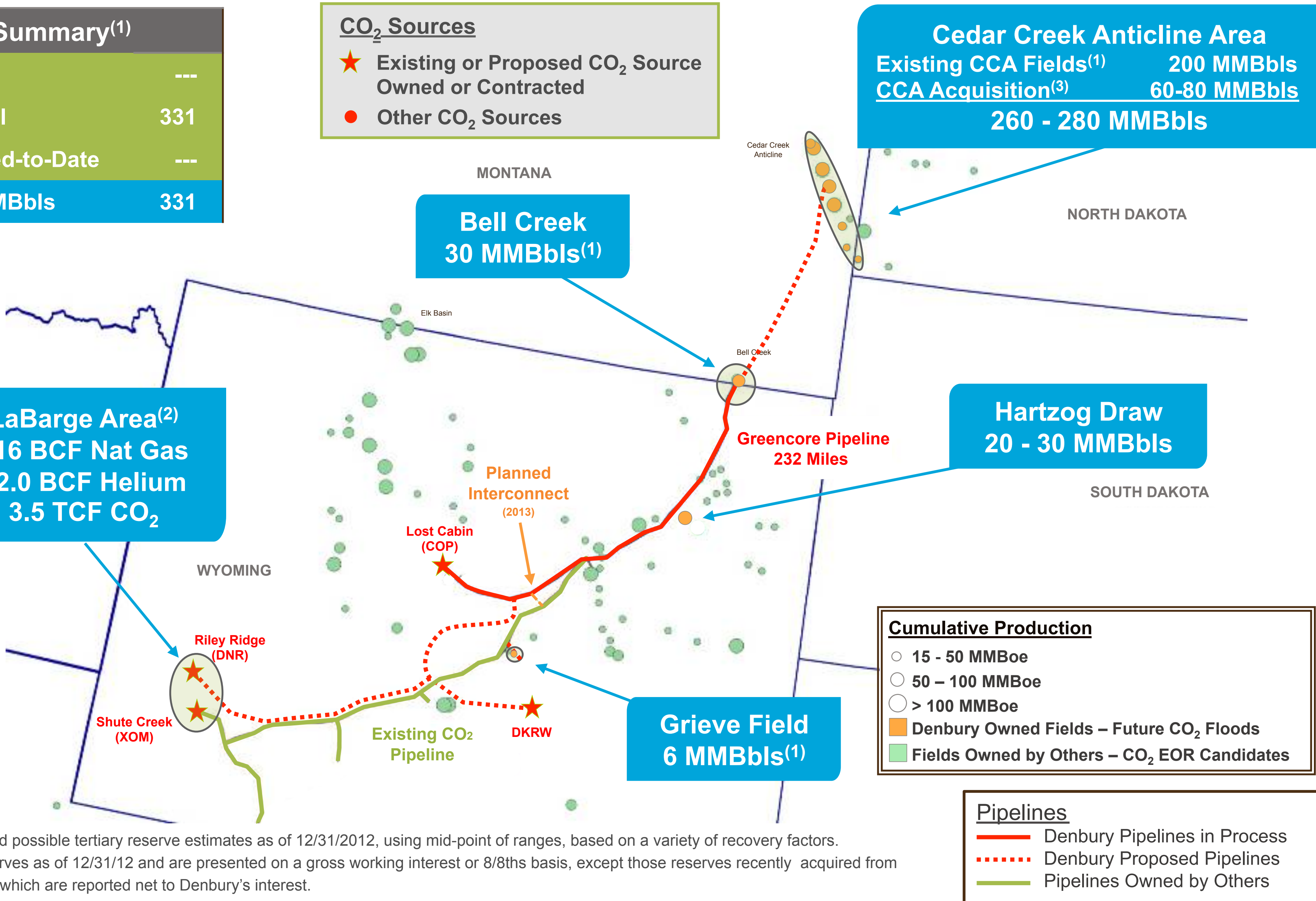
Hastings	60 - 80 MMBbls
Webster	60 - 75 MMBbls
Thompson	30 - 60 MMBbls
Other	10 - 20 MMBbls
	160 - 235 MMBbls



(1) Proved tertiary oil reserves based on year-end 12/31/12 SEC proved reserves. Probable and possible tertiary reserve estimates as of 12/31/2012, based on a variety of recovery factors.
(2) Produced-to-Date is cumulative tertiary production through 12/31/12.
(3) Using mid-points of range.

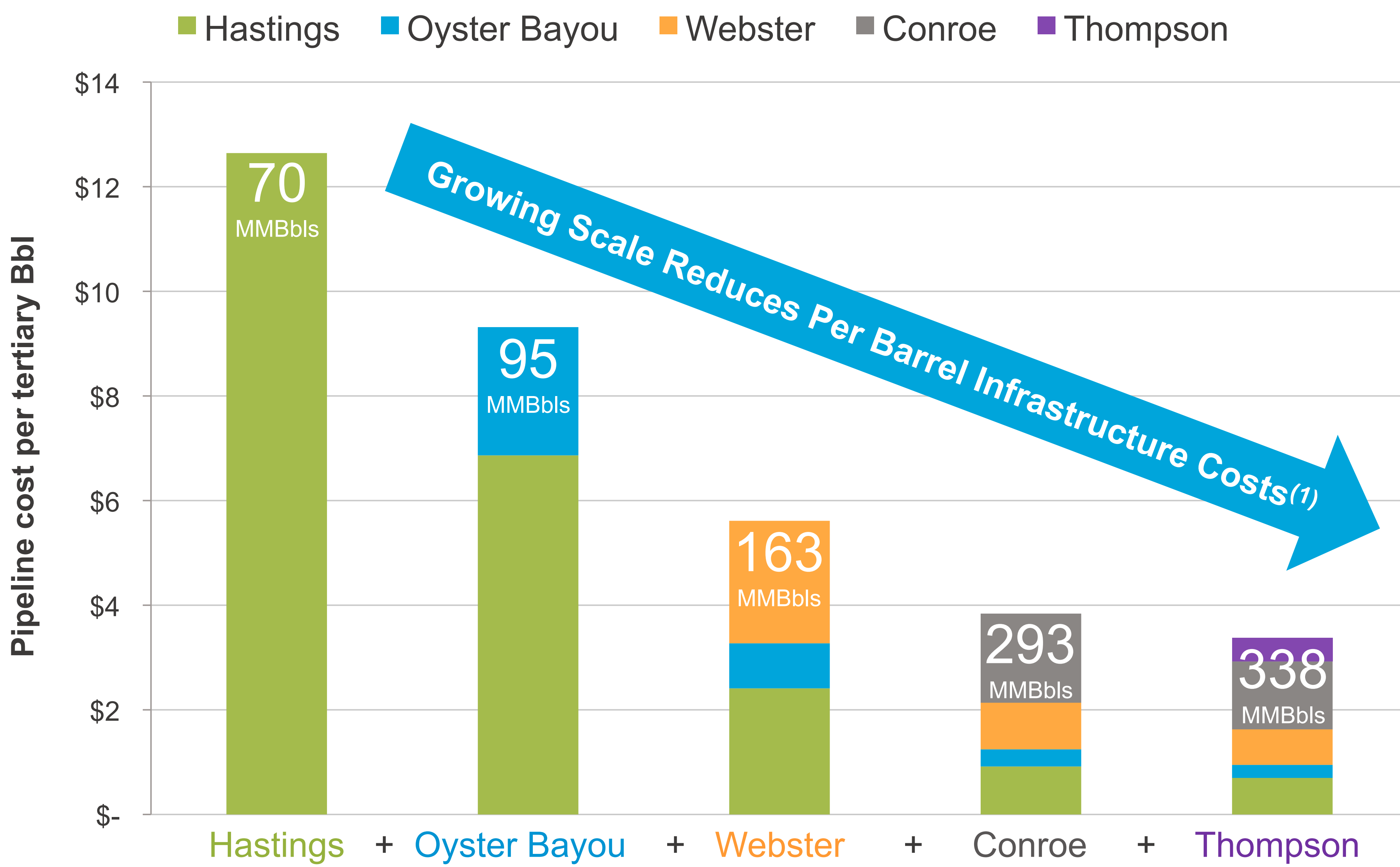
CO_2 EOR in Rocky Mountain Region:
Control of CO_2 Sources & Pipeline Infrastructure Provides a Strategic Advantage

Summary(1)	
Proved	---
Potential	331
Produced-to-Date	---
Total MMBbls	331



(1) Probable and possible tertiary reserve estimates as of 12/31/2012, using mid-point of ranges, based on a variety of recovery factors.
(2) Proved reserves as of 12/31/12 and are presented on a gross working interest or 8/8ths basis, except those reserves recently acquired from ExxonMobil which are reported net to Denbury's interest.
(3) Recently agreed to purchase from ConocoPhillips in a transaction expected to close near the end of the first quarter of 2013.

Texas CO_2 Pipeline Expansions – Economies of Scale



(1) Using mid-point of ranges and includes costs of Green Pipeline plus forecasted costs for required incremental pipelines.

