Quarterly Report

December 2014

Lonestar Resources, Ltd. (ASX:LNR, OTCQX: LNREF) is pleased to provide an update on its financial and operational results for the three months ended December 31, 2014 (4Q14).

Fourth Quarter Highlights

- Setting a new Company record, Lonestar reported a 54% increase in net oil and gas production to 5,816 BOEPD in 4Q14, vs. 3,772 BOEPD in 4Q13, 87% of which was crude oil and NGL's. Lonestar's 4Q14 sales volumes also represented a 25% sequential increase over 3Q14 production levels.
- Net Revenues From Ordinary Activities increased 41% to US$35.5 million for 4Q14, vs. 4Q13 revenues of $25.1 million.
- EBITDAX increased 46% to $27.3 million for 4Q14 vs. $18.7 million for 4Q13, and rose 43% sequentially over 3Q14 levels, in spite of a 25% sequential decline in oil prices. Full year 2014 EBITDAX was $86.6 million, an increase of 60% over 2013 levels, and despite a precipitous fall in crude oil prices late in the year exceeded the low end of our $85 to $88 million guidance, thanks to excellent performance of new wells, notably in our Central Region.
- Net income was $25.4 million for 4Q14, or $0.03 per share vs. net income of $4.5 million reported for 4Q13. Net of the effect of the unrealized gain on the Company's hedges and impairment of assets, net income was $14.1 million, or $0.02 per share.
- Based on the results generated from our independent consultants for the year ended December 31, 2014. Proved Reserves net of royalties were 31.0 million barrels of oil equivalent (MMBOE), an increase of 70% over the 18.2 MMBOE reported at year ended December 31, 2013. The PV-10 of Lonestar's Proved Reserves increased to US$705.8 million represents an increase of 65% over 2013 levels. For a full discussion of our reserves, please refer to our press release issued today.
- After observing commodity price movements and taking stock of energy service costs, Lonestar is updating its 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 leads to EBITDAX guidance of $84 to $95 million for 2015.

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

Contacts

Lonestar Resources, Ltd.
11 Ventnor Ave, Ground Floor
West Perth, WA 6009
+61-8-6355-6888

Lonestar Resources America, Inc.
600 Bailey Avenue, Suite 200
Fort Worth, Texas 76107
+1-817-546-6400

www.lonestarresources.com

Management

Managing Director & Chief Executive Officer
Frank D. Bracken, III

Chief Operating Officer
Barry D. Schneider

Senior Vice President
Tom H. Olle

VP- Geosciences
Scott E. Sabatka

Chief Financial Officer
Douglas W. Banister

Company Secretary
Mitchell Wells

Management's Discussion and Analysis

Lonestar Resources, Ltd. is pleased to announce its operational and unaudited financial results for the quarter ended December 31, 2014.

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 30,306 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.

FOURTH QUARTER 2014 HIGHLIGHTS

Corporate

- Lonestar set its third consecutive set of record operating metrics in 2014. A strong fourth quarter placed full-year production volumes at an average of 4,480 BOEPD, an increase of 48% over 2013 levels. 2014 also saw the Company generate record levels of EBITDAX, totaling $86.6 million, representing an increase of 60% over 2013 results. These strong financial results are underpinned by a 70% increase in Lonestar's Proved Reserves, which grew to 31.0 MMBOE at December 31, 2014, according to its third-party engineering reports. It is notable that these reserves represent a 21% increase over the Company's pro-forma Proved Reserves of 25.6 MMBOE, which account for its acquisition of Eagle Ford Shale properties from Clayton Williams, which closed on March 13, 2014. For full disclosure regarding the Company's third party reserves, please refer to our press release issued today.
- Lonestar's senior lending group, led by Wells Fargo, confirmed a 38% increase in the borrowing base on our Senior Secured Credit Facility from $108.8 million to $150.0 million, providing the Company with in excess of $100 million of liquidity at year-end 2014.

Operational

- Lonestar's net production for the fourth quarter of 2014 set its second consecutive record, averaging 5,816 BOE per day. Fourth quarter 2014 volumes were comprised of 4,312 barrels of oil per day, 538 barrels of NGL's per day, and 5,796 Mcf of natural gas per day. 4Q14 production was 54% higher than 4Q13 levels. Fourth quarter production was comprised of 83% crude oil and natural gas liquids, and 17% natural gas. Of equal importance was the significant sequential production gains that were achieved- a gain of 25% over third quarter 2014 volumes.
- In the fourth quarter of 2014, Lonestar generated Discretionary Cash Flow of $22.1 million, a 19% increase over third quarter Discretionary Cash Flow of $18.5 million.
- As it scales its business, Lonestar continues to generate significant improvement in total unit cash operating expenses in the Eagle Ford Shale, which it believes will help insulate the Company from lower crude oil prices. Total cash unit operating expenses in the Eagle Ford Shale were reduced sequentially by 19%, from $29.17 per BOE in 3Q14 to $23.77 per BOE in 4Q14, as absolute costs were contained and production volumes were increased.
  - Lease Operating Expense was reduced 24% sequentially. In the third quarter of 2014, Lonestar's Eagle Ford Shale assets recorded LOE of $3.1 million, or $8.44 per BOE, at the time a record-low. Benefitting from cost control measures in its Western Region and the addition of low-cost producers in its Eastern and Central Regions, 4Q14 LOE actually decreased marginally in absolute dollar terms to $3.0 million, which equates to a record-low $6.47 per BOE.
  - Production Taxes fell 31% sequentially. Owing to a combination of lower crude oil prices and lower percentage tax rates on a higher mix of crude oil, production taxes fell from $4.52 per BOE in 3Q14 to $3.12 per BOE in 4Q14.
  - General & Administrative Expense decreased 13% sequentially. Lonestar's General & Administrative Expense was $2.4 million, or $4.44 per BOE in 4Q14, which represents a 13% reduction compared to 3Q14 levels of $5.09 per BOE.
  - Interest Expense fell 12% sequentially. Lonestar's Interest Expense was $5.2 million in 3Q14, or $9.74 per BOE, which represents a 39% reduction compared to 3Q14 levels of $11.12 per BOE.
- In an effort to provide additional long-term visibility to its cash flow streams and associated liquidity 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 West Texas Intermediate (WTI) swaps covering 2,496 barrels of oil per day for calendar 2015 at an average strike price of $88.00 per barrel and WTI swaps covering 1,905 barrels of oil per day for calendar 2016 at an average strike price of $80.00 per barrel.

