Quarterly Report

March 2015

Lonestar Resources, Ltd. (ASX:LNR, OTCQX: LNREF) is pleased to provide an update on its financial and operational results for the three months ended March 31, 2015 (1Q15).

First Quarter Highlights

- Lonestar Resources registered a 46% increase in net oil and gas production to 5,547 BOEPD in 1Q15, vs. 3,800 BOEPD in 1Q14, 83% of which was crude oil and NGL's. The Company's Eagle Ford Shale properties recorded a 55% increase in net oil and gas production to 4,827 BOEPD in the first quarter of 2015.
- Net Revenues From Ordinary Activities increased 14% to US$29.1 million for 1Q15, vs. 1Q14 revenues of $25.6 million. This increase was achieved despite a 51% decrease in average West Texas Intermediate prices.
- EBITDAX rose 14% to $21.7 million for 1Q15 vs. $19.1 million for 1Q14, as increased production and incremental revenues from crude oil hedges more than offset a 53% decrease in its average wellhead price.
- Excluding a $3.8 million unrealized loss on commodity derivatives and a non-recurring $0.7 million loss on sale of oil and gas properties, Lonestar would have reported Net Income of $3.7 million for 1Q15 vs. Net Income of $7.2 million reported for 1Q14.
- The Company's Borrowing Base on its Senior Secured Revolving Credit Facility has been re-affirmed at $150 million, $89 million of which was undrawn at March 31, 2015.
- Lonestar is pleased to announce that it has reached definitive agreements to acquire leasehold associated with approximately 6,122 gross / 4,047 [1] net mineral acres in La Salle County, Texas. Lonestar's independent engineering consultant estimates that Proved net reserves associated with these properties are 2.7 million barrels of liquids and 11.0 billion cubic feet of natural gas, or 4.5 million barrels of oil equivalent (MMBOE). More importantly, Lonestar estimates that Proved and Probable net reserves associated with the transactions are 6.4 million barrels of liquids and 26.3 billion cubic feet of natural gas, or 10.8 MMBOE. [1]
- With the first quarter under its belt, Lonestar reiterates its previous 2015 guidance. Based on a price range or $50 to $60 per barrel for West Texas Intermediate and the expectation for the Company to drill 15 gross wells in 2015, Lonestar currently forecasts production levels to average between 5,700 and 6,100 BOE per day, which yields EBITDAX guidance of $84 to $95 million for 2015. [1]

[1] *Please see the Notes & Disclosures at the end of this document*

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Management's Discussion and Analysis

Lonestar Resources, Ltd. is pleased to announce its operational and unaudited financial results for the quarter ended March 31, 2015.

OVERVIEW

Lonestar Resources, Ltd. ("Lonestar" or the "Company") is listed on the Australian Securities Exchange (ASX) and the OTCQX in the United States, and is headquartered in Fort Worth, Texas. Lonestar Resources is focused on the acquisition, development and production of unconventional resources in the United States. Alongside optimizing cash flows from its Conventional assets, Lonestar is focusing its attention and capital to continuing its growth strategy in the crude oil window of the Eagle Ford Shale. Lonestar currently operates 100% of its 34,180 net acres in the Eagle Ford, and continues to expand its leasehold. Lonestar believes it is capitalized to fund the development of its existing Eagle Ford Shale drilling inventory though internal means. Lonestar is also engaged in an early-stage project in the Bakken Petroleum System, where it has assembled a 52,559 acre leasehold (34,163 net acres) and tested light oil from the Bakken, Three Forks and Lower Lodgepole formations.

FIRST QUARTER 2015 HIGHLIGHTS

Corporate

- Lonestar is pleased to announce that it has reached definitive agreements to acquire leasehold associated with approximately 6,122 gross / 4,047 net mineral acres in La Salle County, Texas. Lonestar's independent engineering consultants estimates that Proved net reserves associated with these properties are 2.7 million barrels of liquids and 11.0 billion cubic feet of natural gas, or 4.5 million barrels of oil equivalent (MMBOE). More importantly, Lonestar's independent engineering consultants estimate that Proved and Probable net reserves associated with the purchase are 6.4 million barrels of liquids and 26.3 billion cubic feet of natural gas, or 10.8 MMBOE.[1] The addition of this leasehold adds 32 gross / 20 net horizontal Eagle Ford Shale drilling locations to Lonestar's drilling inventory. At year-end 2014, Lonestar held interests in 143 engineered Eagle Ford Shale drilling locations. This acreage is in two blocks and is in different parts of La Salle County, Texas:
  - **Greater Burns Ranch**- Lonestar has added 1,720 gross / 1,225 net acres, in the Greater Burns Ranch area of northern La Salle County. This acquisition represents the third bolt-on deal closed since Lonestar established a footprint on the Burns Ranch when it acquired interests from Clayton Williams Energy, Inc. in March, 2014. Lonestar expended $2.1 million to acquire all of the working interests it did not previously own in 960 gross / 480 net acres, which holds 9 gross / 4 net Eagle Ford drilling locations with lateral lengths of 8,000 feet, and acquired interests in 760 gross / 745 net acres in offsetting acreage which may hold as many as 4 additional Eagle Ford drilling locations. The purchase also adds net production of 33 barrels of oil equivalent per day (BOEPD) from 5 Austin Chalk wells, which hold all of the leasehold by production. Lonestar's independent engineering consultants estimate that Proved net reserves associated with the purchase are 0.5 million barrels of liquids and 0.6 billion cubic feet of natural gas, or 0.6 million barrels of oil equivalent (MMBOE). Lonestar's independent engineering consultant estimates that Proved and Probable net reserves associated with the purchase are 1.3 million barrels of liquids and 1.6 billion cubic feet of natural gas, or 1.6 MMBOE.[1]
  - **"Horned Frog"-** Lonestar has executed a farm-in agreement via which we will acquire working interests in 4,402 gross / 2,822 net acres in west central La Salle County. This acreage, which is in a contiguous block, affords Lonestar the potential to drill a minimum of 19 gross / 12 net horizontal wells with lateral lengths of approximately 8,000 feet. The agreement calls for Lonestar to drill two wells in 2015 to hold this leasehold. Lonestar's independent engineering consultant estimates that Proved net reserves associated with the farm-in are 2.1 million barrels of liquids and 10.4 billion cubic feet of natural gas, or 3.9 MMBOE. Lonestar independent engineering consultant estimates that Proved and Probable net reserves associated with the farm-in are 5.1 million barrels of liquids and 24.7 billion cubic feet of natural gas, or 9.2 MMBOE.[1] Additional reserves upside lies in the 1,580 net unleased net mineral acres on the block. Lonestar believes that it is in an excellent position to acquire these working interests associated with this tract, which would increase these reserves estimates by approximately 50%.
- Lonestar's senior lending group, led by Wells Fargo, re-affirmed the borrowing base on our Senior Secured Credit Facility at $150 million., $89 million of which was undrawn at March 31, 2015.

