Quarterly Report

June 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 June 30, 2015 (2Q15).

Second Quarter Highlights

- Lonestar Resources registered a 61% increase in net oil and gas production to 5,804 BOEPD in 2Q15, vs. 3,613 BOEPD in 2Q14, 83% of which was crude oil and NGL's. The Company's Eagle Ford Shale properties recorded a 70% increase in net oil and gas production to 5,113 BOEPD over 2Q14. Lonestar's 2Q15 sales volumes also represented a 5% sequential increase over 1Q15 production levels.
- Net Revenues From Ordinary Activities increased 25% to US$30.9 million for 2Q15, vs. 2Q14 revenues of $24.7 million. This increase was achieved despite a 44% decrease in average West Texas Intermediate prices.
- EBITDAX rose 32% to $22.1 million for 2Q15 vs. $16.7 million for 2Q14, as increased production volumes and incremental revenues from crude oil hedges more than offset a 45% decrease in its average wellhead price.
- Excluding a $14.9 million unrealized loss on commodity derivatives, Lonestar would have reported Net Income of $6.5 million for 2Q15 vs. a net loss of $0.9 million in 2Q14.
- The Company has closed a new $500 million Senior Secured Revolving Credit Facility. The initial borrowing base has been set at $180 million, a 20% increase over its prior level of $150 million. At June 30, 2015, $104 million was undrawn, proforma the new facility.
- Lonestar continues to build production momentum, with volumes exceeding 6,100 BOEPD in June and July, and expects to post sequential growth of the rest of 2015
- Lonestar's new Joint Development Agreement with IOG Capital provides the Company with incremental financial capacity to fund and develop additional farm-in opportunities such as Horned Frog, where our initial wells are on-track and under budget thus far.
- With the second quarter under its belt, Lonestar reiterates its previous 2015 guidance. Based on a WTI price range of $50 to $60 per barrel 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 BOEPD, yielding EBITDAX guidance of $84 to $95 million for 2015.[1]

[1] *Please see the Notes & 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

Vice President- 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 June 30, 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 34,360 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.

SECOND QUARTER 2015 HIGHLIGHTS

Corporate

Lonestar continues to make strides towards its core goal of expanding its resource base during the current downturn in commodity prices. Lonestar's preference is to use its flexible drilling schedule to gain access to additional leasehold and reserves in proven areas via farm-in, supplemented by primary term leases. This strategy allows Lonestar to grow its asset base without straining its liquidity, as the Company continues to retain its borrowing base liquidity in anticipation of a growing number of distressed sales as the effects of a downturn in commodity prices are amplified.

- Year-to-date, Lonestar has used its flexible drilling program and a small amount of its borrowing base to capture high quality leasehold in its focus areas in the Eagle Ford Shale play. To date, 6 of its 16 drilling slots have been diverted away from originally budgeted drilling operations in favor of new farm-in opportunities in La Salle, Gonzales and Wilson Counties. These farm-ins have garnered an additional 2,800 net acres in the Company's Western and Central Regions of the Eagle Ford Shale play. Lonestar has also spent another $2.0 million on tuck-in acquisitions to bolster these positions by another 2,000 net acres, in most cases, increasing the Company's interest in leases in which it already owned an interest. The Company is encouraged by the volume of opportunities currently under review which could result in additional farm-in and/or tuck-in acquisitions.
- On July 27, 2015, Lonestar closed a new $100 million drilling joint venture with IOG Capital, L.P., an investment partnership led by industry veteran Marc Rowland and partnered with Fortress Investment Group, who has $69.9 billion in assets under management and Metalmark Capital, a private equity firm which is currently investing its latest fund with $2.5 billion. As a group, IOG Capital has committed capital of $700 million. The joint venture calls for IOG Capital to participate as a non-operated working interest partner in Lonestar's drilling program, and at Lonestar's option, on a promoted basis. This off-balance sheet financing provides Lonestar with the ability to pursue more acreage-adding and reserve-adding deals with the drillbit, while allowing it to maintain its balance sheet discipline.
- On July 28, 2015, Lonestar closed a new $500 million Senior Secured Revolving Credit Facility led by Citibank, N.A.. The initial borrowing base has been set at $180 million, a 20% increase over its prior level of $150 million. At June 30, 2015, $76 million was outstanding on the facility leaving $104 million available, on a proforma basis. The new revolving credit facility offers several positive features, including: an extension in the maturity from March, 2018 to October, 2018; a 0.25% reduction in interest rate spreads; the capacity to hedge higher levels of oil and gas production; and the addition of three prominent banks, BBVA Compass, Comerica Bank, and Barclays Bank.

