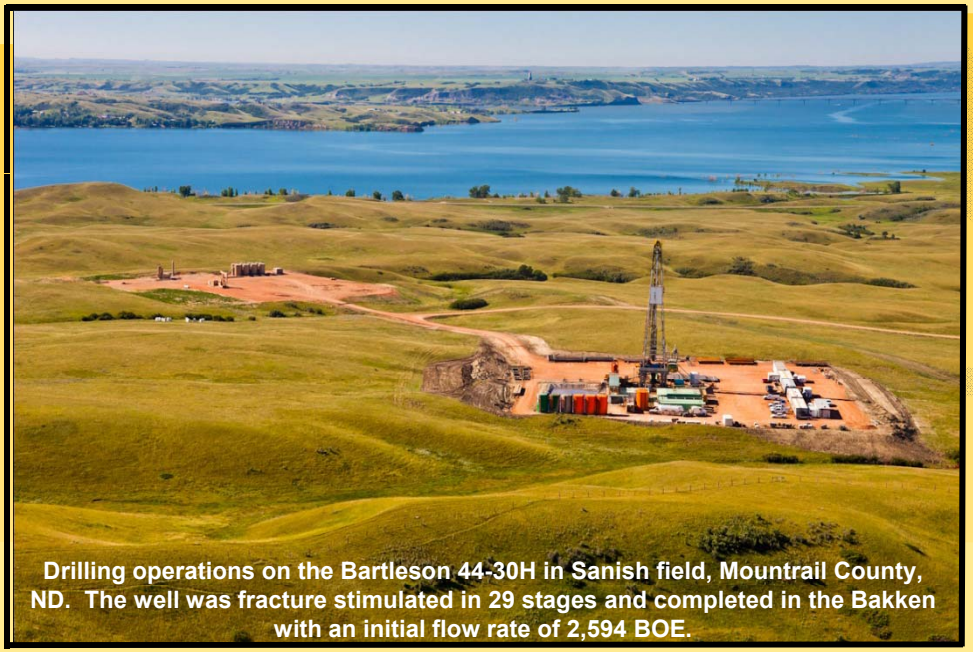
Whiting Petroleum Corporation



Drilling operations on the Bartleson 44-30H in Sanish field, Mountrail County, ND. The well was fracture stimulated in 29 stages and completed in the Bakken with an initial flow rate of 2,594 BOE.

First Quarter 2011
Financial and Operating Results
April 28, 2011

Drilling operations on the Hagey 12-13H in Sanish field, Mountrail County, ND. The well was fracture stimulated in 22 stages and completed in the Bakken with an initial flow rate of 2,264 BOE/d.

Forward-Looking Statement Disclosure, Non-GAAP Measures

This presentation includes forward-looking statements that the Company believes to be forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. All statements other than statements of historical fact included in this presentation are forward-looking statements. These forward looking statements are subject to risks, uncertainties, assumptions and other factors, many of which are beyond the control of the Company. Important factors that could cause actual results to differ materially from those expressed or implied by the forward-looking statements include the Company's business strategy, financial strategy, oil and natural gas prices, production, reserves and resources, impacts from the global recession and tight credit markets, the impacts of state and federal laws, the impacts of hedging on our results of operations, level of success in exploitation, exploration, development and production activities, uncertainty regarding the Company's future operating results and plans, objectives, expectations and intentions and other factors described in the Company's Annual Report on Form 10-K for the year ended December 31, 2010 and Form 10-Q for the quarter ended March 31, 2011. In addition, Whiting's production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

In this presentation, we refer to Adjusted Net Income and Discretionary Cash Flow, which are non-GAAP measures that the Company believes are helpful in evaluating the performance of its business. A reconciliation of Adjusted Net Income and Discretionary Cash Flow to the relevant GAAP measures can be found at the end of the presentation.

Reserve and Resource Information

Whiting uses in this presentation the terms proved, probable and possible reserves. Proved reserves are reserves which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. Probable reserves are reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Possible reserves are reserves that are less certain to be recovered than probable reserves. Estimates of probable and possible reserves which may potentially be recoverable through additional drilling or recovery techniques are by nature more uncertain than estimates of proved reserves and accordingly are subject to substantially greater risk of not actually being realized by the Company.

Whiting uses in this presentation the term “total resources,” which consists of contingent and prospective resources, which SEC rules prohibit in filings of U.S. registrants. Contingent resources are resources that are potentially recoverable but not yet considered mature enough for commercial development due to technological or business hurdles. For contingent resources to move into the reserves category, the key conditions, or contingencies, that prevented commercial development must be clarified and removed. Prospective resources are estimated volumes associated with undiscovered accumulations. These represent quantities of petroleum which are estimated to be potentially recoverable from oil and gas deposits identified on the basis of indirect evidence but which have not yet been drilled. This class represents a higher risk than contingent resources since the risk of discovery is also added. For prospective resources to become classified as contingent resources, hydrocarbons must be discovered, the accumulations must be further evaluated and an estimate of quantities that would be recoverable under appropriate development projects prepared. Estimates of resources are by nature more uncertain than reserves and accordingly are subject to substantially greater risk of not actually being realized by the Company.

Company Overview

Drilling the Hutchins Stock Association #1096 in North Ward Estes Field, Whiting's EOR project in Winkler County, Texas.

Market Capitalization[1]	*$8.5 B*
Long-term Debt[2]	*$980.0 MM*
Shares Outstanding	*117.4 MM*
Debt/Total Cap[2]	*27.8%*
Proved reserves[3]	*304.9 MMBOE*
% Oil	*83%*
RP ratio[4]	*12.9 years*
Q1 2011 Production	*66.0 MBOE/d*

1 Assumes a $72.67 share price (closing price as of April 25, 2011) on 117,368,706 common shares outstanding as of March 31, 2011.

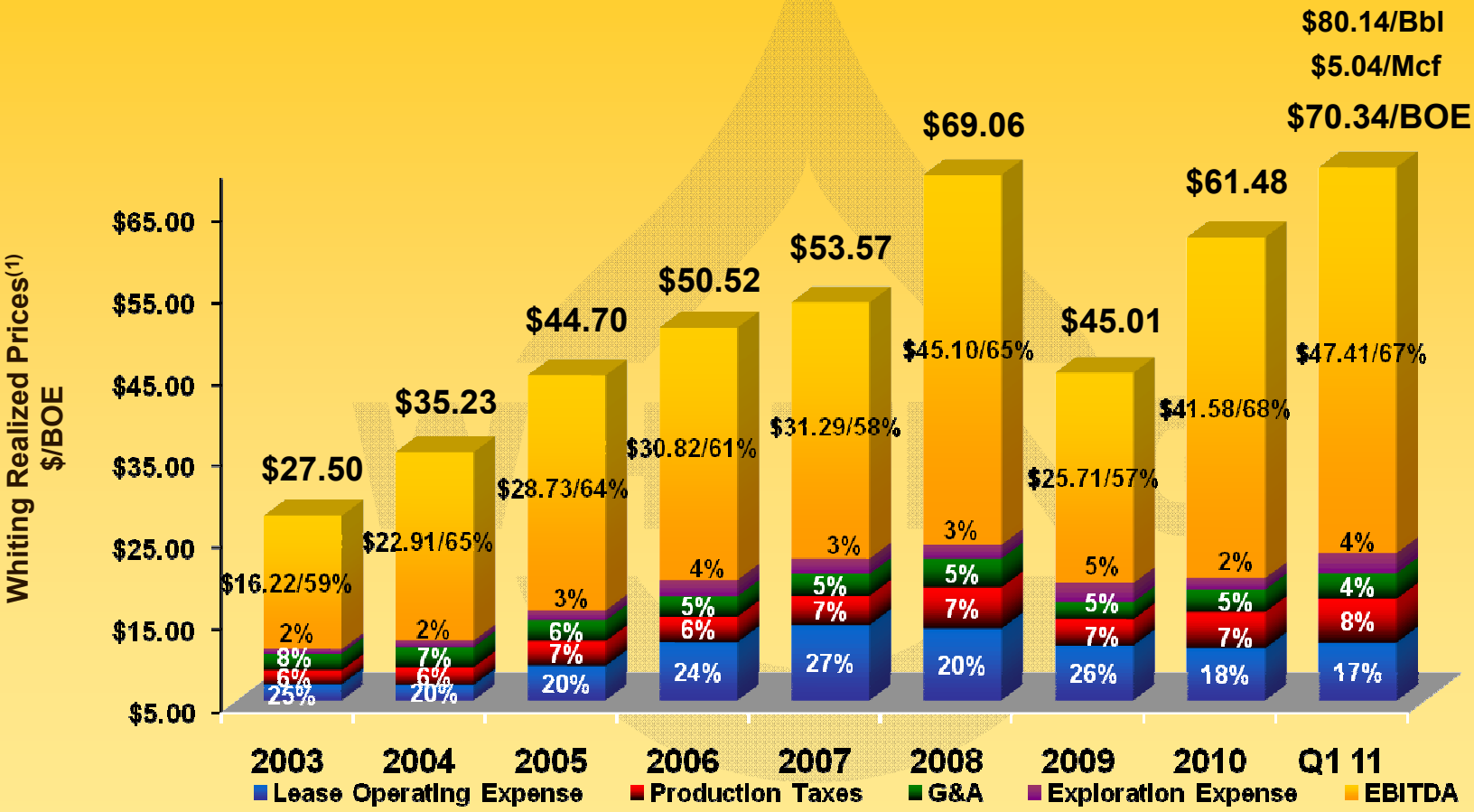
2 As of March 31, 2011. Please refer to Slide #40 for details.

3 Whiting reserves at December 31, 2010 based on independent engineering.

4 R/P ratio based on year-end 2010 proved reserves and 2010 production.

Consistently Strong Margins

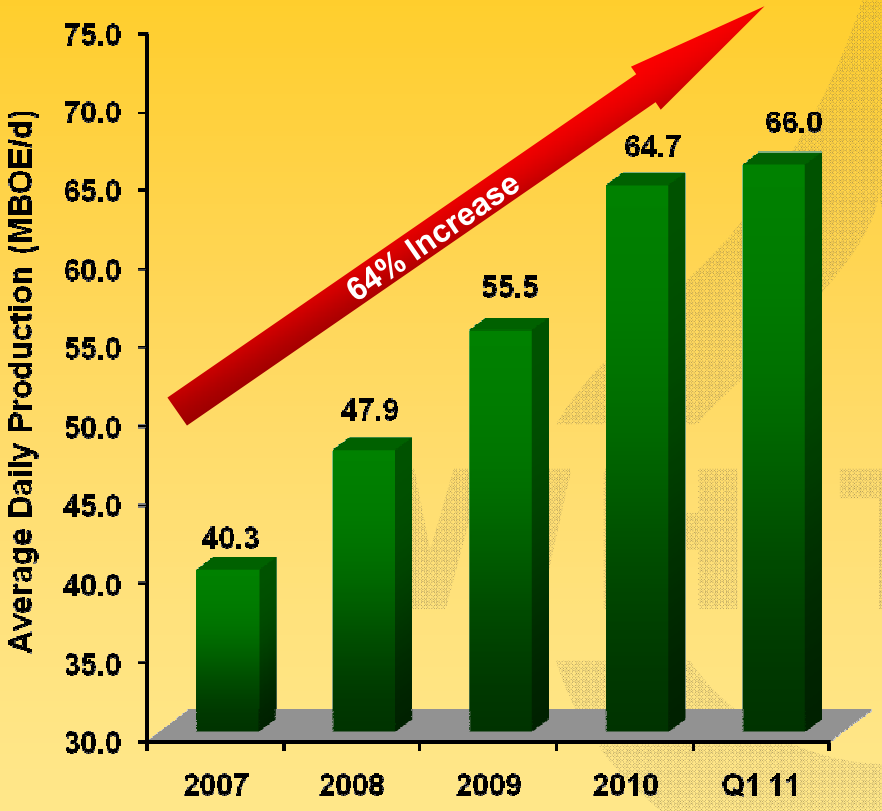
Consistently Delivering Strong EBITDA Margins (1)



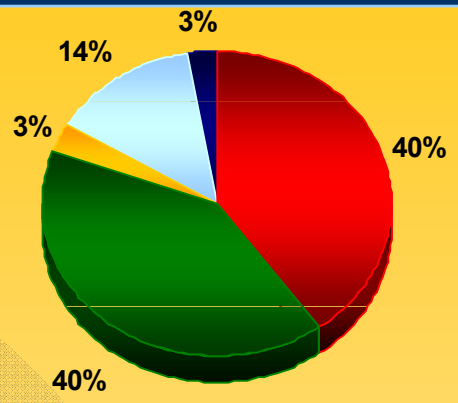
(1) Includes hedging adjustments.

Platform for Continued Growth

Average Daily Production



Proved Reserves (12/31/2010)

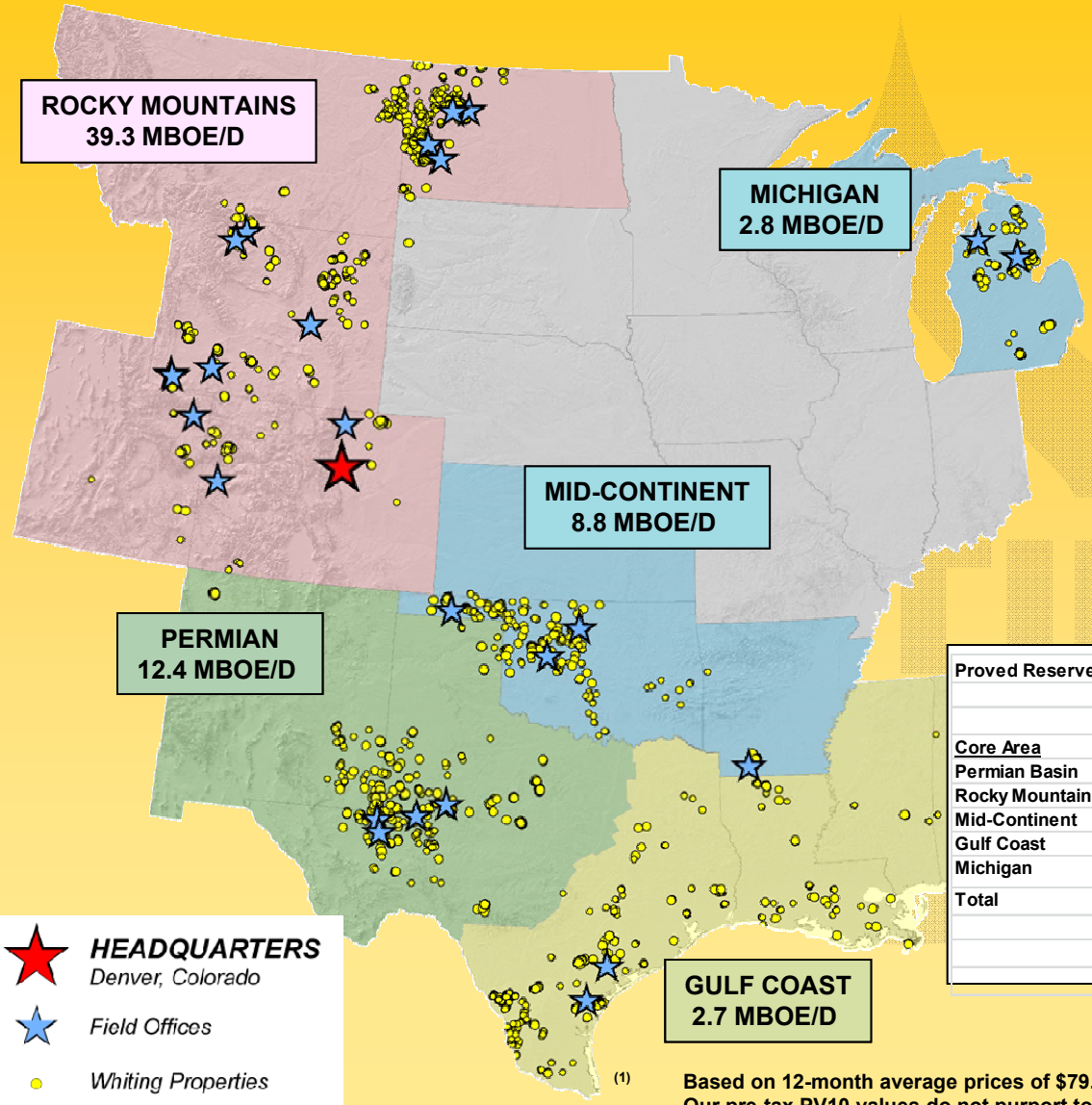


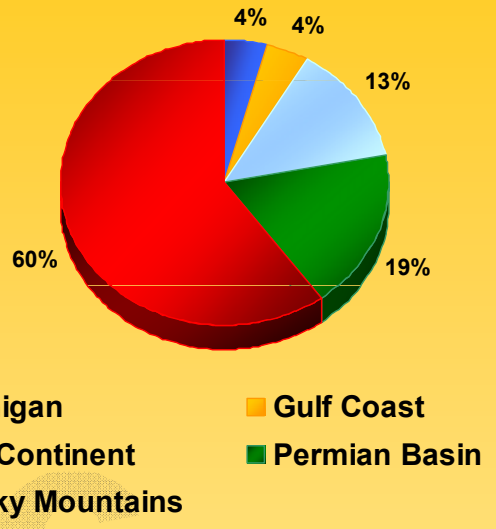
- 304.9 MMBOE (12/31/2010)
- 83% Oil / 17% Natural Gas
- 71% Developed / 29% Undeveloped
- 1,328,665 Net Acres (43% Developed)
- $5.0 Billion PV10% (pre-tax) at SEC NYMEX prices of $79.43/Bbl and $4.38/Mcf

At December 31, 2010, Whiting Had a 12.9 Year R/P Ratio (1) Supported by a Strong Portfolio of Development Opportunities

(1) R/P ratio based on year-end 2010 proved reserves and 2010 production.

