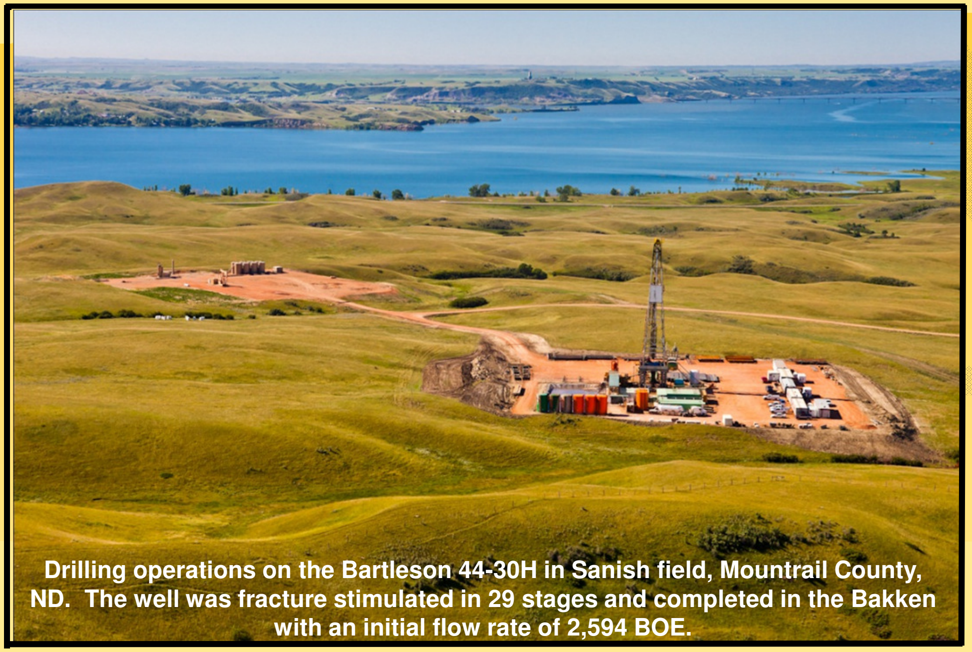
# Whiting Petroleum Corporation



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.

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.

## Current Corporate Information
## May 2011

# 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

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

| | |
|---|---|
| Market Capitalization[1] | *$7.4 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* |

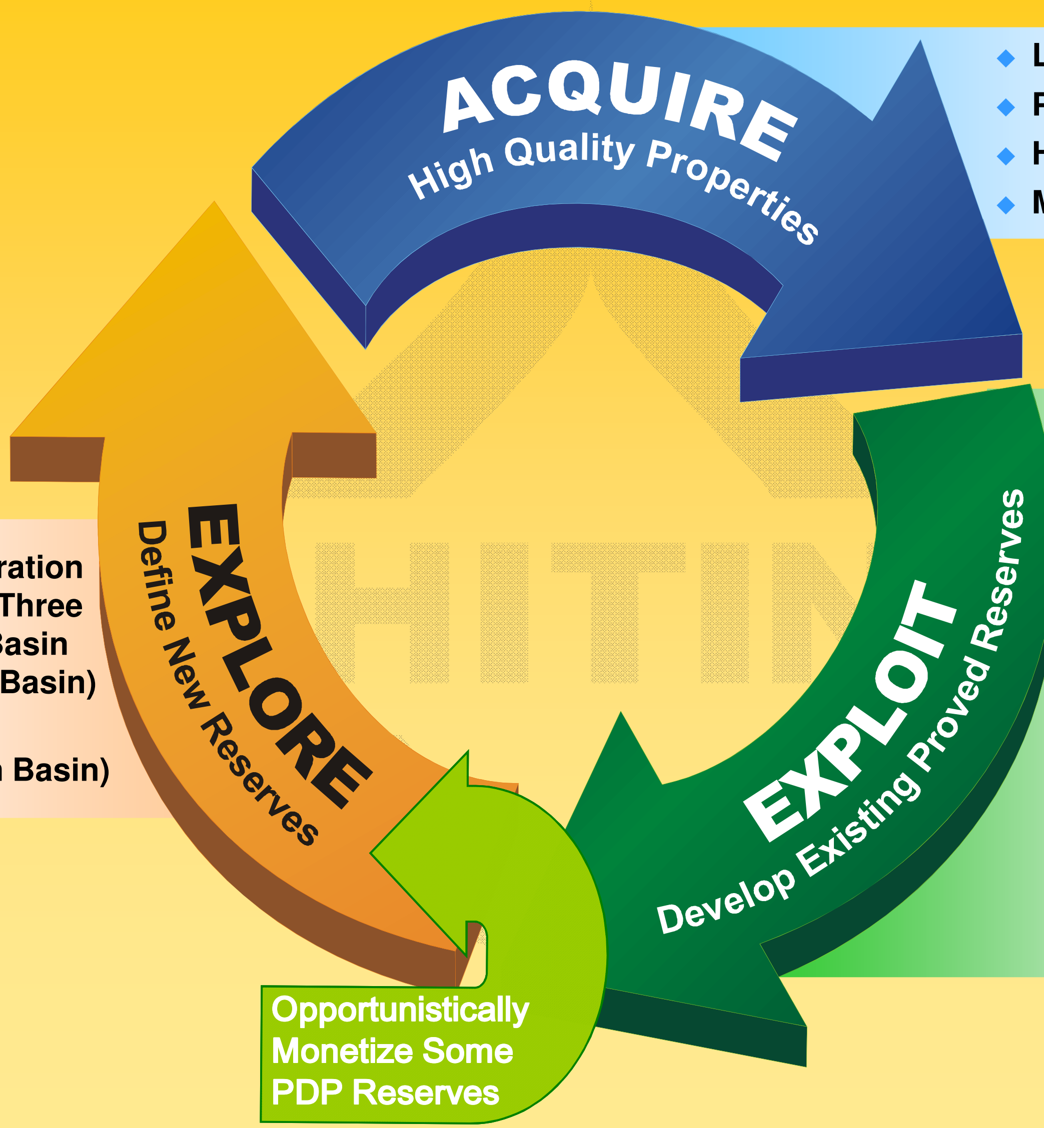
1 Assumes a $63.07 share price (closing price as of May 11, 2011) on 117,368,706 common shares outstanding as of March 31, 2011.

2 As of March 31, 2011. Please refer to Slide #51 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.

# Our Formula for Success




- Long-lived properties
- Predictable performance
- High PDP content
- Multi-zone potential

- Permian Basin – North Ward Estes field
- Anadarko Basin – Postle field
- Williston Basin – Bakken in Sanish and Parshall field areas and Three Forks in Lewis & Clark prospect
- Piceance Basin - Boies Ranch / Jimmy Gulch areas
- Uintah Basin – Flat Rock Field

- New Rockies exploration areas (Bakken and Three Forks in Williston Basin and Niobrara in DJ Basin)
- Other horizontal oil prospects (Permian Basin)

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

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| | 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 |

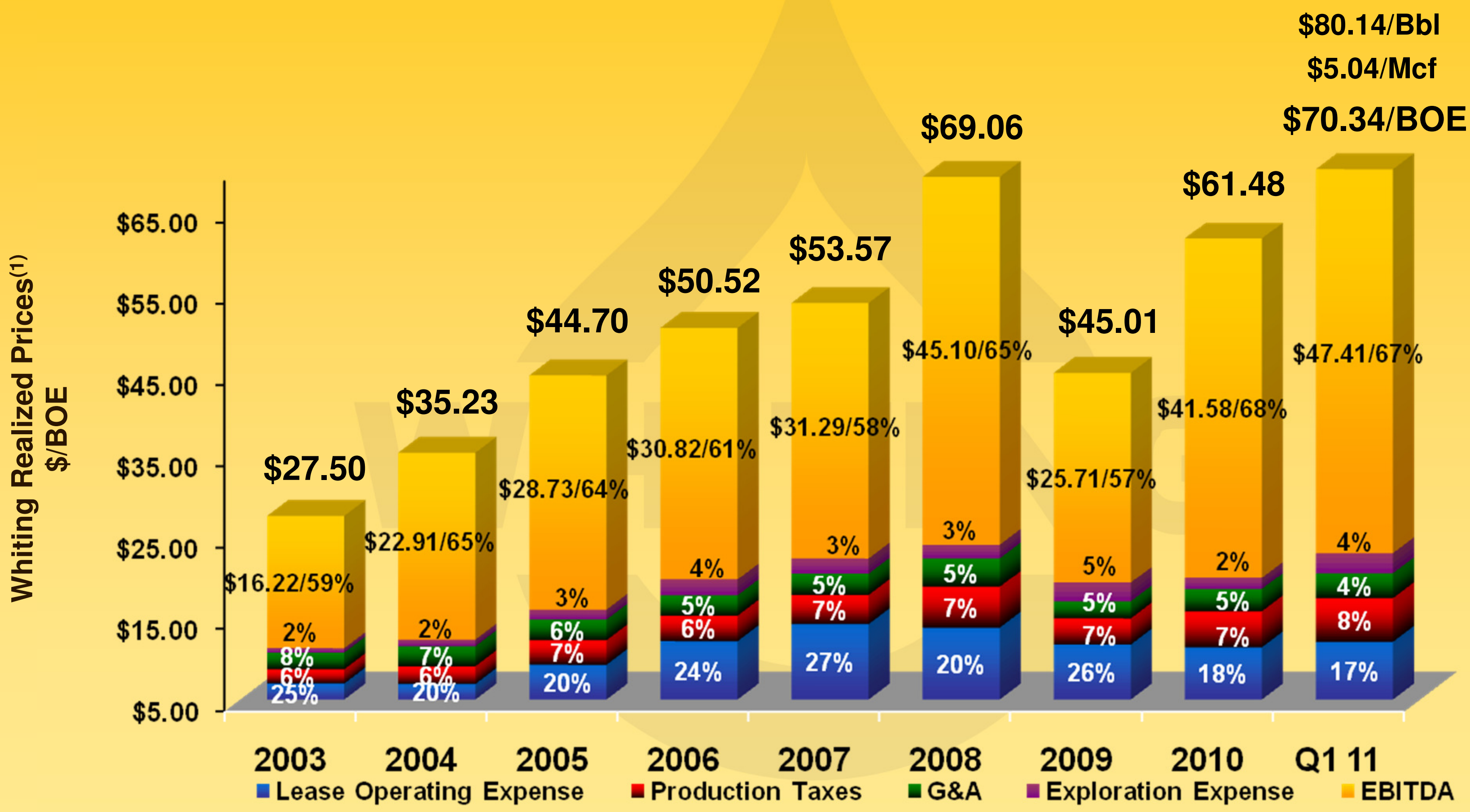
(1) Please refer to slide #56 for a Reconciliation of Net Income Available to Common Shareholders to Adjusted Net Income Available to Common Shareholders.

(2) Please refer to slide #57 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.

# Consistently Strong Margins

## Consistently Delivering Strong EBITDA Margins (1)




(1) Includes hedging adjustments.

# Platform for Continued Growth

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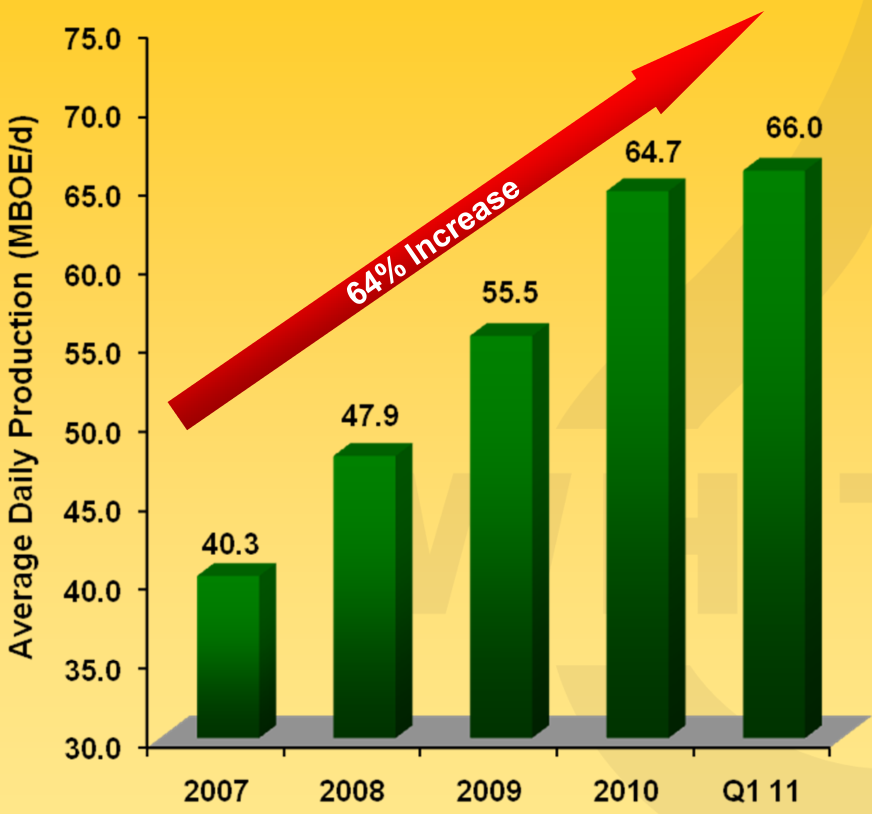
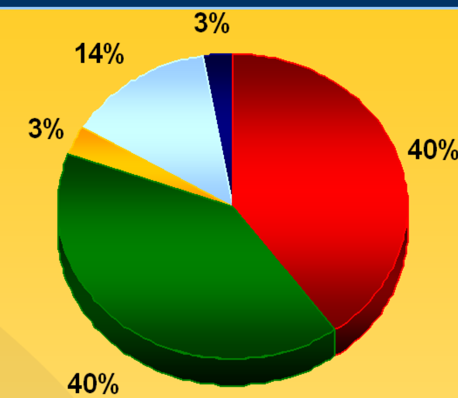
## Average Daily Production




## Proved Reserves (12/31/2010)

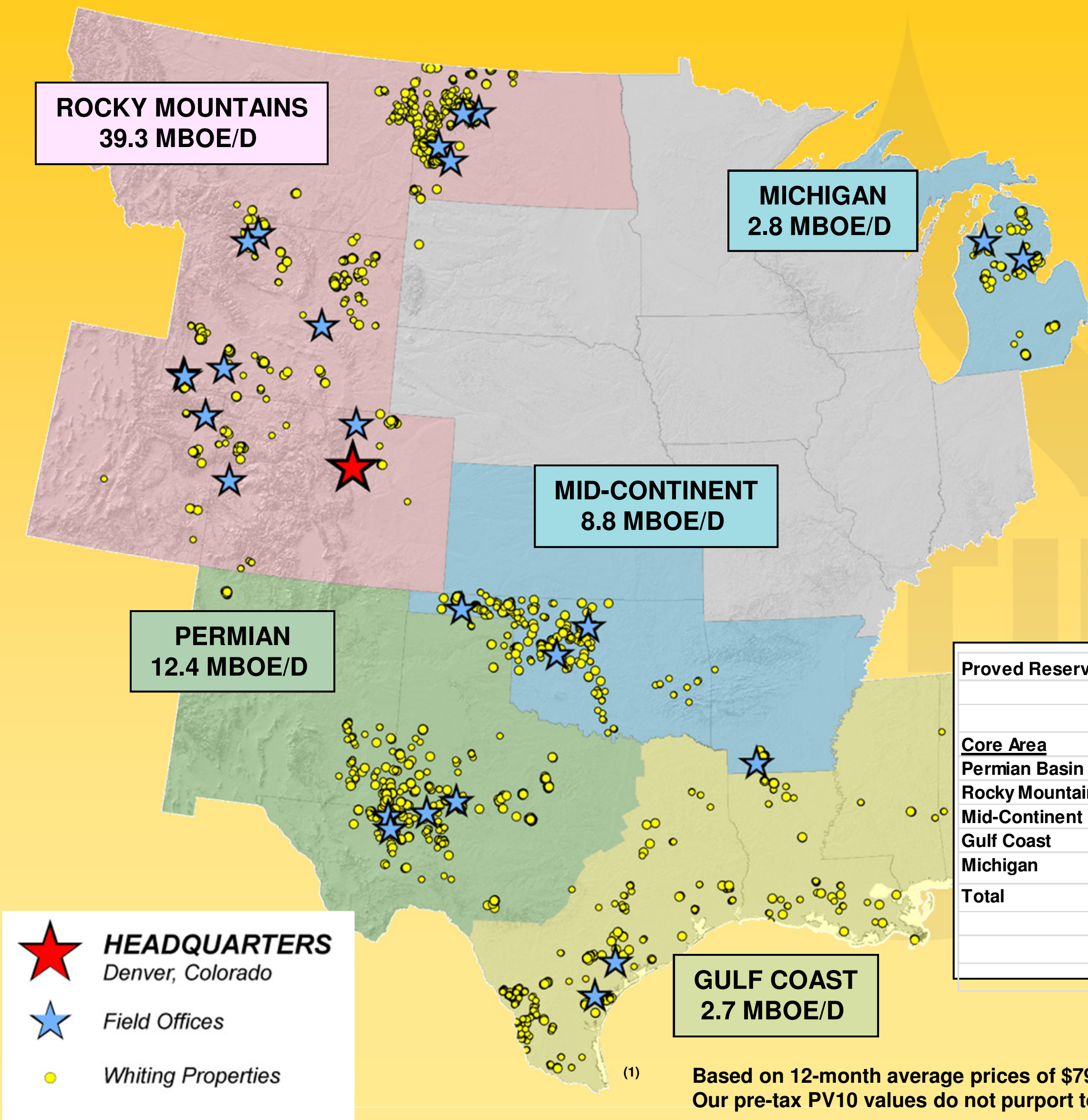


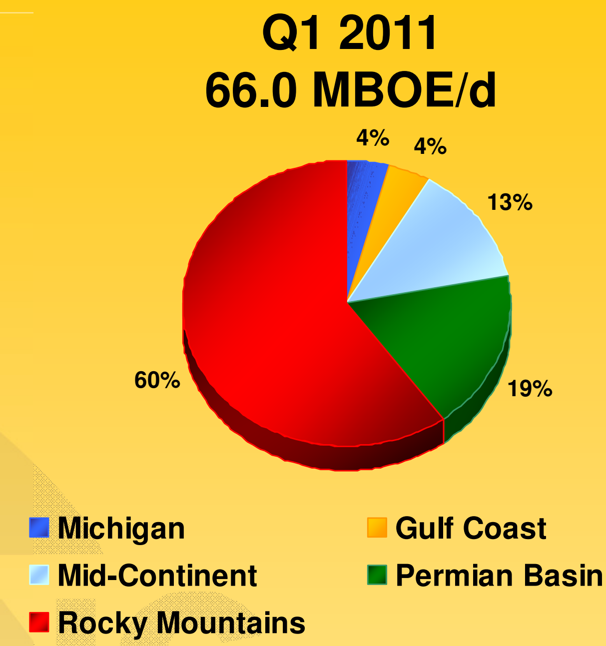

- 304.9 MMBOE (12/31/2010)
- 83% Oil / 17% Natural Gas
- 71% Developed / 29% Undeveloped
- 1,328,665 Net Acres (43% Developed)
- $5.0 Billion PV10% (pre-tax) at SEC NYMEX prices of $79.43/Bbl and $4.38/Mcf

***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



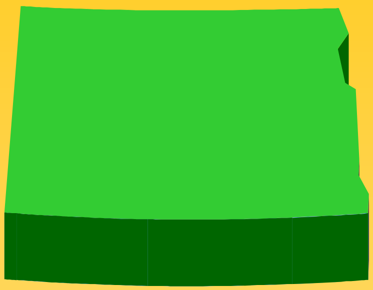




| Proved Reserves at December 31, 2010 [1] | | | | | Pre-Tax | Q1 2011 |
|---|---|---|---|---|---|---|
| | | | | | PV10% | Average Daily Net |
| | Oil [2] | Gas | Total | | Value [1] | Production |
| Core Area | (MMBbl) | (Bcf) | (MMBOE) | Oil % | (in millions) | (MBOE/d) |
| Permian Basin | 115.6 | 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.

