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): June 5, 2015

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 900, 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 June 5, 2015, Laredo Petroleum, Inc. (the "Company") posted to its website a Corporate Presentation. The presentation is available on the Company's website, www.laredopetro.com, and is attached to this Current Report on Form 8-K as Exhibit 99.1 and incorporated into this Item 7.01 by reference.

All statements in the presentation, other than historical financial information, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Although the Company believes the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance, and actual results or developments may differ materially from those in the forward-looking statements. See the Company's Annual Report on Form 10-K for the year ended December 31, 2014 and the Company's other filings with the SEC for a discussion of other risks and uncertainties. The Company disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

In accordance with General Instruction B.2 of Form 8-K, the information in this report (including Exhibit 99.1) 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 Exhibit 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	Corporate Presentation.

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.

Date: June 5, 2015	By:	/s/ Kenneth E. Dornblaser
		Kenneth E. Dornblaser
		Senior Vice President & General Counsel

EXHIBIT INDEX

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LAREDO
PETROLEUM
Corporate Presentation
June 2015

Forward-Looking / Cautionary Statements

This presentation (which includes oral statements made in connection with 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," "project," "intend," "indicator," "foresee," "forecast," "guidance," "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 rate of return 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 risks relating to financial performance and results, current economic conditions and resulting capital restraints, prices and demand for oil and natural gas, availability and cost of drilling equipment and personnel, availability of sufficient capital to execute the Company's business plan, impact of compliance with legislation and regulations, successful results from our identified drilling locations, 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 From 10-K for the year ended December 31, 2014 and other reports filed with the Securities Exchange Commission ("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 "unproved reserves", "resource potential", "estimated ultimate recovery", "EUR", "development ready", "horizontal commerciality confirmed", "horizontal commerciality untested" or other descriptions of potential reserves or volumes of reserves which the SEC guidelines restrict from being included in filings with the SEC without strict compliance with SEC definitions. Unproved reserves refers to the Company's internal estimates of hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques. Resource potential is used by the Company to refer to the estimated quantities of hydrocarbons that may be added to proved reserves, largely from a specified resource play. A resource play is a term used by the Company to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section, which, when compared to a conventional play, typically has a lower geological and/or commercial development risk. The Company does not choose to include unproved reserve estimates in its filings with the SEC. Estimated ultimate recovery, or EUR, refers to the Company's internal estimates of per-well hydrocarbon quantities that may be potentially recovered from a hypothetical and/or 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 and cost of drilling services and equipment, 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.

Established Track Record

1991 1992 1993 1994 1995 1996 1997 1998 1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014

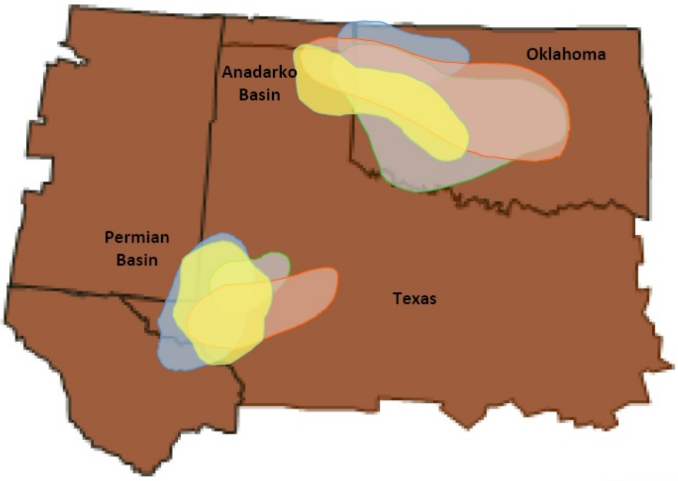
Colt Resource Corp
Equity:
First Reserve
2.5x Return

Lariat Petroleum
Equity:
Warburg Pincus
3.0x Return

Latigo Petroleum
Equity:
Warburg Pincus,
JP Morgan
3.4x Return

Laredo Petroleum
Equity:
Warburg Pincus
>3x Return

- >20-year history of generating significant value for investors
- Common areas of operations
- Common approach



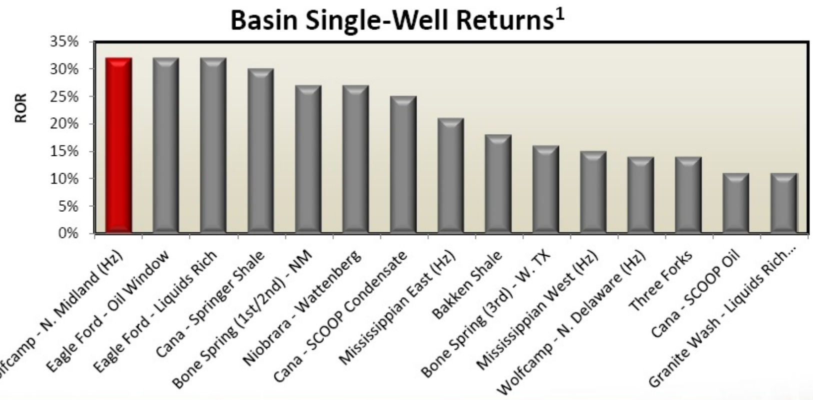
Focus on long-term value from the beginning

- Hire quality people, and support them with the tools they need to be successful
- Acquire contiguous acreage in the right basin
- Collect quality data at the right time and use the data to drive decisions
- Maximize NPV by increasing resource recovery and minimizing cost in development plans
- Maintain optionality in operations through ownership of infrastructure and logistical flexibility
- Maintain financial flexibility and cash flow certainty in an uncertain commodity price environment

Targeted Acreage in the Best Basin

Permian Basin Attributes

- Tremendous oil in place
- Long history of oil production
- Multi-stack horizontal targets
- Infrastructure and takeaway capacity
- Industry knowledgeable State and mineral owners

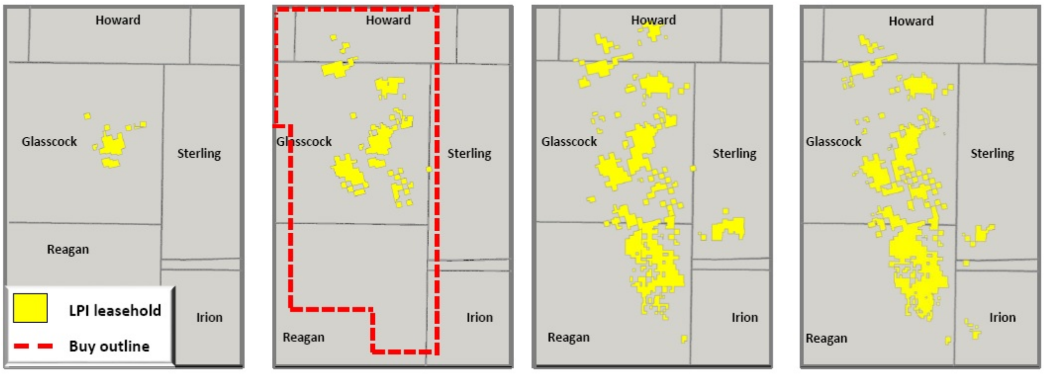


[1] Credit Suisse data based on strip pricing as of 2/19/15

Land Position Chronology

EXPLORATION | DELINEATION | DEVELOPMENT

2008 | 2010 | 2012 | 2015



~15,000 Net Acres | ~50,000 Net Acres | ~140,000 Net Acres | ~149,000 Net Acres[1]

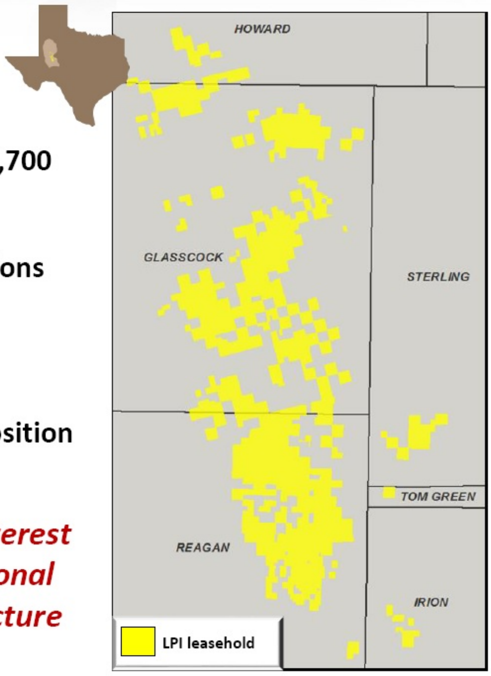
Primary objective has always been to build contiguous acreage positions in the best part of the basin

[1] As of 3/31/15

High-Quality Contiguous Acreage

- 179,722 Gross/149,141 net acres[1]
- ~4.3 billion barrels of resource potential on >7,700 identified locations
- ~3,200 operated Development Ready Hz locations with >90% average WI
- ~96% average WI in operated wells[1]
- Current drilling plan preserves core acreage position

Contiguous acreage with high working interest enables the company to achieve operational efficiencies by leveraging data, infrastructure and maximizing resource recovery

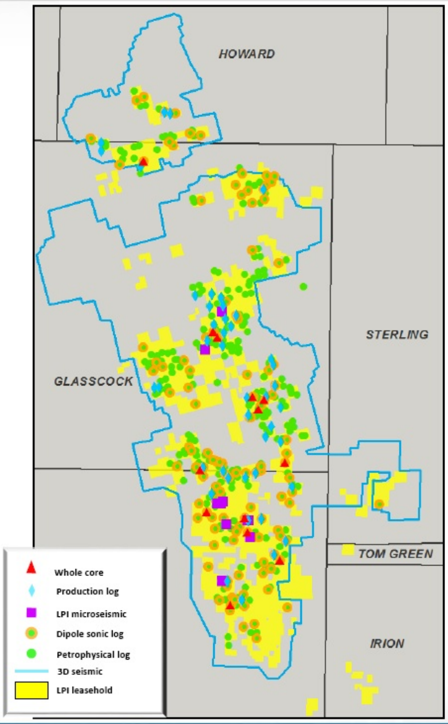


[1] As of 3/31/15

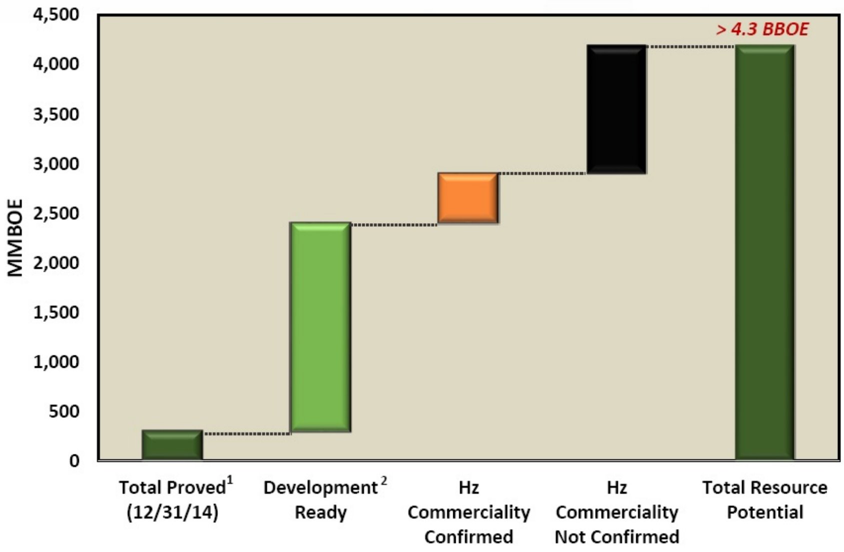
Building an Extensive Technical Database

- Technical database consisting of whole cores, sidewall cores, single-zone tests, open-hole logs, 3D seismic and production logs
- Provides the building blocks for identification of resource potential and horizontal locations
- Majority of technical database attributes are proprietary to Laredo's acreage
- Timing of data acquisition is integral to data quality

Comprehensive technical database integrated with 3D seismic enables Laredo to successfully identify where to locate and position wells across multiple horizons to maximize value



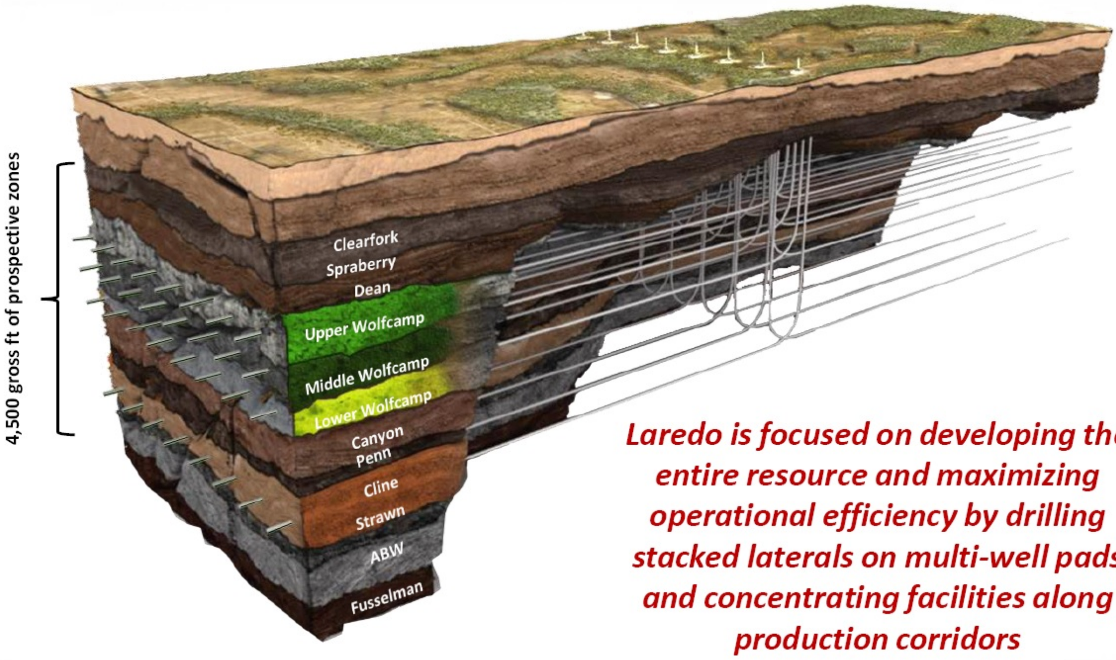
Identified Resource Potential



Approximately 4.3 billion barrels of resource potential from an inventory of ~7,700 low-risk drilling locations

[1] Based on YE-2014 2-stream proved reserves, prepared by Ryder Scott. Internally converted to 3-stream based on actual gas plant economics of 30% shrink and a yield of 127 Bbl of NGL per MMcf
[2] Additional development ready resource not already included in Total Proved reserves

Developing to Maximize NPV



Laredo is focused on developing the entire resource and maximizing operational efficiency by drilling stacked laterals on multi-well pads and concentrating facilities along production corridors