Operational

- Lonestar's net production for the first quarter of 2015 rose 46% to 5,547 BOE per day. First quarter 2015 volumes were comprised of 4,043 barrels of oil per day, 542 barrels of NGL's per day, and 5,770 Mcf of natural gas per day. First quarter production was comprised of 83% crude oil and natural gas liquids, and 17% natural gas.
- In the first quarter of 2015, Lonestar generated Discretionary Cash Flow of $15.5 million, a 30% decrease over first quarter 2014 Discretionary Cash Flow of $21.1 million.
- As has been our practice since inception, crude oil hedging has been a key element to providing visibility to its cash flow streams and associated liquidity in the current crude oil price environment. Currently, the Company has West Texas Intermediate (WTI) swaps covering 2,359 barrels of oil per day for the remainder of 2015 at an average strike price of $87.33 per barrel and WTI swaps covering 2,276 barrels of oil per day for calendar 2016 at an average strike price of $77.15 per barrel. The Company has also entered into three-way collars covering 1,000 bopd in 2017.

1 *Please see the reserves disclosures at the end of this document*

Operations Review

EAGLE FORD SHALE TREND- WESTERN REGION

- **Asherton**- In central Dimmit County, no new wells were completed during the quarter. However, Lonestar continues to make progress in decreasing operating costs at Asherton, achieving a 16% reduction in cash costs and a 5% reduction in unit costs compared to 4Q14. In 1Q15, Lease Operating Expenses were $0.2 million, or $6.56 per BOE, compared to $0.3 million, or $6.91 per BOE in 4Q14. The Asherton leasehold is Held by Production, and Lonestar has not planned drilling activity here in 2015.
- **Beall Ranch-** In Dimmit and La Salle Counties, no new wells were completed during the quarter. However, Lonestar continues to make progress in reducing operating costs at Beall Ranch, achieving a 14% reduction in absolute dollar cash costs compared to 4Q14. In 1Q15, Lease Operating Expenses were $1.1 million, or $7.07 per BOE, compared to $1.2 million, or $6.82 per BOE in 4Q14. Lonestar has permitted 3 short laterals at Beall Ranch, and plans to commence drilling operations in May, 2015. While drilling activity is lower than in past years, the Company is actively evaluating methods for improving the productivity of its existing producers. These efforts include: conversion of wells to gas lift, pilot tests of innovative paraffin treatments, and perhaps more importantly, decentralization of the field's gas gathering and compression systems, which we anticipate will reduce system pressures, and improve well productivity and improve well uptime.
- **Burns Ranch Area-** In La Salle County, Lonestar has completed the Gerke #1H-3H with an average perforated interval of 4,380 feet and began flowback in early February. These wells were drilled and completed at an average cost of $5.0 million, which included substantial costs associated with drilling a pilot hole and obtaining extensive advanced formation characterization logs. The Gerke wells, which were pad-drilled and zipper fracked with an average proppant concentration of 1,610 pounds per foot, tested at a per-well average of 448 bopd and 497 Mcfgpd, or 562 BOEPD on a processed three-stream basis on a 17/64" choke. The three wells registered average Max-30 production rates of 322 bopd and 271 Mcfgpd, or 384 BOEPD, on a 20/64" choke. Also during the first quarter of 2015, Lonestar drilled the Burns Ranch Eagle Ford Unit A #1H-3H wells. These wells had an average total measured depth of 16,617' and became the longest laterals drilled by Lonestar in the Western Region to-date. The three Burns Ranch Eagle Ford Unit A wells were recently completed with an average perforated interval of 8,000' and each was fracture stimulated with 32 stages. Completed well costs for these wells are expected to be within their AFE, and are scheduled to commence flowback in May, 2015.
- **Horned Frog-** In La Salle County, Lonestar is planning to spud two 8,000' laterals as part of its farm-in on this acreage, which was announced today. As part of its review of this area in partnership with the Company's independent engineers, Lonestar believes that it can materially improve on the results generated by many of the offset operators. Lonestar's experience indicates this improvement will come from more precise geo-steering and higher levels of proppant concentration in its fracture stimulations. In fact, superior performance in these categories has demonstrated to increase average estimated ultimate recoveries substantially in offset wells. The Company anticipates commencing drilling operations on the property in July, 2015. Preliminary AFE's for these two wells are $6.3 million per well. On this schedule, first production would be expected in September, 2015.

EAGLE FORD SHALE TREND- CENTRAL REGION

- **Pirate Area-** In southwest Wilson County, no new wells were completed during the quarter. However, Lonestar continues to make progress in reducing operating costs at Pirate, achieving a 31% reduction in cash costs and a 8% reduction in unit costs compared to 4Q14. In 1Q15, Lease Operating Expenses were $0.3 million, or $6.97 per BOE, compared to $0.5 million, or $7.56 per BOE in 4Q14. Lonestar currently plans to drill two 7,500-foot laterals in the Pirate Area during the second half of 2015.
- **Southern Gonzales County**- Production on the Harvey Johnson #1H-3H continues to outperform the type curves in the Company's third-party reserve report, with individual gross well production from the three wells averaging 407 BOEPD in March, 2015, their 4th month of production. After encouraging results from the Harvey Johnson #1H-3H, Lonestar executed an additional farm-in agreement, and commenced drilling its next three-well pad adjacent to the Harvey Johnson #1H-3H. Lonestar has completed the drilling phase of operations on the Harvey Johnson #4H-6H and the three wells achieved an average total depth of 15,400' in an average of 10.5 days compared to its AFE of 16 days. These wells are expected to have an average perforated interval of 5,650' and are AFE'd at $5.3 million. Based on our ability to reduce drilling days and on projected costs for pressure pumping, Lonestar is highly confident that it will be able to complete these wells at costs that are materially below original AFE. Fracture stimulations for the Harvey Johnson #4-6H wells are expected to commence in May, 2015, with first production expected by July, 2015.

EAGLE FORD SHALE TREND- EASTERN REGION

- **Brazos & Robertson Counties** - In Brazos and Robertson Counties, no new wells were completed during the quarter. Lonestar currently plans to drill two 8,000-foot laterals in Brazos County in late 2015. These wells are currently scheduled to be drilled on its Wildcat property near Carter Lake, offsetting acreage where Apache has recently placed an estimated 10 wells into production, and has an additional 20 permits filed to drill offsetting wells with the Texas Railroad Commission.

BAKKEN-THREE FORKS TREND

- **Poplar West, Montana-** Based on its geological analysis, core evaluation, and production testing, the Poplar West project area is prospective for the entire unconventional resource "Bakken Petroleum System", which includes the Basal Lodgepole, Upper Bakken Shale, Middle Bakken, Lower Bakken Shale and the Third and Fourth Benches of the Three Forks formations. Further, Poplar West is highly prospective for the Amsden, Charles, Heath, Mission Canyon and Nisku formations. After processing and interpreting its 105 square miles of 3-D seismic data covering the Poplar West project area, Lonestar and its partners have identified 39 Charles prospects (conventional) and 41 Nisku prospects (conventional) and a total of 340 drilling locations in the Non-conventional Bakken Petroleum System. In May, 2015, Lonestar will submit its final application for the establishment of the Stone Turtle Indian Exploratory unit to the Bureau of Land Management (BLM) and Bureau of Indian Affairs (BIA), which it has downsized to cover 44,050 gross acres and expects to receive approval imminently. As currently contemplated, formation of the unit would establish a 5-year primary term on all leasehold in the unit, in exchange for drilling activity. Lonestar believes it has strong support for future development from all governmental regulatory agencies including the BIA, BLM and the Fort Peck Tribe. Lonestar and its partners have commenced a process that may lead the Company and its partners to farm-out a portion of their interest in Poplar West.