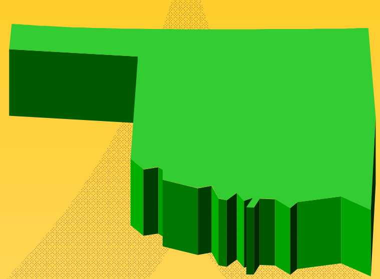
# Whiting a Top Oil Producer in Three States



**NORTH DAKOTA** [1]

**#2**

**13,705,737 Barrels in 2010**



**OKLAHOMA** [2]

**#3**

**Total Barrels: 3,089,028**

**TEXAS** [3]

**#17**

**Total Barrels: 3,888,017**

(1) **Whiting was the second largest oil producer, according to the North Dakota Industrial Commission, for the year ended December 31, 2010, during which Whiting's gross operated production totaled 13,705,737 barrels of oil.**

(2) **According to Whiting production records and the Oklahoma Corporation Commission Top 100 Oil Producers Report for the year 2009.**

(3) **According to the Railroad Commission of Texas for the year 2010.**

# 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 | 130 | 1,199 | 9.22 |
| (Additional phases and larger $CO_2$ slug sizes) | | | | |
| Rockies | Various Fields and Prospects | 75 | 968 | 12.91 |
| (Bakken and Three Forks Development) | | | | |
| Rockies | Sulphur Creek | 32 | 398 | 12.44 |
| (225 20- and 10-acre wells) | | | | |
| | 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*

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| | 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.

# Whiting Pre-Tax PV10 Values at December 31, 2010 [1]

*Using $79.43/Bbl and $4.38/Mcf Held Flat*

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| | MMBO | MMBNGL | Oil & NGL MMBO | Nat. Gas BCF | MMBOE | PV10, MM$ |
|---|---|---|---|---|---|---|
| **PDP** | 134 | 13 | 147 | 204 | 181 | $ 3,718 |
| **PBP** | 2 | 1 | 3 | 13 | 5 | $ 42 |
| **PNP** | 24 | 4 | 28 | 3 | 29 | $ 423 |
| **PUD** | 64 | 12 | 76 | 83 | 90 | $ 861 |
| **Total Proved** | 224 | 30 | 254 | 303 | 305 | $ 5,044 |
| **Total Probable** | 50 | 15 | 65 | 212 | 100 | $ 546 |
| **Total Possible** | 146 | 37 | 183 | 205 | 217 | $ 1,869 |
| **Total 3P Reserves** | 420 | 82 | 502 | 720 | 622 | |

(1) Reserve estimates shown are based on independent engineering by Cawley, Gillespie & Associates, Inc. at December 31, 2010 using 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.

# Finding Costs

*(in Thousands)*

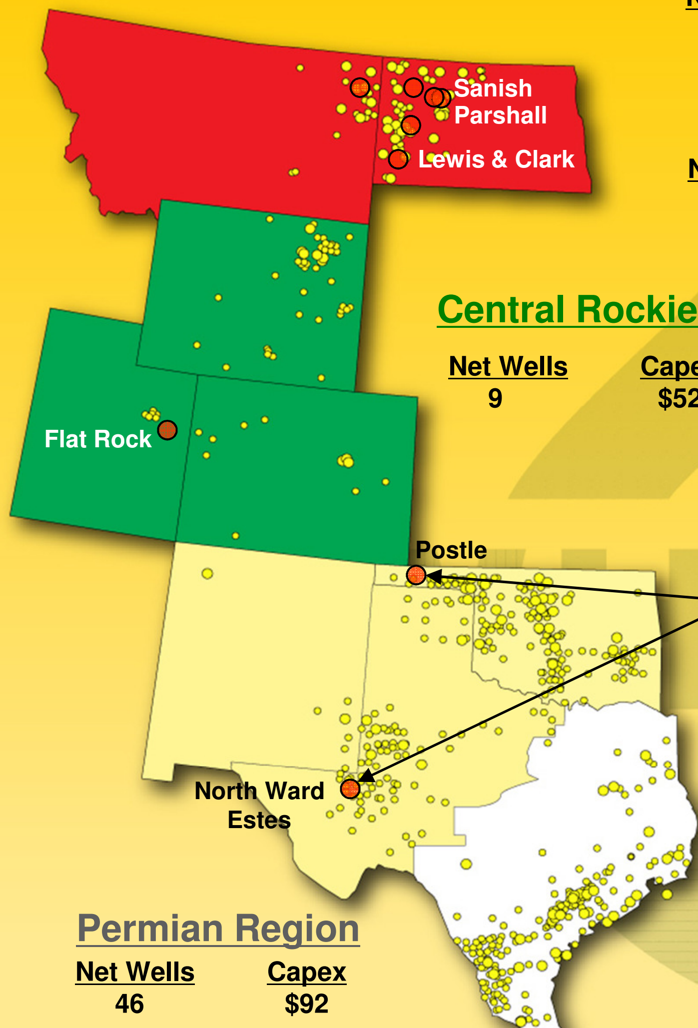
| | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | Seven-Year Total/Avg (2004 – 2010) |
|---|---|---|---|---|---|---|---|---|
| Proved Acquisitions | $ 525,563 | $ 906,208 | $ 29,778 | $ 8,128 | $ 294,056 | $ 78,800 | $ 22,763 | $ 1,865,296 |
| Unproved Acquisitions | $ 4,401 | $ 16,124 | $ 38,628 | $ 13,598 | $ 98,841 | $ 12,872 | $ 155,472 | $ 339,936 |
| Development Cost | $ 74,476 | $ 215,162 | $ 408,828 | $ 506,057 | $ 914,616 | $ 436,721 | $ 723,687 | $ 3,279,547 |
| Exploration Cost | $ 9,739 | $ 22,532 | $ 81,877 | $ 56,741 | $ 42,621 | $ 50,970 | $ 114,012 | $ 378,492 |
| Change in Future Dvlp. Cost | $ 150,538 | $ 692,229 | $ 267,685 | $ 10,048 | $ ( 204,633) | $ 423,541 | $ 86,203 | $ 1,425,611 |
| Total | $ 764,717 | $ 1,852,255 | $ 826,796 | $ 594,572 | $1,145,501 | $ 1,002,904 | $ 1,102,137 | $ 7,288,882 |
| ***Acquisition Reserves*** | | | | | | | | |
| Acquisition – Oil (MBbls) | 52,288 | 115,737 | 670 | 691 | 513 | 3,177 | 505 | 173,581 |
| Acquisition – Gas (MMcf) | 114,715 | 101,082 | 4,009 | - | 90,329 | 4,155 | 1,526 | 315,816 |
| Total Acquisition (MBOE) | 71,407 | 132,584 | 1,338 | 691 | 15,568 | 3,870 | 759 | 226,217 |
| ***Development Reserves*** | | | | | | | | |
| Development – Oil (MBbls) | 5,175 | 1,956 | 4,125 | 10,973 | 20,395 | 25,115 | 29,434 | 97,173 |
| Development – Gas (MMcf) | 29,133 | 21,068 | 19,362 | 40,936 | 57,093 | 41,969 | 23,135 | 232,696 |
| Total Development (MBOE) | 10,031 | 5,467 | 7,352 | 17,796 | 29,911 | 32,109 | 33,290 | 135,956 |
| ***Revisions*** | | | | | | | | |
| Reserve Revisions – Oil (MBbls) | ( 853 ) | 950 | 2,053 | 392 | ( 20,851 ) | 33,566 | 19,799 | 35,056 |
| Reserve Revisions – Gas (MMcf) | ( 9,862 ) | ( 45,322 ) | ( 57,780 ) | 8,079 | ( 74,689 ) | ( 62,618 ) | ( 618) | ( 242,810 ) |
| Total Reserve Revisions (MBOE) | ( 2,497 ) | ( 6,604 ) | ( 7,577 ) | 1,739 | ( 33,299 ) | 23,130 | 19,695 | ( 5,413 ) |
| Cost Per BOE to Acquire | $ 7.36 | $ 6.83 | $ 22.25 | $ 11.76 | $ 18.89 | $ 20.36 | $ 29.99 | $ 8.25 |
| Cost Per BOE to Develop | $ 31.74 | $ - | $ - | $ 30.02 | $ - | $ 16.73 | $ 20.37 | $ 41.55 |
| All-In Finding Cost Per BOE | $ 9.69 | $ 14.09 | $ 742.74 | $ 29.40 | $ 94.05 | $ 16.97 | $ 20.51 | $ 20.43 |

| | |
|---|---|
| Unrisked Probable and Possible Reserves – BOE | 317,215 |
| Probable and Possible Cap-Ex | $ 3,536,055 |
| All-In Rate with Future Dvlp. Cost and Prob. & Poss. | $ 16.06 |

# 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

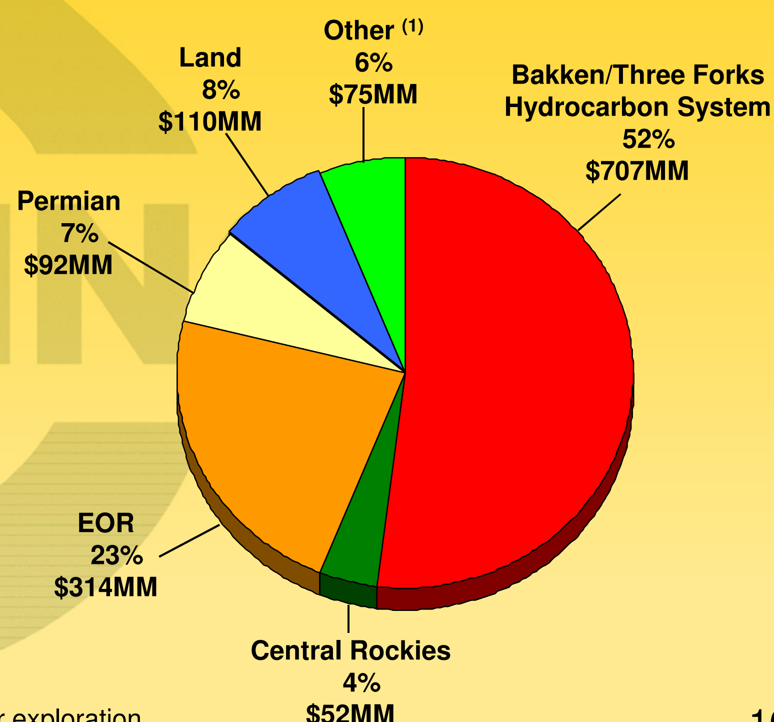
| Capex |
|---|
| $314 |

### 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

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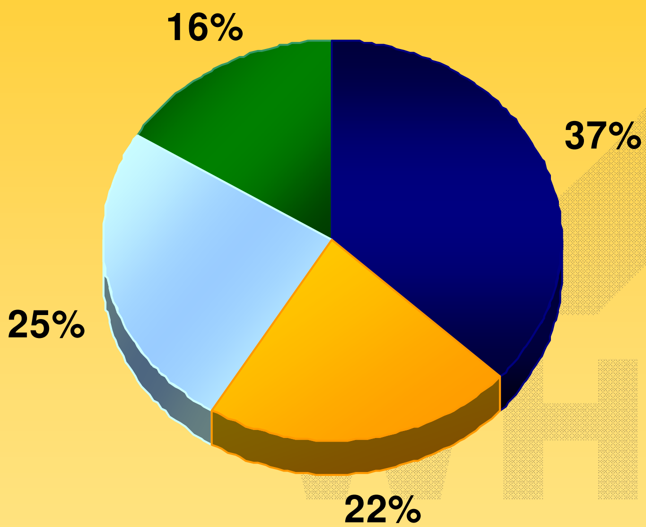
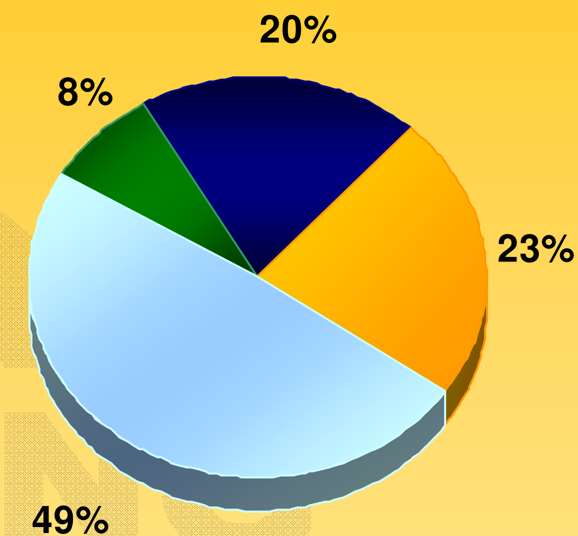
**2010 – $978 MM Actual**