Map of Operations





Proved Reserves at December 31, 2010 [1]					Pre-Tax PV10% Value [1]	Q1 2011 Average Daily Net Production
Core Area	Oil [2] (MMBbl)	Gas (Bcf)	Total (MMBOE)	Oil %	(in millions)	(MBOE/d)
Permian Basin	115.6	47.9	123.6	94%	$1,471.5	12.4
Rocky Mountains	94.5	162.8	121.6	78%	$2,425.5	39.3
Mid-Continent	38.2	19.9	41.5	92%	$955.2	8.8
Gulf Coast	3.2	36.9	9.4	34%	$113.3	2.7
Michigan	2.8	36.0	8.8	32%	$78.9	2.8
Total	254.3	303.5	304.9	83%	$5,044.4	66.0

[2] Oil includes natural gas liquids

(1) Based on 12-month average prices of $79.43/Bbl and $4.38/Mcf in accordance with SEC requirements. Our pre-tax PV10 values do not purport to present the fair value of our oil and natural gas reserves.

Whiting Total Reserves and Resources at Dec. 31, 2010

	MMBO	MMBNGL	Oil & NGL MMBO	BCF	MMBOE	% of Total 3P MMBOE
PDP	134	13	147	204	181	29%
PBP	2	1	3	13	5	1%
PNP	24	4	28	3	29	5%
PUD	64	12	76	83	90	14%
Total Proved (1) (2)	224	30	254	303	305	
Total Probable (1) (3)	50	15	65	212	100	16%
Total Possible (1) (4)	146	37	183	205	217	35%
Total 3P Reserves	420	82	502	720	622	100.0%
Resource Potential (5)	228	27	255	711	374	

(1) Proved, Probable and Possible Reserves based on independent engineering by Cawley Gillespie & Associates, Inc. at December 31, 2010. Based on 12-month average prices of $79.43/Bbl and $4.38/Mcf in accordance with SEC requirements. Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information." All volumes shown are unrisked.

(2) Future capital expenditures for total Proved Reserves are estimated at $1,492MM.

(3) Future capital expenditures for total Probable Reserves are estimated at $1,500MM.

(4) Future capital expenditures for total Possible Reserves are estimated at $2,036MM.

(5) Whiting has internally estimated its unrisked Total Resource potential using year-end 2010 SEC pricing of $79.43/Bbl and $4.38/Mcf held flat. Future capital expenditures associated with Resources are estimated at $5,089MM. Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information." All volumes shown are unrisked.

Major Fields with Probable and Possible Reserves at December 31, 2010 (1) (2)

Region	Field	MMBOE	Capex MM$	$ Per BOE
Permian	**North Ward Estes** (Additional phases and larger CO_2 slug sizes)	**130**	**1,199**	**9.22**
Rockies	**Various Fields and Prospects** (Bakken and Three Forks Development)	**75**	**968**	**12.91**
Rockies	**Sulphur Creek** (225 20- and 10-acre wells)	**32**	**398**	**12.44**
	Total (75% of 317 MMBOE)	**237**	**2,565**	**10.82**

(1) **Based on independent engineering by Cawley Gillespie & Associates, Inc. at December 31, 2010. Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information." All volumes shown are unrisked.**

(2) **Based on 12-month average prices of $79.43/Bbl and $4.38/Mcf in accordance with SEC requirements.**

Whiting Total Resource Potential at Dec. 31, 2010 (1)(2)(3)

Using SEC Prices of $79.43/Bbl and $4.38/Mcf Held Flat

	MMBO	MMBNGL	Oil & NGL MMBO	Nat. Gas BCF	MMBOE	PV10, MM$
Williston Basin Bakken & Three Forks **(Continued exploration in ND & MT)**	127	11	138	70	149	$ 1,670
Big Tex – TX **(Wolfcamp and Bone Spring exploration)**	37	0	37	65	48	$ 1,040
Redtail – CO **(Niobrara exploration)**	38	0	38	24	42	$ 853
Sulphur Creek – CO (4)	1	10	11	139	34	$ 20
Other Areas – **(CO, MI, ND, TX, UT and WY)**	25	6	31	413	101	$ 655
Total Resource Potential	228	27	255	711	374	$ 4,238

(1) **Whiting has internally estimated its unrisked Total Resource potential. PV10 values were based on SEC NYMEX price assumptions of $79.43/Bbl and $4.38/Mcf. Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information." All volumes shown are unrisked. Our pre-tax PV10 values do not purport to present the fair value of our oil and natural gas reserves.**

(2) **Future capital expenditures for Total Resources are estimated at $5,089MM.**

(3) **Estimated future capital expenditures associated with these areas are as follows: Williston Basin $2,370MM; Big Tex $652MM; Redtail $638MM; Sulphur Creek $355MM; Other Areas $1,074MM.**

(4) **Whiting estimates continued development will occur at NYMEX prices of approximately $6.00 per Mcf.**

Whiting Total Reserves at December 31, 2010

with Breakout of % Bakken / Three Forks and EOR

	MMBOE	BAK & 3FKS (MMBOE)	BAK & 3FKS %	EOR (MMBOE)	EOR %
PDP	181	49	27%	65	36%
PBP	5	0	2%	0	0%
PNP	29	0	0%	27	93%
PUD	90	25	28%	41	46%
Total Proved (1)	305	74	24%	133	44%
Total Probable (1)	100	6	6%	41	41%
Total Possible (1)	217	69	32%	110	51%
Total 3P Reserves	622	149	24%	284	46%
Resource Potential (2)					
Williston Basin BAK & 3FKS – ND & MT	149	149	100%		
Big Tex – TX	48	--	--		
Redtail Niobrara – CO	42	--	--		
Sulphur Creek – CO	34	--	--		
Other Areas – CO, MI, ND, TX, UT & WY	101	--	--		
Total Resource Potential	374	149	40%		

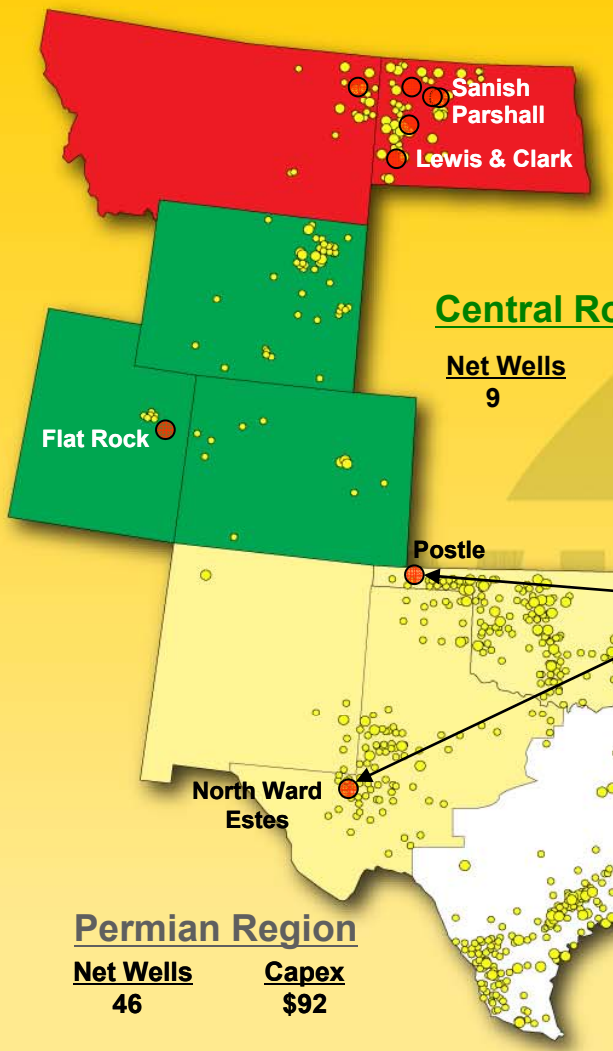
(1) The Proved, Probable and Possible reserve estimates shown are based on independent engineering by Cawley, Gillespie & Associates, Inc. at December 31, 2010 using SEC NYMEX prices of $79.43/Bbl and $4.38/Mcf. Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information." All volumes shown are unrisked.

(2) Whiting has internally estimated its "Total Resource" potential at SEC NYMEX prices of $79.43/Bbl and $4.38/Mcf. Please see Slide #2 for the definition of "Total Resource." All volumes shown are unrisked.

Key Development Areas for 2011

($ in millions)

Northern Rockies



Sanish Field

Net Wells	Capex
54	$352

Lewis & Clark

Net Wells	Capex
30	$278

Central Rockies

Net Wells	Capex
9	$52

EOR Projects

Capex
$314

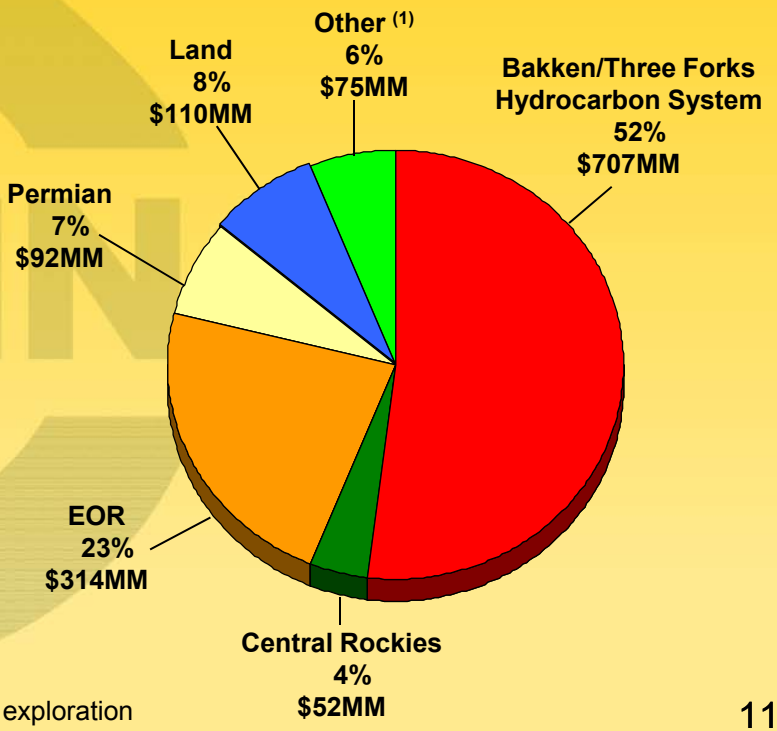
Permian Region

Net Wells	Capex
46	$92

Existing Properties

2011 Capital Projects

2011 Exploration & Development Budget $1.35 B



(1) Comprised primarily of exploration salaries, lease delay rentals, seismic and other exploration and development.

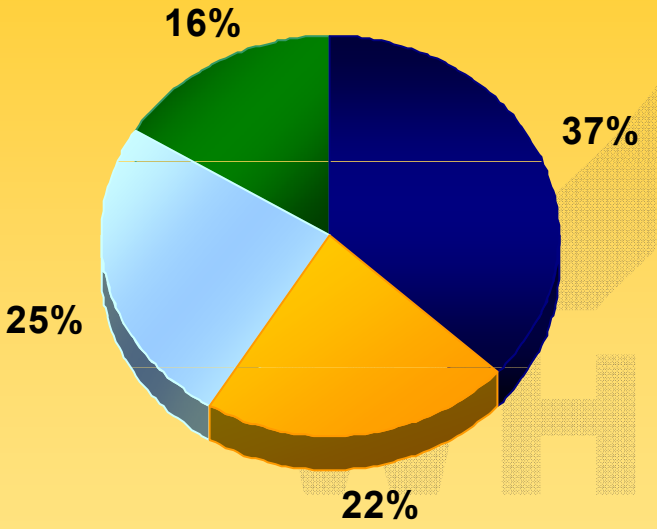
2011 Exploration and Development Budget
Estimated Gross and Net Wells in 2011

	EST. 2011 CAPEX (In MM)	PLANNED WELLS Gross	Net
NORTHERN ROCKIES			
Sanish Field	$ 352	95	54
Parshall Field	$ 12	11	2
Lewis & Clark Area	$ 278	51	30
Other (Hidden Bench, Starbuck, Cassandra & Big Island)	$ 65	23	14
SUBTOTAL	$ 707	180	100
EOR PROJECTS			
North Ward Estes	$ 201	--	--
Postle	$ 113	--	--
SUBTOTAL	$ 314	--	--
PERMIAN BASIN			
Big Tex	$ 89	23	23
Other Permian	$ 3	23	23
SUBTOTAL	$ 92	46	46
CENTRAL ROCKIES			
Redtail Prospect	$ 35	6	6
Other Central Rockies	$ 17	4	3
SUBTOTAL	$ 52	10	9
GULF COAST			
Various	$ 2	1	1
MICHIGAN			
PDC Expl. & Dvlp.	$ 5	1	1
OTHER, EXPLORATION	$ 11	--	--
OTHER, NON-OPERATED	$ 17	--	--
EXPL. EXPENSE (1)	$ 40	--	--
LAND	$ 110	--	--
GRAND TOTAL	$1,350	238	157

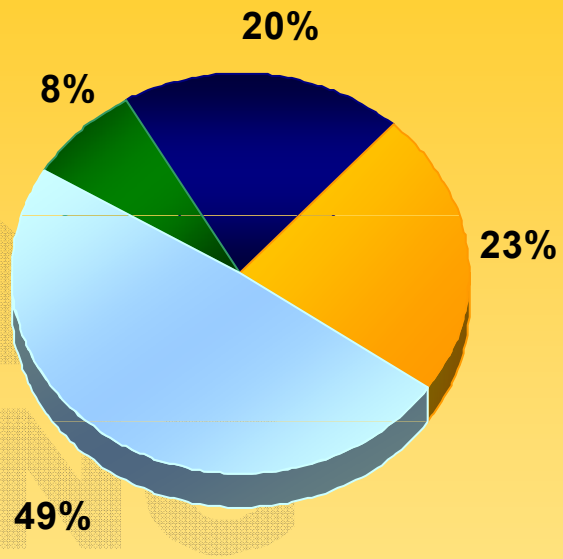
(1) Comprised primarily of exploration salaries, lease delay rentals and seismic activities.