Operational

- Lonestar generated sequential production growth of 5% over first quarter 2015 results . The Company's net production for the second quarter of 2015 also represented a 61% increase over 2Q14 levels, rising to 5,804 BOE per day. Second quarter 2015 volumes were comprised of 4,175 barrels of oil per day, 644 barrels of NGL's per day, and 5,909 Mcf of natural gas per day. Second quarter 2015 production was comprised of 83% crude oil and natural gas liquids, and 17% natural gas.
- In the second quarter of 2015, Lonestar generated EBITDAX of $22.1 million, a 32% increase over 2Q14 EBITDAX of $16.7 million. A 61% increase in oil and gas production and a strong hedge position more than offset a 45% decrease in wellhead price realizations. EBITDAX also advanced over 1Q15 levels, in line with the Company's sequential production growth.
- As has been our practice since inception, crude oil hedging has been a key element to providing visibility to cash flow streams and associated liquidity in the current crude oil price environment. Currently, the Company has West Texas Intermediate (WTI) swaps covering 2,593 barrels of oil per day for the remainder of 2015 at an average strike price of $82.58 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 notes and 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, production rates from the 4 producing wells continued to outperform the third-party engineering projections. The Asherton leasehold is Held by Production, and Lonestar does not plan drilling activity here in 2015.
- **Beall Ranch-** In Dimmit County, Lonestar has drilled and completed the Beall Ranch #26H-#28H. These wells were drilled to an average total depth of 11,500 feet in an average of 10 days, compared to the AFE of 13 days. These wells are short laterals, possessing an average perforated interval of 3,200. The wells were AFE'd at $3.4 million, which appears highly achievable based drilling time and field costs associated with the fracture stimulation. Fracture stimulation was completed in early July with flowback operations under way. The wells were pad drilled and zipper-fracked with an average proppant concentration of 1,654 pounds per foot. The wells have been producing hydrocarbons for 11 days, and to date, the 3 wells tested at a per-well average rate of 386 bopd and 322 Mcfgpd, or 460 BOEPD on a processed three-stream basis on a 18/64" choke.
- **Burns Ranch Area-** In northern La Salle County, Lonestar drilled and completed the Burns Ranch Eagle Ford Unit A #1H-3H with an average perforated interval of 8,000 feet. The three new wells, which were pad-drilled and zipper fracked with an average proppant concentration of 1,570 pounds per foot, tested at a per-well average of 594 bopd and 396 Mcfgpd, or 685 BOEPD on a processed three-stream basis on a 23/64" choke. The 3 wells registered average Max-30 production rates of 486 bopd and 405 Mcfgpd, or 580 BOEPD, on a 22/64" choke. Recent rates, achieved in the wells' 85th day of production, were still averaging 518 BOEPD per well.
- **Horned Frog-** In La Salle County, Lonestar has completed the drilling phase of its 2 commitment wells on its recently-acquired La Salle County acreage. The Horned Frog A #1H was drilled to a total depth of 18,725' in 17 days, which included 4 days associated with a pilot hole, which was drilled to obtain advanced rock properties data which the Company will use in fracture stimulation design and geo-targeting. The Company's second well, the Horned Frog B #1H was drilled to a total depth of 18,265' in 11.5 days, versus a pre-drill AFE of 17 days. Casing has been cemented in place on both wells, which are expected to have average perforated lateral lengths of 8,000'. Fracture stimulation is scheduled for early August with production expected by September, 2015. These wells, which are AFE'd at $6.2 million, exclusive of pilot hole costs, are on-track to come in at or under budget. Lonestar continues to pursue additional leasehold opportunities in the vicinity of its Horned Frog leasehold position. Since last report, Lonestar has entered into primary term leases totaling an additional 775 net acres within its Horned Frog acreage position. The Company spent less than $1.0 million on lease bonuses to acquire these additional tracts. Lonestar's current net leasehold stands at 4,402 gross / 3,614 net acres at Horned Frog. Lonestar continues to evaluate a number of additional opportunities to grow its leasehold and reserves position in the vicinity of its Horned Frog acreage.