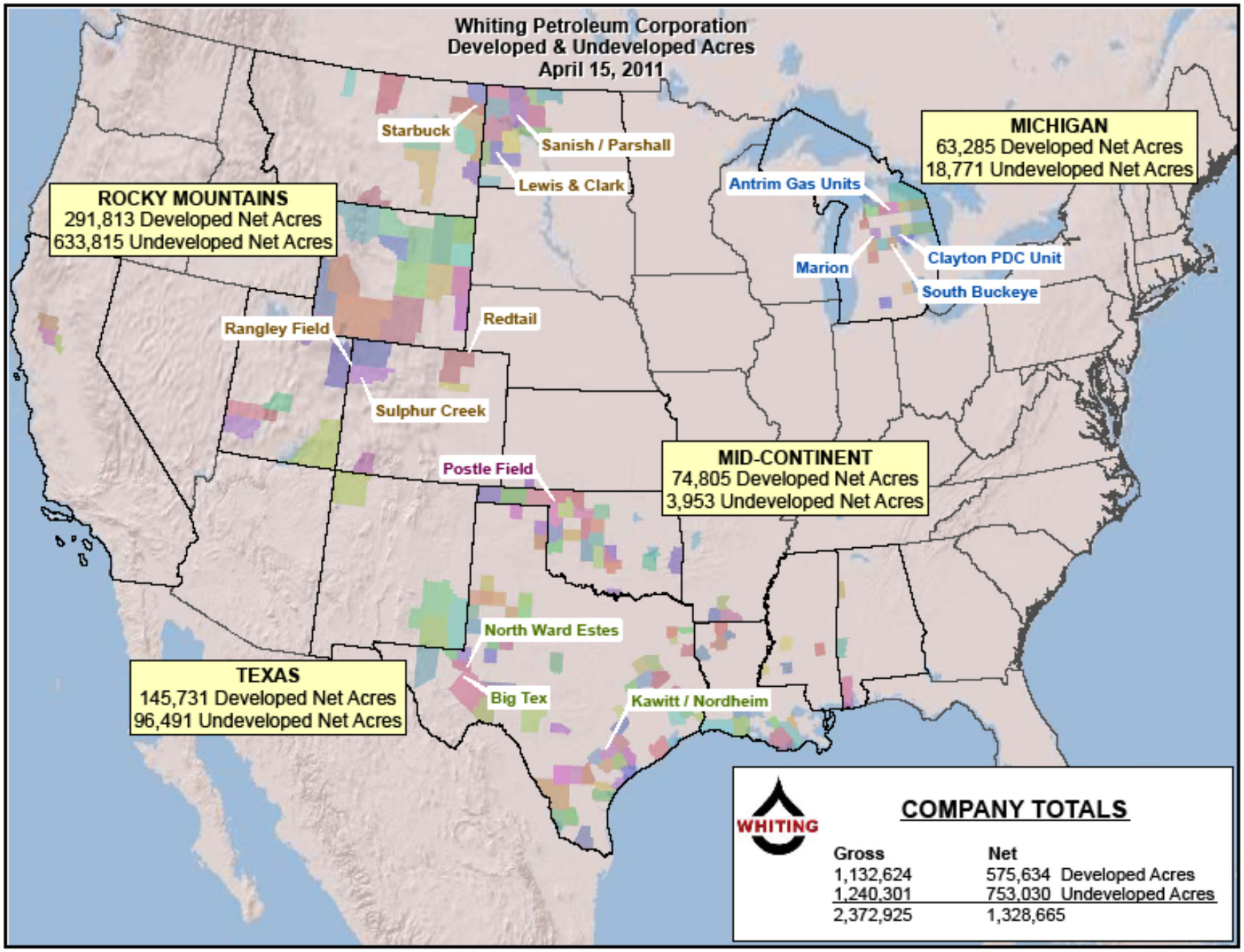



**2011 – $1,350 MM Budget**

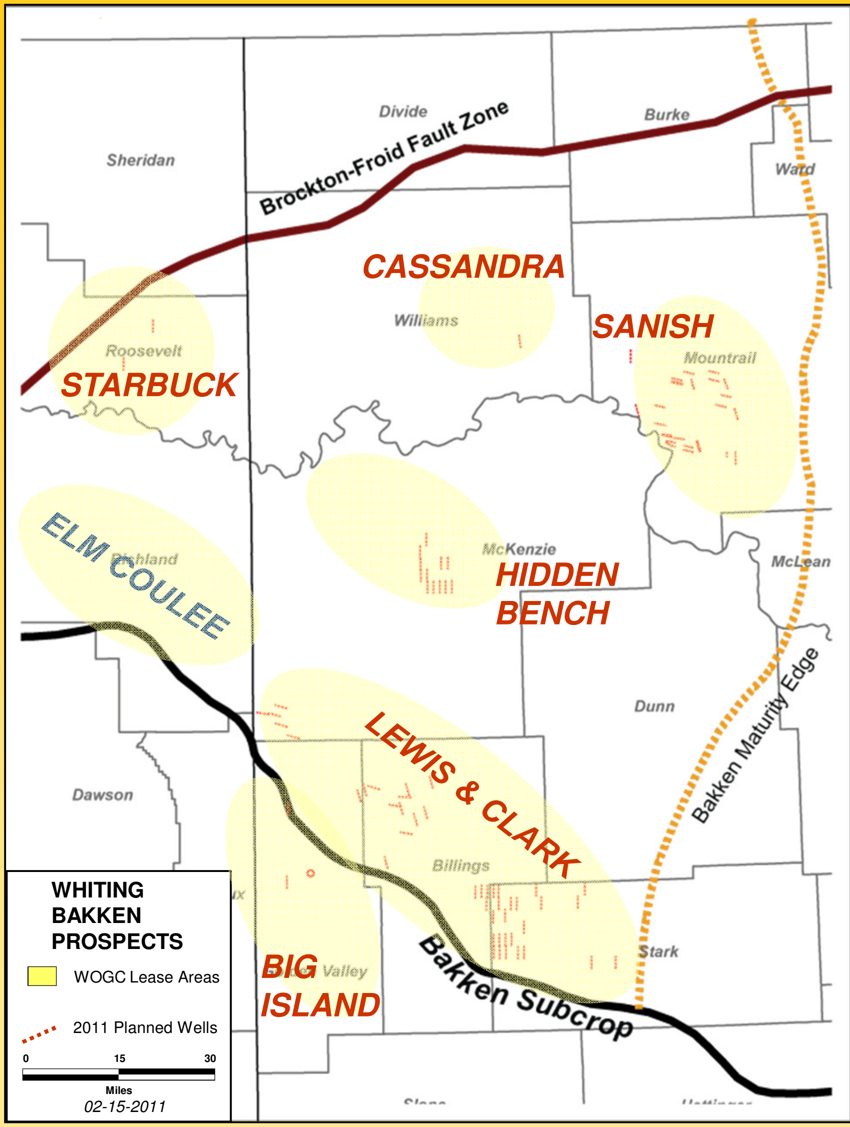



- Proved
- $CO_2$ Recovery Projects (Proved)
- Non-Proved
- Land

# Whiting Developed & Undeveloped Acreage by Core Area



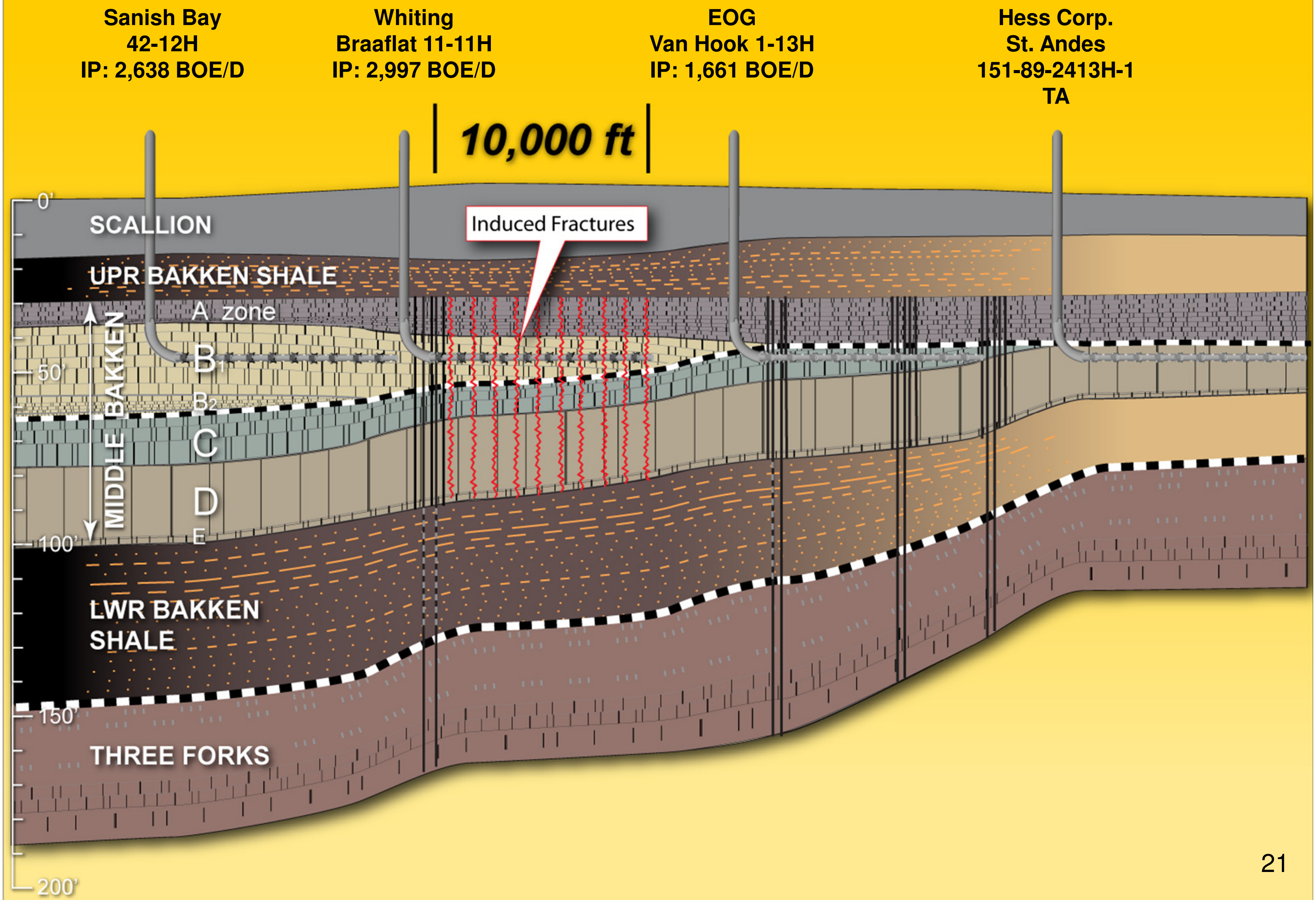
# Whiting Prospect Areas in Bakken/Three Forks Hydrocarbon System at March 31, 2011[1]



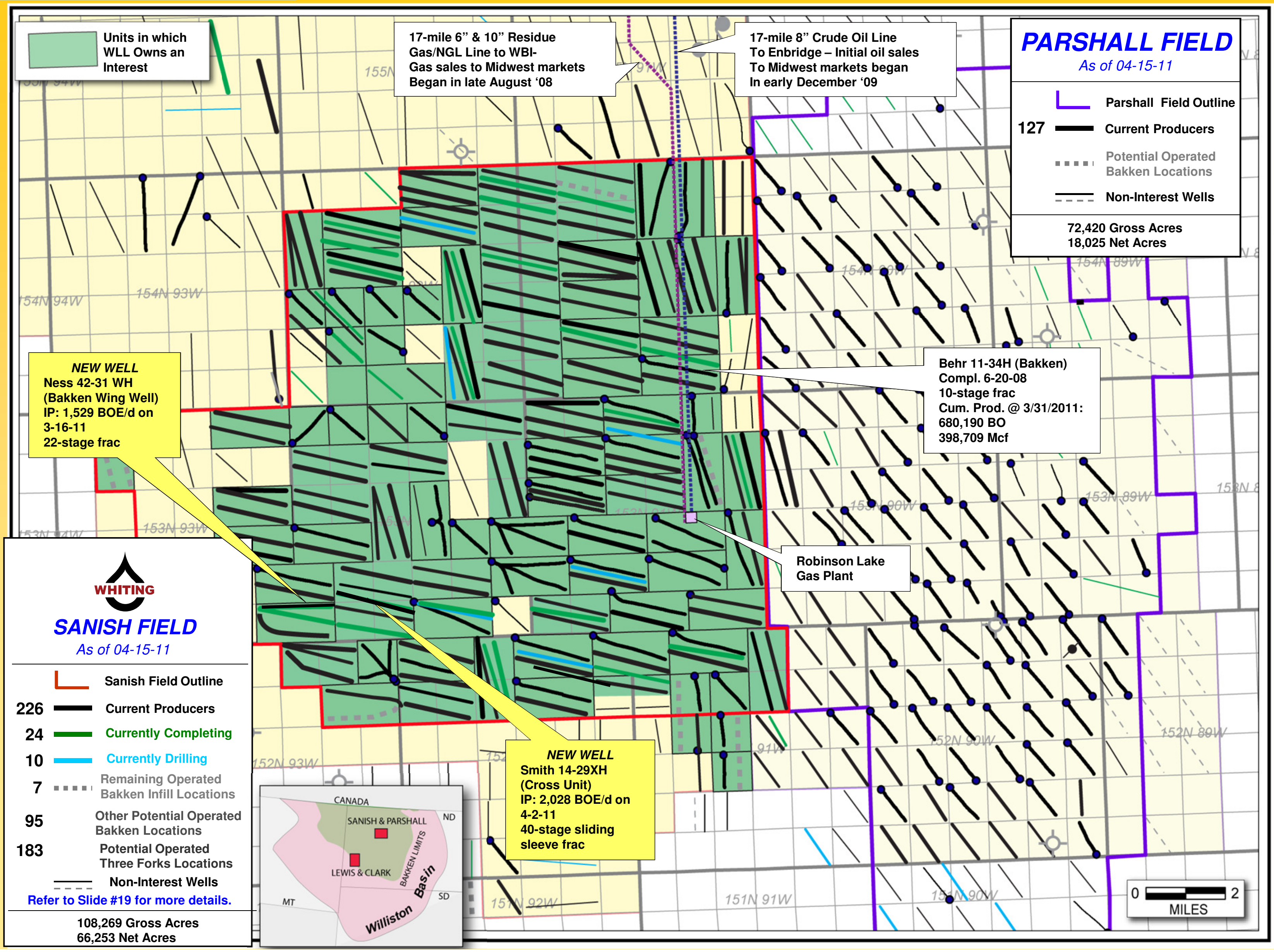

| | Gross Acres | Net Acres |
|---|---|---|
| ***Sanish / Parshall*** | | |
| - Bakken and Three Forks Objectives | | |
| - 194 producing wells in Sanish | 180,689 | 84,278 |
| - 127 producing wells in Parshall | | |
| - 99 Wells in 2010, 106 in 2011 | | |
| - $364MM capex in 2011 | | |
| ***Lewis & 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.

# *Bakken / Three Forks Hydrocarbon System*

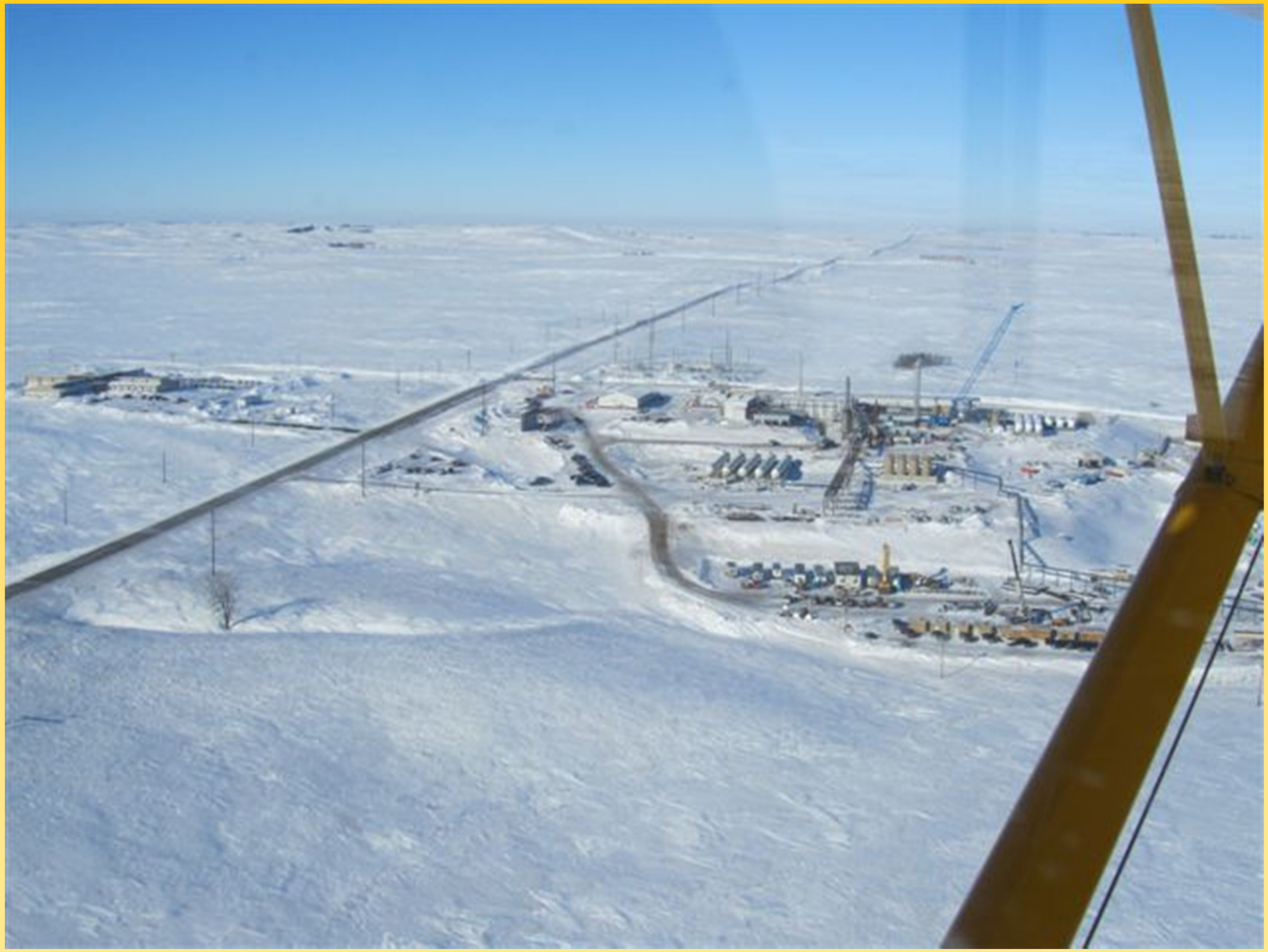


# Sanish and Parshall Fields -
# *Recent and Notable Wells*



# Robinson Lake Field Office and Gas Plant
## *Mountrail County, North Dakota*

WHITING



**On right, current 60 MMcfd Inlet Capacity Robinson Lake Gas Plant (with expansion to 90 MMcfd in the third quarter of 2011 underway). On left, adjoining newly constructed 30,000 sq. ft. office building.**

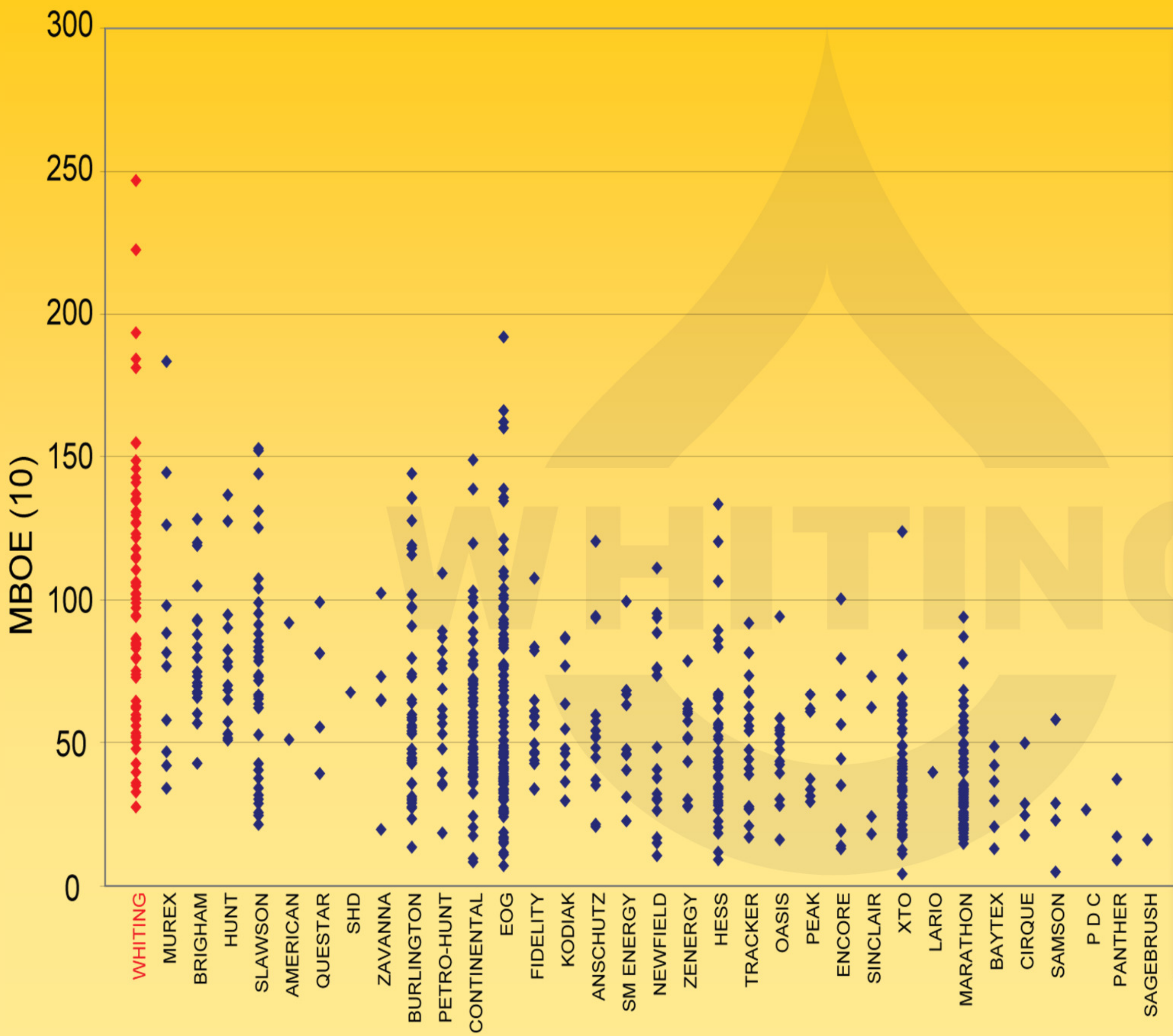
# New Robinson Lake Field Office
## *Mountrail County, North Dakota*