2010 vs. 2011 Capital Expenditures By Reserve Category

2010 – $978 MM Actual

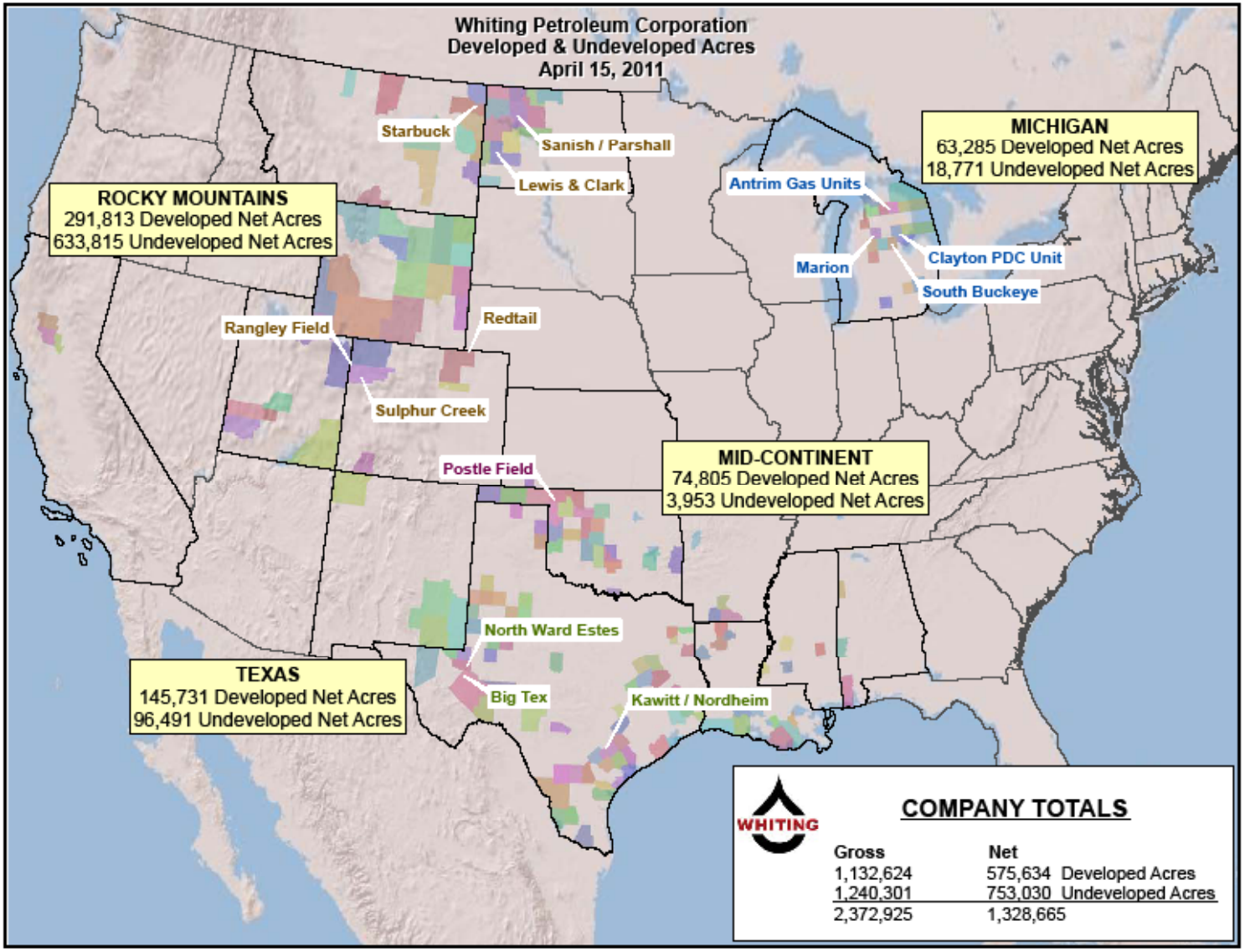


2011 – $1,350 MM Budget

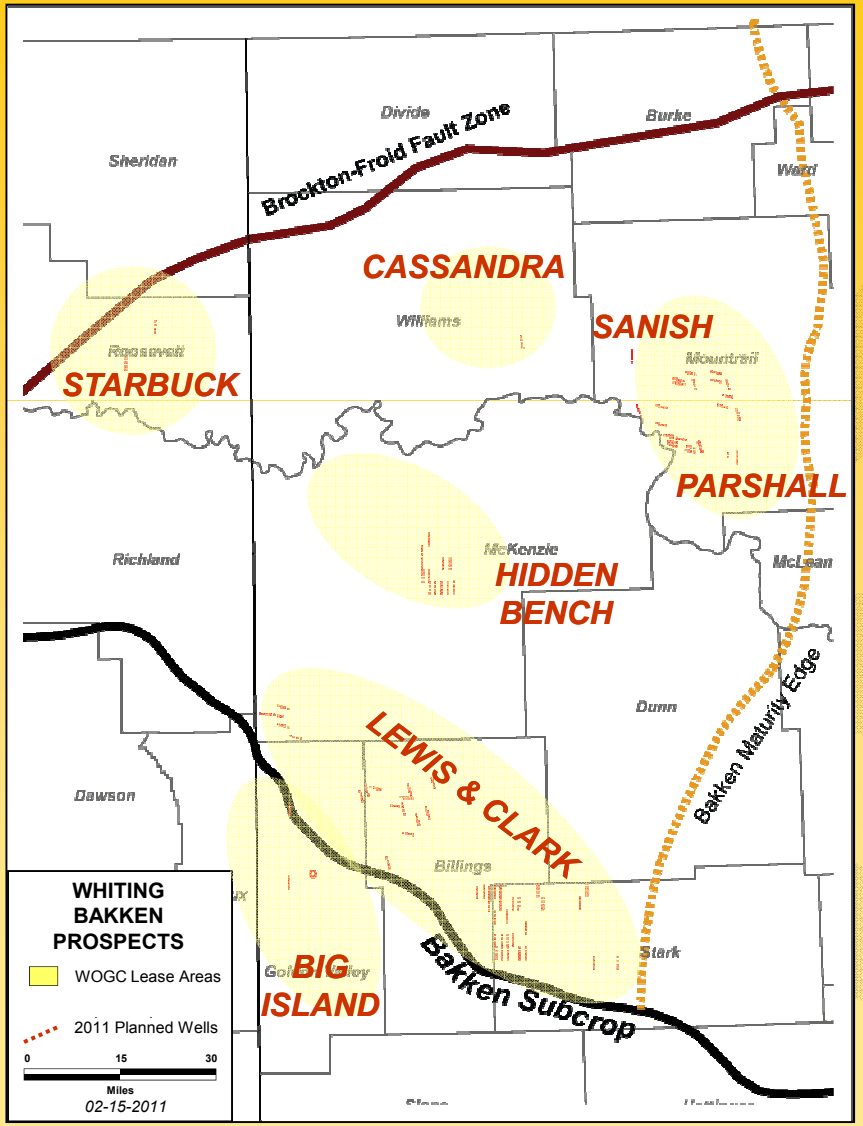


- Proved
- CO_2 Recovery Projects (Proved)
- Non-Proved
- Land

Whiting Developed & Undeveloped Acreage by Core Area



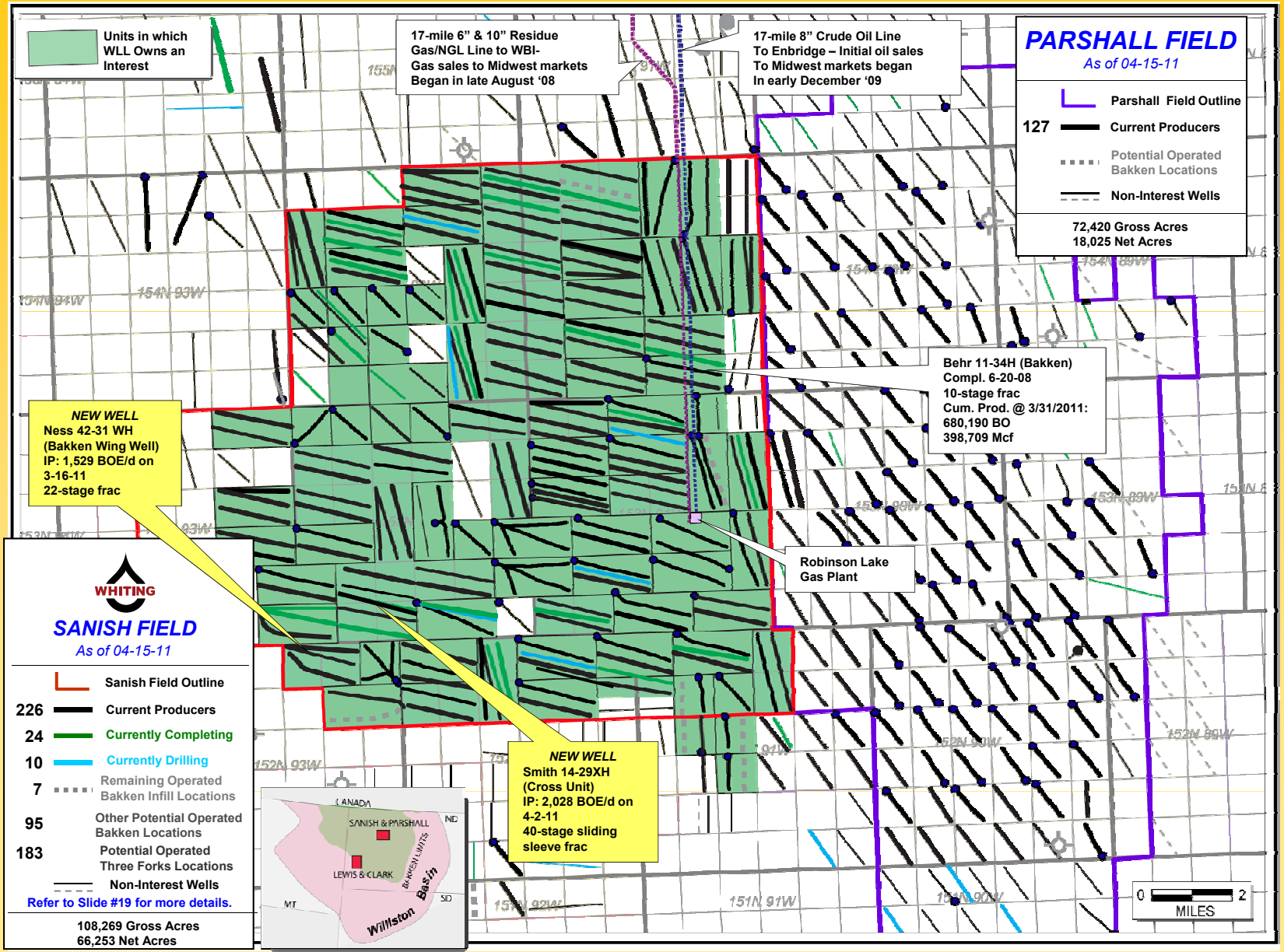
Whiting Prospect Areas in Bakken/Three Forks Hydrocarbon System at March 31, 2011(1)



	Gross Acres	Net Acres
Sanish / Parshall		
- Bakken and Three Forks Objectives		
- 194 producing wells in Sanish	180,689	84,278
- 127 producing wells in Parshall		
- 99 Wells in 2010, 106 in 2011		
- $364MM capex in 2011		
Lewis & Clark	376,111	245,744
- Three Forks Objective		
- Control 164 1,280-acre spacing units		
- 12 Wells in 2010, 51 in 2011		
- $278MM capex in 2011		
Hidden Bench / Tarpon	64,176	33,949
- Middle Bakken "C" Objective		
- Control 15 1,280-acre spacing units		
- 12 Wells in 2011, $35MM capex in 2011		
Starbuck	110,326	88,534
- Middle Bakken Objective		
- Control 75 1,280-acre spacing units		
- 2 Wells in 2011, $13MM capex in 2011		
Cassandra	28,776	13,846
- Middle Bakken Objective		
- Control 9 1,280-acre spacing units		
- 2 Wells in 2010, 2 in 2011		
- $6MM capex in 2011		
Big Island	131,600	94,570
- Multiple Objectives		
- Control 64 1,280-acre spacing units		
- 1 Well in 2011, $4MM capex in 2011		
Subtotals	891,678	560,921
Other ND and Montana	108,294	42,781
	999,972	603,702

(1) Whiting's total acreage cost in 604M net acres is approximately $214 million, or $354 per net acre.

Sanish and Parshall Fields -
Recent and Notable Wells

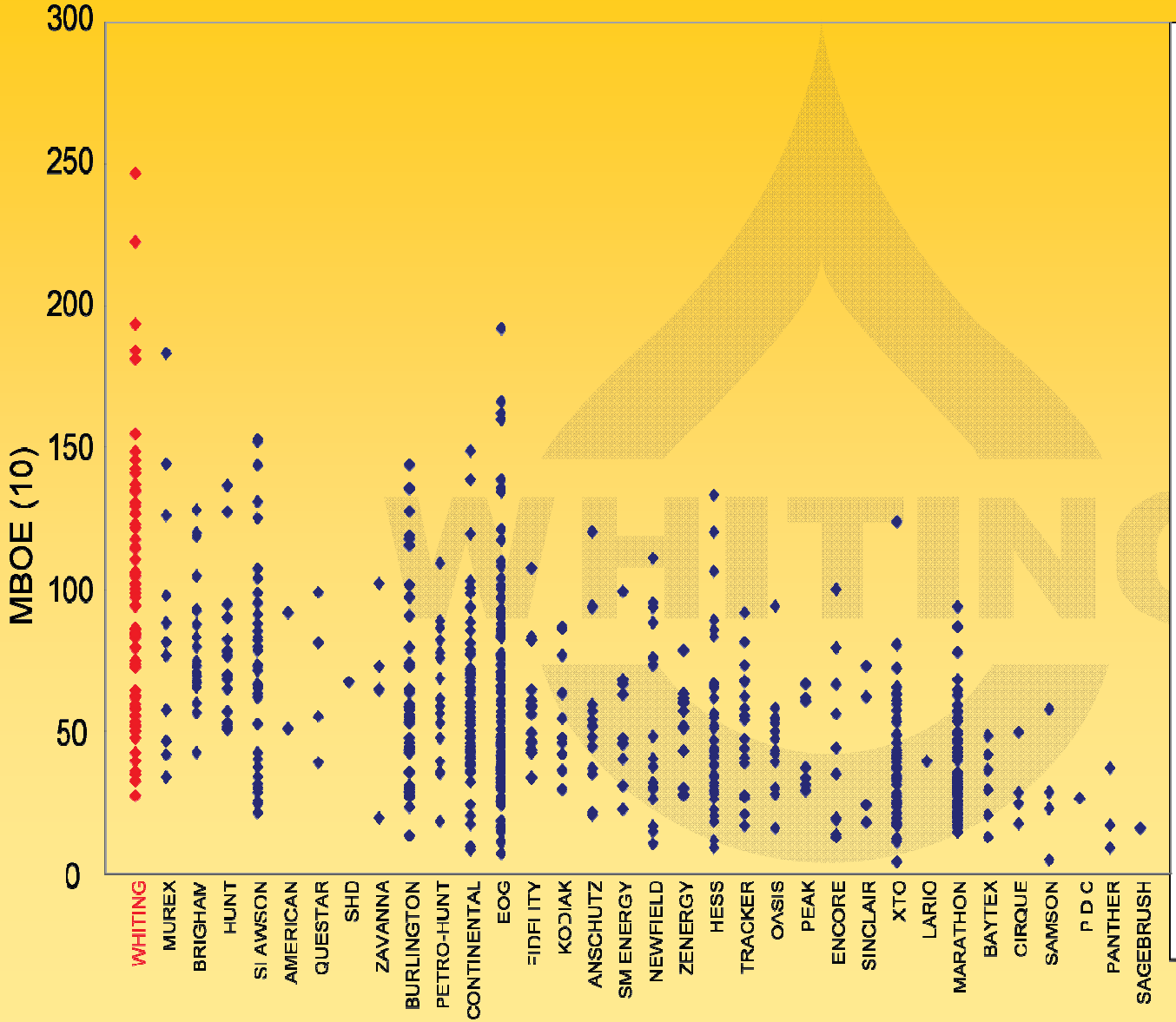


IP, 30-, and 60- day Average Production Rates for Whiting Operated Wells in Sanish Field in 2011

	Well Name	WI%	Completion Date	BOEPD	Average 1st 30 Days (BOE/d)	Average 1st 60 Days (BOE/d)
1)	STATE 12-32H	39.84%	4/11/2011	2,247		
2)	ROBERT PATTEN 44-3TFH	92.75%	4/5/2011	440		
3)	HOLLINGER 11-14TFH	47.24%	4/4/2011	596		
4)	HOLLINGER 21-14TFH	47.24%	3/31/2011	1,232		
5)	SMITH 14-29XH	42.95%	3/30/2011	2,028		
6)	GUINN TRUST 1-13TFH	40.85%	3/24/2011	1,254		
7)	HOOVER 14-1XH	27.28%	3/20/2011	2,212		
8)	WARDEN 43-9TFH	30.04%	3/17/2011	715		
9)	NESS 42-31WH	78.16%	3/14/2011	1,529		
10)	SCOTT MEIERS 12-17TFH	87.06%	3/13/2011	1,087		
11)	ARNDT 14-5XH	28.17%	3/7/2011	1,416	700	
12)	DEAL 43-28TFH	71.86%	3/4/2011	920		
13)	BARLOW 14-6XH	74.64%	2/28/2011	1,182	511	
14)	OJA 14-27XH	65.09%	2/18/2011	2,072	558	
15)	NIEMITALO 31-15XH	52.04%	2/15/2011	2,905	843	
16)	BARTLESON 21-3H	50.00%	2/13/2011	1,235	552	
17)	HEIPLE 14-3XH	63.41%	2/9/2011	2,080	1,163	
18)	BERNARD ROGGENBUCK 24-25H	72.65%	1/22/2011	2,072	698	567
19)	SIKES STATE 43-16H	100.00%	1/19/2011	3,385	1,291	1,052
20)	BREHM 12-7H	50.00%	1/14/2011	987	439	253
21)	MILLER 44-11H	76.28%	1/8/2011	1,447	343	
22)	NESS 21-3H	50.00%	1/4/2011	1,730	690	546
	Averages	*58.53%*		*1,581*	*708*	*605*