Strategic and Value-Driven M&A Transactions

Divestitures

Assets (Quarter close date)	Est. Production[1] (BOE/d)	Est. Proved Reserves (MMBOE)	Est. PDP %	Impact on Current FCF[4]	Est. Potential Reserves[2] (MMBOE)	Est. Proved PV10[3] ($Billions)
Non-Core LA & MS (1Q12)	1,400	6	54%	+	---	0.2
Non-Operated Greater Aneth (2Q12)	650	6	58%	+	---	0.1
Bakken (4Q12)	15,850	109	30%	–	191	1.5
Total Sold	**17,900**	**121**	**33%**		**191**	**1.8**

Acquisitions

Assets (Quarter close date)	Est. Production[1] (BOE/d)	Est. Proved Reserves (MMBOE)	Est. PDP %	Impact on Current FCF[4]	Est. Potential Reserves[2] (MMBOE)	Est. Proved PV10[3] ($Billions)
Thompson Field (2Q12)	2,200	17	34%	+	45	0.5
Webster Field (4Q12)	1,000	4	100%	+	68	0.1
Hartzog Draw (4Q12)	2,600	5	100%	+	25	0.1
COP CCA Assets (1Q13E)	11,000	42	91%	+	70	1.1
Total Purchased	**16,800**	**68**	**78%**		**208**	**1.8**

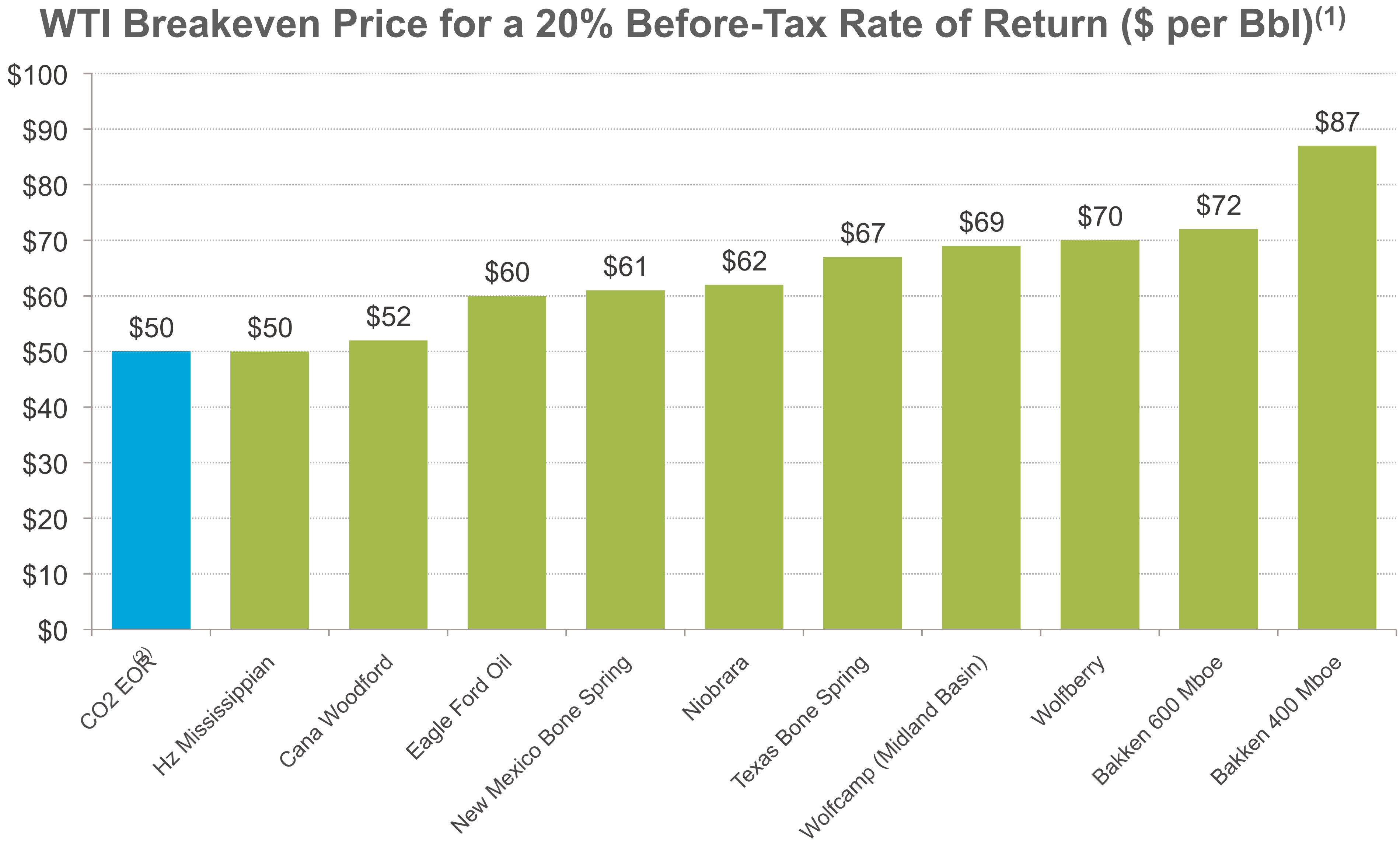
+ ~$100MM in cash

+ Additional CO_2 Supply in the Rockies:

XOM LaBarge CO_2 (4Q12)	**Up to 115 MMcf/d Production**	**1.3 TCF Proved Reserves at 12/31/2012**

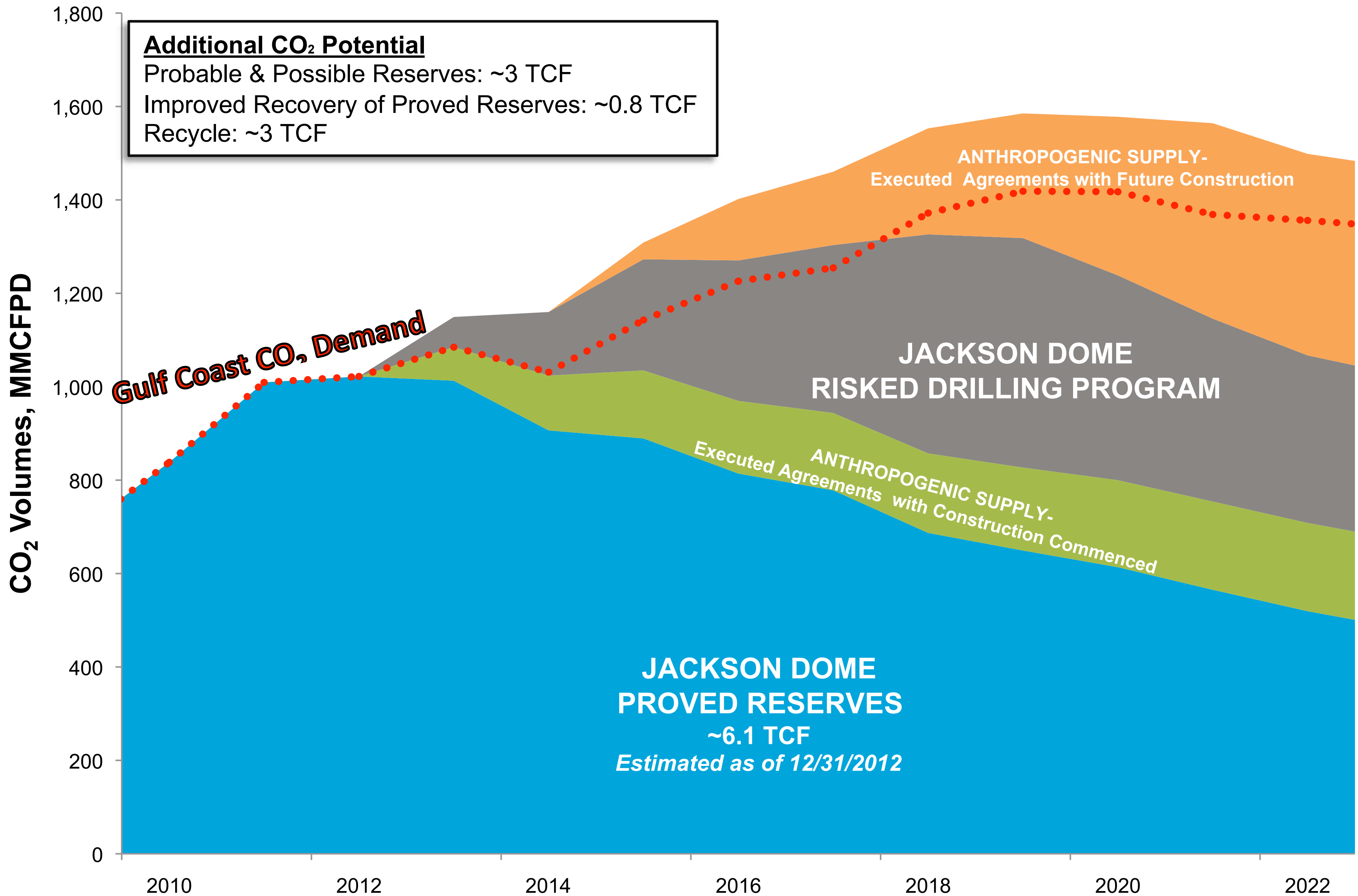
(1) Estimated production at time of acquisition, divestiture or agreement to purchase in case of CCA; Bakken area production is actual year-to-date average production through 9/30/12.
(2) Preliminary mid-point of estimates based on internal calculations, refer to slide 3 for full disclosure of forward-looking statements. Potential reserves include probable and possible reserves.
(3) Estimated discounted net present value of proved reserves or impact of sales on net present value, using a 10% annum discount rate.
(4) Spent $90 million in excess of operating cash flow on Bakken area assets in first nine months of 2012; expect capital expenditures on acquired properties to be minimal.

CO_2 EOR – Compelling Economics



(1) Source: KeyBanc as of October 2012, Defined as the threshold WTI oil price necessary to generate a 20% before-tax rate of return. Excludes acreage costs.
(2) Internal estimate for indicative large CO_2 EOR development project in the Gulf Coast Region.

Gulf Coast CO_2 Supply



Note: Forecast based on internal management estimates and includes fields currently owned. Actual results may vary.

Gulf Coast Industrial Partners

Air Products • Port Arthur, Texas • Hydrogen Plant • Capture Date: 1Q 2013 • Quantity: ~50 MMcf/d	**PCS Nitrogen** • Geismar, Louisiana • Ammonia Products • Capture Date: ~1Q 2013 • Quantity: ~25 MMcf/d	**Mississippi Power – (Under Construction)** • Kemper County, MS • Gasifier • Capture Date: ~2014 • Quantity: ~115 MMcf/d
Lake Charles Cogeneration(1) • Lake Charles, Louisiana • Petroleum Coke to Methanol Plant • Capture Date: ~2018 • Quantity: >200 MMcf/d	**Ammonia Plant(1)** • Near Green Pipeline • Capture Date: ~1Q 2016 • Quantity: ~85 MMcf/d	**Chemical Plant(1)** • Near Green Pipeline • Capture Date: ~2020 • Quantity: ~200 MMcf/d

(1) Planned or proposed, not currently under construction

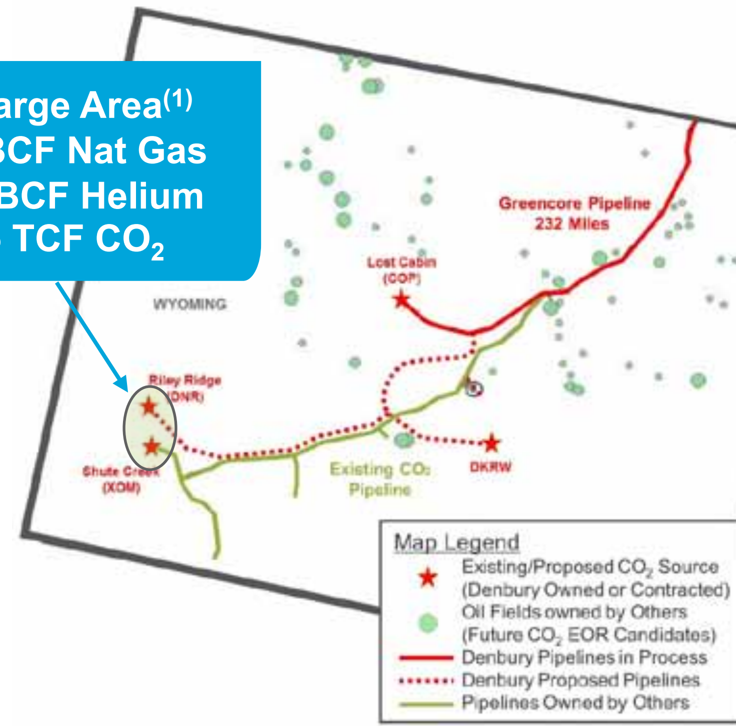
Secure CO_2 Supply to Support Rocky Mountain Growth

