



JOHNSON RICE ENERGY CONFERENCE

NO OIL LEFT BEHIND[®]
OCTOBER 5, 2011

Forward Looking Statements / Additional Information & Cautionary Note Regarding Hydrocarbon Disclosure

Except for the historical information contained herein, the matters discussed in this presentation are forward-looking statements that are based upon current expectations. Important factors that could cause actual results to differ materially from those in the forward-looking statements include risks inherent in exploratory drilling activities, the timing and extent of changes in commodity prices, unforeseen engineering and mechanical or technological difficulties in drilling wells, availability of drilling rigs and other services, land issues, federal and state regulatory developments and other risks more fully described in the Company's filings with the U.S. Securities and Exchange Commission (SEC).

The SEC requires oil and gas companies, in their filings with the SEC, to disclose proved reserves which are those quantities of oil and gas, 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, and under existing economic conditions (using unweighted average 12-month first day of the month prices), 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, regardless of whether deterministic or probabilistic methods are used for the estimation. We currently do not disclose probable or possible reserves in our filings with the SEC.

In this presentation, the term EUR, or estimated ultimate recovery, refers to the Company's internal estimates of hydrocarbon volumes that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques. These estimates do not necessarily represent reserves as defined under SEC rules or the Society of Petroleum Engineer's Petroleum Resource Management System and by their nature and accordingly are more speculative and substantially less certain of recovery and no discount or other adjustment is included in the presentation of such estimates. Drilling locations included in this presentation are Company estimates based upon its current acreage position, which have not necessarily been assigned reserves and may not ultimately be drilled.

EUR estimates and drilling locations have not been risked by Company management. Actual locations drilled and quantities that may be ultimately recovered from the Company's interests could differ substantially. Factors affecting ultimate recovery include the scope of our ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, commodity prices, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals and other factors; and actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of EUR and other recoverable hydrocarbon potential may change significantly as development of the Company's resource plays and prospects provide additional data.

Unless otherwise indicated, other estimates of hydrocarbon volumes contained herein have been prepared internally by the Company without review by independent petroleum engineers. Investors are urged to consider closely the reserves disclosures in our Annual Report on Form 10-K for the year ended December 31, 2010.

"De-risked" core development acreage and related well locations in the Williston Basin refers to acreage and locations that the Company believes the relative geological risks with recovery has been reduced as a result of drilling operations to date. However, only a small portion of such acreage and locations has been attributed proved undeveloped reserves and ultimate recovery from such acreage and locations remains subject to all the recovery risks applicable to other acreage.

Pre-tax PV10% Value is the estimated present value of the future net revenues from the Company's proved oil and natural gas reserves before income taxes, discounted using a 10% discount rate. Pre-tax PV10% Value is considered a non-GAAP financial measure under SEC regulations because it does not include the effects of future income taxes, as is required in computing the standardized measure of discounted future net cash flows. The Company believes that pre-tax PV10% Value is an important measure that can be used to evaluate the relative significance of its oil and natural gas properties and that pre-tax PV10% Value is widely used by security analysts and investors when evaluating oil and natural gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes to be paid, the use of a pre-tax measure provides greater comparability of assets when evaluating companies. The Company believes that most other companies in the oil and natural gas industry calculate pre-tax PV10% Value on the same basis. Pre-tax PV10% Value is computed on the same basis as the standardized measure of discounted future net cash flows, but without deducting income taxes.

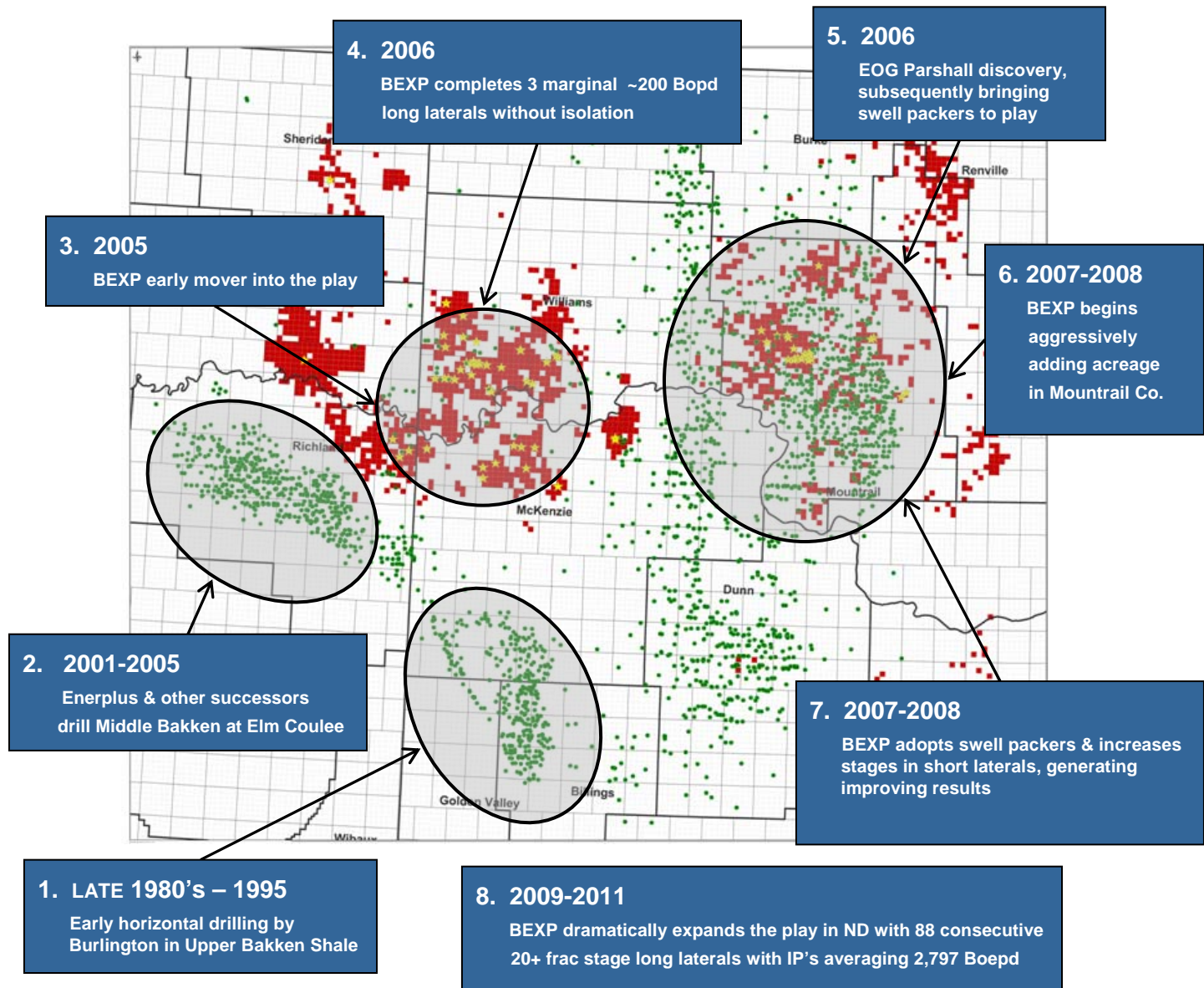
- **De-risked inventory - Williston Basin drilling program de-risked ~235,200* net core acres**
 - 88 ND Bakken / Three Forks long lateral, high frac stage wells completed at average peak rate of 2,797 Boe/d
 - 794 net development locations remaining in current core acreage
 - Opportunity to grow to 1,299 net development locations based on Rough Rider Three Forks potential
- **Outstanding returns - advanced drilling and completion techniques driving industry leading returns**
 - ~\$8.9 million CWC and 600 Mboe EUR generates estimated NPV per well of ~\$8.7 million**
 - ~51% IRR**; undiscounted payback period of ~1.9 years**
- **Drilling acceleration - growing to 12 rigs by Q1 2012; ~132 gross well annual run rate**
 - Accelerates incremental wells in 2011 and 2012 at an estimated \$8.7 million** NPV per well
 - Acceleration drives estimated 100% growth in oil volumes in 2011
 - Converts majority of core acreage to HBP status over ~ 3 years
- **Significant oil driven reserve growth - Williston Basin drilling drives 141% reserve growth in 2010**
 - Proved reserves total 66.8 million Boe, 78% oil, 35% proved developed, 55.5 million Boe Williston Basin reserves
 - Highly attractive \$9.23 per Boe drilling and leasehold acquisition finding and development costs
- **Strong liquidity position - funding in place for 2011 and 2012 cap-ex budgets**
 - \$687 million of liquidity at June 30, 2011 – \$362 million of cash and short term investments and untapped credit facility with \$325 million borrowing base
 - Non-core divestitures planned to fund further acceleration
- **Additional catalysts - substantial incremental NAV creation to be assessed over the next 12 months**
 - BEXP and other operators completed 5 successful Rough Rider Three Forks well at avg. IP of 2,053 Boe/d, further delineating attractive Rough Rider Three Forks drilling economics; two additional BEXP wells completing
 - BEXP has completed 7 Montana wells with avg. IP of 1,576 Boe/d; 4 additional wells planned for 2011
 - Smart pad drilling & completions already driving efficiency improvements that should increasingly enhance well NAVs
 - Increased Williston Basin core net acreage by 10,800 net acres; additional drilling success could further grow core acreage
 - Assessing other unconventional and conventional Williston Basin objectives

* Net acreage amounts as of August 4, 2011.

** AFE based on current costs of \$8.9M and BEXP internal mid-range EUR estimate of 600 Mboe per well. 8/4/11 NYMEX Strip. Price differentials: -\$8.00/Bbl & 1.4 Gas Price F actor, \$15,100/mo OPEX.

Williston Basin Historical Activity Map

Premier Early Mover Position and Best-in-Class Operator



88 North Dakota Bakken and Three Forks Wells Average IP ~ 2,797 Boepd

Most Recent



North Dakota					Avg 1st 7 Days	Avg 1st 30 Days	Avg 1st 60 Days
Well	Area	Objective	Frac Stages	IP (Boe/d)	(Boe/d)**	(Boe/d)**	(Boe/d)**
Enderud 9-4 #2H	Rough Rider	Bakken	42	4,289	3,186	NA	NA
Art 6-7 #1H	Rough Rider	Bakken	35	2,391	1,615	NA	NA
Judy 22-15 #1H	Rough Rider	Bakken	38	3,295	1,977	NA	NA
Irgens 27-34 #2H	Rough Rider	Three Forks	32	2,906	1,416	NA	NA
Irgens 27-34 #1H	Rough Rider	Bakken	32	2,133	1,162	NA	NA
Holm 9-4 #2H	Ross	Three Forks	32	2,196	1,106	729	NA
Holm 9-4 #1H	Ross	Bakken	32	3,032	1,742	1,083	NA
Alger State 16-21 #1H	Ross	Bakken	34	3,089	2,014	1,354	NA
Donald 1-12 #1H	Rough Rider	Bakken	39	1,376	1,114	629	NA
Lucy Hanson 15-22 #1H	Rough Rider	Bakken	36	4,358	2,272	1,227	934
Raymond 17-20 #1H	Rough Rider	Bakken	39	2,602	1,844	951	674
Larsen 3-10 #2H	Rough Rider	Bakken	31	3,212	1,624	1,029	807
Hovde 33-4 #1H	Rough Rider	Bakken	31	2,349	1,434	874	NA
Pladson 4-9 #1H	Ross	Three Forks	38	1,104	682	543	NA
Stanley Larson 8-5 #1H	Rough Rider	Bakken	37	1,020	679	423	311
Gunderson 15-22 #1H	Rough Rider	Bakken	38	3,905	2,739	1,638	1,220
SCHA 33-34 #1H	Ross	Bakken	30	2,974	1,614	983	NA
Russell 10-3 #1H	Rough Rider	Bakken	38	2,993	1,621	915	688
lrw in 15-22 #1H	Rough Rider	Bakken	32	2,073	1,265	856	668
DeLorme 12-1 #1H	Rough Rider	Bakken	37	2,074	1,131	735	580
Field Trust 7-6 #1H	Rough Rider	Bakken	38	2,245	1,328	825	631
L. Tufto 7-6 #1H	Rough Rider	Bakken	37	3,215	1,719	985	800
A. Tufto 18-19 #1H	Rough Rider	Bakken	33	2,871	1,926	1,027	861
O'Neill 17-20 #1H	Rough Rider	Bakken	33	3,349	1,611	996	789
Dave Arnson 8-5 #1H	Rough Rider	Bakken	32	2,464	1,700	976	788
MacMaster 11-2 #1H	Rough Rider	Bakken	34	1,129	745	500	380
Kalil Farms 14-23 #1H	Rough Rider	Bakken	33	1,603	1,013	608	501
Vachal 3-34 #1H	Ross	Bakken	38	3,800	1,948	1,304	1,029
Greenstein 30-31 #1H	Rough Rider	Bakken	31	3,232	2,033	1,099	808
Erickson 8-17 #3H	Rough Rider	Bakken	32	3,091	1,707	974	724
Brad Olson 9-16 #3H	Rough Rider	Bakken	32	2,375	1,558	839	666
Esther Hynek 10-11 #1H	Ross	Bakken	31	1,904	1,309	828	670
Sorenson 29-32 #2H	Ross	Bakken	38	5,330	3,181	1,815	1,371
Cvancara 20-17 #1H	Ross	Bakken	36	4,402	2,630	1,577	1,229
Afseth 34-3 #1H	Ross	Bakken	38	1,267	1,026	618	510
Brown 30-19 #1H	Ross	Bakken	37	3,309	1,360	1,324	1,045
Hospital 31-36 #1H	Ross	Bakken	33	1,449	1,140	785	595
Gibbins 1-12 #1H	Rough Rider	Bakken	33	2,582	1,852	1,101	831
Knoshaug 14-11 #1H	Rough Rider	Bakken	36	4,443	2,460	1,390	1,051
Lloyd 34-3 #1H	Rough Rider	Bakken	31	4,030	2,489	1,456	1,094

Earliest

*Updated from previous release ** Excludes any days well was down for work. *** Some gas data points calculated using average GOR due to unavailable data.

88 North Dakota Bakken and Three Forks Wells Average IP ~ 2,797 Boepd

Most Recent	Well	Area	Objective	Frac Stages	IP (Boe/d)	Avg 1st 7 Days	Avg 1st 30 Days	Avg 1st 60 Days
						(Boe/d)**	(Boe/d)**	(Boe/d)**
	Bratcher 10-3 #1H	Rough Rider	Bakken	30	3,667	2,040	1,129	880
	M. Macklin 15-22 #1H	Rough Rider	Bakken	38	2,534	1,529	1,062	848
	M. Olson 20-29 #1H	Rough Rider	Bakken	38	2,080	1,481	1,007	802
	Heen 26-35 #1H	Rough Rider	Bakken	38	3,791	1,966	1,379	1,073
	Arvid Anderson 14-11 #1H	Ross	Bakken	38	3,191	1,839	1,330	1,015
	Lippert 1-12 #1H	Rough Rider	Bakken	31	2,214	1,512	942	729
	Roger Sorenson 8-5 #1H	Ross	Bakken	38	2,658	1,778	1,120	864
	Brakken 30-31 #1H	Rough Rider	Bakken	30	3,573	2,241	1,277	955
	Brad Olson 9-16 #2H	Rough Rider	Bakken	32	2,717	1,387	773	560
	Smith Farm 23-14 #1H	Rough Rider	Bakken	32	2,417	1,630	1,041	824
	Abelmann 23-14 #1H	Rough Rider	Bakken	33	4,169	2,333	1,407	1,155
	Clifford Bakke 26-35 #1H	Ross	Bakken	38	5,061	3,657	2,328	1,796
	State 36-1#2H	Rough Rider	Three Forks	31	2,356	1,438	874	696
	Domaskin 30-31#1H	Ross	Bakken	38	4,675	3,092	1,882	1,482
	Larsen 3-10 #1H	Rough Rider	Bakken	31	3,090	1,754	1,034	815
	Boots 13-24 #1H	Rough Rider	Bakken	31	1,946	1,194	662	517
	Abe Ow an 21-16 #1H	Rough Rider	Bakken	37	2,213	1,369	900	640
	Weisz 11-14 #1H	Rough Rider	Bakken	37	2,278	1,652	1,014	763
	Wright 4-33 #1H	Ross	Bakken	38	3,660	2,124	1,322	1,013
	Sukut 28-33 #1H	Rough Rider	Bakken	32	1,959	1,330	801	672
	Michael Ow an 26-35 #1H	Rough Rider	Bakken	33	2,931	1,605	889	651
	Sedlacek Trust 33-4 #1H	Rough Rider	Bakken	30	2,695	1,446	826	612
	Abe 30-31 #1H	Rough Rider	Bakken	31	1,847	1,139	731	569
	Ow an 29-32 #1H	Rough Rider	Bakken	31	2,302	1,510	868	631
	Ross-Alger 6-7 #1H	Ross	Bakken	32	3,070	2,074	1,465	1,170
	Jack Cvancara 19-18 #1H	Ross	Bakken	36	5,035	2,972	1,800	1,368
	Tjelde 29-32 #1H	Rough Rider	Bakken	30	3,171	1,710	931	714
	Mortenson 5-32 #1H	Rough Rider	Bakken	23	2,314	1,129	584	416
	Abelmann St. 21-16 #1H	Rough Rider	Bakken	31	3,301	1,935	1,044	822
	Arnson 13-24 #1H	Rough Rider	Bakken	30	1,339	776	480	385
	Sorenson 29-32 #1H	Ross	Bakken	27	5,133	3,141	1,909	1,425
	Jack Erickson 6-31 #1H	Rough Rider	Bakken	30	2,652	1,482	833	658
	Jerome Anderson 15-10 #1H	Ross	Bakken	30	3,115	1,938	1,146	853
	Papineau Trust 17-20 #1H	Rough Rider	Bakken	29	3,042	1,743	971	774
	Kalil 25-36 #1H	Rough Rider	Bakken	30	1,586	1,056	650	475
	Liffrig 29-20 #1H	Ross	Three Forks	29	2,477	1,659	1,082	798
	Jackson 35-34 #1H	Rough Rider	Bakken	30	3,540	1,616	907	700
	Ow an-Nehring 27-34 #1H	Rough Rider	Bakken	30	2,513	1,737	1,089	843
	State 36-1 #1H	Rough Rider	Bakken	30	3,807	2,497	1,516	1,135

Earliest

*Updated from previous release ** Excludes any days well was down for work. *** Some gas data points calculated using average GOR due to unavailable data.

7 Montana Bakken Wells Average IP ~ 1,576 Boepd

Most Recent

North Dakota (cont.)

Well	Area	Objective	Frac Stages	IP (Boe/d)	Avg 1st 7 Days (Boe/d)*	Avg 1st 30 Days (Boe/d)*	Avg 1st 60 Days (Boe/d)*	
Williston 25-36 #1H	Rough Rider	Bakken	32	3,394	2,342	1,505	1,128	
Strand 16-9 #1H	Rough Rider	Bakken	26	2,264	1,578	948	694	
Lee 16-21 #1H	Rough Rider	Bakken	28	1,544	1,183	698	594	
BCD Farms 16-21 #1H	Rough Rider	Bakken	28	1,776	1,176	702	530	
Brad Olson 9-16 #1H	Rough Rider	Bakken	28	2,112	1,447	811	641	
Anderson 28-33 #1H	Ross	Bakken	24	2,154	1,811	1,346	1,059	
Strobeck 27-34 #1H	Ross	Three Forks	18	2,021	1,410	989	740	
Figaro 29-32 #1H	Rough Rider	Bakken	19	1,895	1,240	831	636	
Olson 10-15 #1H	Rough Rider	Bakken	20	1,433	1,132	730	600	
				ND Average	2,797	1,714	1,043	815

Montana

Well	Area	Objective	Frac Stages	IP (Boe/d)	Avg 1st 7 Days (Boe/d)*	Avg 1st 30 Days (Boe/d)*	Avg 1st 60 Days (Boe/d)*	
Storvik 7-6 #1H	Montana	Bakken	34	2,066	1,244	645	507	
Charley 10-15 #1H	Montana	Bakken	30	1,069	579	534	NA	
Gobbs 17-8 #1H	Montana	Bakken	36	1,818	957	633	495	
Voss 21-11H	Montana	Bakken	28	1,143	584	325	217	
Johnson 30-19 #1H	Montana	Bakken	36	2,962	1,512	803	639	
Swindle 16-9 #1H	Montana	Bakken	20	1,065	620	400	312	
Rogney 17-8 #1H	Montana	Bakken	30	909	478	355	285	
				MT Average	1,576	853	528	409



Earliest

* Excludes any days well was down for work. ** Some gas data points calculated using average GOR due to unavailable data.