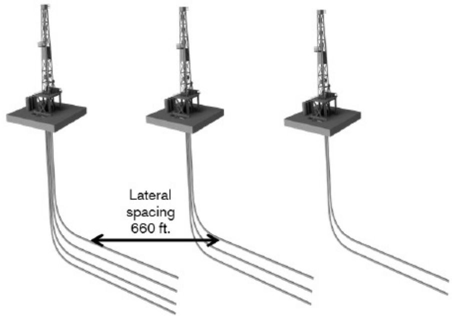
Not to scale

Efficient Development of the Entire Resource

Stacked Lateral Multi-Well Pads

# of pads completed	Four-stacked	Three-stacked	Two-stacked
	2	11	16

73 wells total[1]



As of Q1 '15, Laredo has completed 73 wells on 29 multi-well pads

Horizontal Wells on Multi-Well Pads	
2013	13
2014	56
2015	4 to date

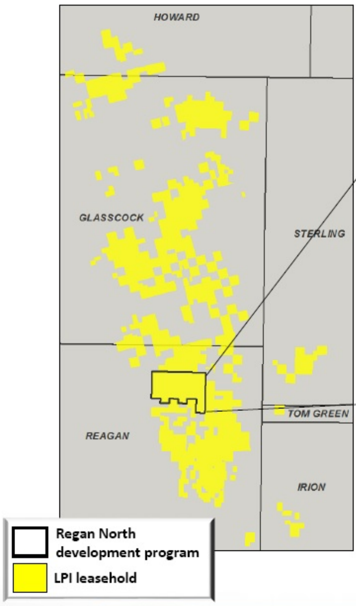
- Average cost savings on a multi-well pad ~$400K / well
- Reduces cycle-time
- Reduces surface footprint

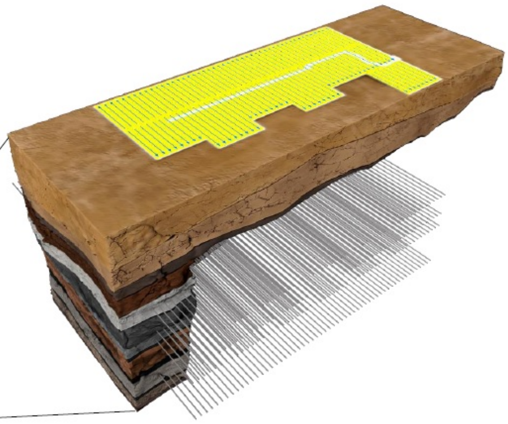
Laredo capitalizes on its large contiguous land position to be extremely efficient on surface footprint to develop all zones

[1] Independent wellbores

Contiguous Acreage Enables Efficient Development

Centralization of infrastructure provides benefits of ~$1.2 MM per well



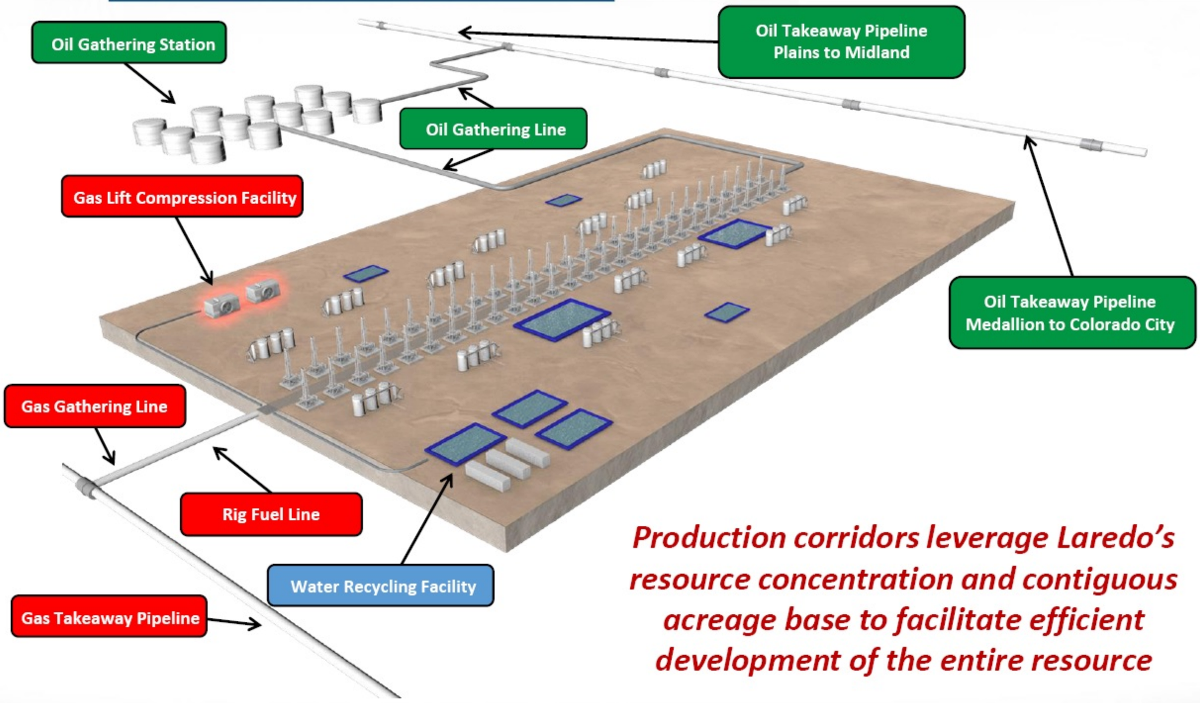


<u>A four-well completion requires[1]:</u>

- 1,000,000 barrels of water in two weeks
- Takeaway capacity for ~82,500 BOE per month during peak production
- Takeaway capacity for ~93,000 barrels of water per month during peak production

[1] *Assumes two 7,500' Upper Wolfcamp and two 7,500' Middle Wolfcamp horizontal wells*

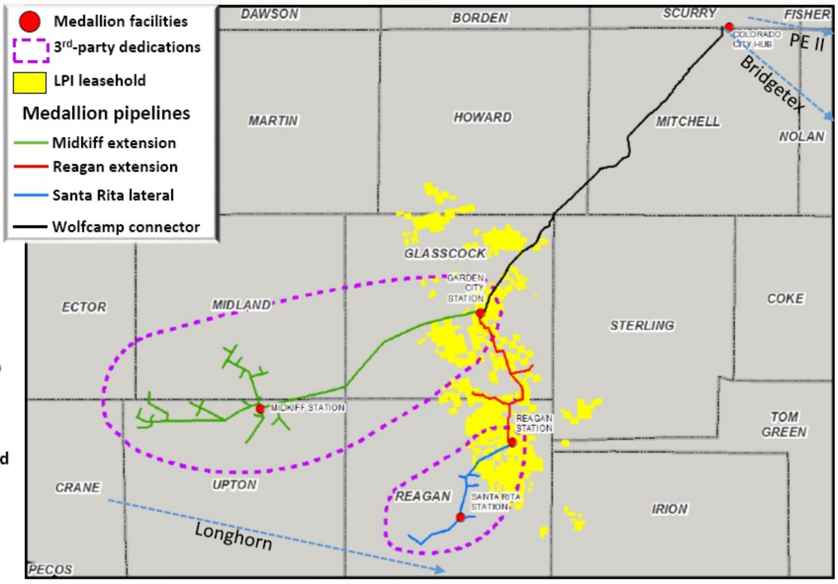
Infrastructure Integrated with Complete Development Plan



Production corridors leverage Laredo's resource concentration and contiguous acreage base to facilitate efficient development of the entire resource

Medallion Crude Oil System Overview

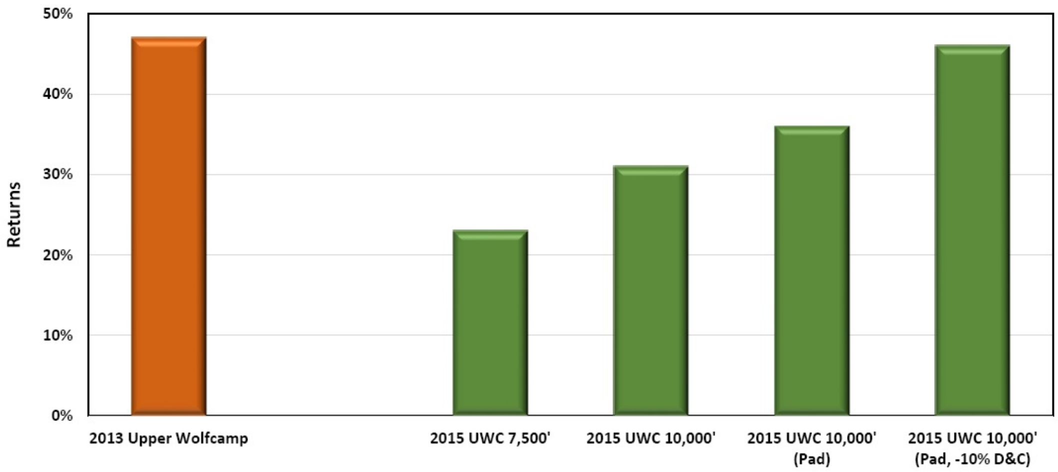
- **Wolfcamp Connector:**
  - 100% Active: ~60 miles of 12"
  - Capacity: ~140,000 BOPD
  - Active October 2014
- **Reagan Extension:**
  - 90% Active: ~53 miles of 4" – 10"
  - Capacity: up to ~90,000 BOPD
  - Active October 2014
- **Midkiff Lateral:**
  - Under Construction: ~95 miles of 4" – 12"
  - Capacity: up to ~150,000 BOPD
  - Partial in-service March 2015
- **Santa Rita Lateral:**
  - Under Construction: Initial build ~28 miles of 4" – 10"
  - Capacity: up to ~90,000 BOPD
  - Partial in-service March 2015



Medallion pipeline system now >230 miles with >111,000 net acres dedicated to system and >1.1 million acres either under AMI or supporting firm commitments on the pipeline

[1] As of 4/1/15

Enhancing Well Returns[1,2]

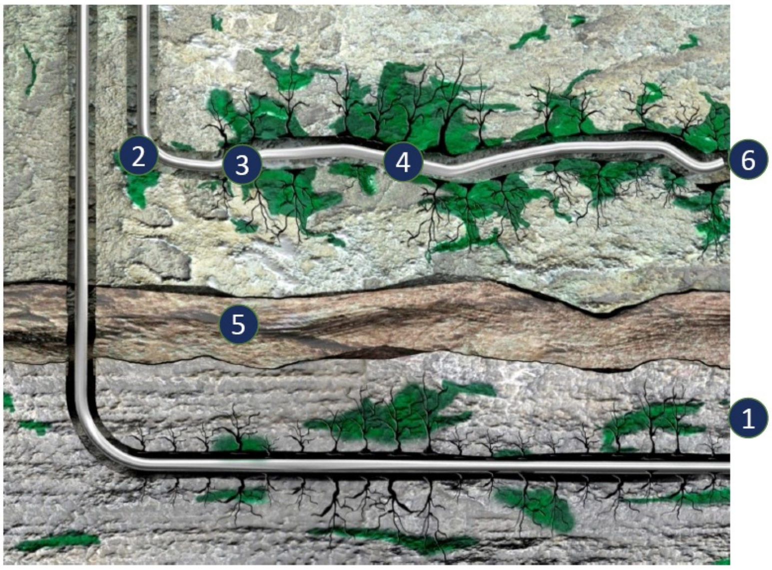


Capital efficiency gains from drilling longer laterals, cost savings from multi-well pad drilling and additional service cost savings can generate well economics in this commodity price environment that rival the returns from a higher oil price environment

[1] *2013 returns reflect $90 oil and $3.75 natural gas*
[2] *2015 returns reflect $50 oil and $3.00 natural gas*

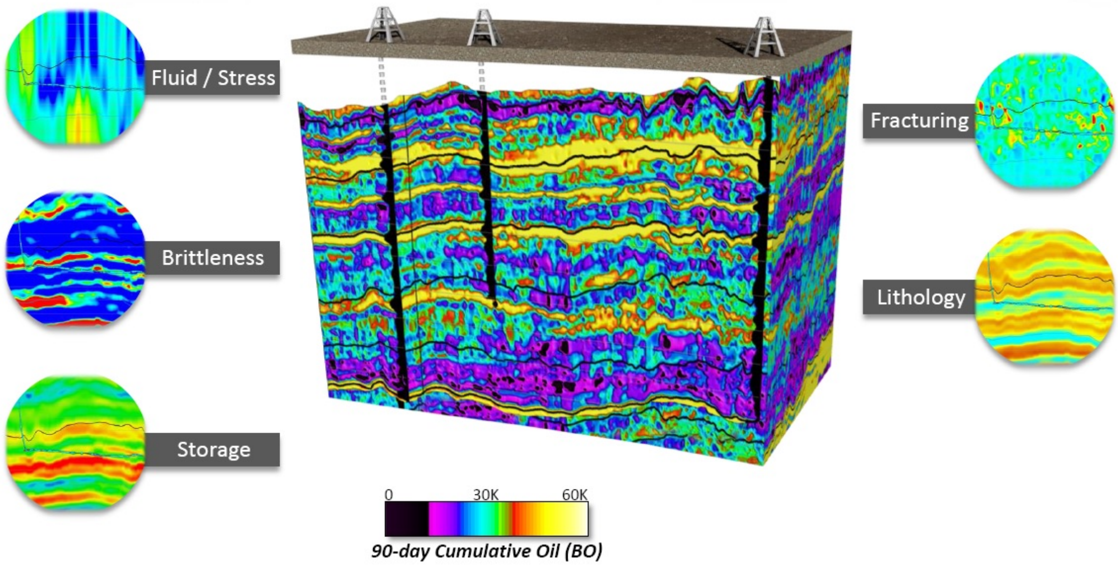
Earth Model Objectives

1. Standard Wellbore
2. Select Landing Point
3. Geosteering (stay in zone)
4. Frac Design & Spacing
5. Frac Barrier
6. Lateral Length



Earth Model potential to optimize development & increase value

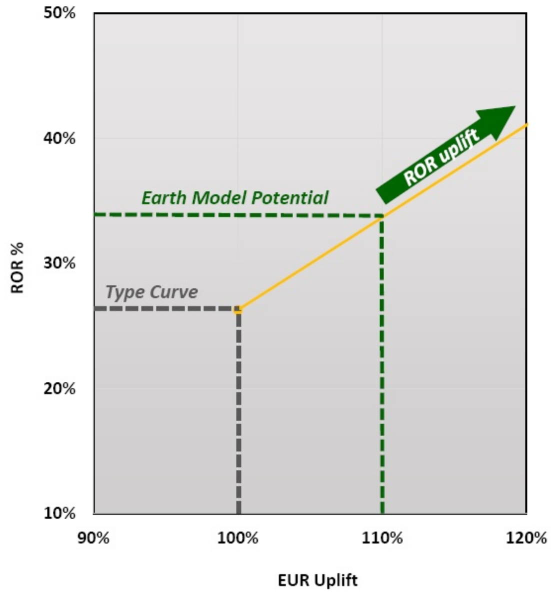
3D Production Attribute



Landing, geosteering & staying in-zone fundamentally linked to highest 90-day cumulative oil production