LaBarge Area
- Estimated Field Size: 750 Square Miles
- Estimated 100 TCF of CO_2 Recoverable

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

Shute Creek – XOM Operated
- Denbury has acquired 1/3 of XOM's CO_2 reserves
- Based on XOM's current plant capacity and availability, Denbury could receive up to ~115 MMcfpd of CO_2 from the plant

LaBarge Area[1]
416 BCF Nat Gas
12.0 BCF Helium
3.5 TCF CO_2



Composition of Produced Gas Stream:
~65% CO_2; ~19% Natural Gas; ~5% Hydrogen Sulfide; <1% Helium, and other gasses

1) Proved reserves as of 12/31/2012

This is what 1,000,000 tons of stored CO_2 looks like.

Questions?

Appendix

Why is CO_2 EOR our core focus?

- **High Confidence of Oil Target**
  - Nearly 70 million barrels produced by Denbury to date
  - Net upward adjustments to reserves-to-date
- **CO_2 Flooding Recovers Oil (CO_2 ♥'s Crude Oil)**
  - First CO_2 EOR production was in 1972
  - Over 1.5 billion barrels produced to date in the US(1)
  - Current estimated production in the US is ~284 MBbls/d(2)
- **A Very Repeatable Process with a lot of Running Room**
  - Up to 10 Billion Barrels Recoverable with CO_2 EOR in our two operating areas
  - Over 900 Million Barrels of CO_2 EOR potential in our portfolio today

(1) Oil & Gas Journal, Dec. 7, 2009
(2) Oil & Gas Journal, July 2, 2012

CO_2 EOR is a Proven Process

Significant CO_2 EOR Operators by Region

Gulf Coast Region	
• Denbury Resources	
Permian Basin Region	
• Occidental	• Kinder Morgan
• Whiting	
Rockies Region	
• Denbury Resources	• Anadarko
Canada	
• Cenovus	• Apache

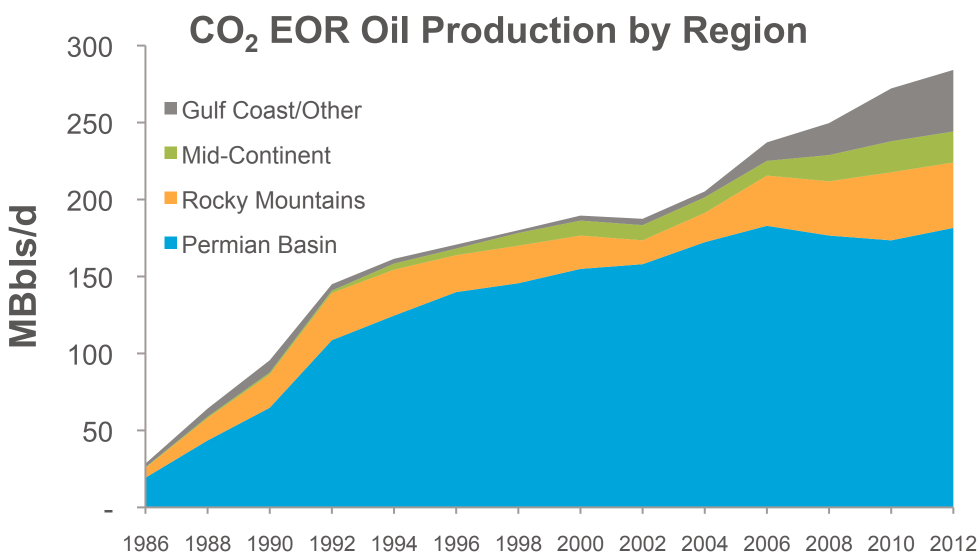
Significant CO_2 Suppliers by Region

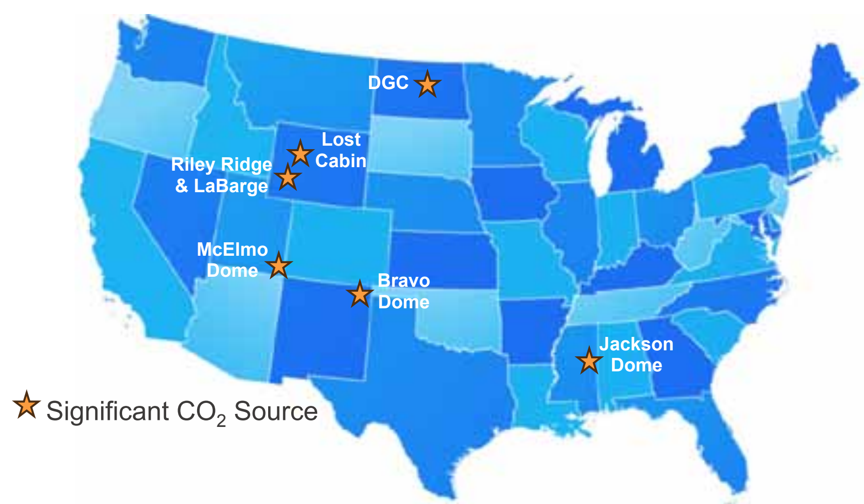
Gulf Coast Region
- Jackson Dome, MS (Denbury Resources)

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

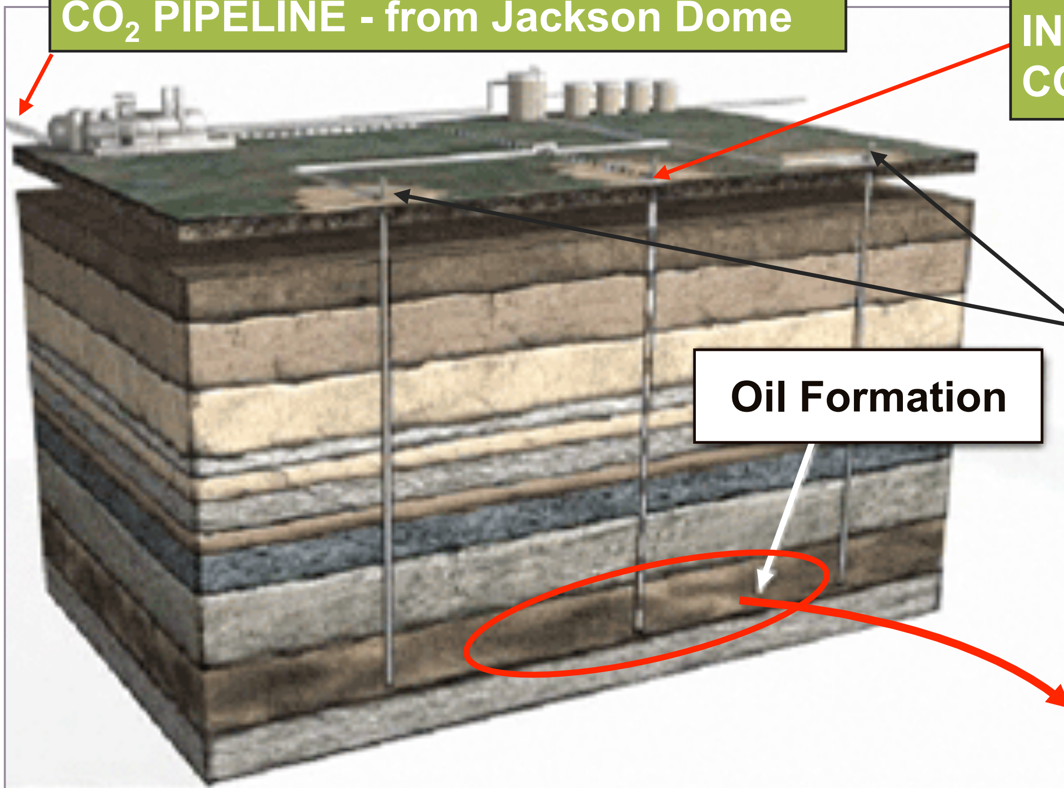
Rockies Region
- Riley Ridge, WY (Denbury Resources)
- LaBarge, WY (ExxonMobil, Denbury Resources)
- Lost Cabin, WY (ConocoPhillips)

Canada
- Dakota Gasification – Anthropogenic (Cenovus, Apache)





CO_2 Operations: Oil Recovery Process



Model for Oil Recovery Using CO_2 is +/- 17% of Original Oil in Place (Based on Little Creek)