EAGLE FORD SHALE TREND- CENTRAL REGION

- **Pirate Area-** In southwest Wilson County, no new wells were completed during the quarter. However, Lonestar has permitted the Pirate #M1 and Pirate #N1 wells and has constructed the pads for these locations. Lonestar currently plans to drill these two wells to a measured depth of approximately 16,800 feet. Accordingly, Lonestar plans for these two wells to have 8,000-foot perforated intervals. Lonestar has a 100% working interest and an average 76.4% net revenue interest in these two wells, which are expected to spud in August. The Pirate #N1 well is being drilled on leasehold which Lonestar was able to obtain via a farm-in of 197 gross / 197 net acres which are contiguous to the Company's Pirate leasehold position, a transaction that was completed during the second quarter of 2015 in exchange for an overriding royalty interest.
- **Southern Gonzales County**- In Gonzales County, Lonestar has drilled and completed the Harvey Johnson #4H-6H with an average perforated interval of 5,700 feet. The Harvey Johnson wells were pad-drilled and zipper-fracked with an average proppant concentration of 1,626 pounds per foot and commenced flowback operations mid-June. These wells tested at a per-well average of 691 bopd and 385 Mcfgpd, or 779 BOEPD on a processed three-stream basis on a 22/64" choke. The 3 new wells registered average Max-30 production rates of 536 bopd and 225 Mcfgpd, or 587 BOEPD, on a 21/64" choke. Meanwhile, the Harvey Johnson #1H-3H wells continue to outperform their third-party type curve, in part due to being re-energized by the fracs on our offset wells. Lonestar is actively evaluating additional leasehold opportunities in the area.

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 submitted 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 has commenced a process that may lead the Company 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 second 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 fracked 3 wells (Gerke #1H, #2H, #3H) in La Salle County and turned to production mid 1Q15.
- **2Q15-** The company fracked 3 wells in on the Burns Ranch (93.3% WI) in La Salle County and began flowback in May 2015. Following execution of a second farm-in, Lonestar drilled 3 wells (50% WI) in Southern Gonzales County near its Harvey Johnson wells. Lonestar completed fracture stimulation operations on these 3 wells in June 2015 and began flowback in mid-June 2015.
- **3Q15-** The Company completed 3 short laterals at Beall Ranch (97.7% WI) (#26H, #27H, #28H) and fracture stimulated these wells in July. The wells are currently in flowback. The Company has concluded the drilling and completion of two 8,000' laterals as part of its Horned Frog farm-in in La Salle County. These wells are on the schedule to be fracked in August and are anticipated to commence production in September.
- **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 may drill in conjunction with attractive farm-ins.

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 June 30, 2015	2014	% Change	Six Months Ended June 30, 2015	2014	% Change
Western Eagle Ford Shale							
Crude Oil	(bbls/day)	**2,437**	1,546	58%	**2,168**	1,651	31%
Natural Gas Liquids	(bbls/day)	**566**	319	78%	**520**	344	51%
Natural Gas	(Mcf/day)	**3,913**	2,623	49%	**3,740**	2,681	40%
Oil Equivalent	**(BOE/day)**	**3,655**	**2,301**	**59%**	**3,311**	**2,443**	**36%**
Central Eagle Ford Shale							
Crude Oil	(bbls/day)	**759**	497	53%	**900**	416	117%
Natural Gas Liquids	(bbls/day)	**27**	-	-	**22**	-	-
Natural Gas	(Mcf/day)	**150**	-	-	**126**	0	32938%
Oil Equivalent	**(BOE/day)**	**811**	**497**	**63%**	**943**	**416**	**127%**
Eastern Eagle Ford Shale							
Crude Oil	(bbls/day)	**591**	181	227%	**648**	183	254%
Natural Gas Liquids	(bbls/day)	**34**	12	174%	**37**	11	250%
Natural Gas	(Mcf/day)	**132**	94	40%	**187**	74	152%
Oil Equivalent	**(BOE/day)**	**647**	**209**	**210%**	**716**	**206**	**247%**
Total Eagle Ford Shale							
Crude Oil	(bbls/day)	**3,787**	2,224	70%	**3,716**	2,250	65%
Natural Gas Liquids	(bbls/day)	**627**	331	89%	**580**	355	63%
Natural Gas	(Mcf/day)	**4,195**	2,717	54%	**4,053**	2,755	47%
Oil Equivalent	**(BOE/day)**	**5,113**	**3,008**	**70%**	**4,971**	**3,064**	**62%**
Conventional							
Crude Oil	(bbls/day)	**388**	445	-13%	**394**	474	-17%
Natural Gas Liquids	(bbls/day)	**17**	2	772%	**14**	3	381%
Natural Gas	(Mcf/day)	**1,714**	951	80%	**1,787**	984	82%
Oil Equivalent	**(BOE/day)**	**691**	**605**	**14%**	**705**	**641**	**10%**
Total Company							
Crude Oil	(bbls/day)	**4,175**	2,668	56%	**4,110**	2,725	51%
Natural Gas Liquids	(bbls/day)	**644**	333	93%	**593**	358	66%
Natural Gas	(Mcf/day)	**5,909**	3,668	61%	**5,840**	3,739	56%
Oil Equivalent	**(BOE/day)**	**5,804**	**3,613**	**61%**	**5,676**	**3,706**	**53%**