WHITING

# Expansion of Robinson Lake Field Gas Plant
## *January 2011*

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

***Source: IHS Energy, Inc.***
***January, 2011***

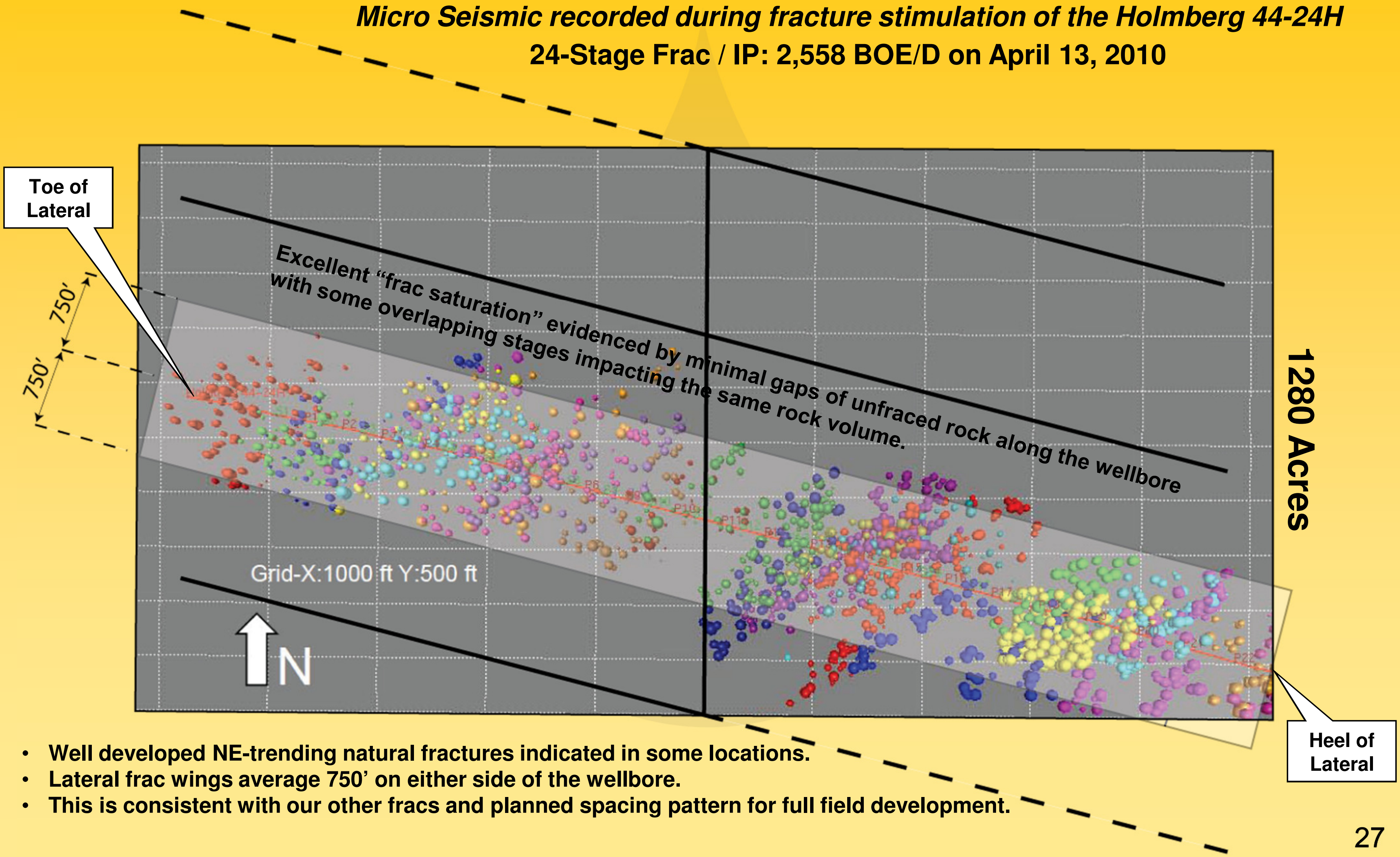



| Operator | 6 mo Total Production (MBOE 10) | Wells Drilled | 6 mo Avg Production (MBOE 10) |
|---|---|---|---|
| WHITING | 7,221 | 72 | 100 |
| MUREX | 980 | 11 | 89 |
| BRIGHAM | 1,628 | 20 | 81 |
| HUNT | 1,103 | 14 | 79 |
| SLAWSON | 2,613 | 35 | 75 |
| AMERICAN | 143 | 2 | 72 |
| QUESTAR | 357 | 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 |

# Bakken Drainage Area

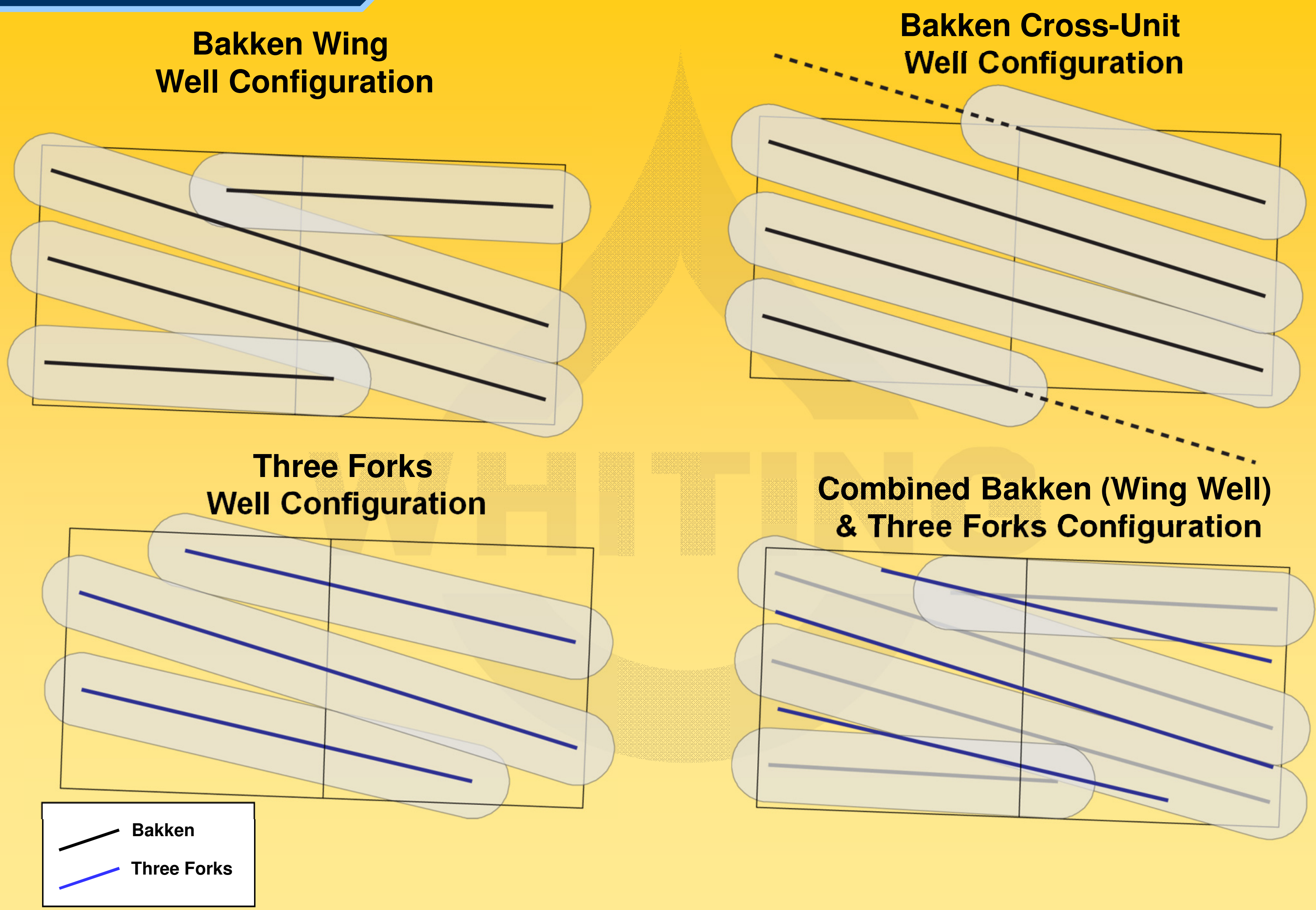
***Micro Seismic recorded during fracture stimulation of the Holmberg 44-24H***

**24-Stage Frac / IP: 2,558 BOE/D on April 13, 2010**



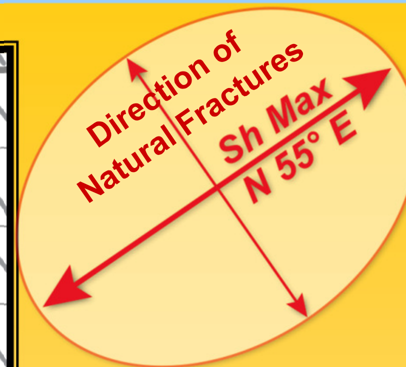

- Well developed NE-trending natural fractures indicated in some locations.
- Lateral frac wings average 750' on either side of the wellbore.
- This is consistent with our other fracs and planned spacing pattern for full field development.

# Sanish Field Development Pattern



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

WHITING


(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.

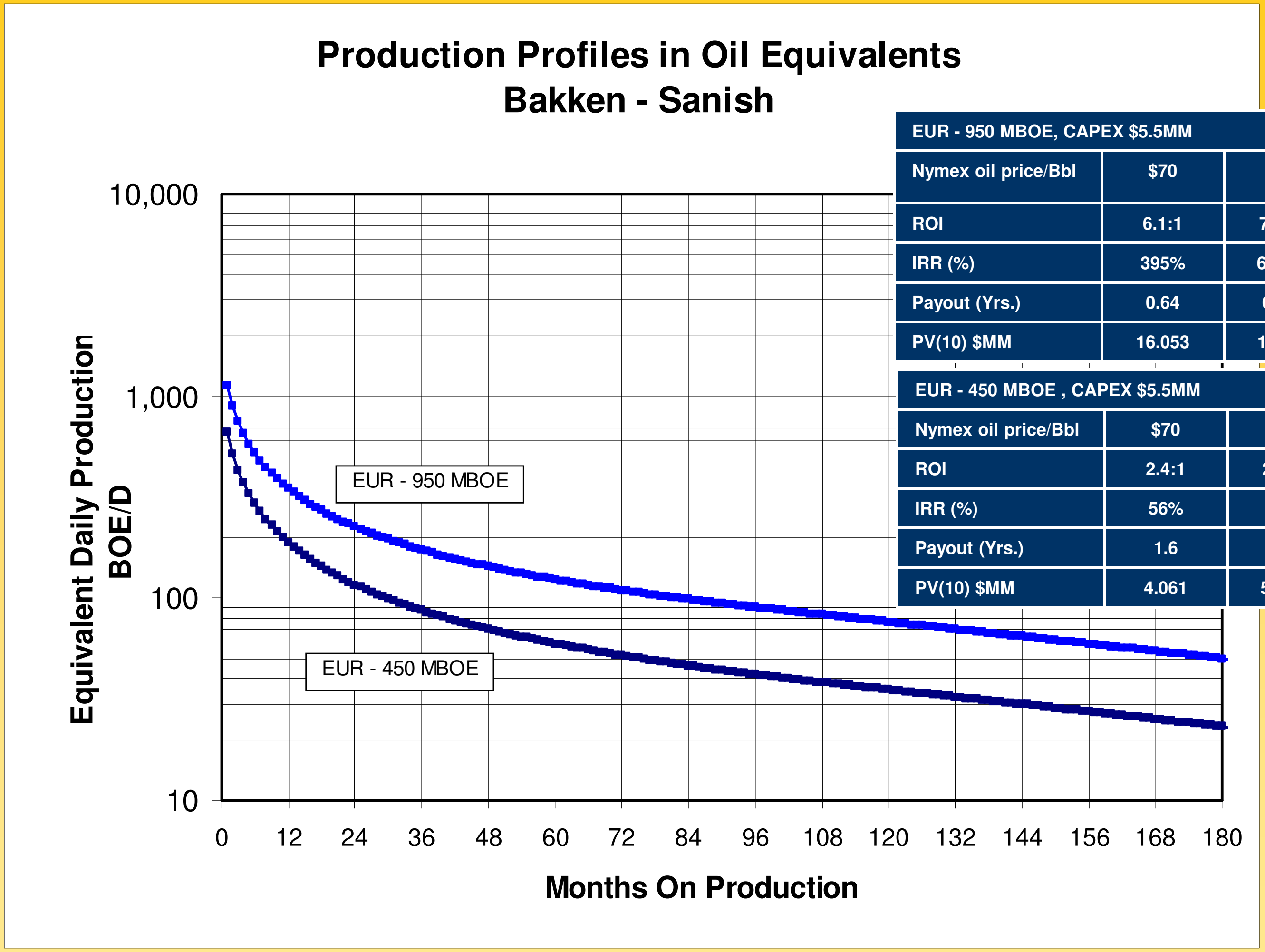
| | Drilling, WOC | Completed | Planned/ Potential | Total |
|---|---|---|---|---|
| Middle Bakken | 3 | 129 | 7 | 139 |
| Cross-Unit Middle Bakken | 4 | 12 | 14 | 30 |
| Wing - Middle Bakken | 2 | 0 | 81 | 83 |
| Three Forks | 17 | 17 | 183 | 217 |
| **Total Operated** | **26** | **158** | **285** |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

As of April 15, 2011

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

| | Well Name | WI% | NRI% | Completion 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) | STATE 12-32H | 40% | 32% | 4/11/2011 | 2,247 | | | |
| 2) | ROBERT PATTEN 44-3TFH | 93% | 75% | 4/5/2011 | 440 | | | |
| 3) | HOLLINGER 11-14TFH | 47% | 38% | 4/4/2011 | 596 | | | |
| 4) | HOLLINGER 21-14TFH | 47% | 38% | 3/31/2011 | 1,232 | | | |
| 5) | SMITH 14-29XH | 43% | 35% | 3/30/2011 | 2,028 | 779 | | |
| 6) | GUINN TRUST 1-13TFH | 41% | 33% | 3/24/2011 | 1,254 | 491 | | |
| 7) | HOOVER 14-1XH | 27% | 22% | 3/20/2011 | 2,212 | 731 | | |
| 8) | WARDEN 43-9TFH | 30% | 24% | 3/17/2011 | 715 | | | |
| 9) | NESS 42-31WH | 78% | 64% | 3/14/2011 | 1,529 | 543 | | |
| 10) | SCOTT MEIERS 12-17TFH | 87% | 71% | 3/13/2011 | 1,087 | | | |
| 11) | ARNDT 14-5XH | 28% | 23% | 3/7/2011 | 1,416 | 700 | 598 | |
| 12) | DEAL 43-28TFH | 72% | 58% | 3/4/2011 | 920 | | | |
| 13) | BARLOW 14-6XH | 75% | 61% | 2/28/2011 | 1,182 | 511 | | |
| 14) | OJA 14-27XH | 65% | 53% | 2/18/2011 | 2,072 | 558 | | |
| 15) | NIEMITALO 31-15XH | 52% | 42% | 2/15/2011 | 2,905 | 843 | 685 | |
| 16) | BARTLESON 21-3H | 50% | 41% | 2/13/2011 | 1,235 | 552 | | |
| 17) | HEIPLE 14-3XH | 63% | 52% | 2/9/2011 | 2,080 | 1,163 | 865 | |
| 18) | B. ROGGENBUCK 24-25H | 73% | 59% | 1/22/2011 | 2,072 | 698 | 567 | |
| 19) | SIKES STATE 43-16H | 100% | 81% | 1/19/2011 | 3,385 | 1,291 | 1,052 | |
| 20) | BREHM 12-7H | 50% | 41% | 1/14/2011 | 987 | 439 | 253 | |
| 21) | MILLER 44-11H | 76% | 62% | 1/8/2011 | 1,447 | 343 | | |
| 22) | NESS 21-3H | 50% | 41% | 1/4/2011 | 1,730 | 690 | 546 | 486 |
| | ***Averages*** | ***59%*** | ***48%*** | | ***1,581*** | ***708*** | ***605*** | ***486*** |

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



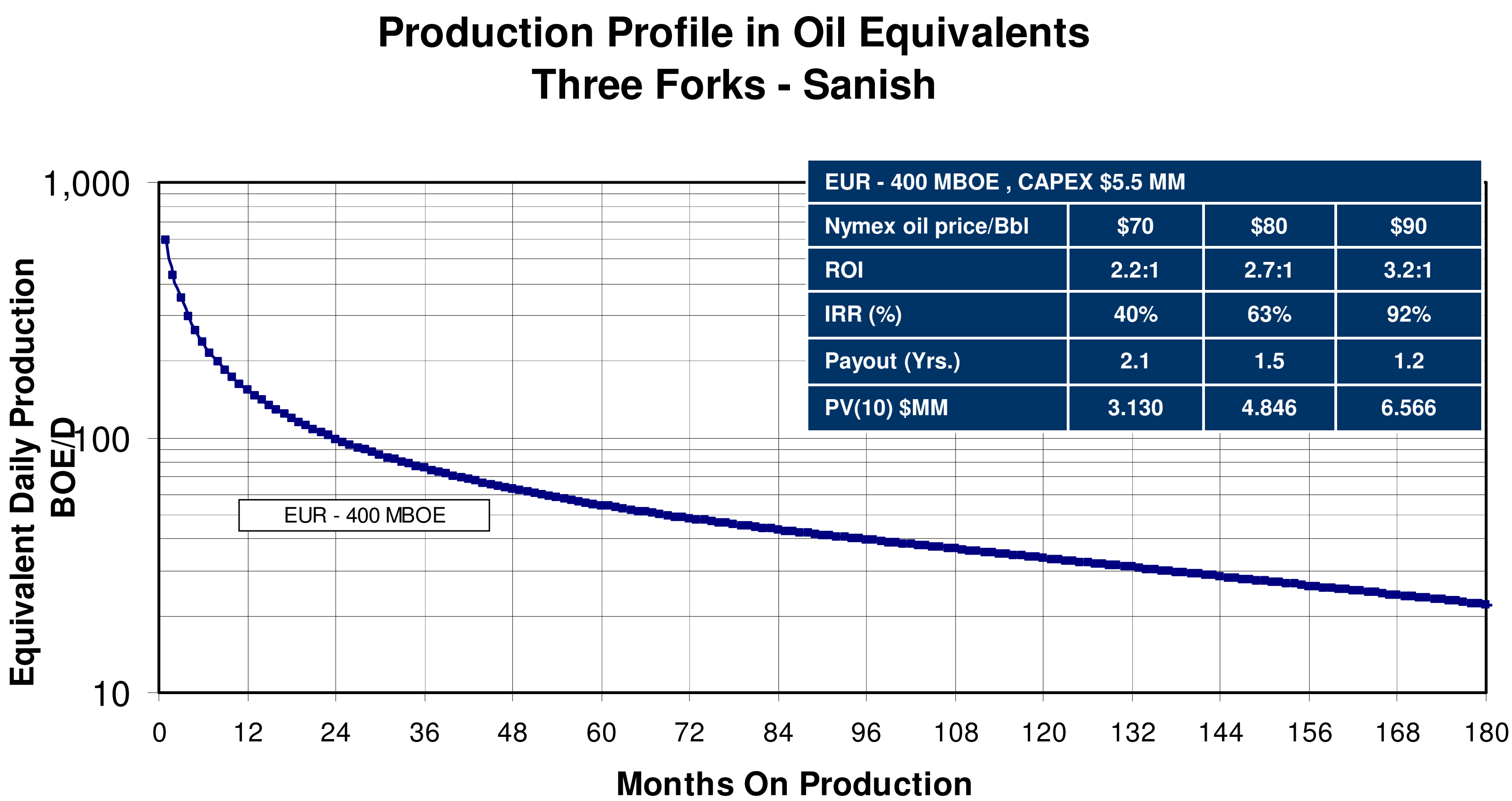

| EUR - 950 MBOE, CAPEX $5.5MM | | | |
|---|---|---|---|
| Nymex oil price/Bbl | $70 | $80 | $90 |
| ROI | 6.1:1 | 7.3:1 | 8.4:1 |
| IRR (%) | 395% | 676% | 1,138% |
| Payout (Yrs.) | 0.64 | 0.55 | 0.48 |
| PV(10) $MM | 16.053 | 19.93 | 23.807 |

| 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)