Key Points

- Premier innovator and operator in basin, as reflected by results over last five quarters
- Drilled six of the ten highest IP rate Bakken wells in the play to date
- Developed optimal drilling and completion “formula” to unlock value
- Potential for continuing operational innovation to lead to further performance enhancements

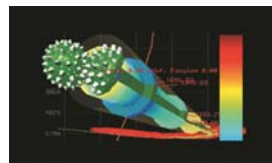
Operator	1Q11		4Q10		3Q10		2Q10		1Q10	
	# of Wells	IP Avg (Boe/d)	# of Wells	IP Avg (Boe/d)	# of Wells	IP Avg (Boe/d)	# of Wells	IP Avg (Boe/d)	# of Wells	IP Avg (Boe/d)
BEXP	3	2,681	4	3,591	12	2,938	11	3,012	8	2,855
BEXP Outperformance		69%		152%		137%		130%		121%
Peer Total/Avg	19	1,590	89	1,424	178	1,240	153	1,312	90	1,293
CLR	1	689	11	580	23	913	11	941	10	835
COP	1	1,605	3	2,502	4	2,277	3	1,916	5	1,944
DNR	1	3,108	3	1,866	3	752	4	1,304	-	-
EOG	3	1,501	5	665	26	850	31	858	3	396
ERF	-	-	2	2,587	2	1,909	3	1,373	-	-
KOG	-	-	3	1,429	2	2,067	1	1,513	2	1,458
HES	1	2,187	5	1,490	23	1,025	7	1,298	6	1,206
MDU	1	896	-	-	3	946	1	1,103	4	837
MRO	-	-	5	529	7	1,579	9	1,327	9	731
NFX	-	-	4	2,994	5	1,985	5	2,901	2	3,033
OAS	-	-	5	1,995	8	1,667	7	1,452	2	744
OXY	2	858	2	557	8	1,680	7	1,419	5	497
QEP	1	1,459	1	1,148	3	1,033	2	1,864	1	1,405
Slawson	1	1,528	3	1,248	13	1,399	8	1,377	8	1,350
SM	-	-	3	1,317	3	711	2	786	3	758
WLL	5	2,051	17	2,254	14	2,411	17	2,439	14	2,711
XOM	-	-	1	420	6	983	8	888	5	558
Others	2	1,133	16	860	25	844	27	947	11	1,067

Source: RBC Capital Markets Bakken Shale Weekly 03/22/11.

* IP rates in Bakken are subject to significant decline rates

Four Key Factors to Outperformance

Geosteering



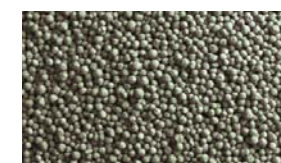
Swell Packers



Perf & Plug



Ceramic Proppants

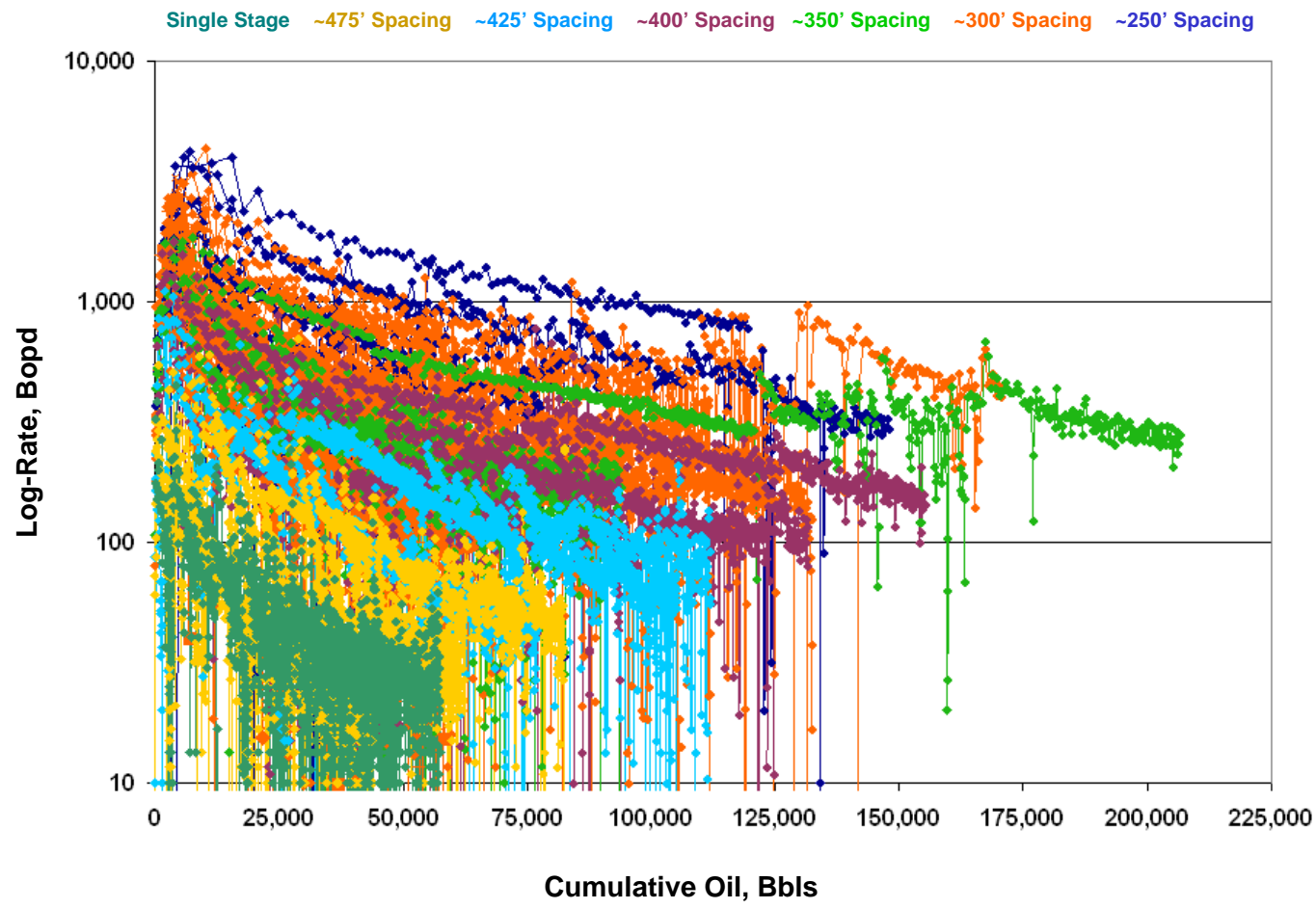


Long Laterals with Increasing Frac Stages

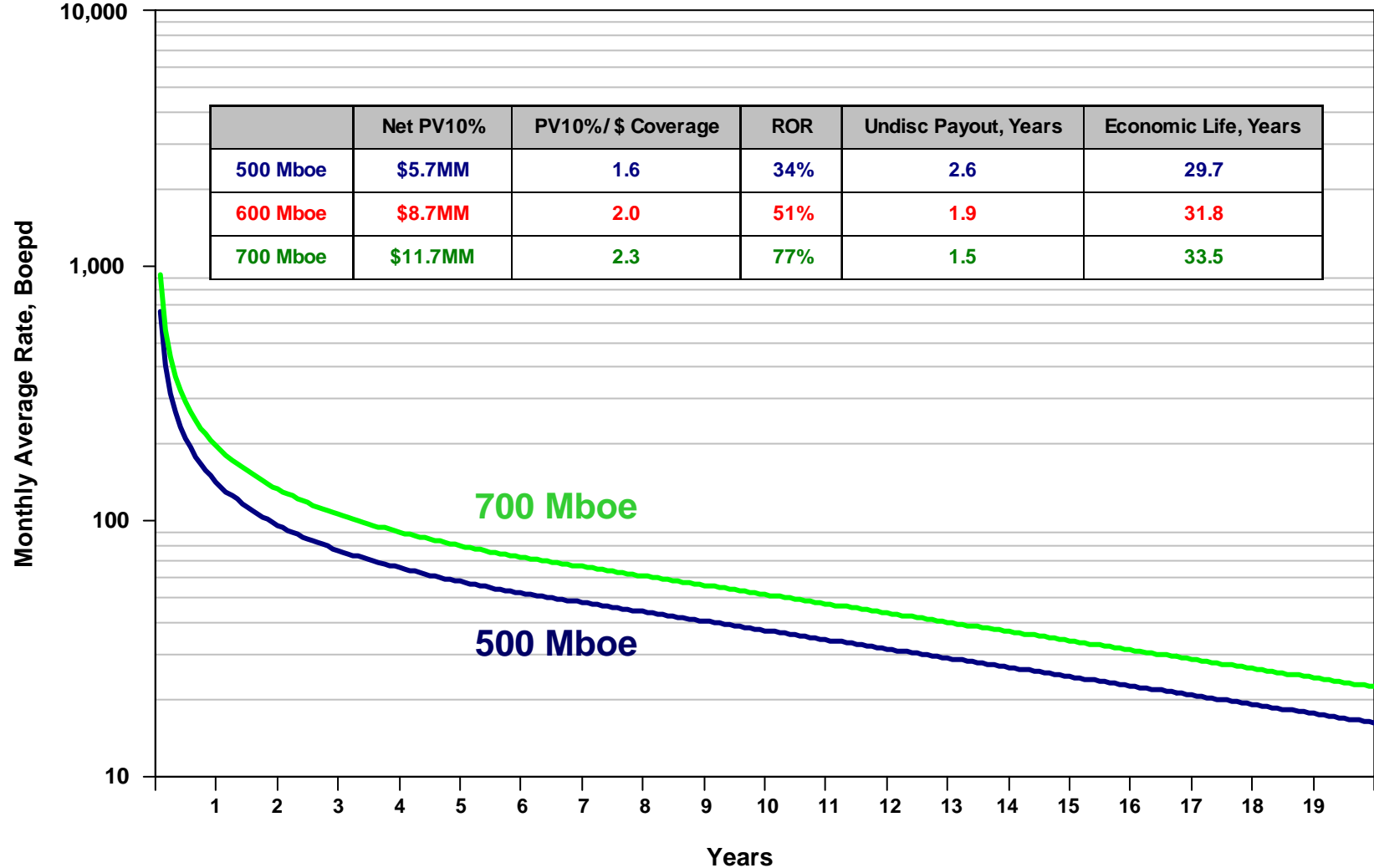
Drove Improved Performance from 2009-2010

Key Points

- As BEXP increased the number of stages - IP rates, production and EURs trended upward
- More effectively stimulated long laterals from toe to heel



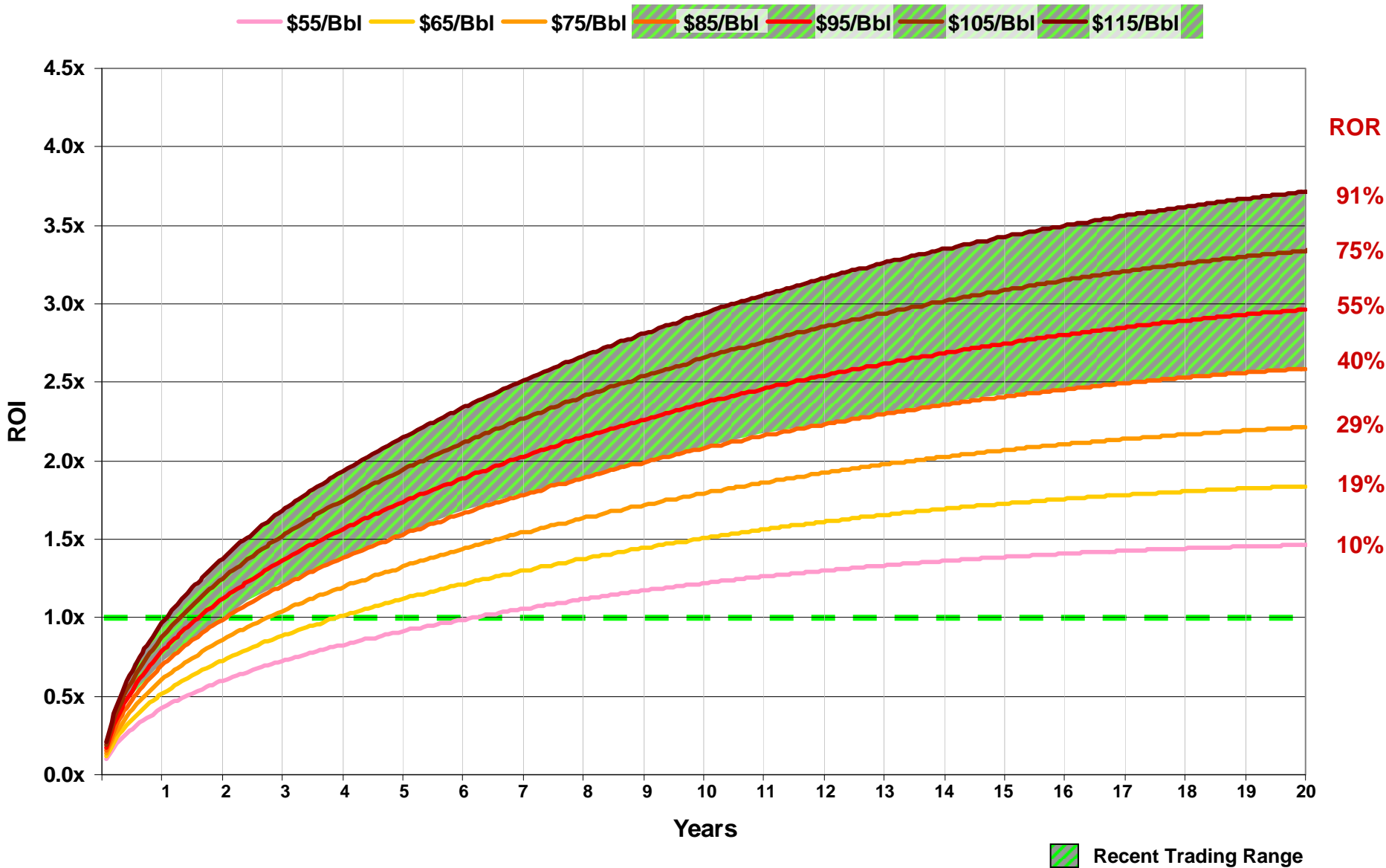
Estimated EUR Range 500-700 Mboe*



*BEXP Internal Estimates. 8/4/11 NYMEX Strip. Price differentials: -\$8.00/Bbl & 1.4 Gas Price Factor. \$8.9MM CWC, \$15,100/mo OPEX. Monthly average rate which given natural declines is less than IP rates. 10

600 Mboe Type Curve ROI vs. Time

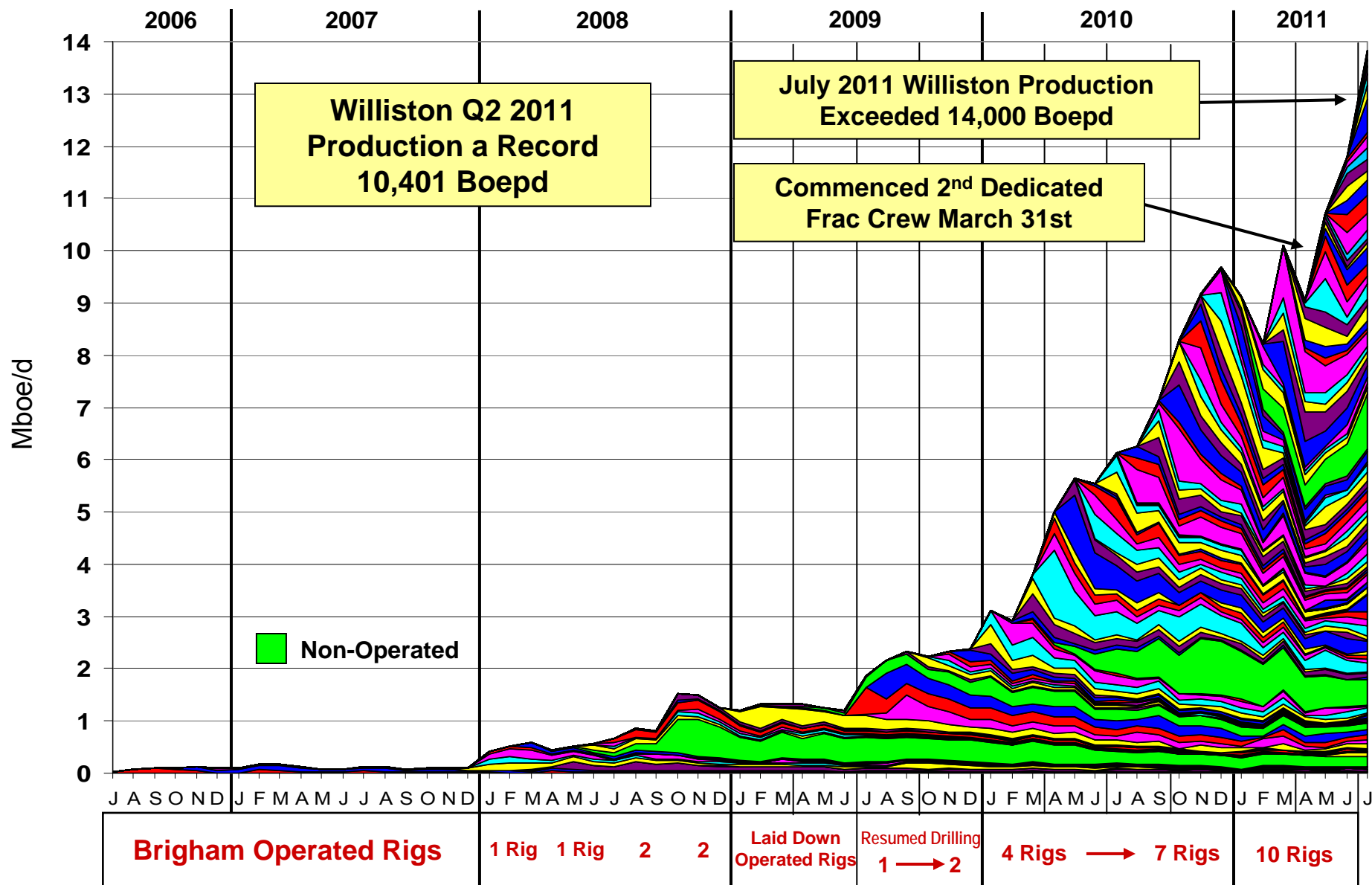
*Outstanding Returns Even at Lower Commodity Prices**



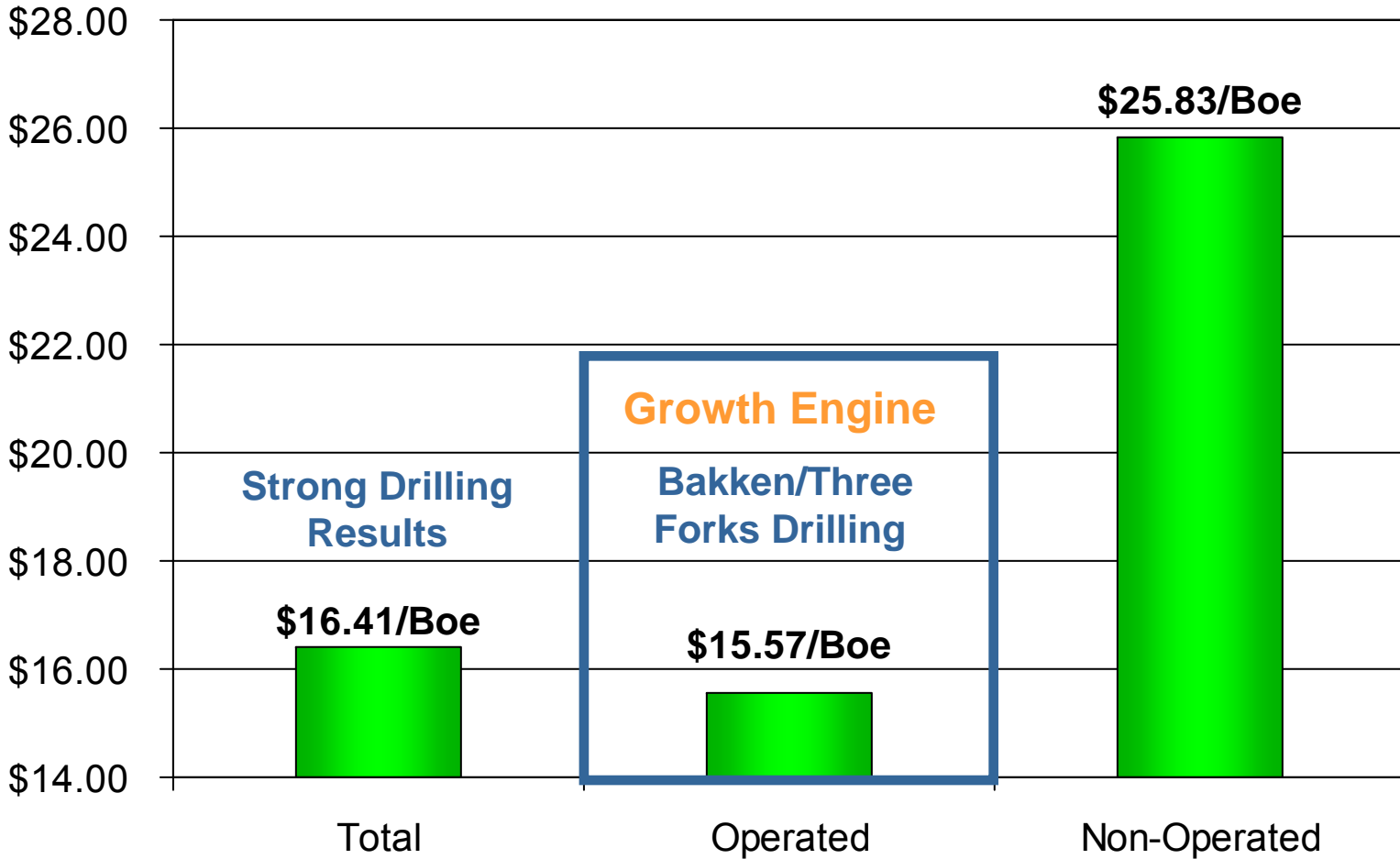
*Assumptions: EUR= 600 MBoe, CWC = \$8.9MM

