UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT PURSUANT TO
SECTION 13 OR 15(d) OF THE

SECURITIES EXCHANGE ACT OF 1934

Date of report (Date of earliest event reported): February 11, 2014

LAREDO PETROLEUM, INC.
(Exact Name of Registrant as Specified in Charter)

Delaware	**001-35380**	**45-3007926**
(State or Other Jurisdiction of Incorporation or Organization)	(Commission File Number)	(I.R.S. Employer Identification No.)

15 W. Sixth Street, Suite 1800, Tulsa, Oklahoma	**74119**
(Address of Principal Executive Offices)	(Zip Code)

Registrant’s telephone number, including area code: **(918) 513-4570**

Not Applicable
(Former Name or Former Address, if Changed Since Last Report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 7.01 Regulation FD Disclosure.

On February 11, 2014, Laredo Petroleum, Inc. (the "Company") issued a press release announcing selected production results for 2013 and proved reserves at December 31, 2013. A copy of the press release is furnished as Exhibit 99.1 to this Current Report on Form 8-K.

Also, on February 11, 2014, the Company posted to its website its Corporate Presentation for February 2014. The presentation is available on the Company's website, www.laredopetro.com, and is furnished as Exhibit 99.2 to this Current Report on Form 8-K.

In accordance with General Instruction B.2 of Form 8-K, the information in this report (including Exhibit 99.1 and Exhibit 99.2) is deemed to be "furnished" and shall not be deemed "filed" for the purpose of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liabilities of that section, nor shall such information and Exhibits be deemed incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended.

Item 9.01. Financial Statements and Exhibits.

(d) *Exhibits.*

Exhibit Number	Description
99.1	Press release
99.2	Corporate Presentation February 2014

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

LAREDO PETROLEUM, INC.

Dated: February 11, 2014	By:	/s/ RICHARD C. BUTERBAUGH
		Richard C. Buterbaugh
		Executive Vice President and Chief Financial Officer

EXHIBIT INDEX

Exhibit Number	Description
99.1	Press release
99.2	Corporate Presentation February 2014

LAREDO PETROLEUM, INC.
15 West 6th Street, Suite, 1800 · Tulsa, Oklahoma 74119 · (918) 513-4570 · Fax: (918) 513-4571
www.laredopetro.com

Laredo Petroleum Announces Production and Record Year-End Proved Reserves For 2013

Permian Assets Achieve 27% Reserve Growth and 577% Production Replacement

TULSA, OK - February 11, 2014 - Laredo Petroleum, Inc. (NYSE: LPI) ("Laredo" or "the Company"), today announced proved reserves and preliminary operating results for year-end 2013.

Proved Reserves and Operating Results Highlights

- Produced 11.2 million barrels of oil equivalent ("MMBOE") in 2013 with 9.1 MMBOE of Permian production, an increase of approximately 20% in Permian production; fourth-quarter 2013 production totaled 24,426 barrels of oil equivalent per day ("BOE/D")
- Replaced approximately 577% of Permian production from the drill bit, with total production replacement of approximately 487% at a finding and development cost of $12.00/BOE
- Increased proved reserves to a record 203.6 MMBOE, up approximately 27% adjusted for the Anadarko Basin divestiture and up approximately 8% from year-end 2012
- Increased oil percentage of proved reserves to approximately 55% from 52% in the prior year
- Increased the pre-tax present value ("PV-10")[(1)] of the Company's reserves to $3.1 billion, up approximately 30% from year-end 2012

"In 2013, Laredo continued along the multi-year path we initiated in 2011 to maximize the value of our Permian-Garden City acreage," said Randy A. Foutch, Laredo Chairman and Chief Executive Officer. "After successfully delineating more than half of our acreage in 2012, we embarked on a very disciplined drilling plan in 2013 to determine the optimal initial development program for this asset. In executing this plan in 2013, we grew our Permian reserves 27%, grew our Permian production 20%, sold our Anadarko Basin assets and redeployed the capital into the Permian and positioned the Company for a multi-zone development program in 2014. We believe execution of this program in 2014 and in future years will drive continued reserve and production growth, decrease unit F&D costs and enhance the value of our Permian-Garden City asset."

Laredo's total proved reserves, presented on a two-stream basis, at year-end 2013 were 203.6 MMBOE, an approximate 8% increase from year-end 2012. At year-end 2013, essentially all of the Company's proved reserves were attributable to the Permian Basin, where Laredo achieved proved reserve growth of approximately 27%. Reserves were comprised of 111.5 million barrels of oil and 552.7 billion cubic feet of liquids-rich natural gas. Proved developed reserves represented approximately 35% of the Company's total proved reserves at December 31, 2013, compared to approximately 43% at the prior year-end. The decrease was attributable to the sale of the Company's Anadarko Basin properties, the proved reserves of which were primarily developed. Adjusting for the Company's sale of its Anadarko Basin properties, the proved developed reserves ratio was unchanged versus year-end 2012. Changes in reserves for 2013 are summarized in the chart below:

	Oil	Natural Gas	Oil Equivalents
	MMBbls	Bcf	MMBOE
Beginning of year - December 31, 2012	98.1	542.9	188.6
Revisions of previous estimates	(18.0)	15.7	(15.3)
Extensions, discoveries and other additions	37.9	192.2	69.9
Purchases of reserves in place	0.2	1.5	0.4
Sales of reserves in place	(1.2)	(165.3)	(28.8)
Production	(5.5)	(34.3)	(11.2)
End of year - December 31, 2013	111.5	552.7	203.6
Standardized measure - ($ millions)			$ 2,322.2
Pre-tax PV-10 - ($ millions)			$ 3,053.3

In 2013, Laredo added 69.9 MMBOE through the drill bit, replacing approximately 487% of production. The Company focused its efforts in its Permian-Garden City acreage on horizontal development of the Upper, Middle and Lower Wolfcamp and Cline shale zones. This drilling was largely responsible for the increase in reserves from extensions, discoveries and other additions. Revisions of previous estimates were a result of the Company continually optimizing its drilling plan by removing some vertical and short-lateral locations. These were partially offset by replacing some of the locations with higher rate of return, long-lateral wells and positive revisions on existing proved undeveloped locations.

Laredo's estimated total proved reserves were prepared by Ryder Scott Company, L.P. as of December 31, 2013 and are based on reference oil and natural gas prices. In accordance with applicable rules of the Securities and Exchange Commission ("SEC"), the reference oil and natural gas prices are derived from the average trailing 12-month index prices (calculated at the unweighted arithmetic average of the first-day-of-the-month price for each month within the applicable 12-month period), held constant throughout the life of the properties. Reference prices used, before differentials were applied, were $93.52 per barrel of oil and $3.57 per MMBtu of natural gas. Realized prices were $92.26 per barrel of oil and $5.52 per Mcf for the Company's liquids-rich natural gas.

For 2013, the preliminary estimate of finding and development (F&D) cost was $12.00/BOE, and the preliminary estimate of finding development and acquisition (FD&A) cost was $12.58/BOE, presented on a two-stream basis. The F&D and FD&A costs will be finalized upon filing the Company's annual report on Form 10-K. For a description of F&D and FD&A costs, please see the discussion below under the heading "Finding & Development and Acquisition Cost."

Laredo Petroleum, Inc. is an independent energy company with headquarters in Tulsa, Oklahoma. Laredo's business strategy is focused on the exploration, development and acquisition of oil and natural gas properties primarily in the Permian region of the United States.

Additional information about Laredo may be found on its website at www.laredopetro.com.

Forward-Looking Statements

This press release contains forward-looking statements as defined under Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, that address activities that Laredo assumes, plans, expects, believes, intends, projects, estimates or anticipates (and other similar expressions) will, should or may occur in the future are forward-looking statements. The forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events.

The preliminary results above are based on the most current information available to management. As a result, our final results may vary from these preliminary estimates. Such variances may be material; accordingly, you should not place undue reliance on these preliminary estimates.

General risks relating to Laredo include, but are not limited to, the risks described in its Annual Report on Form 10-K for the year ended December 31, 2012, Quarterly Report on Form 10-Q for the quarter ended June 30, 2013, and those set forth from time to time in other filings with the SEC. These documents are available through Laredo's website at www.laredopetro.com under the tab "Investor Relations" or through the SEC's Electronic Data Gathering and Analysis Retrieval System ("EDGAR") at www.sec.gov. Any of these factors could cause Laredo's actual results and plans to differ materially from those in the forward-looking statements. Therefore, Laredo can give no assurance that its future results will be as estimated. Laredo does not intend to, and disclaims any obligation to, update or revise any forward-looking statement.

Actual quantities of reserves that may be ultimately recovered from the Company's interests may differ substantially from those presented herein. Factors affecting ultimate recovery include the scope of the Company's ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease *expirations, transportation constraints, regulatory approvals and other factors as well as actual drilling results, including geological and mechanical factors affecting recovery rates. In addition, our 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.*

Finding & Development and Acquisition Cost

Finding and development cost, or F&D cost, is calculated by dividing (x) development, exploitation, and exploration capital expenditures for the period, plus unevaluated capital expenditures as of the beginning of the period, less unevaluated capital expenditures as of the end of the period, by (y) reserve additions for the period, excluding acquired reserves. Finding, development and acquisition cost, or FD&A cost, is calculated by dividing (x) development, exploitation, exploration and acquisition capital expenditures for the period, plus unevaluated capital expenditures as of the beginning of the period, less unevaluated capital expenditures as of the end of the period, by (y) reserve additions for the period, including acquired reserves. The methods we use to calculate our F&D and FD&A costs may differ significantly from methods used by other companies to compute similar measures. As a result, our F&D and FD&A costs may not be comparable to similar measures provided by other companies. We believe that providing measures of F&D and FD&A costs are useful in evaluating the costs, on a per barrel of oil equivalent basis, to add proved reserves.