Earth Model Economic “Uplift” Implications

7,500’ Upper Wolfcamp Multi-Well Pad Type Curve

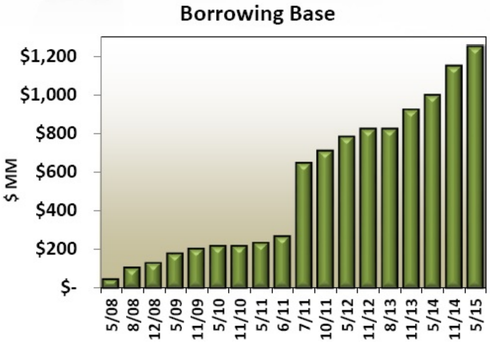


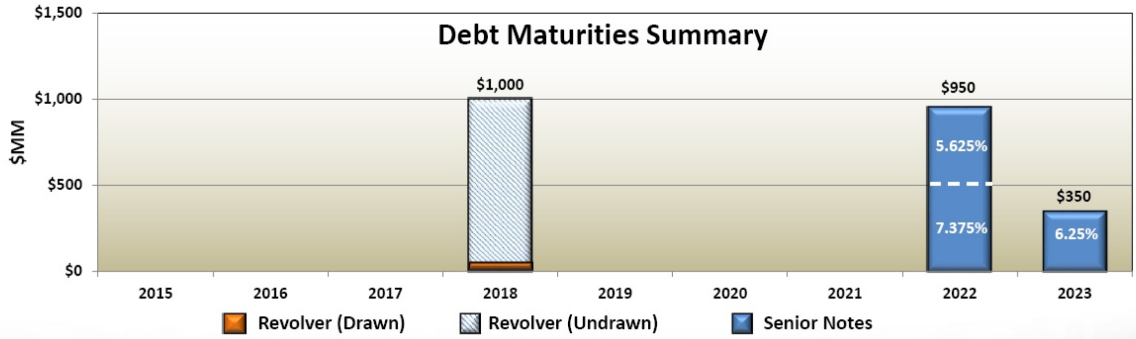
- Anticipate that the Earth Model will be utilized to select the landing point and geosteer for 90% of 2015 horizontal wells
- Landing, geosteering & staying in-zone fundamentally linked to highest 90-day cumulative oil production
- 10% increase in EUR increases ROR by ~25%, from ~26% to ~33%

[1] *Forward strip price deck, as of 4/1/2015*

Financial Flexibility to Enhance Value to Stakeholders

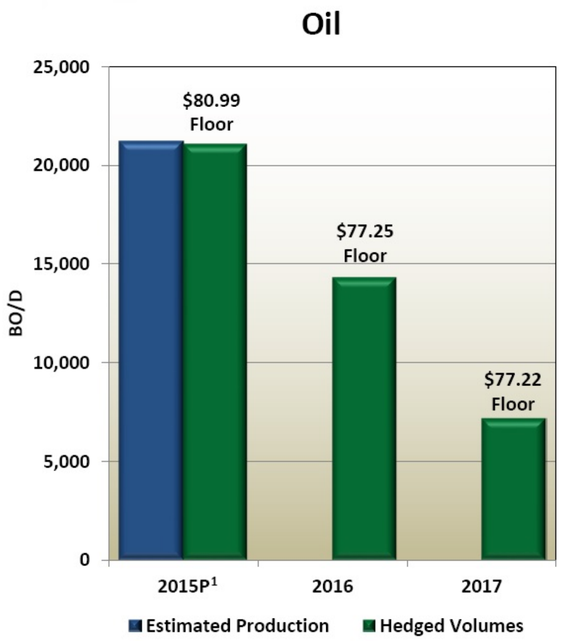
- Decreased total debt ~$675 MM
- Reduced annual interest payment ~$40 MM
- Extended first maturity to seven years
- Reduced weighted-average cost of long-term notes to 6.5%: ⬇110 bps
- Increased liquidity to ~$950 MM[1]

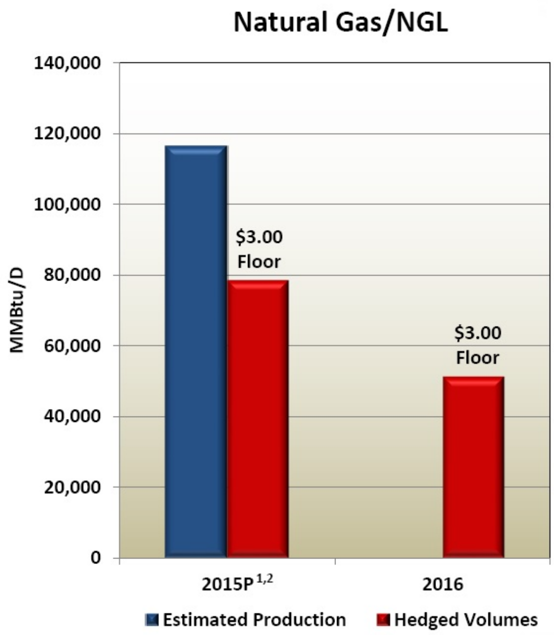




[1]As of 5/5/15

Cash Flow Underpinned With Hedges



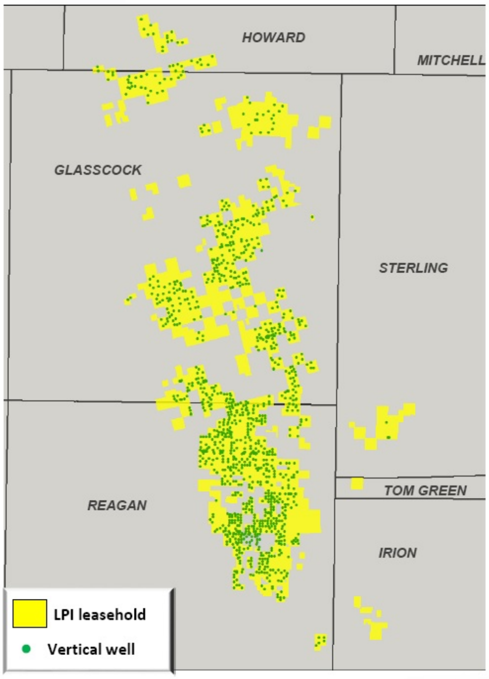


[1] *Estimated production based on 2015 production growth guidance issued 12/16/2014, as of 4/1/15*
[2] *Heat content of estimated production based on 1311 Btu/cubic foot*

Appendix

Vertical Wells Across Asset Enable Data Collection

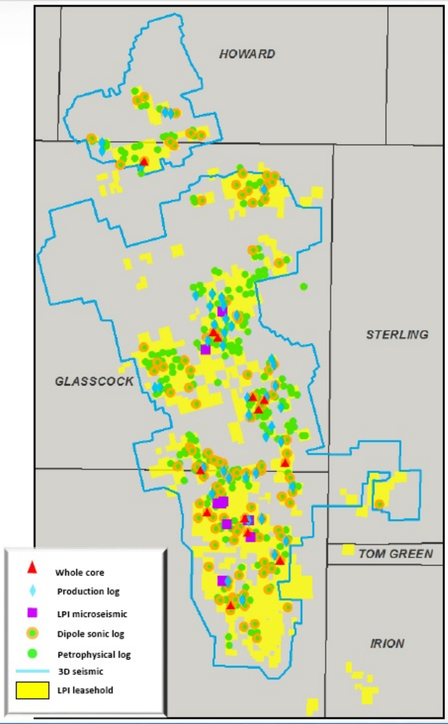
- Laredo Petroleum has taken advantage of its vertical well program to gather critical open-hole and petrophysical data
- >950 vertical wells across entire acreage position
  - ~50% of the vertical wells are considered "deep" or of sufficient depth to penetrate the Cline or below
- Production logs, single-zone tests and cores from vertical drilling provide confidence in resource potential in multiple formations
- On average, one vertical well per ~160 acres



Permian Asset – Extensive Technical Database

- **Technical database consisting of whole cores, sidewall cores, single-zone tests, open-hole logs, 3D seismic and production logs**
- **Provides the building blocks for identification of resource potential and horizontal locations**
- **Majority of technical database attributes are proprietary to Laredo's acreage**
- **Timing of data acquisition is integral to data quality**

Comprehensive technical database integrated with 3D seismic enables Laredo to successfully identify where to locate and position wells across multiple horizons to maximize value

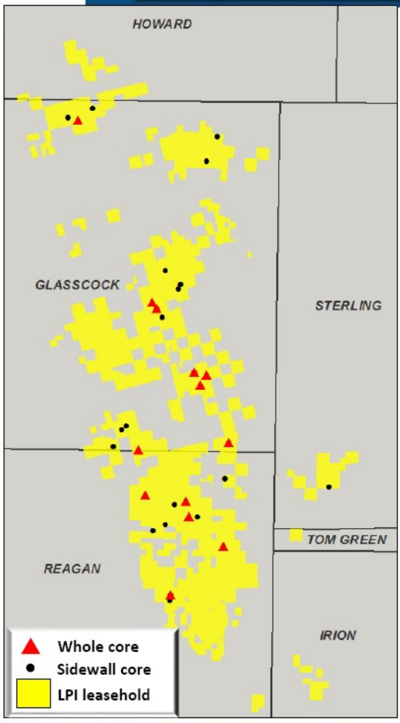


3D Seismic Program

A high-quality, "meaningful" data set

- **High fold: 250 fold (historical data sets are 100 fold or less)**
- **High frequency sweeps: up to 120 hertz**
- **Tight bin spacing: 70 feet (normal is 110 feet or greater)**
- **Wide azimuth: farthest receiver is ~11,500 feet (equals full fold coverage at deepest target)**
  - **Used in modeling (pre-stack inversion)**
  - **Used in fracture analysis**
- **Acquisition positives**
  - **Reasonable cost**
  - **Lack of surface "cultural" obstacles**
  - **Quality crew**
- **Older spec (purchased) data: dramatically upgraded with latest processing techniques**

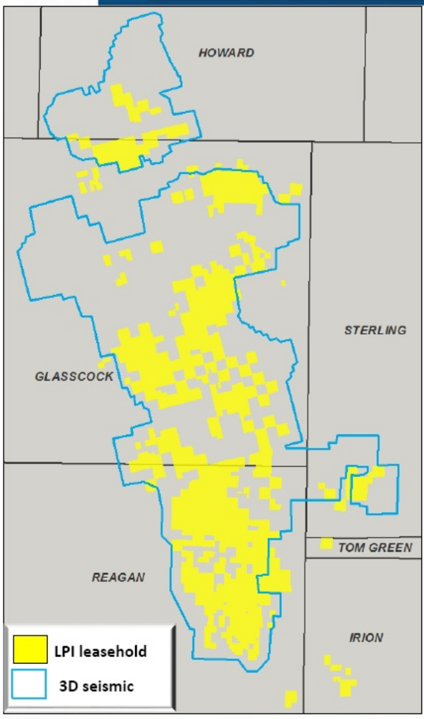
Core Data



Cores provides the technical bridge between the actual reservoir rocks and the petrophysical analysis metrics

- ~3,700' of proprietary whole cores in objective section
  - 14 whole cores
  - >715 sidewall core samples
- In addition to our own core library Laredo has access to core data from 110 wells as a member of Core Lab's Tight Oil Reservoirs Midland Basin Core Consortium
- Whole and sidewall cores provides a source for lithologic, mineralogic, TOC content and geochemical properties
- Timing: Data must be obtained during drilling operations or prior to setting casing

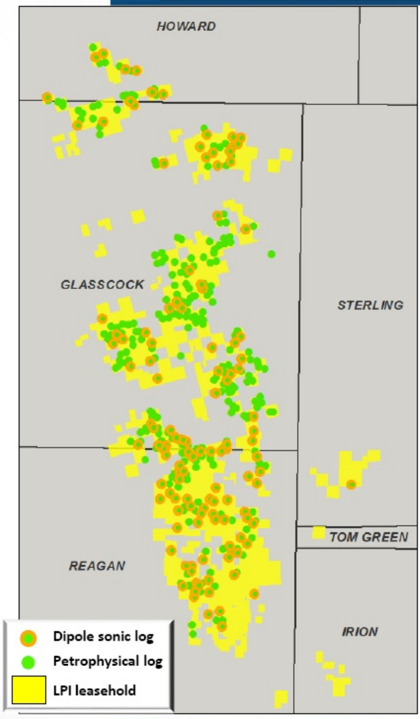
Geophysical Data



High-quality 3D seismic is a key foundation of the Earth Model in that it gives the geoscientists insight as to how the area-wide reservoir, petrophysical and seismic properties correlate relative to each targeted interval

- 990 sq mi 3D seismic
  - 95% coverage of Garden City acreage
  - ~40% of seismic inventory is high-quality, proprietary 3D data
- 27 micro-seismic surveys (operated and trades) used to validate current well spacing
- Timing: 3D seismic data needs to be completed as early in the asset evaluations process to insure availability for processing and incorporation into the Earth Model

Log Data



Logs provide the framework for building the Earth Model and tying in the available petrophysical database

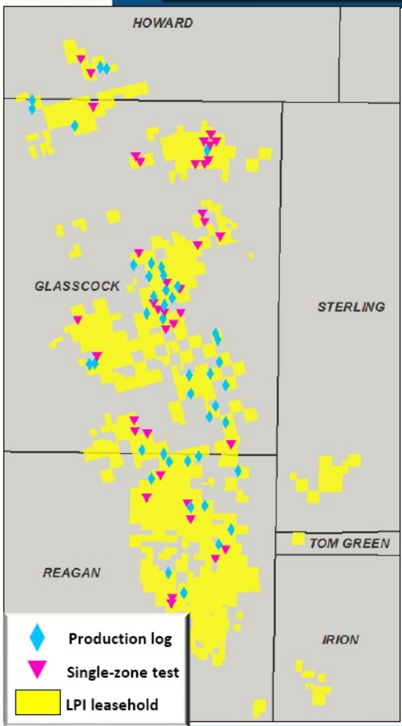
- >8,000 conventional public and proprietary open-hole logs
- 303 in-house proprietary petrophysical logs
  - Extensive database fully calibrated by in-house petrophysicists to cores and used to calculate reservoir properties and original oil in place "OOIP" numbers
- 120 dipole sonic logs
  - Used to calculate rock mechanical properties and to optimize frac design
- Timing: Open-hole logs must be obtained prior to setting casing