Growing Williston Basin Oil Production

Growth in High Value Long Life Production



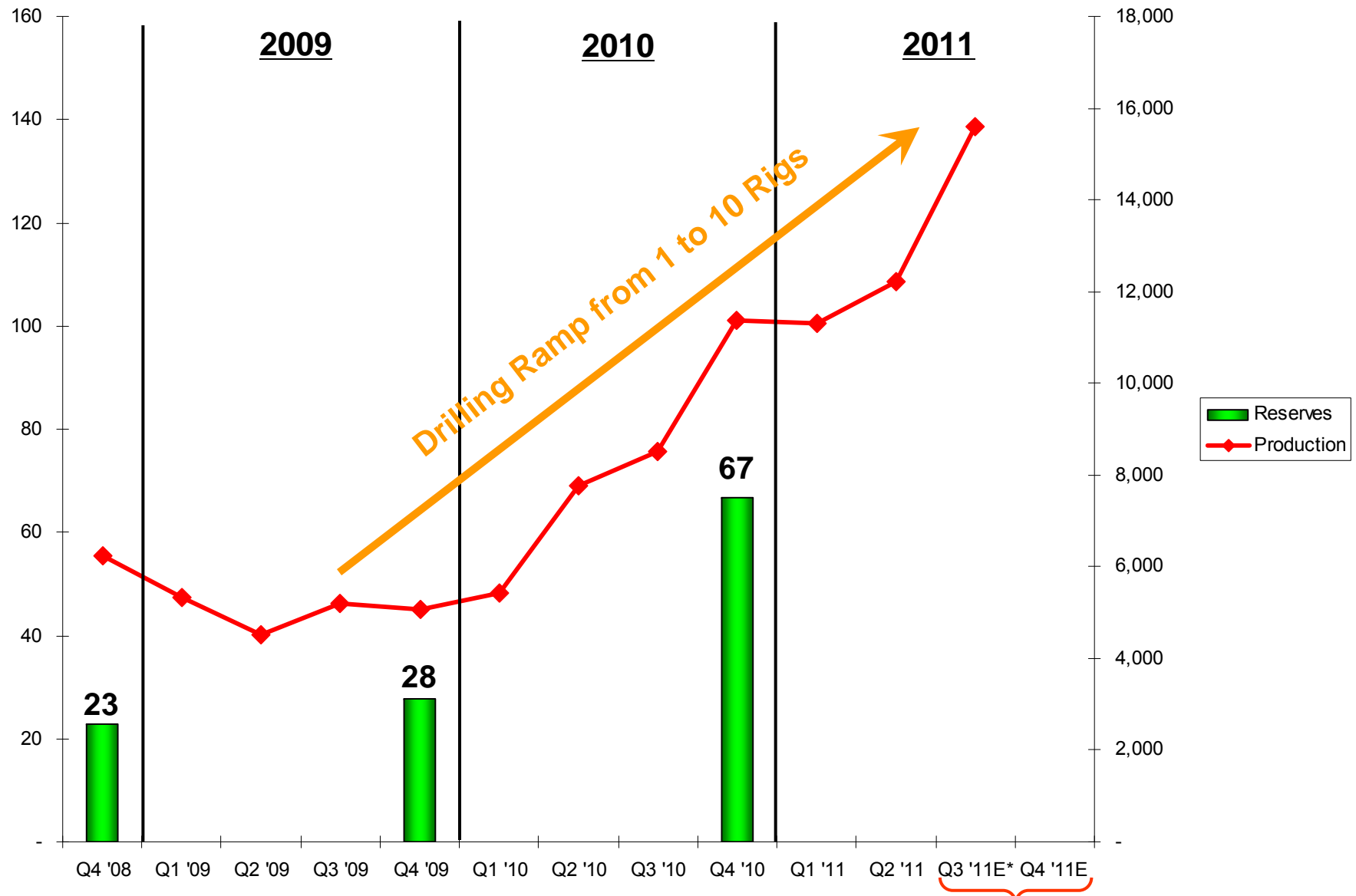
Drilling CapEx / Proved Developed Rsvs



Bakken / Three Forks Operated Wells Delivering Lower Proved Developed Finding Costs Than Non-Operated Wells

Accelerating Growth in Production & Reserves

Production as a Proxy for 2011 Reserve Growth

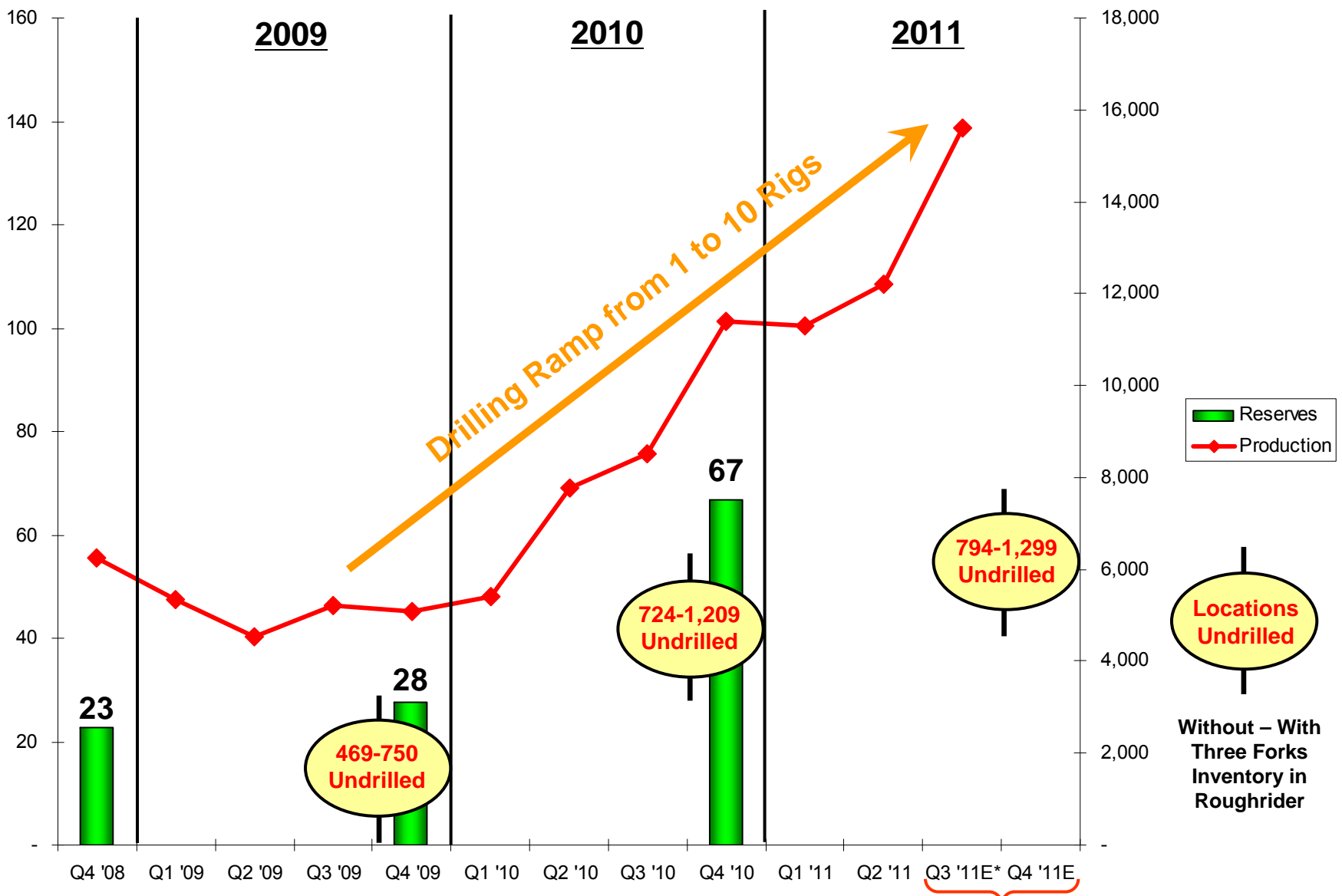


* Company estimate is based solely on the midpoint of production guidance we issued on August 8, 2011. On September 23, 2011, we indicated that production would be at or possibly above the high end of guidance.

Company Estimates

Accelerating Growth in Production & Reserves

BEXP Growing De-Risked Inventory Faster Than Its Accelerated Drilling



* Company estimate is based solely on the midpoint of production guidance we issued on August 8, 2011. On September 23, 2011, we indicated that production would be at or possibly above the high end of guidance. **Company Estimates**

Williston Basin Net Drilling Locations

Prior to State 36-1 #2H and Irgens 27-34 #2H Three Forks Completions

BRIGHAM PROJECT AREA	Producing Formation	Brigham Net Acres(1)	Assumed Drilling Unit Size	Initial Wells(2)	Development Wells(3)	Total Number of Wells
Current Development Projects:						
Parshall / Austin / Sanish	Bakken	4,900	640	7	23	30
	Three Forks ⁽⁴⁾	2,450	640	—	15	15
Parshall / Austin / Sanish Subtotal				7	38	45
Ross	Bakken	35,200	1280	27	83	110
	Three Forks	35,200	1280	—	110	110
Ross Subtotal				27	193	220
Rough Rider ⁽⁵⁾	Bakken	161,600	1280	126	379	505
Eastern Montana	Bakken	33,500	1280	26	78	104
CORE DEVELOPMENT ACREAGE		235,200		186	688	874
Future Projects:						
Rough Rider ⁽⁵⁾	Three Forks	161,600	1280	—	505	505
Eastern Montana	Three Forks	33,500	1280	—	104	104
Other Eastern Montana	Bakken	85,600	1280	66	201	267
	Three Forks	85,600	1280	—	267	267
Other Eastern Montana Subtotal				66	468	534
Mercer	Bakken	30,100	1280	23	71	94
	Three Forks	30,100	1280	—	94	94
Mercer Subtotal				23	165	188
Other Extensional Areas	Multiple	24,900				
FUTURE POTENTIAL DEVELOPMENT		140,600		89	1,242	1,331
TOTAL		375,800		275	1,930	2,205

794 net locations remaining as of MY2011. Each net de-risked location at 600 Mboe EUR/well equates to ~\$8.7 million PV-10/well*

(1) Acreage estimates as of 8/4/11.

(2) Assumes initial well is a Bakken well. Represents wells needed to hold acreage HBP.

(3) Assumes additional 3 Bakken / 4 Three Forks potential development wells per drilling unit.

(4) Only a portion of Brigham's Parshall / Austin / Sanish acreage is considered prospective for the Three Forks.

(5) Net acreage amounts do not reflect Rough Rider drilling participation agreement as acreage is not earned until wells are drilled and completed.

Rough Rider Three Forks Activity Map

5 Proximal Three Forks Completions with Avg. IP: 2,053 Boepd



Williston Basin Net Drilling Locations

Inclusive of State 36-1 #2H and Irgens 27-34 #2H Three Forks Completions

BRIGHAM PROJECT AREA	Producing Formation	Brigham Net Acres ⁽¹⁾	Assumed Drilling Unit Size	Initial Wells ⁽²⁾	Development Wells ⁽³⁾	Total Number of Wells
Current Development Projects:						
Parshall / Austin / Sanish	Bakken	4,900	640	7	23	30
	Three Forks ⁽⁴⁾	2,450	640	—	15	15
Parshall / Austin / Sanish Subtotal				7	38	45
Ross	Bakken	35,200	1280	27	83	110
	Three Forks	35,200	1280	—	110	110
Ross Subtotal				27	193	220
Rough Rider ⁽⁵⁾	Bakken	161,600	1280	126	379	505
Eastern Montana	Bakken	33,500	1280	26	78	104
Rough Rider ⁽⁵⁾	Three Forks	161,600	1280	—	505	505
CORE DEVELOPMENT ACREAGE		235,200		186	1,193	1,379
Future Projects:						
Eastern Montana	Three Forks	33,500	1280	—	104	104
Other Eastern Montana	Bakken	85,600	1280	66	201	267
	Three Forks	85,600	1280	—	267	267
Other Eastern Montana Subtotal				66	468	534
Mercer	Bakken	30,100	1280	23	71	94
	Three Forks	30,100	1280	—	94	94
Mercer Subtotal				23	165	188
Other Extensional Areas	Multiple	24,900				
FUTURE POTENTIAL DEVELOPMENT		140,600		89	737	826
TOTAL		375,800		275	1,930	2,205

*Each net de-risked location at 600 Mboe EUR/well equates to ~\$8.7 million PV-10/well**

⁽¹⁾ Acreage estimates as of 8/4/11.

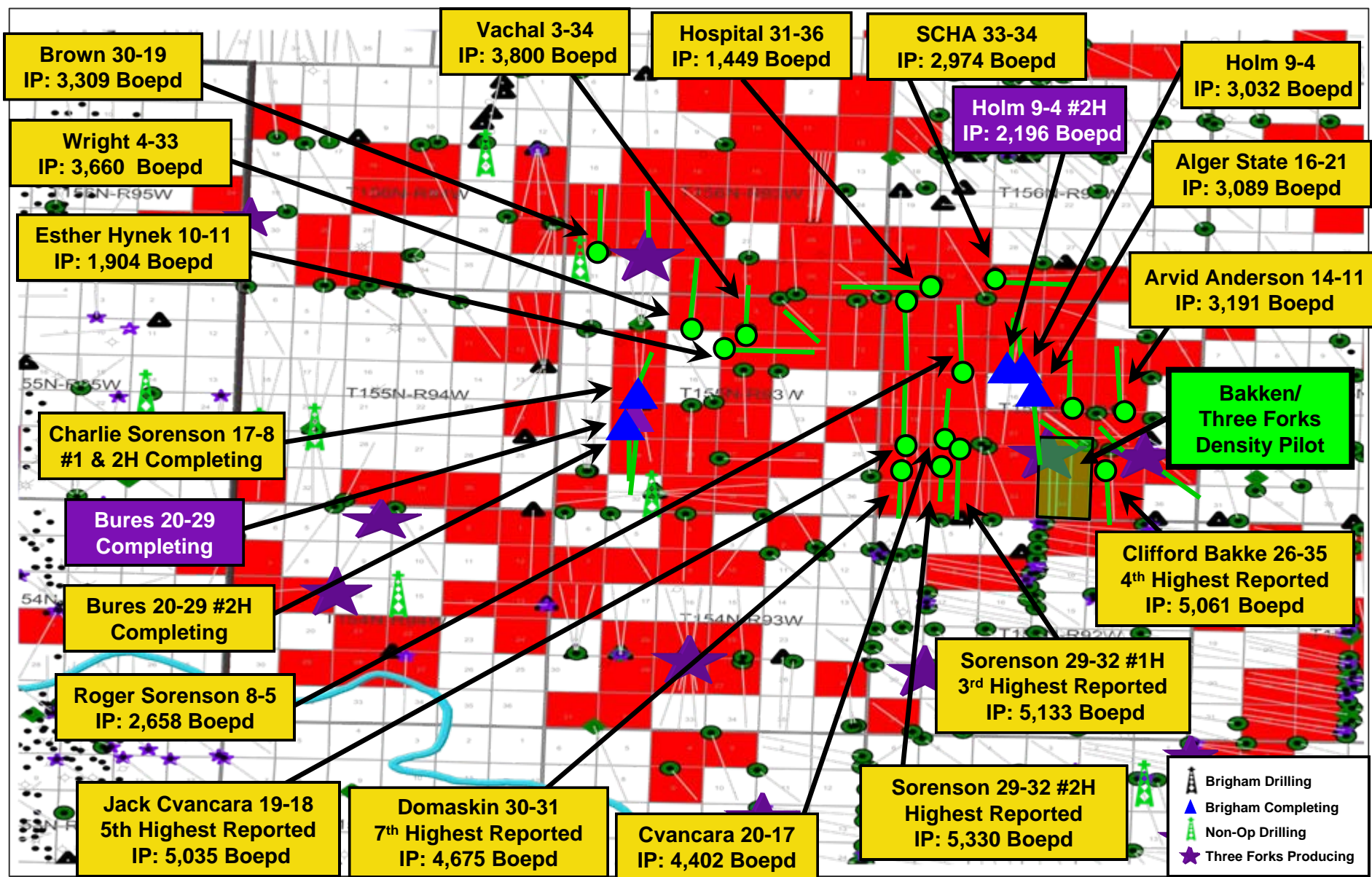
⁽²⁾ Assumes initial well is a Bakken well. Represents wells needed to hold acreage HBP.

⁽³⁾ Assumes additional 3 Bakken / 4 Three Forks potential development wells per drilling unit.

⁽⁴⁾ Only a portion of Brigham's Parshall / Austin / Sanish acreage is considered prospective for the Three Forks.

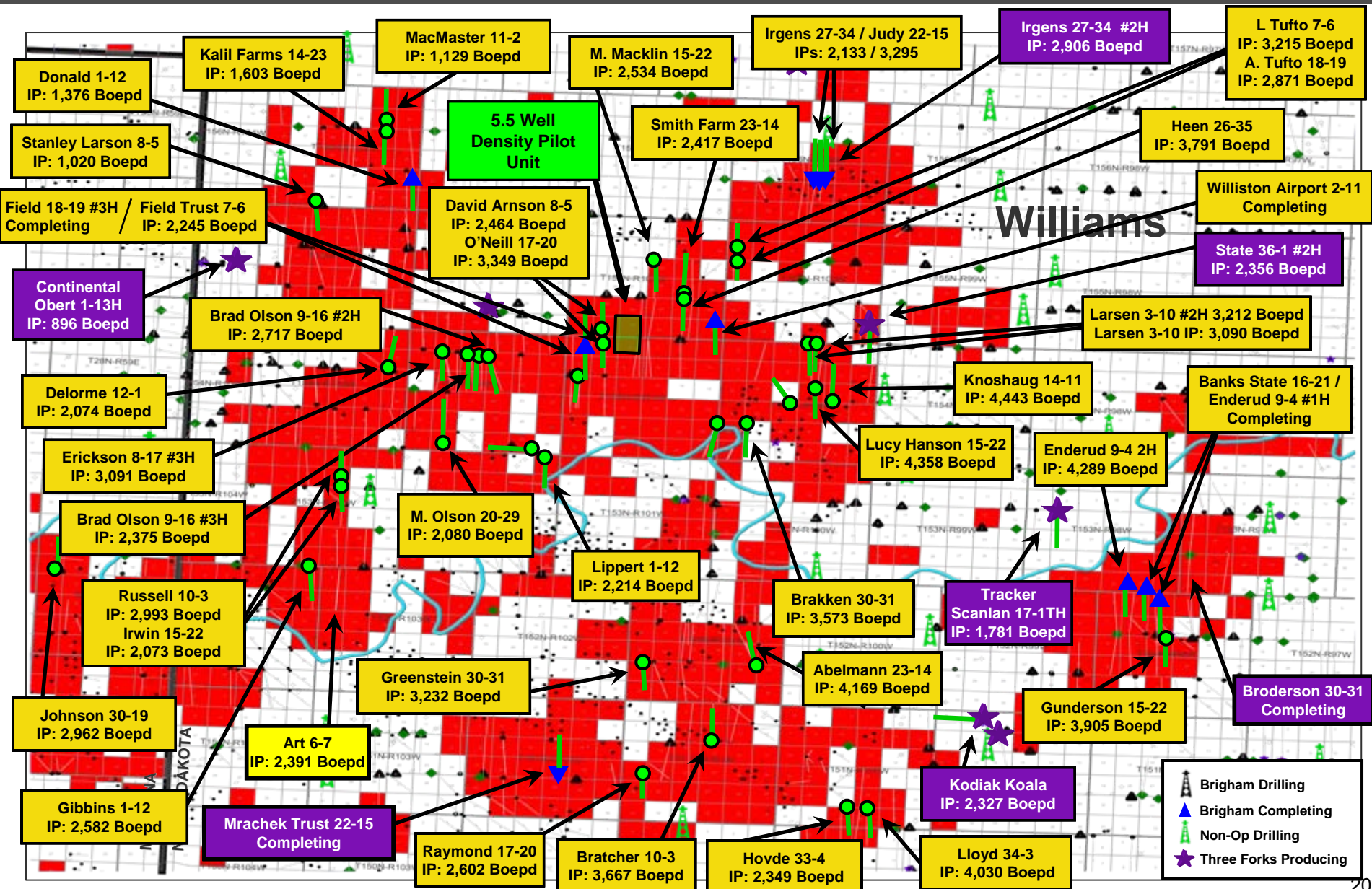
⁽⁵⁾ Net acreage amounts do not reflect Rough Rider drilling participation agreement as acreage is not earned until wells are drilled and completed.