However, these measures are provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with generally accepted accounting principles. Due to various factors, including timing differences in the addition of proved reserves and the related costs to develop those reserves, F&D and FD&A costs do not necessarily reflect precisely the costs associated with particular reserves. As a result of various factors that could materially affect the timing and amounts of future increases in reserves and the timing and amounts of future costs, we cannot assure you that our future F&D or FD&A costs will not differ materially from those presented.

[1] ***PV-10: A Non-GAAP Financial Measure***

PV-10 is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the standardized measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the standardized measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of the PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas assets. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas assets. However, PV-10 is not a substitute for the standardized measure of discounted future net cash flows. Our PV-10 measure and the standardized measure of discounted future net cash flows do not purport to present the fair value of our oil and natural gas reserves.

Laredo Petroleum, Inc.
2013 F&D and FD&A Costs
Unaudited

($ in millions, except per unit amounts)	F&D	FD&A
Exploration, development & exploitation capital	$ 696.4	$ 696.4
Acquisitions (if applicable)	—	36.7
Asset retirement obligation additions	6.8	6.8
Adjustments:		
Unevaluated costs as of December 31, 2012	159.9	159.9
Unevaluated costs as of December 31, 2013	(208.1)	(208.1)
Adjusted capital expenditures related to reserve additions	$ 655.0	$ 691.7
Reserve extensions, discoveries and revisions	54.6	54.6
Acquisitions (if applicable)	—	0.4
Total reserve additions	54.6	55.0
Cost per BOE	$ 12.00	$ 12.58

Laredo Petroleum, Inc.
Reconciliation of Pre-tax PV-10 Non-GAAP Financial Measure
Unaudited

($ in millions)	December 31, 2013
Pre-tax PV-10	$ 3,053.3
Present value of future income taxes discounted at 10%	(731.1)
Standardized measure of discounted future net cash flows	$ 2,322.2

# # #

Contacts:
Ron Hagood: (918) 858-5504 - RHagood@laredopetro.com

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EXHIBIT 99.2

Forward-Looking / Cautionary Statements

This presentation contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical fact, included in this presentation that address activities, events or developments that Laredo Petroleum, Inc. (the "Company", "Laredo" or "LPI") assumes, plans, expects, believes or anticipates will or may occur in the future are forward-looking statements. The words "believe," "expect," "may," "estimates," "will," "anticipate," "plan," "intend," "foresee," "should," "would," "could," or other similar expressions are intended to identify forward-looking statements, which are generally not historical in nature. However, the absence of these words does not mean that the statements are not forward-looking. Without limiting the generality of the foregoing, forward-looking statements contained in this presentation specifically include the expectations of plans, strategies, objectives and anticipated financial and operating results of the Company, including as to the Company's drilling program, production, hedging activities, capital expenditure levels and other guidance included in this presentation. These statements are based on certain assumptions made by the Company based on management's expectations and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. These include, but are not limited to, risks relating to financial performance and results, current economic conditions and resulting capital restraints, prices and demand for oil and natural gas, availability of drilling equipment and personnel, availability of sufficient capital to execute the Company's business plan, impact of compliance with legislation, regulations, and regulatory actions, successful results from our drilling activities, the Company's ability to replace reserves and efficiently develop and exploit its current reserves and other important factors that could cause actual results to differ materially from those projected as described in the Company's Annual Report on Form 10-K for the year ended December 31, 2012, Quarterly report on form 10-Q for the quarter ended June 30, 2013, Quarterly report on form 10-Q for the quarter ended September 30, 2013 and Laredo's other reports filed with the SEC.

Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

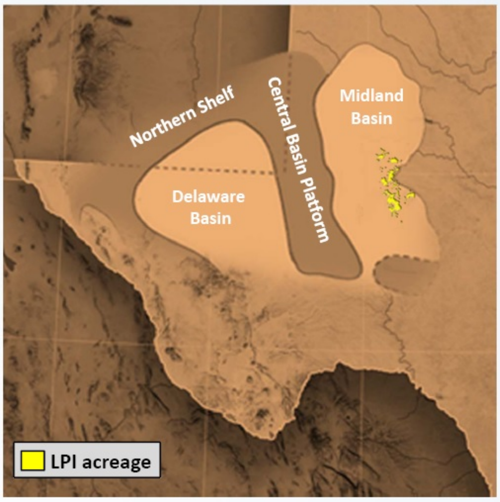
The SEC generally permits oil and gas companies, in filings made with the SEC, to disclose proved reserves, which are reserve estimates that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions and certain probable and possible reserves that meet the SEC's definitions for such terms. In this presentation, the Company may use the terms "estimated ultimate recovery", "EUR" or descriptions of volumes of reserves which the SEC guidelines restrict from being included in filings with the SEC without strict compliance with SEC definitions. The Company does not choose to include unproved reserve estimates in its filings with the SEC. Estimated ultimate recovery, refers to the Company's internal estimates of per well hydrocarbon quantities that may be potentially recovered, from a hypothetical and actual well completed in the area. Actual quantities that may be ultimately recovered from the Company's interests are unknown. Factors affecting ultimate recovery include the scope of the Company's ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals and other factors, as well as actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of ultimate recovery from reserves may change significantly as development of the Company's core assets provide additional data. In addition, the Company'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.

This presentation includes financial measures that are not in accordance with generally accepted accounting principles ("GAAP"), including Adjusted EBITDA. While management believes that such measures are useful for investors, they should not be used as a replacement for financial measures that are in accordance with GAAP. For a reconciliation of Adjusted EBITDA to the nearest comparable measure in accordance with GAAP, please see the Appendix.

As previously disclosed, on August 1, 2013 (with an economic effective date of April 1, 2013) the Company disposed of its oil and natural gas properties, associated pipeline assets and various other associated property and equipment in the Anadarko Granite Wash, Central Texas Panhandle and the Eastern Anadarko Basin. As a result of such sale, the reserves, cash flows and all other attributes associated with the ownership and operations of these properties have been eliminated from the ongoing operations of the Company, and the information in this presentation has been prepared on such basis.

Laredo Petroleum Today

- High-quality acreage position in the fairway of the Midland Basin
- Top-tier well results in multiple horizons
- Significant resource potential: >10x existing reserves [1]
- Transitioning to development manufacturing mode
- Strong financial structure

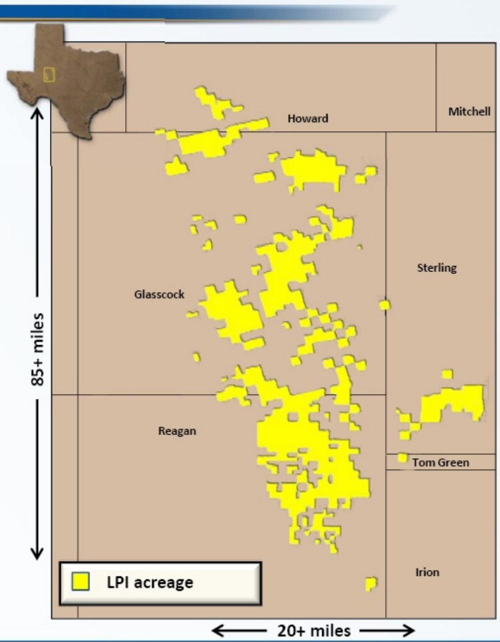


Concentrated Garden City acreage is in the heart of the Permian's Midland Basin

[1] Based on reserves as of 12/31/13, prepared by Ryder Scott, presented on a two-stream basis

Concentrated Asset Portfolio Focused in Midland Basin

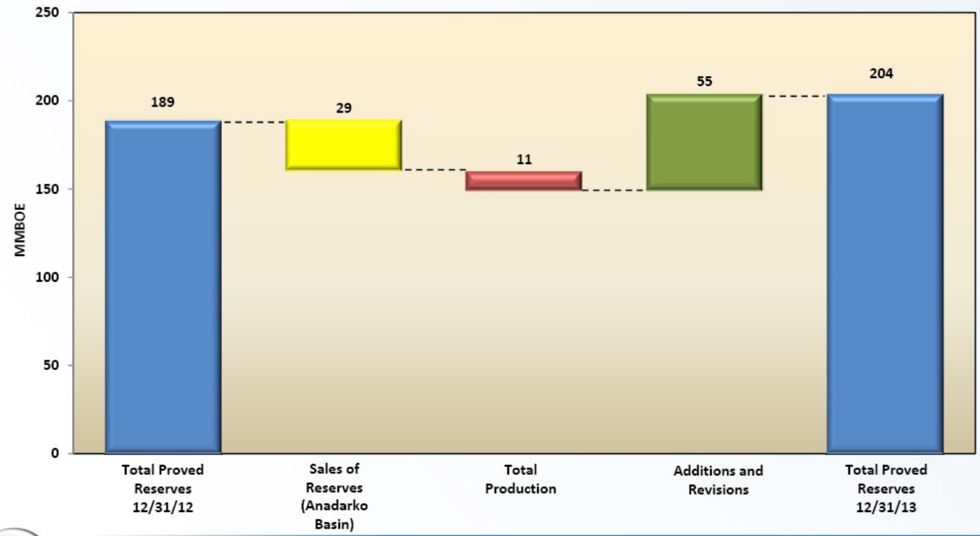
- ~143,212 net acres[1]
- ~65% held by production[1]
- ~90% average working interest[2]
- Multiple horizontal zones in addition to the Wolfcamp and Cline.