2015 DRILLING AND COMPLETION PLANS

Lonestar currently intends to run a one-rig program in 2015, with a goal of closely matching its drilling capital expenditures with cash flow from operations. In January, Lonestar set a budget of drilling 16 Eagle Ford Shale wells during 2015 at a projected cost of between $74 and $83 million, net to the Company. To date, well costs have met or been below AFE. In the first quarter, Lonestar was able to reduce average total well costs by 20% versus 4Q14 levels, and continues to make progress towards additional reductions. The schedule below reflects the 16 wells Lonestar currently plans to drill and complete in 2015, 16 of which will be turned to production during the calendar year, with 3 wells which were drilled and completed in 2014 being fracked in early 2015, while 2 wells it expects to drill and complete in late 2015 are not expected to be fracked and turned to production until early 2016.

- **1Q15**- The Company has fracked 3 wells (Gerke #1H, #2H, #3H) in La Salle County and turned to production mid 1Q15. Lonestar has drilled three 8,000' laterals in La Salle County, and fracture stimulated them in 2Q15.
- **2Q15**- The company has fracked 3 wells in La Salle County and expects to begin flowback in May 2015. Following execution of a second farm-in, Lonestar has drilled 3 wells in Southern Gonzales County near its recent Harvey Johnson wells. Lonestar reached total depth on these 3 wells and anticipates commencing fracture stimulation operations during 2Q15.
- **3Q15**- Lonestar currently plans to drill and complete 3 wells on its Beall Ranch property. The Company also currently plans to drill two 8,000' laterals as part of its Horned Frog farm-in in La Salle County.
- **4Q15**- Lonestar currently plans to drill two 7,500' laterals in Wilson County near the Pirate K1H and L3H wells drilled in 2014. The company also currently plans to drill two 8,000' laterals in Brazos County, most likely on its Wildcat area, where the Eagle Ford lies at a TVD of 9,500 feet.

Lonestar has minimal drilling commitments in 2015, providing flexibility to defer any of its budgeted wells in favor of wells that it drill in conjunction with attractive farm-ins, such as the Horned Frog agreement announced today.

2015 DRILLING AND COMPLETION TIMETABLE

	1Q15	2Q15	3Q15	4Q15	2015
Western Eagle Ford					
Beall Ranch	0 - 0	0 - 0	3 - 3	0 - 0	3 - 3
Asherton	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
La Salle County	3 - 3	3 - 3	2 - 2	0 - 0	8 - 8
Western Eagle Ford	**3 - 3**	**3 - 3**	**5 - 5**	**0 - 0**	**11 - 11**
Central Eagle Ford					
Gonzo	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
Pirate	0 - 0	0 - 0	0 - 0	2 - 2	2 - 2
Southern Gonzales	0 - 0	3 - 3	0 - 0	0 - 0	3 - 3
Central Eagle Ford	**0 0**	**3 - 3**	**0 - 0**	**2 - 2**	**5 5**
Eastern Eagle Ford					
Brazos County	0 - 0	0 - 0	0 - 0	0 - 2	0 - 2
Robertson County	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
Eastern Eagle Ford	**0 - 0**	**0 - 0**	**0 - 0**	**0 - 2**	**0 - 2**
TOTAL EAGLE FORD	**3 - 3**	**6 - 6**	**5 - 5**	**2 - 4**	**16 - 18**

Management's Discussion and Analysis

Net Production (after royalties)

		Three months ended March 31, 2015	2014	% Change
Western Eagle Ford Shale				
Crude Oil	(bbls/day)	**1,896**	1,759	8%
Natural Gas Liquids	(bbls/day)	**474**	370	28%
Natural Gas	(Mcf/day)	**3,564**	2,739	30%
Oil Equivalent	**(BOE/day)**	**2,964**	**2,585**	**15%**
Central Eagle Ford Shale				
Crude Oil	(bbls/day)	**1,042**	333	213%
Natural Gas Liquids	(bbls/day)	**18**	-	-
Natural Gas	(Mcf/day)	**102**	1	13200%
Oil Equivalent	**(BOE/day)**	**1,077**	**333**	**223%**
Eastern Eagle Ford Shale				
Crude Oil	(bbls/day)	**706**	186	280%
Natural Gas Liquids	(bbls/day)	**40**	9	362%
Natural Gas	(Mcf/day)	**242**	54	349%
Oil Equivalent	**(BOE/day)**	**786**	**203**	**287%**
Total Eagle Ford Shale				
Crude Oil	(bbls/day)	**3,644**	2,277	60%
Natural Gas Liquids	(bbls/day)	**532**	379	40%
Natural Gas	(Mcf/day)	**3,909**	2,794	40%
Oil Equivalent	**(BOE/day)**	**4,827**	**3,122**	**55%**
Conventional				
Crude Oil	(bbls/day)	**400**	505	-21%
Natural Gas Liquids	(bbls/day)	**10**	4	175%
Natural Gas	(Mcf/day)	**1,861**	1,018	83%
Oil Equivalent	**(BOE/day)**	**720**	**678**	**6%**
Total Company				
Crude Oil	(bbls/day)	**4,043**	2,782	45%
Natural Gas Liquids	(bbls/day)	**542**	383	42%
Natural Gas	(Mcf/day)	**5,770**	3,811	51%
Oil Equivalent	**(BOE/day)**	**5,547**	**3,800**	**46%**

Lonestar's net production for the first quarter of 2015 averaged 5,547 BOE per day, and was comprised of 4,043 barrels of oil per day, 542 barrels of NGL's per day, and 5,770 Mcf of natural gas per day, 83% of the Company's sales volumes were derived from liquids. Net production for the first quarter of 2015 rose 46% over rates reported in the first quarter of 2014.

- Lonestar's net production from its Eagle Ford Shale assets averaged 4,827 BOE per day during the first quarter of 2015, and was comprised of 3,644 barrels of oil per day, 532 barrels of NGL's per day, and 3,909 Mcf of natural gas per day. In the first quarter of 2015, 86% of the Company's Eagle Ford production was derived from liquid hydrocarbons. First quarter 2015 Eagle Ford Shale volumes represented an increase of 55% compared to the first quarter of 2014. Also notable is that production declined a modest 5% versus 4Q14 levels. Fourth quarter 2014 levels were bolstered by the completion of 9 new Eagle Ford wells, while the Company's Eagle Ford Shale onstream well count rose by a more modest 3 wells in the first quarter of 2015. Based on its current drilling plans, the Company anticipates sequential increases in its Eagle Ford Shale production in the remaining quarters of 2015.
- Lonestar's net production from its Conventional assets averaged 720 BOE per day during the first quarter of 2015, and was comprised of 400 barrels of oil per day, 10 barrels of NGL's per day, and 1,861 Mcf of natural gas per day. 57% of the Company's Conventional production was from liquid hydrocarbons. First quarter volumes represented an increase of 6% compared to the first quarter of 2014, and a 1% decrease sequentially. Notably, Lonestar has been able to largely arrest production declines on its Conventional assets via workovers and recompletions, which have been executed at minimal capital costs.