Operations Review

EAGLE FORD SHALE TREND- WESTERN REGION

- **Asherton-** In central Dimmit County, no new wells were completed during the quarter. However, Lonestar has made considerable progress in stabilizing operating costs at Asherton. In 4Q14, Lease Operating Expenses were $0.3 million, or $6.91 per BOE, flat with the third quarter. 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 has made considerable progress in reducing operating costs at Beall Ranch, achieving a 35% reduction in unit costs over the past two quarters. In 4Q14, Lease Operating Expenses were $1.2 million, or $6.82 per BOE, compared to $1.5 million, or $10.50 per BOE in 2Q14. Lonestar currently plans to drill 3 short laterals at Beall Ranch in the fourth quarter of 2015.

- **Burns Ranch Area-** In La Salle County, Lonestar completed 3 wells on its Meiners lease, in which it holds an 85.0% WI and a 63.7% NRI. The initial test rates and the 30-day Max rates were disclosed in our third quarter report. These wells contributed fully to the Company's fourth quarter production results. On a neighboring lease, which was acquired during the course of 2014, Lonestar drilled and completed the Gerke #1H, #2H and #3H with a 100.0% WI and a 75.0% NRI during the fourth quarter. The Company elected to defer the fracture stimulation of these wells until January, 2015 based on its view that it could obtain more favorable pressure pumping pricing at that time. The Company is pleased to announced that all three wells have been fracture stimulated with an average of 1,610 pounds of sand per perforated foot utilizing tighter stage spacing and a modified proppant slate than it has used in this area thus far. Lonestar estimates that the completed well costs for the Gerke wells will average $4.9 million per well, which is a significant savings when compared to the neighboring Meiners wells. Lonestar anticipates turning the Gerke wells to flowback within the next 7 days. During the quarter, Lonestar was able to execute a trade with another company that gives it a higher working interest in the Lonestar-operated Asherton property in exchange for its interest in the non-operated Centavo property. The exchange also delivered to Lonestar an additional 217 gross / 145 net acres in the Burns Ranch. This acreage is part of the unit on which the Company is currently drilling three 8,000-foot Eagle Ford Shale laterals. The Company anticipates fracture stimulating these wells in March, 2015.

EAGLE FORD SHALE TREND- CENTRAL REGION

- **Pirate Area-** In southwest Wilson County, Lonestar is pleased to announce that it has added acreage that is contiguous to its existing leasehold. The Company leased under primary term an additional 576 gross/ 576 net acres. The lease bonus was $1,875 per net mineral acre, and importantly, changed the Company's leasehold geometry so as to allow the addition of 3 long laterals to the Company's inventory. Lonestar currently plans to drill two 7,000-foot laterals in the Pirate Area during 2015.

- **Southern Gonzales County-** During the fourth quarter, Lonestar has drilled and completed 3 wells in Southern Gonzales County. On or around December 1, 2014, the Company placed the Harvey Johnson #1H, #2H & #3H into flowback. The wells had an average lateral length of 6,371 feet at an average TVD of 9,710 feet, and an average completed well cost of $6.8 million. To date, these are the deepest Eagle Ford laterals drilled by the Company. Lonestar paid 58% of the completed well costs to earn a 50.0% Working Interest and a 37.5% NRI in these wells. These wells, which were fracked with an average proppant concentration of 1,600 pounds per foot, have now been onstream for 60 days, and are outperforming the Type Curve issued by our third party engineers. Lonestar is sufficiently encouraged by its initial success that it plans to drill three more wells on acreage that is immediately contiguous to its initial wells. These wells have been designated Proved Undeveloped in its 2014 reserve report. Based on its best and most current assessment of energy service costs, Lonestar believes that it will be able to achieve reductions of at least $1.0 million per well (adjusted for length) on these next three wells, which are currently planned to be 5,800-foot laterals. Based on these successes, Lonestar is actively pursuing additional leasehold in southern Gonzales County.

EAGLE FORD SHALE TREND- EASTERN REGION

- **Brazos & Robertson Counties -** In Southern Robertson County, Lonestar has drilled and completed the Dunn #A-1H with a perforated interval of 5,720 feet. Lonestar also drilled and completed the Dunn #A-2H with a perforated interval of 5,995 feet. These wells were completed at an average cost of $6.3 million, which included substantial costs associated with drilling a pilot hole and obtaining extensive advanced formation characterization logs. The Dunn wells, which were pad drilled and zipper fracked, tested at a per-well average of 649 bopd and 192 Mcfgpd, or 693 BOEPD on a processed three-stream basis. The two wells registered Max-30 production rates of 353 bopd and 126 Mcfgpd, or 382 BOEPD, on a 16/64" choke. In Brazos County, Lonestar placed the Scasta #3H onstream in early November at a completed well costs of $4.8 million. The well has a perforated interval of 4,537 feet, and was stimulated with 1,511 pounds of proppant per foot. The well tested at a rate of 337 bopd and 65 Mcfgpd, equating to a processed three-stream rate of 352 BOEPD on a 16/64" choke. Lonestar currently plans to drill two 8,000-foot laterals in Brazos County in 2015. These wells are currently scheduled to be drilled in the Carter Lake area, offsetting acreage where Apache recently has 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, 2014, Lonestar submitted the application for the establishment of the Stone Turtle Indian Exploratory unit to the Bureau of Land Management (BLM) and Bureau of Indian Affairs (BIA), covering 52,559 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 to farm-out a portion of their interest in Poplar West.

2015 DRILLING AND COMPLETION PLANS

While the Company continues to monitor returns in light of evolving oil prices and energy service costs, 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. After making an initial assessment of its liquidity at Strip prices and its ability to obtain cost reductions from its energy services providers, Lonestar has set a budget of 15 Eagle Ford Shale wells during 2015. Presently, Lonestar expects its 2015 Eagle Ford Shale drilling and completion program to cost between $74 and $83 million, net to the Company. The schedule below reflects the 15 wells Lonestar will drill and complete in 2015, 15 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 3 wells it expects to drill and complete in late 2015 are not expected to be fracked and turned to production until early 2016. The Company continues to emphasize that it has very few obligation wells in 2015, and as opportunities present themselves to access higher return projects or farm-ins, Lonestar has the flexibility to alter its drilling plans without increasing capital outlays.