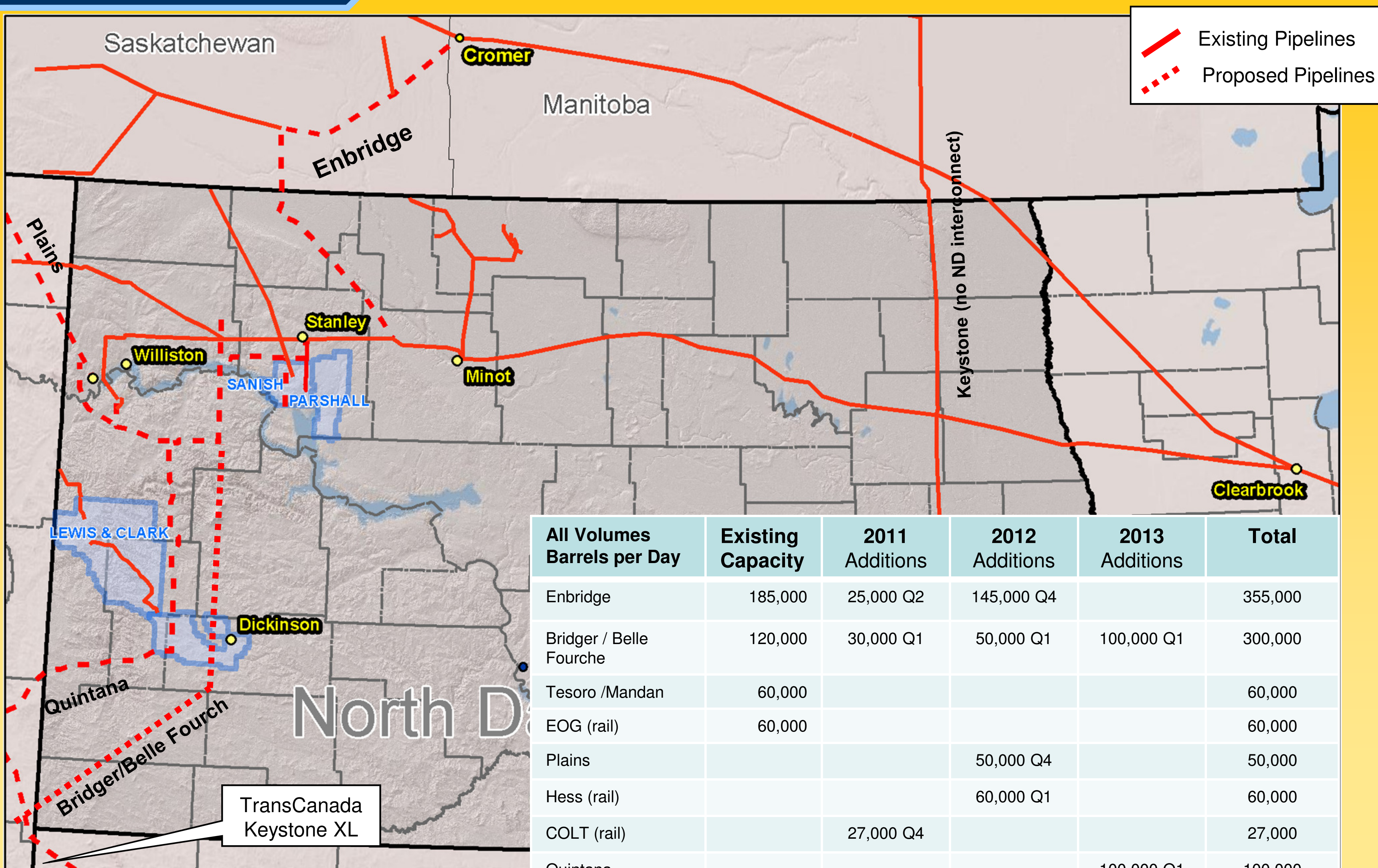



| EUR - 400 MBOE , CAPEX $5.5 MM | | | |
|---|---|---|---|
| Nymex oil price/Bbl | $70 | $80 | $90 |
| ROI | 2.2:1 | 2.7:1 | 3.2:1 |
| IRR (%) | 40% | 63% | 92% |
| Payout (Yrs.) | 2.1 | 1.5 | 1.2 |
| PV(10) $MM | 3.130 | 4.846 | 6.566 |

(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.

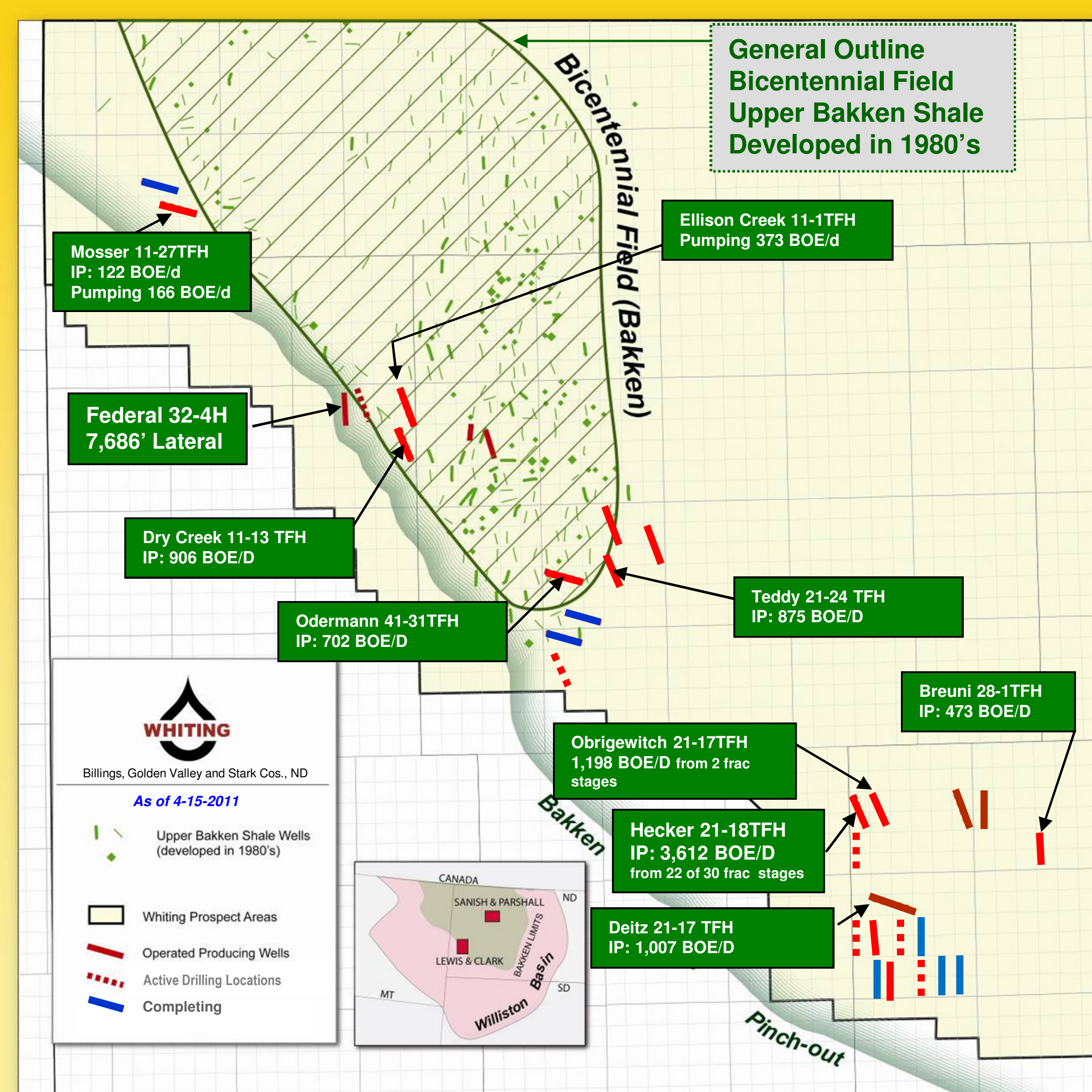
(2) EURs, ROIs, IRRs and PV10 values will vary well to well. Whiting holds an average WI of 60% and an average NRI of 50% in its operated Three Forks wells in Sanish field.

# 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

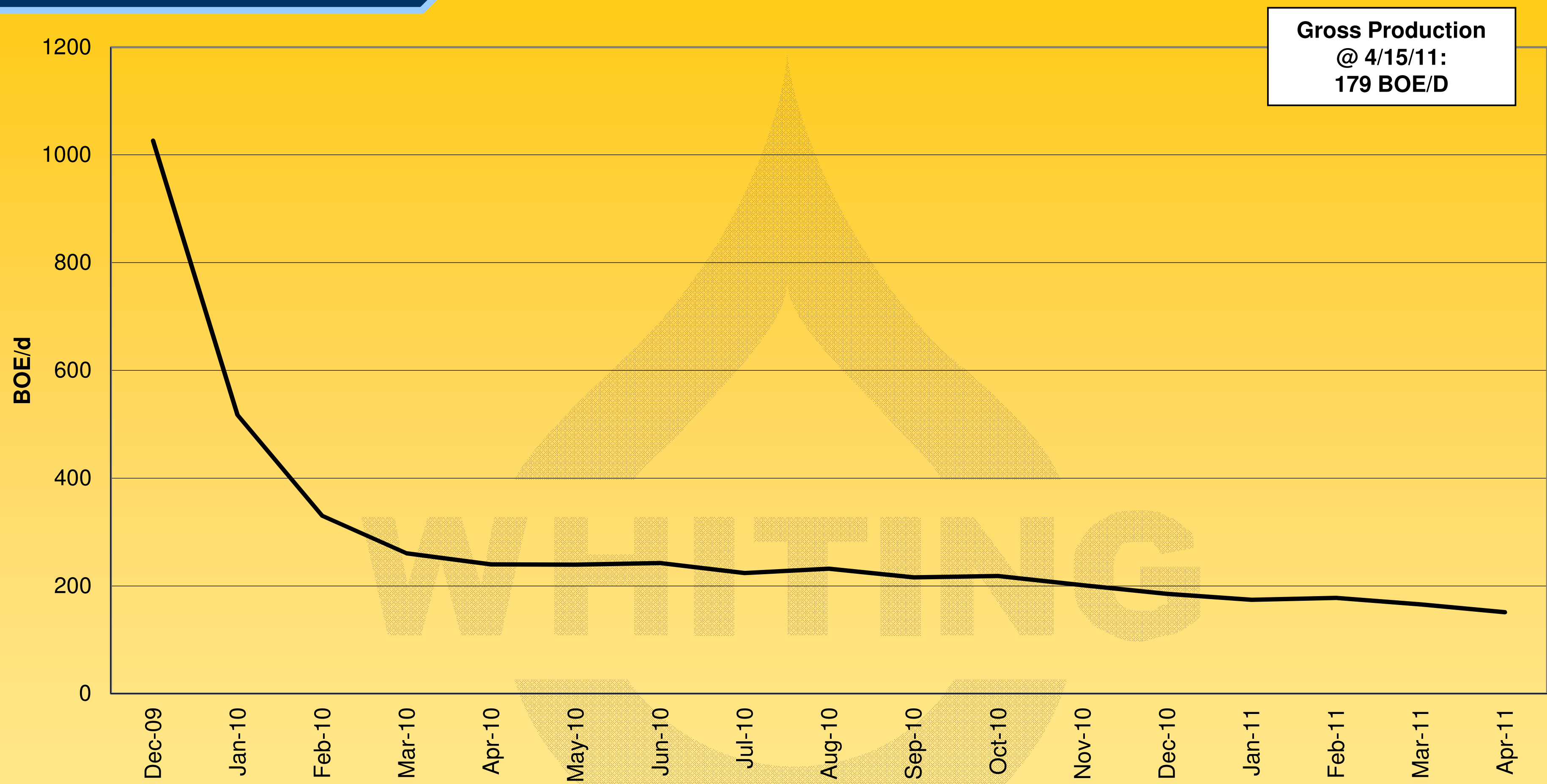
**DRILLING PROGRAM**

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.

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




(1) The table above reflects production from November 23, 2009 through January 10, 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.

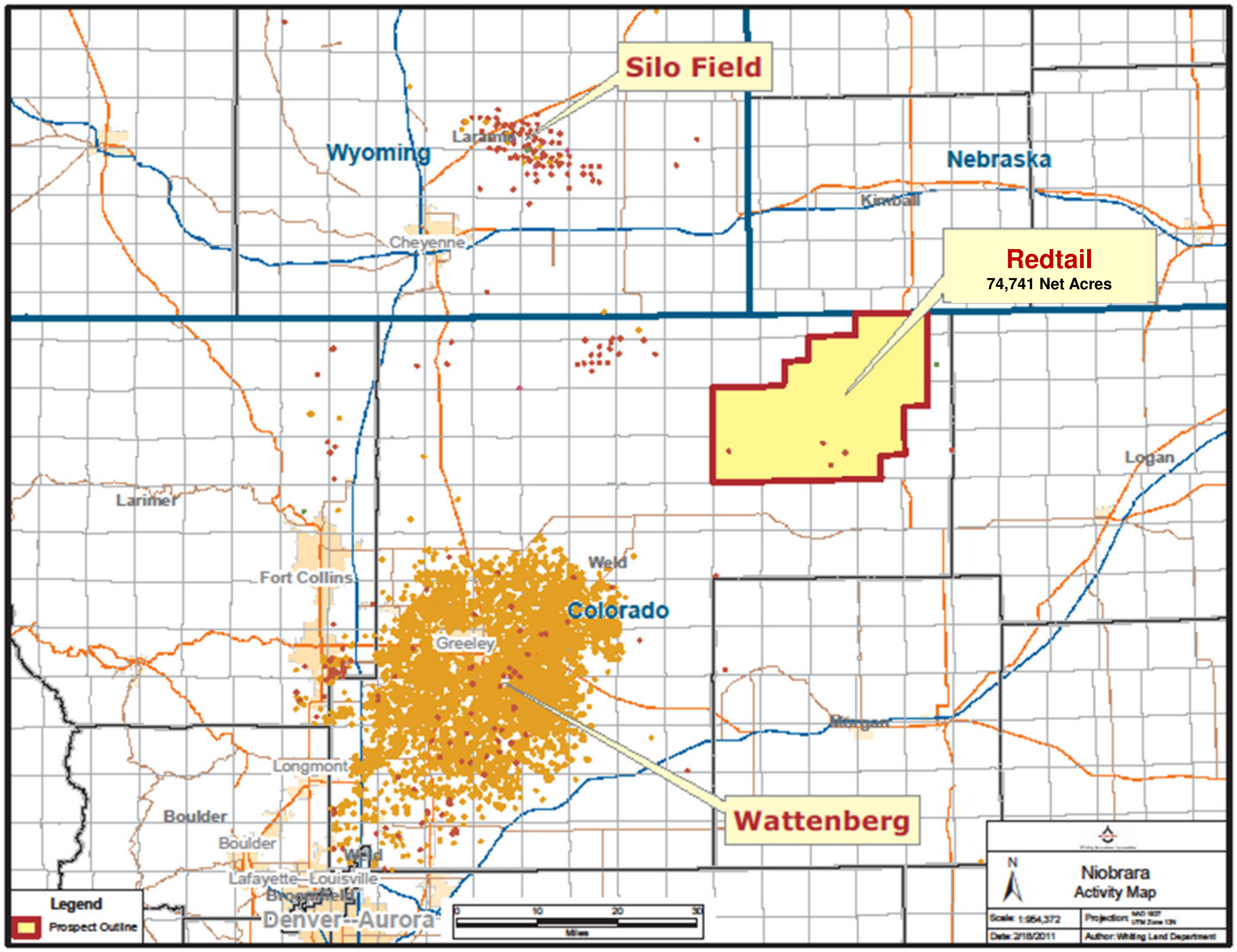
# IP, 30-, 60- and 90-day Average Production Rates for Whiting Operated Wells in Lewis & Clark Field

| 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 (1) | 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 | 603 | | |
| 4) DIETZ 21-17TFH | 98% | 78% | 3/16/2011 | 1,007 | 555 | | |
| 5) MOSSER 11-27 | 64% | 51% | 3/11/2011 | 122 | | | |
| 6) HECKER 21-18TFH | 77% | 61% | 3/4/2011 | 3,612 | 1,504 | 1,307 | |
| 7) BRUENI 28-1H | 44% | 35% | 3/1/2011 | 473 | 260 | | |
| 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 (2) | 81% | 65% | 11/12/2010 | 381 | 187 | 169 | 175 |
| 12) ELLISON CREEK 11-1TFH (3) | 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) Currently producing from an estimated 2 frac stages.**
**(2) Fracture stimulated into water-bearing zone. Whiting plans to modify frac design.**
**(3) Partially pressure depleted by 1980s' Upper Bakken Shale well.**