[1] As of 12/31/2013
[2] Working interest in wells drilled as of 12/31/2013

2013 Reserve Update [1]

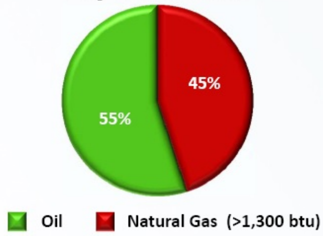
487% Production Replacement



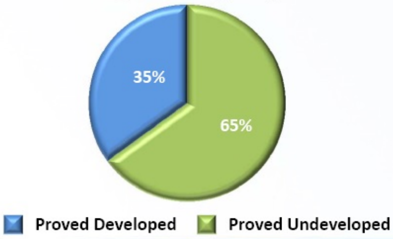
[1] Based on reserves as of 12/31/13, prepared by Ryder Scott and presented on a two-stream basis

Permian Reserves

By Product

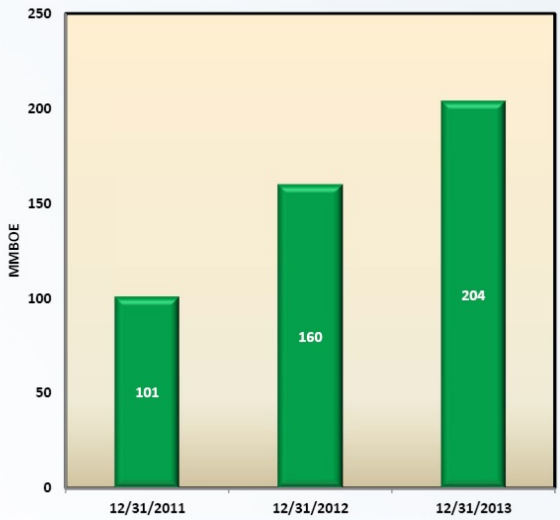


By Category



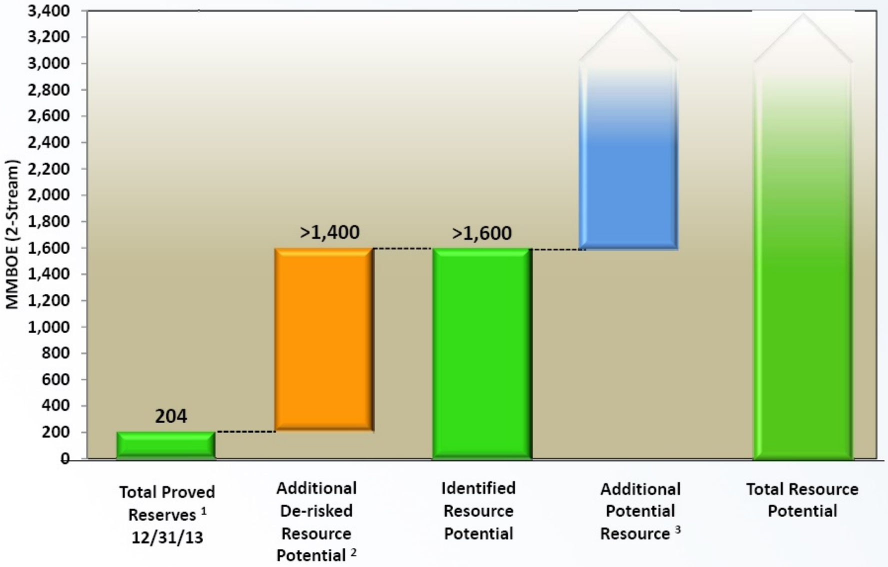
204 MMBOE as of 12/31/13[1]

Permian Reserve Growth



[1] Based on reserves as of 12/31/13, prepared by Ryder Scott and presented on a two-stream basis

Identified Path for Growth

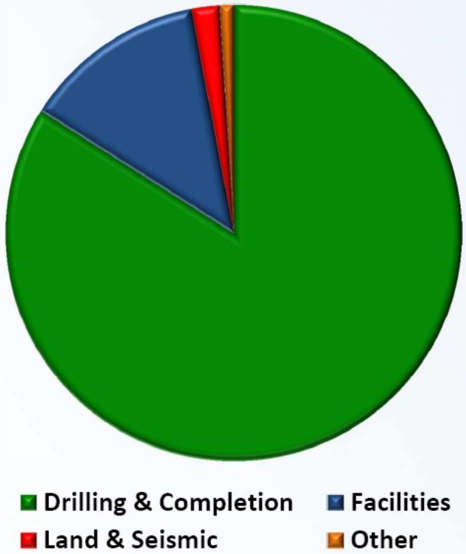


[1] Based on reserves as of 12/31/13, prepared by Ryder Scott and presented on a two-stream basis
[2] Based upon un-booked identified well locations for vertical Wolfberry and horizontal wells in the Upper Wolfcamp, Middle Wolfcamp, Lower Wolfcamp and Cline
[3] Includes potential locations on acreage not de-risked by Hz wells, additional zones for Hz development and potential down-spacing

2014 Capital Program

Total Capital - 2014
~$1,000 MM

Drilling & Completion	$840 MM
Facilities	130 MM
Land & Seismic	20 MM
Other	10 MM



Drilling & Completion Capital

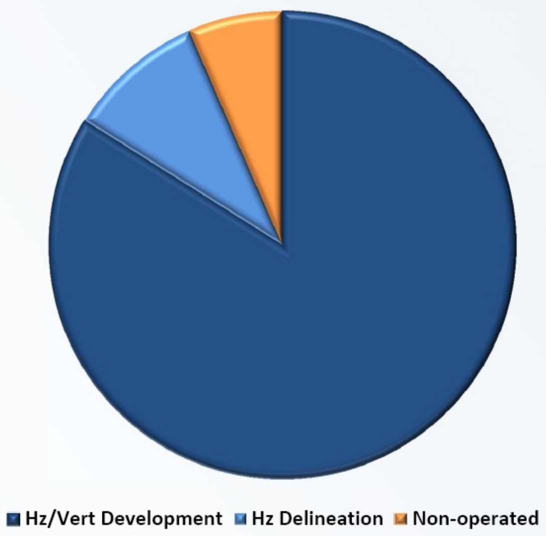
Drilling & Completion
~$840 MM

Hz Development	~55%
Vertical Development	~30%
Hz Delineation	~10%
Non-operated	~ 5%