- **1Q15-** The Company has fracked 3 wells (Gerke #1H, #2H, #3H) in La Salle County and will turn to production mid 1Q15. Lonestar is currently drilling three 8,000' laterals in La Salle County.
- **2Q15-** Based on its ability to execute a second farm-in, Lonestar plans to drill 3 wells in Southern Gonzales County near its recent Harvey Johnson wells. Lonestar will hold a 50.0% WI / 37.5% NRI in these wells.
- **3Q15-** Lonestar currently plans to drill two 8,000' laterals in La Salle County in the Greater Burns Ranch area. The Company also currently plans to drill two 7,500' laterals in Wilson County near the Pirate K 1H and L3H wells drilled in 2014.
- **4Q15-** Lonestar currently plans to drill two 8,000' laterals in Brazos County, most likely in its Carter Lake area, where the Eagle Ford lies at a TVD of 9,500 feet. The Company also plans to drill and complete 3 wells on its Beall Ranch property. These well are planned to be fracked and turned to production in 1Q16.

2015 DRILLING AND COMPLETION TIMETABLE

	1Q15	2Q15	3Q15	4Q15	2015
Western Eagle Ford					
Beall Ranch	0 - 0	0 - 0	0 - 0	3 - 3	3 - 3
Asherton	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
La Salle County	3 - 6	0 - 0	2 - 2	0 - 0	5 - 8
Western Eagle Ford	**3 - 6**	**0 - 0**	**2 - 2**	**3 - 3**	**8 - 11**
Central Eagle Ford					
Gonzo	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
Pirate	0 - 0	0 - 0	2 - 2	0 - 0	2 - 2
Gonzales County	0 - 0	3 - 3	0 - 0	0 - 0	3 - 3
Central Eagle Ford	**0 0**	**3 - 3**	**2 - 2**	**0 - 0**	**5 5**
Eastern Eagle Ford					
Brazos County	0 - 0	0 - 0	0 - 0	2 - 2	2 - 2
Robertson County	0 - 0	0 - 0	0 - 0	0 - 0	0 - 0
Eastern Eagle Ford	**0 - 0**	**0 - 0**	**0 - 0**	**2 - 2**	**2 - 2**
TOTAL EAGLE FORD	**3 - 6**	**3 - 3**	**4 - 4**	**5 - 5**	**15 - 18**

Management's Discussion and Analysis

Net Production (after royalties)

		Three months ended December 31, 2014	2013	% Change	Twelve Months Ended December 31, 2014	2013	% Change
Western Eagle Ford Shale							
Crude Oil	(bbls/day)	**1,948**	2,240	-13%	**1,817**	1,476	23%
Natural Gas Liquids	(bbls/day)	**450**	402	12%	**399**	265	51%
Natural Gas	(Mcf/day)	**3,632**	2,722	33%	**3,149**	1,897	66%
Oil Equivalent	**(BOE/day)**	**3,003**	**3,095**	**-3%**	**2,741**	**2,057**	**33%**
Central Eagle Ford Shale							
Crude Oil	(bbls/day)	**949**	-	-	**623**	-	-
Natural Gas Liquids	(bbls/day)	**1**	-	-	**0**	-	-
Natural Gas	(Mcf/day)	**4**	-	-	**2**	-	-
Oil Equivalent	**(BOE/day)**	**950**	**-**	**-**	**624**	**-**	**-**
Eastern Eagle Ford Shale							
Crude Oil	(bbls/day)	**1,030**	-	-	**393**	-	-
Natural Gas Liquids	(bbls/day)	**61**	-	-	**24**	-	-
Natural Gas	(Mcf/day)	**272**	-	-	**126**	-	-
Oil Equivalent	**(BOE/day)**	**1,135**	**-**	**-**	**437**	**-**	**-**
Total Eagle Ford Shale							
Crude Oil	(bbls/day)	**3,926**	2,240	75%	**2,832**	1,476	92%
Natural Gas Liquids	(bbls/day)	**511**	402	27%	**424**	265	60%
Natural Gas	(Mcf/day)	**3,907**	2,722	44%	**3,277**	1,897	73%
Oil Equivalent	**(BOE/day)**	**5,089**	**3,095**	**64%**	**3,802**	**2,057**	**85%**
Barnett Shale							
Crude Oil	(bbls/day)	**-**	-	-	**-**	-	-
Natural Gas Liquids	(bbls/day)	**-**	-	-	**-**	-	-
Natural Gas	(Mcf/day)	**-**	-	-	**-**	1,224	-100%
Oil Equivalent	**(BOE/day)**	**-**	**-**	**-**	**-**	**204**	**-100%**
Conventional							
Crude Oil	(bbls/day)	**385**	486	-21%	**434**	547	-21%
Natural Gas Liquids	(bbls/day)	**27**	4	614%	**13**	3	303%
Natural Gas	(Mcf/day)	**1,889**	1,122	68%	**1,387**	1,248	11%
Oil Equivalent	**(BOE/day)**	**727**	**676**	**7%**	**679**	**759**	**-11%**
Total Company							
Crude Oil	(bbls/day)	**4,312**	2,725	58%	**3,267**	2,024	61%
Natural Gas Liquids	(bbls/day)	**538**	406	33%	**436**	268	63%
Natural Gas	(Mcf/day)	**5,796**	3,844	51%	**4,664**	4,368	7%
Oil Equivalent	**(BOE/day)**	**5,816**	**3,772**	**54%**	**4,480**	**3,020**	**48%**

Lonestar's net production for the fourth quarter of 2014 averaged a record 5,816 BOE per day, and was comprised of 4,312 barrels of oil per day, 538 barrels of NGL's per day, and 5,796 Mcf of natural gas per day, 83% of the Company's sales volumes were derived from liquids. 4Q14 production rose 54% over rates reported in 4Q13, and also represented a 25% sequential increase over reported sales for the third quarter of 2014.