Lonestar's net production for the second quarter of 2015 averaged 5,804 BOE per day, and was comprised of 4,175 barrels of oil per day, 644 barrels of NGL's per day, and 5,909 Mcf of natural gas per day, 83% of the Company's sales volumes were derived from liquids, with 72% of which coming from crude oil. Net production for the second quarter of 2015 rose 61% over rates reported in the second quarter of 2014, and also represented a 5% sequential increase over reported sales for the first quarter of 2015. Total Company production rates in June and July have exceeded 6,100 BOEPD.

- Lonestar's net production from its Eagle Ford Shale assets averaged 5,113 BOE per day during the second quarter of 2015, and was comprised of 3,787 barrels of oil per day, 627 barrels of NGL's per day, and 4,195 Mcf of natural gas per day. In the second quarter of 2015, 86% of the Company's Eagle Ford production was derived from liquid hydrocarbons, of which 74% was derived from crude oil. Second quarter 2015 Eagle Ford Shale volumes represented an increase of 70% compared to the second quarter of 2014 and a 6% sequential increase over first quarter 2015 volumes .
- Lonestar's net production from its Conventional assets averaged 691 BOE per day during the second quarter of 2015, and was comprised of 388 barrels of oil per day, 17 barrels of NGL's per day, and 1,714 Mcf of natural gas per day. 59% of the Company's Conventional production was from liquid hydrocarbons. Second quarter volumes represented an increase of 14% compared to the second quarter of 2014, despite the fact that Lonestar is not conducting drilling operations on its Conventional assets and is limiting work to workover and well optimizations. Wet weather in north and west Texas impaired crude oil sales during the second quarter of 2015.