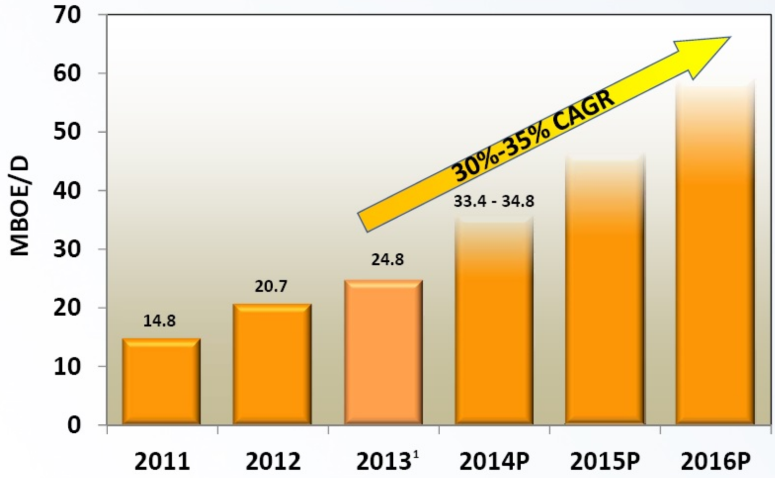
Number of Rigs / Wells

6-7 Horizontal Rigs
Development: 60 - 65
Delineation: 10 - 12

5 Vertical Rigs
Development: 120 - 125

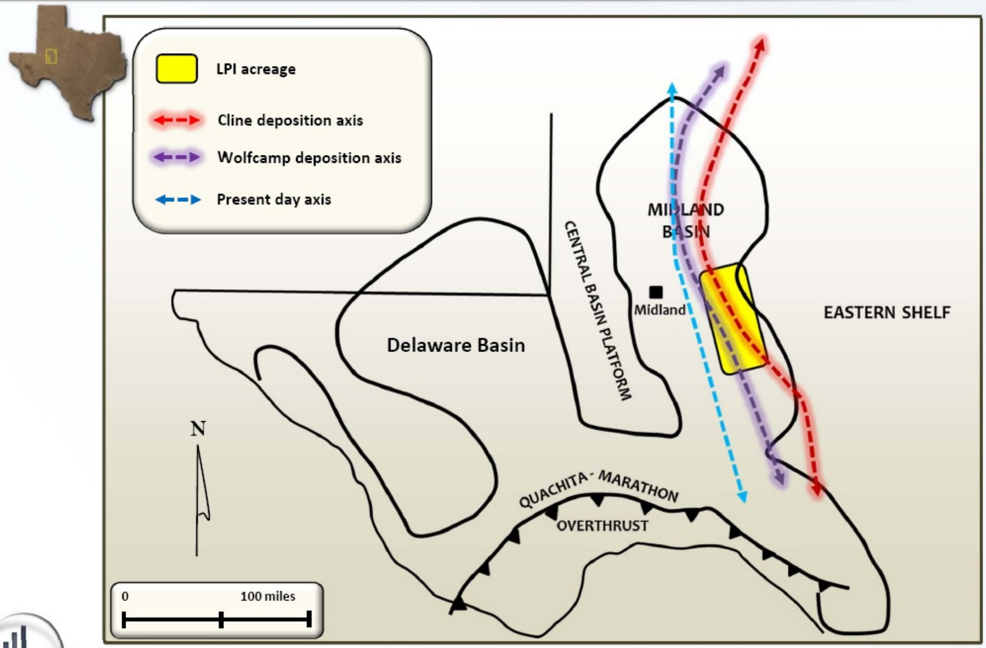


Permian Production Growth

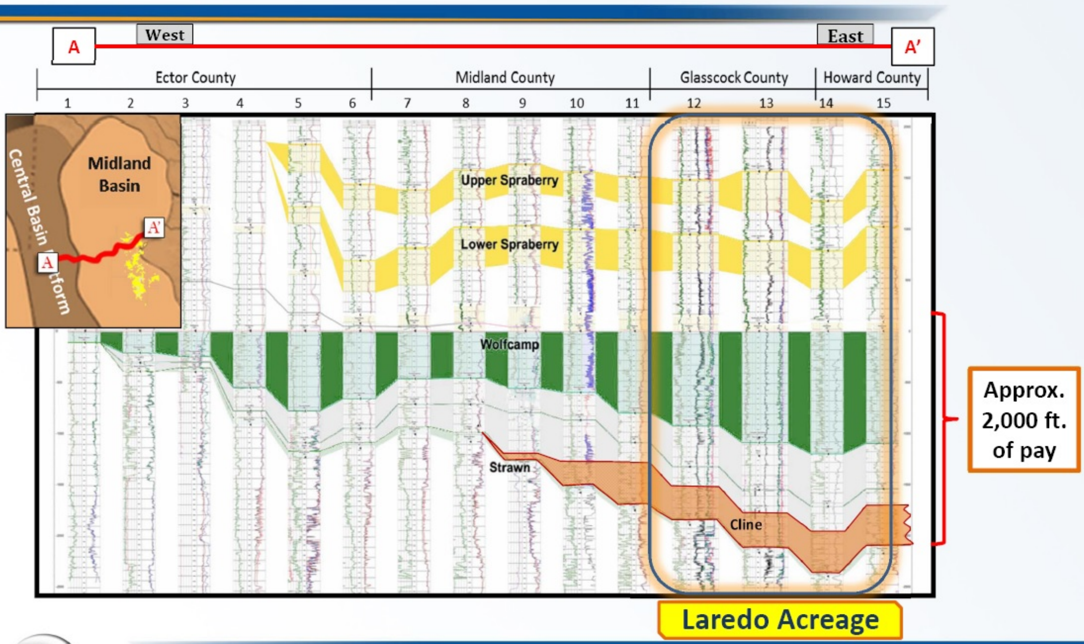


[1]Preliminary

Permian Basin: Present Day

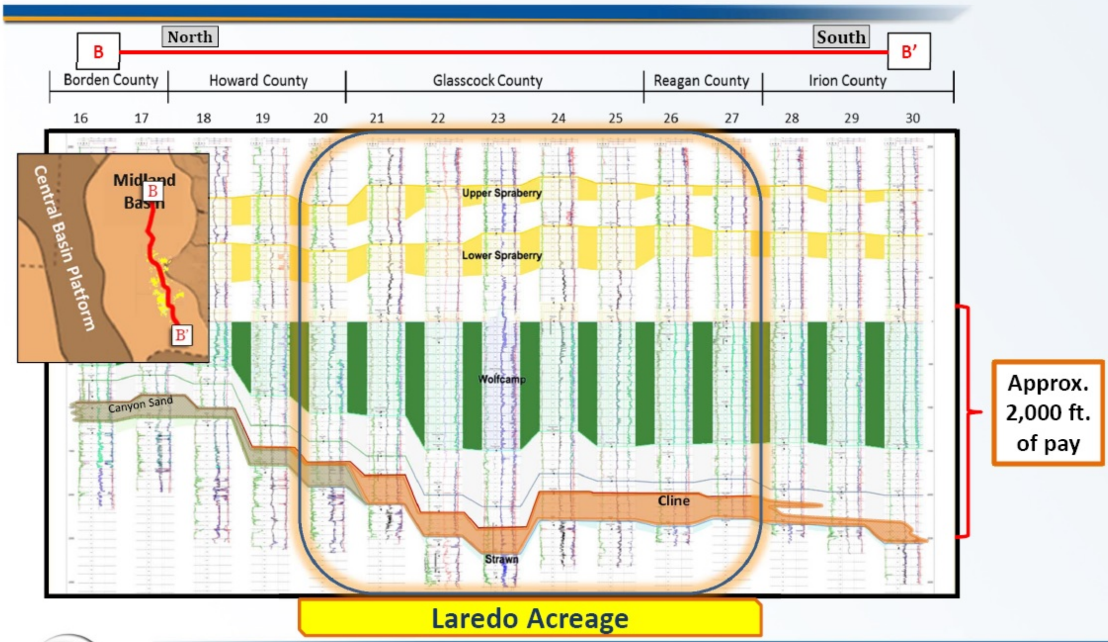


Laredo Situated Over Thickest Column of Sediment: W-E



[1] Modified from Core-Lab, 2013

Laredo Situated Over Thickest Column of Sediment: N-S



[1] Modified from Core-Lab, 2013

Laredo's Permian-Garden City Shales[1]

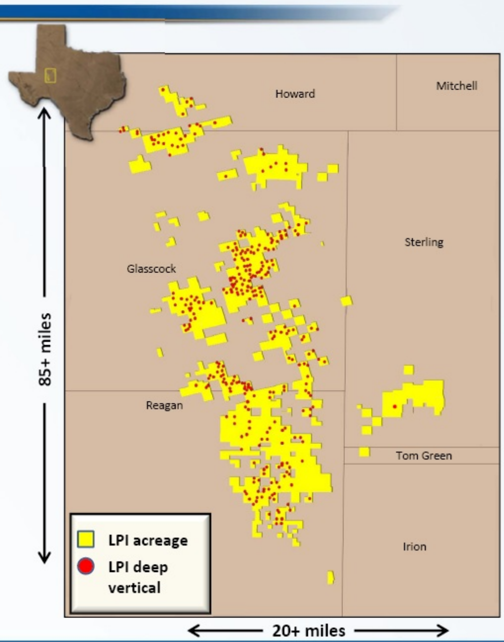
Significant oil in place in multiple stacked zones

	Spraberry	Wolfcamp	Cline	A/B/W	Combined
Depth (ft)	5,000 – 7,000	7,000 – 8,500	9,000 – 9,500	9,500 – 10,500	5,000 – 10,500
Average Thickness (ft)	1,500 – 2,000	1,200 – 1,500	250 – 350	350 – 400	3,300 – 4,250
TOC (%)	4.0 – 13.0	2.0 – 9.0	2.0 – 7.5	2.0 – 13.0	2.0 – 13.0
Thermal maturity (% RSO)	0.6 – 0.7	0.7 – 0.9	0.9 – 1.1	0.9 – 1.2	0.6 – 1.2
Total porosity (%)	6.0% – 16.0%	4.0% – 8.0%	5.0% – 8.0%	3.0% – 13.0%	3.0% – 16.0%
Clay content (%)	15 – 40	25 – 45	30 – 40	20 – 45	15 – 45
Pressure gradient (psi/ft)	0.40 – 0.50	0.45 – 0.50	0.55 – 0.65	0.55 – 0.65	0.40 – 0.65
OOIP (MMBOE/Section)	45 – 85	70 – 115	25 – 35	40 – 55	180 – 290

[1] Properties from proprietary LPI core analysis

Vertical Wolfberry: Confirms Quality of Acreage[1]

- >800 vertical Wolfberry wells across acreage
  - >300 deep vertical Wolfberry wells through the Atoka
- Average vertical well density is approximately one well per 175 acres across acreage
- >20% rate of return

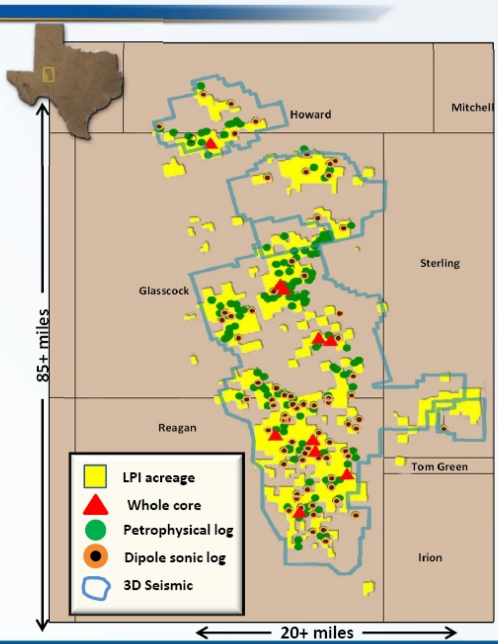


[1] As of 12/31/2013

Vertical Program Data Collection

Garden City Data Inventory [1]

- ~3,400' of whole cores in objective section
  - 13 whole cores
  - >650 SWC samples
- 34 single-zone tests from objective section (Spraberry to Ellenberger)
- >8,000 conventional open-hole logs
  - 207 in-house petrophysical logs
  - 80 dipole sonic logs
  - Fully core-calibrated
- 774 sq mi 3D Seismic
  - 95% coverage of Garden City acreage
  - >50% of seismic inventory is high-quality, proprietary 3D data



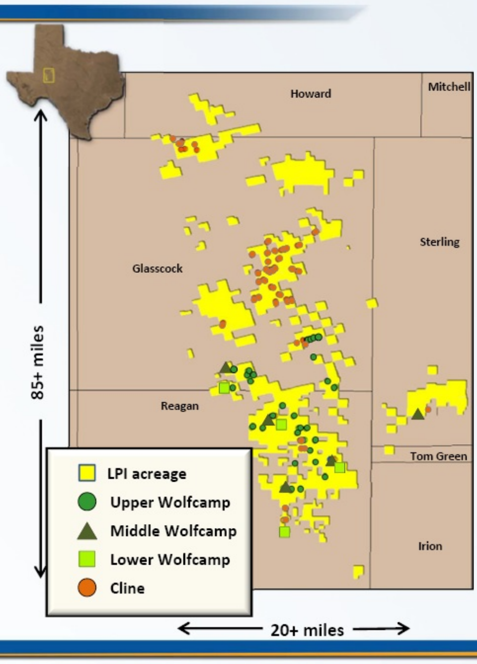
[1] As of 6/30/2013

Proven Multi-zone Horizontal Performance

Average 30-day IP results from the Upper, Middle and Lower Wolfcamp at high end or exceeding type curve