- Lonestar's net production from its Eagle Ford Shale assets averaged a record 5,089 BOE per day during the fourth quarter of 2014, and was comprised of 3,926 barrels of oil per day, 511 barrels of NGL's per day, and 3,907 Mcf of natural gas per day. Fourth quarter 2014 volumes represented an increase of 64% compared to the fourth quarter of 2013, and a 28% increase sequentially. In the fourth quarter of 2014, 87% of the Company's Eagle Ford production was derived from liquid hydrocarbons. The increase in production volumes was attributable to the completion of 6.0 gross / 4.1 net new Eagle Ford wells, which produced for varied portions of the fourth quarter of 2014.
- Lonestar's net production from its Conventional assets averaged 727 BOE per day during the fourth quarter of 2014, and was comprised of 385 barrels of oil per day, 27 barrels of NGL's per day, and 1,889 Mcf of natural gas per day. 57% of the Company's Conventional production was from liquid hydrocarbons. Fourth quarter volumes represented an increase of 7% compared to the fourth quarter of 2013, and a 3% increase sequentially. Additive recompletion and wellbore optimization activities during the fourth quarter of 2014 were responsible for generating sequential volume growth. Notably, this growth was achieved at negligible 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 December 31, 2014	2013	% Change	Twelve Months Ended December 31, 2014	2013	% Change
Western Eagle Ford Shale							
Crude Oil	($/bbl)	**$70.48**	$91.71	-23%	$89.64	$98.82	-9%
Natural Gas Liquids	($/bbl)	**$21.83**	$30.22	-28%	$29.32	$29.34	0%
Natural Gas	($/Mcf)	**$3.71**	$3.35	11%	$4.09	$3.40	20%
Western Eagle Ford Shale	**($/BOE)**	**$53.47**	**$73.23**	**-27%**	**$68.38**	**$77.82**	**-12%**
Central Eagle Ford Shale							
Crude Oil	($/bbl)	**$67.22**	-	-	$85.46	-	-
Natural Gas Liquids	($/bbl)	**$23.36**	-	-	$24.17	-	-
Natural Gas	($/Mcf)	**$3.44**	-	-	$3.36	-	-
Central Eagle Ford Shale	**($/BOE)**	**$67.14**	**-**	**-**	**$85.39**	**-**	**-**
Eastern Eagle Ford Shale							
Crude Oil	($/bbl)	**$71.57**	-	-	$79.70	-	-
Natural Gas Liquids	($/bbl)	**$20.68**	-	-	$25.03	-	-
Natural Gas	($/Mcf)	**$2.54**	-	-	$2.70	-	-
Eastern Eagle Ford Shale	**($/BOE)**	**$66.61**	**-**	**-**	**$73.70**	**-**	**-**
Total Eagle Ford Shale							
Crude Oil	($/bbl)	**$69.98**	$91.71	-24%	$87.34	$98.82	-12%
Natural Gas Liquids	($/bbl)	**$21.69**	$30.22	-28%	$29.08	$29.34	-1%
Natural Gas	($/Mcf)	**$3.63**	$3.35	8%	$4.04	$3.40	19%
Total Eagle Ford Shale	**($/BOE)**	**$58.95**	**$73.23**	**-19%**	**$71.78**	**$77.82**	**-8%**
Barnett Shale							
Crude Oil	($/bbl)	**-**	-	-	-	-	-
Natural Gas Liquids	($/bbl)	**-**	-	-	-	-	-
Natural Gas	($/Mcf)	**-**	-	-	-	$3.37	-100%
Barnett Shale	**($/BOE)**	**-**	**-**	**-**	**-**	**$20.24**	**-100%**
Conventional							
Crude Oil	($/bbl)	**$70.85**	$87.38	-19%	$87.89	$91.91	-4%
Natural Gas Liquids	($/bbl)	**$30.66**	$107.48	-71%	$35.06	$66.65	-47%
Natural Gas	($/Mcf)	**$4.52**	$6.36	-29%	$5.59	$6.06	-8%
Conventional	**($/BOE)**	**$50.42**	**$73.88**	**-32%**	**$68.37**	**$76.57**	**-11%**
Total Company Wellhead							
Crude Oil	($/bbl)	**$70.05**	$90.94	-23%	$87.41	$96.95	-10%
Natural Gas Liquids	($/bbl)	**$22.14**	$30.93	-28%	$29.26	$29.78	-2%
Natural Gas	($/Mcf)	**$3.92**	$4.23	-7%	$4.50	$4.15	8%
Total Company Wellhead	**($/BOE)**	**$57.89**	**$73.35**	**-21%**	**$71.27**	**$73.62**	**-3%**

Lonestar's average wellhead commodity price for the fourth quarter of 2014 was $57.89 per barrel of oil equivalent (BOE), which was 21% lower than the $73.35 per BOE average price realized in the fourth quarter of 2013. Principally, reported wellhead realizations declined as a result of a $24.31 per barrel (25%) decline in the benchmark West Texas Intermediate oil price, when compared to 4Q13 prices. While not expressed in this table, Lonestar's post-hedge crude oil price was bolstered by its swap position, which added $11.31 per barrel to its fourth quarter revenues.