Dipole Sonic Importance & Integration

- Laredo was one of the first operators in the Midland Basin to acquire dipole enhanced geophysics for completion design
- Laredo now has 120 dipole sonic logs
- Dipole sonic is now the operator standard
- Key tool in determining brittleness (ductile vs brittle)
- Assist in drilling and completion design
  - Wellbore stability
  - Hydrofracture design
- Seismic calibration Earth Model
  - Horizontal wellbore placement

Image credit to Schlumberger

Production Logs & Single-Zone Tests



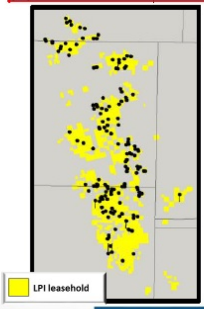
Single-zone tests confirm the productivity of potential zones

- **Provide a multi-phase analysis (oil, gas & water) of each stage completed**
- **Identify the source of hydrocarbon (oil & gas) and water production**
- **Could assist in determining lateral placement in prospective horizontal zones**
- **May offer correlations to reservoir rock quality and/or completion effectiveness**
- **42 production logs**
  - **36 vertical wells**
  - **6 horizontal wells**
- **39 single-zone tests**
- **<u>Timing</u>: For best results, production logs and single-zone tests should be acquired early in the completion**

Multi-Stacked Targets With Significant Resource Potential

Utilization of our large technical dataset[1] has permitted the identification, evaluation and ability to estimate resource potential across primary and additional horizons

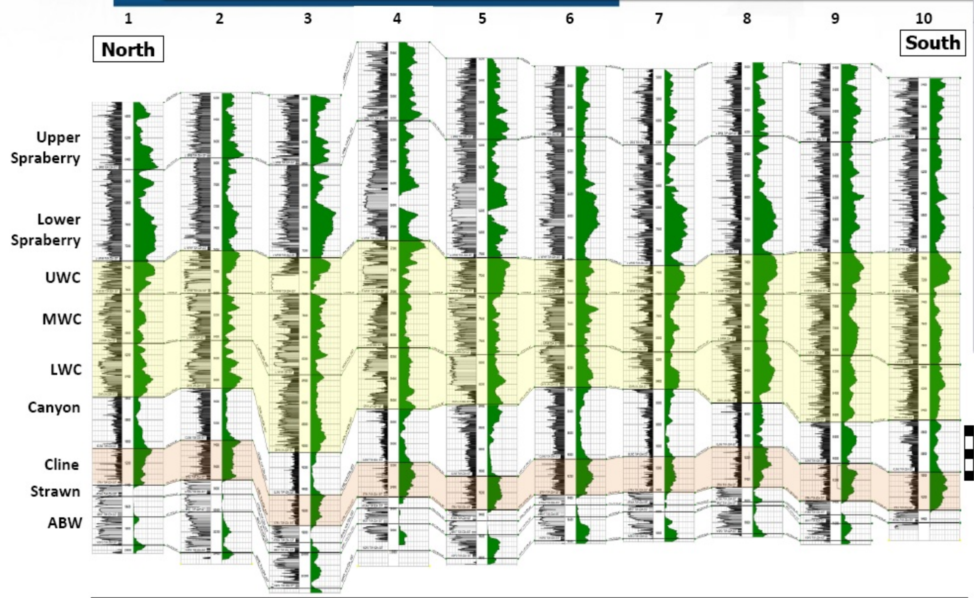
	Upper Spraberry	Lower[2] Spraberry	UWC	MWC	LWC	Canyon[3]	Cline	Strawn	ABW	Wolfcamp Combined	Total Combined
Depth (ft)[4]	5,308-5,916	5,916-6,951	6,951-7,440	7,440-7,960	7,960-8,453	8,453-9,078	9,078-9,412	9,412-9,530	9,530-9,874	6,951-8,453	5,308-9,874
TOC (%)	1.6-4.9	1.4-4.3	0.9-5.3	0.9-4.8	1.0-4.0	1.0-3.8	0.9-5.2	0.0-3.3	0.4-3.9	0.9-5.3	0.0-5.3
Thermal maturity (% Ro)	0.5-0.6	0.6-0.7	0.7-0.8	0.75-0.85	0.8-0.9	0.8-0.9	0.9-1.1	1.0-1.2	1.1-1.3	0.7-0.9	0.5-1.3
Clay content (%)	10.5-35.0	9.7-31.8	7.3-29.3	12.4-33.7	12.2-33.6	21.6-40.2	27.4—42.7	1.6-19.5	5.6-32.8	7.3-33.7	1.6-42.7
Pressure gradient (psi/ft)	0.30-0.40	0.30-0.40	0.40-0.50	0.40-0.50	0.40-0.50	0.40-0.50	0.55-0.65	0.40-0.50	0.40-0.50	0.40-0.50	0.30-0.65
So (dec)	0.367	0.439	0.470	0.370	0.433	0.307	0.379	0.463	0.523	0.423	0.408
Porosity (dec)	0.051	0.048	0.055	0.058	0.056	0.053	0.068	0.035	0.049	0.056	0.053
Average thickness[4] (ft)	608	1,035	489	520	493	625	334	118	334	1,502	4,556

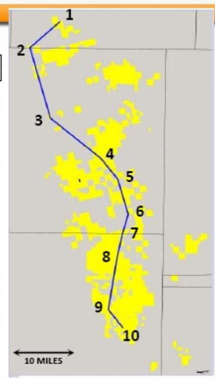


Multiple stacked targets in the Garden City prospect represent >4,500 feet of vertical section

[1] 149 LPI wells with updated petrophysical model implemented 7/8/2014 (indicated on map)
[2] Lower Spraberry includes Dean
[3] Canyon includes Penn Shale
[4] Depths and tops subject to change pending completion of sequence stratigraphy review

Regional Cross-Section





Flattened on the Middle Wolfcamp

- GAMMA RAY

- Stock Tank Original Oil in Place (STOOIP)*

STOOIP TOTALS	1	2	3	4	5	6	7	8	9	10
	292 MMBO	254 MMBO	305 MMBO	302 MMBO	320 MMBO	322 MMBO	272 MMBO	352 MMBO	354 MMBO	279 MMBO

Contiguous thick stratigraphic section from Spraberry through ABW interval indicated by geologic cross-section

ABW – Atoka, Barnett & Woodford

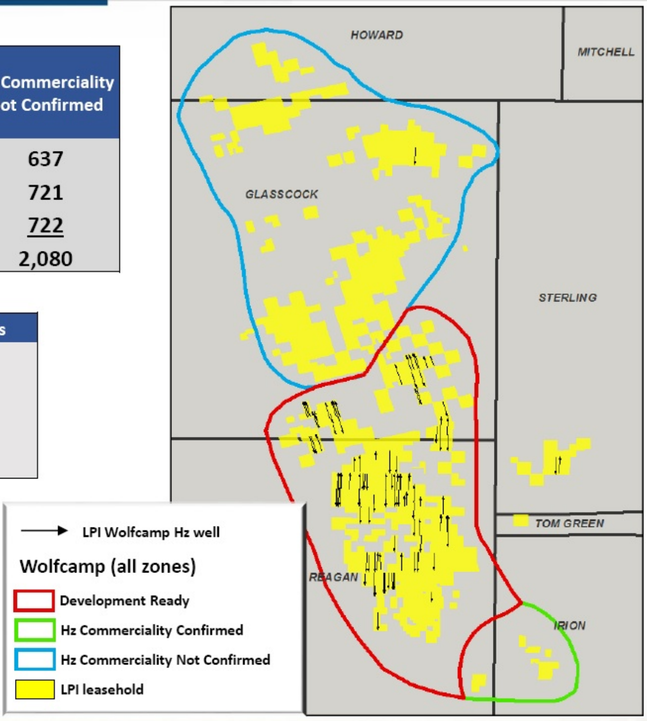
*STOOIP CURVES CALCULATED WITH 50' HEIGHT

$$MMSTOOIP = \frac{7758 * Phie * (1-Sw) * h * 640ac}{Bo} \Big/ 1{,}000{,}000$$

Wolfcamp Inventory

Formation/Zone	Development Ready	Hz Commerciality Confirmed	Hz Commerciality Not Confirmed
Upper Wolfcamp	828	36	637
Middle Wolfcamp	807	36	721
Lower Wolfcamp	813	36	722
Total	2,448	108	2,080

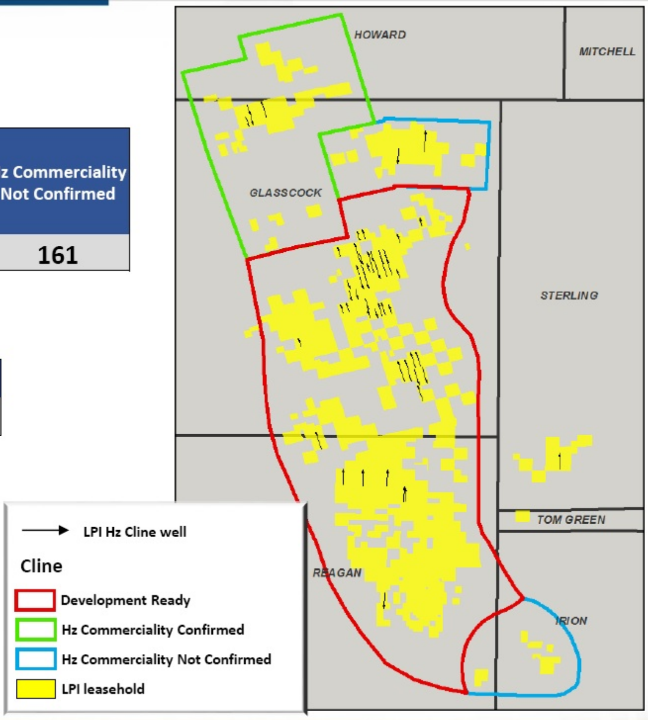
Formation/Zone	LPI Operated Hz Wells
Upper Wolfcamp	81
Middle Wolfcamp	33
Lower Wolfcamp	23
Total	137



Cline Inventory

Formation/Zone	Development Ready	Hz Commerciality Confirmed	Hz Commerciality Not Confirmed
Cline	1,223	182	161

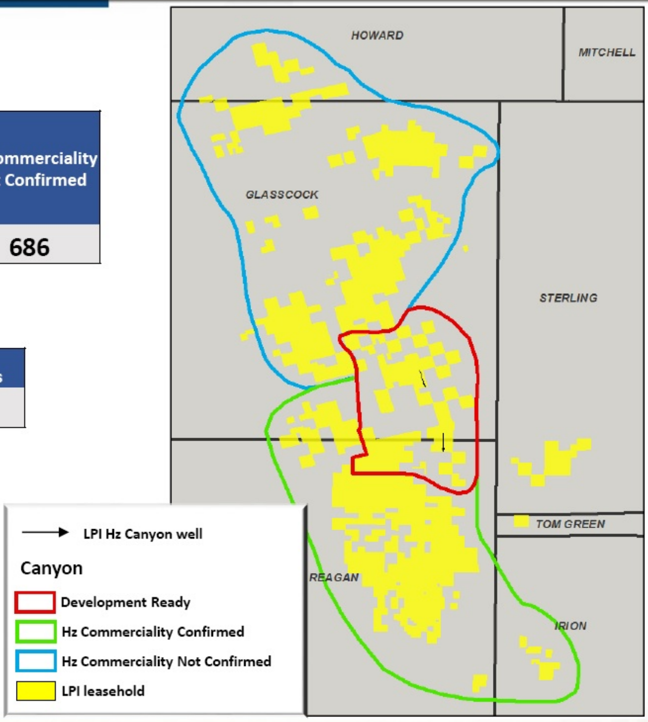
Formation/Zone	LPI Operated Hz Wells
Cline	52



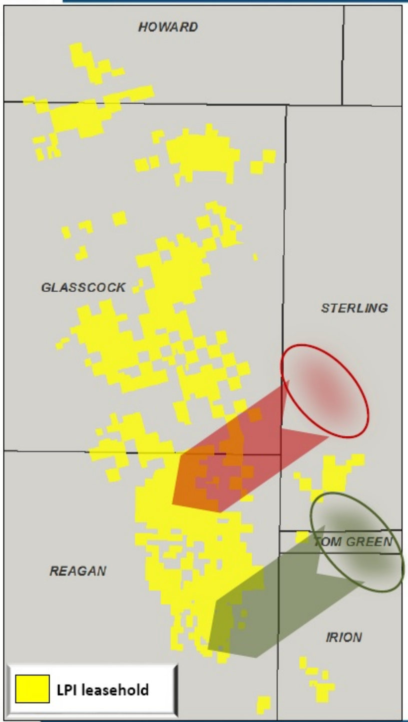
Canyon Inventory

Formation/Zone	Development Ready	Hz Commerciality Confirmed	Hz Commerciality Not Confirmed
Canyon	311	593	686

Formation/Zone	LPI Operated Hz wells
Canyon	2



Canyon Formation: Geologic Concept



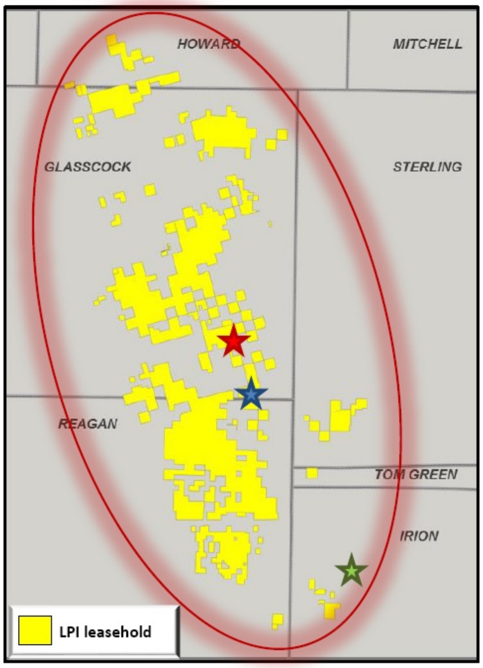
Conger Gas Field:
Cumulative Oil: 30.8 MMBbl
Cumulative Gas: 839.5 BCF