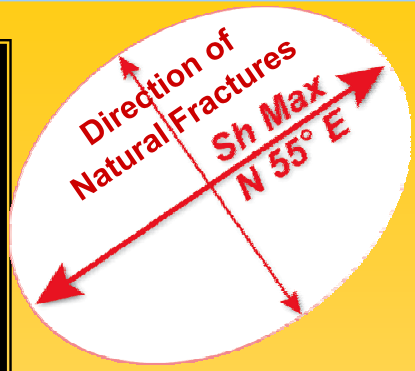
Six Month Cumulative Production by Operator For Bakken Wells Drilled Since January 2009

Source: IHS Energy, Inc.
January, 2011



Operator	6 mo Total Production (MBOE 10)	Wells Drilled	6 mo Avg Production (MBOE 10)
WHITING	7,221	72	100
MUREX	980	11	89
BRIGHAM	1,628	20	81
HUNT	1,103	14	79
SLAWSON	2,613	35	75
AMERICAN	143	2	72
QUESTAR	357	5	71
SHD	68	1	68
ZAVANNA	325	5	65
BURLINGTON	2,847	44	65
PETRO-HUNT	997	16	62
CONTINENTAL	4,145	69	60
EOG	7,134	119	60
FIDELITY	917	16	57
KODIAK	571	10	57
ANSCHUTZ	791	14	57
SM ENERGY	599	11	54
NEWFIELD	1,006	19	53
ZENERGY	666	13	51
HESS	2,148	43	50
TRACKER	931	19	49
OASIS	642	14	46
PEAK	321	7	46
ENCORE	448	10	45
SINCLAIR	178	4	44
XTO	1,960	49	40
LARIO	40	1	40
MARATHON	2,187	60	36
BAYTEX	191	6	32
CIRQUE	121	4	30
SAMSON	115	4	29
P D C	27	1	27
PANTHER	63	3	21
SAGEBRUSH	16	1	16

Fully Developed Bakken and Three Forks Horizontal Wells in Sanish Field Area

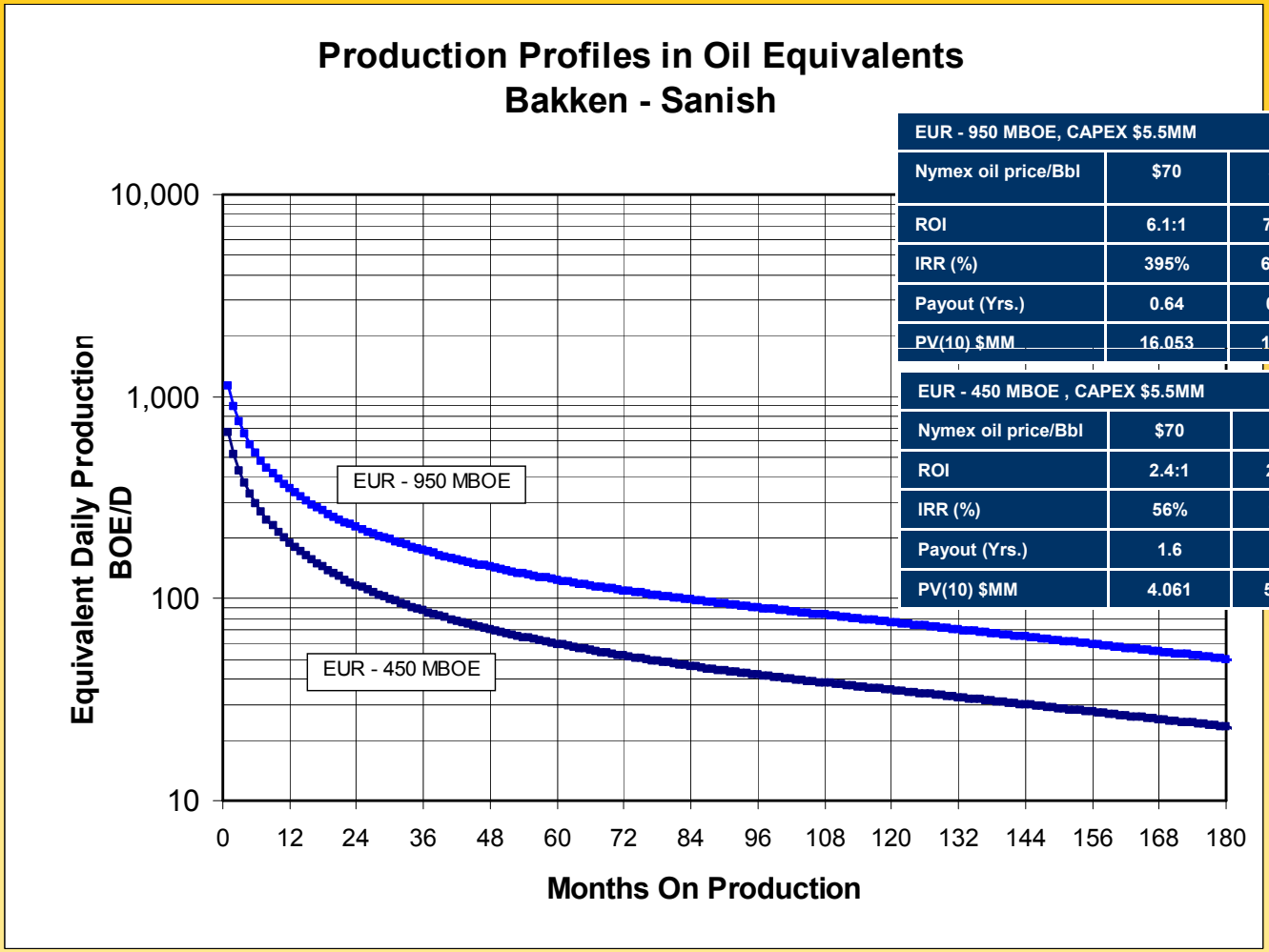


(1) Represents an increase of 163 gross wells from the previous estimate of 382. Well counts and well plans will vary based upon continued evaluation.

	Drilling, WOC	Completed	Planned/ Potential	Total
Middle Bakken	3	129	7	139
Cross-Unit Middle Bakken	4	12	14	30
Wing - Middle Bakken	2	0	81	83
Three Forks	17	17	183	217
Total Operated	**26**	**158**	**285**	**469**
Non-Op Bakken	7	63	0	70
Non-Op Three Forks	1	5	0	6
Grand Total	**34**	**226**	**275**	**545(1)**

As of April 15, 2011

Typical Bakken Production Profiles
Sanish Field (1) (2)



EUR - 950 MBOE, CAPEX $5.5MM			
Nymex oil price/Bbl	$70	$80	$90
ROI	6.1:1	7.3:1	8.4:1
IRR (%)	395%	676%	1,138%
Payout (Yrs.)	0.64	0.55	0.48
PV(10) $MM	16.053	19.93	23.807

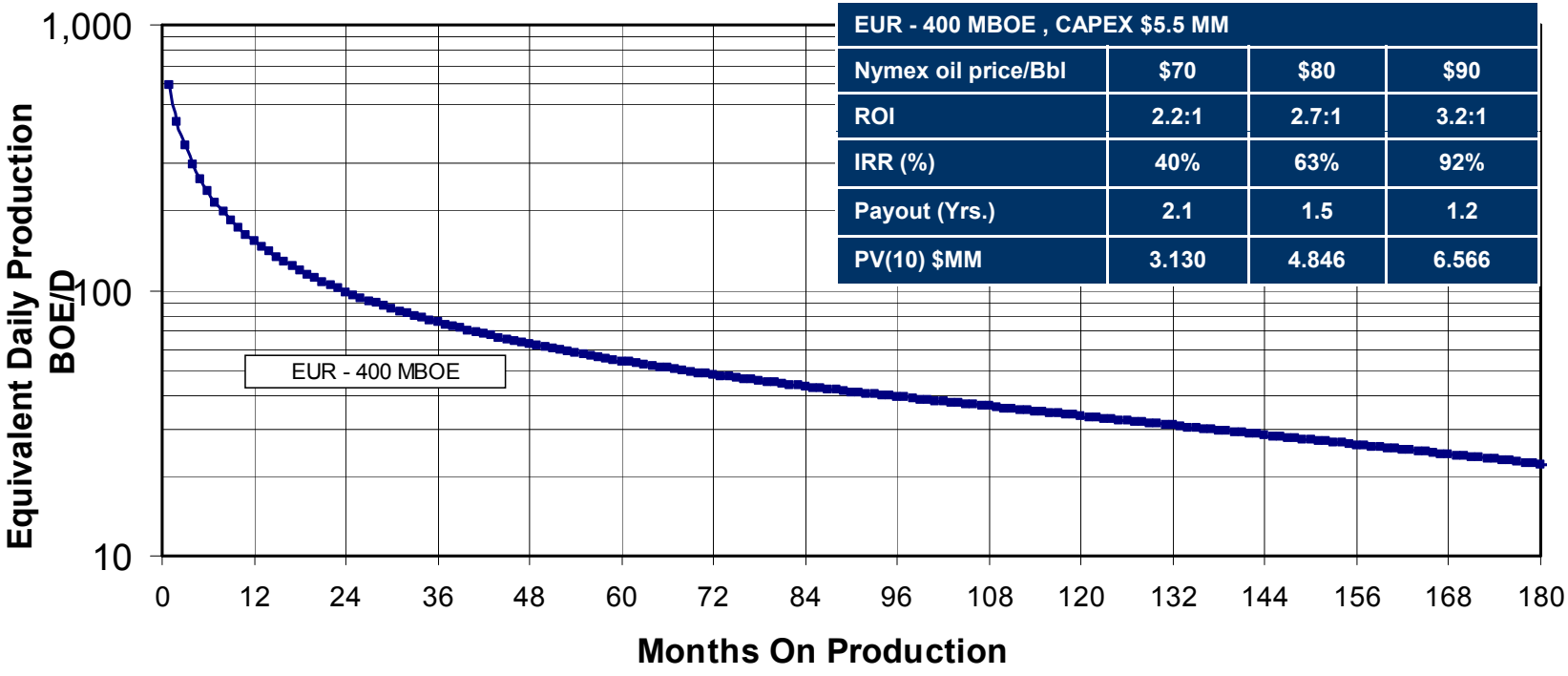
EUR - 450 MBOE , CAPEX $5.5MM			
Nymex oil price/Bbl	$70	$80	$90
ROI	2.4:1	2.9:1	3.5:1
IRR (%)	56%	91%	133%
Payout (Yrs.)	1.6	1.1	0.9
PV(10) $MM	4.061	5.959	7.861

(1) Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information." All volumes shown are un-risked. Our pre-tax PV10 values do not purport to present the fair value of our oil and natural gas reserves.

(2) EURs, ROIs, IRRs and PV10 values will vary well to well. Whiting holds an average WI of 60% and an average NRI of 50% in its operated Bakken wells in Sanish field.

Typical Three Forks Production Profile
Sanish Field (1) (2)

Production Profile in Oil Equivalents
Three Forks - Sanish

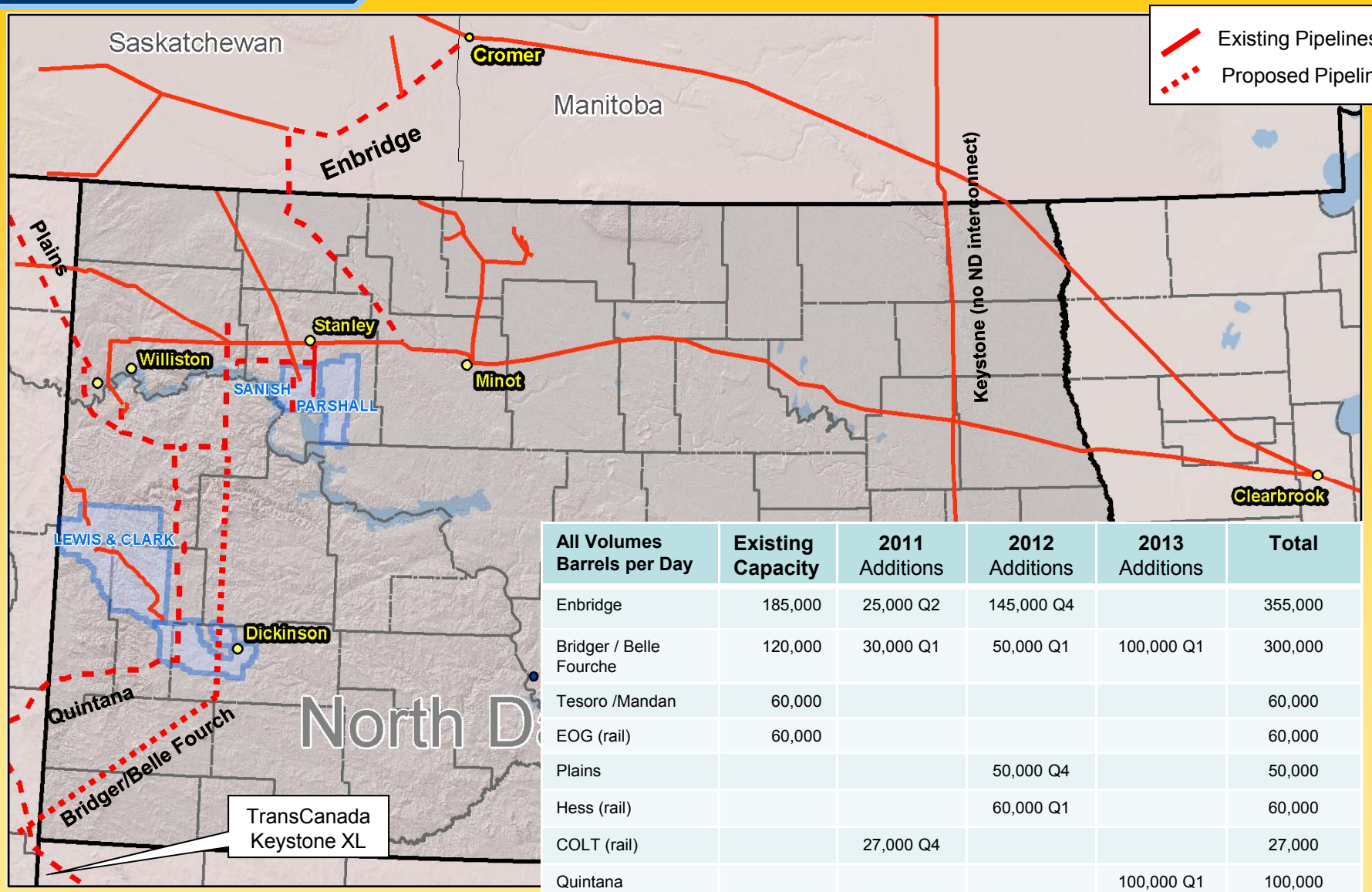


EUR - 400 MBOE , CAPEX $5.5 MM			
Nymex oil price/Bbl	$70	$80	$90
ROI	2.2:1	2.7:1	3.2:1
IRR (%)	40%	63%	92%
Payout (Yrs.)	2.1	1.5	1.2
PV(10) $MM	3.130	4.846	6.566

(1) Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information." All volumes shown are un-risked. Our pre-tax PV10 values do not purport to present the fair value of our oil and natural gas reserves.