- On its Eagle Ford Shale assets, Lonestar recorded energy equivalent wellhead price realization of $58.95 per BOE during 4Q14, a 19% decrease compared to 4Q13. While WTI prices fell $24.31 per bbl, Lonestar's average oil price benefitted from favorable localized basis and sales price improvements generated by its own remarketing efforts, which resulted in reduced discounts to WTI postings, and as a result, Lonestar's wellhead oil realization only dropped $16.58 per barrel. NGL realizations fell 28% vs. 4Q13, owing to lower WTI prices. Natural gas realizations rose 8% to $3.63, in spite of 2% lower Henry Hub gas prices, year-over-year.
- On its Conventional assets, Lonestar recorded an average wellhead price realization of $50.42 per BOE during 4Q14, down 32% versus 4Q13. This variance is also largely due to lower WTI pricing compared to 4Q13. Additionally, the product mix has shifted from 72% crude oil and NGL's in 4Q13 to 57% crude oil and NGL's in 4Q14 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 December 31,			Twelve Months Ended December 31,		
		2014	2013	% Change	2014	2013	% Change
Western Eagle Ford Shale							
Crude Oil	($,000)	**$12,630**	$18,897	-33%	**$59,438**	$53,240	12%
Natural Gas Liquids	($,000)	**$903**	$1,117	-19%	**$4,275**	$2,914	47%
Natural Gas	($,000)	**$1,239**	$840	47%	**$4,702**	$2,336	101%
Western Eagle Ford Shale Revenues	**($,000)**	**$14,772**	**$20,854**	**-29%**	**$68,414**	**$58,490**	**17%**
Central Eagle Ford Shale							
Crude Oil	($,000)	**$5,868**	$0	-	**$19,433**	$0	-
Natural Gas Liquids	($,000)	**$2**	$0	-	**$4**	$0	-
Natural Gas	($,000)	**$1**	$0	-	**$2**	$0	-
Central Eagle Ford Shale Revenues	**($,000)**	**$5,871**	**$0**	**-**	**$19,439**	**$0**	**-**
Eastern Eagle Ford Shale							
Crude Oil	($,000)	**$6,780**	$0	-	**$11,419**	$0	-
Natural Gas Liquids	($,000)	**$115**	$0	-	**$216**	$0	-
Natural Gas	($,000)	**$63**	$0	-	**$124**	$0	-
Eastern Eagle Ford Shale Revenues	**($,000)**	**$6,959**	**$0**	**-**	**$11,759**	**$0**	**-**
Total Eagle Ford Shale							
Crude Oil	($,000)	**$25,278**	$18,897	34%	**$90,290**	$53,240	70%
Natural Gas Liquids	($,000)	**$1,021**	$1,117	-9%	**$4,495**	$2,914	54%
Natural Gas	($,000)	**$1,303**	$840	55%	**$4,828**	$2,336	107%
Total Eagle Ford Shale Revenues	**($,000)**	**$27,602**	**$20,854**	**32%**	**$99,613**	**$58,490**	**70%**
Barnett Shale							
Crude Oil	($,000)	**$0**	$0	-	**$0**	$0	-
Natural Gas Liquids	($,000)	**$0**	$0	-	**$0**	$0	-
Natural Gas	($,000)	**$0**	$0	-	**$0**	$1,507	-100%
Barnett Shale Revenues	**($,000)**	**$0**	**$0**	**-**	**$0**	**$1,507**	**-100%**
Conventional							
Crude Oil	($,000)	**$2,509**	$3,903	-36%	**$13,938**	$18,362	-24%
Natural Gas Liquids	($,000)	**$76**	$37	104%	**$165**	$78	112%
Natural Gas	($,000)	**$786**	$656	20%	**$2,832**	$2,760	3%
Conventional Revenues	**($,000)**	**$3,371**	**$4,597**	**-27%**	**$16,935**	**$21,200**	**-20%**
Total Company Wellhead							
Crude Oil	($,000)	**$27,788**	$22,800	22%	**$104,228**	$71,602	46%
Natural Gas Liquids	($,000)	**$1,097**	$1,155	-5%	**$4,660**	$2,992	56%
Natural Gas	($,000)	**$2,089**	$1,496	40%	**$7,660**	$6,603	16%
Total Company Wellhead Revenues	**($,000)**	**$30,973**	**$25,451**	**22%**	**$116,548**	**$81,197**	**44%**

Lonestar's net wellhead oil and gas revenues for the fourth quarter of 2014 rose 22% to $31.0 million, versus $25.5 million a year ago. Revenue growth was a function of a 54% increase in production, partially offset by a 21% decline in realized wellhead prices. While crude oil prices fell sharply in the fourth quarter of 2014, Lonestar's wellhead oil and gas revenues decreased 4% sequentially over 3Q14 levels, as a result of the sharp increase in production volumes.

- Lonestar's net oil and gas revenues from its Eagle Ford Shale assets rose 32% to $27.6 million for the fourth quarter of 2014 versus $20.9 million a year ago. Revenue growth was driven by a 64% increase in production partially offset by a 19% decrease in wellhead price realizations per BOE. Crude oil contributed 92% of revenues, while natural gas liquids contributed 4% of revenues and natural gas contributed 4% of revenues. Sequentially, net oil and gas revenues fell 1%, as volumes rose 28% while BOE price realizations fell 23%.
- Lonestar's net oil and gas revenues from its Conventional assets totaled $3.4 million during the fourth quarter of 2014, a 27% decrease over the fourth quarter of 2013. The decrease in revenue was driven by a 32% decrease in wellhead price realizations per BOE partially offset by a 7% increase in production. Crude oil contributed 75% of revenues while natural gas liquids contributed 2% 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 December 31,			Twelve Months Ended December 31,		
		2014	2013	% Change	2014	2013	% Change
Western Eagle Ford Shale							
Lease Operating Expense	($/BOE)	**$7.42**	$7.04	5%	**$8.26**	$6.67	24%
Production Taxes	($/BOE)	**$3.13**	$3.80	-18%	**$4.07**	$4.30	-5%
Western Eagle Ford Shale	**($/BOE)**	**$10.55**	**$10.84**	**-3%**	**$12.33**	**$10.97**	**12%**
Central Eagle Ford Shale							
Lease Operating Expense	($/BOE)	**$7.71**	$0.00	-	**$9.59**	$0.00	-
Production Taxes	($/BOE)	**$2.73**	$0.00	-	**$4.47**	$0.00	-
Central Eagle Ford Shale	**($/BOE)**	**$10.44**	**$0.00**	**-**	**$14.06**	**$0.00**	**-**
Eastern Eagle Ford Shale							
Lease Operating Expense	($/BOE)	**$2.91**	$0.00	-	**$4.85**	$0.00	-
Production Taxes	($/BOE)	**$3.42**	$0.00	-	**$4.36**	$0.00	-
Eastern Eagle Ford Shale	**($/BOE)**	**$6.33**	**$0.00**	**-**	**$9.21**	**$0.00**	**-**
Total Eagle Ford Shale							
Lease Operating Expense	($/BOE)	**$6.47**	$7.04	-8%	**$8.08**	$6.67	21%
Production Taxes	($/BOE)	**$3.12**	$3.80	-18%	**$4.17**	$4.30	-3%
Total Eagle Ford Shale	**($/BOE)**	**$9.59**	**$10.84**	**-12%**	**$12.25**	**$10.97**	**12%**
Barnett Shale							
Lease Operating Expense	($/BOE)	**$0.00**	$0.00	-	**$0.00**	$11.21	-100%
Production Taxes	($/BOE)	**$0.00**	$0.00	-	**$0.00**	$1.24	-100%
Barnett Shale	**($/BOE)**	**$0.00**	**$0.00**	**-**	**$0.00**	**$12.45**	**-100%**
Conventional							
Lease Operating Expense	($/BOE)	**$13.90**	$25.86	-46%	**$20.02**	$25.65	-22%
Production Taxes	($/BOE)	**$4.72**	$5.23	-10%	**$5.41**	$6.52	-17%
Conventional	**($/BOE)**	**$18.61**	**$31.09**	**-40%**	**$25.43**	**$32.17**	**-21%**
Total Company							
Lease Operating Expense	($/BOE)	**$7.40**	$10.42	-29%	**$9.89**	$11.75	-16%
Production Taxes	($/BOE)	**$3.32**	$4.06	-18%	**$4.36**	$4.65	-6%
Total Company	**($/BOE)**	**$10.72**	**$14.47**	**-26%**	**$14.25**	**$16.40**	**-13%**