Sugg Ranch Gas Field:
Cumulative Oil: 43.9 MMBbl
Cumulative Gas: 624.3 BCF

Structural Dip

Laredo acreage positioned basinward of highly-productive, legacy Canyon fields

Canyon Formation: Discovery & Delineation

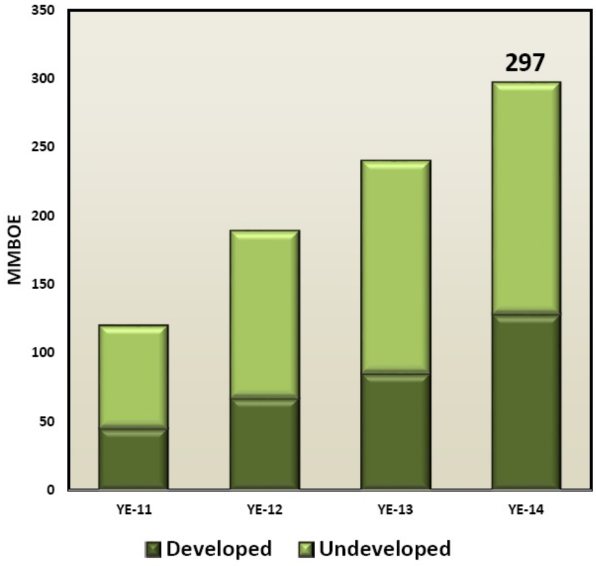


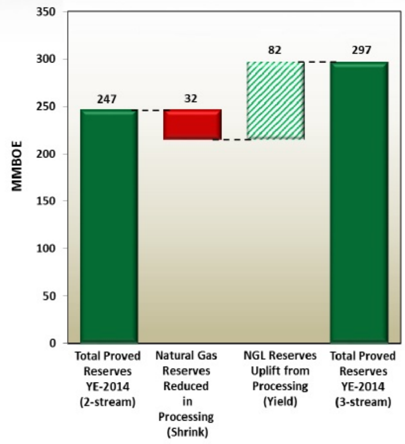
- LPI - Glass 22A-Aermotor #7SP
  7,000' Lateral
  30 Day IP: 1,151 BOED
  EUR 650 MBOE
  Normalized 7,500' lateral EUR: 696 MBOE
- LPI - Barbee C-1-1B #2SP
  8,300' Lateral
  WOC
- EOG – Rocker B "1949" #1H
  2,750' Lateral
  EUR 271 MBOE
  Normalized 7,500' lateral EUR: 739 MBOE
- Potential Canyon Fairway

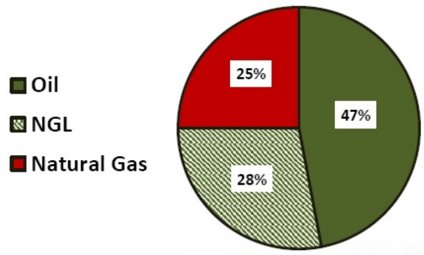
LPI anticipates adding additional Canyon locations to its development ready inventory

2014 Reserve Summary

Permian Year-End Reserves[1]



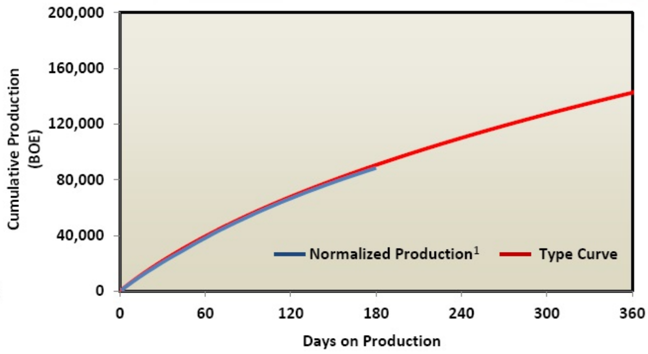


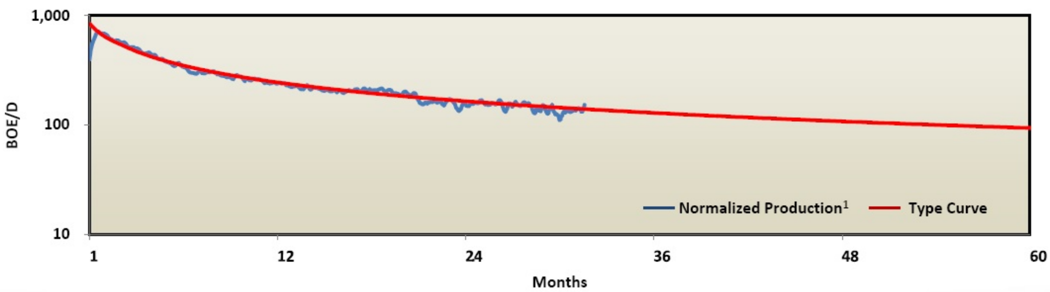


[1] *Based on YE-2014 2-stream proved reserves, prepared by Ryder Scott. Internally converted to 3-stream based on actual gas plant economics of 30% shrink and a yield of 127 Bbl of NGL per MMcf. Annual reserve volumes prior to 2014* have been converted to 3-stream using an 18% uplift

Upper Wolfcamp 7,500' Type Curve

- EUR: 850 MBOE (45% oil)
- 180 cumulative: 91 MBOE (60% oil)
- 80 UWC wells
  - 60 UWC wells operated by LPI included in 7,500' type curve normalized production
- PUDs booked: 153 locations
- Total Development Ready: 828 locations[2]

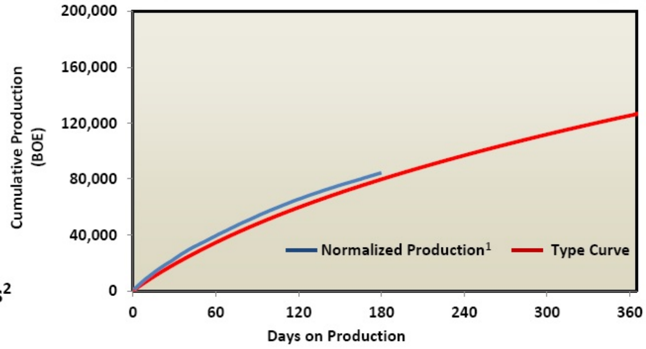


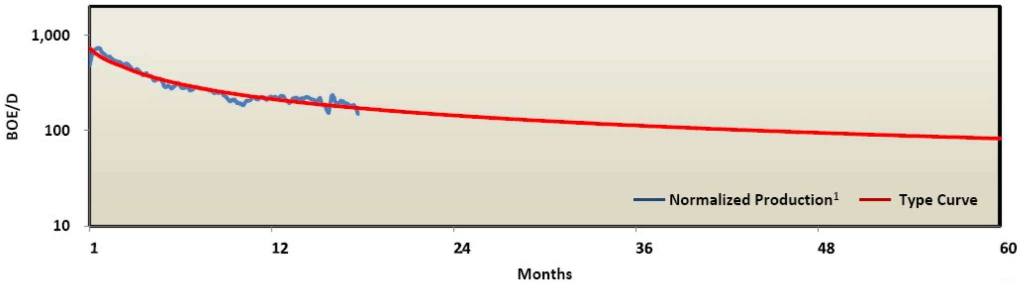


[1] Data includes horizontal wells with lateral lengths >6,000' and 24 stages. As of 3/31/15.
[2] Total Development Ready locations includes PUDs

Middle Wolfcamp 7,500’ Type Curve

- EUR: 750 MBOE (50% oil)
- 180 cumulative: 80 MBOE (61% oil)
- 28 MWC wells
  - 26 MWC wells operated by LPI included in 7,500’ type curve normalized production
- PUDs booked: 34 locations
- Total Development Ready: 807 locations[2]

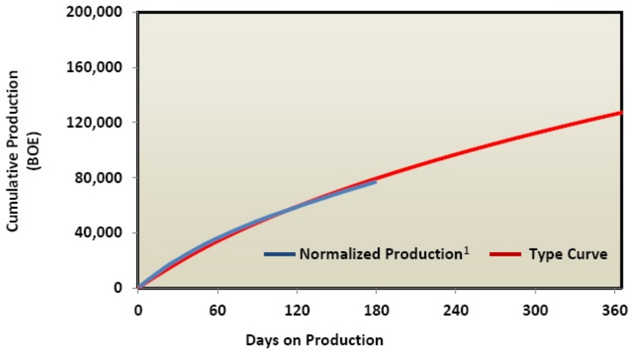


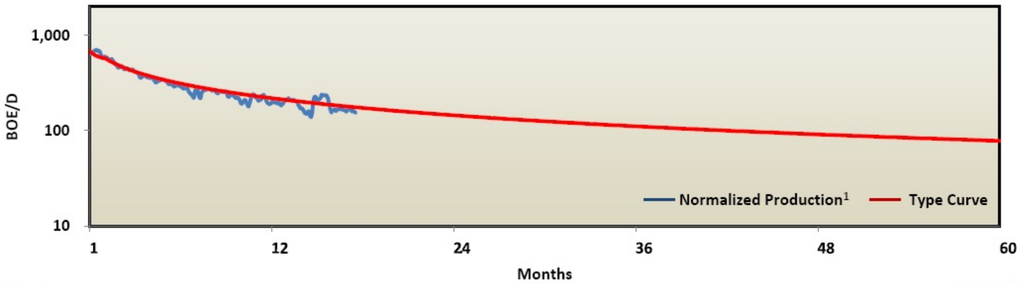


[1] *Data includes horizontal wells with lateral lengths >6,000’ and 24 stages. As of 3/31/15.*
[2] *Total Development Ready locations includes PUDs*

Lower Wolfcamp 7,500' Type Curve

- EUR: 700 MBOE (45% oil)
- 180 cumulative: 80 MBOE (55% oil)
- 20 LWC wells
  - 20 LWC wells operated by LPI included in 7,500' type curve normalized production
- PUDs booked: 45 locations
- Total Development Ready: 813 locations[2]

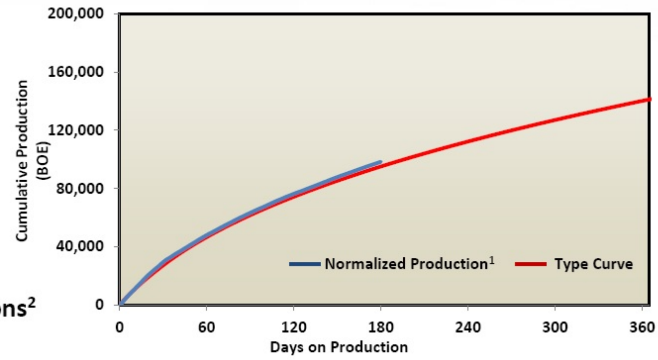


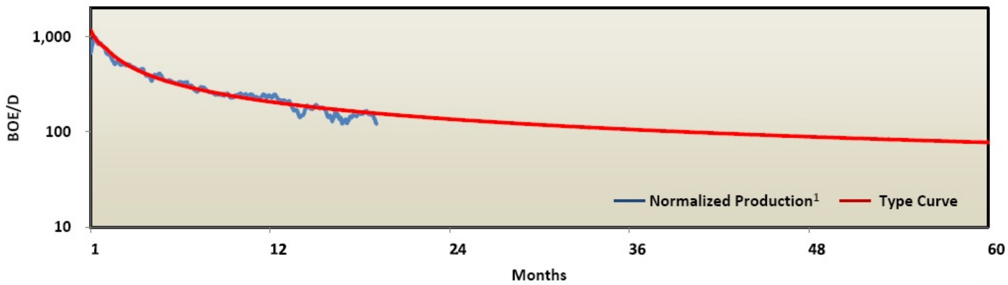


[1] *Data includes horizontal wells with lateral lengths >6,000' and 24 stages. As of 3/31/15.*
[2] *Total Development Ready locations includes PUDs*

Cline 7,500' Type Curve

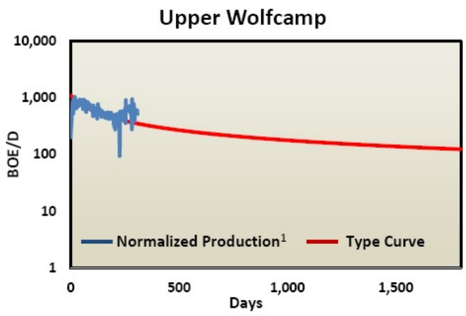
- EUR: 725 MBOE (50% oil)
- 180 cumulative: 96 MBOE (55% oil)
- 50 Cline wells
  - 12 Cline wells operated by LPI included in 7,500' type curve normalized production
- PUDs booked: 24 locations
- Total Development Ready: 1,223 locations[2]

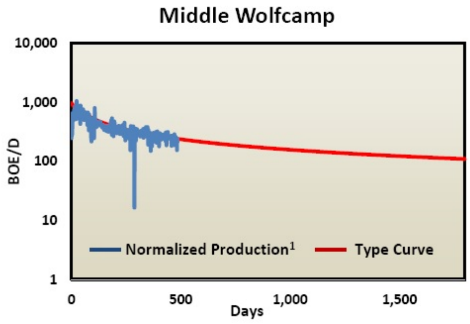


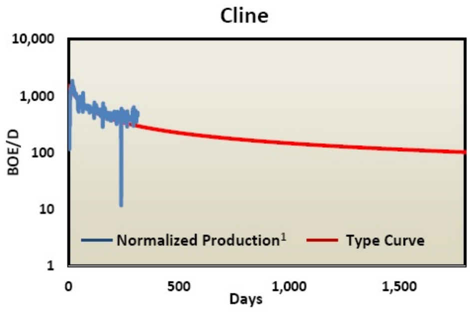


[1] *Data includes horizontal wells with lateral lengths > 6,000' and 24 stages. As of 3/31/15.*
[2] *Total Development Ready locations includes PUDs*

10,000' Lateral Type Curves



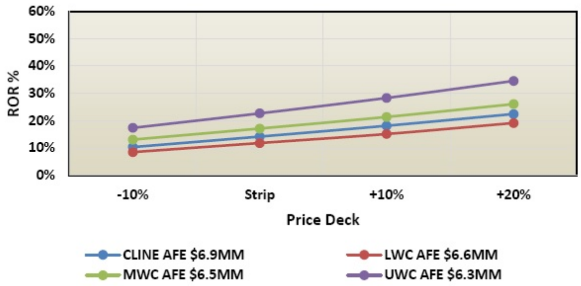




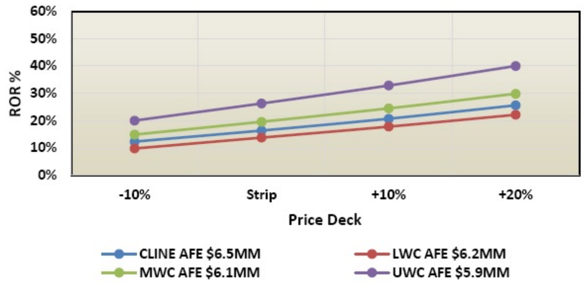
	Upper Wolfcamp	Middle Wolfcamp	Cline
Lateral Length	~10,000'	~10,000'	~10,000'
EUR (MBOE)	1,110	1,000	1,000
Well Count	6	5	3
Frac Stages	33	32	33

ROR Sensitivities vs Strip Pricing[1]

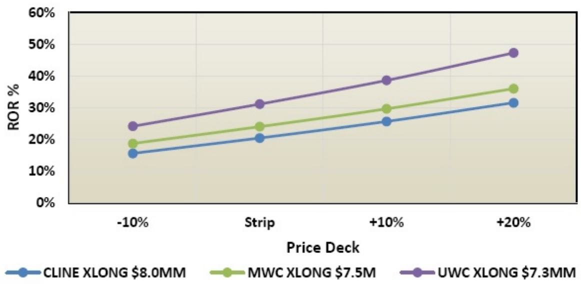
7,500' Single-Well Pad ROR Sensitivities