# 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**

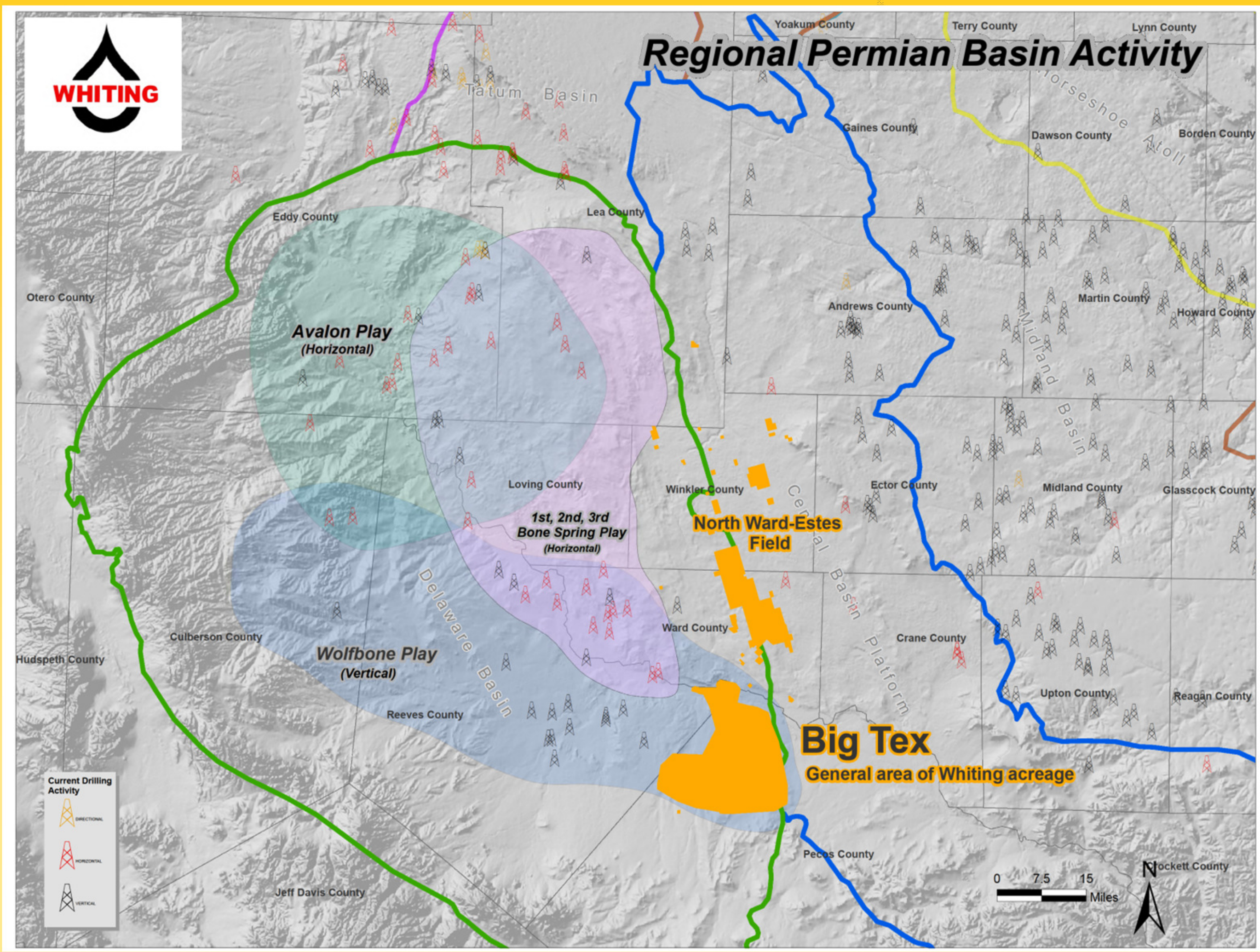
**COMPLETED WELL COST**

**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

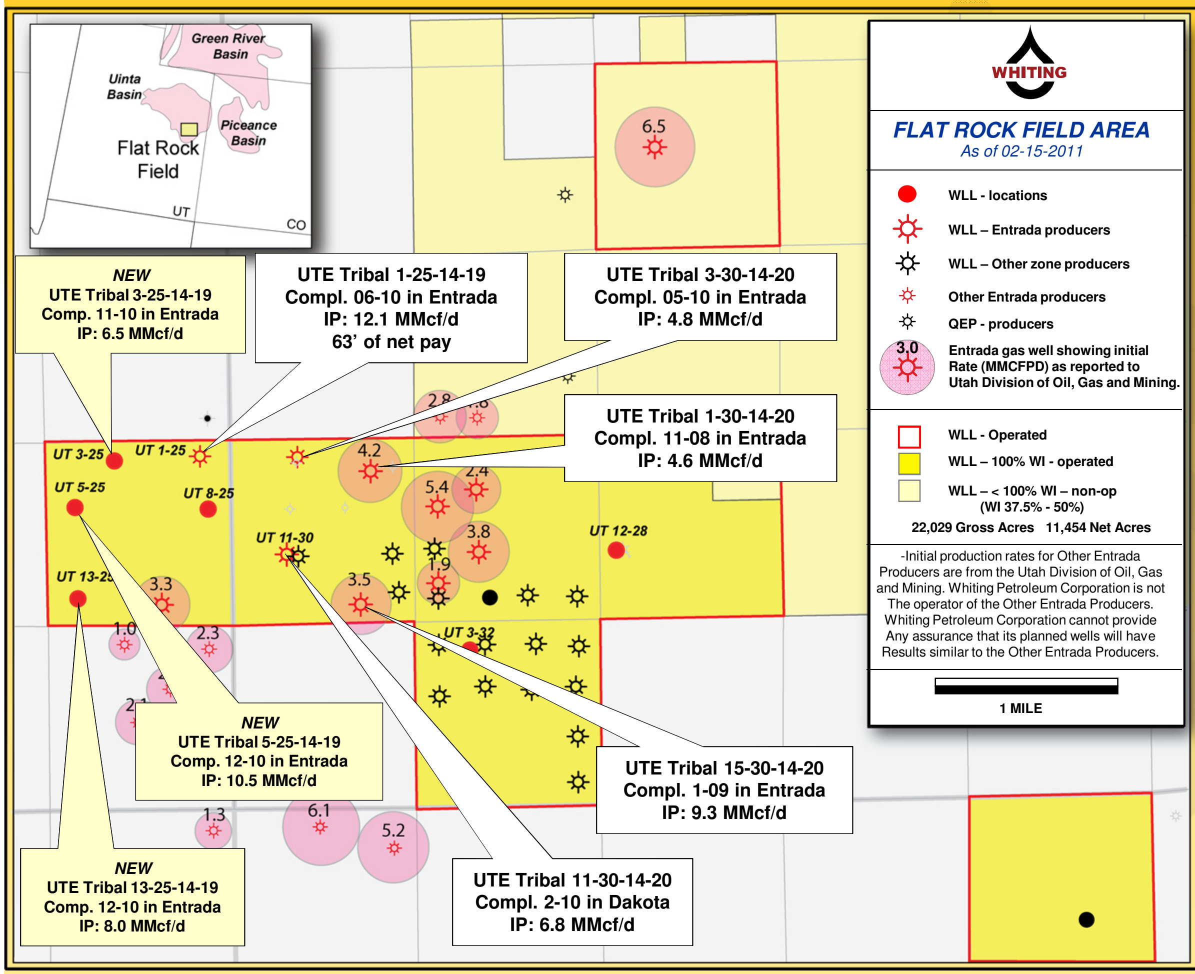
**ACREAGE**
Whiting has assembled 111,665 gross (83,303 net) acres in our Big Tex prospect in the Delaware Basin:

- 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

# Flat Rock Field
## *Uintah County, Utah*



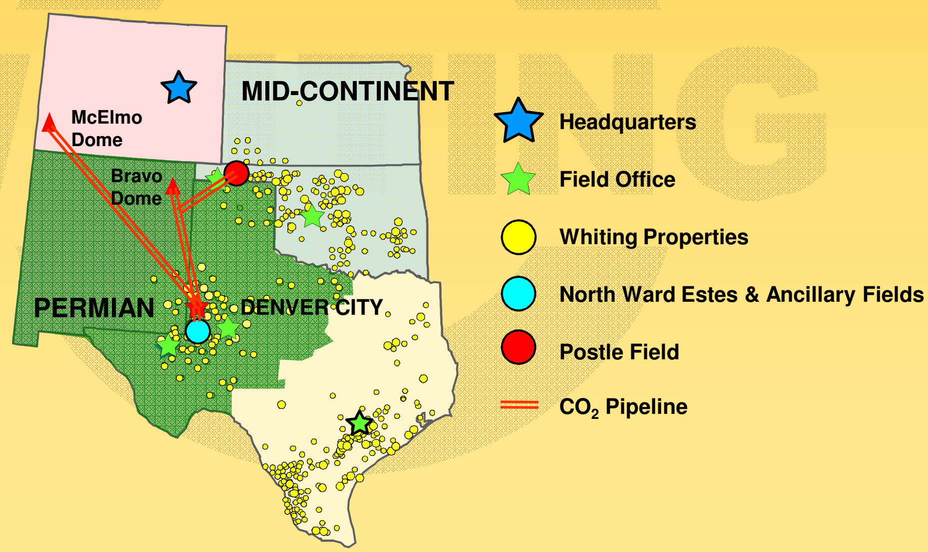

- 22,029 gross acres (11,454 net)
- 25.2 MMcfe of daily net production as of February 15, 2011, up from 20.9 MMcf/d in December 2010
  - 13 wells in the Entrada formation (11,500 feet)
  - 25 wells in the Wasatch and Dakota formations
- 95% of current production is from the Entrada formation
  - 49 square miles of 3-D seismic support
  - Up to 100 feet of net pay
  - 46 additional drilling locations (2 P1, 1P2 and 43 P3)
- In November 2010, Whiting completed the Ute Tribal 3-25-14-19 well in the Entrada formation flowing at a restricted rate of 6.5 MMcf/d
- In December 2010, Whiting completed the Ute Tribal 5-25-14-19 well in the Entrada formation flowing 10.5 MMcf/d and the Ute Tribal 13-25-14-19 well in the Entrada formation flowing 8.0 MMcf/d
- Whiting has a five-year gas sales contract covering 10 MMcf of gas per day at a flat fixed-price of $5.50 per Mcf at the wellhead. In 2011 and in Q1 2012, an additional 9 MMcf of daily gas volumes are under contract at a weighted average flat fixed-price of $5.15 per Mcf at the wellhead. (Please refer to slide #53.)

*Source: Utah Oil and Gas Commission as of September 1, 2008*

# EOR Projects - Postle and North Ward Estes Fields

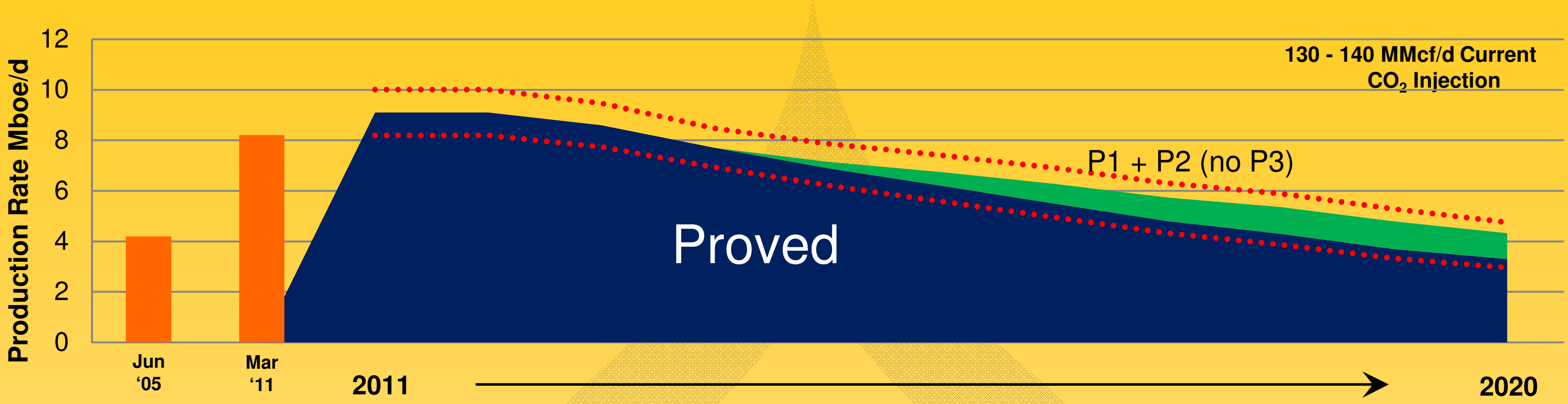
| | Whiting | Postle N. Ward Estes | Total Whiting | % Postle N. Ward Estes |
|---|---|---|---|---|
| 12/31/10 Proved Reserves | | | | |
| Oil – MMBbl | 130 | 124 | 254 | 49% |
| Gas – Bcf | 276 | 27 | 304 | 9% |
| Total – MMBOE | 177 | 128 [1] | 305 | 42% [1] |
| % Crude Oil | 74% | 96% | 83% | |
| 2010 Production | | | | |
| Total – MBOE/d | 47.5 | 17.1 | 64.6 | 26% |

[1] Includes Ancillary Properties



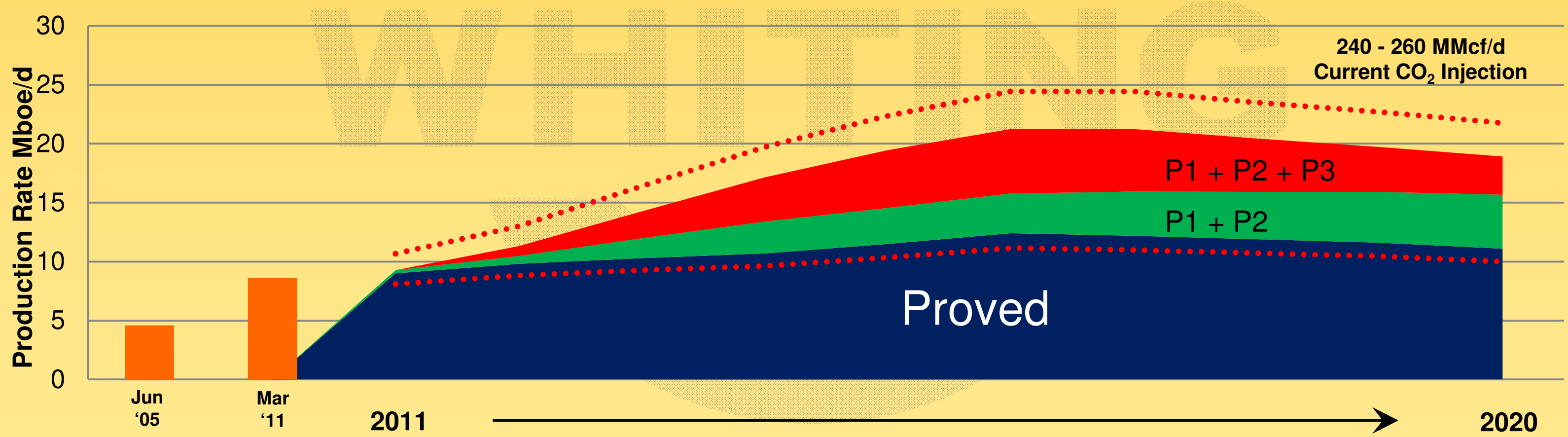
# EOR Projects Net Production Forecasts [1]

## Postle Field 3P Unrisked Net Production Forecast [2]




Magnitude and timing of results could vary.

## 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.

# Total Postle, N. Ward Estes and Ancillary Properties

WHITING

## Fully Developed Costs Per BOE

| | Net (MM$) | Reserves or Production (Net MMBOE) | Acq. and Dev. Cost ($/BOE) |
|---|---|---|---|
| Acquisition Purchase Price (effective 7/1/05) | $ 802 | | |
| Remaining Proved at 12/31/10 – Capex / Reserves | 800 [1] | 128.3 [1] [2] [3] | |
| Six Months 2005 – Capex / Production | 55 | 1.9 | |
| 2006 – Capex / Production | 243 | 4.4 | |
| 2007 – Capex / Production | 283 | 4.2 | |
| 2008 – Capex / Production | 326 | 4.6 | |
| 2009 – Capex / Production | 165 | 5.3 | |
| 2010 – Capex / Production | 213 | 6.3 | |
| 2006 – 2010 Divestments – Sales Price | (27) | -- | |
| 2009 Acquisitions – Purchase Price | 66 | -- | |
| Total Actual Plus Proved at 12/31/10 – Capex / Reserves | 2,926 [1] | 155.0 [1] [2] | $18.88 [1] |
| Probable and Possible at 12/31/10 – Capex / Reserves | 1,450 [1] [4] | 142.9 [1] [2] | |
| Total Actual Plus All Reserve Cats. – Capex / Reserves | $4,376 [1] | 297.9 [1] [2] | $14.69 [1] |

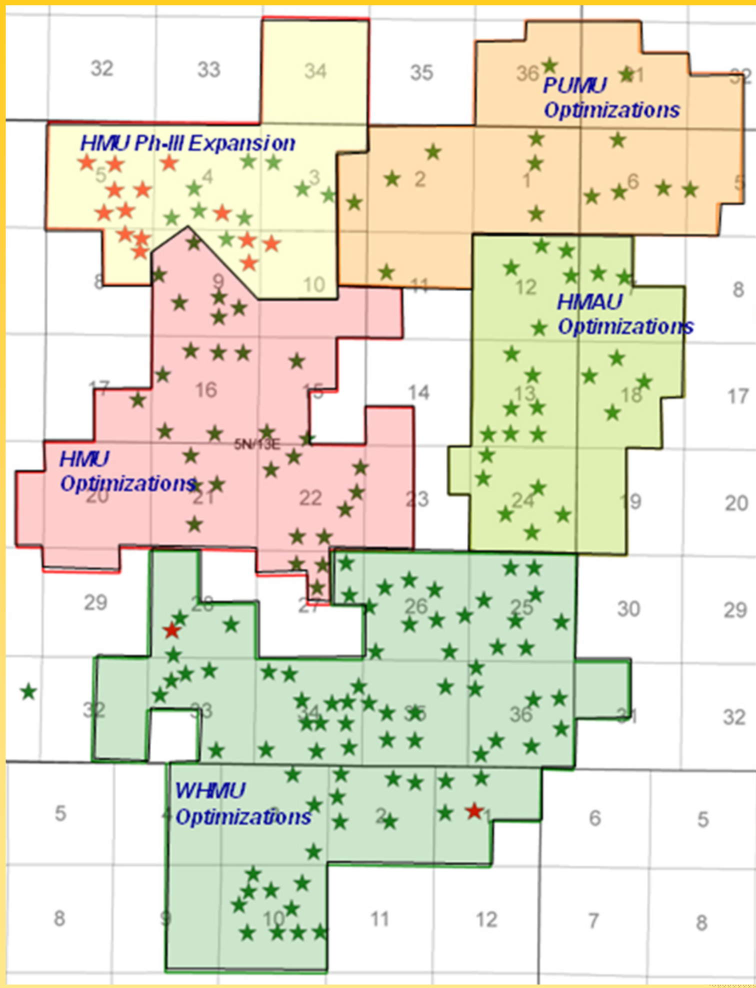
(1) Based on 12-month average prices of $79.43/Bbl and $4.38/Mcf in accordance with SEC requirements.

(2) 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.

(3) The estimated proved reserves at acquisition in June 2005 were 122.3 MMBOE.

(4) Includes $45 million for Ancillary Properties.