Lonestar's field operating expenses for the fourth quarter of 2014 were $5.7 million, an increase of 14% over 4Q13 field operating expenses of $5.0 million. On a unit of production basis, the Company's field operating expenses declined 26% from 4Q13 to $10.72 per BOE. Lease Operating Expense ("LOE") was $4.0 million for 4Q14, rising only 9% over 4Q13 levels in spite of a 54% increase in production volume. Production taxes were $1.8 million for the fourth quarter of 2014, a 26% increase over comparable levels in 2013, attributable to substantial increases in production from the Company's Eagle Ford Shale properties.

- Lonestar's field operating expenses from its Eagle Ford Shale assets totaled $4.5 million during the fourth quarter of 2014, a 45% increase over the fourth quarter of 2013. On a unit of production basis, field operating expenses decreased 12% to $9.59 per BOE, year-over-year. Perhaps more important is the fact that Lonestar's Eagle Ford Shale achieved a 2% reduction in absolute dollar LOE and a 23% sequential reduction in LOE per BOE, to a record-low $6.47 per BOE, compared to $8.44 per BOE in the third quarter of 2014. Production taxes were $1.5 million, or $3.12 per BOE, compared to $1.1 million, or $3.80 per BOE in the year-ago quarter.
- Lonestar's field operating expenses from its Conventional assets totaled $1.2 million during the fourth quarter of 2014, a 36% decrease versus the fourth quarter of 2013. On a unit of production basis, field operating expenses decreased 40% to $18.61 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 $13.90 per BOE, compared to $1.6 million, or $25.86 per BOE in 4Q13. Production taxes were $0.3 million, or $4.72 per BOE, compared to $0.3 million, or $5.23 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 December 31, 2014	2013	% Change	Twelve Months Ended December 31, 2014	2013	% Change
Western Eagle Ford Shale							
Production Revenue	($/BOE)	$53.47	$73.23	-27%	$68.38	$77.82	-12%
Lease Operating Expenses	($/BOE)	$7.42	$7.04	5%	$8.26	$6.67	24%
Production Taxes	($/BOE)	$3.13	$3.80	-18%	$4.07	$4.30	-5%
Field Netback	**($/BOE)**	**$42.92**	**$62.39**	**-31%**	**$56.06**	**$66.85**	**-16%**
Field Netback	**($MM)**	**$11.9**	**$17.8**	**-33%**	**$56.1**	**$50.19**	**12%**
Central Eagle Ford Shale							
Production Revenue	($/BOE)	$67.14	-	-	$85.39	-	-
Lease Operating Expenses	($/BOE)	$7.71	-	-	$9.59	-	-
Production Taxes	($/BOE)	$2.73	-	-	$4.47	-	-
Field Netback	**($/BOE)**	**$56.70**	**-**	**-**	**$71.33**	**-**	**-**
Field Netback	**($MM)**	**$5.0**	**-**	**-**	**$16.2**	**-**	**-**
Eastern Eagle Ford Shale							
Production Revenue	($/BOE)	$66.61	-	-	$73.70	-	-
Lease Operating Expenses	($/BOE)	$2.91	-	-	$4.85	-	-
Production Taxes	($/BOE)	$3.42	-	-	$4.36	-	-
Field Netback	**($/BOE)**	**$60.28**	**-**	**-**	**$64.49**	**-**	**-**
Field Netback	**($MM)**	**$6.3**	**-**	**-**	**$10.3**	**-**	**-**
Total Eagle Ford Shale							
Production Revenue	($/BOE)	$58.95	$73.23	-19%	$71.78	$77.82	-8%
Lease Operating Expenses	($/BOE)	$6.47	$7.04	-8%	$8.08	$6.67	21%
Production Taxes	($/BOE)	$3.12	$3.80	-18%	$4.17	$4.30	-3%
Field Netback	**($/BOE)**	**$49.37**	**$62.39**	**-21%**	**$59.53**	**$66.85**	**-11%**
Field Netback	**($MM)**	**$23.1**	**$17.8**	**30%**	**$82.6**	**$50.19**	**65%**
Barnett Shale							
Production Revenue	($/BOE)	-	-	-	-	$20.24	-100%
Lease Operating Expenses	($/BOE)	-	-	-	-	$11.21	-100%
Production Taxes	($/BOE)	-	-	-	-	$1.24	-100%
Field Netback	**($/BOE)**	**-**	**-**	**-**	**-**	**$7.79**	**-100%**
Field Netback	**($MM)**	**-**	**-**	**-**	**-**	**$0.58**	**-100%**
Conventional							
Production Revenue	($/BOE)	$50.42	$73.88	-32%	$68.37	$76.57	-11%
Lease Operating Expenses	($/BOE)	$13.90	$25.86	-46%	$20.02	$25.65	-22%
Production Taxes	($/BOE)	$4.72	$5.23	-10%	$5.41	$6.52	-17%
Field Netback	**($/BOE)**	**$31.81**	**$42.79**	**-26%**	**$42.94**	**$44.40**	**-3%**
Field Netback	**($MM)**	**$2.1**	**$2.7**	**-20%**	**$10.6**	**$12.3**	**-13%**
Total Company							
Production Revenue	($/BOE)	$57.89	$73.35	-21%	$71.27	$73.62	-3%
Lease Operating Expenses	($/BOE)	$7.40	$10.42	-29%	$9.89	$11.75	-16%
Production Taxes	($/BOE)	$3.32	$4.06	-18%	$4.36	$4.65	-6%
Field Netback	**($/BOE)**	**$47.17**	**$58.87**	**-20%**	**$57.02**	**$57.22**	**0%**
Field Netback	**($MM)**	**$25.2**	**$20.4**	**24%**	**$93.2**	**$63.1**	**48%**