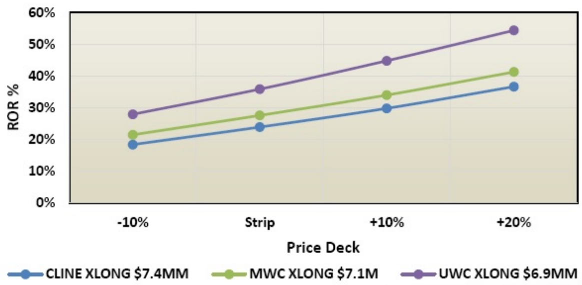
7,500' Multi-Well Pad ROR Sensitivities



10,000' Single-Well Pad ROR Sensitivities

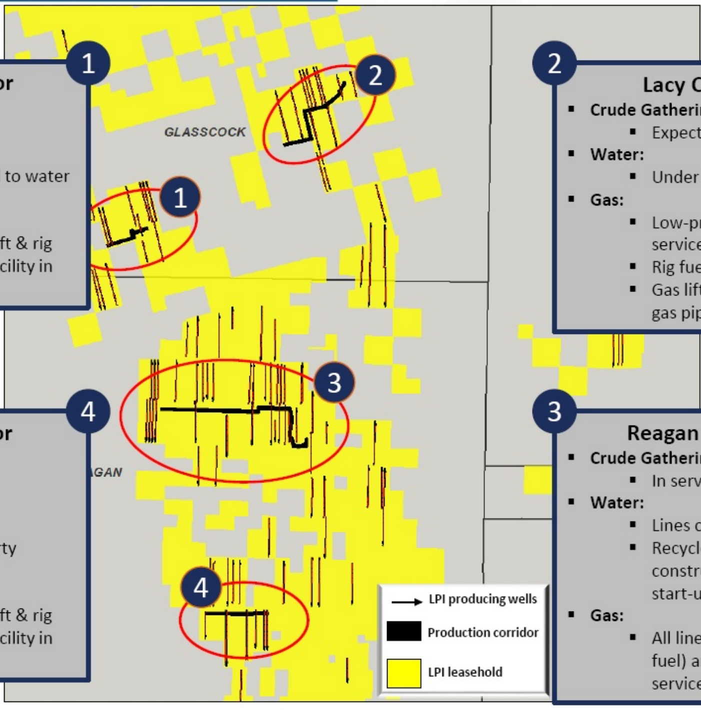


10,000' Multi-Well Pad ROR Sensitivities



[1] Forward strip price deck, as of 4/1/2015

Production Corridor Status



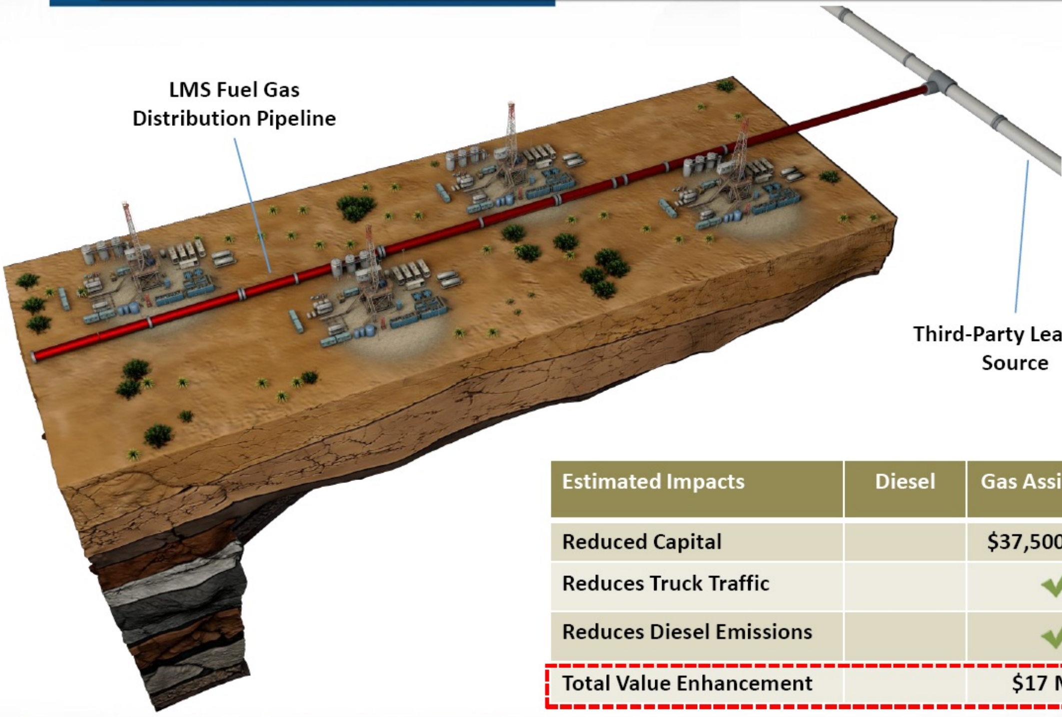
1 JE Cox/Blanco Corridor
- **Crude Gathering:**
  - In service
- **Water:**
  - In service and connected to water recycle facility
- **Gas:**
  - All lines (gathering, gas lift & rig fuel) and compression facility in service

2 Lacy Creek Corridor
- **Crude Gathering:**
  - Expected in service date 3Q-15
- **Water:**
  - Under review
- **Gas:**
  - Low-pressure gas gathering in service
  - Rig fuel line in service
  - Gas lift supply from EnLink lean gas pipeline in service

4 Reagan South Corridor
- **Crude Gathering:**
  - In service
- **Water:**
  - Lines constructed
  - Plans to pipe to third-party disposal
- **Gas:**
  - All lines (gathering, gas lift & rig fuel) and compression facility in service

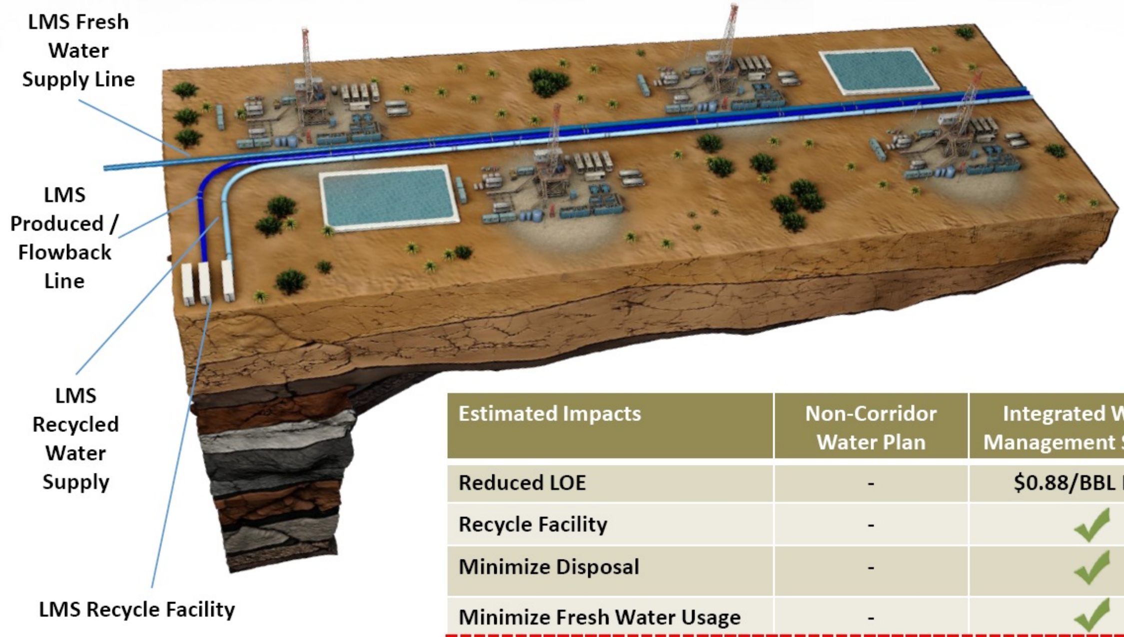
3 Reagan North Corridor
- **Crude Gathering:**
  - In service
- **Water:**
  - Lines constructed
  - Recycle facility under construction, 2Q-15 estimated start-up
- **Gas:**
  - All lines (gathering, gas lift & rig fuel) and compression facility in service

Reagan North Corridor – Rig Fuel



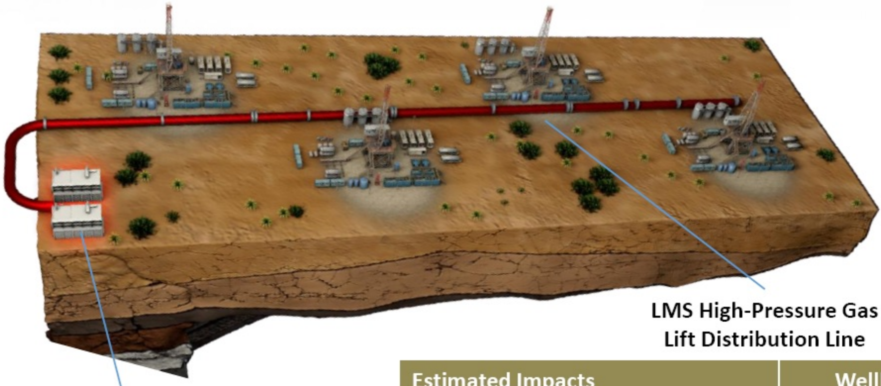
Estimated Impacts	Diesel	Gas Assist Fuel
Reduced Capital		$37,500/Well
Reduces Truck Traffic		✓
Reduces Diesel Emissions		✓
Total Value Enhancement		$17 MM

Reagan North Corridor – Water System



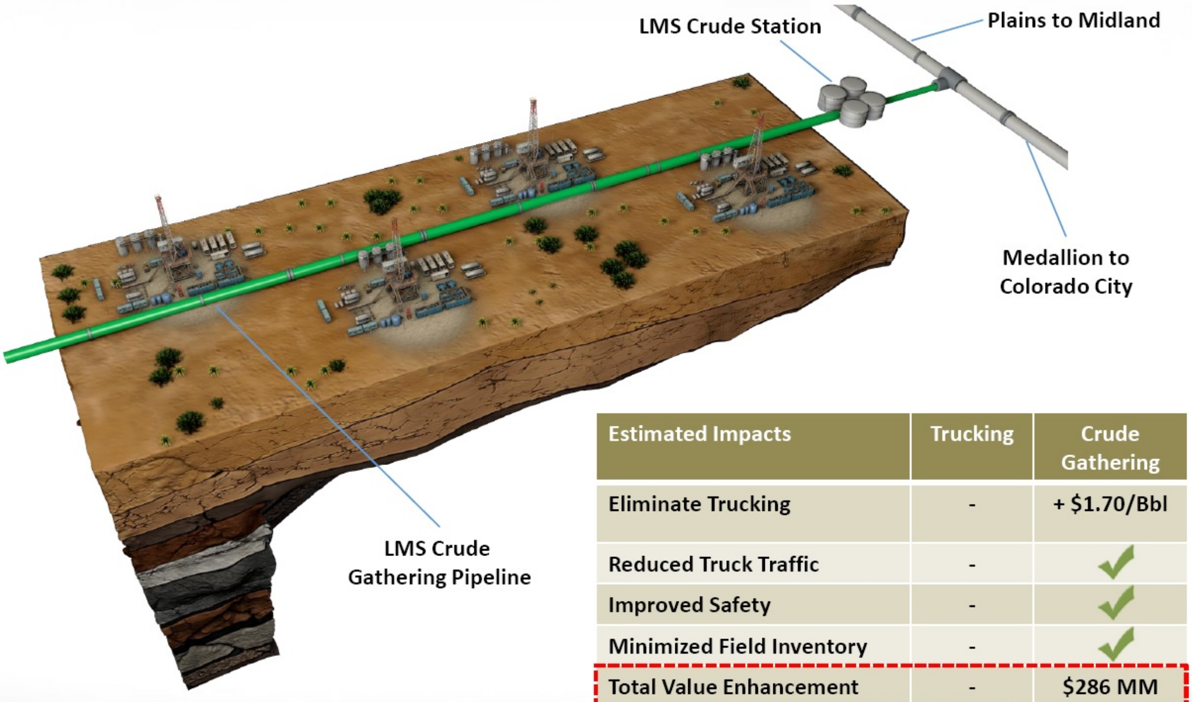
Estimated Impacts	Non-Corridor Water Plan	Integrated Water Management System
Reduced LOE	-	$0.88/BBL H_2O
Recycle Facility	-	✓
Minimize Disposal	-	✓
Minimize Fresh Water Usage	-	✓
Total Value Enhancement	-	$113 MM

Reagan North Corridor – Centralized Gas Lift



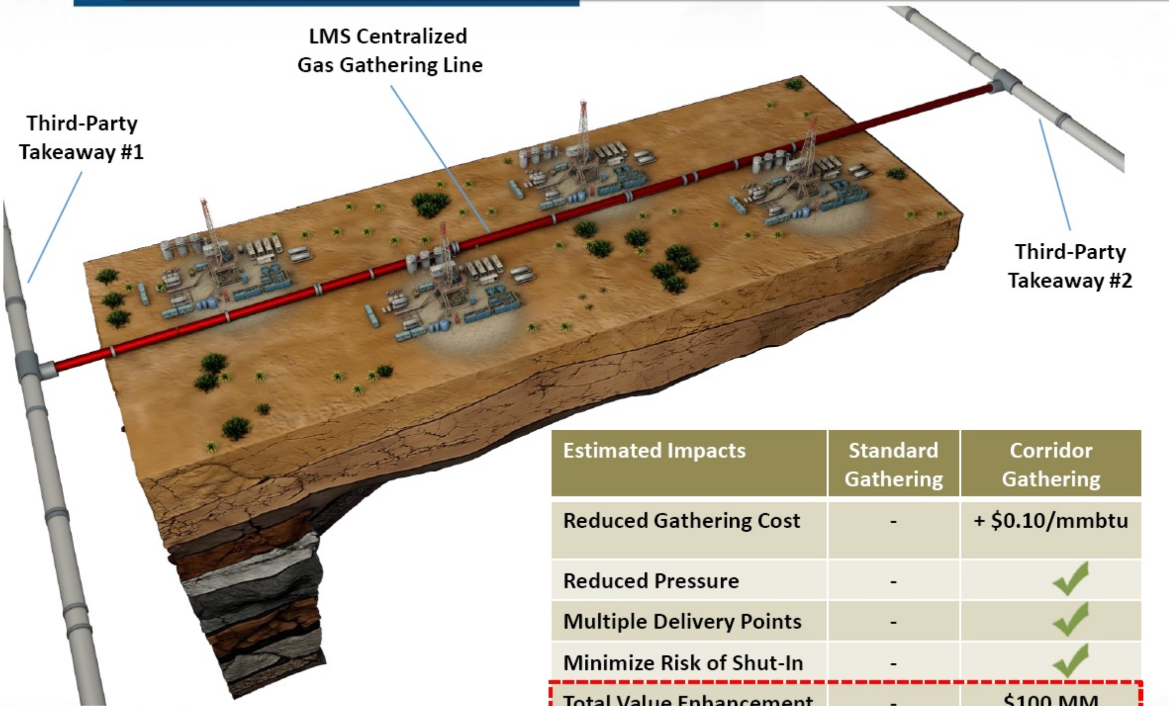
Estimated Impacts	Wellhead Compression	Centralized Gas Lift Compression
Construct/ Maintain	Multiple Installations	1 Facility
Facility Uptime	~93%	~98%
LOE Savings ($/well/month)	-	$2,250
Improved Well Performance	-	✓
Alternative Source of Gas Lift Gas	-	✓
Total Value Enhancement	-	$36 MM