All figures are unaudited. All figures are in US dollars unless noted otherwise

Management's Discussion and Analysis

Wellhead Commodity Price Realizations

		Three months ended March 31, 2015	2014	% Change
Western Eagle Ford Shale				
Crude Oil	($/bbl)	**$44.01**	$96.09	-54%
Natural Gas Liquids	($/bbl)	**$14.63**	$36.25	-60%
Natural Gas	($/Mcf)	**$2.70**	$4.84	-44%
Western Eagle Ford Shale	**($/BOE)**	**$33.73**	**$75.67**	**-55%**
Central Eagle Ford Shale				
Crude Oil	($/bbl)	**$44.61**	$95.35	-53%
Natural Gas Liquids	($/bbl)	**$20.00**	-	-
Natural Gas	($/Mcf)	**$2.80**	$3.79	-26%
Central Eagle Ford Shale	**($/BOE)**	**$43.77**	**$95.32**	**-54%**
Eastern Eagle Ford Shale				
Crude Oil	($/bbl)	**$44.96**	$94.39	-52%
Natural Gas Liquids	($/bbl)	**$11.77**	$36.34	-68%
Natural Gas	($/Mcf)	**$1.86**	$4.02	-54%
Eastern Eagle Ford Shale	**($/BOE)**	**$41.54**	**$88.82**	**-53%**
Total Eagle Ford Shale				
Crude Oil	($/bbl)	**$44.36**	$95.84	-54%
Natural Gas Liquids	($/bbl)	**$14.59**	$36.25	-60%
Natural Gas	($/Mcf)	**$2.65**	$4.82	-45%
Total Eagle Ford Shale	**($/BOE)**	**$37.24**	**$78.63**	**-53%**
Conventional				
Crude Oil	($/bbl)	**$46.49**	$86.97	-47%
Natural Gas Liquids	($/bbl)	**$17.13**	$52.12	-67%
Natural Gas	($/Mcf)	**$3.04**	$7.04	-57%
Conventional	**($/BOE)**	**$33.92**	**$75.58**	**-55%**
Total Company Wellhead				
Crude Oil	($/bbl)	**$44.58**	$94.23	-53%
Natural Gas Liquids	($/bbl)	**$14.64**	$36.41	-60%
Natural Gas	($/Mcf)	**$2.78**	$5.41	-49%
Total Company Wellhead	**($/BOE)**	**$36.81**	**$78.08**	**-53%**
Total Company Hedging Revenues				
Crude Oil	($/bbl)	**$29.52**	($4.20)	-802%
Hedging Revenues	**($/BOE)**	**$21.52**	**($3.08)**	**-799%**
Total Company Net Oil & Gas Revenues				
Crude Oil	($/bbl)	**$74.10**	$90.03	-18%
Natural Gas Liquids	($/bbl)	**$14.64**	$36.41	-60%
Natural Gas	($/Mcf)	**$2.78**	$5.41	-49%
Net Oil & Gas Revenues	**($/BOE)**	**$58.33**	**$75.01**	**-22%**

Lonestar's average wellhead commodity price for the first quarter of 2015 was $36.81 per barrel of oil equivalent (BOE), which was 53% lower than the $78.08 per BOE average price realized in the first quarter of 2014. Principally, reported wellhead realizations declined as a result of a $50.05 per barrel (51%) decline in the benchmark West Texas Intermediate oil price and $2.31 per Mcf (44%) decline in the benchmark Henry Hub gas price, when compared to 1Q14 prices. Lonestar's post-hedge crude oil price was bolstered by its crude oil hedge positions, which added $29.52 per barrel to its first quarter revenues.

- On its Eagle Ford Shale assets, Lonestar recorded energy equivalent wellhead price realization of $37.24 per BOE during 1Q15, a 53% decrease compared to 1Q14. Again, this variance is the result of a substantial decline in benchmark pricing compared to 1Q14.
- On its Conventional assets, Lonestar recorded an average wellhead price realization of $33.92 per BOE during 1Q15, down 55% versus 1Q14. This variance is also largely due to lower WTI pricing compared to 1Q14. Additionally, the product mix has shifted from 75% crude oil and NGL's in 1Q14 to 57% crude oil and NGL's in 1Q15 due to higher gas production associated with recompletion activities on the Company's non-operated leases in Lavaca County.

All figures are unaudited. All figures are in US dollars unless noted otherwise

Management's Discussion and Analysis

Wellhead Oil & Gas Revenues

		Three months ended March 31, 2015	2014	% Change
Western Eagle Ford Shale				
Crude Oil	($MM)	**$7.5**	$15.2	-51%
Natural Gas Liquids	($MM)	**$0.6**	$1.2	-48%
Natural Gas	($MM)	**$0.9**	$1.2	-27%
Western Eagle Ford Shale Revenues	**($MM)**	**$9.0**	**$17.6**	**-49%**
Central Eagle Ford Shale				
Crude Oil	($MM)	**$4.2**	$2.9	46%
Natural Gas Liquids	($MM)	**$0.0**	$0.0	-
Natural Gas	($MM)	**$0.0**	$0.0	9739%
Central Eagle Ford Shale Revenues	**($MM)**	**$4.2**	**$2.9**	**48%**
Eastern Eagle Ford Shale				
Crude Oil	($MM)	**$2.9**	$1.6	81%
Natural Gas Liquids	($MM)	**$0.0**	$0.0	50%
Natural Gas	($MM)	**$0.0**	$0.0	107%
Eastern Eagle Ford Shale Revenues	**($MM)**	**$2.9**	**$1.6**	**81%**
Total Eagle Ford Shale				
Crude Oil	($MM)	**$14.5**	$19.6	-26%
Natural Gas Liquids	($MM)	**$0.7**	$1.2	-43%
Natural Gas	($MM)	**$0.9**	$1.2	-23%
Total Eagle Ford Shale Revenues	**($MM)**	**$16.2**	**$22.1**	**-27%**
Conventional				
Crude Oil	($MM)	**$1.7**	$3.9	-58%
Natural Gas Liquids	($MM)	**$0.0**	$0.0	-10%
Natural Gas	($MM)	**$0.5**	$0.6	-21%
Conventional Revenues	**($MM)**	**$2.2**	**$4.6**	**-52%**
Total Company Wellhead				
Crude Oil	($MM)	**$16.2**	$23.6	-31%
Natural Gas Liquids	($MM)	**$0.7**	$1.3	-43%
Natural Gas	($MM)	**$1.4**	$1.9	-22%
Total Company Wellhead Revenues	**($MM)**	**$18.4**	**$26.7**	**-31%**
Total Company Hedging Revenues				
Crude Oil	($MM)	**$10.7**	($1.1)	921%
Hedging Revenues	**($MM)**	**$10.7**	**($1.1)**	**921%**
Total Company Net Oil & Gas Revenues				
Crude Oil	($MM)	**$27.0**	$22.5	20%
Natural Gas Liquids	($MM)	**$0.7**	$1.3	-43%
Natural Gas	($MM)	**$1.4**	$1.9	-22%
Net Oil & Gas Revenues	**($MM)**	**$29.1**	**$25.6**	**14%**

Lonestar's net wellhead oil and gas revenues for the first quarter of 2015 fell 31% to $18.4 million, versus $26.7 million a year ago. Revenue decline was a function of a 53% decline in realized wellhead prices partially offset by a 46% increase in production. While wellhead oil and gas revenues decreased 31% versus 1Q14 levels, the Company's hedges yielded a 14% increase in total company oil and gas revenues.