# Development Plans – Postle Field
## *Texas County, Oklahoma*



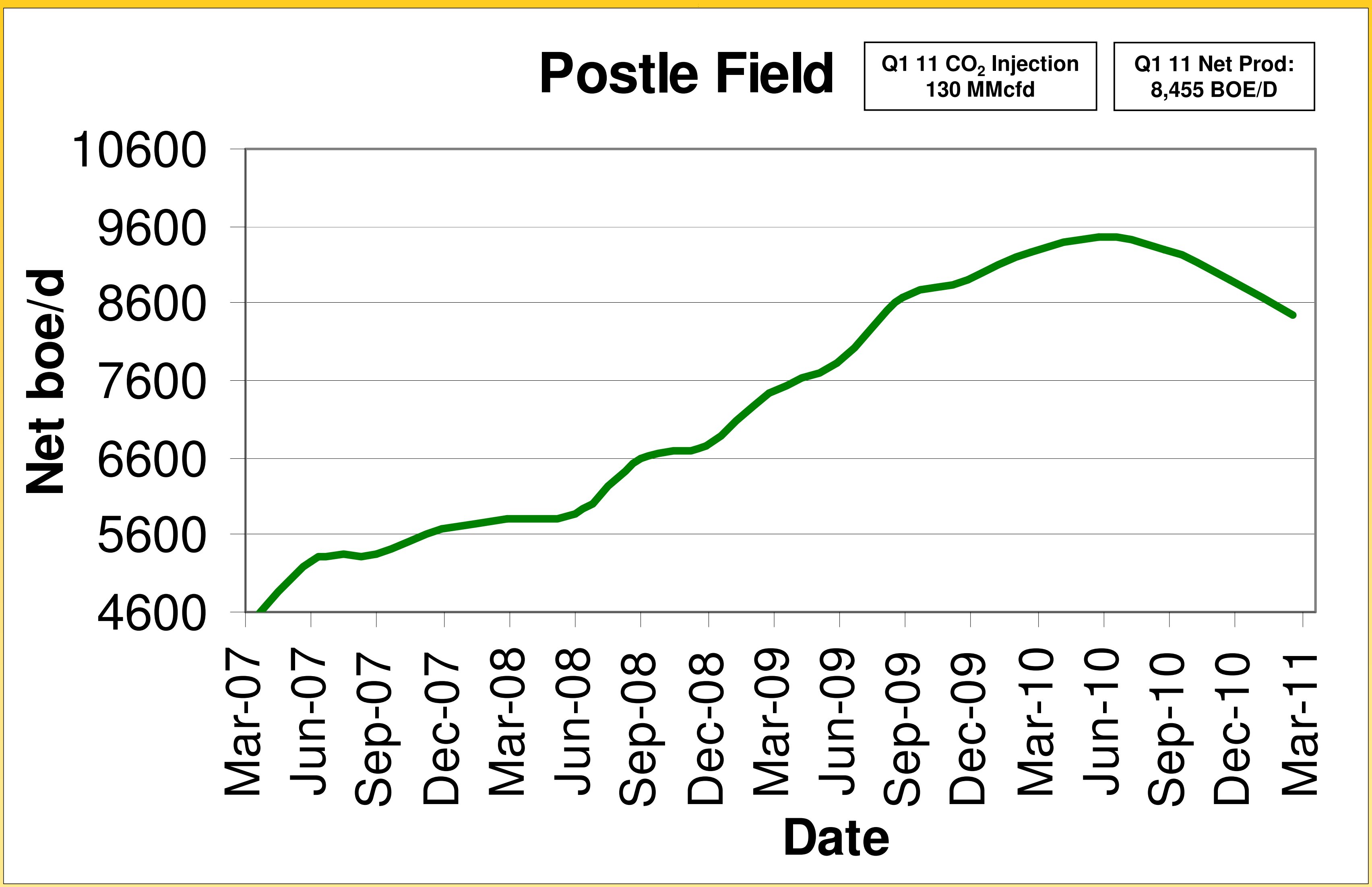

*Completed 157 Wells (2005 – 2010)*
*Remaining 16 Wells (2011 – 2012)*

**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 |

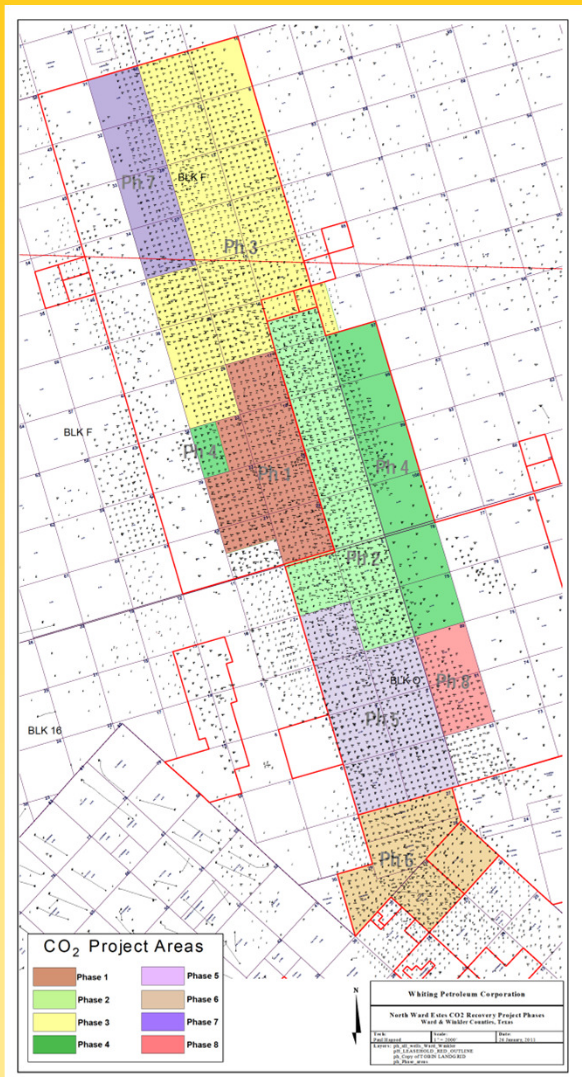
# Postle Quarterly Average Net BOE/D Production



# Development Plans – North Ward Estes Field

## *Ward and Winkler Counties, Texas*

WHITING




**58,000 Net Acres**

### Project Timing and Net Reserves [1]

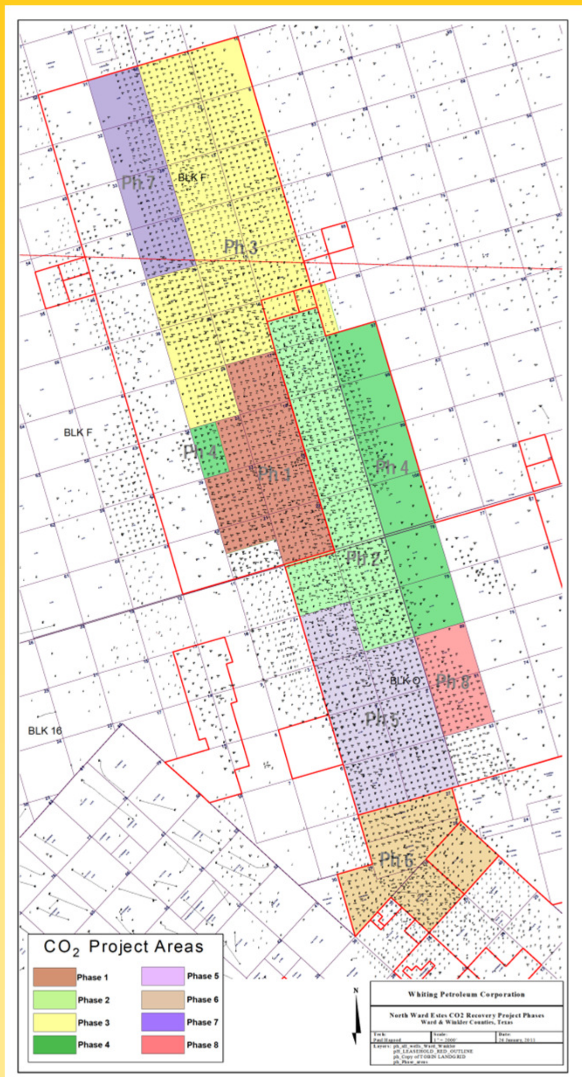
| $CO_2$ Project | Injection Start Date | PVPD | Other Proved | P2 | P3 | Total |
|---|---|---|---|---|---|---|
| Base: Primary, WF & $CO_2$ | | 33 | 12 | 1 | 64 | 110 |
| Phase 1 | 2007 - 2008 | 0 [2] | 3 | 4 | 2 | 9 |
| Phase 2 | 2009 - 2010 | 0 [2] | 6 | 4 | 4 | 14 |
| Phase 3 | 2010 - 2014 | 0 | 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*




**58,000 Net Acres**

| $CO_2$ 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 |

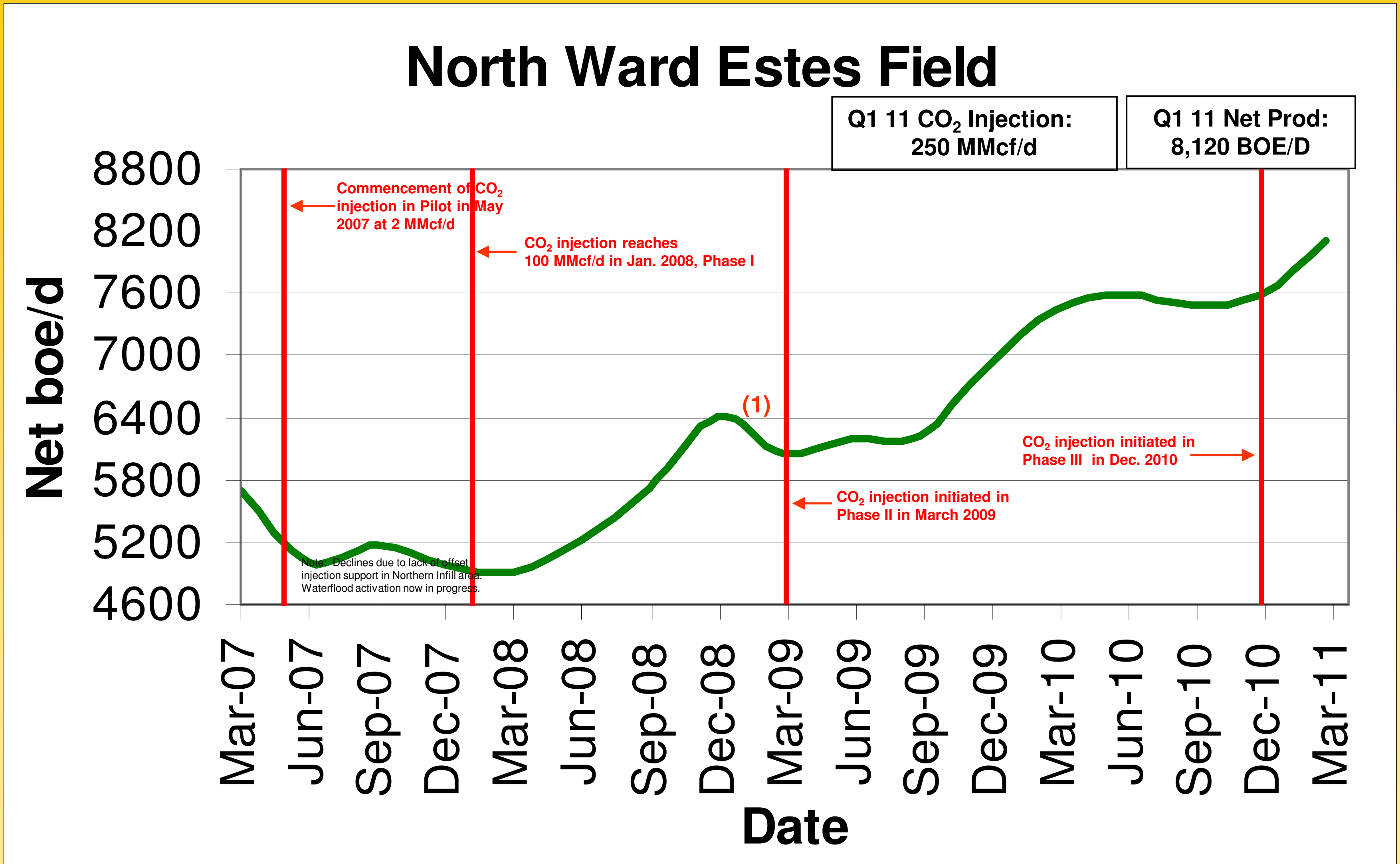
**Total 2011 - 2040 Remaining Capital Expenditures (1)**
(In Millions)

| | 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.

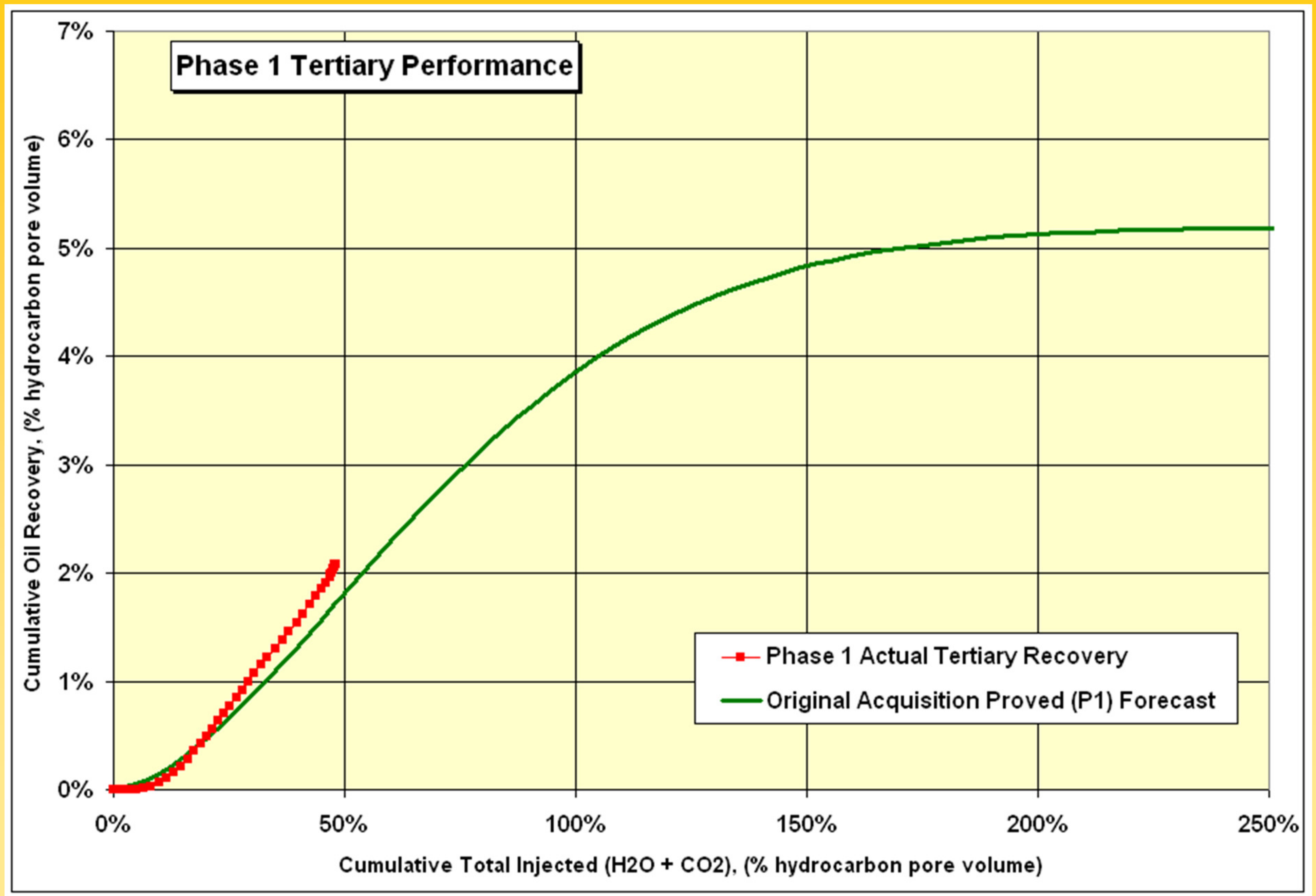
(2) Consists of CapEx for Proved, Probable and Possible reserves. Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information."

# 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.

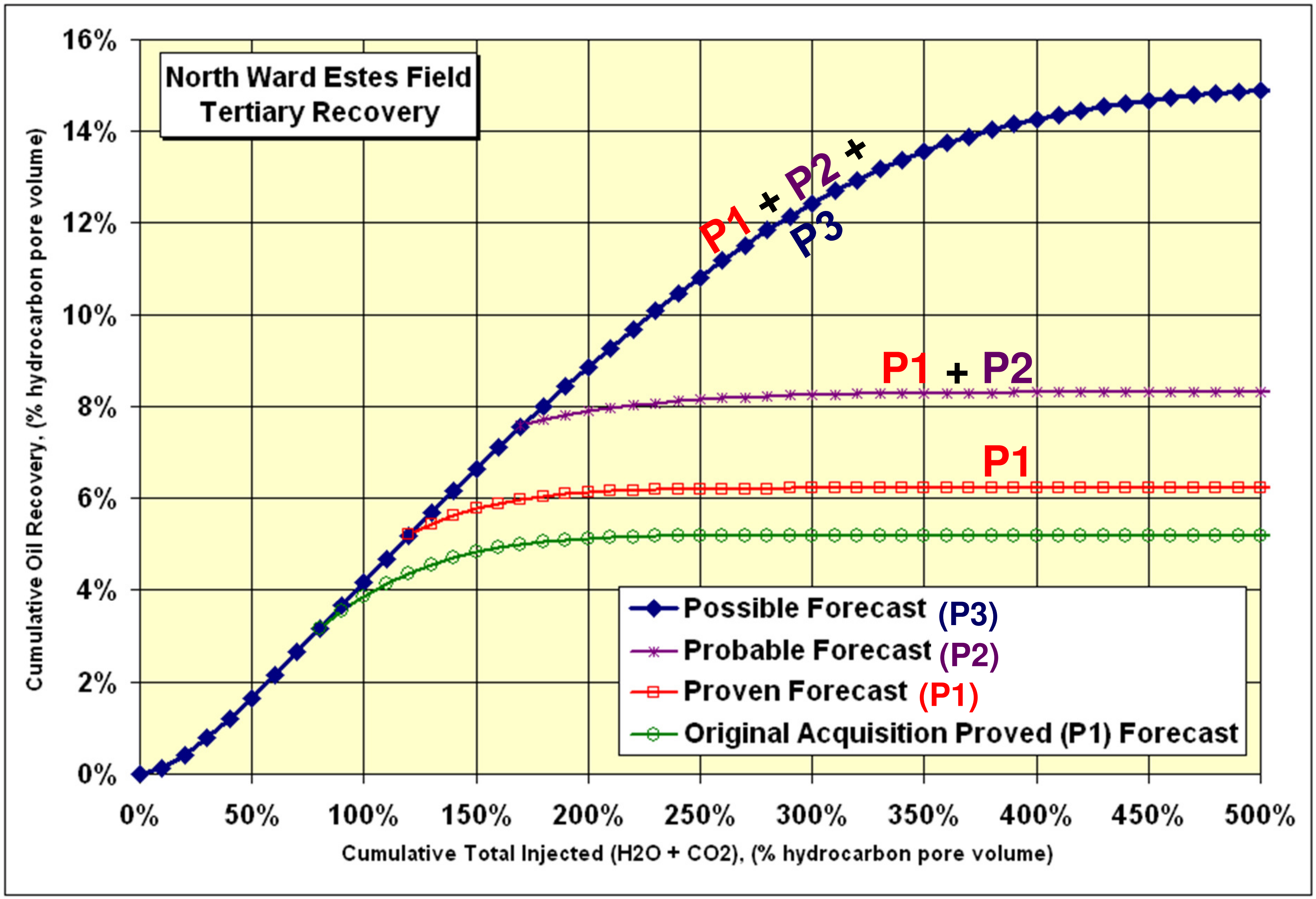
# Whiting Estimated Oil Recovery Type Curve from $CO_2$ Flood *North Ward Estes* *(1)*




(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)