Primary recovery = +/- 20%

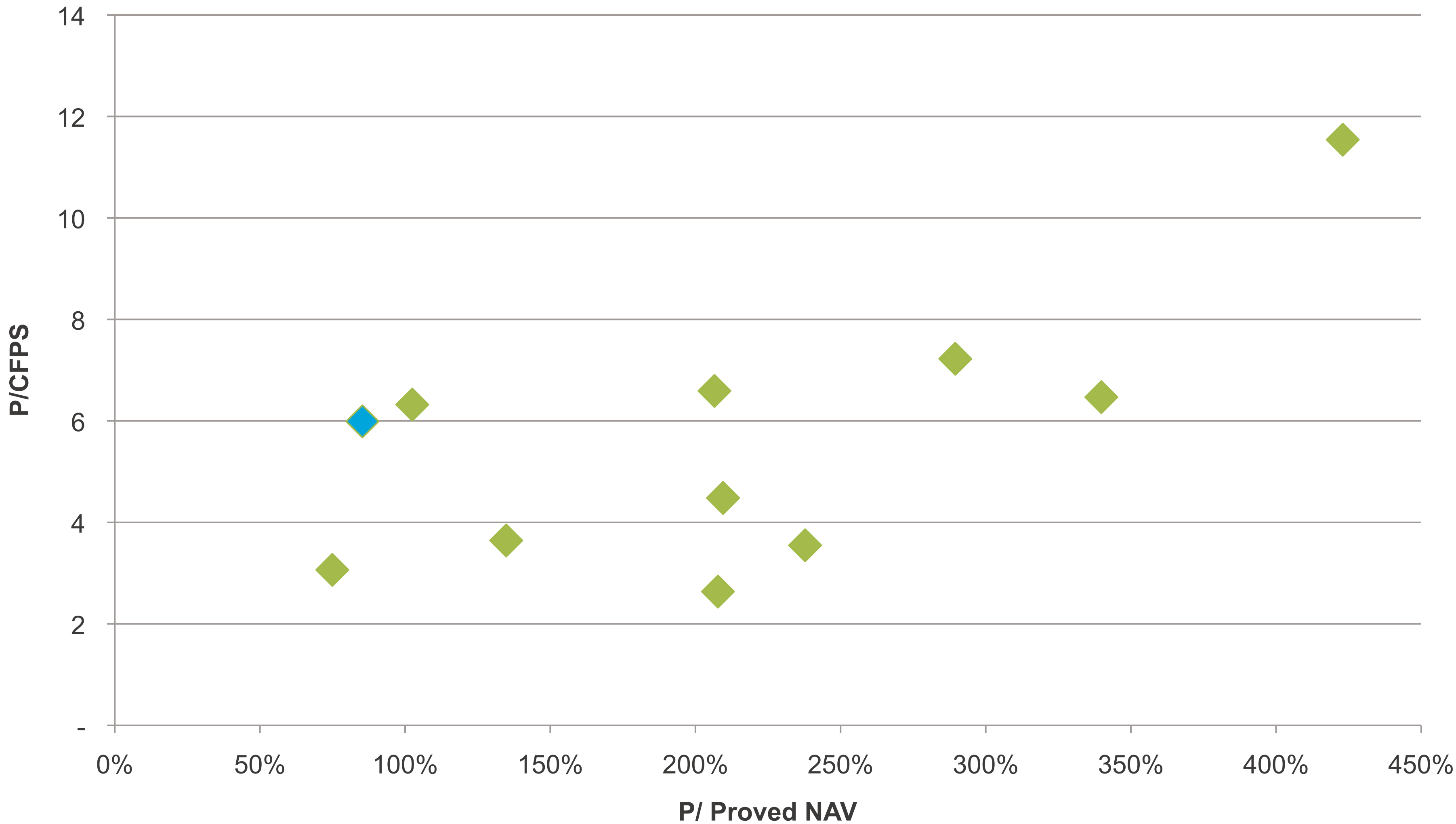
Secondary recovery (waterfloods) = +/- 18%

Tertiary (CO_2) = +/- 17%

CO_2 EOR – Proven Value Creation

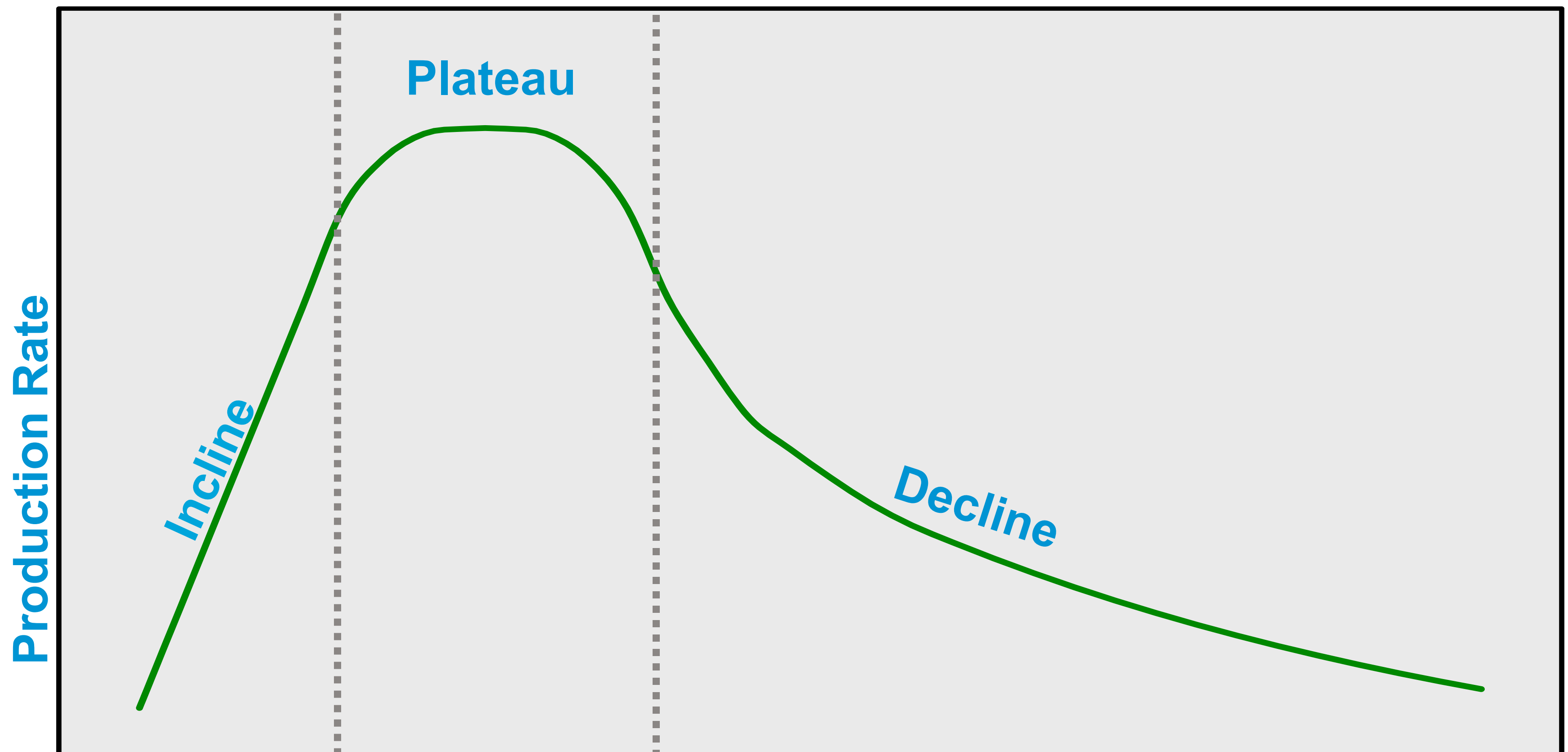
Investments – Inception-to-12/31/2011		**($) Billions**
Gulf Coast EOR Fields		$2.7
Gulf Coast CO_2 Sources & Pipelines		1.9
Less Undeveloped:		
EOR Fields	0.6	
CO_2 Pipelines	1.0	
		(1.6)
Net Investment-to-Date – Proved Properties		3.0
Inception-to-Date Net Revenues		3.1
Net Cash flow		0.1
PV10 of proved EOR at 12/31/11		5.7
Value Created		**$5.8**

Denbury vs. Peer Group Trading Multiples



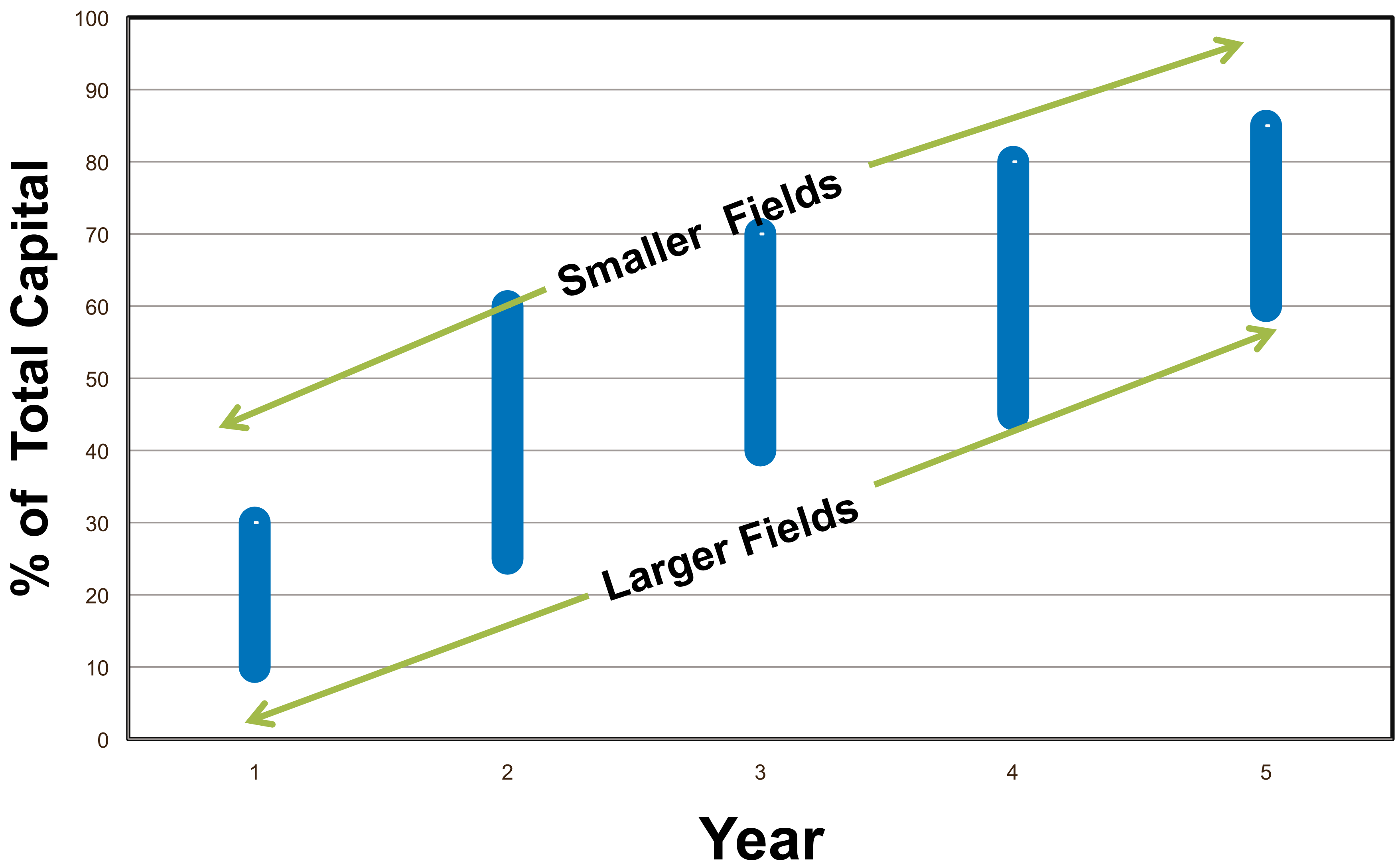
Source: KeyBanc – Net Asset Values (NAVs) based on YE11 proved reserves and KeyBanc price deck with balance sheet adjustments to reflect latest 10Q; January 2013