24 Long Lateral High Frac Stage Wells w/ 3,171 Boepd Avg. IP

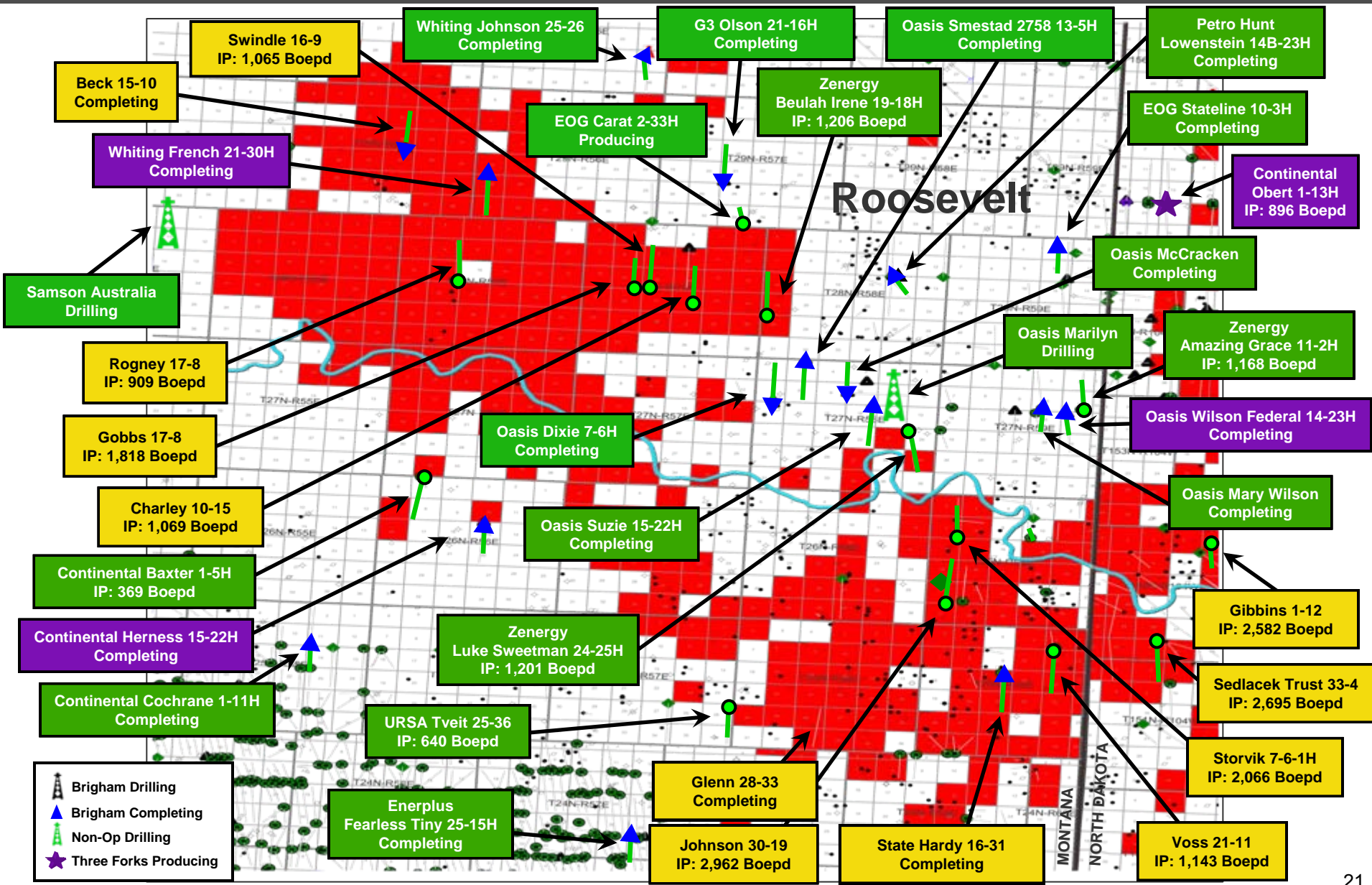


- Brigham Drilling
- Brigham Completing
- Non-Op Drilling
- Three Forks Producing

64 Long Lateral High Frac Stage Wells w/ 2,657 Boepd Avg. IP



Eastern Montana Activity Map

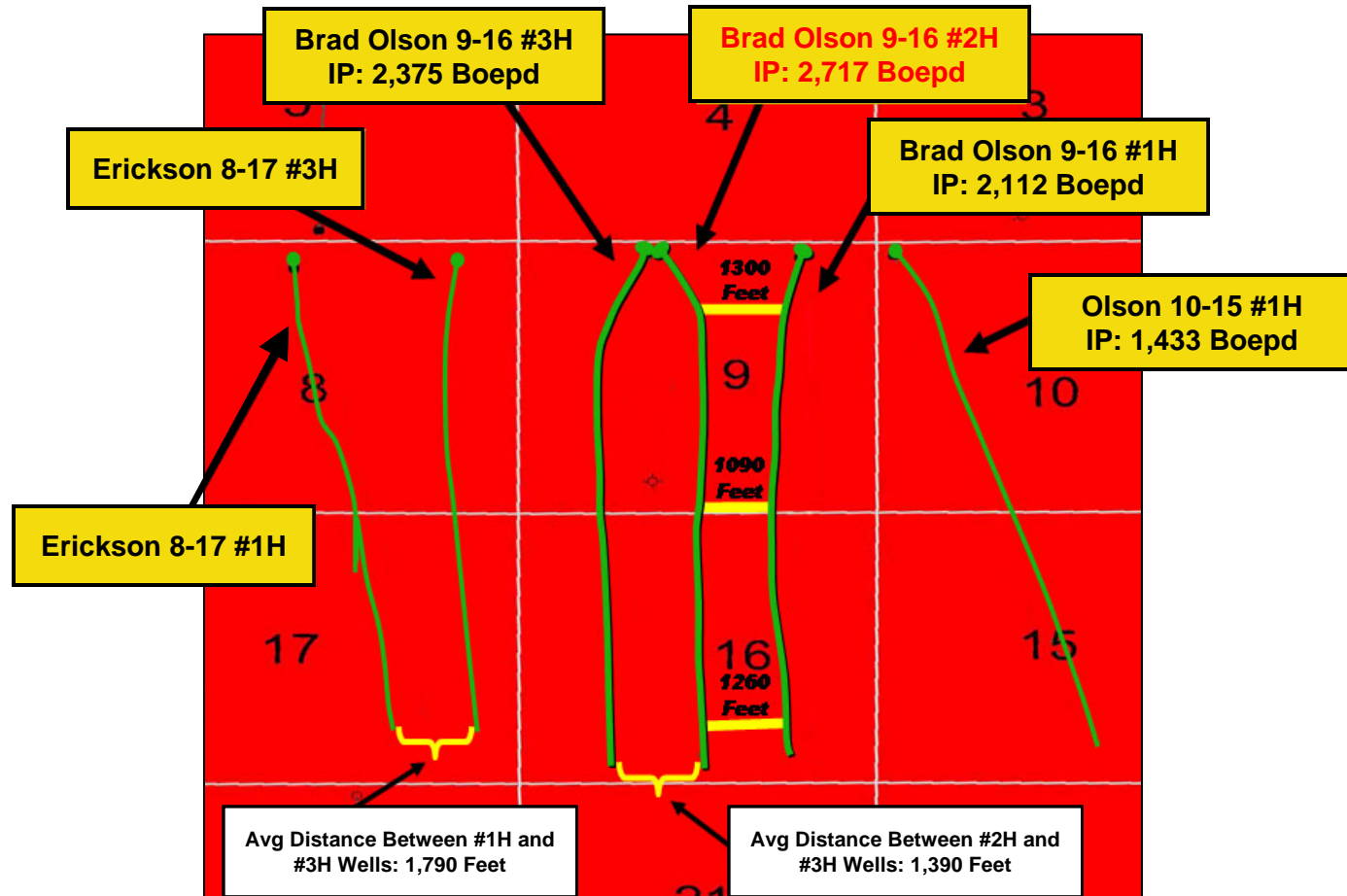


Density Pilots



Key Points

- Completed Rough Rider density wells the Brad Olson 9-16 #2H and the Brad Olson 9-16 #3H
- First density well averages approximately 1,200' from previously completed Brad Olson #1H, a distance more consistent with four well spacing
- Results from these wells, along with microseismic data, demonstrate the viability of increased density drilling
- Plan to initiate four well density pattern in both Rough Rider and Ross in Q3 2011
- 5.5 well density pattern in Q4 2011
- Four well spacing also utilized by Kodiak and Continental in recently announced drilling plans

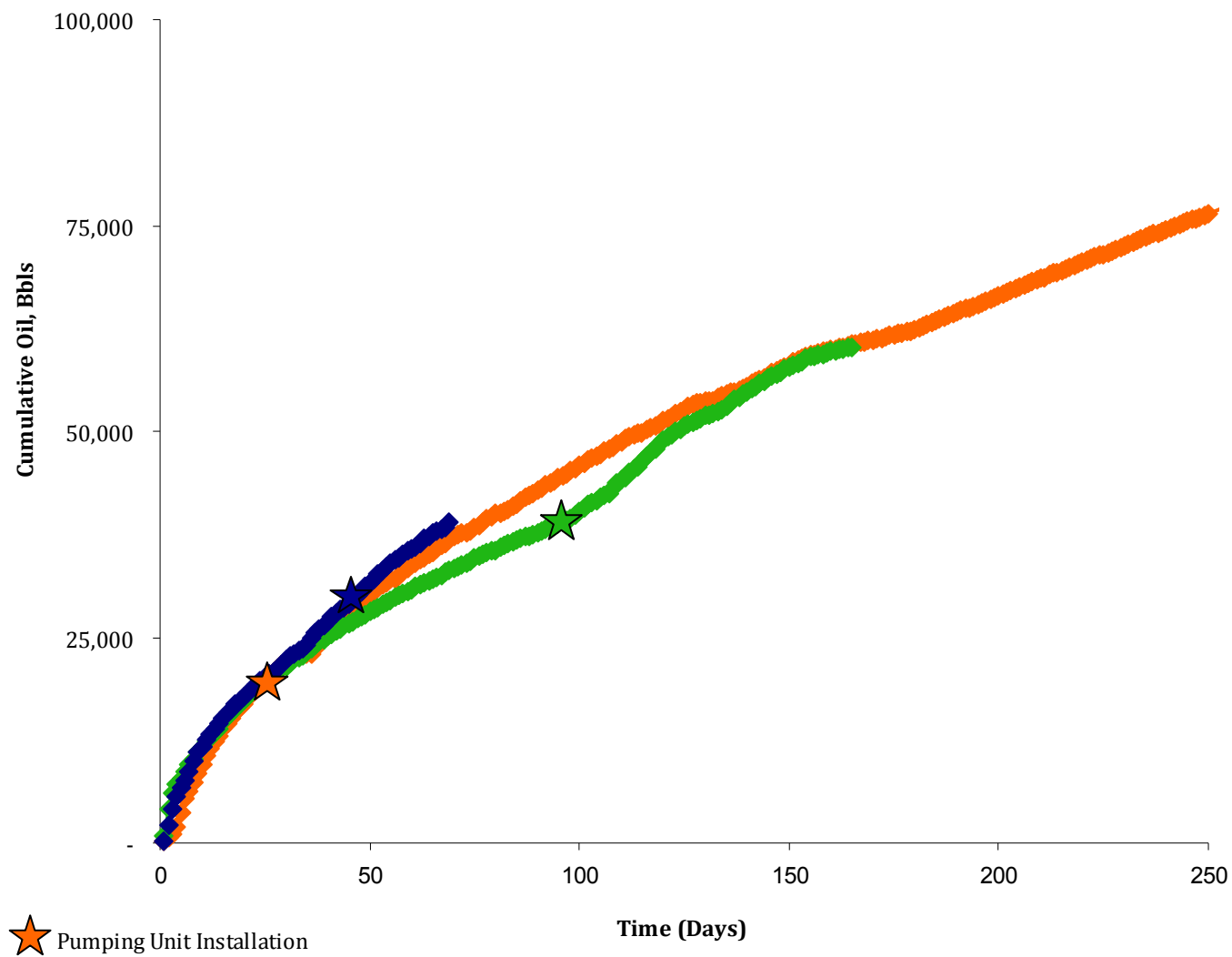


Rough Rider Increased Density Drilling Program

Brad Olson 9-16 #1H (orange), Brad Olson 9-16 #2H (green) and Brad Olson 9-16 #3H (blue)

Key Points

- Downtime removed
- Brad Olson #2H flowed 2x more oil than the Brad Olson #1H before going on pump
- Brad Olson #3H currently being put on pump and flowed 1.3x more oil than the Brad Olson #1H



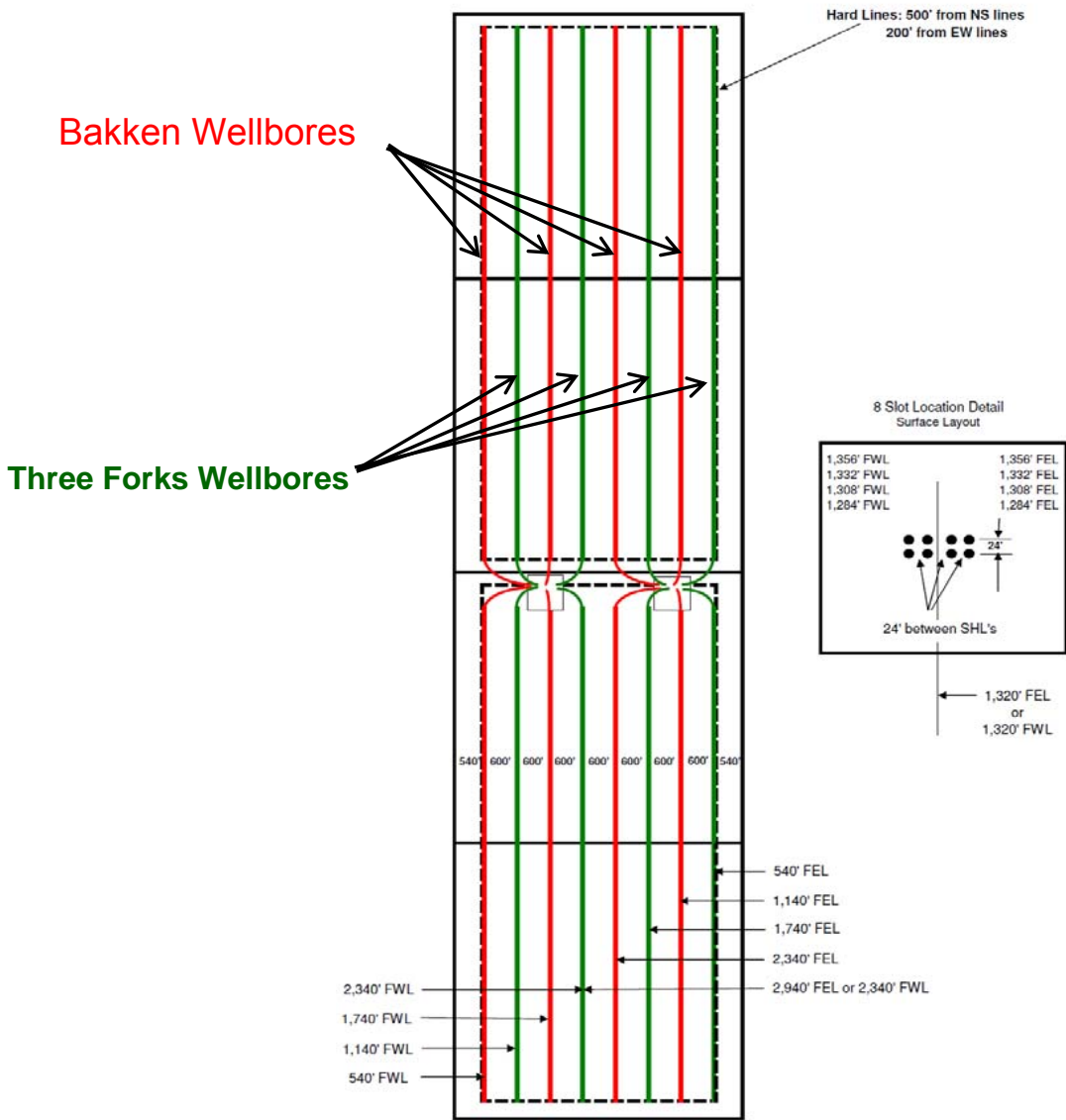
★ Pumping Unit Installation

Large Continuous Acreage Blocks

Provide Operational Efficiency (4.5 Well Spacing Pattern Per Horizon)

Key Points

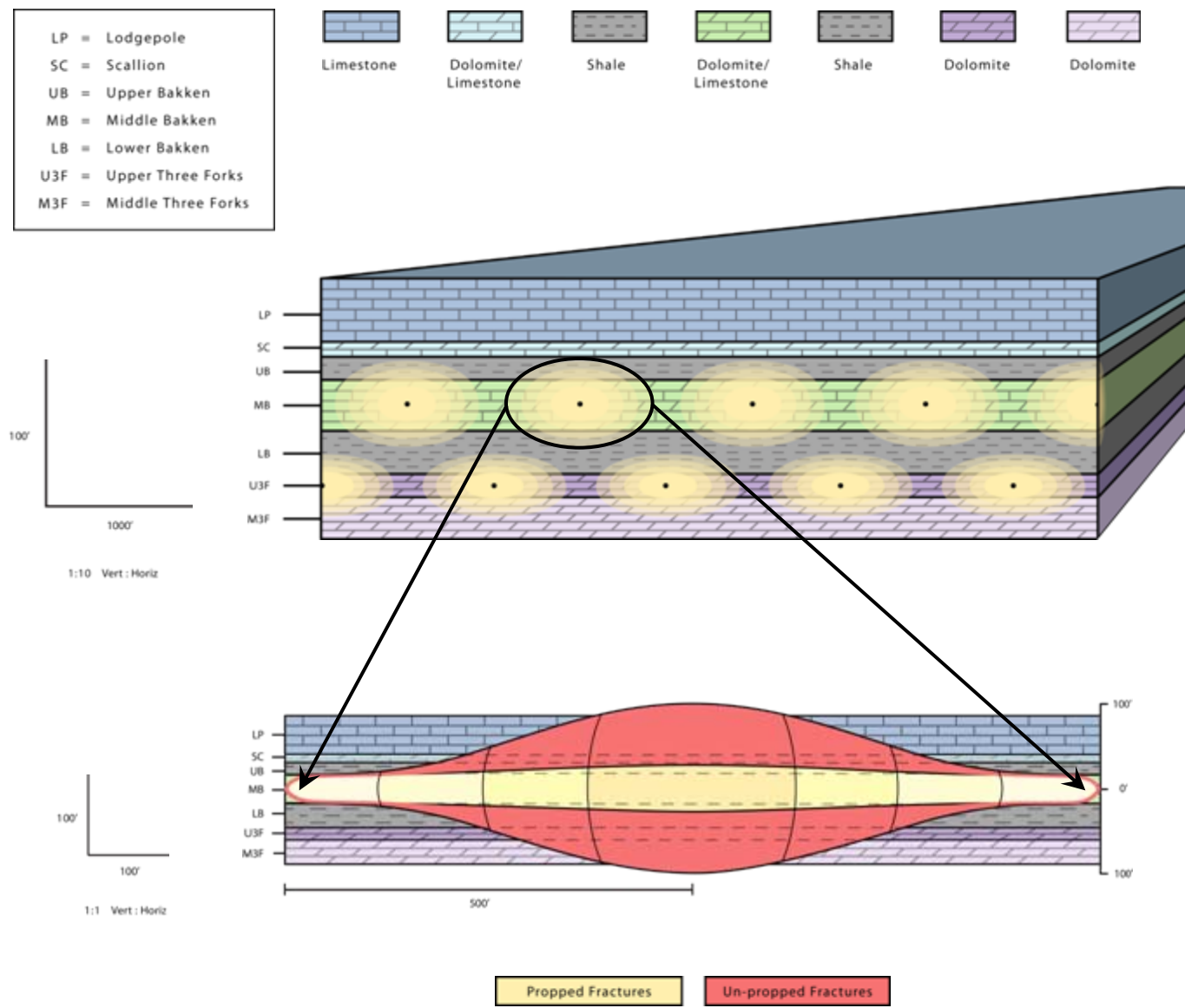
- Smart pads minimize surface footprint
- Reduces D&C Costs
- Allows for simultaneous stimulations
- Permits use of centralized tank batteries