Horizontal Zone	Total # of Completions[1] Short Lateral	Total # of Completions[1] Long Lateral	Long Lateral 30-Day Average IP[2] *BOE/D 2-Stream*
Upper Wolfcamp	7	25	717
Middle Wolfcamp	1	5	630
Lower Wolfcamp	0	4	861
Cline	31	6	594

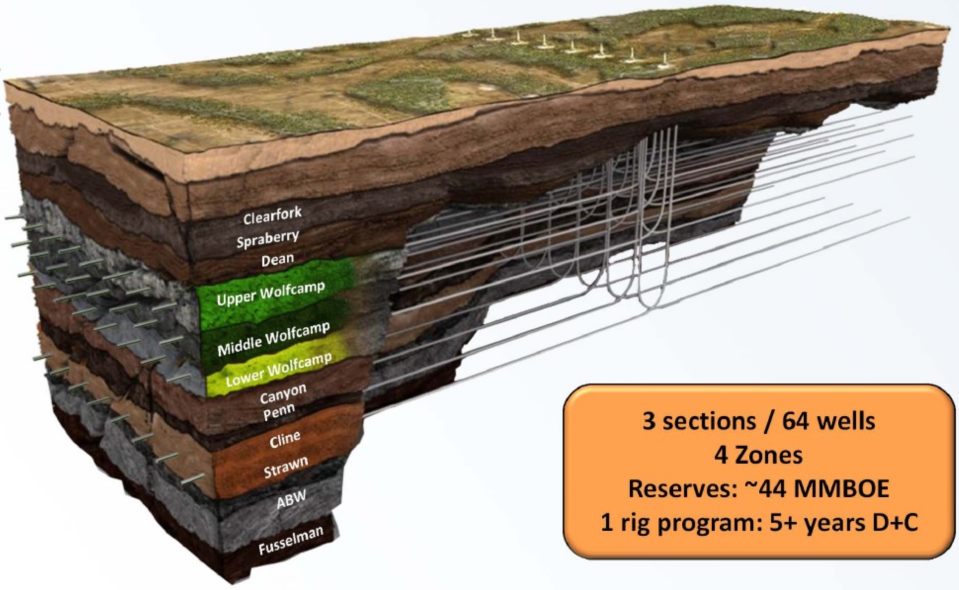
Commercial development has been proven for all four zones from 79 horizontal wells



[1] Well completions as of 9/30/2013
[2] Based on long lateral completions of over 6,000 ft with at least 30 days of production history past peak production as of 9/30/2013

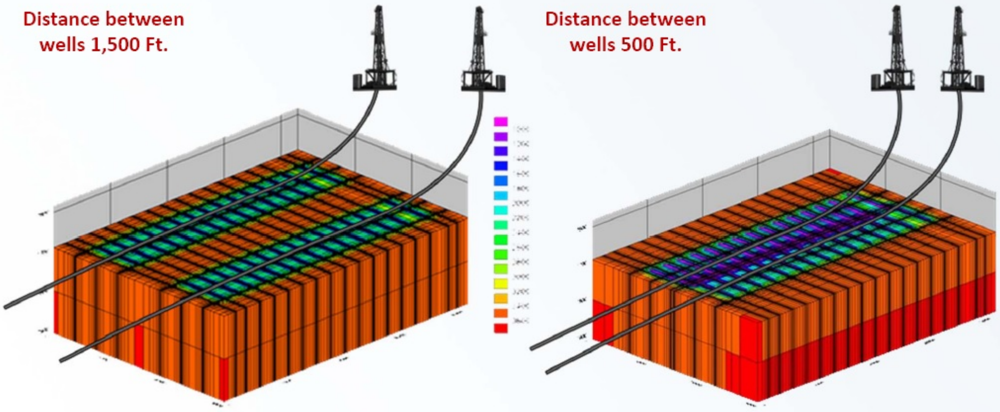
Concentration of Resources Drives Efficiencies

Not to scale
Represents
~5,000 ft



3 sections / 64 wells
4 Zones
Reserves: ~44 MMBOE
1 rig program: 5+ years D+C

Lateral Spacing Reservoir Simulation[1]



Reservoir Modeling Goals

- Optimize economics
  - Maximize recovery
  - Minimize wells
- Plan with life-cycle in mind

20-year reservoir drainage simulation supports 660-ft spacing for initial development phase

[1] Reservoir simulations resulted from joint project with Halliburton

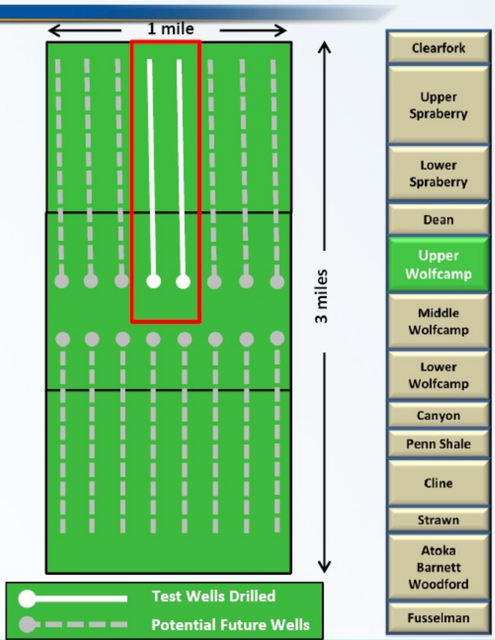
Side-by-Side Conceptual Design

Side-by-Side Design

- Two side-by-side wells both drilled in one zone
- Lateral lengths: 7,000 – 7,500 feet
- Spacing: 660 feet

Objectives

- Optimize spacing
- Minimize interference
- Frac design and monitoring
- Frac optimization

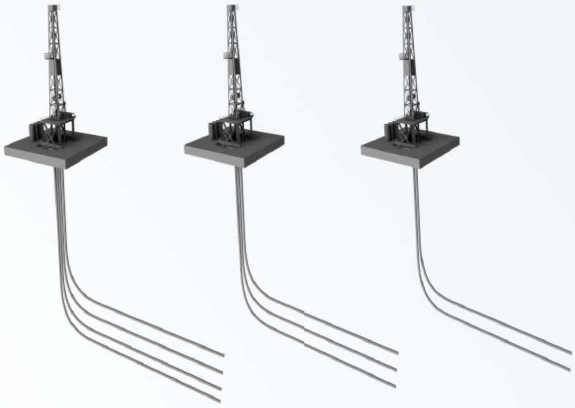


Muti-Zone Development in 2014

Stacked Lateral Development

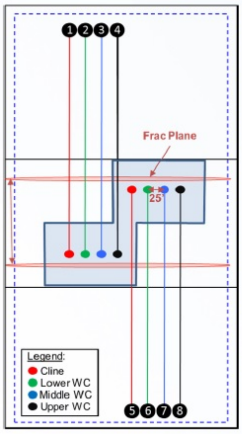
- **2014 program expected to drill ~60 stacked laterals utilizing 20 multi-well pads**
- **First 3-well stacked pad completed in 2013**
  - **two-stream, 24-hour production rate of 3,318 BOE/D[1]**

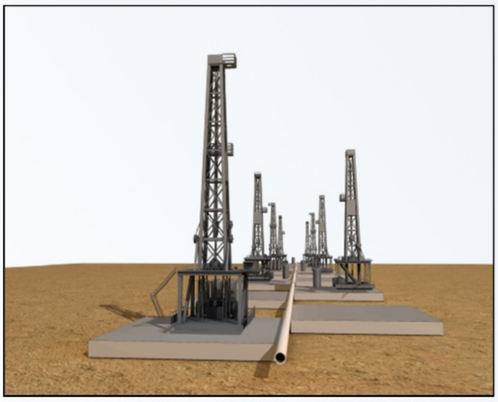
4-Stacked 28 wells ***3-Stacked 18 wells*** ***2-Stacked 14 wells***