CO_2 EOR Generalized Type Curve



	Incline (Yrs)	Plateau (Yrs)	Decline (Yrs)
Large Fields	6	6.5	30
Average Fields	4.5	5.5	25
Small Fields	4	5	20

Capital Spending Range for CO_2 Floods



Capital Spending Flexibility in Low Oil Price Environment

Unique characteristics of CO_2 EOR provides significant capital flexibility

- 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
- We can hold production flat over the next several years using 50% or less of our 2013 forecasted capital expenditures

Production by Area (BOE/d)[1]

Operating area	1Q12	2Q12	3Q12	4Q12	2012	2013E
Tertiary Oil Fields	33,257	35,208	34,786	37,550	35,206	*36,500 – 39,500*
Texas Non-Tertiary	3,674	4,573	5,173	5,513	4,737	*6,300*
Other Gulf Coast Non-Tertiary	5,854	5,401	4,538	4,880	5,165	*4,300*
Cedar Creek Anticline	8,496	8,535	8,490	8,493	8,503	*8,500*
Other Rockies Non-Tertiary	3,204	3,060	3,037	3,616	3,231	*5,400*
Incremental Cedar Creek Anticline[2]	---	---	---	---	---	*7,700*
Total Continuing Production	**54,485**	**56,777**	**56,024**	**60,052**	**56,842**	**68,700 – 71,700**
Bakken Area	15,285	15,503	16,752	10,064	14,395	**~94% Oil**
Gulf Coast Non-Core Properties	1,054	---	---	---	262	
Paradox Basin Properties	708	57	---	---	190	
Total Production	**71,532**	**72,337**	**72,776**	**70,116**	**71,689**	

(1) See slide 3 for full disclosure of forward-looking statements.
(2) Assumes recently announced CCA acquisition closes at the end of the first quarter of 2013. See slide 13 for more details.

Tertiary Production by Field

Field	Average Daily Production (BOE/d)								
	2008	2009	2010	2011	2012	1Q12	2Q12	3Q12	4Q12
Brookhaven	2,826	3,416	3,429	3,255	2,692	3,014	2,779	2,460	2,520
Little Creek Area	1,683	1,502	1,805	1,561	1,091	1,216	1,131	1,021	999
Mallalieu Area	5,686	4,107	3,377	2,693	2,338	2,585	2,461	2,181	2,127
McComb Area	1,901	2,391	2,342	1,997	1,785	1,746	1,902	1,769	1,722
Lockhart Crossing	186	804	1,397	1,465	1,176	1,284	1,313	1,039	1,072
Martinville	865	877	720	462	507	551	480	476	522
Eucutta	3,109	3,985	3,495	3,121	2,868	3,090	2,870	2,782	2,730
Soso	2,111	2,834	3,065	2,347	1,989	2,063	1,947	1,923	2,021
Heidelberg	---	651	2,454	3,448	3,763	3,583	3,823	3,716	3,930
Tinsley	1,010	3,328	5,584	6,743	7,947	7,297	8,168	8,153	8,166
Cranfield	---	448	911	1,123	1,159	1,152	1,094	1,119	1,269
Delhi	---	---	483	2,739	4,315	4,181	4,023	3,813	5,237
Hastings	---	---	---	---	2,188	618	1,913	2,794	3,409
Oyster Bayou	---	---	---	5	1,388	877	1,304	1,540	1,826
Total Tertiary Production	**19,377**	**24,343**	**29,062**	**30,959**	**35,206**	**33,257**	**35,208**	**34,786**	**37,550**

Analysis of Tertiary Operating Costs

	Correlation w/Oil	3Q10 $/BOE	4Q10 $/BOE	1Q11 $/BOE	2Q11 $/BOE	3Q11 $/BOE	4Q11 $/BOE	1Q12 $/BOE	2Q12 $/BOE	3Q12 $/BOE	4Q12 $/BOE
CO_2 Costs	Direct	$4.52	$5.38	$5.39	$5.43	$4.87	$4.53	$5.76	$5.14	$4.96	$5.21
Power & Fuel	Partially	6.03	5.76	6.12	6.17	6.24	6.71	6.71	6.69	6.69	5.98
Labor & Overhead	None	3.70	3.43	3.94	3.77	3.85	3.90	4.59	4.64	4.74	4.57
Equipment Rental	None	1.93	1.79	2.20	1.52	2.28	2.38	2.30	0.15	0.08	0.15
Chemicals	Partially	1.73	1.67	1.62	1.44	1.80	1.67	1.63	1.27	1.46	1.59
Workovers	Partially	2.78	2.36	3.75	2.53	3.44	2.68	3.43	3.01	3.68	3.30
Other	None	1.68	1.34	1.91	2.01	2.43	1.72	2.32	2.05	1.89	1.79
Total		**$22.37**	**$21.73**	**$24.93**	**$22.87**	**$24.91**	**$23.59**	**$26.74**	**$22.95**	**$23.50**	**$22.59**
NYMEX Oil Price		**$76.09**	**$85.16**	**$94.26**	**$102.58**	**$89.60**	**$93.93**	**$102.89**	**$93.49**	**$92.29**	**$88.18**

Pro Forma Bakken Transaction

	4Q 2012	Pro Forma(1)
Production (BOE/d)	70,116	60,052
% Oil Production	93%	95%
NYMEX Oil Price Differential ($/Bbl)	$9.43	$11.65
LOE/BOE	$21.61	$24.33
Operating Margin/BOE(2)	$65.33	$66.07
DD&A/BOE(3)	$18.20	~$19.00 to ~$21.00

Bakken Area Cash Flow ($MM)	YTD 12/31/2012
Operating Cash Flow(4)	$300
Capital Expenditures	(430)
Net	($130)

(1) Pro forma for recently closed Bakken sale, does not include Webster or Hartzog Draw. Also does not include recently announced CCA acquisition.
(2) Calculated as oil, natural gas, and related product sales less production and ad valorem taxes and LOE.
(3) Preliminary estimate, subject to change materially.
(4) Cash flow from operations before working capital reflecting only results from the portion of 4Q before sale of Bakken assets.

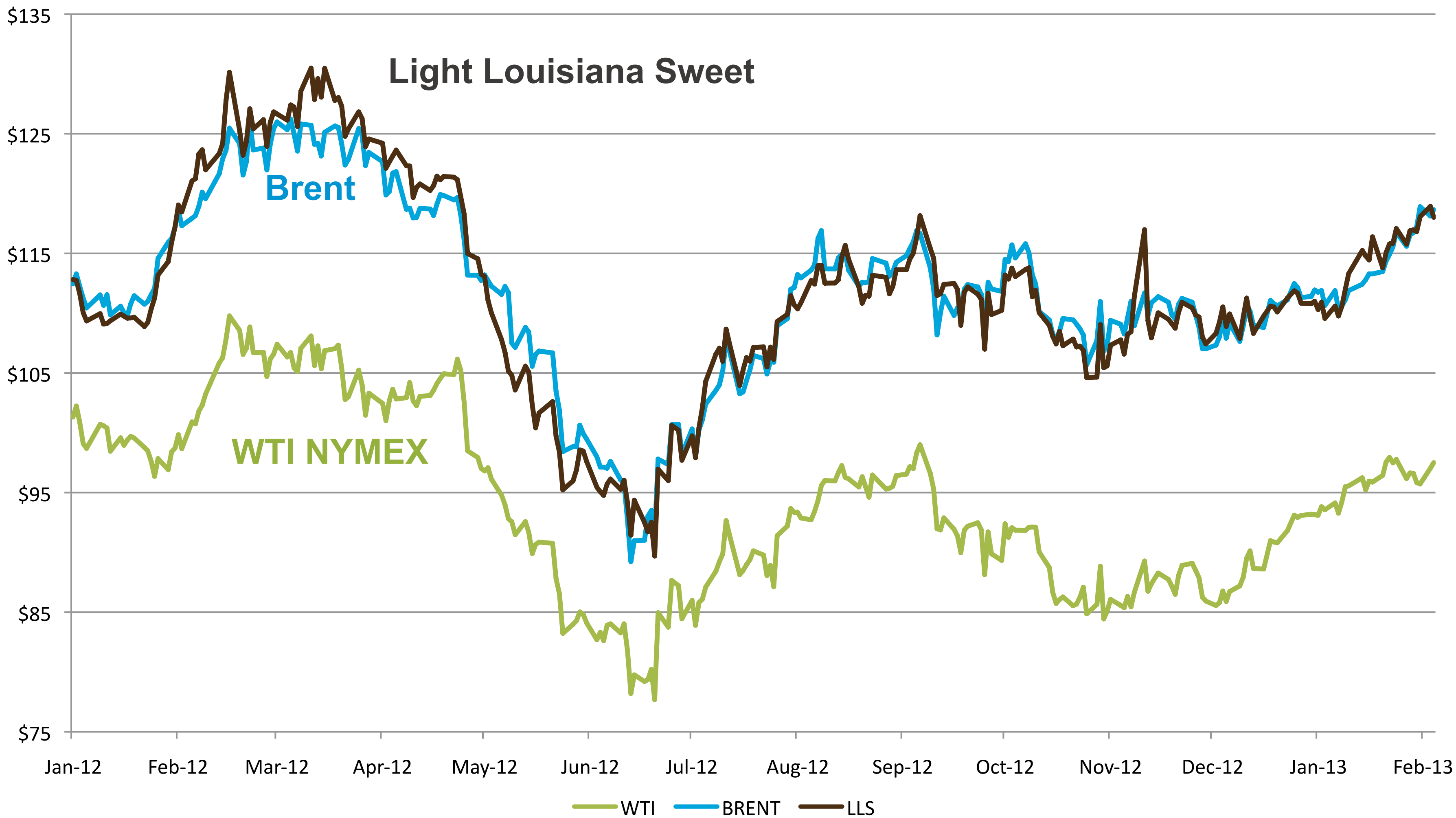
NYMEX Differential Summary

Crude Oil Differentials	3Q10	4Q10	1Q11	2Q11	3Q11	4Q11	1Q12	2Q12	3Q12	4Q12
Tertiary Oil Fields	$0.66	$0.90	$4.33	$9.69	$14.84	$19.44	$9.80	$13.60	$10.61	$15.57
Mississippi	(7.59)	(8.02)	(4.50)	1.32	7.25	6.98	2.44	8.63	2.48	10.82
Texas	(3.67)	(4.33)	(4.29)	(3.46)	1.19	12.29	1.77	5.38	5.46	13.10
Cedar Creek Anticline	(5.70)	(5.01)	(3.27)	1.25	0.85	(0.29)	(9.89)	(7.44)	(9.26)	(0.23)
Bakken Area Assets (1)	(11.41)	(13.24)	(11.67)	(9.61)	(5.67)	(8.45)	(16.96)	(20.07)	(16.32)	(5.35)
Other Rockies	(10.88)	(11.64)	(12.04)	(6.25)	(6.25)	(8.11)	(16.30)	(16.67)	(14.42)	(6.57)
Denbury Totals	**($3.86)**	**($3.90)**	**($0.59)**	**$3.72**	**$7.25**	**$9.14**	**($0.37)**	**$2.14**	**$0.80**	**$9.43**

(1) Represents certain Bakken area assets sold at the end of Nov. 2012.