Continues to Provide Growing Resource Base for Development – Rough Rider

Key Points

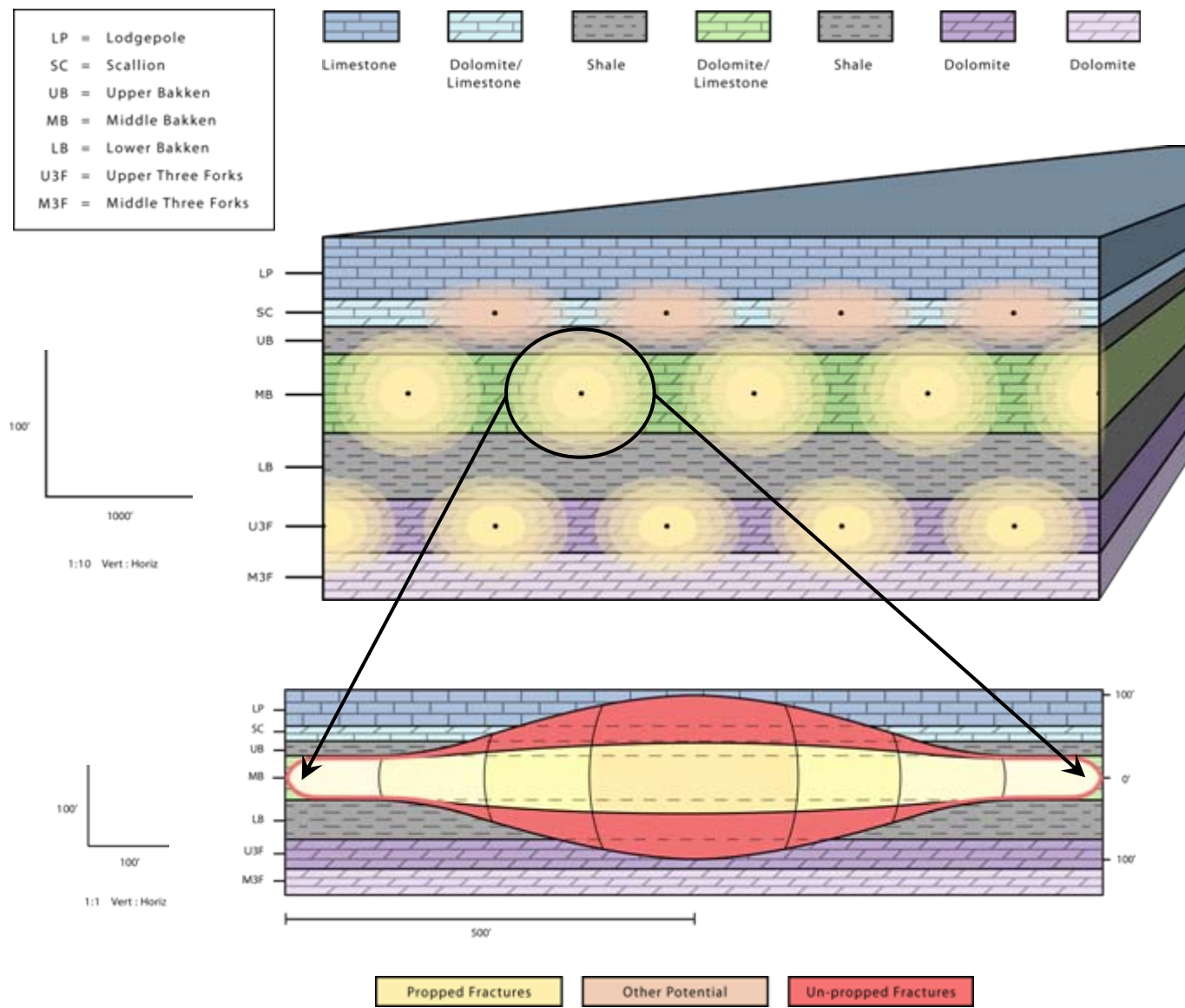
- Micro-Seismic interpretation indicates 500' Avg. Lateral Frac Extent (1,000' Total)
- Most of the frac energy within 200-300' of well bore
- Potential for additional increased density drilling
- Expect continued improvement in recovery factors



Continues to Provide Growing Resource Base for Development – Ross

Key Points

- Micro-Seismic interpretation indicates 500' Avg. Lateral Frac Extent (1,000' Total)
- Most of the frac energy within 200-300' of well bore
- Potential for additional increased density drilling
- Expect continued improvement in recovery factors
- Option on refracs / secondary recovery
- Other targets/reservoirs
 - Red River – BEXP 4 discoveries in 4 attempts
 - Heath/Tyler
 - Ratcliffe
 - Mission Canyon
 - Lodgepole
 - Nisku
 - Duperow
 - Winnipeg
 - Deadwood