Lonestar's field netback for the fourth quarter of 2014 was $25.2 million, an increase of 24% over the field netback of $20.4 million in 4Q13. On a per BOE basis, field netbacks declined 20% to $47.17 in the fourth quarter of 2014 vs. $58.87 in the fourth quarter of 2013. The decrease in the per BOE field netback is associated solely with a 25% decrease in WTI pricing compared to 4Q13. However, compared to the third quarter of 2014, Lonestar's field netback decreased only 3% sequentially, despite a 25% decrease in WTI compared from the previous quarter. This favorable result was achieved by significant reductions in per BOE Field Operating Expenses and a modest improvement in natural gas price realizations.

- Lonestar's field netback from its Eagle Ford Shale assets totaled $23.1 million during the fourth quarter of 2014, which represents a 30% increase in the field netback compared to the $17.8 million reported in the fourth quarter of 2013. On a BOE basis, field netbacks declined 21% to $49.37 in fourth quarter of 2014 vs. $62.39 in 4Q14, largely influenced by a 25% reduction in crude oil prices.
- Lonestar's field netback from its Conventional assets totaled $2.1 million during the fourth quarter of 2014 which represents a 20% decrease in field netbacks compared to the $2.7 million reported in the fourth quarter of 2013. On a BOE basis, field netbacks declined 26% largely due to a 25% reduction in crude oil prices and higher gas sales volumes which are sold at a lower price per BOE compared to crude oil.

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

Management's Discussion and Analysis

Depreciation and Depletion

		Three months ended December 31,			Twelve Months Ended December 31,		
		2014	2013	% Change	2014	2013	% Change
Total Expense	($,000)	$14,158	$10,242	38%	$40,914	$29,462	39%
Depreciation & Depletion	($/BOE)	$26.46	$29.52	-10%	$25.02	$26.73	-6%

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 fourth quarter of 2014 was $14.2 million, or $26.46 per BOE compared to $10.2 million, or $29.52 per BOE reported in the fourth quarter of 2013.

General and Administrative Expenses

		Three months ended December 31,			Twelve Months Ended December 31,		
		2014	2013	% Change	2014	2013	% Change
Total Expense	($,000)	$2,376	$1,386	71%	$8,426	$7,175	17%
General & Administrative	($/BOE)	$4.44	$3.99	11%	$5.15	$6.51	-21%

Lonestar reported General & Administrative expenses of $2.4 million for the fourth quarter of 2014, a 71% increase over the $1.4 million of General & Administrative expenses reported in the fourth quarter of 2013. On a BOE basis, the Company reported an 11% increase in G&A per BOE of $4.44, compared to $3.99 reported in the fourth quarter of 2013. 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 rising 9% to $2.4 million, and on a per BOE basis, delivering a 13% sequential reduction over 3Q14 results. Company expects continued reductions in G&A on a unit basis as Lonestar achieves further scale.

Finance Expenses

		Three months ended December 31,			Twelve Months Ended December 31,		
		2014	2013	% Change	2014	2013	% Change
Interest Expense	($,000)	$5,210	$1,226	325%	$17,481	$3,452	406%
Amortization of Finance Costs	($,000)	$498	$87	472%	$2,468	$152	1527%
Total Finance Costs	**($,000)**	**$5,709**	**$1,313**	**335%**	**$19,949**	**$3,604**	**454%**
Finance Costs	($/BOE)	$10.67	$3.78	**182%**	$12.20	$3.27	**273%**

Lonestar reported Finance expenses of $5.7 million for the fourth quarter of 2014, a 325% increase over the $1.3 million of Finance expenses reported in the fourth quarter of 2013. On a BOE basis, the Company reported Finance expenses of $10.67, a 14% decrease compared to $12.45 reported in the third 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 Revolver averaged $44.6 million during the quarter with interest expense averaging 2.45% 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 December 31, 2014	2013	% Change	Twelve Months Ended December 31, 2014	2013	% Change
Crude Oil	($,000)	**$4,485**	($322)	-1494%	**$1,216**	($1,820)	-167%
Natural Gas Liquids	($,000)	**$0**	$0	-	**$0**	$0	-
Natural Gas	($,000)	**$0**	$0	-	**$0**	($20)	-100%
Hedging Revenues (Expenses)	**($,000)**	**$4,485**	**($322)**	**-1494%**	**$1,216**	**($1,840)**	**-166%**
Hedging Revenues (Expenses)	($/BOE)	**$8.38**	($0.93)		**$0.74**	($1.67)	

- Lonestar realized crude oil hedge revenues of $4.5 million in the fourth quarter of 2014 vs. a crude oil hedge expense of $0.3 million reported in the fourth quarter of 2013. As of December 31, 2014 the Mark to Market of Lonestar's remaining hedge contracts totaled $43.8 million.

Derivative Commodity Contracts

Commodity	Quantity	Term			Reference	Strike	Put	Call	Option Traded
Crude Oil	244,200	Jan 1, 2015	-	Dec 31, 2015	WTI	$87.00	-	-	Swap
Crude Oil	255,500	Jan 1, 2015	-	Dec 31, 2015	WTI	$81.25	-	-	Swap
Crude Oil	35,460	Jan 1, 2015	-	Mar 31, 2015	WTI	$92.10	-	-	Swap
Crude Oil	63,400	Jan 1, 2015	-	Mar 31, 2015	WTI	$98.15	-	-	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	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	35,800	Jan 1, 2015	-	Mar 31, 2015	WTI	$91.60	-	-	Swap
Crude Oil	31,400	Apr 1, 2015	-	Jun 30, 2015	WTI	$89.50	-	-	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	183,400	Jan 1, 2016	-	Dec 31, 2016	WTI	$56.90	-	-	Swap

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 hedge the Company from the risks associated with the oil and gas business.