Tracking Oil Prices

- We currently sell ~45% of our oil production based on LLS index price, ~25% based on various other indexes, most of which have also improved relative to WTI, but to a lesser degree



Crude Oil Hedge Detail

2013 Crude Oil Hedges (BOPD)[1]

	Instrument	Volume	Average[2] Floor	Average[2] Ceiling	Ceiling Low	Ceiling High
Q1	Collars	6,000	70.00	109.67	106.50	113.00
		9,000	80.00	105.14	102.25	106.50
		40,000	80.00	108.41	108.00	109.60
Q2	Collars	4,000	75.00	118.25	115.00	121.50
		10,000	80.00	105.65	104.50	106.50
		42,000	80.00	108.40	108.00	109.60
Q3	Collars	4,000	75.00	126.80	120.50	133.10
		12,000	80.00	105.58	104.50	106.50
		40,000	80.00	108.46	108.00	109.60
Q4	Collars	16,000	80.00	103.39	102.25	105.00
		20,000	80.00	120.66	120.00	121.50
		18,000	80.00	126.63	126.00	127.50

2014 Crude Oil Hedges (BOPD)[1]

	Instrument	Volume	Average[2] Floor	Average[2] Ceiling	Ceiling Low	Ceiling High
1H	Collars	6,000	80.00	97.22	96.55	97.60
		16,000	80.00	102.43	101.60	102.70
		24,000	80.00	103.32	103.00	103.90
		6,000	80.00	104.23	104.10	104.50
2H	Collars	20,000	80.00	96.77	96.55	96.90
		16,000	80.00	97.36	97.00	97.75
		12,000	80.00	98.74	98.60	98.80

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

Capital Structure

($MM)	12/31/12	Pro forma for debt offering 12/31/12
Cash and cash equivalents[(1)]	**$99**	**$99**
Bank credit facility[(2)] (Borrowing base of $1.6 billion, matures May 2016)	700	209
9.75% Sr. Sub Notes due 2016 (Callable March 2013 at 104.875% of par)	413	---
9.50% Sr. Sub Notes due 2016 (Callable May 2013 at 104.75% of par)	234	---
8.25% Sr. Sub Notes due 2020 (Callable February 2015 at 104.125% of par)	996	996
6.375% Sr. Sub Notes due 2021 (Callable August 2016 at 103.188% of par)	400	400
4.625% Sr. Sub Notes due 2023 (Callable January 2018 at 102.313% of par)	---	1,200
Other Encore Sr. Sub Notes	4	4
Genesis pipeline financings / other capital leases	357	357
Total long-term debt[(3)]	**$3,104**	**$3,166**
Equity	5,115	5,115
Total capitalization	**$8,219**	**$8,281**

Annualized 4Q12 Adjusted cash flow from operations[(4)]	$1,431	$1,431
Net Debt to Annualized 4Q12 Adjusted cash flow from operations[(4)]	2.1x	2.1x
Net Debt to Annualized 4Q12 EBITDA[(4)]	1.9x	1.9x

Debt to total capitalization	**38%**	**38%**

(1) As of 12/31/12, our cash and cash equivalents totaled ~$100 million. At 12/31/12, ~$1.05 billion in restricted cash remained deposited with a qualified intermediary designated for the recently announced acquisition of CCA, which is expected to close at the end of March 2013.

(2) As of 12/31/12, we had ~$700 million of borrowings outstanding under our $1.6 billion bank credit facility.

(3) Excludes current portion of capital lease obligations and pipeline financings totaling $36.6 million.

(4) A non-GAAP measure, please visit our website for a full reconciliation. Also excludes current taxes related to Bakken Exchange Transaction in Q4 2012 of approximately $42 million. Represents historical amounts not adjusted for the Bakken exchange or recent CCA acquisition.

Sources and Uses

Sources of Funds	($MM)
4.625% Senior Subordinated Notes	$1,200
Total Sources	**$1,200**

Uses of Funds	($MM)
Repay 9.75% Senior Subordinated Notes due 2016[(1)]	$426
Repay 9.50% Senior Subordinated Notes dues 2016[(2)]	225
Repay Revolver Outstandings	491
Tender Premiums	39
Transaction Expenses	19
Total Uses	**$1,200**

(1) Excludes unamortized discount of $13.2 million at 1/31/2013
(2) Excludes unamortized premium of $8.9 million at 1/31/2013

Encore Acquisition was Highly Profitable

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

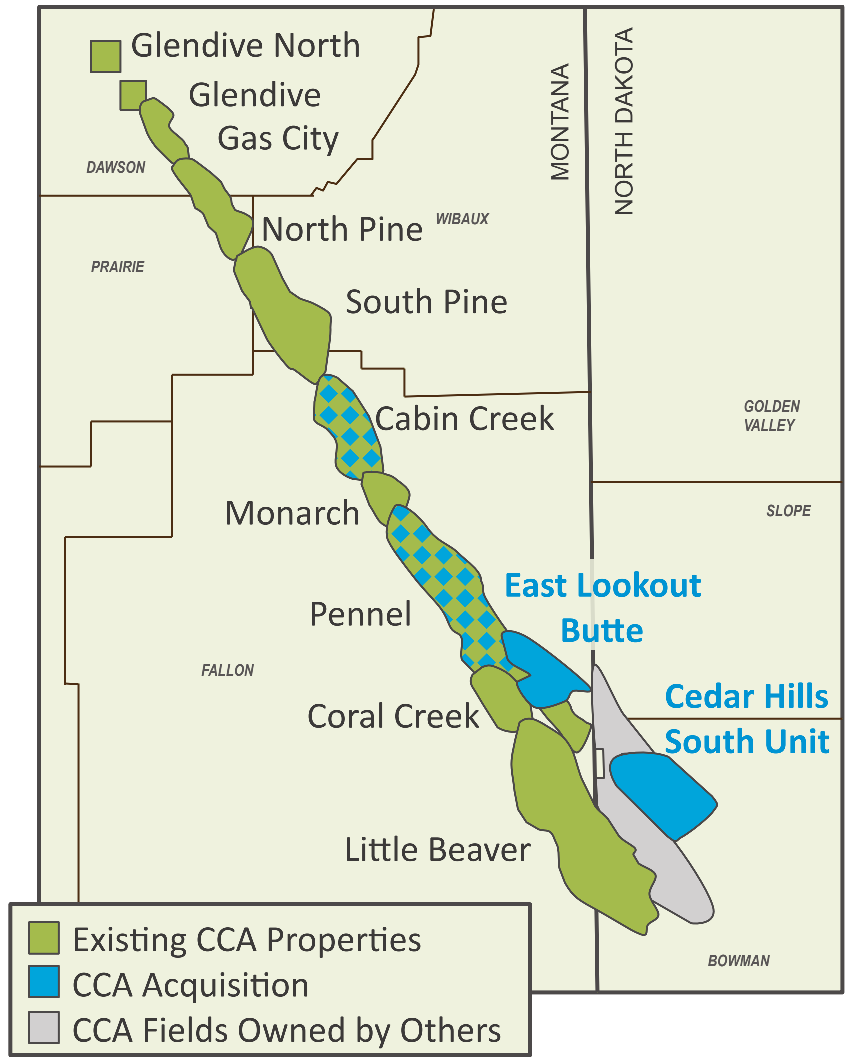
Value: (Estimated values at $94.71/Bbl – 12/31/12 SEC Pricing)	
Proved reserves at 12/31/12	$1.5 (2)
Value received from sold properties	~3.6 (3)
Net cash flow from 3/9/10 to 9/30/12	0.4
Total	**~$5.5**
Additional potential:	
CO_2 EOR potential	230 MMBOE (4)

(1) Excludes consolidated ENP debt and minority interest in ENP.
(2) Excludes sold properties, and ENP reserves.
(3) Includes ~$2 billion of estimated value of Bakken sale.
(4) Made up of CO_2 EOR potential at Bell Creek and CCA acquired from Encore.