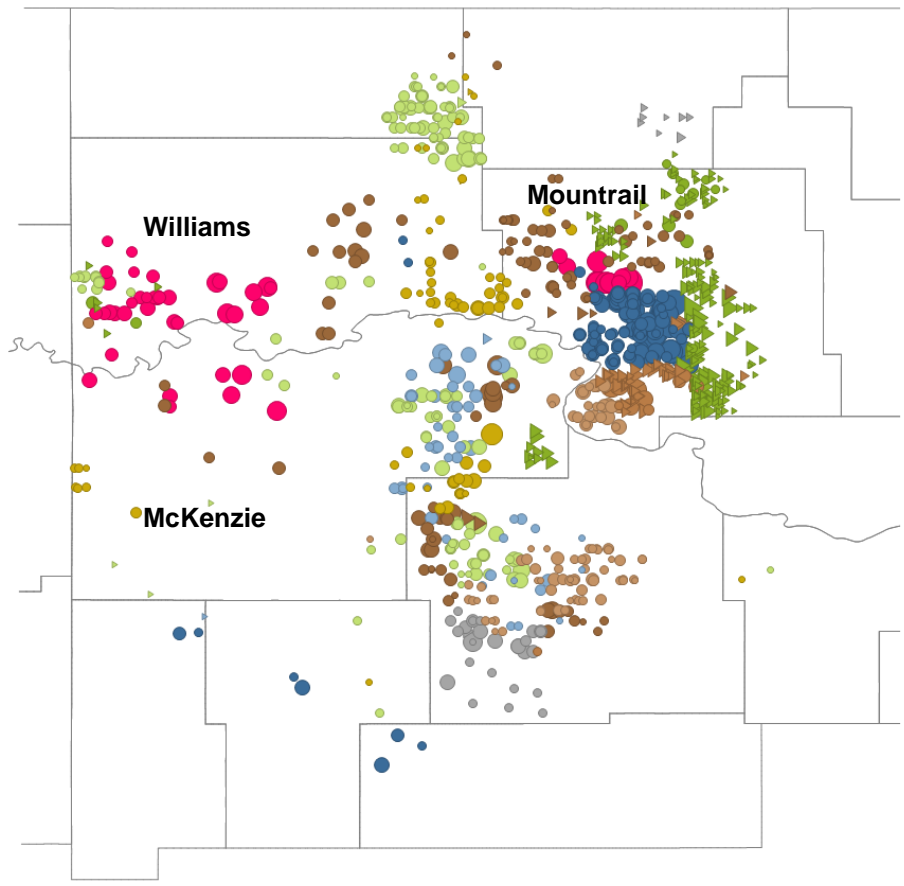




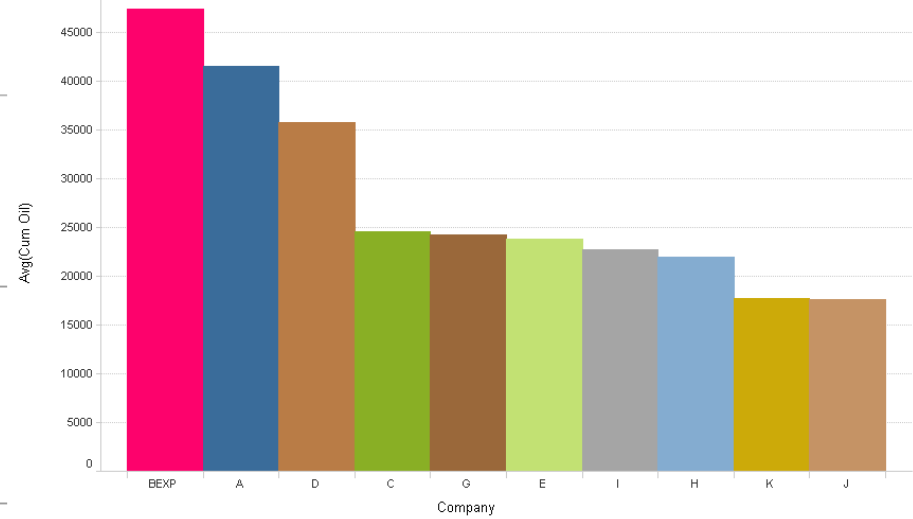
BRIGHAM

OPERATIONS & TECHNOLOGY

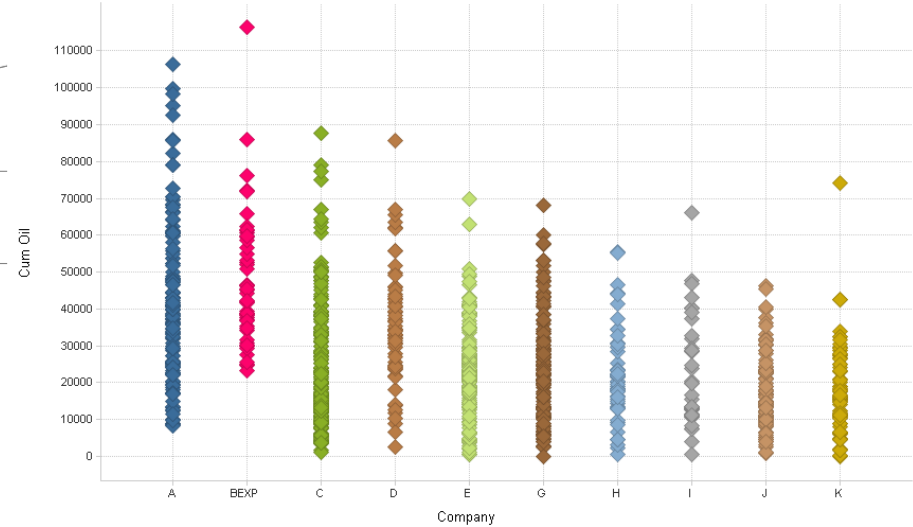
Map Chart



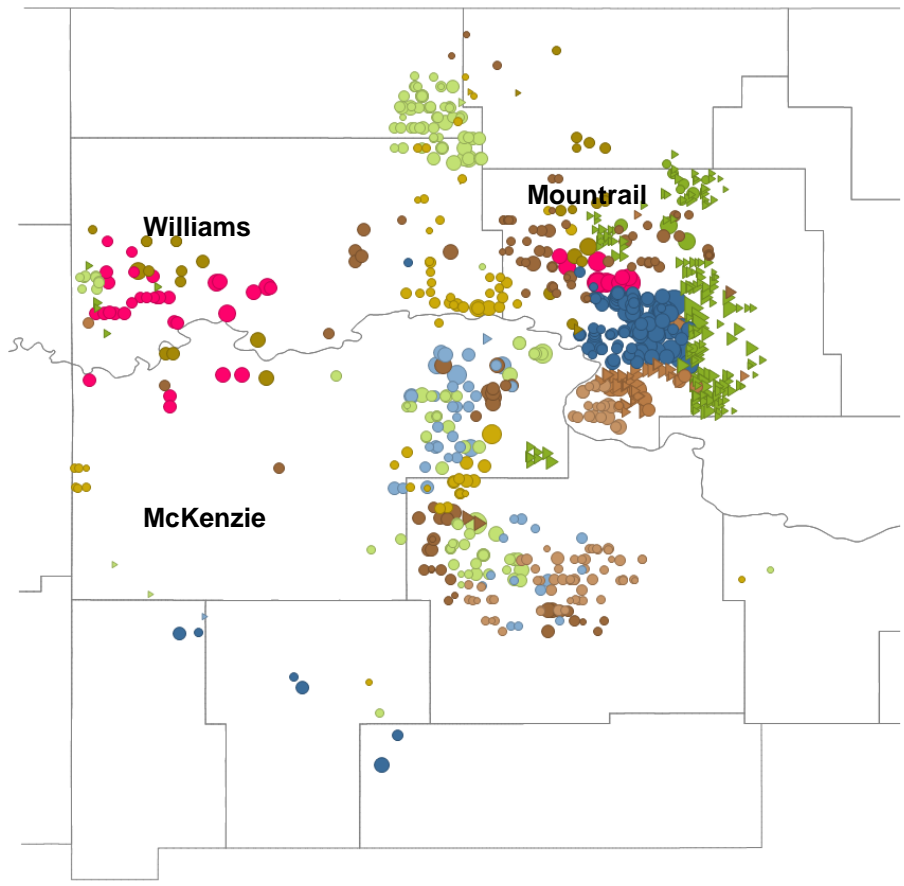
Bar Chart



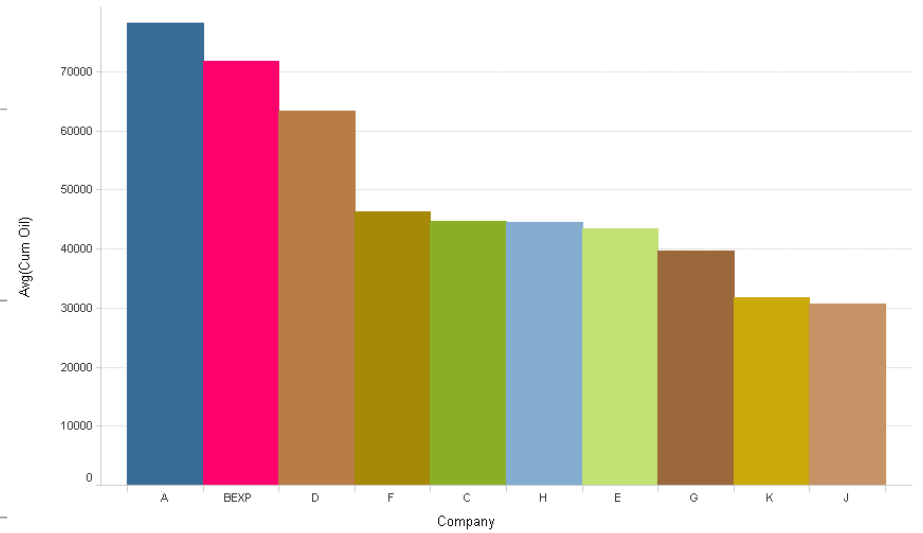
Scatter Plot



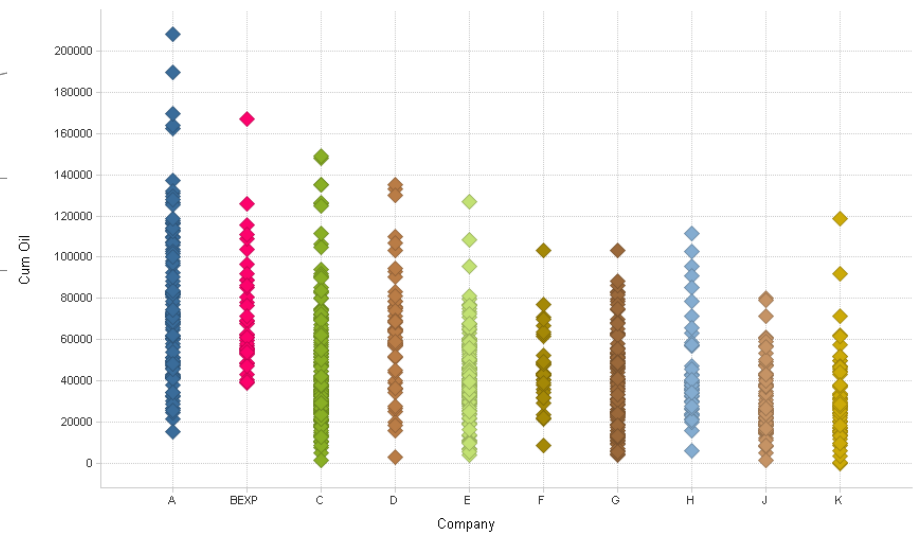
Map Chart



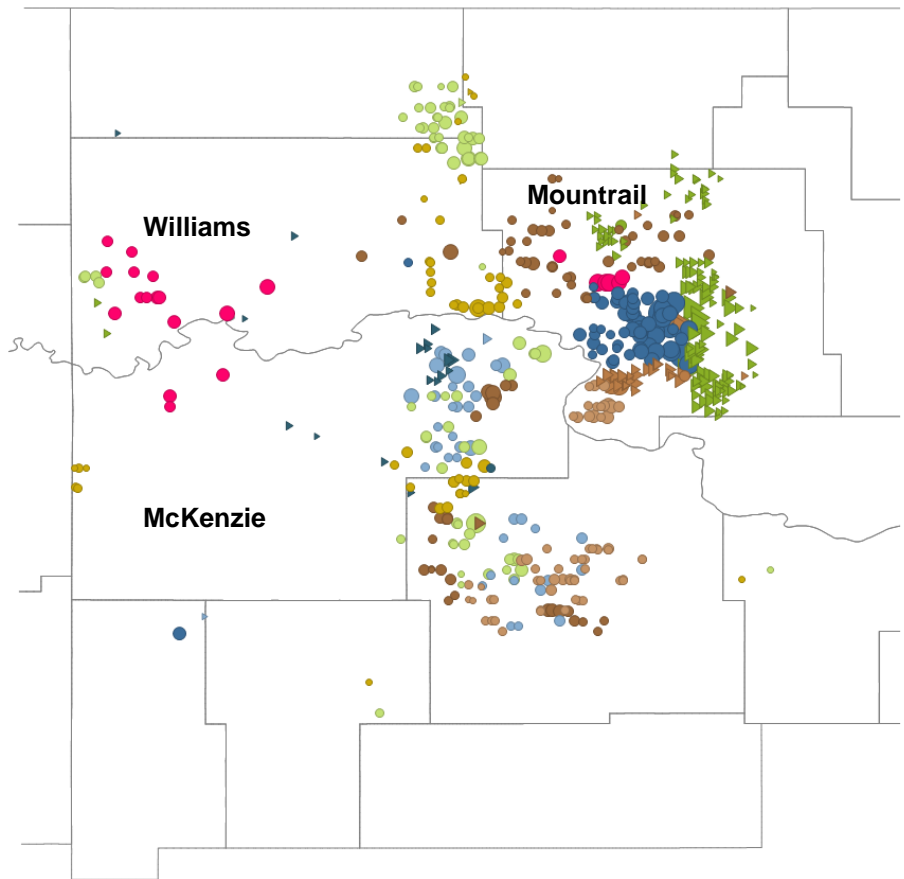
Bar Chart



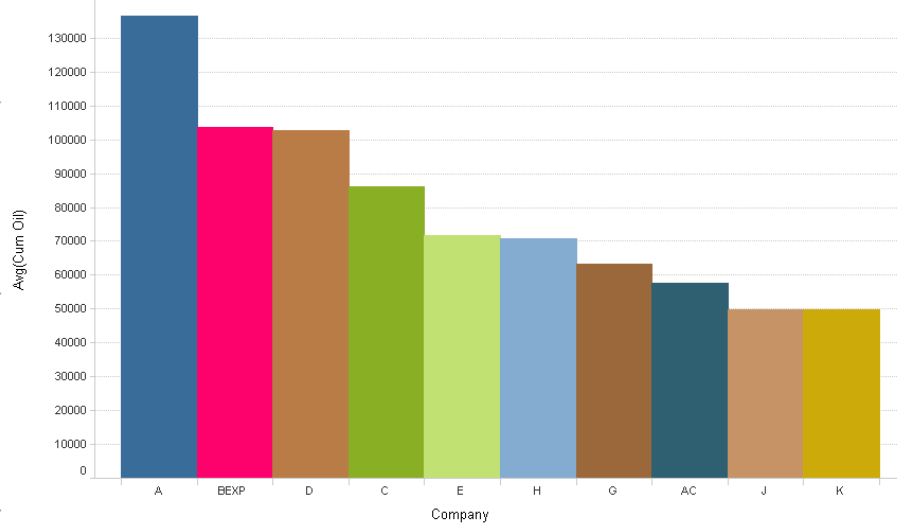
Scatter Plot



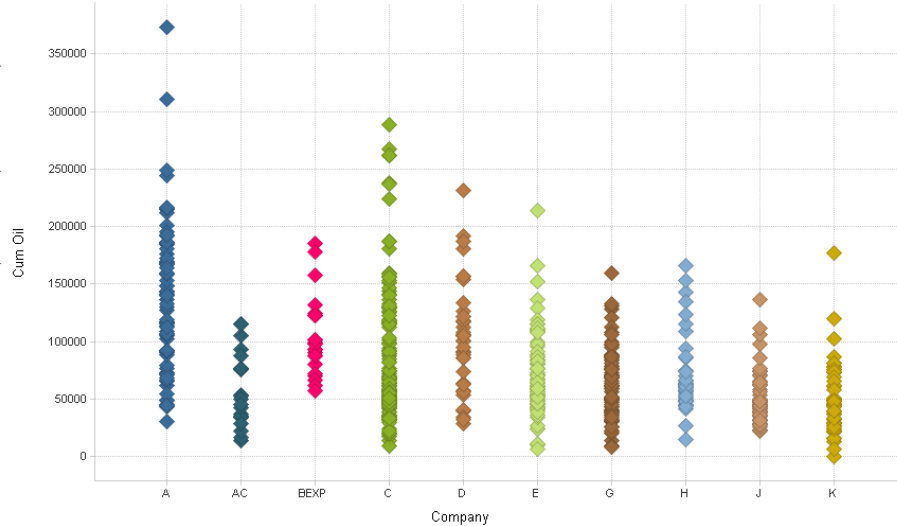
Map Chart



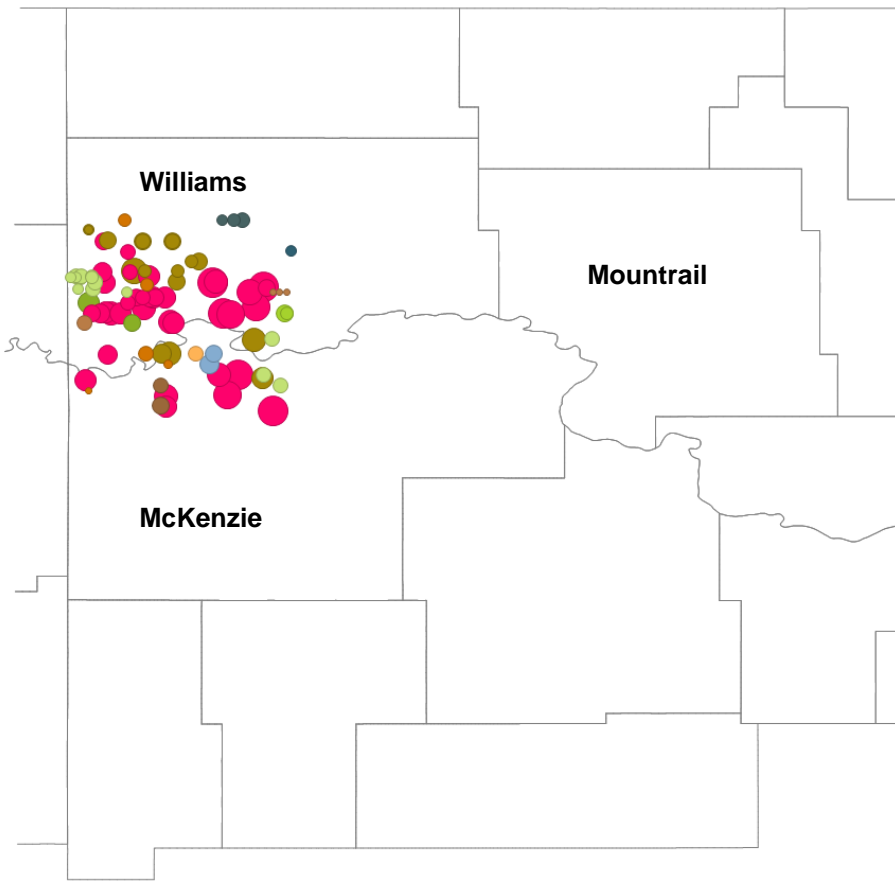
Bar Chart



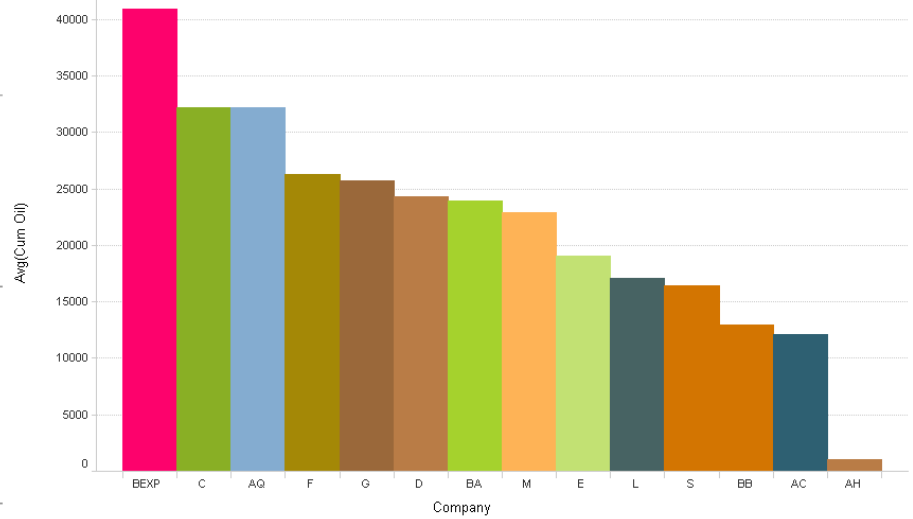
Scatter Plot



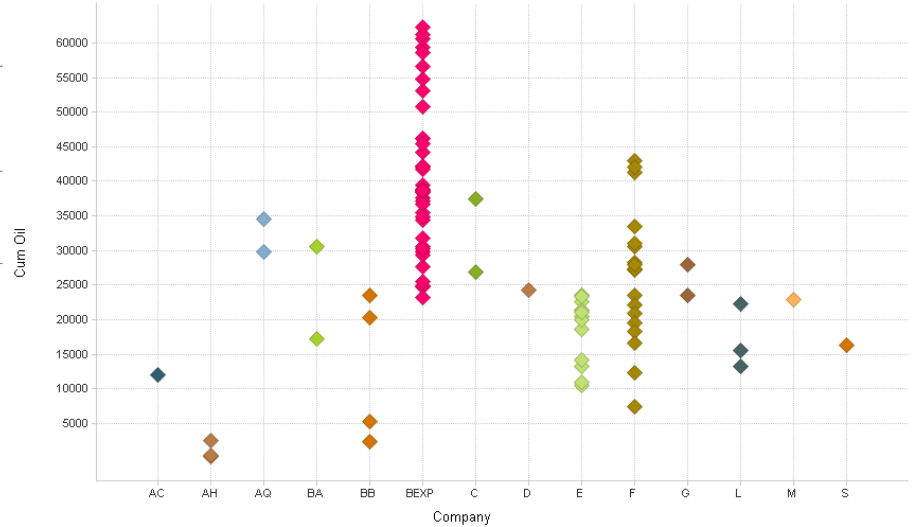
Map Chart



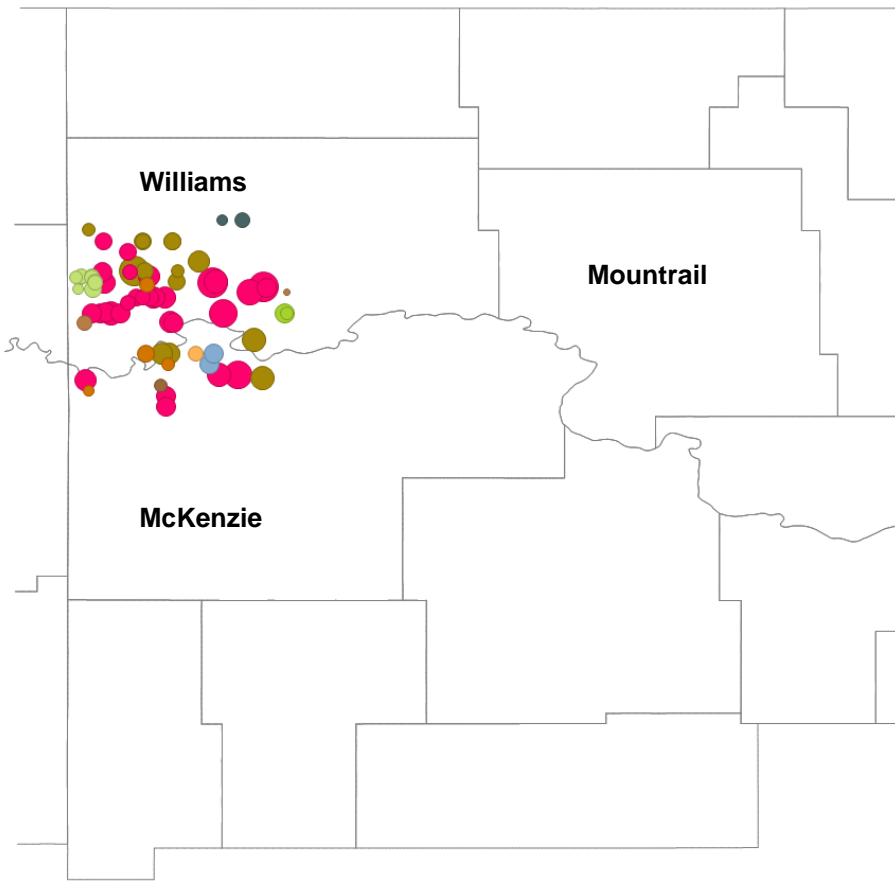
Bar Chart



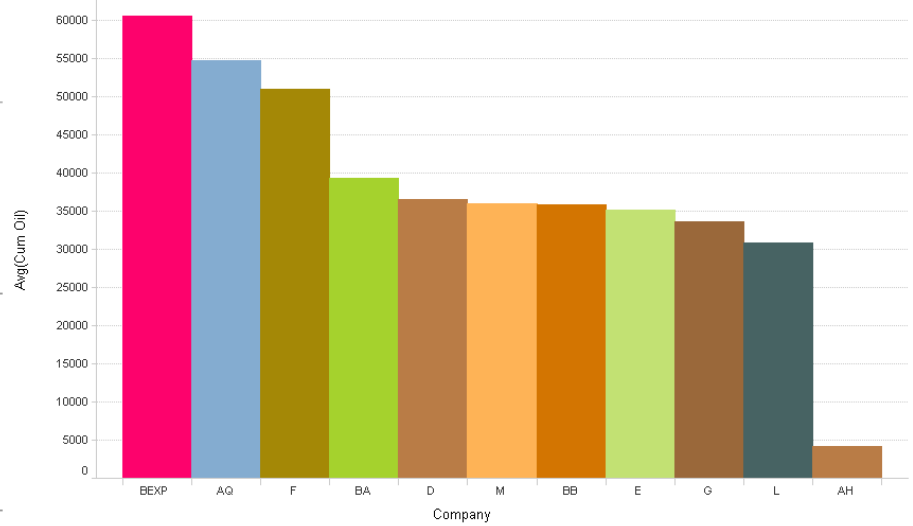
Scatter Plot



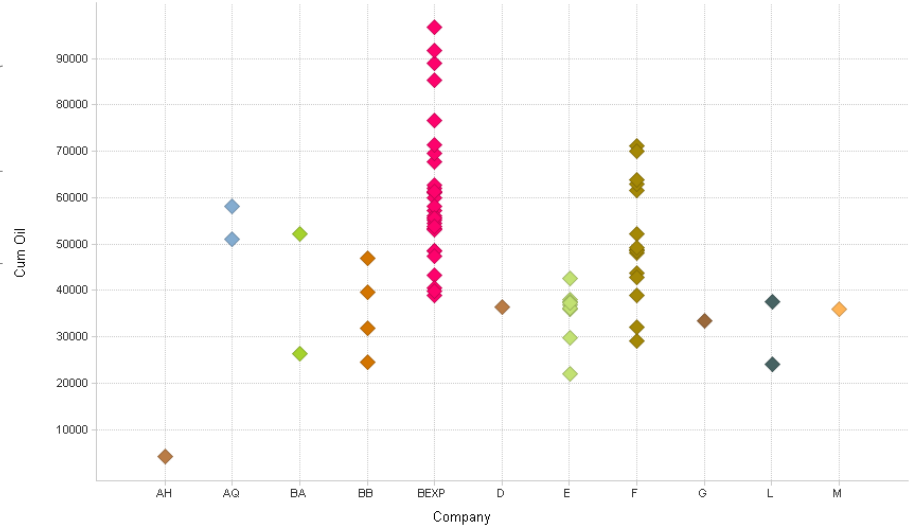
Map Chart



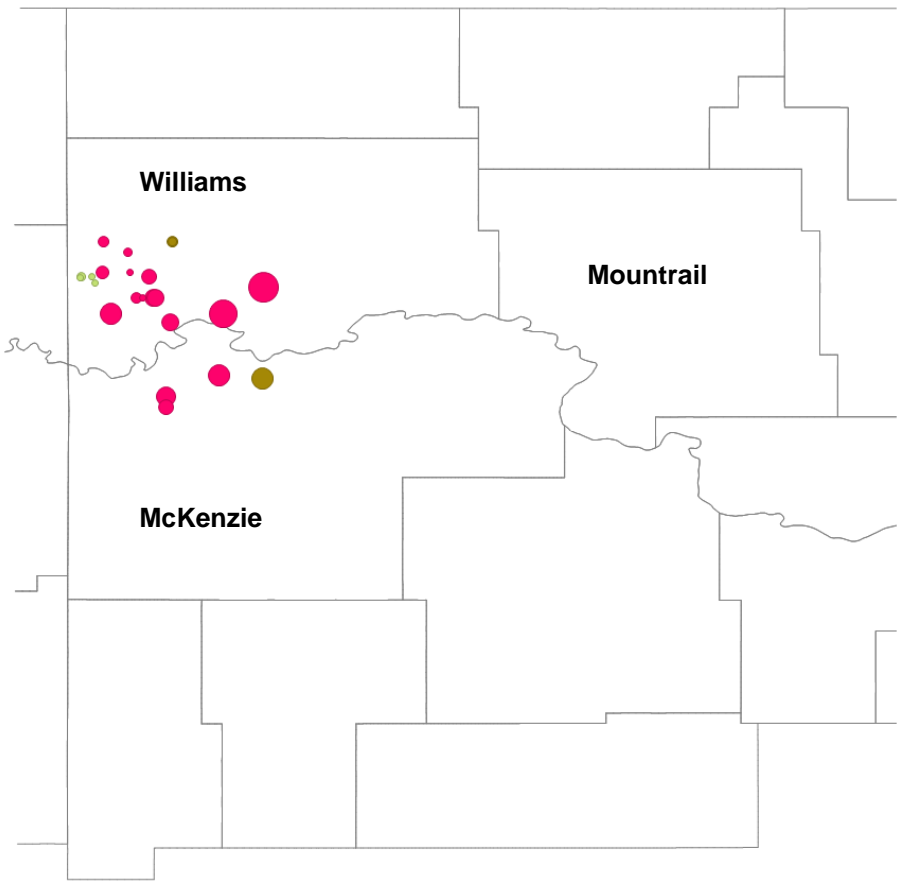
Bar Chart



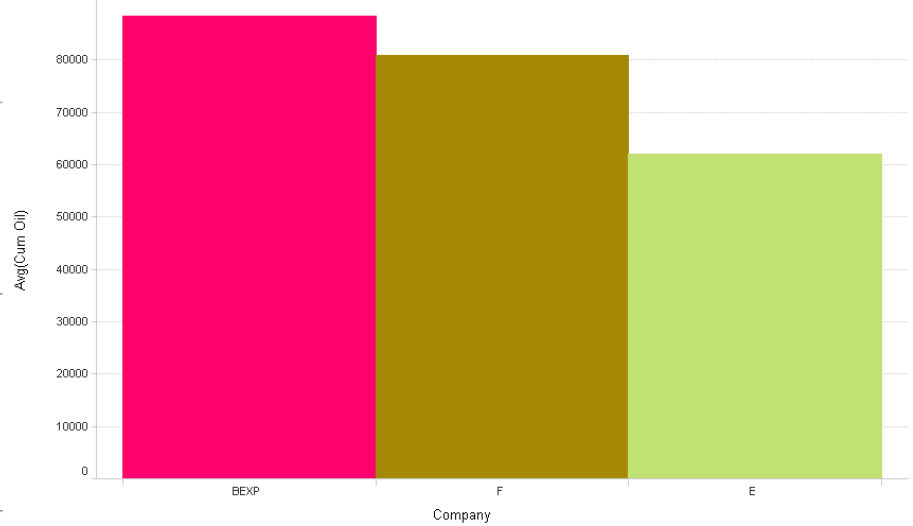
Scatter Plot



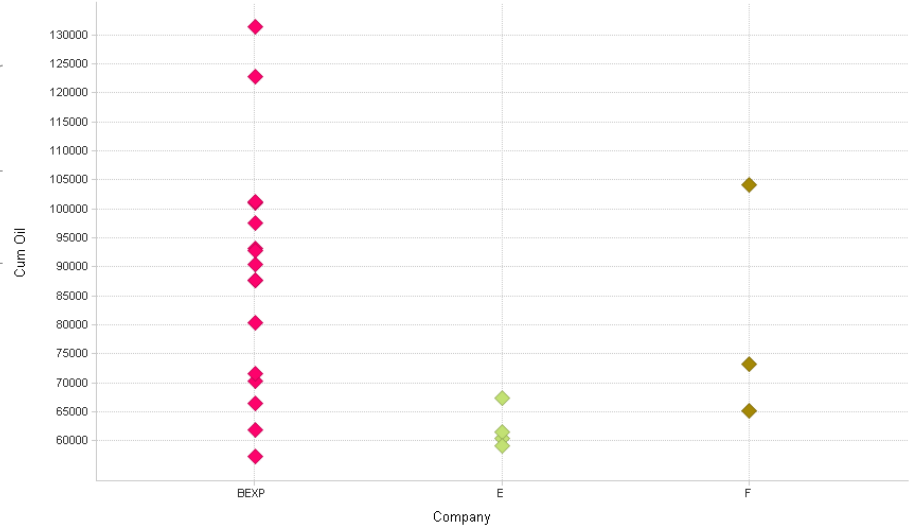
Map Chart



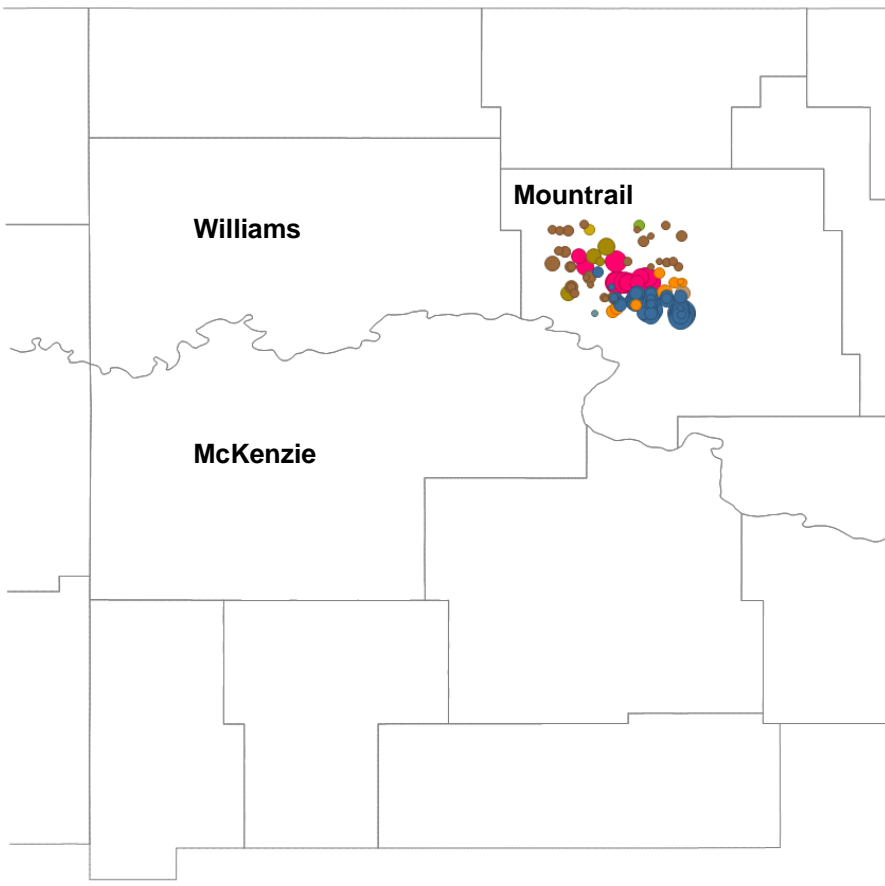
Bar Chart



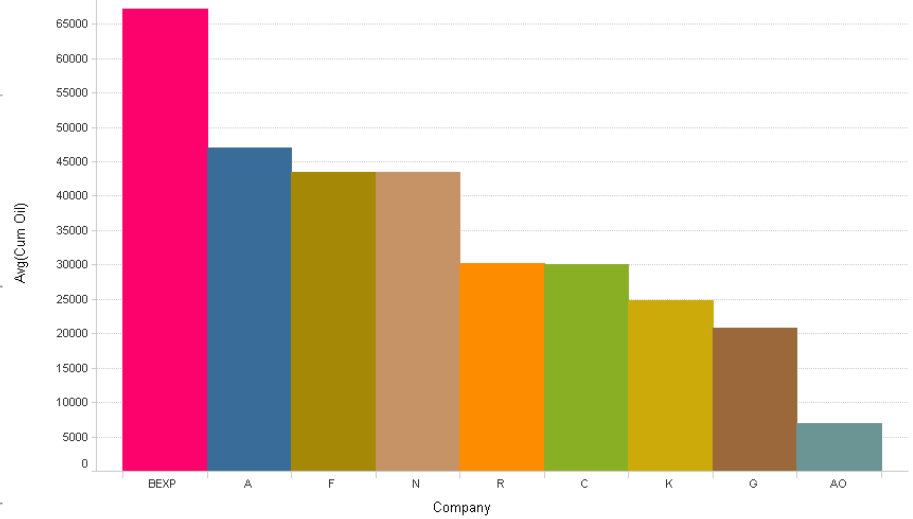
Scatter Plot