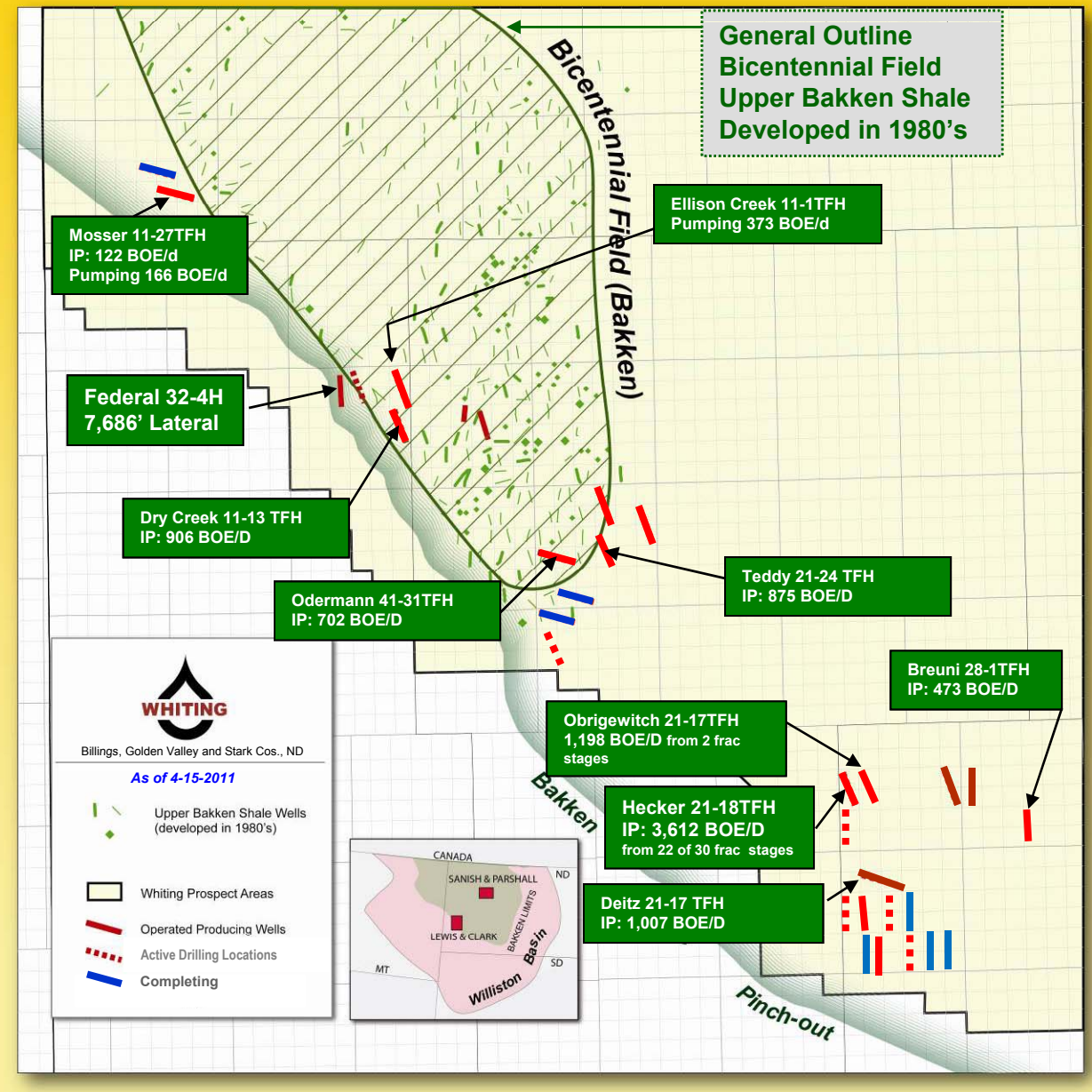
(2) EURs, ROIs, IRRs and PV10 values will vary well to well. Whiting holds an average WI of 60% and an average NRI of 50% in its operated Three Forks wells in Sanish field.

Williston Basin Off-take Expansion



All Volumes Barrels per Day	Existing Capacity	2011 Additions	2012 Additions	2013 Additions	Total
Enbridge	185,000	25,000 Q2	145,000 Q4		355,000
Bridger / Belle Fourche	120,000	30,000 Q1	50,000 Q1	100,000 Q1	300,000
Tesoro /Mandan	60,000				60,000
EOG (rail)	60,000				60,000
Plains			50,000 Q4		50,000
Hess (rail)			60,000 Q1		60,000
COLT (rail)		27,000 Q4			27,000
Quintana				100,000 Q1	100,000
Total	**425,000**	82,000	305,000	200,000	**1,012,000**

Lewis & Clark Area – 250 Units / 500 Potential Locations



OBJECTIVE

Upper Three Forks along pinch-out of the overlying Bakken Shale

ACREAGE

Whiting has assembled 376,111 gross (245,744 net) acres in our Lewis & Clark prospect area in the southwestern Williston Basin

This acreage position would allow up to 250 possible 1,280-acre spacing units within the prospective area:

- **Average WI of 65%**
- **Average NRI of 52%**
- **Well by well WI and NRI will vary based on ownership in each spacing unit**

ECONOMICS

Well Cost: $6.5 MM per well
EUR: 350 to 500 MBOE

DRILLING PROGRAM

5 rigs currently active in the area. Plans are to ramp this to 9 rigs by third quarter 2011. Planned budget for the area is $278 MM

FEDERAL 32-4H IP: 1,970 BOE/D. Avg during first 30, 60 and 90 days was 695 BOE/D, 531 BOE/D and 447 BOE/D.

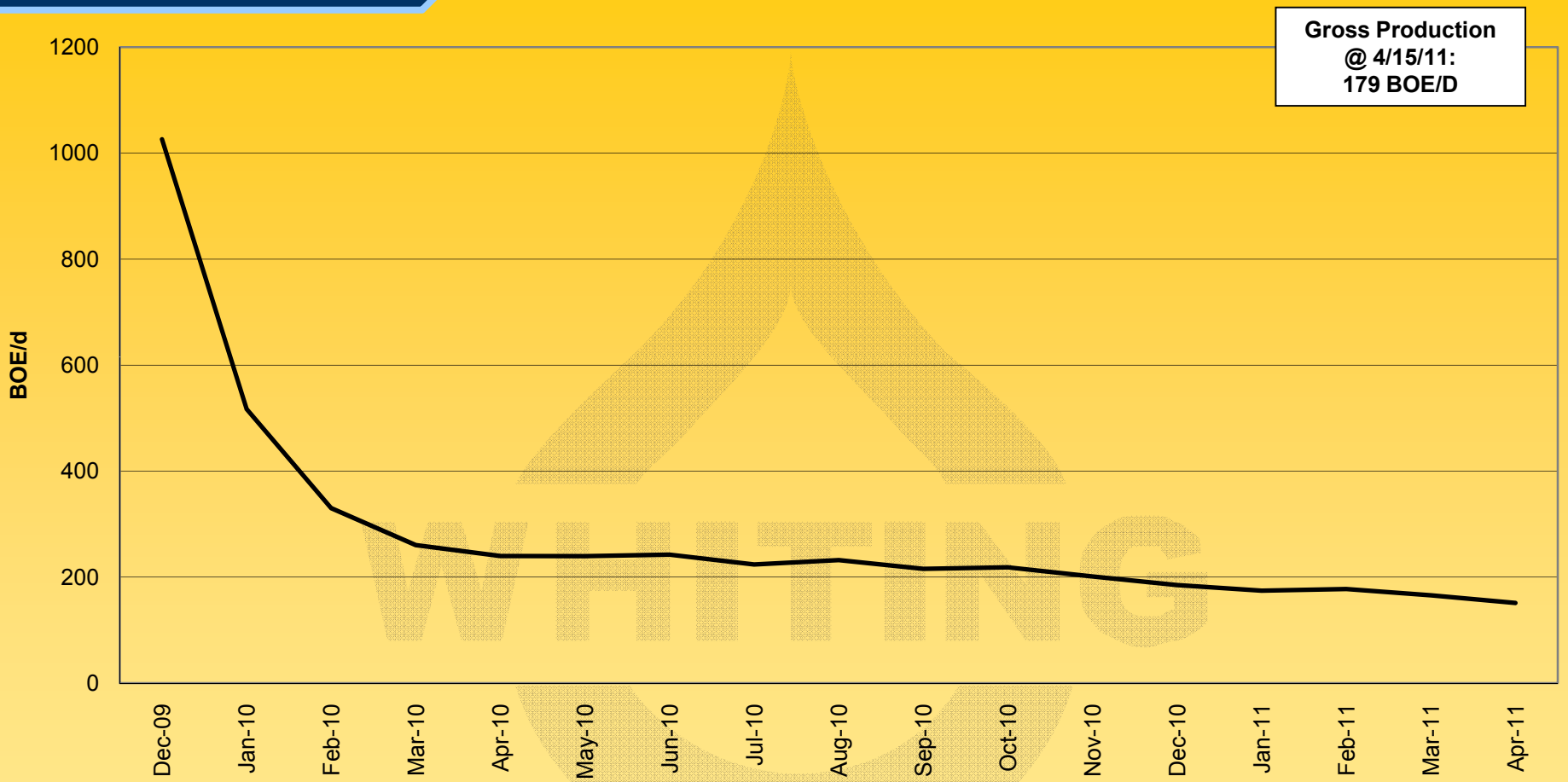
Currently 9 wells are waiting on completion.

IP, 30-, 60- and 90-day Average Production Rates for Whiting Operated Wells in Lewis & Clark Field

WellName	WI	NRI	Test Date	IP (BOE/d) 24-hr Test	Average 1st 30 Days (BOE/d)	Average 1st 60 Days (BOE/d)	Average 1st 90 Days (BOE/d)
1) OBRIGEWITCH 21-17TFH	96%	77%	4/18/2011	1,189			
2) TEDDY 21-24TFH	63%	50%	4/1/2011	875			
3) DRY CREEK 11-13TFH	56%	45%	3/27/2011	906			
4) DIETZ 21-17TFH	98%	78%	3/16/2011	1,007			
5) MOSSER 11-27	64%	51%	3/11/2011	122			
6) HECKER 21-18TFH	77%	61%	3/4/2011	3,612			
7) BRUENI 28-1H	44%	35%	3/1/2011	473			
8) ODERMANN 41-31TFH	48%	38%	2/27/2011	702			
9) MANN 21-18TFH	66%	55%	12/21/2010	870	425	312	261
10) TEDDY 44-30TFH	88%	70%	11/17/2010	1,874	766	618	530
11) TEDDY 44-13TFH (1)	81%	65%	11/12/2010	381	187	169	175
12) ELLISON CREEK 11-1TFH (2)	63%	51%	9/28/2010	608	343	326	299
13) FROEHLICH 44-9TFH	90%	72%	9/18/2010	2,090	1,049	819	698
14) KUBAS 11-13TFH	91%	73%	9/13/2010	1,953	711	530	457
15) FEDERAL 32-4HBKCE	84%	70%	11/25/2009	1,970	695	531	447
16) MOI 22-15H	91%	79%	3/1/2009	339	210	200	175
17) BUCKHORN RANCH 31-16H	91%	78%	12/24/2008	552	311	267	252
Averages	***76%***	***62%***		***1,148***	***522***	***419***	***366***

(1) Fracture stimulated into water-bearing zone. Whiting plans to modify frac design.
(2) Partially pressure depleted by 1980s' Upper Bakken Shale well.

Production History of Federal 32-4TFH Well at Lewis & Clark (1) (2) (3)



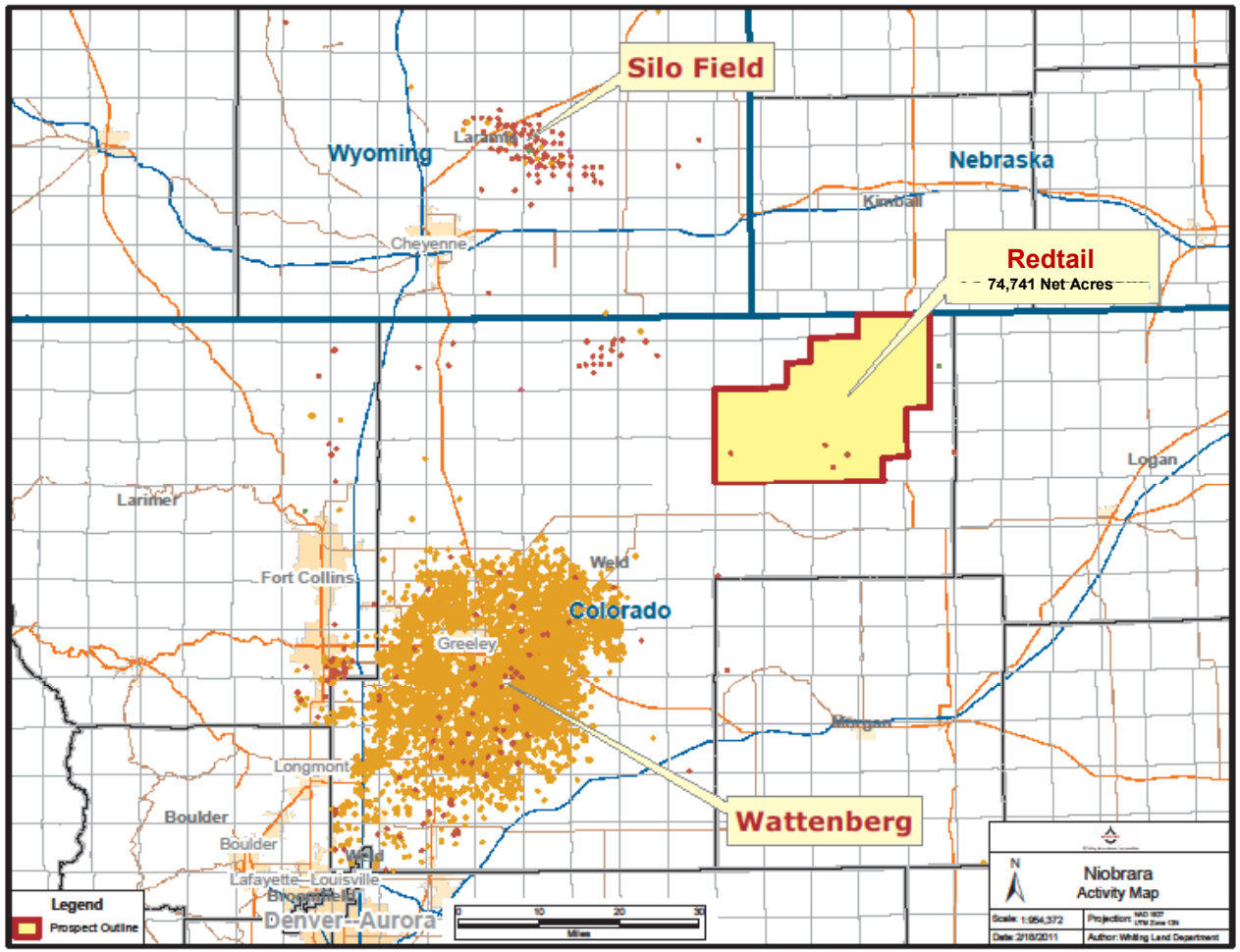
(1) The graph above reflects production from November 23, 2009 through April 15, 2011.

(2) The Federal 32-4TFH was completed in the Three Forks formation on 11/23/09 flowing 1,970 BOE/D.

(3) Total monthly production from all Whiting-operated wells in North Dakota is reported to the North Dakota Industrial Commission (NDIC) at approximately the end of the following month. The NDIC included only 8 days of production from the Federal 32-4TFH in November 2009. Thus, the NDIC reported total production in the first six months for the Federal 32-4TFH to be 51,000 BOE during a 159-day period.

NOTE: Production in the first six months (181 days) totaled 66,300 BOE. Through 4/15/2011 cum prod 127,293 BOE.