Reagan North Corridor – Crude Gathering



Estimated Impacts	Trucking	Crude Gathering
Eliminate Trucking	-	+ $1.70/Bbl
Reduced Truck Traffic	-	✓
Improved Safety	-	✓
Minimized Field Inventory	-	✓
Total Value Enhancement	-	$286 MM

Reagan North Corridor – Gas Gathering



Estimated Impacts	Standard Gathering	Corridor Gathering
Reduced Gathering Cost	-	+ $0.10/mmbtu
Reduced Pressure	-	✓
Multiple Delivery Points	-	✓
Minimize Risk of Shut-In	-	✓
Total Value Enhancement	-	$100 MM

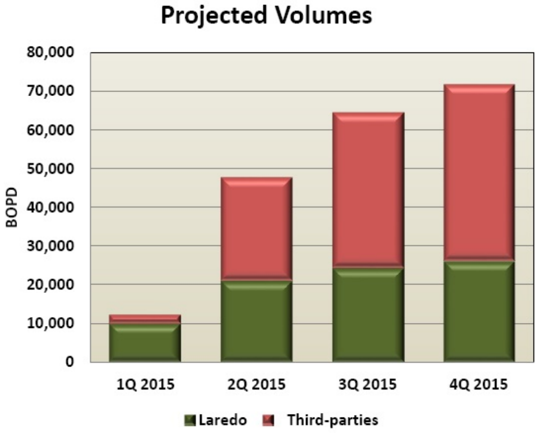
Reagan North Corridor

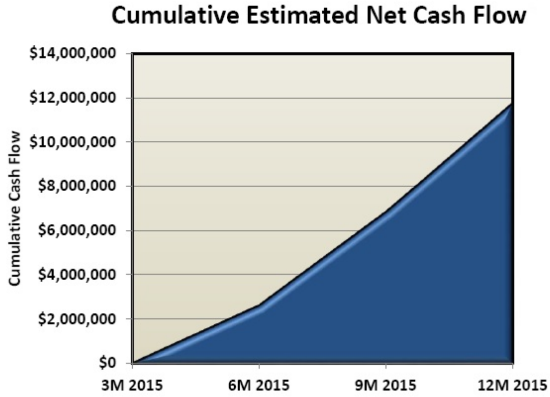
Per well estimated benefits of corridor investment (capital savings, LOE savings and price uplift)

Natural gas for rig fuel, displaces higher cost diesel	$37,500
Approximately 40% total investment pays out before well is even producing	
Flowback and produced water savings over life of well	$253,000
85% of savings in initial flowback of load water used in completion	
Per well payout occurs at <25% load recovery	
Natural gas for gas lift for first 3 years of well life	$81,000
Crude oil gathering price uplift to LPI over life of well	$356,250
Crude oil gathering revenue to LMS over life of well	$281,250
Reduced gas gathering expense over life of well	$225,000
Total estimated benefit of Reagan North Production Corridor ***for each well***	$1,234,000

$553 million in total estimated benefits from investment of $44 million

Medallion 2015 Forecast

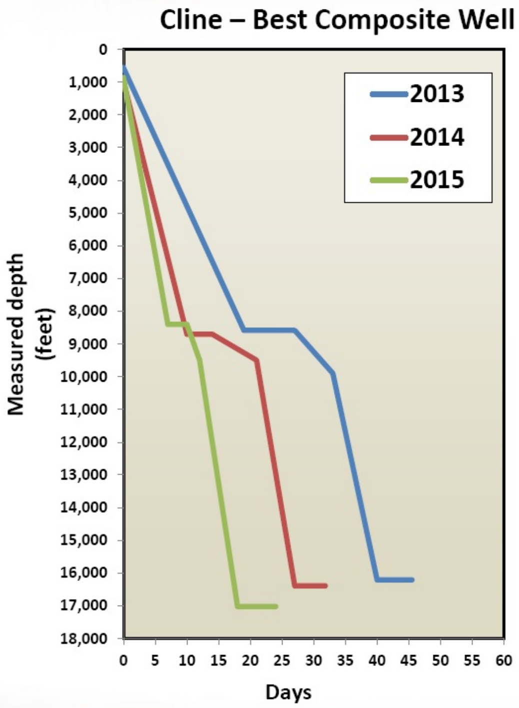




Third-party volume growth driven by continued expansions of the pipeline system and the optionality provided by the redelivery options on the system

Total estimate 2015 LMS net cash flow from the Medallion pipeline of $11 MM

Best Composite Well: Cline Example



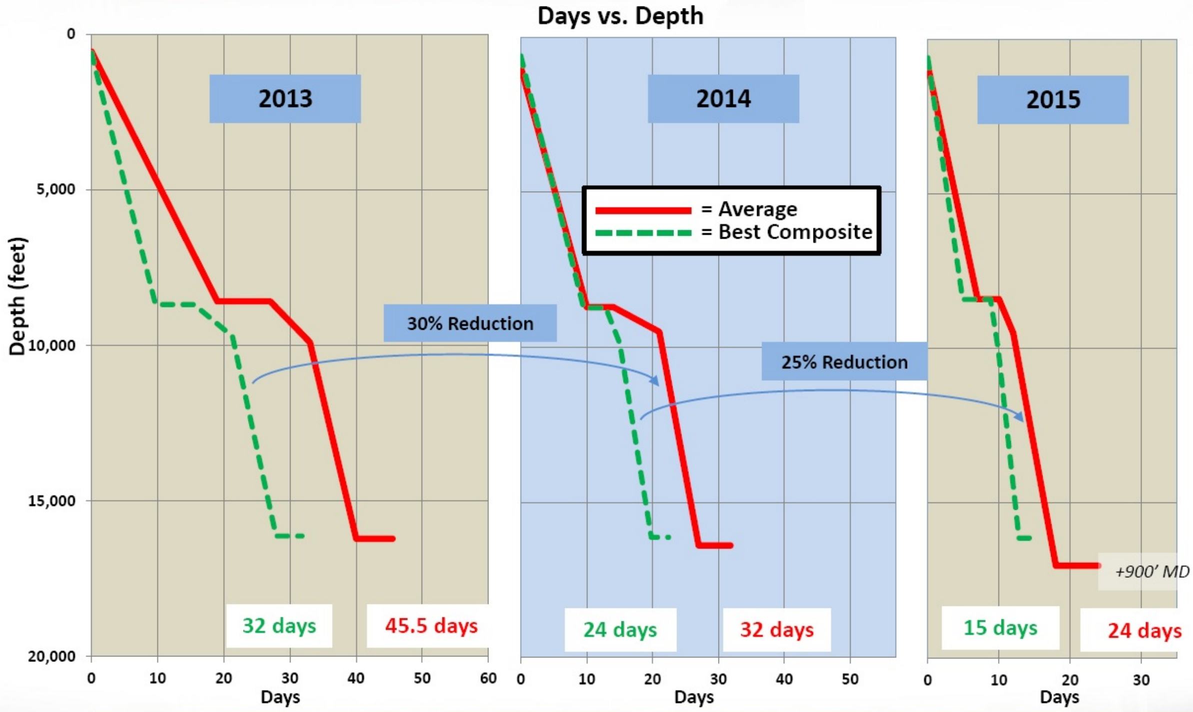
Composite well goals

- Continuous improvement
- Identification of best practices
- Implementation of best practices

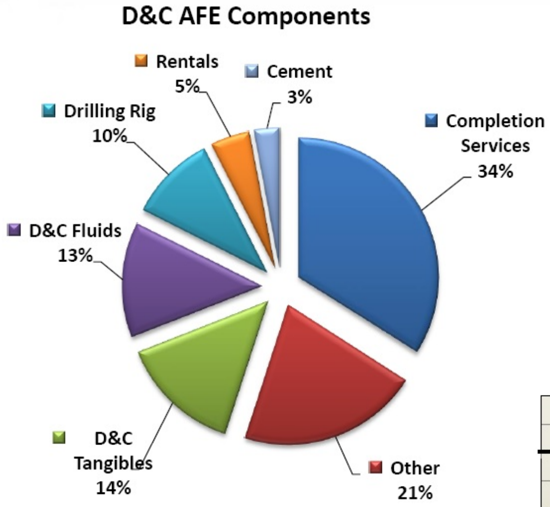
Composite well process

- Well divided into key sections
- Best performance key sections identified
- Best practices identified
  - Operational practices
  - Operating parameters
- Lessons learned applied to future wells
  - Incorporated in well plans
  - Weekly meetings/discussions
  - Operating parameter Monitoring

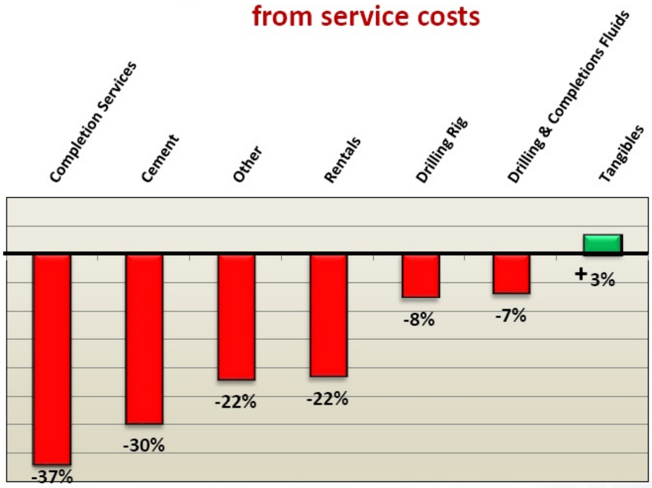
Composite – Average Wells Comparison (Cline Example)



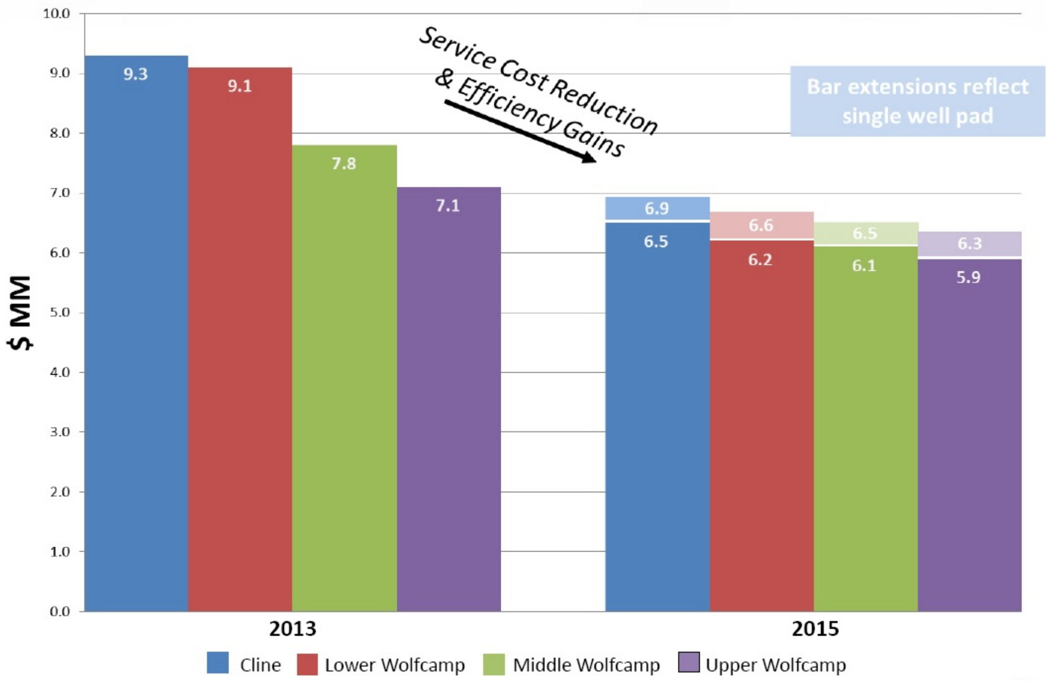
Drilling & Completion: Service Cost Reductions



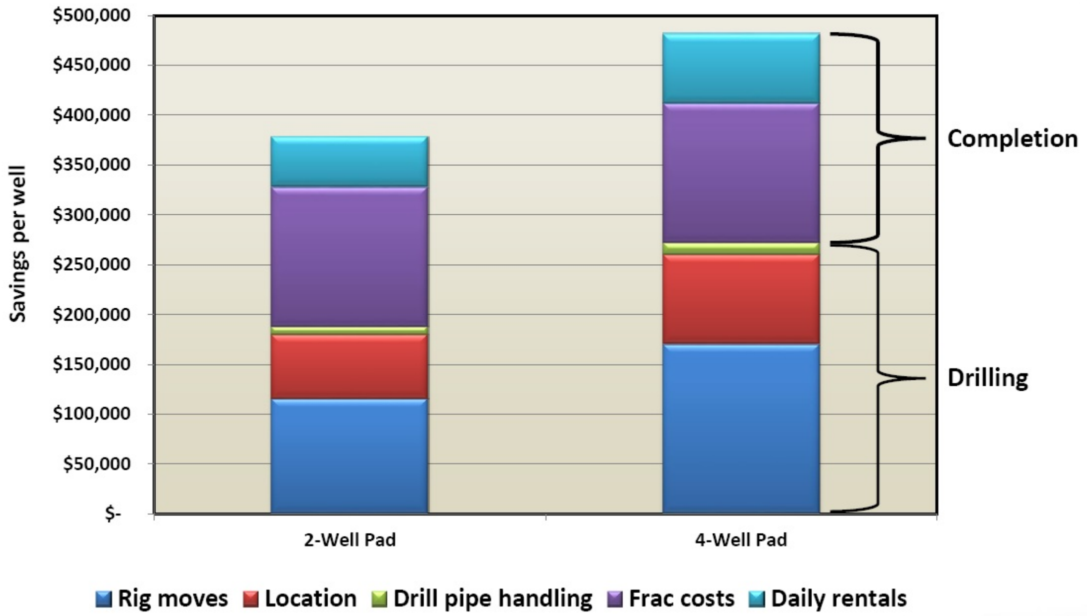
15% - 20% cost reductions to date from service costs