[1] Drilled into the Upper, Middle and Lower Wolfcamp

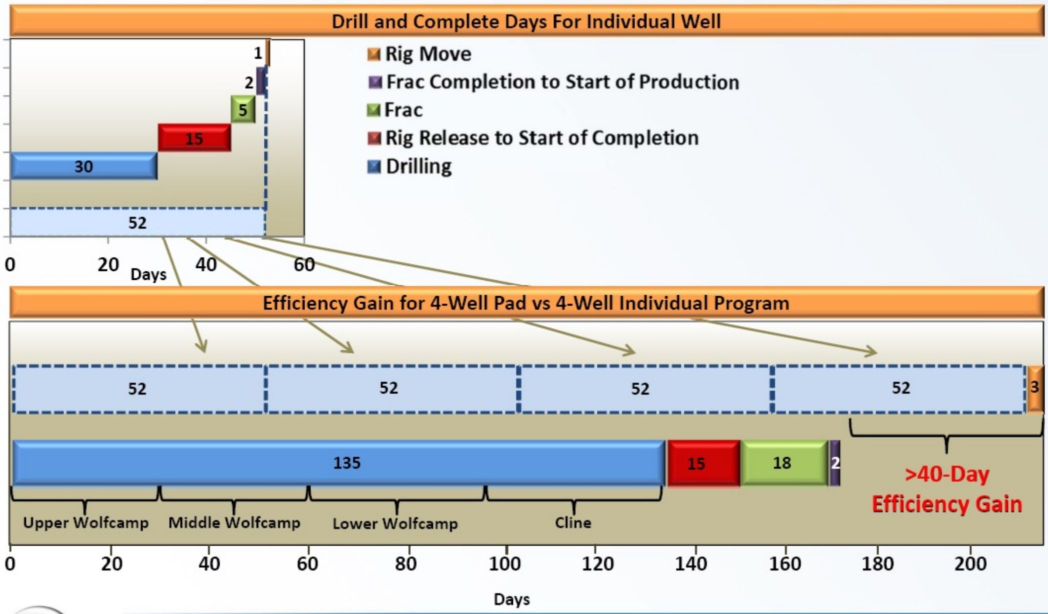
Offset Pad Development



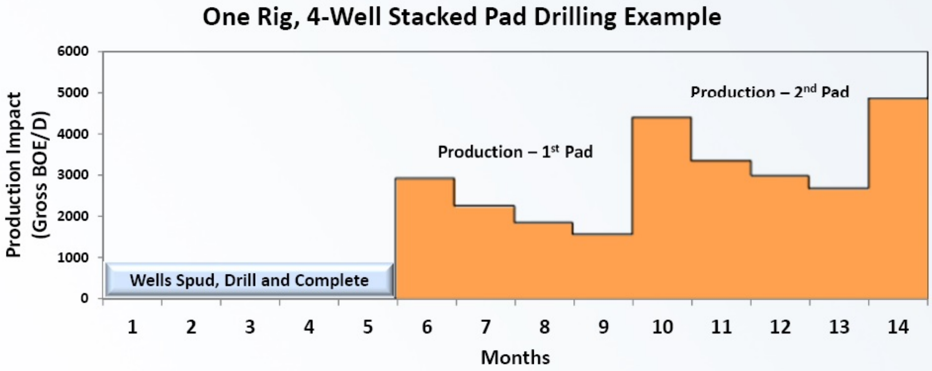


Offset pad configuration provides the optimal geometry to fully drain a section

Efficiency Gains from Pad Drilling

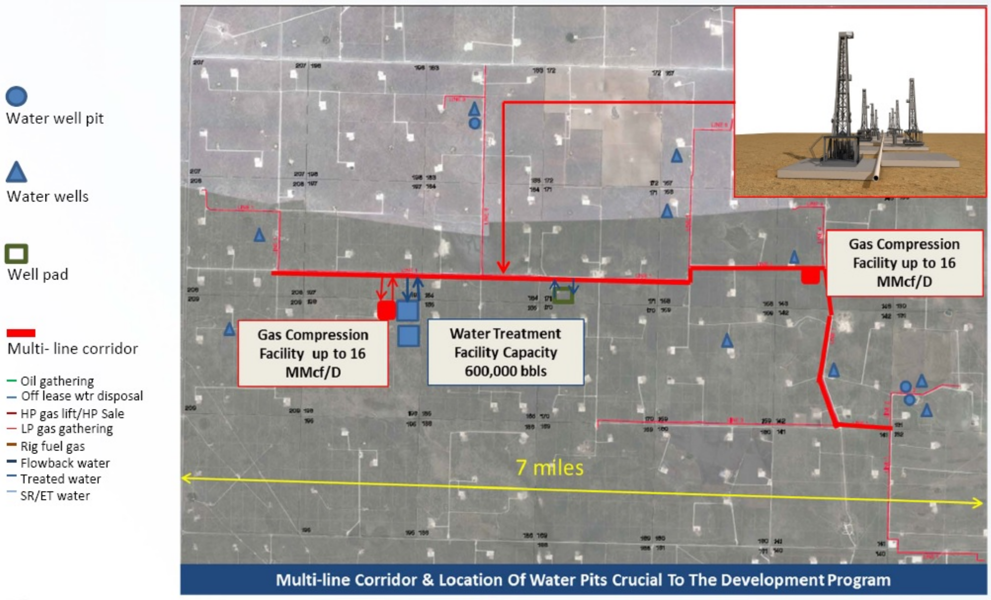


Production Impact From Multi-Well Pads



- Creates lumpy production
- Up to 123-day delay in initial production vs an individual well
- Balancing production impact and pad drilling efficiencies
- 2014 development will include 2, 3 and 4-well pad drilling

Fluid / Gas Management Plan

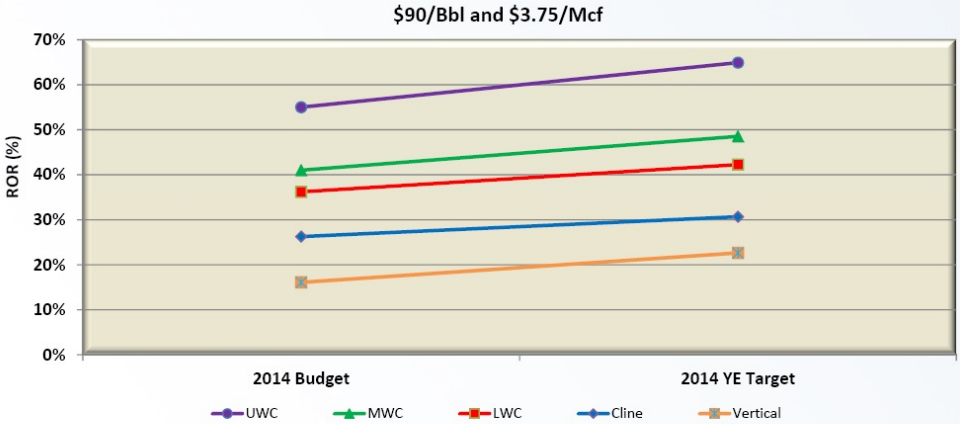


Cost Savings Initiatives

- Pad drilling efficiencies
- Multi-well frac efficiencies
- Negotiated service cost reductions
  - Coil
  - Pumping services
  - Wireline logging
  - Frac tank
- Optimizing drilling and completions operations
- Proppant sourcing improvements
- Reduction in transportation cost
- Improved water management
- Integration of new technologies
- Reduction in chemical usage
- Natural gas fueling

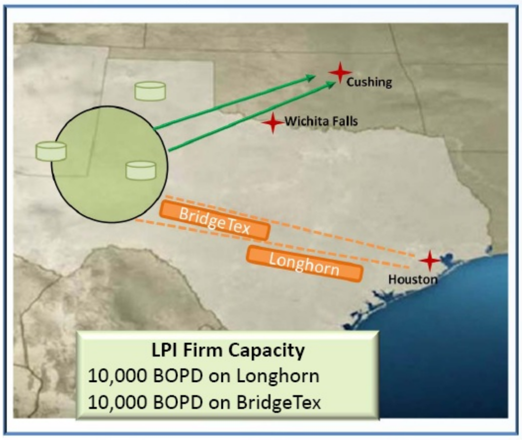
ROR vs Well Capital Costs

Permian Well Costs					
($MM)	Upper Wolfcamp	Middle Wolfcamp	Lower Wolfcamp	Cline	Vertical
2014 Budget	7.4	7.4	8.1	8.6	2.2
2014 YE Target	6.8	6.8	7.5	8.0	1.9



Sales Price Diversification[1]

Firm transportation out of the Permian

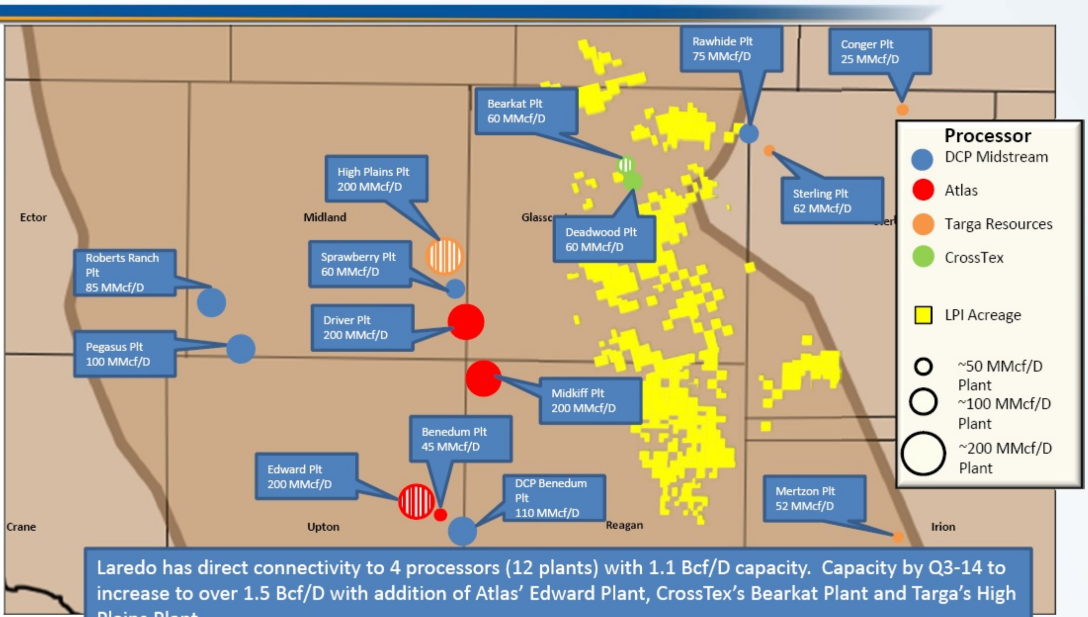


Existing Refinery
Existing Pipelines
New Pipelines and Additions

- 10,000 BOPD committed to Longhorn, increasing annually to 22,000 BOPD over 5 years
  - Eliminates Mid/Cush basis differential
  - Benefit from LLS Gulf Coast pricing premium to WTI
- 10,000 BOPD committed to BridgeTex (Mid 2014)
  - Eliminates Mid/Cush basis differential
  - Benefit from Brent pricing premium to WTI
- Balance sold in local Midland market
  - No long-term or volumetric commitments
  - Basis hedges in place to protect Mid/Cush basis risk