- Lonestar's net wellhead oil and gas revenues from its Eagle Ford Shale assets fell 27% to $16.2 million for the first quarter of 2015 versus $22.1 million a year ago. Revenue decline was driven by a 52% decrease in wellhead price realizations per BOE partially offset by a 55% increase in production. Crude oil contributed 90% of revenues, while natural gas liquids contributed 4% of revenues and natural gas contributed 6% of revenues. Sequentially, wellhead net oil and gas revenues fell 41% as BOE price realizations fell 37% and production fell by 5%.
- Lonestar's net wellhead oil and gas revenues from its Conventional assets totaled $2.2 million during the first quarter of 2015, a 52% decrease over the first quarter of 2014. The decrease in revenue was driven by a 55% decrease in wellhead price realizations per BOE partially offset by a 6% increase in production. Crude oil contributed 76% of revenues while natural gas liquids contributed 1% of revenues and natural gas contributed 23% of revenues.

All figures are unaudited. All figures are in US dollars unless noted otherwise

Management's Discussion and Analysis

Field Operating Expenses

		Three months ended March 31, 2015	2014	% Change
Western Eagle Ford Shale				
Lease Operating Expense	($/BOE)	**$7.40**	$7.95	-7%
Production Taxes	($/BOE)	**$2.37**	$4.42	-46%
Western Eagle Ford Shale	**($/BOE)**	**$9.77**	**$12.38**	**-21%**
Central Eagle Ford Shale				
Lease Operating Expense	($/BOE)	**$6.01**	$9.79	-39%
Production Taxes	($/BOE)	**$3.64**	$5.01	-27%
Central Eagle Ford Shale	**($/BOE)**	**$9.65**	**$14.80**	**-35%**
Eastern Eagle Ford Shale				
Lease Operating Expense	($/BOE)	**$5.09**	$6.33	-20%
Production Taxes	($/BOE)	**$2.68**	$4.15	-35%
Eastern Eagle Ford Shale	**($/BOE)**	**$7.77**	**$10.48**	**-26%**
Total Eagle Ford Shale				
Lease Operating Expense	($/BOE)	**$6.72**	$8.04	-17%
Production Taxes	($/BOE)	**$2.70**	$4.47	-39%
Total Eagle Ford Shale	**($/BOE)**	**$9.42**	**$12.51**	**-25%**
Conventional				
Lease Operating Expense	($/BOE)	**$13.43**	$16.98	-21%
Production Taxes	($/BOE)	**$2.79**	$3.73	-25%
Conventional	**($/BOE)**	**$16.22**	**$20.71**	**-22%**
Total Company				
Lease Operating Expense	($/BOE)	**$7.59**	$9.64	-21%
Production Taxes	($/BOE)	**$2.71**	$4.34	-37%
Total Company	**($/BOE)**	**$10.30**	**$13.97**	**-26%**

Lonestar's field operating expenses for the first quarter of 2015 were $5.1 million, an increase of 7% over 1Q14 field operating expenses of $4.8 million. However, the Company reduced total field operating expenses by 26% on a unit of production basis from 1Q14 to $10.30 per BOE. Lease Operating Expense ("LOE") was $3.8 million for 1Q15, rising only 15% over 1Q14 levels on an absolute dollar basis but decreasing 21% on a BOE basis. Production taxes were $1.4 million for the first quarter of 2015, a 9% decrease over comparable levels in 2014, and a 37% decrease to $2.71 on a unit of production basis.

- Lonestar's field operating expenses from its Eagle Ford Shale assets totaled $4.1 million during the first quarter of 2015, a 16% increase over the first quarter of 2014. However, on a unit of production basis, field operating expenses decreased 25% to $9.42 per BOE, year-over-year. Perhaps more noteworthy is the fact that Lonestar achieved a 9% reduction in lease operating expenses in absolute dollar terms and a 2% reduction on a BOE basis compared to a then-record 4Q14 . Production taxes were $1.2 million, or $2.70 per BOE, compared to $1.3 million, or $4.47 per BOE in the year-ago quarter.
- Lonestar's field operating expenses from its Conventional assets totaled $1.1 million during the first quarter of 2015, a 17% decrease versus the first quarter of 2014. On a unit of production basis, field operating expenses decreased 22% to $16.22 per BOE. Lonestar continues efforts to lower operating expenses for the Conventional assets to maximize cashflow on this low-decline asset. Lonestar was able to achieve substantial reductions in Lease Operating Expense, both on an absolute-dollar and per-unit basis. In total, LOE was $0.9 million, or $13.43 per BOE, compared to $1.0 million, or $16.98 per BOE in 1Q14. Production taxes were $0.2 million, or $2.79 per BOE, compared to $0.2 million, or $3.73 per BOE in the quarter a year ago.

All figures are unaudited. All figures are in US dollars unless noted otherwise

Management's Discussion and Analysis

Field Netbacks

		Three months ended March 31, 2015	2014	% Change
Western Eagle Ford Shale				
Production Revenue	($/BOE)	$33.73	$75.67	-55%
Lease Operating Expenses	($/BOE)	$7.40	$7.95	-7%
Production Taxes	($/BOE)	$2.37	$4.42	-46%
Field Netback	**($/BOE)**	**$23.96**	**$63.30**	**-62%**
Field Netback	**($MM)**	**$6.4**	**$14.7**	**-57%**
Central Eagle Ford Shale				
Production Revenue	($/BOE)	$44.47	$95.32	-53%
Lease Operating Expenses	($/BOE)	$6.01	$9.79	-39%
Production Taxes	($/BOE)	$3.64	$5.01	-27%
Field Netback	**($/BOE)**	**$34.82**	**$80.53**	**-57%**
Field Netback	**($MM)**	**$3.3**	**$2.4**	**38%**
Eastern Eagle Ford Shale				
Production Revenue	($/BOE)	$41.54	$88.82	-53%
Lease Operating Expenses	($/BOE)	$5.09	$6.33	-20%
Production Taxes	($/BOE)	$2.68	$4.15	-35%
Field Netback	**($/BOE)**	**$33.77**	**$78.34**	**-57%**
Field Netback	**($MM)**	**$2.4**	**$1.4**	**67%**
Total Eagle Ford Shale				
Production Revenue	($/BOE)	$37.38	$78.63	-52%
Lease Operating Expenses	($/BOE)	$6.72	$8.04	-17%
Production Taxes	($/BOE)	$2.70	$4.47	-39%
Field Netback	**($/BOE)**	**$27.96**	**$66.11**	**-58%**
Field Netback	**($MM)**	**$12.1**	**$18.6**	**-35%**
Conventional				
Production Revenue	($/BOE)	$33.92	$75.58	-55%
Lease Operating Expenses	($/BOE)	$13.43	$16.98	-21%
Production Taxes	($/BOE)	$2.79	$3.73	-25%
Field Netback	**($/BOE)**	**$17.70**	**$54.87**	**-68%**
Field Netback	**($MM)**	**$1.1**	**$3.3**	**-66%**
Total Company				
Production Revenue	($/BOE)	$36.92	$78.08	-53%
Lease Operating Expenses	($/BOE)	$7.59	$9.64	-21%
Production Taxes	($/BOE)	$2.71	$4.34	-37%
Field Netback	**($/BOE)**	**$26.62**	**$64.11**	**-58%**
Field Netback	**($MM)**	**$13.2**	**$21.9**	**-40%**