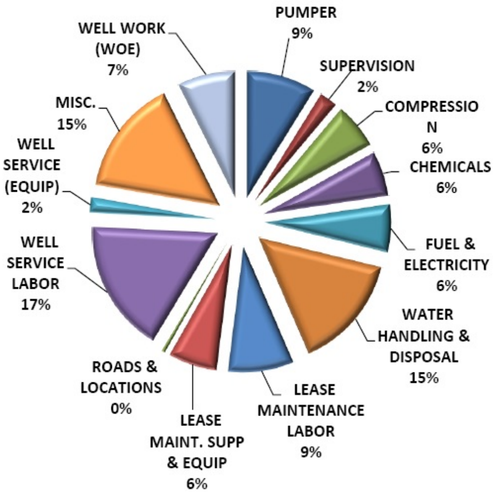
Well Cost Evolution (7,500' Laterals)



Multi-Well Pad Savings



Lease Operating Expenses (LOE)



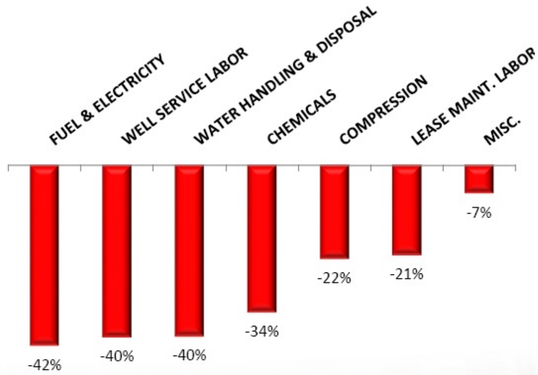
Current Expense Breakdown

Targeted LOE Annualized Savings

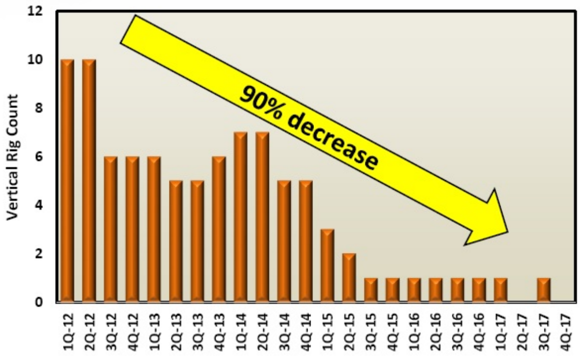
Water:	Expanding water management infrastructure
Power:	Replacing generators with the grid in new areas
Compression:	Well pad compressors to centralized compression
Automation:	Bringing SCADA management "in-house"

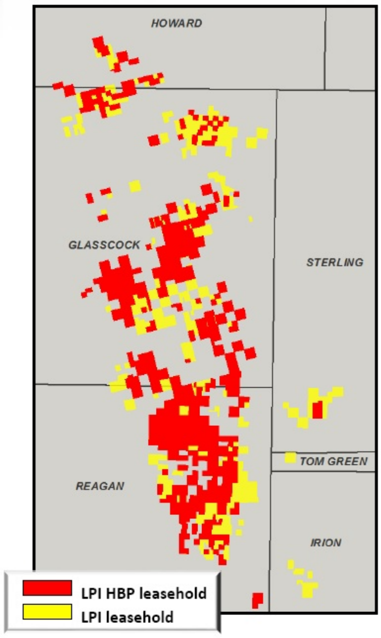
Lease Maintenance Labor:

	Roustabout gang efficiency/management
	Per gang service cost reduction
Well Service:	Rig cost reduction
Chemicals:	Bidding – expect significant cost reduction



Decreasing Vertical Drilling Activities

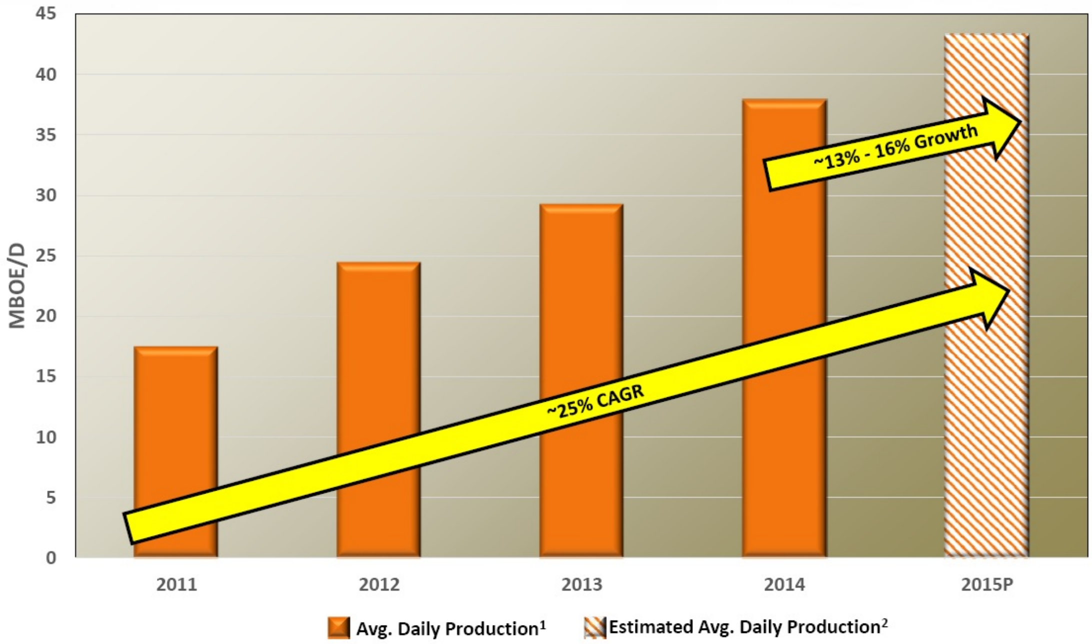




- **Decreased reliance on vertical program to hold acreage position will enhance portfolio rate of return**
- **2015 and future capital programs to concentrate on horizontal development drilling**
- **Blocked acreage position now ~71% held by production[1]**

[1] As of 3/31/15

2015 Estimated Production Growth

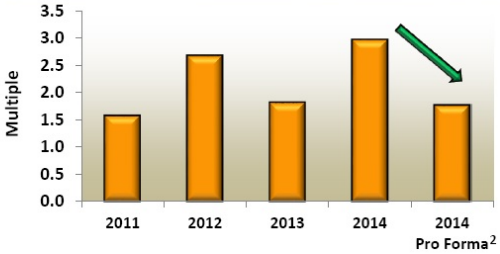


[1] Quarterly production numbers prior to 2014 have been converted to 3-stream using an 18% uplift. 2014 quarterly results have been converted to 3-stream using actual gas plant economics

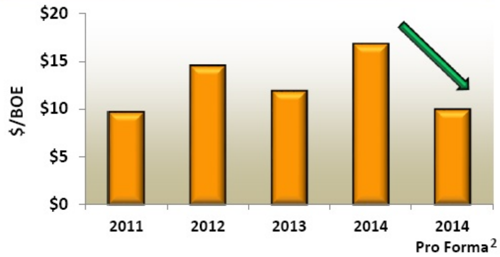
[2] Based on midpoint of guidance of 15.6 MMBOE – 16.0 MMBOE for full-year 2015

Improved Debt Metrics

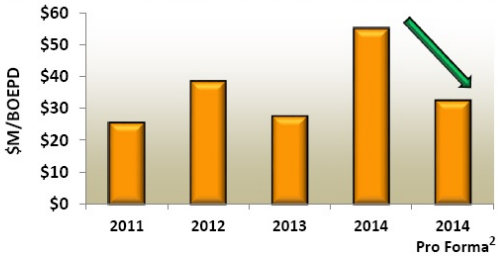
Debt[1] / Adjusted EBITDA



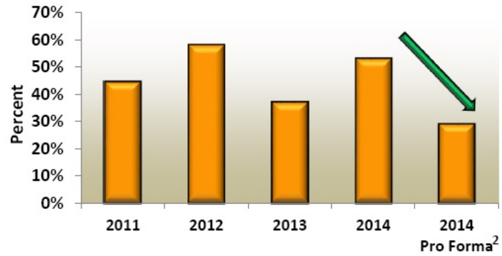
Debt[1] / Proved Developed Reserves



Debt[1] / Daily Production



Debt[1] / Total Capitalization



[1] Debt reflects Debt less cash and cash equivalents
[2] Pro forma ratios reflect the repayment in full of the Company's Senior Secured Credit Facility and calling the 9-1/2% notes following the issuance of 69 MM shares of common stock and $350 MM of 6-1/4% notes

Oil Hedges

Open Positions As of March 31, 2015 [1]	2015	2016	2017	Total
OIL [2]				
Puts:				
Hedged volume (Bbls)	342,000	-	-	342,000
Weighted average price ($/Bbl)	$75.00	$ -	$ -	$75.00
Swaps:				
Hedged volume (Bbls)	504,000	1,573,800	-	2,077,800
Weighted average price ($/Bbl)	$96.56	$84.82	$ -	$87.67
Collars:				
Hedged volume (Bbls)	4,922,140	3,654,000	2,628,000	11,204,140
Weighted average floor price ($/Bbl)	$79.81	$73.99	$77.22	$77.30
Weighted average ceiling price ($/Bbl)	$95.40	$89.63	$97.22	$95.46
Total volume with a floor (Bbls)	**5,768,140**	**5,227,800**	**2,628,000**	**13,623,940**
Weighted average floor price ($/Bbl)	**$80.99**	**$77.25**	**$77.22**	**$78.83**
NYMEX WTI to Midland Basis Swaps:				
Hedged volume (Bbls)	2,750,000	-	-	2,750,000
Weighted average price ($/Bbl)	$ 1.95	$ -	$ -	$1.95

[1] *Updated to reflect hedges placed through 6/3/15*
[2] *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 March 31, 2015 [1]	2015	2016	2017	Total
NATURAL GAS [2]				
Collars:				
Hedged volume (MMBtu)	21,520,000	18,666,000	-	40,186,000
Weighted average floor price ($/MMBtu)	$3.00	$ 3.00	$ -	$3.00
Weighted average ceiling price ($/MMBtu)	$5.96	$ 5.60	$ -	$5.82
Total volume with a floor (MMBtu)	**21,520,000**	**18,666,000**	**-**	**40,186,000**
Weighted average floor price ($/MMBtu)	**$3.00**	**$3.00**	**$ -**	**$3.00**

[1] Updated to reflect hedges placed through 4/13/15
[2] Natural gas derivatives are settled based on Inside FERC index price for West Texas Waha for the calculation period.

2015 Guidance

	2Q-2015		FY-2015
Production (MMBOE)	4.0 - 4.2		15.6 - 16.0
Crude oil % of production	50%		50%
Natural gas liquids % of production	25%		25%
Natural gas % of production	25%		25%
Price Realizations (pre-hedge):			
Crude oil (% of WTI)	~85%		~85%
Natural gas liquids (% of WTI)	~25%		~25%
Natural Gas (% of Henry Hub)	~70%		~70%
Operating Costs & Expenses:			
Lease operating expenses ($/BOE)	$6.75 - $7.75		$6.75 - $7.75
Midstream expenses ($/BOE)	$0.40 - $0.50		$0.40 - $0.50
Production and ad valorem taxes (% of oil and gas revenue)	7.75%		7.75%
General and administrative expenses ($/BOE)	$6.00 - $7.00		$6.00 - $7.00
Depletion, depreciation and amortization ($/BOE)	$16.50 - $17.50		$16.75 - $17.75

EBITDA Reconciliation

($ thousands, unaudited)	2011	2012	2013	2014	1Q-15
Net income (loss)	$105,554	$61,654	$118,000	$265,573	$(472)
Plus:					
Interest expense	50,580	85,572	100,327	121,173	32,414
Depletion, depreciation and amortization	176,366	243,649	234,571	246,474	71,942
Impairment expense	243	--	--	3,904	878
Restructung expenses	--	--	--	--	6,042
Write-off of debt issuance costs	6,195	--	1,502	124	--
Bad debt expense	--	--	653	342	--
Loss on disposal of assets, net	40	52	1,508	3,252	762
Gain on derivatives, net	(19,736)	(8,388)	(79,878)	(327,920)	(63,155)
Cash settlements received for matured commodity derivatives, net	3,719	27,025	4,046	28,241	63,141
Cash settlements received for early terminations and modifications of commodity derivatives, net	--	--	6,008	76,660	--
Premiums paid for derivatives that matured during the period[1]	(4,104)	(9,135)	(11,292)	(7,419)	(1,421)
Non-cash stock-based compensation, net of amount capitalized	6,111	10,056	21,433	23,079	4,788
Income tax expense	59,374	32,949	75,288	164,286	3,643
Adjusted EBITDA	**$384,342**	**$443,434**	**$472,166**	**$597,769**	**$118,562**

[1] Reflects premiums incurred previously or upon settlement that are attributable to instruments settled in the respective periods presented

Two-Stream to Three-Stream Conversions

		1Q-14	2Q-14	3Q-14	4Q-14	FY-14
Production	**Production (2-Stream)**					
	BOE/D	**27,041**	**28,653**	**32,970**	**39,722**	**32,134**
	% oil	**58%**	**58%**	**59%**	**60%**	**59%**
	Production (3-Stream)					
	BOE/D	**32,358**	**33,829**	**38,798**	**46,379**	**37,882**
	% oil	**49%**	**49%**	**50%**	**51%**	**50%**
Realized Pricing	**2-Stream Prices**					
	Gas ($/Mcf)	$7.04	$6.08	$5.80	$4.46	$5.72
	Oil ($/Bbl)	$91.78	$94.47	$87.65	$65.05	$82.83
	3-Stream Prices					
	Gas ($/Mcf)	$4.00	$3.73	$3.25	$3.00	$3.45
	NGL ($/Bbl)	$32.88	$28.79	$29.21	$19.65	$27.00
	Oil ($/Bbl)	$91.78	$94.47	$87.65	$65.05	$82.83
Unit Cost Metrics	**2-Stream Unit Cost Metrics**					
	Lease Operating ($/BOE)	$8.95	$7.74	$8.30	$8.04	$8.23
	Midstream ($/BOE)	$0.35	$0.59	$0.40	$0.50	$0.46
	G&A ($/BOE)	$11.36	$11.34	$8.93	$5.95	$9.04
	DD&A ($/BOE)	$20.38	$20.35	$21.08	$21.85	$21.01
	3-Stream Unit Cost Metrics					
	Lease Operating ($/BOE)	$7.48	$6.55	$7.05	$6.88	$6.98
	Midstream ($/BOE)	$0.29	$0.50	$0.34	$0.43	$0.39
	G&A ($/BOE)	$9.50	$9.60	$7.59	$5.10	$7.67
	DD&A ($/BOE)	$17.03	$17.23	$17.91	$18.72	$17.83