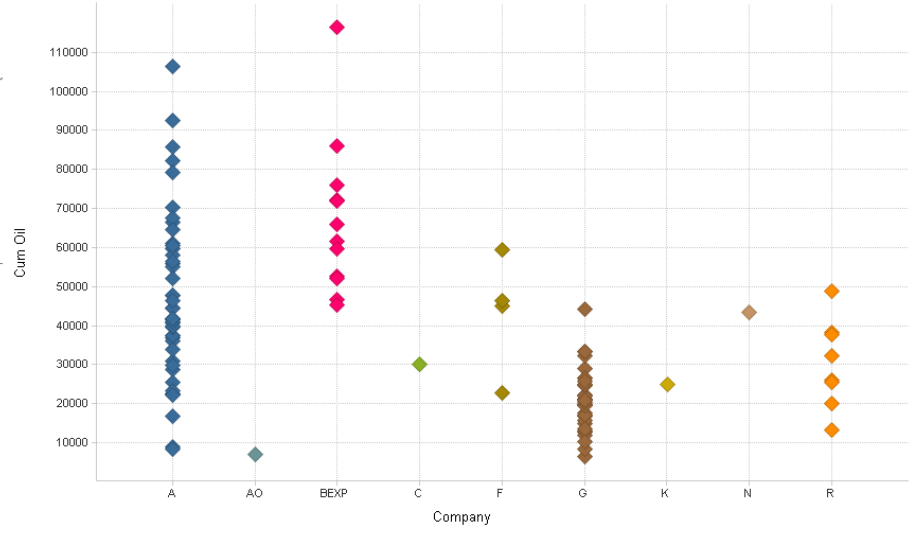
Map Chart



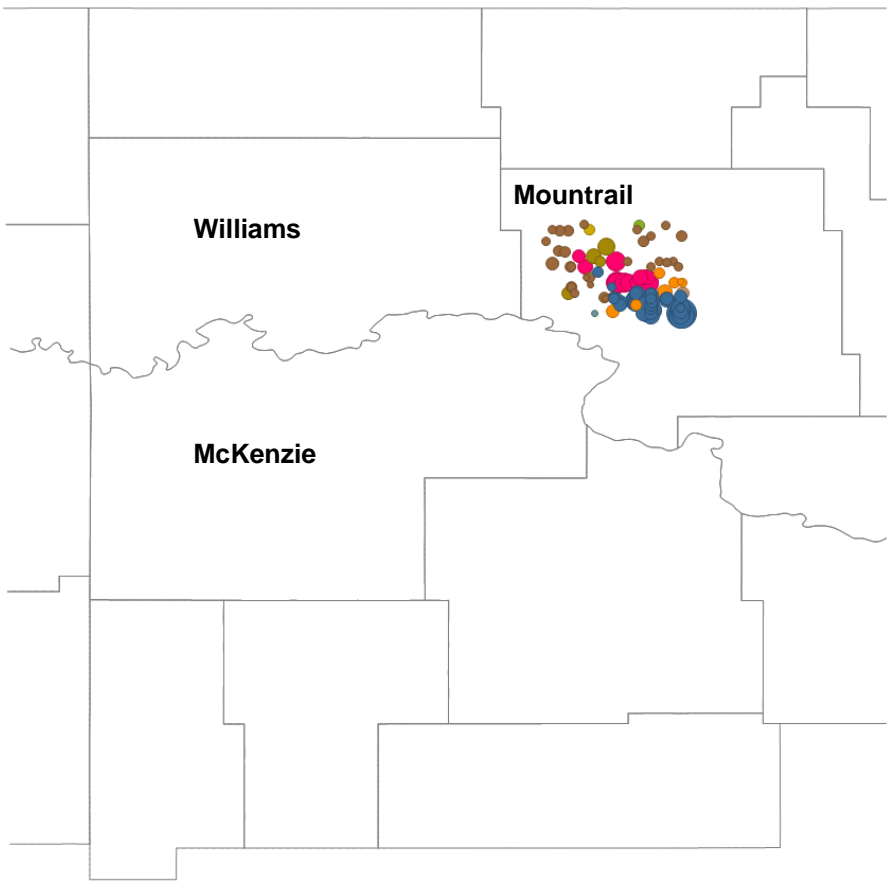
Bar Chart



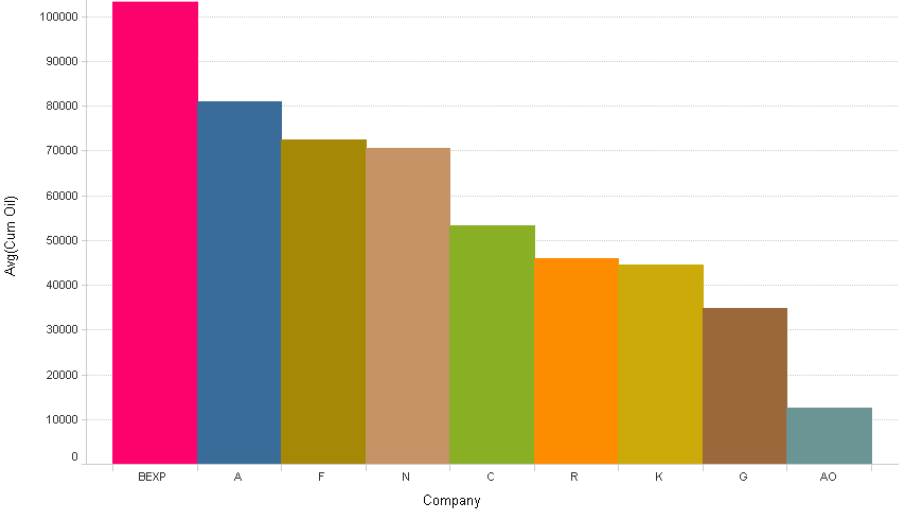
Scatter Plot



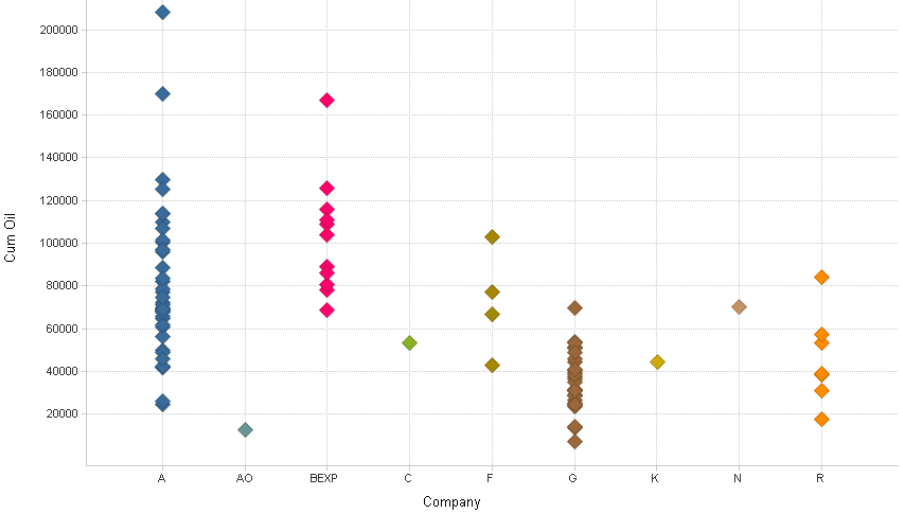
Map Chart



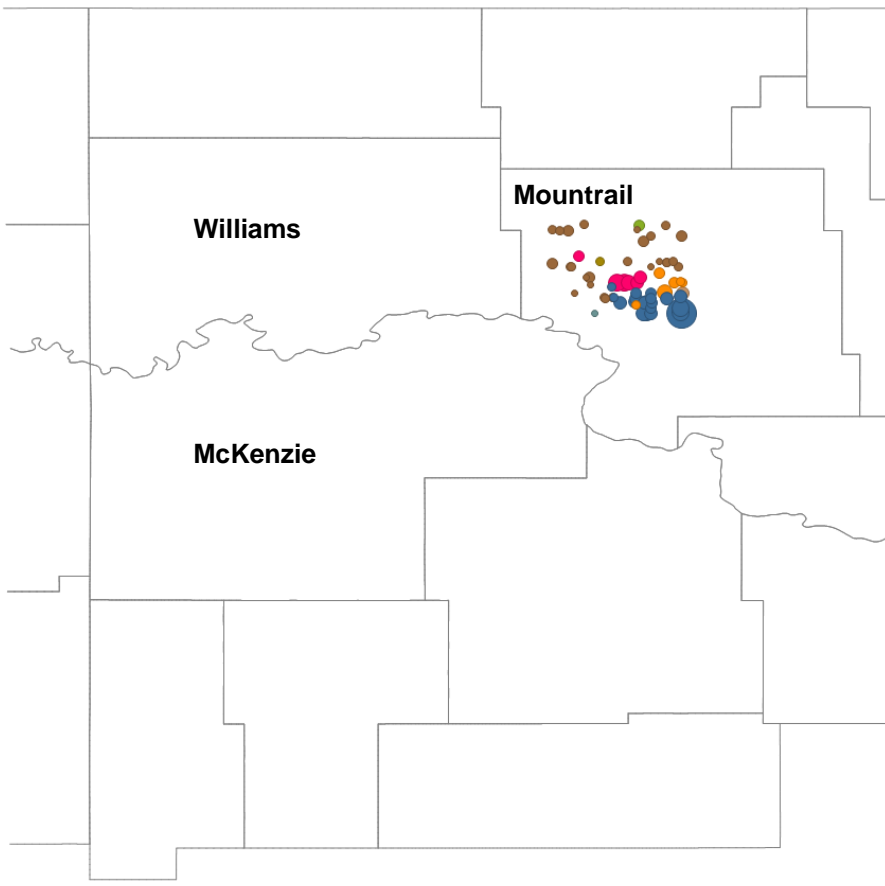
Bar Chart



Scatter Plot



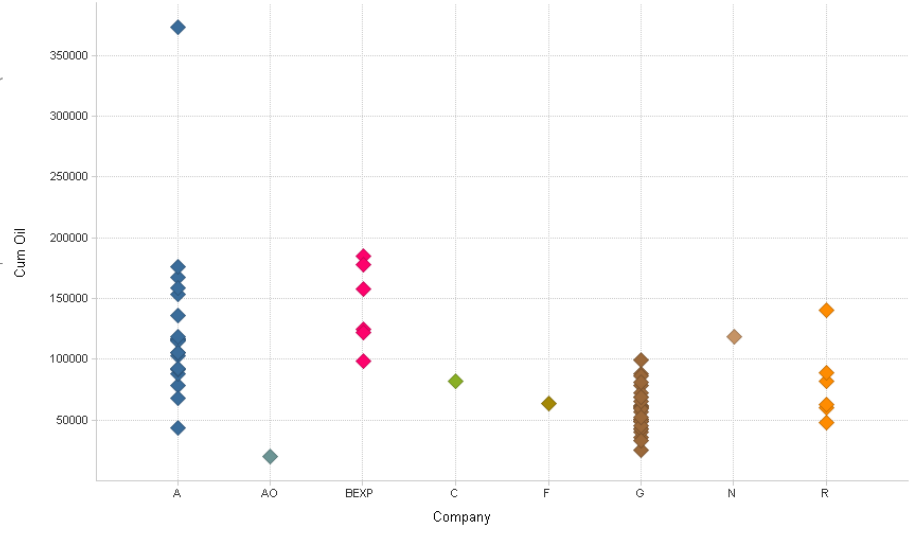
Map Chart



Bar Chart



Scatter Plot





BRIGHAM



**OPERATIONAL
ENHANCEMENTS**

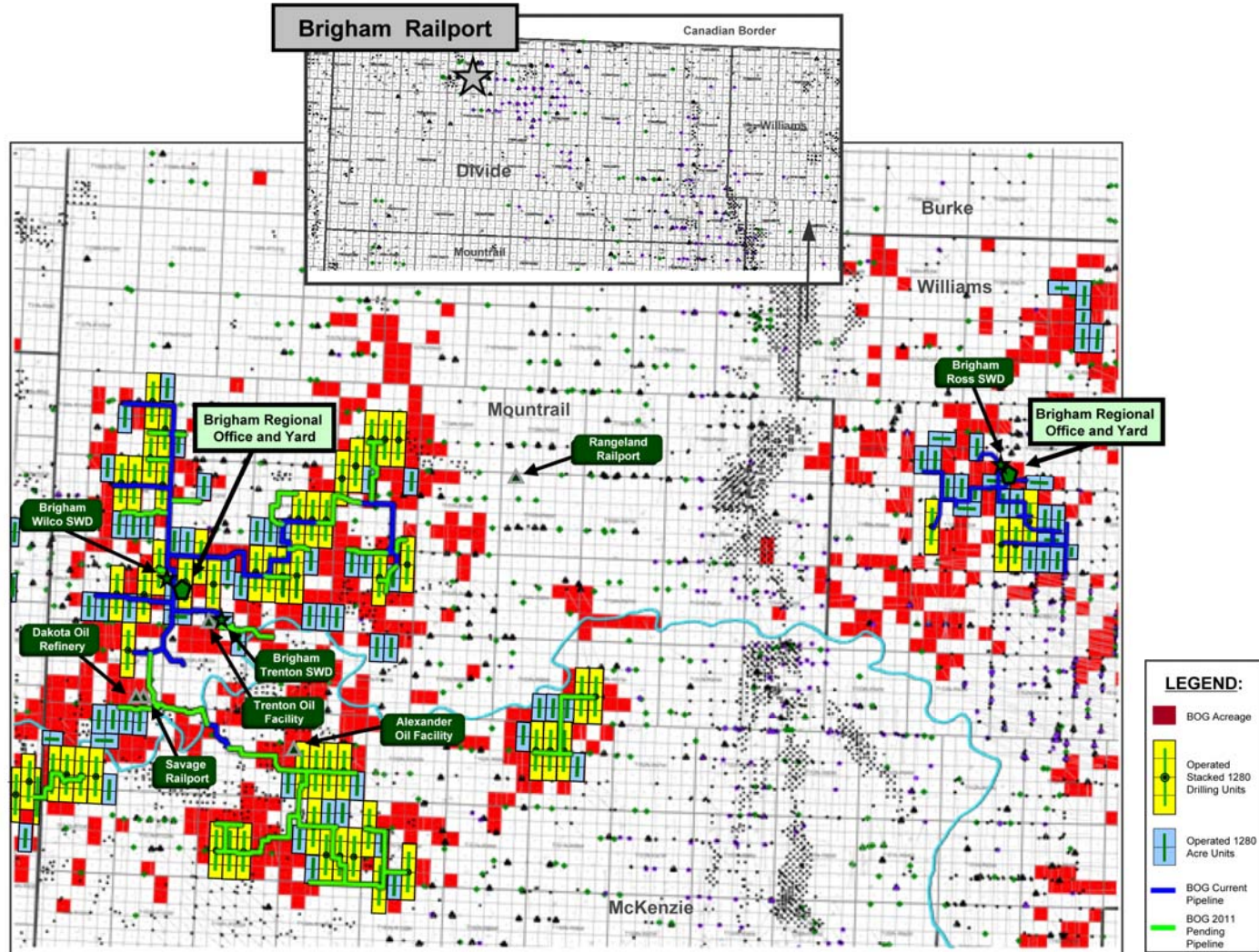
Large Continuous Acreage Blocks

Provide Operational Efficiencies (~188 Operated Drilling Units)

Key Points

- Contiguous acreage blocks provide significant advantages over competitors
 - Enables efficient multi-well pad development drilling
 - Stacked locations allow for simultaneous “zipper fracs”
 - Ability to operate majority of acreage and thereby control pace of development
 - Provides flexibility to avoid surface issues
 - Provides for efficient infrastructure development
 - Targeting 10 to 20% cost savings per well

- Executing acreage trades to further consolidate net acreage positions and increase operational control



Note: Assumes ≥ 30% WI = Operated.