Lonestar's field netback for the first quarter of 2015 was $13.2 million, a decrease of 40% over the field netback of $21.9 million in 1Q14. On a per BOE basis, field netbacks declined 58% to $26.62 in the first quarter of 2015 vs. $64.11 in the first quarter of 2014. The decrease in the per BOE field netback is associated primarily with a 51% decrease in WTI pricing and a 44% decrease in Henry Hub pricing compared to 1Q14, and in spite of significant reductions in the Company's unit operating costs.

- Lonestar's field netback from its Eagle Ford Shale assets totaled $12.1 million during the first quarter of 2015, which represents a 35% decrease in the field netback compared to the $18.6 million reported in the first quarter of 2014. On a BOE basis, field netbacks declined 58% to $27.96 in first quarter of 2015 vs. $66.11 in 1Q14, largely influenced by a 51% reduction in WTI and a 44% reduction in Henry Hub.
- Lonestar's field netback from its Conventional assets totaled $1.1 million during the first quarter of 2015 which represents a 66% decrease in field netbacks compared to the $3.3 million reported in the first quarter of 2014. On a BOE basis, field netbacks declined 68% largely due to a 51% reduction in crude oil prices and a 44% reduction in Henry Hub.

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Management's Discussion and Analysis

Depreciation and Depletion

		Three months ended March 31,		
		2015	2014	% Change
Total Expense	($MM)	$12.8	$7.9	63%
Depreciation & Depletion	($/BOE)	$25.71	$23.00	12%

Depletion is calculated using the units of production method, which involves dividing the carrying value of the assets by the estimated Proved reserves and applying this depletion rate to the production reported during the period. Depreciation of property plant and equipment is calculated on a declining basis so as to write down the net cost of each asset over its useful life, which ranges from 5 to 25 years.

Lonestar's Depreciation and Depletion expense for the first quarter of 2015 was $12.8 million, or $25.71 per BOE compared to $7.9 million, or $23.00 per BOE reported in the first quarter of 2014. This variance in absolute terms is due to a 46% increase in production compared to 1Q14 levels.

General and Administrative Expenses

		Three months ended March 31,		
		2015	2014	% Change
Total Expense	($MM)	$2.3	$1.8	28%
General & Administrative	($/BOE)	$4.60	$5.22	-12%

Lonestar reported General & Administrative expenses of $2.3 million for the first quarter of 2015, a 28% increase over the $1.8 million of General & Administrative expenses reported in the first quarter of 2014. However on a sequential basis, first quarter 2015 General & Administrative expenses are actually down 4% in absolute dollar terms when compared to the fourth quarter of 2014. On a BOE basis, the Company achieved a 12% decrease in G&A per BOE to $4.60, compared to $5.22 per BOE reported in the first quarter of 2014. However, after staffing up over the course of 2014 to properly manage the growing scope of its business, Lonestar has begun to achieve scale, with absolute dollar G&A expense declining 4% from $2.4 million in 4Q14.

Finance Expenses

		Three months ended March 31,		
		2015	2014	% Change
Interest Expense	($MM)	$5.3	$1.4	289%
Amortization of Finance Costs	($MM)	$0.5	$0.2	183%
Total Finance Costs	**($MM)**	**$5.8**	**$1.6**	**277%**
Finance Costs	($/BOE)	$11.75	$4.54	**159%**

Lonestar reported Finance expenses of $5.8 million for the first quarter of 2015, a 277% increase over the $1.6 million of Finance expenses reported in the first quarter of 2014. On a BOE basis, the Company reported Finance expenses of $11.75, a 159% increase compared to $4.54 per BOE reported in the first quarter of 2014. Increased Finance expenses are a result of the placement of the Company's 8.75% Notes coupled with borrowings from its Senior Secured credit facility. The Company's borrowings from its senior unsecured notes was $220.0 million during the quarter with interest expense averaging 8.75% on an annualized rate during the quarter. The Company's borrowings from its $150.0 million Senior Secured Revolving Credit Facility averaged $60.9 million during the quarter with interest expense averaging 2.67% on an annualized rate during the quarter.

All figures are unaudited. All figures are in US dollars unless noted otherwise

Management's Discussion and Analysis

Hedging Revenues (Expenses)

		Three months ended March 31, 2015	2014	% Change
Crude Oil	($MM)	**$10.7**	($1.1)	921%
Natural Gas Liquids	($MM)	**$0.0**	$0.0	-
Natural Gas	($MM)	**$0.0**	$0.0	-
Hedging Revenues (Expenses)	**($MM)**	**$10.7**	**($1.1)**	**921%**
Hedging Revenues (Expenses)	($/BOE)	**$21.52**	($3.08)	

- Lonestar realized crude oil hedge revenues of $10.7 million in the first quarter of 2015 vs. a crude oil hedge expense of $1.1 million reported in the first quarter of 2014. As of March 31, 2015 the Mark to Market of Lonestar's remaining hedge contracts totaled $37.5 million.

Derivative Commodity Contracts

Commodity	Quantity	Term			Reference	Strike	Put	Call	Option Traded
Crude Oil	179,500	Apr 1, 2015	-	Dec 31, 2015	WTI	$87.00	-	-	Swap
Crude Oil	192,500	Apr 1, 2015	-	Dec 31, 2015	WTI	$81.25	-	-	Swap
Crude Oil	32,942	Apr 1, 2015	-	Jun 30, 2015	WTI	$90.40	-	-	Swap
Crude Oil	55,300	Apr 1, 2015	-	Jun 30, 2015	WTI	$95.65	-	-	Swap
Crude Oil	31,400	Apr 1, 2015	-	Jun 30, 2015	WTI	$89.50	-	-	Swap
Crude Oil	32,016	Jul 1, 2015	-	Sep 30, 2015	WTI	$88.87	-	-	Swap
Crude Oil	49,700	Jul 1, 2015	-	Sep 30, 2015	WTI	$93.65	-	-	Swap
Crude Oil	29,992	Oct 1, 2015	-	Dec 31, 2015	WTI	$87.80	-	-	Swap
Crude Oil	45,500	Oct 1, 2015	-	Dec 31, 2015	WTI	$92.25	-	-	Swap
Crude Oil	205,000	Jan 1, 2016	-	Dec 31, 2016	WTI	$84.45	-	-	Swap
Crude Oil	309,000	Jan 1, 2016	-	Dec 31, 2016	WTI	$90.45	-	-	Swap
Crude Oil	135,600	Jan 1, 2016	-	Dec 31, 2016	WTI	$63.20	-	-	Swap
Crude Oil	183,400	Jan 1, 2016	-	Dec 31, 2016	WTI	$56.90	-	-	Swap
Crude Oil	365,100	Jan 1, 2017	-	Dec 31, 2017	WTI	-	$40/$60	$85.0	3-Way