Redtail Niobrara Prospect
Weld County, Colorado



OBJECTIVE
Niobrara Shale

ACREAGE
Whiting has assembled 102,920 gross (74,741 net) acres in our Redtail prospect in the northeastern portion of the DJ Basin

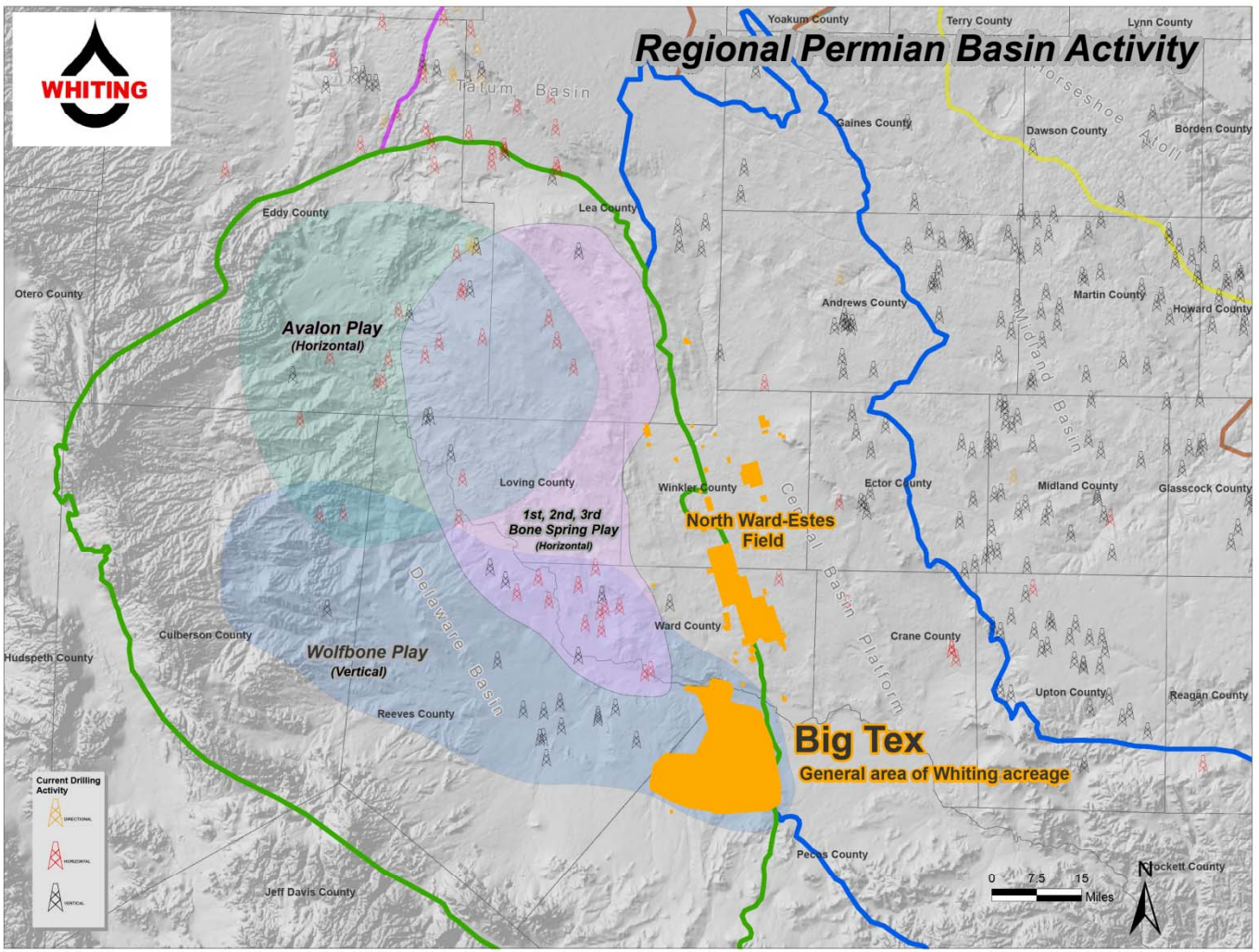
This acreage position would allow up to 220 operated wells and an additional 131 non-operated wells based on 320-acre spacing:

- **Average WI of 73%**
- **Average NRI of 61%**
- **Well by well WI and NRI will vary based on ownership in each spacing unit**

COMPLETED WELL COST
Horizontal: $4 to $5 MM

DRILLING PROGRAM
One rig currently active in the area. One well drilled in 2010 and 6 wells planned for 2011. Planned budget in 2011 is $35 MM

Big Tex Prospect
Pecos, Reeves and Ward Counties, Texas



OBJECTIVE
Wolfcamp and Bone Spring

ACREAGE
Whiting has assembled 111,665 gross (83,303 net) acres in our Big Tex prospect in the Delaware Basin:

- **Average WI of 75%**
- **Average NRI of 56%**
- **Well by well WI and NRI will vary based on ownership in each spacing unit**

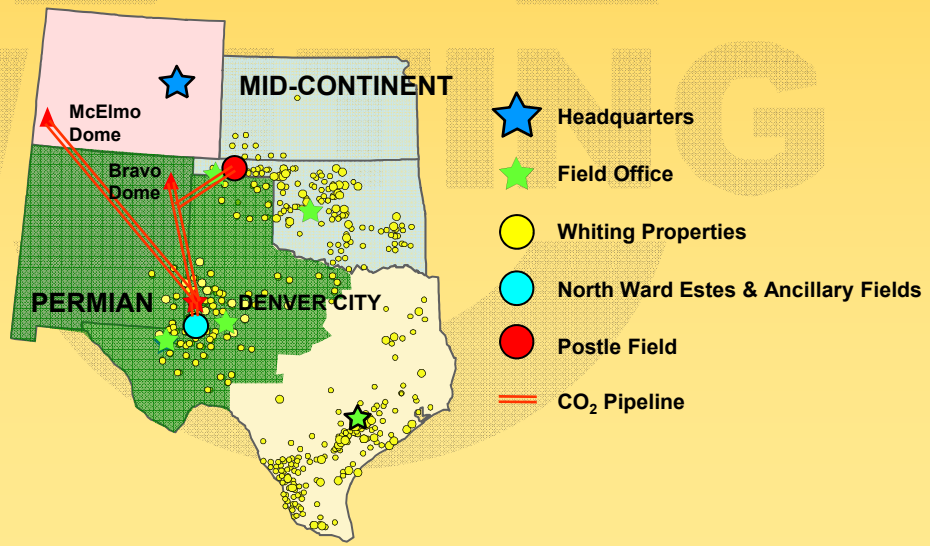
COMPLETED WELL COST
Vertical: $2 MM
Horizontal: $4.5 MM

DRILLING PROGRAM
4 rigs currently active in the area. Recently kicked off a 4 well horizontal drilling program. Plan to drill 23 wells in 2011. Planned budget for the prospect in 2011 is $89 MM

EOR Projects - Postle and North Ward Estes Fields

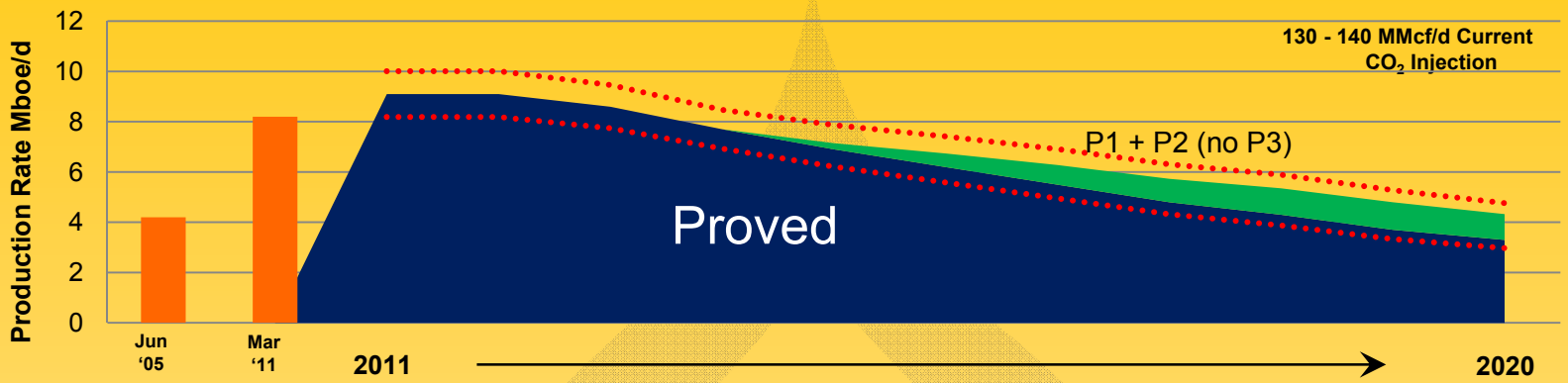
	Whiting	Postle N. Ward Estes	Total Whiting	% Postle N. Ward Estes
12/31/10 Proved Reserves				
Oil – MMBbl	130	124	254	49%
Gas – Bcf	276	27	304	9%
Total – MMBOE	177	128 [1]	305	42% [1]
% Crude Oil	74%	96%	83%	
Q1 2011 Production				
Total – MBOE/d	49.4	16.6	66.0	25%

[1] Includes Ancillary Properties

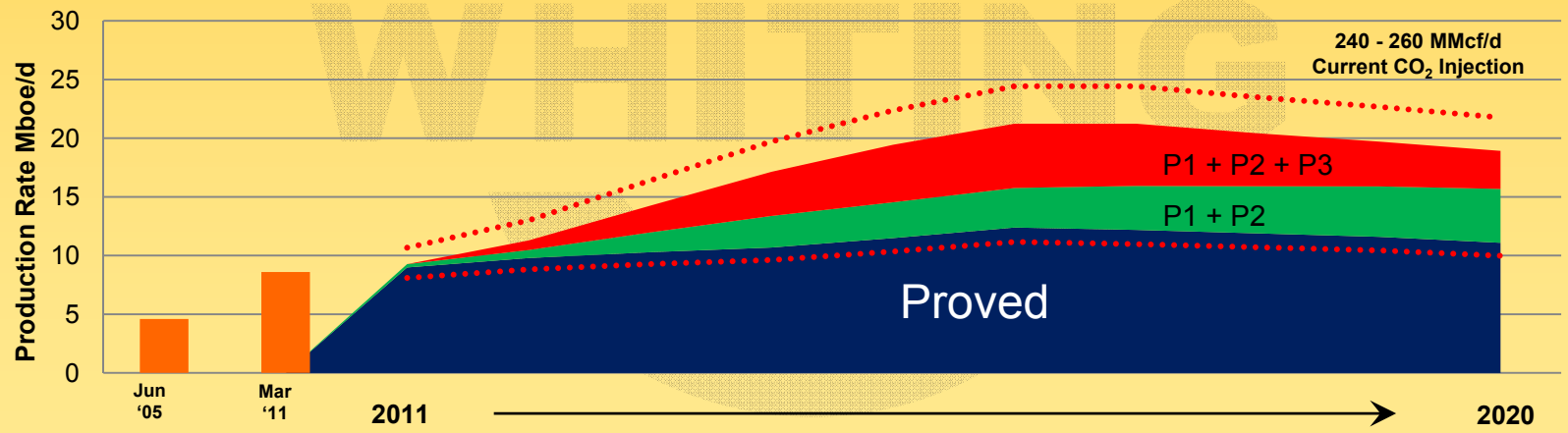


EOR Projects Net Production Forecasts (1)

Postle Field 3P Unrisked Net Production Forecast (2)



North Ward Estes 3P Unrisked Net Production Forecast (3)



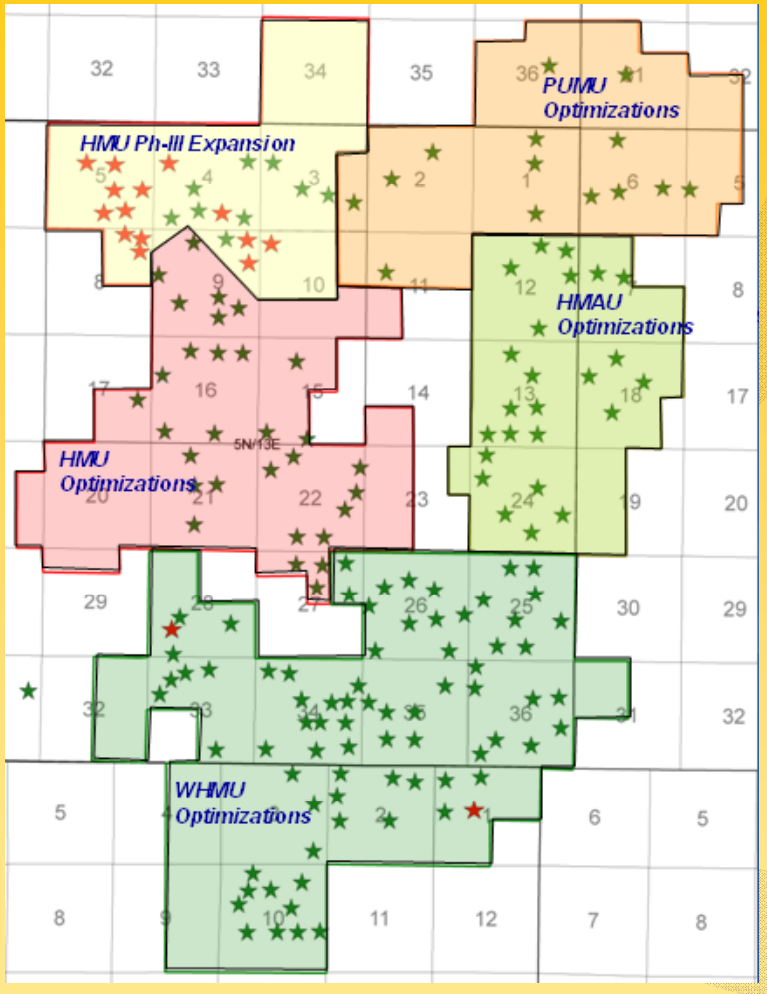
(1) Based on independent engineering by Cawley, Gillespie & Associates, Inc. at December 31, 2010. Includes ancillary fields. Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information." All volumes shown are unrisked.

(2) Production forecasts based on assumptions in December 31, 2010 reserve report. After 2020, Postle field proved reserve production is expected to decline at 8% - 11% year over year.

(3) Production forecasts based on assumptions in December 31, 2010 reserve report. After 2020, North Ward Estes field proved reserve production is expected to decline at 5% - 7% year over year.

Development Plans – Postle Field

Texas County, Oklahoma



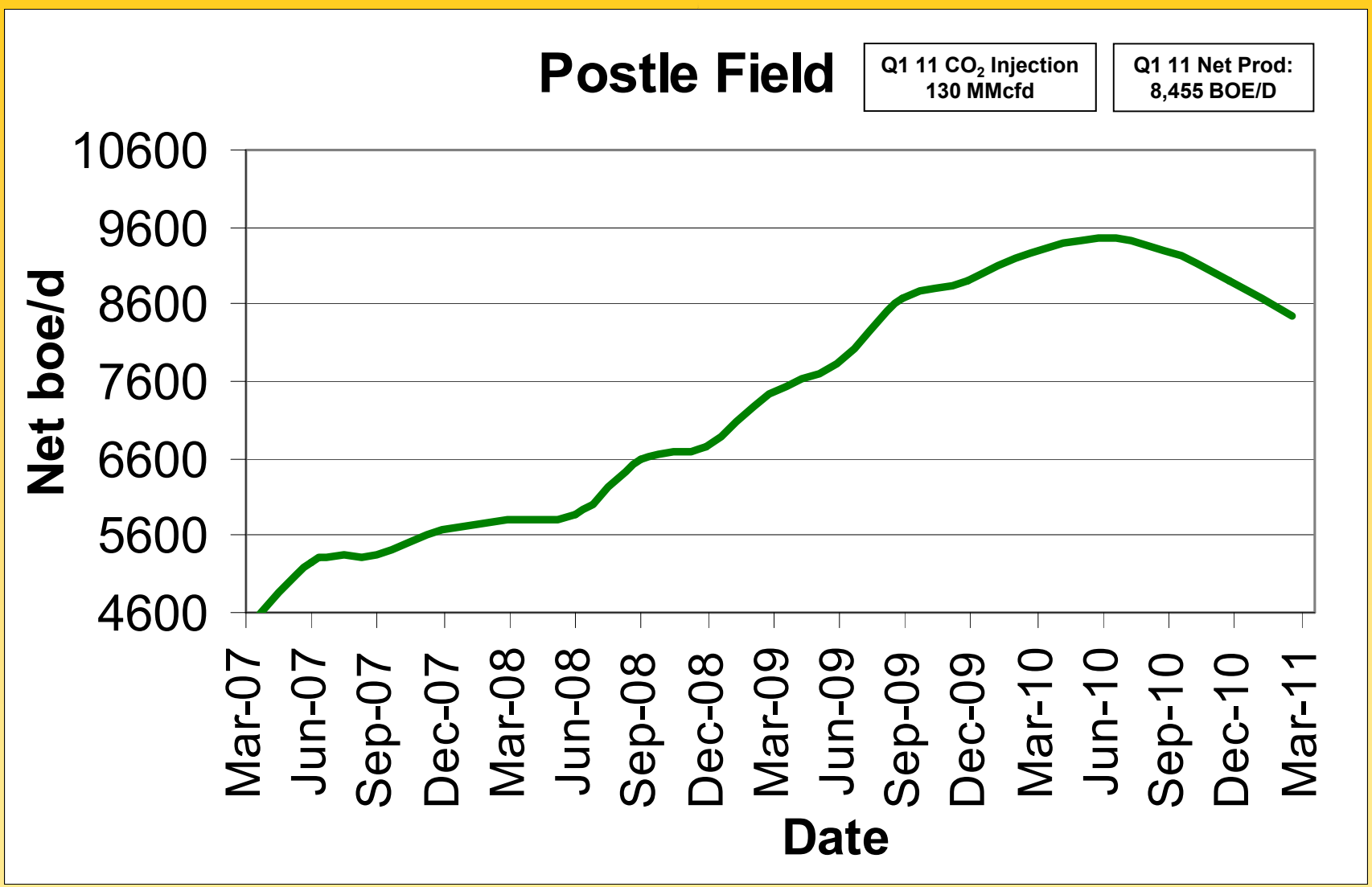
★ Completed 157 Wells (2005 – 2010)
★ Remaining 16 Wells (2011 – 2012)