[1] As of 2/1/14

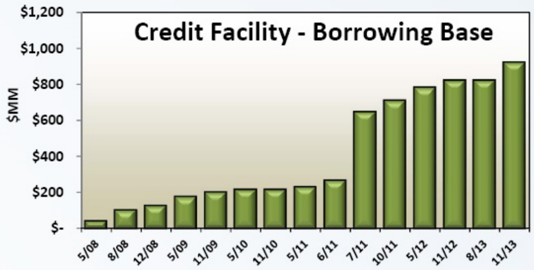
Processing Plant Capacity With LPI Direct Connectivity

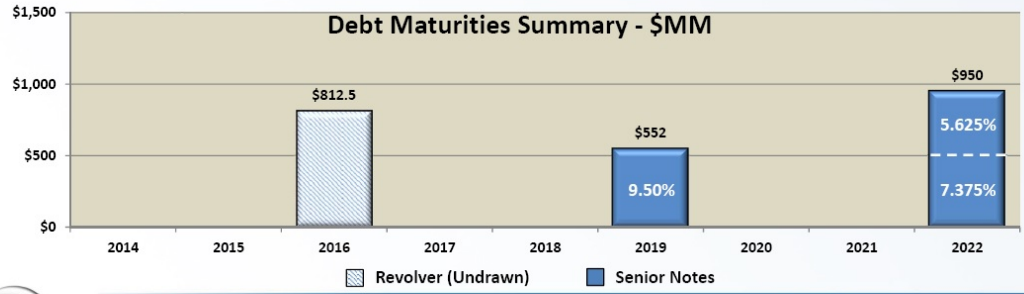


Laredo has direct connectivity to 4 processors (12 plants) with 1.1 Bcf/D capacity. Capacity by Q3-14 to increase to over 1.5 Bcf/D with addition of Atlas' Edward Plant, CrossTex's Bearkat Plant and Targa's High Plains Plant.

Preserving Financial Flexibility [1]

- >$1.4 billion of liquidity
- Growing borrowing base
- No near-term maturities
- Strong financial metrics





[1] As of 2/1/14

Oil Hedges

Open Positions As of February 1, 2014	2014	2015	2016	2017	2018	Total
OIL [1]						
Puts:						
Hedged volume (Bbls)	495,000	456,000	-		-	951,000
Weighted average price ($/Bbl)	$75.00	$75.00	$ -	$ -	$ -	$75.00
Swaps:						
Hedged volume (Bbls)	1,975,663	-	-	-	-	1,975,663
Weighted average price ($/Bbl)	$94.44	$ -	$ -	$ -	$ -	$94.44
Collars:						
Hedged volume (Bbls)	2,700,500	6,557,020	1,860,000	-	-	11,117,520
Weighted average floor price ($/Bbl)	$86.42	$79.81	$80.00	$ -	$ -	$81.45
Weighted average ceiling price ($/Bbl)	$104.89	$95.40	$91.37	$ -	$ -	$97.03
Total volume with a floor (Bbls)	**5,171,163**	**7,013,020**	**1,860,000**	-	-	**14,044,183**
Weighted average floor price ($/Bbl)	**$88.39**	**$79.50**	**$80.00**	$ -	$ -	**$82.84**
~ % of Total Oil Production	**75%**	**65%**	**15%**	**0%**	**0%**	
NYMEX WTI to Midland Basis Swaps:						
Hedged volume (Bbls)	2,004,000	-	-	-	-	2,004,000
Weighted average price ($/Bbl)	$1.00	$ -	$ -	$ -	$ -	$1.00
Brent to LLS Basis Swaps:						
Hedged volume (Bbls)	1,840,000	3,650,000	3,660,000	3,650,000	1,810,000	14,610,000
Weighted average price ($/Bbl)	$2.85	$2.85	$2.85	$2.85	$2.85	$2.85

[1] Oil derivatives are settled based on the month's average daily NYMEX price of WTI Light Sweet Crude Oil

Natural Gas Hedges

Open Positions As of February 1, 2014	2014	2015	2016	2017	2018	Total
NATURAL GAS [1]						
Swaps:						
Hedged volume (MMBtu)	5,508,000	-	-	-	-	5,508,000
Weighted average price ($/MMBtu)	$4.32	$ -	$ -	$ -	$ -	$4.32
Collars:						
Hedged volume (MMBtu)	8,800,000	8,160,000	-	-	-	16,960,000
Weighted average floor price ($/MMBtu)	$3.00	$3.00	$ -	$ -	$ -	$3.00
Weighted average ceiling price ($/MMBtu)	$5.50	$6.00	$ -	$ -	$ -	$5.73
Total volume with a floor (MMBtu)	**14,308,000**	**8,160,000**	**-**	**-**	**-**	**22,468,000**
Weighted average floor price ($/MMBtu)	**$3.51**	**$3.00**	**$ -**	**$ -**	**$ -**	**$3.32**
Weighted average floor price ($/Mcf) [2]	**$4.60**	**$3.93**	**$ -**	**$ -**	**$ -**	**$4.35**
~ % of Total Natural Gas Production	**40%**	**15%**	**0%**	**0%**	**0%**	

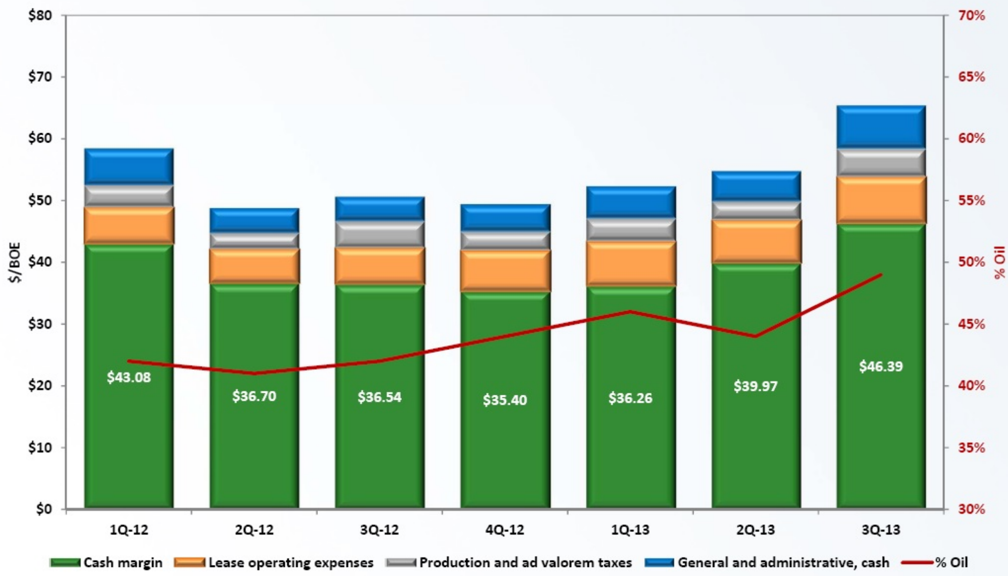
[1] Natural gas derivatives are settled based on NYMEX gas futures, the Northern Natural Gas Co. demarcation price, the Panhandle Eastern Pipe Line, Oklahoma ANR or the West Texas WAHA spot price of natural gas for the calculation period. The basis swap derivatives are settled based on the differential between the NYMEX gas futures and the West Texas WAHA index gas price.
[2] $/Mcf is converted based upon Company average BTU content of 1.311; prices include basis swaps

Laredo Investment Opportunity

- High-quality acreage position in the fairway of the Midland Basin
- Significant resource potential: >10x existing reserves
- Top-tier well results in multiple horizons
- Stacked laterals optimizing multi-zone development manufacturing process
- Strong financial structure