Key Points

- Programmable AC Electric 1500 HP Land Rig
- Canrig 1250 AC, 500 ton Top Drive
- Columbia Walking System
- Two 1600 HP pumps
- BOP Handling System
- Canrig Automated Catwalk
- 800,000 lb static hook load



Key Points

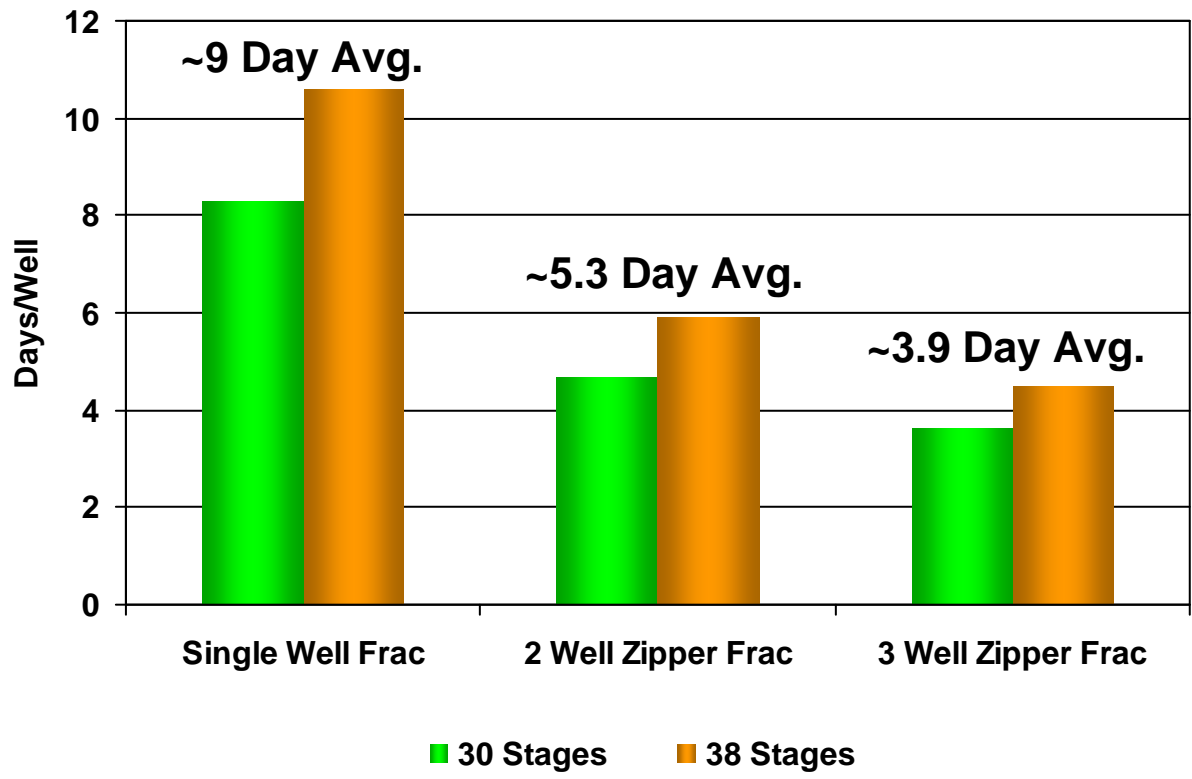
- A direct result of “Smart Pad” drilling
- Allows for simultaneous fracking and plug & perf operations
- One well is being fraced while wireline operations are performed on the other
- Fracing days are reduced by 50% resulting in significant cost savings
- Reduction in equipment mobilization, water transfer, road utilization, diesel, etc.
- Flow backs are optimized by consolidating equipment and resources



Key Points

- Current Results
 - 2 Well Zipper Frac results in a 75% improvement when compared to a single well frac
 - 3 Well Zipper frac results in a 130% improvement when compared to a single well frac

Days to Complete Per Well*

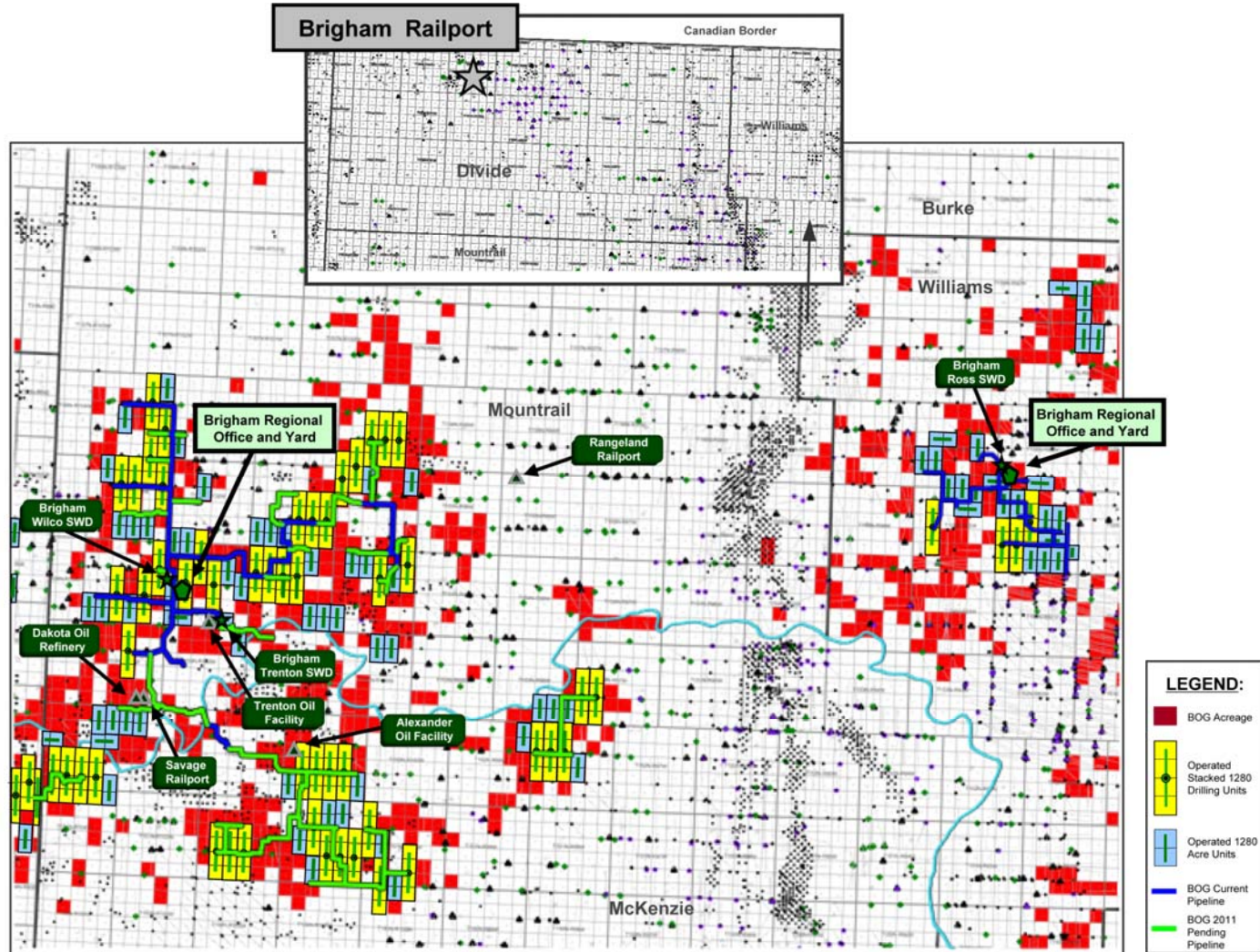


*These counts include a 2-day rig move



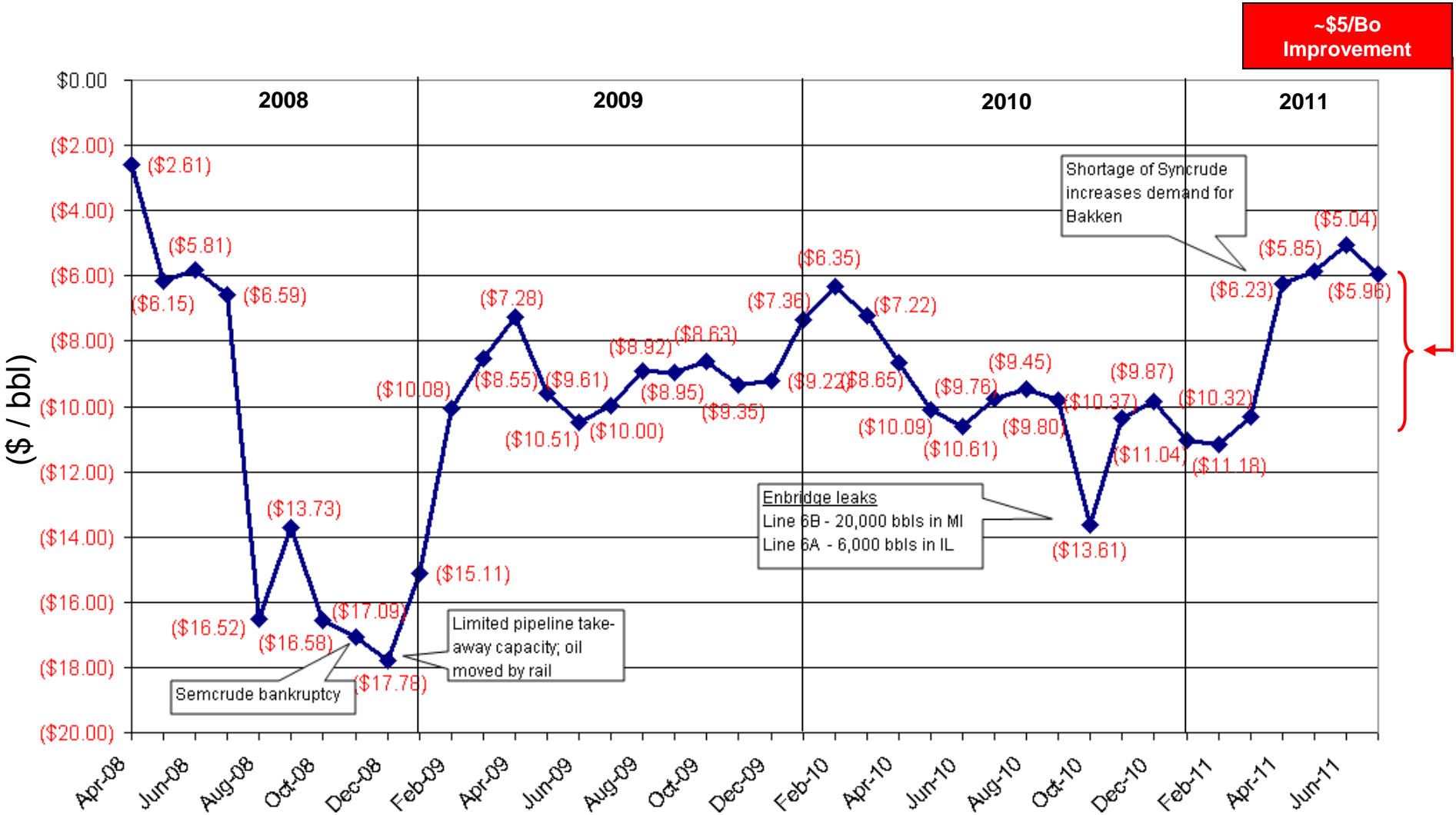
Key Points

- Over 430 miles of oil, produced water, fresh water, and gas gathering lines
- ~112 Stacked 1280 acre units (896 Gross wells) with an additional ~76 Operated 1280 acre units (608 Gross wells)
- Reduced capital costs
- Ensure execution of plan through winter and thaw seasons
- **Competitive and robust returns for midstream investments when compared to well economics**



Brigham Bakken & Three Forks Oil Differentials

Differentials Stabilized in 2009-2010, Improved After Q1 2011



FINANCIAL UPDATE



Oil & Gas Capital Expenditures

	<u>Announced Budget</u>	<u>Updated Budget Forecast</u>	<u>Change from Announced Budget</u>
Drilling	\$582.1	\$669.2	\$87.1
Support Infrastructure	83.2	87.1	3.9
Land	27.4	79.2	51.8
Total Oil & Gas Cap-ex	\$692.7	\$835.5	\$142.8
<i>% Increase from Announced Budget</i>		21%	

Net Wells Drilled

	<u>Announced Budget</u>	<u>Updated Budget Forecast</u>	<u>Change from Announced Budget</u>
Williston Basin	65.7	73.9	8.2
Other	2.4	2.4	-
Total Net Wells	68.1	76.3	8.2

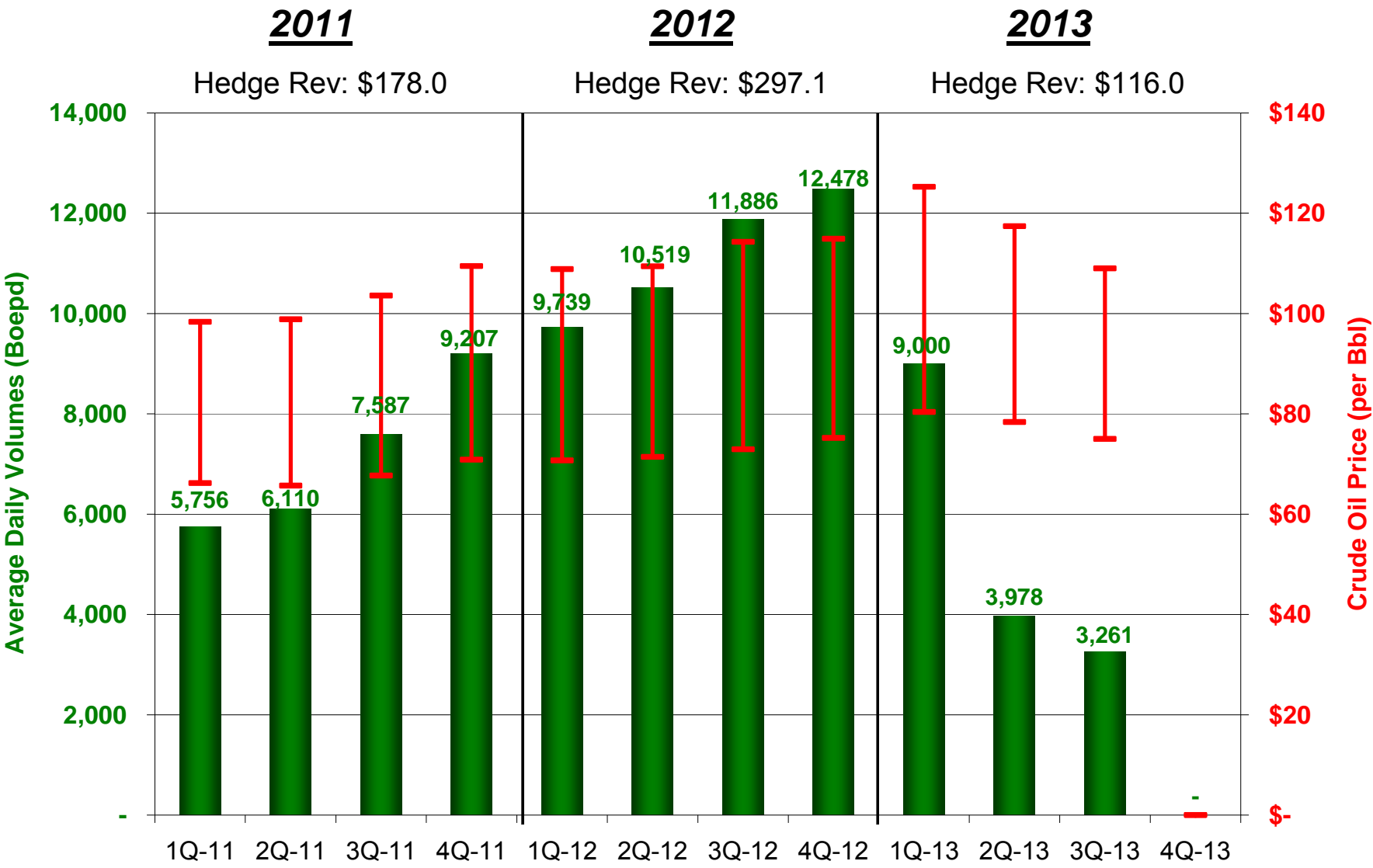
- Further drilling acceleration by bringing forward rigs 9 through 12
- 8.2 incremental net Williston Basin wells and acreage acquisitions account for majority of incremental cap-ex

• Cash position at June 30, 2011	\$362 million
• Re-evaluated borrowing base of undrawn new five year Senior Credit Facility	\$325 million
• Total corporate liquidity	\$687 million

Other potential sources of liquidity:

- Growing production volumes / associated cash flow
- Other conventional asset sales
- October 2011 borrowing base redetermination
- Potential monetization of Midstream business unit

Oil Hedges Outstanding 2011-2013*



*As of 9/29/2011

- **“Manufacturing oil”** – Commanding / growing presence in premier domestic oil resource play, with multiple pay zones and infill drilling providing significant optionality
- **Advanced drilling and completion designs** driving industry leading production, EURs and returns
- **11 to 18 year remaining inventory on de-risked core acreage**
- **Significant incremental NAV growth catalysts** to be assessed over the next 12 months
- **Continuing to add to core acreage position**
- **Accelerating to 12 rigs by March 2012, bringing forward significant NAV growth in 2011 and 2012**
- **Current liquidity position able to fund level of acceleration beyond 12 rig program**

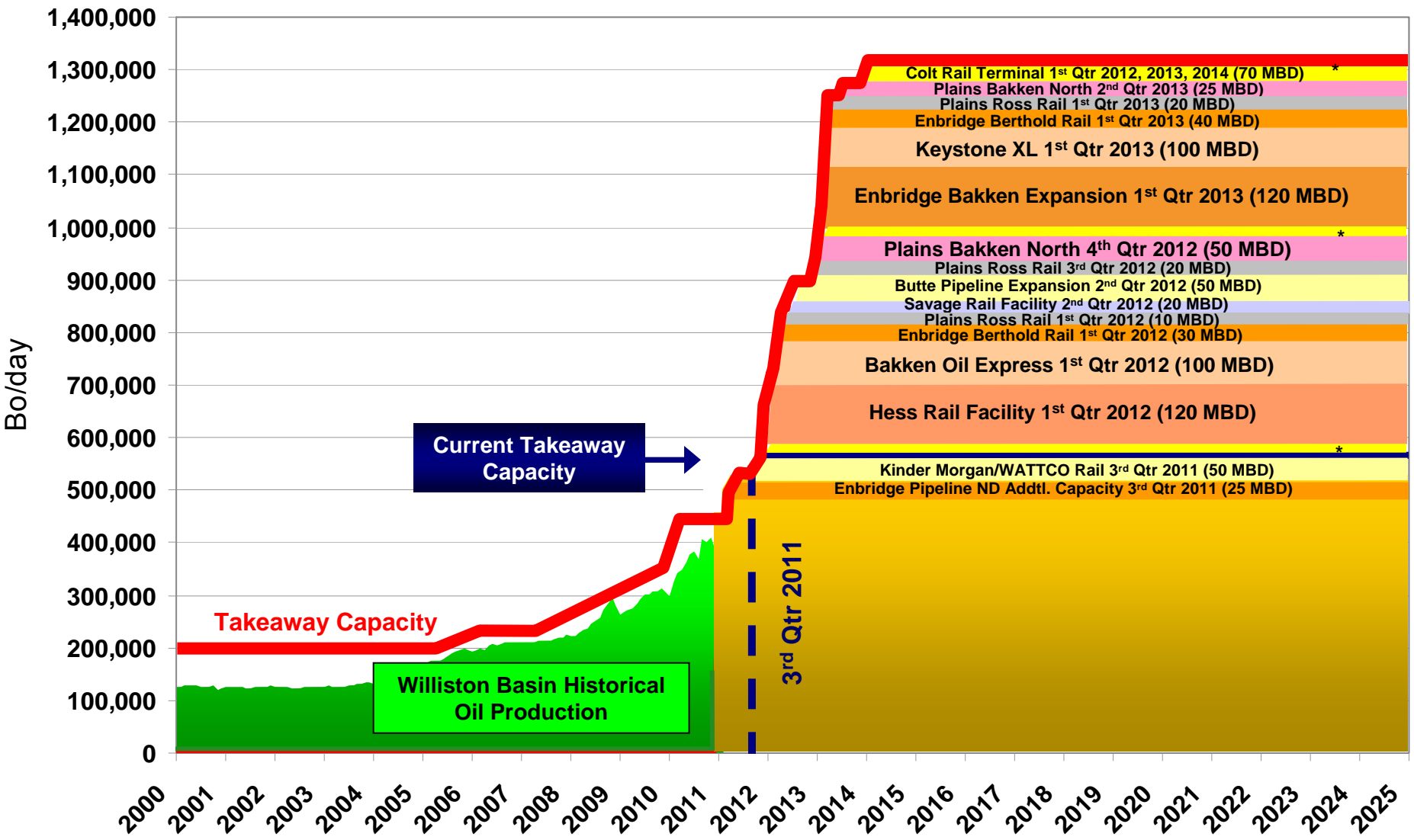
Outstanding drilling results, significant and growing inventory of development drilling locations, favorable operating environment and current liquidity position create an opportunity to accelerate drilling activity and bring forward incremental net asset value per share.

APPENDIX



Williston Basin Oil Production

& Major Takeaway Capacity Expansions



Not Including Tesoro Refining – 58,000 Bopd and Possible Future Expansions EPND Bakken P/L Phase 2 – 180,000 Bopd , Cochin P/L – 50,000 Bopd, Savage Rail – Addtl. 40,000 Bopd & Bakken Oil Express – Addtl. 150,000 bopd