WHITING

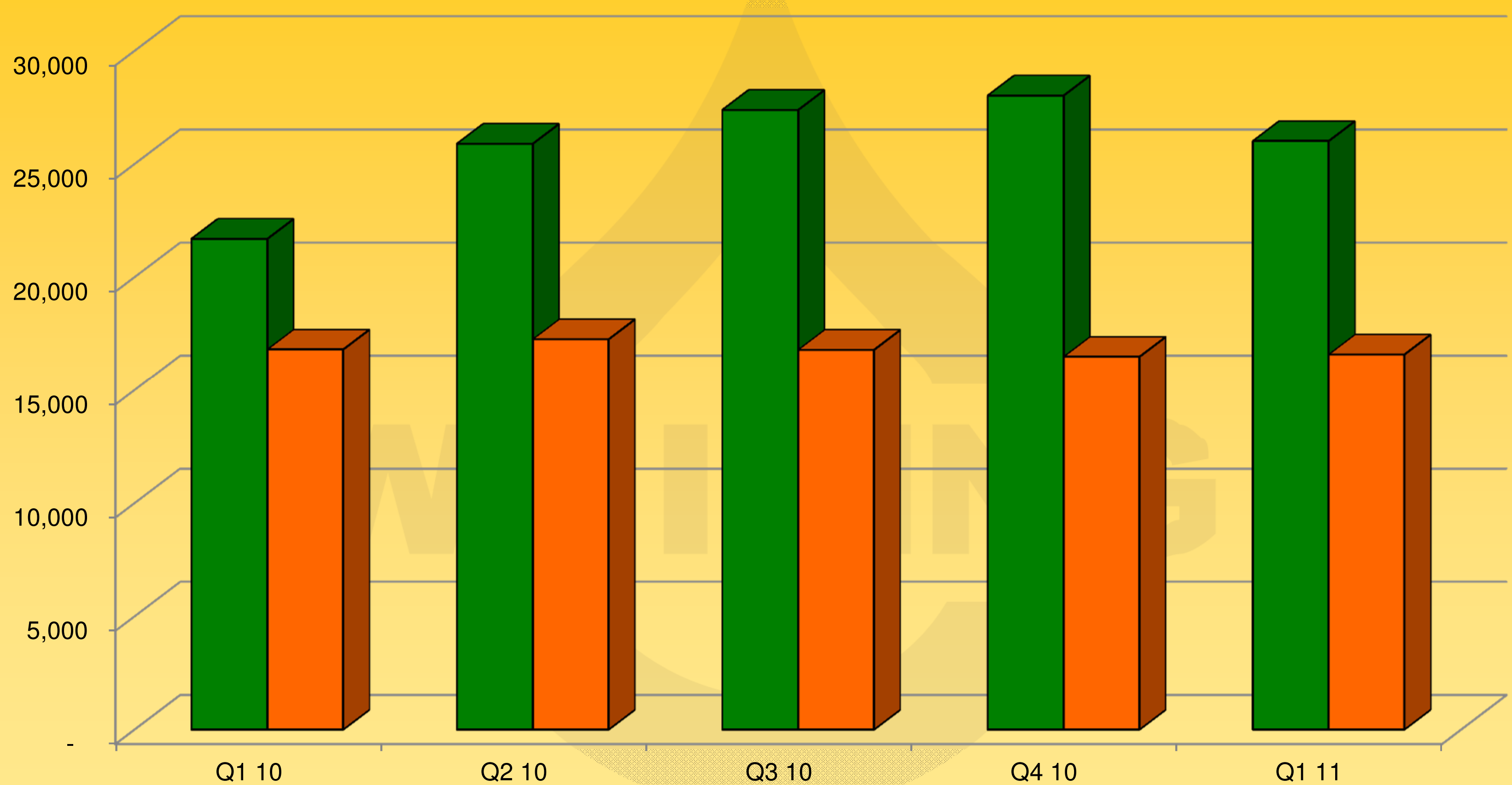



(1) Whiting currently estimates a 15% recovery factor in arriving at its total for proved, probable and possible reserve potential. The Company is conducting tests to ascertain if additional oil may be recoverable.

# Production Growth (in BOE/D)

WHITING

## 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)**

# 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% |

# 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

| | Existing Crude Oil Hedge Positions | | | Existing Natural Gas Hedge Positions | | |
|---|---|---|---|---|---|---|
| Hedge Period | Hedged Volumes (Bbls per Month) | Hedge Price Weighted Average Range ($/Bbl) | As a Percentage of Mar. 2011 Oil Production | Hedged Volumes (MMBtu per Month) | Weighted Average Hedge Price Range ($/MMBtu) | 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 300% from 17.0 MBOE/D at Nov. 2003 IPO to 67.9 MBOE/D in Q4 2010
- **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.

# 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 $1.9 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)**

# Adjusted Net Income (1)
## (In Thousands)

**Reconciliation of Net Income (Loss) Available to Common Shareholders to Adjusted Net Income (Loss) Available to Common Shareholders**

| | Three Months Ended Mar. 31, 2011 | Three Months Ended Mar. 31, 2010 |
|---|---|---|
| **Net Income (Loss) 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 (Loss) (1)…………………………………** | **$ 99,668** | **$ 62,341** |
| **Adjusted Earnings (Loss) Available to Common Shareholders per Share, Basic (2)……………………………...** | **$ 0.85** | **$ 0.61** |
| **Adjusted Earnings (Loss) Available to Common Shareholders per Share, Diluted (2)……………………………** | **$ 0.84** | **$ 0.57** |

(1) Adjusted Net Income (Loss) 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 (Loss) 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 | Three Months Ended Mar. 31, 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.

# Whiting Provides Answers to Recent Investor and Analyst Questions (1)(2)

WHITING

**Bakken and Three Forks Reservoir and Geology**

**Q1 – What is the estimated oil in place per 1,280-acre spacing unit for Sanish (Bakken)?**

**A1 – It varies across the field and is difficult to calculate in this complex reservoir. We estimate that there are approximately 16-23 MMBOE per 1,280-acre unit. We hold interests in 105 1,280-acre units and 21 640-acre units in the Sanish field.**

**Q2 – What is the ultimate recovery for Sanish (Bakken)?**

**A2 – We estimate the expected recovery to be between 8% and 12% of the original oil in place (OOIP). Note that we are drilling at least 3 wells on each 1,280-acre (2 sections) unit.**

**Q3 – What is the estimated oil in place per 1,280-acre spacing unit for Sanish (Three Forks)?**

**A3 – We have less geologic and reservoir data on the Three Forks since we are very early in the development. OOIP will vary across the field and is difficult to calculate in this complex reservoir. We estimate there to be 12 to 16 MMBOE per 1,280-acre spacing unit.**

**Q4 – What is the ultimate recovery for Sanish (Three Forks)?**

**A4 – We estimate the expected recovery to be between 7% and 10% of OOIP. Again, we plan to drill at least 3 wells per 1,280-acre (2 sections) unit.**

**Q5 – How does the geology compare across your project areas in terms of porosity, thickness, and pressure gradients? Sanish, Lewis & Clark, McKenzie/Williams Counties.**

**A5 – In each project area it varies to some extent as you can see on our slide titled "Middle Bakken Induced Fractures" where the Middle Bakken exists over Sanish but pinches out and is almost non-existent over at Parshall. Permeability varies both in the matrix and due to the intensity of natural fracturing. Comparing prospect area to prospect area, there are wide variations in the geology. For example, the Middle Bakken has pinched out and does not exist at Lewis & Clark.**

(1) The answers above include forward-looking statements that the Company believes to be forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Please refer to "Forward-Looking Statement Disclosure" on slide #1 of this presentation.

(2) Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information." All volumes shown are unrisked.

# (Continued) Whiting Provides Answers to Recent Investor and Analyst Questions [1]

**Bakken and Three Forks Reservoir and Geology (Continued)**

**Q6 – What led you to the Lewis & Clark extension?**

**A6 – Regional mapping; taking what we learned at Sanish and Parshall and applying that to other parts of the basin.**

**Q7 – How does the Three Forks play vary between the Sanish and Lewis & Clark areas?**

**A7 – They are geologically very similar. The Three Forks may be slightly tighter at Lewis & Clark.**

**Q8 – Is the Sanish Sand required to make a productive well in the extensional Lewis & Clark area?**

**A8 – No, we had very little Sanish Sand in the Federal 32-4H.**

**Q9 – Are there any specific catalysts that would encourage you to step up drilling activity in the Lewis & Clark area?**

**A9 – Based on our results to date, we are stepping up activity at Lewis & Clark. We plan to increase the number of drilling rigs there from 6 to 11 in 2011. Periodically during the year, several of these 11 rigs will be moved to our Bakken / Three Forks exploratory prospects, such as Hidden Bench, Cassandra, Big Island and Starbuck.**

**Q10 – Are the Scallion Limestone and Lodgepole formations valid resource targets?**

**A10 – Yes, in various parts of the basin.**

[1] The answers above include forward-looking statements that the Company believes to be forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Please refer to "Forward-Looking Statement Disclosure" on slide #1 of this presentation.

# (Continued) Whiting Provides Answers to Recent Investor and Analyst Questions [1]

**Bakken Well Design and Completion**

**Q11 – Why sliding sleeve versus perf and plug?**

**A11 – It is mechanically simpler, less moving parts. We can complete wells through the winter. On a sliding sleeve job, we can pump continuously and complete the fracture stimulation in about 24 hours.**

**Q12 – At Sanish, where should the horizontal well be landed within the Middle Bakken target zone to achieve the best production?**

**A12 – See slide titled "Bakken / Three Forks Hydrocarbon System." It is our opinion that it is in the "B" zone of the Middle Bakken.**

**Q13 – Does the azimuth of the lateral well matter in meeting stimulation and reservoir drainage objectives?**

**A13 – Yes, we believe you need to drill in a direction that is approximately perpendicular to the maximum principal stress. This is 55 degrees northeast. See our slide titled "Fully Developed Bakken and Three Forks Horizontal Wells in Sanish Field Area."**

**Q14 – Do the natural fractures impact fracture initiation?**

**A14 – Probably, we see slightly lower fracturing pressure on the east side of Sanish field where we know the natural fracturing intensity is higher.**

**Q15 – How might your completions vary by area and what are the geologic factors that drive your approach?**

**A15 – If the rock is tighter and contains fewer natural fractures, we will pump more stages.**

**Q16 – Why white sand vs. ceramics in the Sanish field?**

**A16 – Our engineering evaluation indicates that we do not need ceramics to maintain open fractures in Sanish.**

**Q17 – A few industry studies suggest that using ceramic proppants can increase EUR. Have you tested this and what are your thoughts on this matter?**

**A17 – Ceramic proppant is about 5 times the cost of sand and it comes down to a cost/benefit evaluation. Our evaluations indicate that sand is providing very good results, but we continue to evaluate the available data.**

[1] The answers above include forward-looking statements that the Company believes to be forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Please refer to "Forward-Looking Statement Disclosure" on slide #1 of this presentation.

# (Continued) Whiting Provides Answers to Recent Investor and Analyst Questions [1][2]

WHITING

**Bakken and Other Development Planning and Well Costs**

**Q18 – How many un-drilled locations at year-end 2010 were included in your reserve report for each of the following areas: Sanish (Bakken); Sanish (Three Forks); and Lewis & Clark (Three Forks)?**

**A18 – Sanish (Bakken): 82 locations in PUD, 9 locations in Probable, 34 locations in Possible for a total 3P of 125 locations; Sanish (Three Forks): 21 PUD, 0 well locations in Probable, 168 locations in Possible for a total 3P of 189 locations; Lewis & Clark (Three Forks): 23 PUD, 35 well locations in Probable, 25 locations in Possible for a total 3P of 83.**

**Q19 – Can you provide some detail on the 3P and Resource drilling inventory as of December 31, 2010?**

**A19 –**

**ESTIMATED TOTAL 3P LOCATIONS**

| Area | Gross | Net |
|---|---|---|
| Sanish Field Area | 314 | 174 |
| Parshall Field Area | 98 | 21 |
| Lewis & Clark | 83 | 41 |
| Other Northern Rockies | 35 | 21 |
| Sulphur Creek Field | 254 | 174 |
| Other Central Rockies | 124 | 83 |
| Mid-Continent | 189 | 165 |
| Gulf Coast | 125 | 75 |
| Permian | 1,039 | 384 |
| Total | 2,261 | 1,138 |

**ESTIMATED TOTAL RESOURCE LOCATIONS**

| Area | Gross | Net |
|---|---|---|
| Williston Basin | 94 | 44 |
| Sanish Field Area | 57 | 28 |
| Lewis & Clark | 582 | 190 |
| Hidden Bench Prospect | 79 | 15 |
| Starbuck Prospect | 132 | 69 |
| Cassandra Prospect | 41 | 9 |
| Big Island Prospect | 158 | 83 |
| Big Tex Prospect | 295 | 245 |
| Redtail Niobrara Prospect | 351 | 213 |
| Sulphur Creek | 277 | 148 |
| Other Areas | 369 | 270 |
| Total | 2,435 | 1,314 |

(1) The answers above include forward-looking statements that the Company believes to be forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Please refer to “Forward-Looking Statement Disclosure” on slide #1 of this presentation.

(2) Please refer to Slide #2 for disclosures regarding “Reserve and Resource Information.”

# (Continued) Whiting Provides Answers to Recent Investor and Analyst Questions [1]

WHITING

<u>Bakken Development Planning and Well Costs (Continued)</u>

**Q20 – What type of pressures are you experiencing on drilling and completion costs?**

**A20 – As the rig count continues to increase in North Dakota, we have implemented longer term service agreements to manage the rising cost. Our frac costs have continued to rise on a relative basis as we increase the size of our frac designs to include more frac stages. The majority of the drilling rigs we have in North Dakota are on 12-month contracts and, in some cases, we have tied the day rate to NYMEX oil prices. These factors have helped keep the drilling economics in line with our expectations, although drilling day rates and services are starting to rise with increased demand.**

**Q21 – What are your current spud to total depth and spud to spud times? How much more efficiency is possible?**

**A21 – Across our program, for winter/spring 2010-11, spud to TD was averaging 22.2 days. Spud to spud average was 40.5 days. We have drilled four wells spud to TD in 15 days or less. For these wells, spud to rig release was about 25 days. At Sanish, for 70 wells spud from January 1 through December 31, 2010, our average spud to TD was 21.1 days. Our spud to spud is averaging 40.4 days. We think there are still efficiencies to be gained and that we can eliminate another 2 to 3 days out of the process.**

**Q22 – How long does it take to complete a well and what types of efficiencies are possible with multi-pad drilling?**

**A22 – We have our wells completed within about three weeks of rig release with slightly longer times during severe winter conditions. We build the battery during that time period. Consequently, once the well is frac'd we can go down the sales line with the production. As we continue to investigate drilling and completion methods to minimize surface impact, multi-well pad drilling continues to be an option. While you can save on rig moves and location cost with multi-well pads, you delay production from the first well drilled until you finish drilling all of the wells on the pad. Pad drilling also results in mechanical issues due to more complicated well designs.**

[1] **The answers above include forward-looking statements that the Company believes to be forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Please refer to "Forward-Looking Statement Disclosure" on slide #1 of this presentation.**

# (Continued) Whiting Provides Answers to Recent Investor and Analyst Questions [1]

**Bakken Development Planning and Well Costs (Continued)**

**Q23 – At present, Whiting is planning 3 Middle Bakken wells per 1,280-acre spacing unit. Are you planning to conduct any further testing beyond that to examine drainage patterns?**

**A23 – Yes, we have an active reservoir surveillance program going on in the field. We collect pressure data, monitor production and monitor offset wells when we perform fracture stimulations. We have also installed a permanent micro seismic array in the field to monitor and map every frac we perform across the entire field.**

**Q24 – With your expertise in EOR, is the Middle Bakken prospective for $CO_2$ flooding and when might you consider testing that, if so?**

**A24 – We have evaluated this option. The initial issue is $CO_2$. There is not a source with sufficient capacity in the Williston Basin. However, man made $CO_2$ projects are being designed and may be available in 2-4 years. Natural fractures may make the $CO_2$ move through the reservoir so fast that it makes a $CO_2$ project risky. In summary, it is unlikely.**

**Q25 – What type of primary/secondary recovery could be expected?**

**A25 – Primary recovery 8% - 12%, secondary recovery currently questionable.**

(1) The answers above include forward-looking statements that the Company believes to be forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Please refer to "Forward-Looking Statement Disclosure" on slide #1 of this presentation.

# (Continued) Whiting Provides Answers to Recent Investor and Analyst Questions [(1)]

WHITING

**<u>Bakken Well Productivity</u>**

**Q26 – Could you review how you measure 24-hour and 30-day IP rates?**

**A26 – After the frac job, we let the well sit for approximately 3 days to allow the gel to break down and the sand to keep the fractures open. We bring the well back at a fairly aggressive rate to ensure we get the balls off seat and get the entire horizontal lateral producing. After about 48 hours of flow back, we initiate the IP test and put the well on a 40/64ths choke and monitor the production for a 24-hour period. Production is measured by strapping the production tanks that are on location. We measure and internally report our production for every well we operate on a daily basis (company wide). The 30-day rate is just that, what the well averages over the first 30 days of production, excluding downtime.**

**Q27 – How strong of an indicator is the 30-day rate on EUR?**

**A27 – The 30-day average rate is an early indicator but additional production history is much more important. Average producing rates over 60 and 90 days and especially over the first six months are much more indicative.**

**Q28 – What are the important milestones when attempting to measure a well's potential deliverability (30-day rates, well performance when on pump)?**

**A28 – All of the above are indicators but 60 day, 90 day and six months average rates are perhaps better for early on scoping as these data start to define the hyperbolic curve the well may follow. Tubing pressure is also a good indicator as well as cumulative production at the time the well goes on pump.**

[(1)] **The answers above include forward-looking statements that the Company believes to be forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Please refer to "Forward-Looking Statement Disclosure" on slide #1 of this presentation.**

# (Continued) Whiting Provides Answers to Recent Investor and Analyst Questions (1)(2)

**Portfolio/EOR**

**Q29 – In the 2010 year-end reserve report, what assumptions were made for North Ward Estes recovery (Proved, 2P and 3P) and for Postle (Proved, 2P and 3P)?**

**A29 –** Estimated remaining reserves at North Ward Estes are based on section by section geologic and reservoir engineering analysis and vary throughout the field depending on reservoir quality and our development plans. In general, the resulting EUR's indicate tertiary recoveries of 5-6% in the Proved category, up to 7-8% in the Probable category and up to 15% in the Possible category. Our estimated remaining reserves at Postle are also based on detailed geologic and engineering analysis on an injection pattern level and vary throughout the field. In general, the resulting EUR's indicate tertiary recoveries of 12-16% or more, all in the proved category due to the mature state of development for most of the Postle field.

**Q30 – In terms of portfolio management, what are the key drivers behind your capital allocation process? The returns in the Bakken are different than EOR, but EOR is a bit more resilient through the cycles.**

**A30 –** You are correct. Generally, drilling provides higher IRR's and EOR projects have a greater assurance of reserve additions. We are fortunate to have a mixture of both in Whiting's inventory of projects. Drilling projects begin to decline after drilling activity peaks. EOR projects begin to incline about a year after project installation and commencement of $H_2O$ and $CO_2$ injection. After production peaks on an EOR project production can plateau and remain relatively flat for several years before beginning to decline. This is caused by the pressure maintenance of the $H_2O$ and $CO_2$. This plateau production may provide cash flow for many years to fund additional exploration and development drilling projects for the company.

**Q31 – What is your capital for all non-Bakken and non-EOR projects?**

**A31 –** See our slide titled "2011 Exploration and Development Budget." The projects on that list not related to our Bakken, Three Forks and EOR projects total $329MM. Please note that this total includes an estimated $110MM in Land costs and $40MM in Exploration expense.

(1) The answers above include forward-looking statements that the Company believes to be forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Please refer to "Forward-Looking Statement Disclosure" on slide #1 of this presentation.

(2) Please refer to Slide #2 for disclosures regarding "Reserve and Resource Information." All volumes shown are unrisked.