24,225 Net Acres

Total 2011 - 2015 Remaining Capital Expenditures (in millions, net)

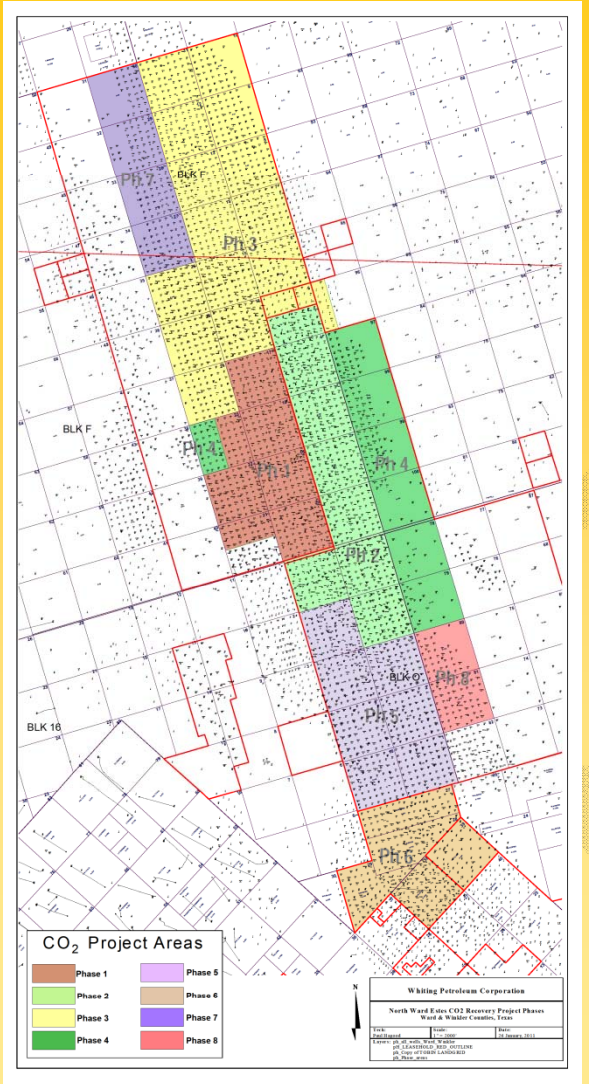
	CapEx
Drilling, Completion, Workovers & Dry Trail Gas Plant	$285
CO_2 Purchases	11
Total:	$ 296

Postle Quarterly Average Net BOE/D Production



Development Plans – North Ward Estes Field

Ward and Winkler Counties, Texas



58,000 Net Acres

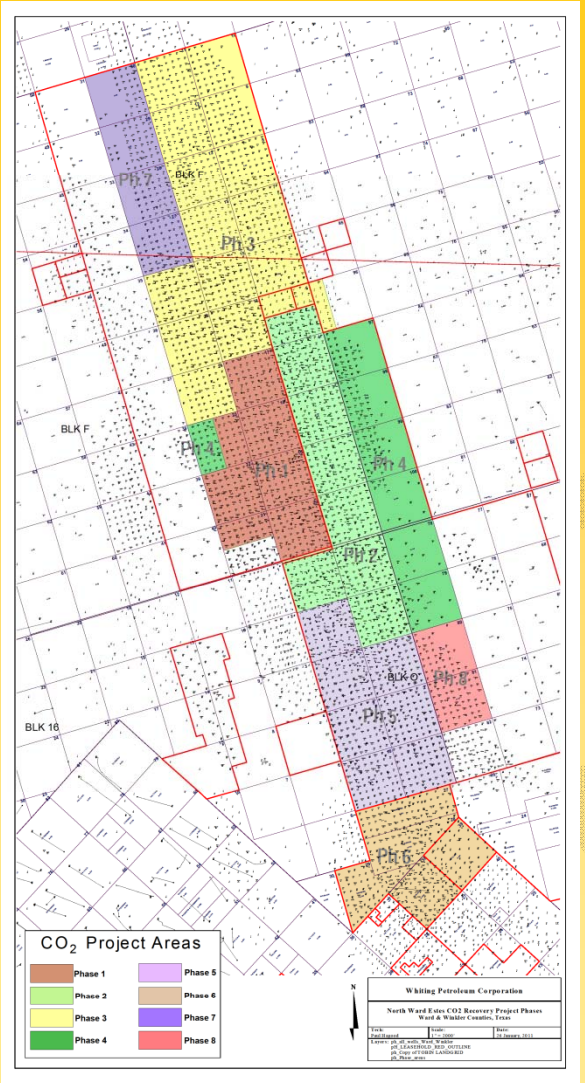
Project Timing and Net Reserves (1)

CO_2 Project	Injection Start Date	PVPD	Other Proved	P2	P3	Total
Base: Primary, WF & CO_2		33	12	1	64	110
Phase 1	2007 - 2008	0 (2)	3	4	2	9
Phase 2	2009 - 2010	0 (2)	6	4	4	14
Phase 3	2010 - 2014	0	22	8	8	38
Phase 4	2011	0	3	1	1	5
Phase 5	2012 - 13	0	3	9	8	20
Phase 6	2015	0	10	4	3	17
Phase 7	2016	0	0	0	6	6
Phase 8	2016	0	0	0	3	3
Totals (MMBOE)		33	59	31	99	222

(1) Based on independent engineering at Dec. 31, 2010. Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information." All volumes shown are unrisked.

(2) Response moved to Base.

Development Plans – North Ward Estes Field
Ward and Winkler Counties, Texas



CO_2 Project	Injection Start Date
Phase 1	2007 - 2008
Phase 2	2009 - 2010
Phase 3	2010 - 2014
Phase 4	2011
Phase 5	2012 – 2013
Phase 6	2015
Phase 7	2016
Phase 8	2016

Total 2011 - 2040 Remaining Capital Expenditures (1)
(In Millions)

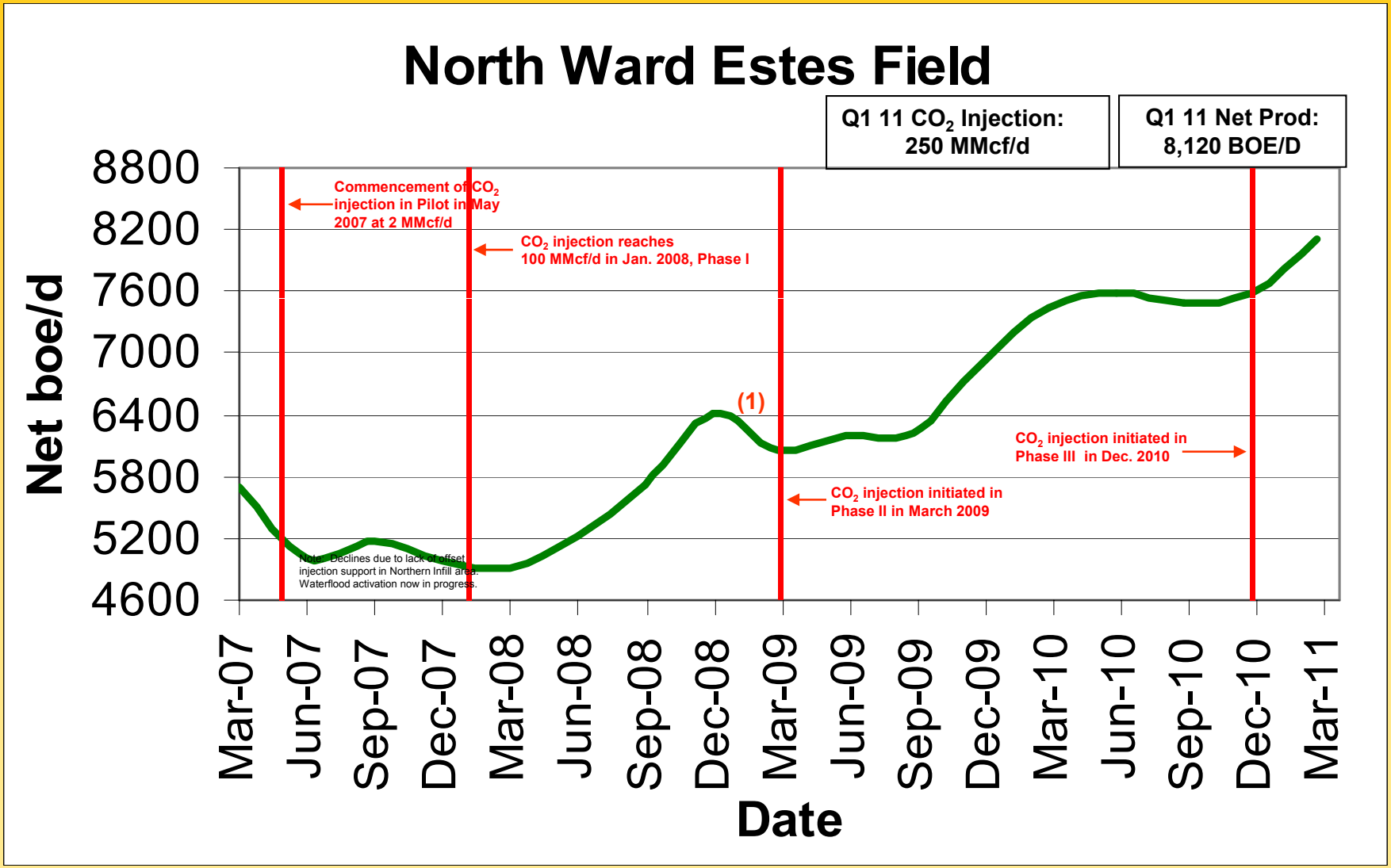
	CapEx (2)
Drilling, Completion, Workovers & Gas Plant Costs	$ 526
CO_2 Purchases	1,383
Total	$1,909

(1) Based on independent engineering at Dec. 31, 2010.

(2) Consists of CapEx for Proved, Probable and Possible reserves. Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information."

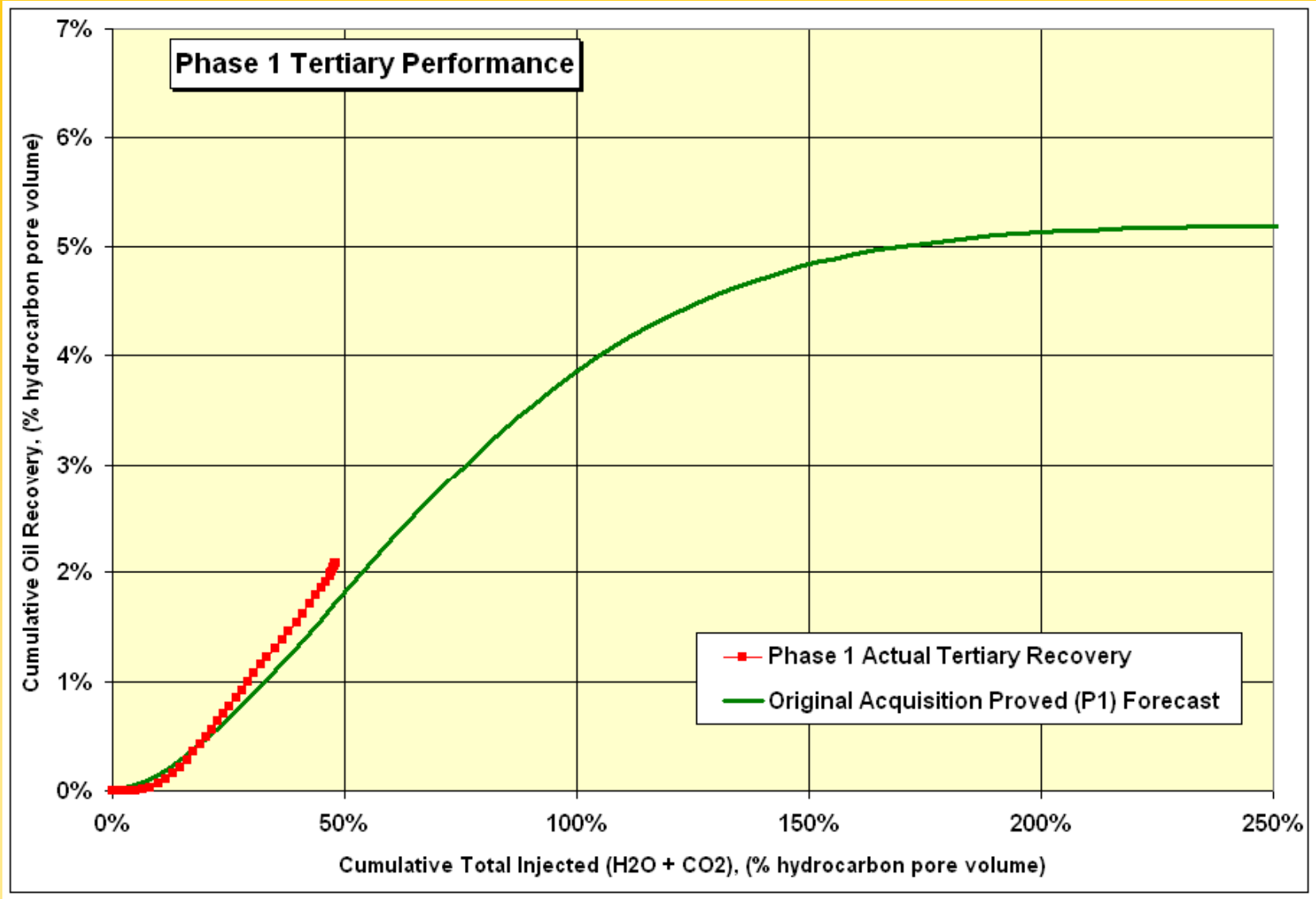
58,000 Net Acres

North Ward Estes Quarterly Average Net BOE/D Production



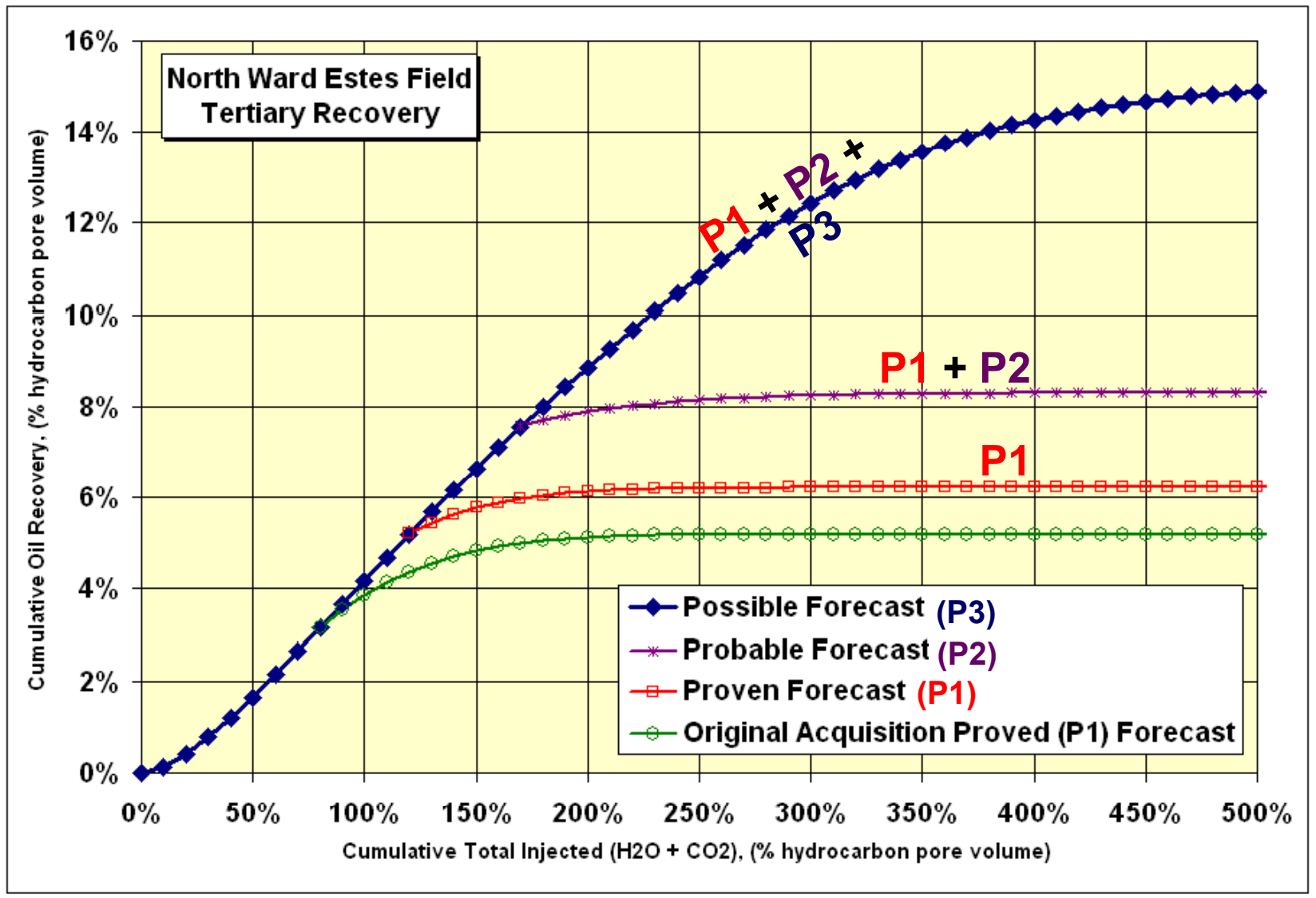
(1) Production decline was due to scaling problems that have been subsequently resolved with mechanical and chemical treatments.