Acquisition of Cedar Creek Anticline Fields

Transaction Terms

- $1.05 billion cash, prior to working capital adjustments
- Acquisition expected to close near the end of the first quarter of 2013 with a 1/1/2013 effective date
- The original oil in place of all units in the CCA is estimated at over three billion barrels of oil
- Including this acquisition, we estimate that a CO_2 flood of our CCA assets could recover between 260-280 million barrels of oil
- Currently producing ~11,000 barrels of oil equivalent per day (~95% oil, ~4% NGLs)
- Assuming acquisition closes at the end of 1Q 2013, we estimate it to add ~7,700 BOE/d to 2013 production estimates
- Conventional (non-tertiary) reserves ~42 million boe

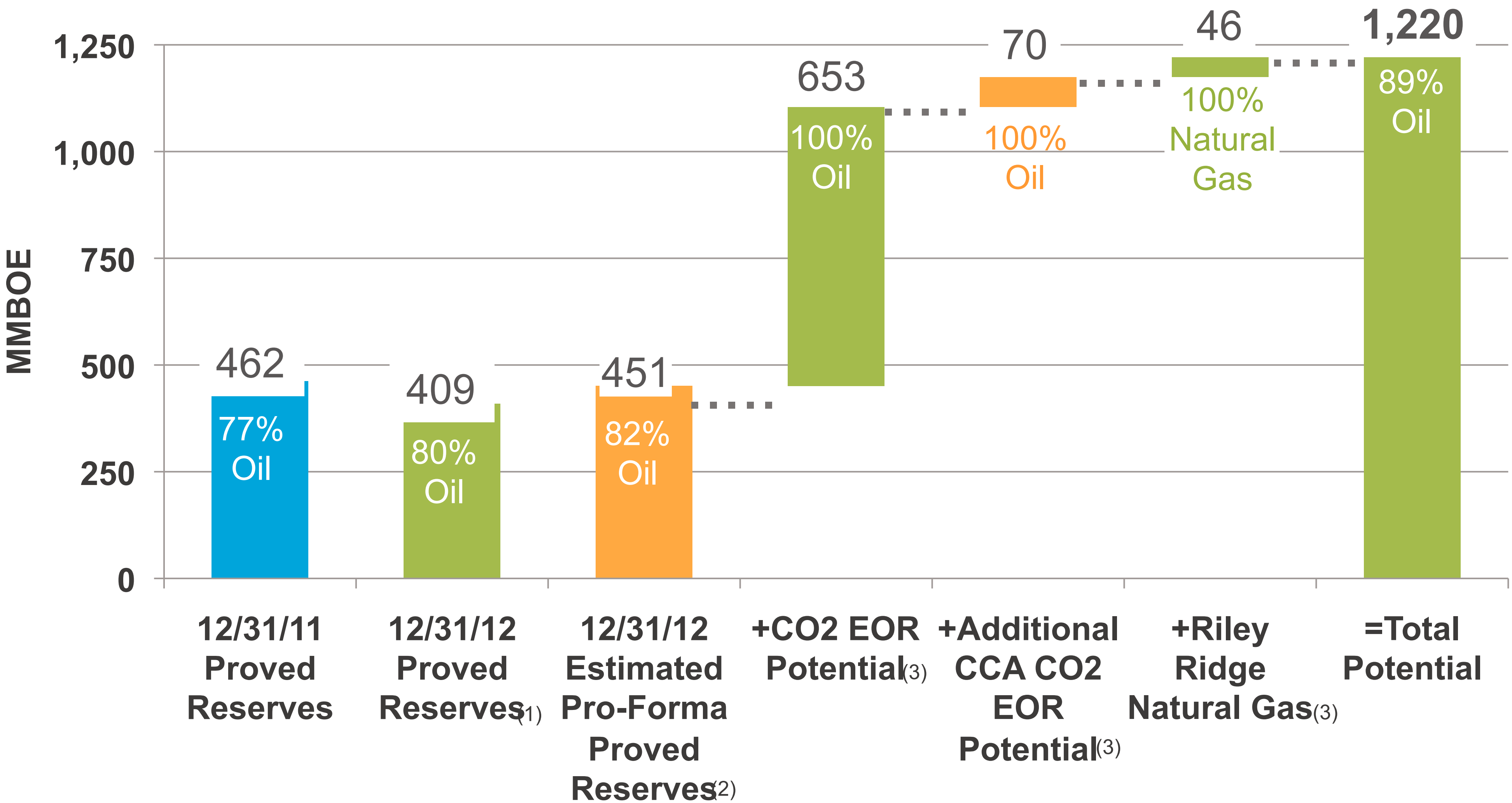


Proved Reserve Changes

	Estimated Proved Reserves (MMBOE)	Estimated PV10 ($Billion)
SEC Proved Reserves 12/31/11	**462**	**$10.6**
New CO_2 Floods (Oyster Bayou & Hastings)	57	
Extensions & Discoveries and Improved Recovery	29	
Acquisitions (Thompson, Hartzog & Webster)	28	
Divestitures (Non-Core Assets & Bakken area assets)	(124)	
Estimated 2012 Production	(26)	
Price Effect[(1)]	(7)	
Other Estimated Revisions	(10)	
SEC Proved Reserves 12/31/12	**409**	**$9.9**
Pending COP CCA Acquisition	~42	1.1
Estimated Pro-Forma Proved Reserves	**~451**	**$11.0**

(1) Primarily due to lower natural gas prices.

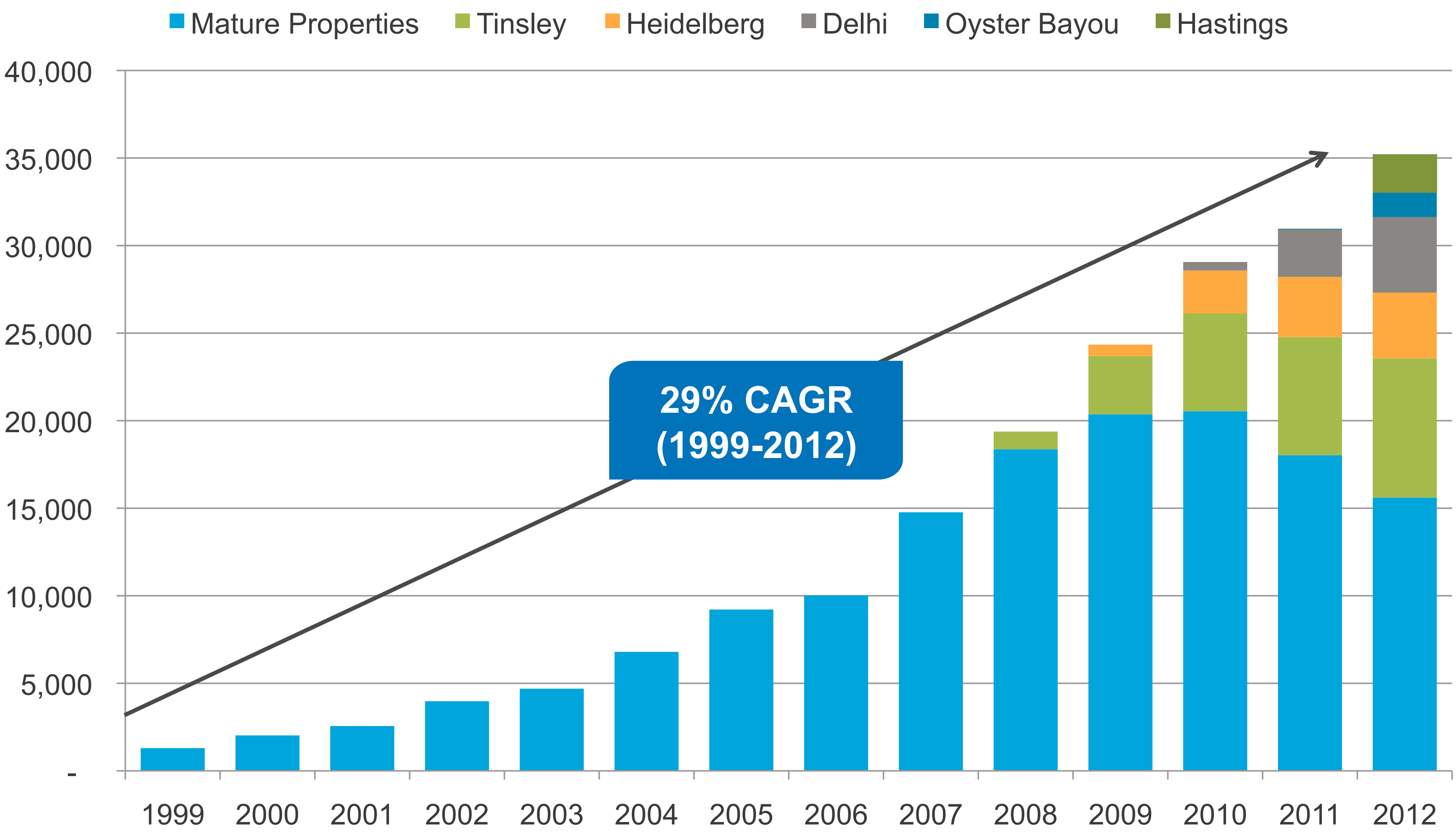
More than a Billion Barrels of Oil Potential



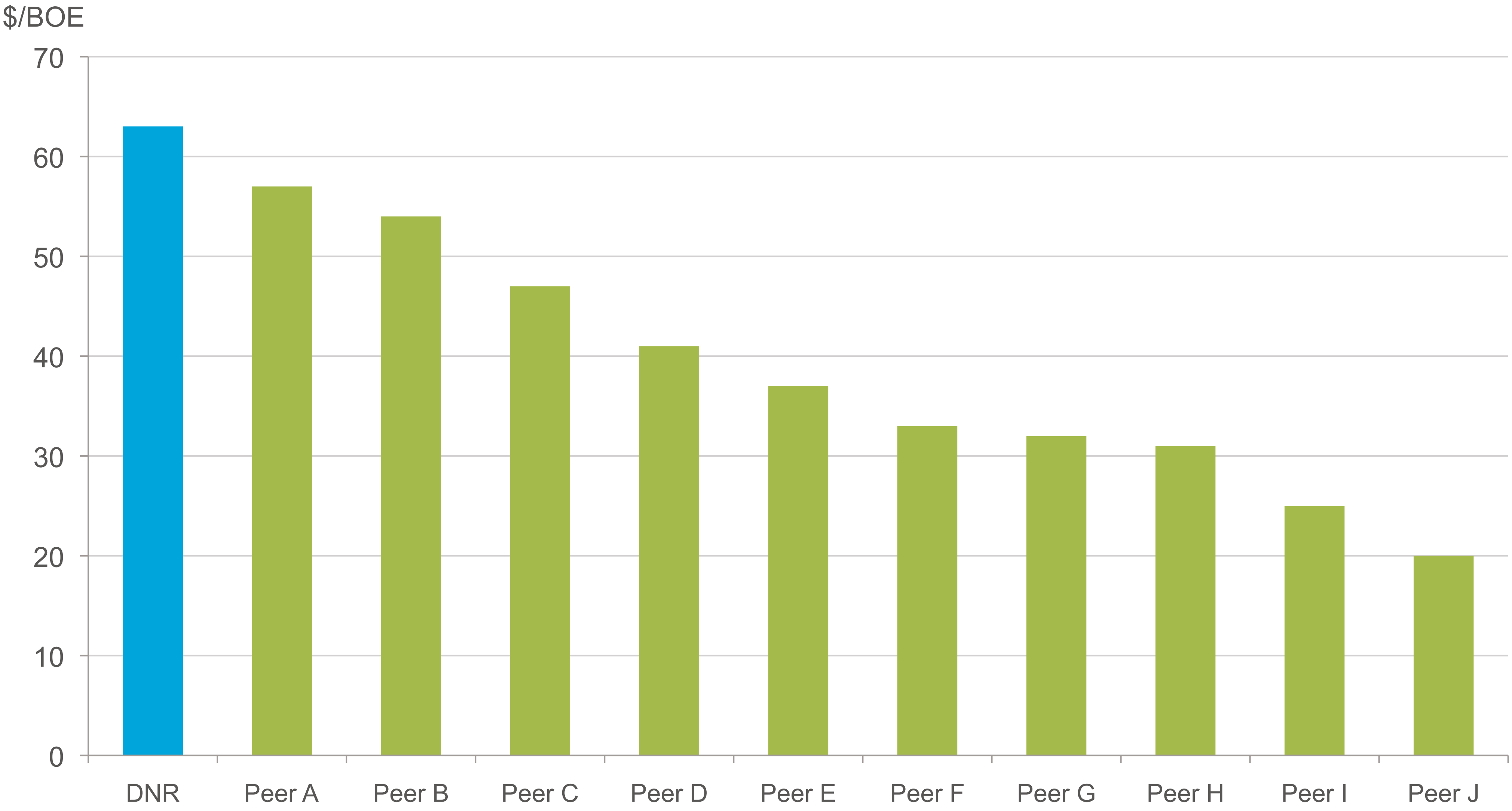
(1) Based on year-end 12/31/12 SEC proved reserves.
(2) Based on year-end 12/31/12 SEC proved reserves pro-forma for recently announced CCA acquisition.
(3) Estimates based on mid-point of internal estimates, refer to slide 3 for full disclosure of forward-looking statements.