Lonestar continues to be an active participant in the commodity derivatives market as a tool to manage commodity price risk, create higher certainty of returns on capital expenditures, and maximize its borrowings available under its Credit Facilities. As the Company places new wells into production, it has historically entered into additional derivatives transactions to further insulate the Company from the risks associated with the oil and gas business, and to lock in attractive returns, a policy that Lonestar expects to continue.

As has been its practice since inception, crude oil hedging has been a key element to providing visibility to its cash flow streams and associated liquidity in the current crude oil price environment. In an effort to provide additional long-term visibility to its cash flow streams in the current crude oil price environment, Lonestar has recently increased its crude oil hedge position. Giving effect for these new hedges, the Company has increased its positions, and currently stand at:

- **2015**- Lonestar has West Texas Intermediate (WTI) swaps covering 2,359 barrels of oil per day for the remainder of 2015 at an average strike price of $87.33 per barrel, equating to 58 to 64% of oil production guidance.
- **2016**- Lonestar has added additional WTI swaps to increase the total to 2,276 barrels of oil per day for the remainder of 2016 at an average strike price of $77.15 per barrel, equating to 50 to 58% of currently budgeted oil production. .
- **2017**- Lonestar entered into a 3-Way WTI Collar covering 1,000 barrels per day for calendar 2017, comprising of a $60.00/$40.00 put spread against an $85.00 call.

All figures are unaudited. All figures are in US dollars unless noted otherwise

UNAUDITED INTERIM FINANCIAL REPORT

For the three months ended March 31, 2015

Consolidated statements of comprehensive income
For the three months ended March 31, 2015 and 2014

(US $MM)	*As Reported* Three months ended March 31, 2015	2014
Revenues (Net of Royalties)		
Crude Oil	16.2	23.6
Natural Gas Liquids	0.7	1.3
Natural Gas	1.5	1.9
Revenues (Net of Royalties)	**18.4**	**26.7**
Hedge Revenues (Expenses)	10.7	(1.1)
Net Revenue From Ordinary Activities	**29.1**	**25.6**
Operating Expenses		
Lease Operating Expenses	(3.8)	(3.3)
Severance Taxes	(0.9)	(1.2)
Ad Valorem Taxes	(0.5)	(0.3)
Depreciation, Depletion & Amortization	(12.8)	(7.9)
General & Administrative	(2.3)	(1.8)
Total Operating Expenses	**(20.3)**	**(14.4)**
Gross Profit from Operating Activities	**8.9**	**11.2**
Other Income (Expense)	(0.7)	(0.0)
Impairment of O&G properties	0.0	0.0
Stock based compensation	(0.4)	(0.4)
Non-recurring expenses	0.0	(0.4)
Interest & Other Finance Expenses	(5.8)	(1.6)
Fair Value Gain (Loss) on derivatives	(3.8)	(2.2)
Profit (Loss) before taxes	**(1.8)**	**6.6**
Income tax (expense) benefit	**1.1**	**(1.6)**
Net Income (Loss)	**(0.7)**	**5.0**
EBITDAX	**21.7**	**19.1**

All figures are unaudited. All figures are in US dollars unless noted otherwise

Consolidated statements of financial position

As of March 31, 2015

(US $MM)	*As Reported* As of March 31, 2015	December 31, 2014
Assets		
Current Assets		
Cash and cash equivalents	3.6	10.0
Trade and other receivables	10.9	17.5
Derivative financial instruments	30.7	31.0
Other assets	1.0	0.7
Total current assets	**46.3**	**59.3**
Non-current assets		
Oil and Gas Properties & Equipment	496.4	479.5
Deferred tax assets	0.3	0.1
Derivative financial instruments	10.9	12.7
Other non-current assets	3.8	3.7
Total non-current assets	**511.4**	**496.1**
Total Assets	**557.7**	**555.3**
Liabilities		
Current liabilities		
Trade and other payables	28.5	35.7
Revenue payable	4.9	5.0
Accrued expenses	0.8	2.4
Derivative financial instruments	0.0	-
Total current liabilities	**34.1**	**43.0**
Non-current liabilities		
Long-term Debt	276.9	264.6
Deferred tax liablilities	30.7	26.0
Other non-current liabilities	8.5	7.8
Total non-current liabilities	**316.1**	**298.5**
Total Liabilities	**350.3**	**341.5**
Net assets	**207.4**	**213.8**
Equity		
Contributed equity	142.6	142.6
Reserves	7.4	6.9
Retained Earnings	57.4	64.3
Total Equity	**207.4**	**213.8**

All figures are unaudited. All figures are in US dollars unless noted otherwise

Consolidated statements of cash flows

As of March 31, 2015

(US $MM)	*As Reported* Three Months Ending March 31, 2015
CASH FLOWS FROM OPERATING ACTIVITIES	
Net Income (loss)	(0.7)
Adjustments to reconcile profit/(loss) to net cash provided by operating activities:	
(Gain) / Loss on sale of oil and gas properties	0.6
Depreciation, depletion, amortisation	12.8
Increase in retirement provision	0.1
Deferred taxes	(1.1)
Share based payments	0.4
Non-cash interest expense	0.3
Changes in operating assets and liabilities:	-
Accounts receivable	6.6
Other assets	(0.4)
Accounts payable and provisions	(13.3)
Net cash inflow from operating activities	5.2
CASH FLOWS FROM INVESTING ACTIVITIES	
Payments for oil and gas property, plant & equipment	(23.0)
Acquisition of oil and gas properties	(3.1)
Net (increase) decrease in derivatives	2.7
Net cash (outflow) from investing activities	(23.6)
CASH FLOWS FROM FINANCING ACTIVITIES	
Net change in borrowings	12.0
Net cash inflow from financing activities	12.0
Net increase / (Decrease) in cash held	(6.4)
Cash and cash equivalents at the beginning of the financial period	10.0
Cash and cash equivalents at the end of the financial period	3.6

All figures are unaudited. All figures are in US dollars unless noted otherwise

Notes to the Quarterly Report

CY15 EBITDAX guidance is based on the following assumptions:

- Oil prices and gas prices are based on a NYMEX futures pricing scenario as set out in the table below. Pricing adjustments are made to these prices for individual assets to account for quality, transportation fees, marketing bonuses and regional price differentials.