Whiting Estimated Oil Recovery Type Curve from CO_2 Flood *North Ward Estes* (1)



(1) Whiting currently estimates a 15% recovery factor in arriving at its total for proved, probable and possible reserve potential. The Company is conducting tests to ascertain if additional oil may be recoverable.

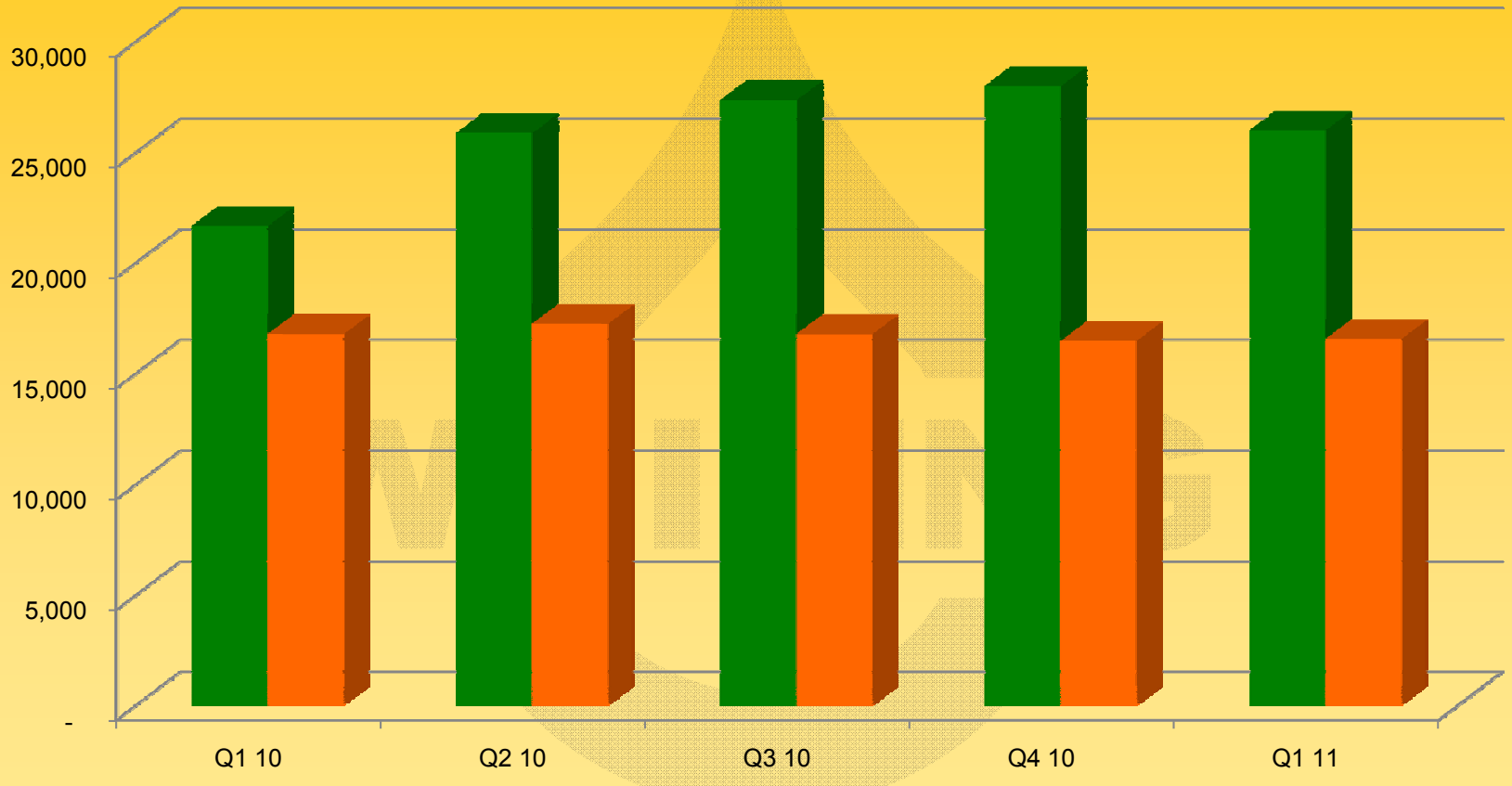
Whiting Estimated Oil Recovery Type Curve from CO_2 Flood *North Ward Estes* (1)



(1) Whiting currently estimates a 15% recovery factor in arriving at its total for proved, probable and possible reserve potential. The Company is conducting tests to ascertain if additional oil may be recoverable.

Production Growth (in BOE/D)

Net Production from Bakken, Postle and N. Ward Estes



	Q1 10	Q2 10	Q3 10	Q4 10	Q1 11
Bakken	21,690	25,890	27,385	28,020	26,010
Postle / N.W.E.	16,800	17,250	16,785	16,475	16,575
Total	38,490	43,140	44,170	44,495	42,585

(Represents 65% of total company production)

Adjusted Net Income and Discretionary Cash Flow for the Three Months Ended March 31, 2011 and 2010 (1)(2)

	Three Months Ended	
	3/31/11	3/31/10
(In millions, except per share data)		
Net Income	$ 19.1	$ 81.2
Adjusted Net Income	$ 99.7	$ 62.3
Adjusted Earnings Per Basic Share	$ 0.85	$ 0.61
Adjusted Earnings Per Diluted Share	$ 0.84	$ 0.57
Discretionary Cash Flow	$ 284.1	$ 214.6

(1) Please refer to slide #45 for a Reconciliation of Net Income Available to Common Shareholders to Adjusted Net Income Available to Common Shareholders.

(2) Please refer to slide #46 for a Reconciliation of Net Cash Provided by Operating Activities to Discretionary Cash Flow.

(3) All share and per share amounts have been retroactively restated for the 2010 period to reflect the Company's two-for-one stock split in February 2011.

Outstanding Bonds and Credit Agreement

Coupon / Description	Maturity	Amount Outstanding	Ratings Moody's / S&P	Current Price
7.00% / Sr. Sub. – NC	02/01/2014	$250.0 mil.	Ba3 / BB	106.500
6.50% / Sr. Sub. – NC4	10/01/2018	$350.0 mil.	Ba3 / BB	103.500

- Bond Finance Covenant: Ratio of pre-tax earnings to fixed charges (interest expense) must be greater than 2:1. It was 12.03:1 at 03/31/11.
- Restricted Payments Basket: Approximately $1.6 billion.
- Bank Credit Agreement size is $1.1 billion, under which $380 million was drawn as of 03/31/11. Interest rate is currently 1.98% (LIBOR + 1.75%). Redetermination date is 11/1/11.
- Bank Credit Agreement Covenants: Total debt to EBITDAX at 03/31/11 was 0.91:1 (must be less than 4.25:1)
  Working capital at 03/31/11 was 2.25:1 (must be greater than 1:1)

Total Capitalization
($ in thousands)

	March 31, 2011	March 31, 2010
Cash and Cash Equivalents	$ 5,026	$ 18,952
Long-Term Debt:		
Credit Agreement	$ 380,000	$ 200,000
Senior Subordinated Notes	600,000	600,000
Total Long-Term Debt	$ 980,000	$ 800,000
Stockholders' Equity	2,542,745	2,531,315
Total Capitalization	$3,522,745	$3,331,315
Total Debt / Total Capitalization	27.8%	24.0%

Guidance for Q2 and Full-Year 2011

	Guidance	
	Second Quarter 2011	Full-Year 2011
Production (MMBOE)	6.15 - 6.35	25.80 - 26.20
Lease operating expense per BOE	$11.60- $11.80	$11.20- $11.40
General and admin. expense per BOE	$3.30 - $3.50	$3.25 - $3.45
Interest expense per BOE	$2.25 - $2.45	$2.15 - $2.35
Depr., depletion and amort. per BOE	$18.35- $18.65	$18.50- $18.70
Prod. taxes (% of production revenue)	7.4% - 7.6%	7.4% - 7.7%
Oil price differentials to NYMEX per Bbl	$10.00- $11.00	$10.00- $11.00
Gas price premium to NYMEX per Mcf (1)	$0.50 - $0.80	$0.50 - $0.80

(1) Includes the effect of Whiting's fixed-price gas contracts. Please refer to fixed-price gas contracts on slide #43.

Disciplined Hedging Strategy (1)

- Utilize hedges to manage exposure against potential commodity price declines while maintaining pricing upside
- Employ mix of contracts weighted toward the short-term

Hedge Period	Existing Crude Oil Hedge Positions: Hedged Volumes (Bbls per Month)	Existing Crude Oil Hedge Positions: Hedge Price Weighted Average Range ($/Bbl)	Existing Crude Oil Hedge Positions: As a Percentage of Mar. 2011 Oil Production	Existing Natural Gas Hedge Positions: Hedged Volumes (MMBtu per Month)	Existing Natural Gas Hedge Positions: Weighted Average Hedge Price Range ($/MMBtu)	Existing Natural Gas Hedge Positions: As a Percentage of March 2011 Gas Production
2011						
Q2	904,696	$61.01 - $98.32	54.0%	36,954	$6.00 - $13.05	1.6%
Q3	904,479	$61.01 - $98.31	53.9%	35,855	$6.00 - $13.65	1.6%
Q4	904,255	$61.00 - $98.31	53.9%	34,554	$7.00 - $14.25	1.5%
2012						
Q1	659,054	$59.93 - $106.28	39.3%	33,381	$7.00 - $15.55	1.5%
Q2	658,850	$59.93 - $106.27	39.3%	32,477	$6.00 - $13.60	1.4%
Q3	658,650	$59.93 - $106.26	39.3%	31,502	$6.00 - $14.45	1.4%
Q4	658,477	$59.92 - $106.26	39.3%	30,640	$7.00 - $13.40	1.3%
2013						
Q1	290,000	$47.67 - $90.21	17.3%			
Q2	290,000	$47.67 - $90.21	17.3%			
Q3	290,000	$47.67 - $90.21	17.3%			
Oct	290,000	$47.67 - $90.21	17.3%			
Nov	190,000	$47.22 - $85.06	11.3%			

(1) As of April 21, 2011.

Fixed-Price Marketing Contracts

Existing Natural Gas Marketing Contracts

Period	Contracted Volumes (Mcf per Month)	Weighted Average Contracted Price ($/Mcf)	As a Percentage of March 2011 Gas Production
Q2 2011	778,914	$5.31	34.2%
Q3 2011	772,460	$5.30	33.9%
Q4 2011	772,460	$5.30	33.9%
Q1 2012	577,127	$5.30	25.3%
Q2 2012	461,460	$5.41	20.3%
Q3 2012	465,794	$5.41	20.5%
Q4 2012	398,667	$5.46	17.5%
Q1 2013	360,000	$5.47	15.8%
Q2 2013	364,000	$5.47	16.0%
Q3 2013	368,000	$5.47	16.2%
Q4 2013	368,000	$5.47	16.2%
Q1 2014	330,000	$5.49	14.5%
Q2 2014	333,667	$5.49	14.7%
Q3 2014	337,333	$5.49	14.8%
Q4 2014	337,333	$5.49	14.8%

In Summary

Geographically diversified, long-lived reserve base	**Five core regions; 12.9 [1] year R/P**
	Grown proved reserves 325% from 71.7 MMBOE at Nov. 2003 IPO to 304.9 MMBOE at 12/31/10
	Grown production 288% from 17.0 MBOE/D at Nov. 2003 IPO to 66.0 MBOE/D in Q1 2011
Multi-year inventory of development, exploitation and exploration projects to drive organic production growth going forward	**Drilling inventory as of 12/31/10 of more than 1,300 gross operated wells based on 3P reserves and over 1,500 additional gross operated wells based on resource potential**
Additional exploration potential in the Rockies, Permian Basin and Gulf Coast	**Significant organic growth potential from drilling programs**
	Continued moderate risk organic growth potential from Postle and North Ward Estes fields
	Other exploration includes horizontal oil prospects (Williston and Permian Basin)
Disciplined acquirer with strong record of accretive acquisitions	**16 acquisitions in 2004 – 2010; 230.9 MMBOE at $8.23 per BOE average acquisition cost**
Commitment to financial strength	**Total Debt to Cap of 27.8% as of March 31, 2011**
Proven management and technical team	**Average 28 years of experience**

(1) R/P ratio based on year-end 2010 proved reserves and total 2010 production.

Adjusted Net Income [1]
(In Thousands)

Reconciliation of Net Income Available to Common Shareholders to Adjusted Net Income Available to Common Shareholders

	Three Months Ended Mar. 31, 2011	2010
Net Income Available to Common Shareholders	$ 19,144	$ 81,220
Adjustments Net of Tax:		
Amortization of Deferred Gain on Sale	(2,121)	(2,343)
Impairment Expense	4,812	2,409
Unrealized Derivative (Gains) Losses	77,833	(18,945)
Adjusted Net Income [1]	$ 99,668	$ 62,341
Adjusted Earnings Available to Common Shareholders per Share, Basic [2]	$ 0.85	$ 0.61
Adjusted Earnings Available to Common Shareholders per Share, Diluted [2]	$ 0.84	$ 0.57

(1) Adjusted Net Income Available to Common Shareholders is a non-GAAP financial measure. Management believes it provides useful information to investors for analysis of Whiting's fundamental business on a recurring basis. In addition, management believes that Adjusted Net Income Available to Common Shareholders is widely used by professional research analysts and others in valuation, comparison, and investment recommendations of companies in the oil and gas exploration and production industry, and many investors use the published research of industry research analysts in making investment decisions. Adjusted Net Income Available for Common Shareholders should not be considered in isolation or as a substitute for net income, income from operations, net cash provided by operating activities or other income, cash flow or liquidity measures under GAAP and may not be comparable to other similarly titled measures of other companies.

(2) All per share amounts have been retroactively restated for the 2010 period to reflect the Company's two-for-one stock split in February 2011.

Discretionary Cash Flow [1]

Reconciliation of Net Cash Provided by Operating Activities to Discretionary Cash Flow (In Thousands)

	Three Months Ended Mar. 31, 2011	2010
Net cash provided by operating activities….....	$ 214,055	$ 196,547
Exploration…….....	14,599	9,063
Exploratory dry hole costs…….	(2,902)	(2,010)
Changes in working capital……..	58,598	16,345
Preferred stock dividends paid…….	(270)	(5,391)
Discretionary cash flow [1]…..……....	$ 284,080	$ 214,554

(1) Discretionary cash flow is computed as net income plus exploration and impairment costs, depreciation, depletion and amortization, deferred income taxes, non-cash interest costs, losses on early extinguishment of debt, non-cash compensation plan charges, non-cash losses on mark-to-market derivatives and other non-current items, less the gain on sale of properties, amortization of deferred gain on sale, non-cash gains on mark-to-market derivatives, and preferred stock dividends paid, not including preferred stock conversion inducements. The non-GAAP measure of discretionary cash flow is presented because management believes it provides useful information to investors for analysis of the Company's ability to internally fund acquisitions, exploration and development. Discretionary cash flow should not be considered in isolation or as a substitute for net income, income from operations, net cash provided by operating activities or other income, cash flow or liquidity measures under GAAP and may not be comparable to other similarly titled measures of other companies.