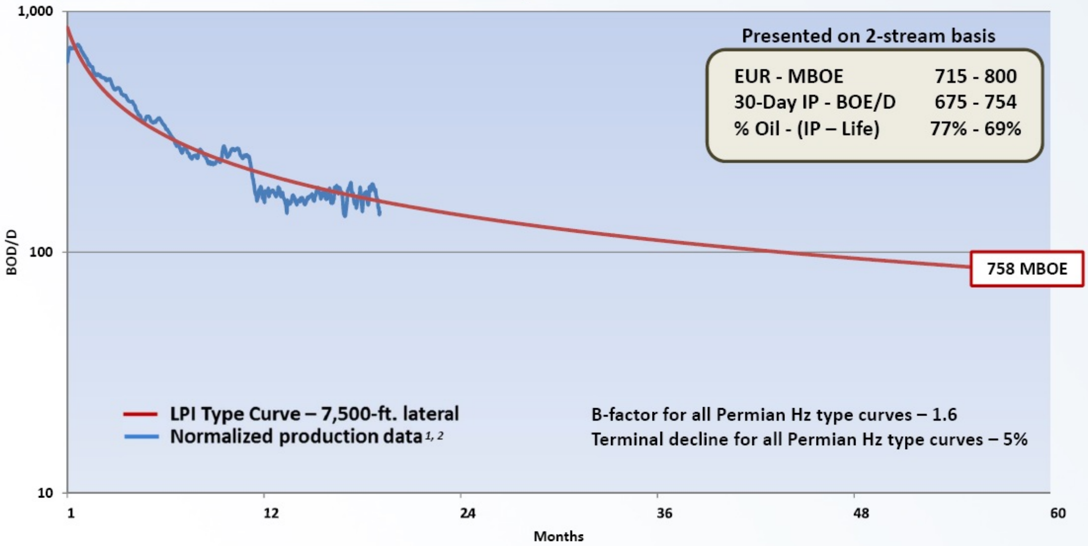
Appendix

Expanding Cash Margin



Hz Upper Wolfcamp Type Curve

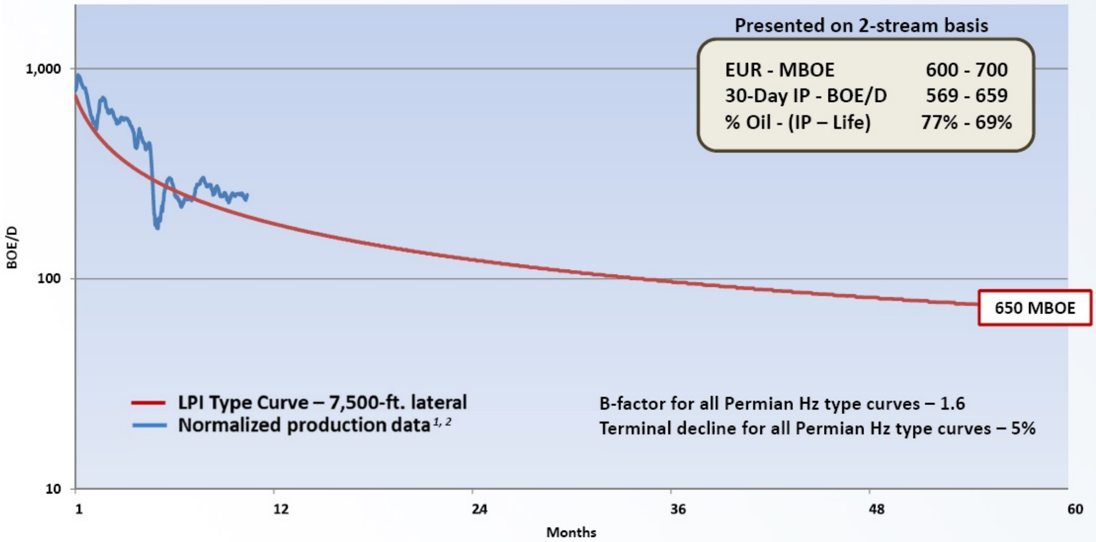
Type Curve – 25 long lateral wells presented



[1] Excludes Sterling County
[2] As of 11/1/13

Hz Middle Wolfcamp Type Curve

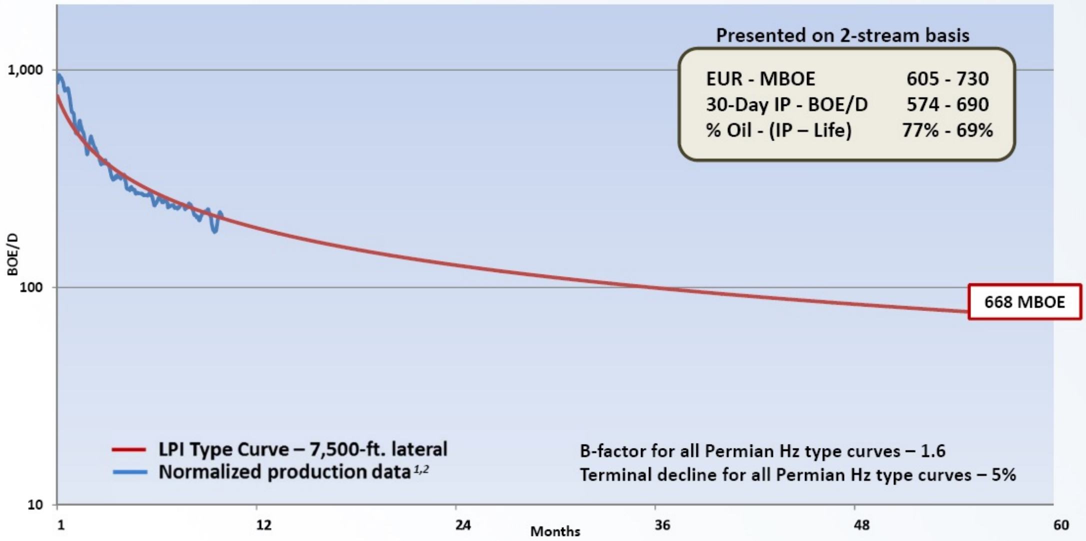
Type Curve – 4 long lateral wells presented



[1] Excludes Sterling County
[2] As of 11/1/13

Hz Lower Wolfcamp Type Curve

Type Curve – 4 long lateral wells presented

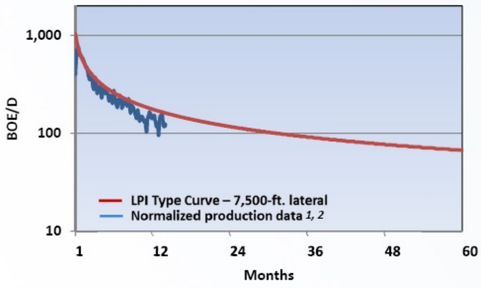


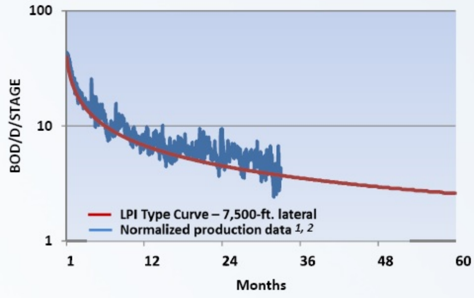
[1] Excludes Sterling County
[2] As of 11/1/13

Hz Cline Type Curve

5 Long lateral wells presented

BOEPD/Frac Stage normalized data from 36 wells presented





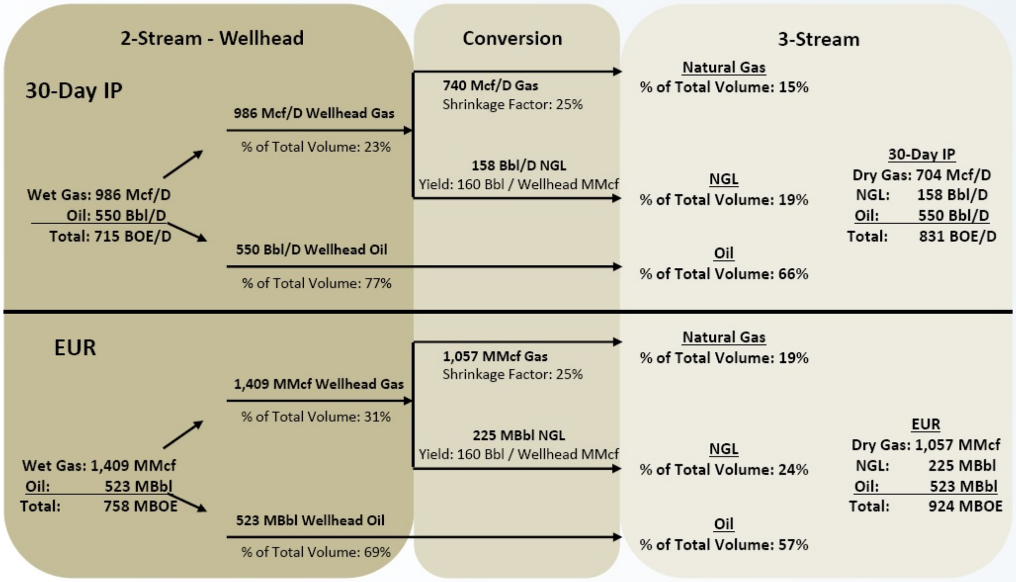
EUR - MBOE	550 - 690
30-Day IP - BOE/D	663 - 828
% Oil - (IP – Life)	77% - 69%

Presented on 2-stream basis

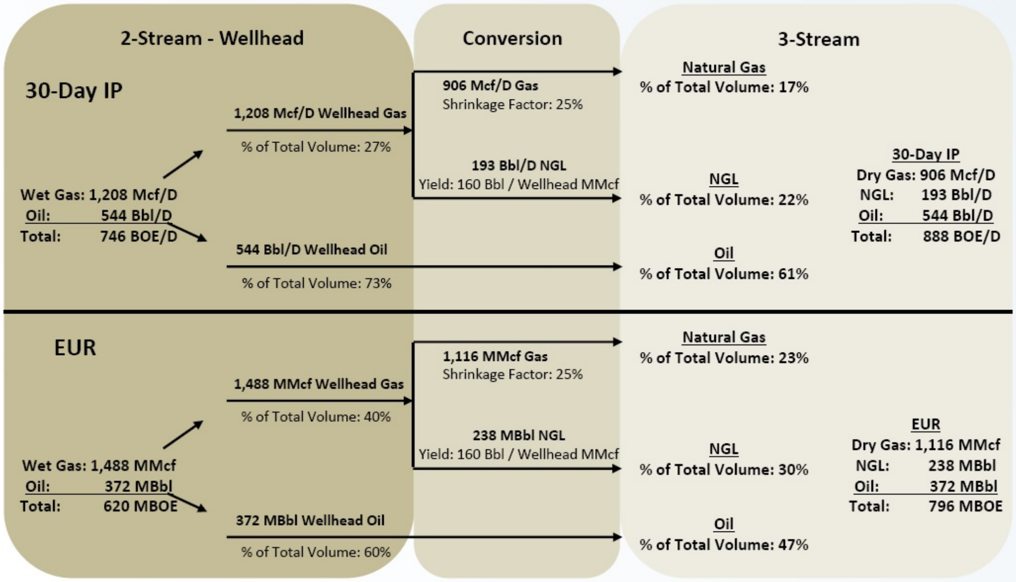
B-factor for all Permian Hz type curves – 1.6
Terminal decline for all Permian Hz type curves – 5%

[1] Excludes Sterling County
[2] As of 11/1/13

Sample Wolfcamp Hz 3-Stream Conversion



Sample Cline Hz 3-Stream Conversion



LAREDO
PETROLEUM