Year	Oil (US$/bbl)	Gas (US$/MMBtu)
2015	$50.00 to $60.00	$2.82

- The total number of planned wells at each asset is consistent with assumptions contained in the respective reserve assessments.
- The estimated well drilling and completion capital expenditures are based on the most recent Authorizations for Expenditures at each asset.
- Operating expenditures for each asset are based on the Company's most current forecast for lease operating expenses for each asset.

Cautionary and Forward Looking Statements
Lonestar has presented petroleum and natural gas production and reserve volumes in barrel of oil equivalent ("boe") amounts. For purposes of computing such units, a conversion rate of 6,000 cubic feet of natural gas to one barrel of oil equivalent (6:1) is used. The conversion ratio of 6:1 is based on an energy equivalency conversion method which is primarily applicable at the burner tip and does not represent value equivalence at the wellhead. Readers are cautioned that boe figures may be misleading, particularly if used in isolation.

Statements in this announcement which reflect management's expectation relating to target dates, expected drilling program, and the ability to fund its development plans are forward-looking statements, and can be generally be identified by words such as "will", "expects", "intends", "believes", "estimates", "anticipates", "projects" or similar expressions. In addition, any statements that refer to expectations, projections or other characterizations of future events or circumstances are forward-looking statements. Statements relating to "reserves" are deemed to be forward looking statements as they involve the implied assessment, based on certain estimates and assumptions that that some or all of the reserves described can be profitably produced in the future. These statements are not historical facts but instead represent the expectations of management and/or its independent petroleum consultants, regarding future events.

Although management believes the expectations reflected in such forward-looking statements are reasonable, forward-looking statements are based on the opinions, assumptions and estimates of management at the date the statements are made, and are subject to a variety of risks and uncertainties and other factors that could cause actual events or results to differ materially from those projected in the forward-looking statements. These factors include risks related to exploration, development and production; oil and gas prices, markets and marketing; acquisitions and dispositions; competition; additional funding requirements; changes in access to and the costs of energy services; reserve estimates being inherently uncertain; incorrect assessments of the value of acquisitions and exploration and development programs; environmental concerns; reliance on key personnel; title to assets; expiration of leases; hedging activities; litigation; government policies; unforeseen expenses; and contractual risk. Additionally, if any of the assumptions or estimates made by management prove to be incorrect, actual results and developments are likely to differ, and may differ materially, from those expressed or implied by the forward-looking statements contained in this document. Such assumptions include, but are not limited to, general economic, market and business conditions and corporate strategy. Accordingly, investors are cautioned not to place undue reliance on such statements.

All of the forward-looking information in this announcement are expressly qualified by these cautionary statements. Forward-looking information contained herein is made as of the date of this document and Lonestar disclaims any obligation to update any forward-looking information, whether as a result of new information, future events or results or otherwise.

Leasehold Statement
While the additional leasehold is not material in the context of the 31,358 net acres already held in the Eagle Ford shale, it is consistent with the company's growth ambitions and expected.

Reserves Reporting:

Pursuant to ASX Listing Rules ("LR") the reserves information in this document:

(i) is effective as at 1 January, 2015 (LR 5.25.1)
(ii) has been estimated and is classified in accordance with SPE-PRMS (Society of Petroleum Engineers - Petroleum Resources Management System) (LR 5.25.2)
(iii) is reported according to the Company's economic interest in each of the reserves and net of royalties (LR 5.25.5)
(iv) has been estimated and prepared using the deterministic method (LR 5.25.6)
(v) has been estimated using a 6:1 BOE conversion ratio for gas to oil, pursuant to the information in the disclaimer section of this document (LR 5.25.7)

Other Reserves Information:

Lonestar operates most of its properties which are generally held by standard oil and gas lease arrangements. Detailed information on the operator and lease arrangements is disclosed in the Company announcement related to the initial acquisition of properties. The Company's working interest ownership (WI%) and net-revenue interest ownership (NRI%) in relation to each of its properties are generally included in the Company's presentations which are available on the ASX or the Company's websites. Well spacing assumptions and lateral length assumptions are generally included in the Company's presentations as is additional information on capital cost and taxation assumptions. In accordance with ASX LR 5.43 the Company confirms that it is not aware of any new information or data that materially affects the reserves information included in previous Company announcements including as to material assumptions and technical parameters underpinning the estimates, other than as set out in this announcement.

Qualified Petroleum Reserves and Resources Evaluators:

In accordance with ASX Listing Rules 5.41 and 5.42:

The reserve reporting provided in this document in relation to the Company's Eagle Ford Shale properties is based on and fairly represents information and supporting documentation that has been prepared by Mr. William D. Von Gonten, Jr., P.E., and Mr. Taylor D. Matthes, P.E. who are employed by W. D. Von Gonten & Co Petroleum Engineering. Mr. Von Gonten holds a Bachelor of Science degree in Petroleum Engineering from Texas A&M University and Mr. Matthes holds a Bachelor of Science degree in Petroleum Engineering from Texas A&M University. Both of these persons are Registered Texas Professional Engineers. Mr. Von Gonten has 24 years of experience as a Petroleum Engineer and Mr. Matthes has more than 5 years of experience as a Petroleum Engineer. Both of these persons are members of the Society of Petroleum Engineers . Messrs. Von Gonten and Matthes have consented to the inclusion in this document of the information and context in which it appears.

The reserve reporting provided in this document in relation to the Company's Conventional properties is based on and fairly represents information and supporting documentation that has been prepared by Mr. William M. Kazmann who is President and Senior Partner La Roche Petroleum Consultants, Ltd. Mr. Kazmann received his Bachelor of Science and Master of Science degrees in Petroleum Engineering from the University of Texas at Austin in 1973 and 1975 respectively. He has worked in the oil and gas industry since that time. Mr. Kazmann is a Licensed Professional Engineer in the State of Texas and is a member of the American Association of Petroleum Geologists, Society of Petroleum Engineers, Society of Independent Professional Earth Scientists (serving as National Director from 1993 to 1996 and National Treasurer in 1994 and 1995), Dallas Geological Society, and Dallas Petroleum Club (serving as Director from 2004 through 2006). Mr. Kazmann has consented to the inclusion in this document of the information and context in which it appears.

Reserves Cautionary Statement:

Hydrocarbon reserves and resource estimates are expressions of judgment based on knowledge, experience and industry practice. Estimates that were valid when originally calculated may alter significantly when new information or techniques become available. Additionally, by their very nature, reserve and resource estimates are imprecise and depend to some extent on interpretations, which may prove to be inaccurate. As further information becomes available through additional drilling and analysis, the estimates are likely to change. The may result in alterations to development and production plans which may, in turn, adversely impact the Company's operations. Reserves estimates and estimates of future earnings are, by nature, forward looking statements and subject to the same risks as other forward looking statements.

Commodity Pricing Used:

Lonestar's reserves and PV-10 have been estimated using index prices determined in accordance with US SEC pricing guidelines for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the life of the properties. The unweighted arithmetic averages of the first-day-of-the-month prices for the year ended December 31, 2014 were $94.99 per bbl for oil and $4.35 per mmbtu for natural gas. These prices were adjusted by lease for quality, energy content, regional price differentials, transportation fees, marketing deductions and other factors affecting the price received at the wellhead."