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 WTI swaps covering 2,496 barrels per day for calendar 2015 at an average strike price of $88.00 per barrel and WTI swaps covering 1,905 barrels per day for calendar 2016 at an average strike price of $80.00 per barrel.

Non-recurring Expenses

Lonestar recorded $0.1 million of regulatory mandated P&A and a $0.1 million provision for the abandonment of the Company's previous corporate office. during the fourth quarter of 2014. This charge has been excluded from the Company's EBITDAX calculation.

Lonestar recorded an impairment charge of approximately $5.5 million relating to the Conventional oil and gas properties located in East Texas.

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

UNAUDITED INTERIM FINANCIAL REPORT

For the three months ended December 31, 2014

Consolidated statements of comprehensive income

For the three and twelve months ended December 31, 2014 and 2013

(US $,000)	*As Reported* Three months ended December 31, 2014	2013	*As Reported* Twelve Months Ended December 31, 2014	2013
Revenues (Net of Royalties)				
Crude Oil	27,788	22,800	104,228	71,602
Natural Gas Liquids	1,097	1,155	4,660	2,992
Natural Gas	2,089	1,496	7,661	6,603
Revenues (Net of Royalties)	**30,973**	**25,451**	**116,548**	**81,197**
Hedge Revenues (Expenses)	4,485	(322)	1,216	(1,840)
Net Revenue From Ordinary Activities	**35,458**	**25,130**	**117,765**	**79,357**
Operating Expenses				
Lease Operating Expenses	(3,958)	(3,615)	(15,638)	(13,115)
Severance Taxes	(1,433)	(1,191)	(5,426)	(3,789)
Ad Valorem Taxes	(342)	(216)	(1,701)	(1,238)
Depreciation, Depletion & Amortization	(14,158)	(10,242)	(40,914)	(28,280)
General & Administrative	(2,376)	(1,386)	(8,426)	(7,175)
Total Operating Expenses	**(22,268)**	**(16,651)**	**(72,105)**	**(53,596)**
Gross Profit from Operating Activities	**13,190**	**8,479**	**45,659**	**25,760**
Other Income (Expense)	**(364)**	**(3)**	**55**	**10,752**
Impairment of O&G properties	**(5,478)**	**(2,762)**	**(5,478)**	**(2,762)**
Stock based compensation	**23**	**0**	**(1,938)**	**(2,245)**
Non-recurring expenses	**(137)**	**(947)**	**(1,699)**	**(1,063)**
Interest & Other Finance Expenses	**(5,709)**	**(1,313)**	**(19,949)**	**(3,744)**
Fair Value Gain (Loss) on derivatives	**38,126**	**1,092**	**42,756**	**(992)**
Profit (Loss) before taxes	**39,652**	**4,547**	**59,405**	**25,706**
Income tax (expense) benefit	**(14,253)**	**0**	**(16,803)**	**4,934**
Net Income (Loss)	**25,400**	**4,547**	**42,602**	**30,640**
EBITDAX	**27,349**	**18,721**	**86,573**	**54,040**

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

Consolidated statements of financial position

As of December 31, 2014

(US $,000)	*As Reported* As of December 31, 2014	December 31, 2013
Assets		
Current Assets		
Cash and cash equivalents	9,992	6,744
Trade and other receivables	17,507	7,919
Derivative financial instruments	31,045	157
Other assets	746	545
Total current assets	**59,292**	**15,365**
Non-current assets		
Oil and Gas Properties & Equipment	479,536	294,926
Deferred tax assets	70	96
Derivative financial instruments	12,713	490
Other non-current assets	3,734	1,987
Total non-current assets	**496,053**	**297,499**
Total Assets	**555,345**	**312,864**
Liabilities		
Current liabilities		
Trade and other payables	35,691	9,461
Revenue payable	4,962	3,130
Accrued expenses	2,363	3,484
Derivative financial instruments	-	-
Total current liabilities	**43,015**	**16,075**
Non-current liabilities		
Long-term Debt	264,614	109,000
Deferred tax liablilities	26,044	8,943
Other non-current liabilities	7,835	9,144
Total non-current liabilities	**298,492**	**127,087**
Total Liabilities	**341,507**	**143,162**
Net assets	**213,838**	**169,701**
Equity		
Contributed equity	142,638	142,638
Reserves	6,913	5,378
Retained Earnings	64,288	21,686
Total Equity	**213,838**	**169,702**

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

Consolidated statements of cash flows
As of December 31, 2014

(US $,000)	*As Reported* Three Months Ending December 31, 2014	Twelve Months Ending December 31, 2014
CASH FLOWS FROM OPERATING ACTIVITIES		
Profit/(loss) for the year	39,841	42,602
Adjustments to reconcile profit/(loss) to net cash	-	-
provided by operating activities:	-	-
Gain on sale of oil and gas properties	-	(466)
Depreciation, depletion, amortisation	14,158	40,713
Impairment	5,478	5,478
Increase in retirement provision	-	201
Deferred taxes	(38)	17,615
Share based payments	(23)	1,938
Non-cash interest expense	275	825
Changes in operating assets and liabilities:	-	-
Accounts receivable	(2,089)	(9,589)
Other assets	984	(1,948)
Accounts payable and provisions	4,328	26,544
Net cash inflow from operating activities	62,914	123,913
CASH FLOWS FROM INVESTING ACTIVITIES		
Payments for oil and gas property, plant & equipment	(53,525)	(161,548)
Acquisition of oil and gas properties	-	(70,978)
Net (increase) decrease in derivatives	(40,319)	(45,808)
Proceeds from sales of oil and gas properties	-	3,200
Net cash (outflow) from investing activities	(93,843)	(275,134)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net change in borrowings	27,000	(60,030)
Proceeds from issuance of long term bonds	-	214,500
Net cash inflow from financing activities	27,000	154,470
Net increase in cash held	(3,930)	3,248
Cash and cash equivalents at the beginning of the financial period	13,922	6,744
Cash and cash equivalents at the end of the financial period	9,992	9,992

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 press release 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 press release is 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 and forward-looking information, whether as a result of new information, future events or results or otherwise, expect as required by law.

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 bee 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 lift 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 $4.35per mmbtu for natural gas and for the year ended December 31, 2013 were $96.94 bbl for oil and $3.66 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."