Proven Track Record

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



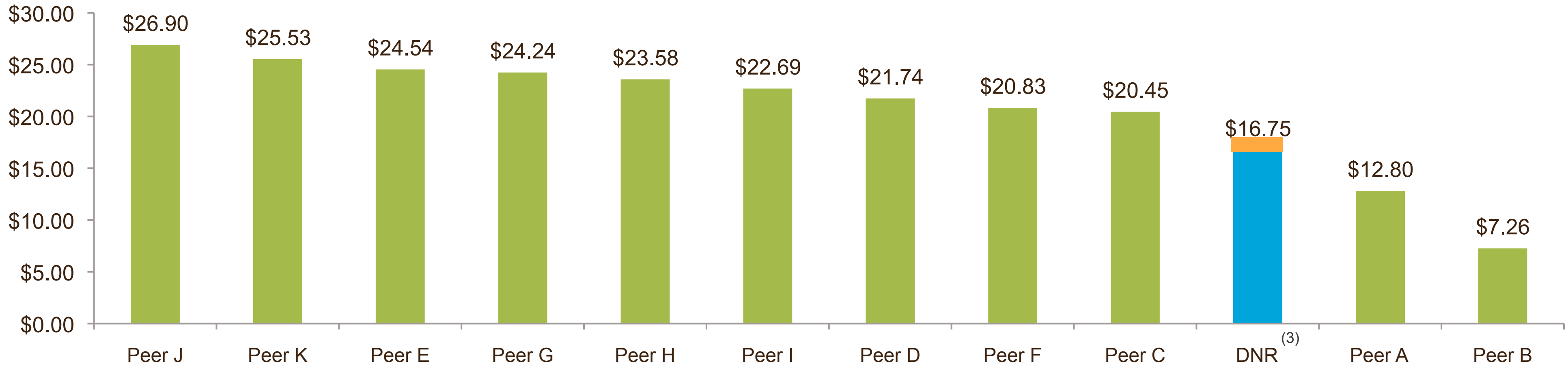
Highest Operating Margin in the Peer Group (1)



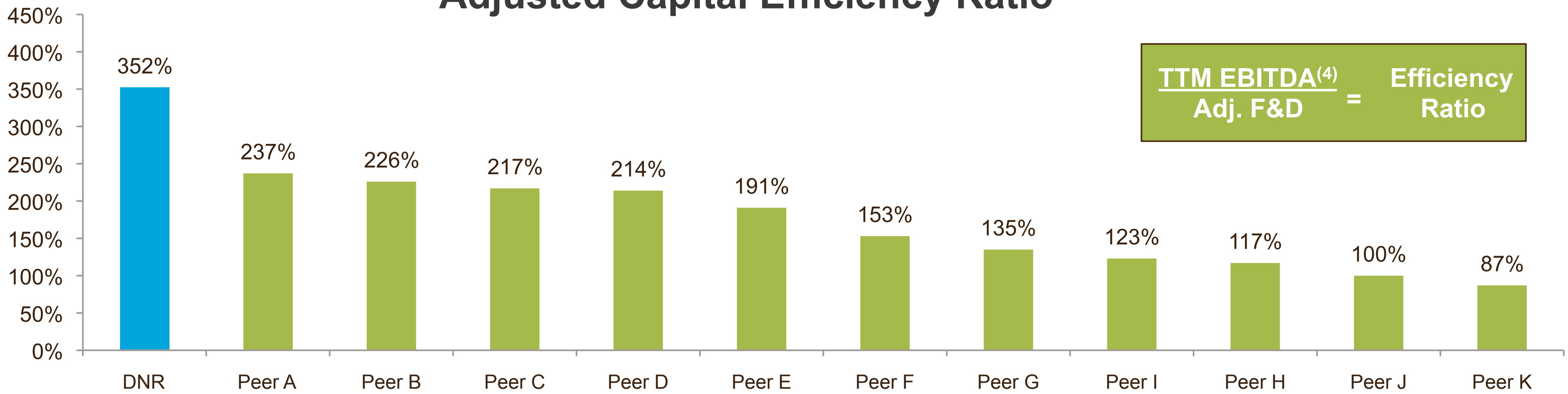
(1) Data derived from SEC filings, 3 months ended 12/30/12 and includes CLR, CXO, FST, NBL, NFX, PXD, RRC, SM, WLL, and XEC. Calculated as revenues less lease operating expenses, marketing/transportation expenses, and production and ad valorem taxes. **Includes historical data only, not adjusted for recent Bakken transaction or CCA acquisition.**

Highest Capital Efficiency in Peer Group[1]

Adjusted 3-Year Finding & Development Cost ($/BOE)[2]



Adjusted Capital Efficiency Ratio



TTM EBITDA[4] / Adj. F&D = Efficiency Ratio

(1) Peer Group includes CLR, CXO, FST, NBL, NFX, PXD, RRC, SD, SM, WLL, XEC. **Includes historical data only, not adjusted for recent Bakken transaction or CCA acquisition.**
(2) Three years ended 12/31/2011, and includes Encore Acquisition in 2010. calculated as total capital expenditures divided by net reserve additions, including changes in future development costs and change in unevaluated properties.
(3) Includes 3 year average DD&A for CO_2 properties of $0.82 per BOE
(4) Trailing twelve months EBITDA ended 9/30/2012.

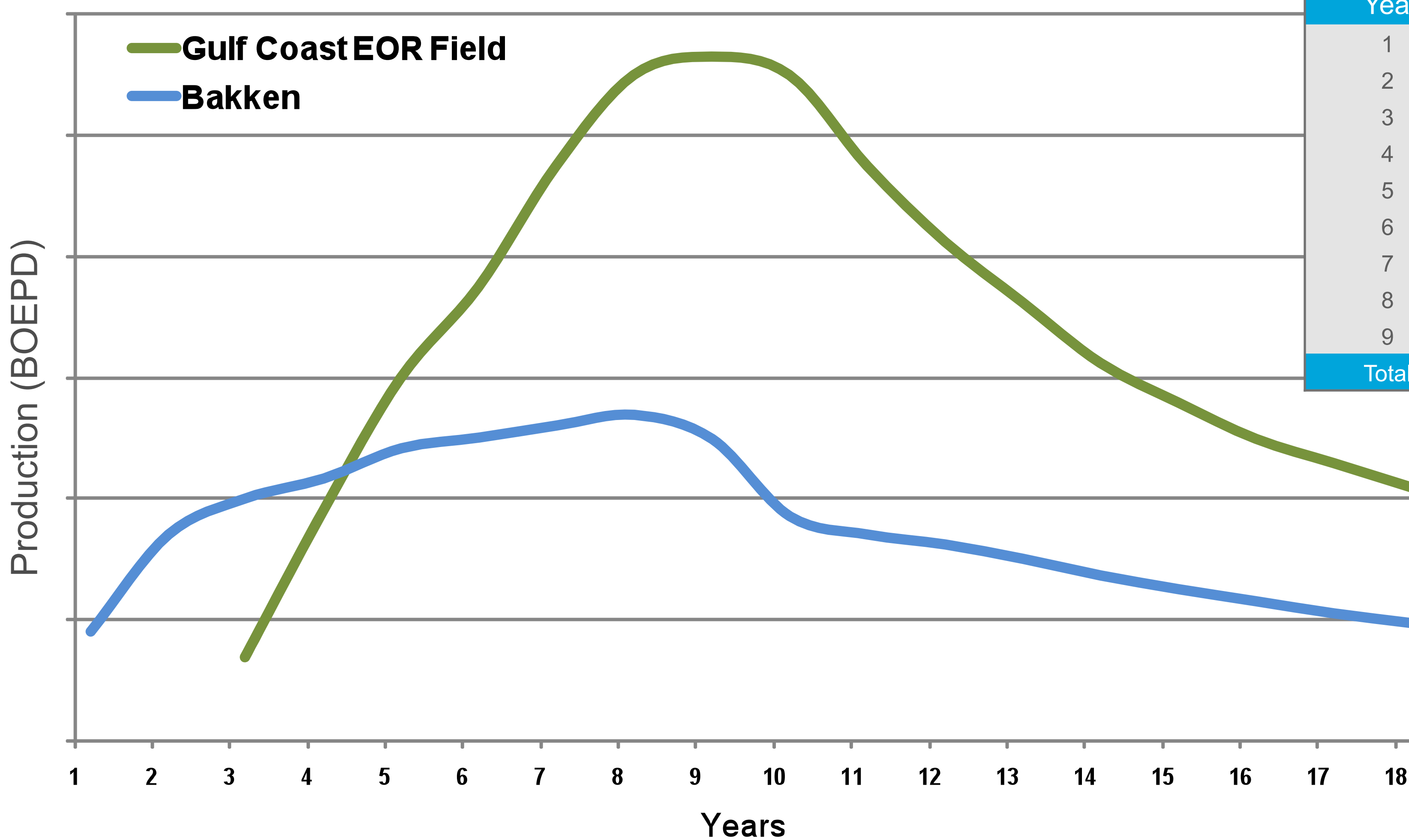
CO_2 EOR – Superior Economics[1]

	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	**4.4x**	**2.7x**

(1) Updated as of 12/31/11 which does not include Thompson or Webster.

CO_2 EOR – Superior Production Profile

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.