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 June 30, 2015	2014	% Change	Six Months Ended June 30, 2015	2014	% Change
Western Eagle Ford Shale							
Crude Oil	($/bbl)	**$56.43**	$99.23	-43%	$51.02	$97.57	-48%
Natural Gas Liquids	($/bbl)	**$14.09**	$28.78	-51%	$14.34	$32.78	-56%
Natural Gas	($/Mcf)	**$2.35**	$4.20	-44%	$2.52	$4.52	-44%
Western Eagle Ford Shale	**($/BOE)**	**$42.32**	**$75.41**	**-44%**	**$38.50**	**$75.55**	**-49%**
Central Eagle Ford Shale							
Crude Oil	($/bbl)	**$56.66**	$99.79	-43%	$49.73	$98.02	-49%
Natural Gas Liquids	($/bbl)	**$20.87**	-	-	$20.53	-	-
Natural Gas	($/Mcf)	**$2.54**	-	-	$2.65	$3.79	-30%
Central Eagle Ford Shale	**($/BOE)**	**$54.20**	**$99.79**	**-46%**	**$48.28**	**$98.01**	**-51%**
Eastern Eagle Ford Shale							
Crude Oil	($/bbl)	**$56.60**	$96.29	-41%	$50.29	$95.33	-47%
Natural Gas Liquids	($/bbl)	**$11.67**	$30.93	-62%	$11.72	$33.13	-65%
Natural Gas	($/Mcf)	**$2.77**	$2.31	19%	$2.18	$2.93	-26%
Eastern Eagle Ford Shale	**($/BOE)**	**$52.86**	**$86.17**	**-39%**	**$46.68**	**$87.47**	**-47%**
Total Eagle Ford Shale							
Crude Oil	($/bbl)	**$56.50**	$99.12	-43%	$50.58	$97.47	-48%
Natural Gas Liquids	($/bbl)	**$14.25**	$28.86	-51%	$14.41	$32.79	-56%
Natural Gas	($/Mcf)	**$2.37**	$4.13	-43%	$2.51	$4.48	-44%
Total Eagle Ford Shale	**($/BOE)**	**$45.54**	**$80.19**	**-43%**	**$41.53**	**$79.40**	**-48%**
Conventional							
Crude Oil	($/bbl)	**$52.89**	$99.13	-47%	$49.66	$92.70	-46%
Natural Gas Liquids	($/bbl)	**$19.79**	$95.76	-79%	$18.79	$67.14	-72%
Natural Gas	($/Mcf)	**$2.61**	$6.91	-62%	$2.84	$6.97	-59%
Conventional	**($/BOE)**	**$36.69**	**$84.01**	**-56%**	**$35.28**	**$79.58**	**-56%**
Total Company Wellhead							
Crude Oil	($/bbl)	**$56.16**	$99.12	-43%	$50.49	$96.64	-48%
Natural Gas Liquids	($/bbl)	**$14.40**	$29.26	-51%	$14.51	$33.06	-56%
Natural Gas	($/Mcf)	**$2.44**	$4.85	-50%	$2.61	$5.14	-49%
Total Company Wellhead	**($/BOE)**	**$44.49**	**$80.83**	**-45%**	**$40.76**	**$79.43**	**-49%**
Total Company Hedging Revenues							
Crude Oil	($/bbl)	**$19.50**	($7.70)	-353%	$24.40	($5.92)	-512%
Hedging Revenues	**($/BOE)**	**$14.03**	**($5.68)**	**-347%**	**$17.67**	**($4.36)**	**-506%**
Total Company Net Oil & Gas Revenues							
Crude Oil	($/bbl)	**$75.66**	$91.42	-17%	$74.90	$90.72	-17%
Natural Gas Liquids	($/bbl)	**$14.40**	$29.26	-51%	$14.51	$33.06	-56%
Natural Gas	($/Mcf)	**$2.44**	$4.85	-50%	$2.61	$5.14	-49%
Net Oil & Gas Revenues	**($/BOE)**	**$58.51**	**$75.14**	**-22%**	**$58.42**	**$75.07**	**-22%**

Lonestar's average wellhead commodity price for 2Q15 was $44.49 per BOE, which was 45% lower than the $80.83 per BOE average price realized in the second quarter of 2014. Principally, reported wellhead realizations declined as a result of a $45.05 per barrel (44%) decline in the benchmark WTI oil price and a $1.88 per Mcf (41%) decline in the benchmark Henry Hub gas price, when compared to 2Q14. Lonestar's post-hedge crude oil price was bolstered by its crude oil hedge positions, which added $14.03 per BOE to its second quarter revenues. Compared to 1Q15, Lonestar posted a 21% sequential improvement in average wellhead commodity prices over 1Q15, driven entirely by increased crude oil prices.

- On its Eagle Ford Shale assets, Lonestar recorded energy equivalent wellhead price realization of $45.54 per BOE during 2Q15, a 43% decrease compared to 2Q14. However, when compared to 1Q15, Lonestar registered a 22% sequential improvement in Eagle Ford realizations.
- On its Conventional assets, Lonestar recorded an average wellhead price realization of $36.69 per BOE during 2Q15, down 56% versus 2Q14. Lower WTI pricing compared to 2Q14 and a shift in product mix from 74% liquids in 2Q14 to 59% liquids in 2Q15 were responsible for the reduction in realizations.

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 June 30, 2015	2014	% Change	Six Months Ended June 30, 2015	2014	% Change
Western Eagle Ford Shale							
Crude Oil	($MM)	**$12.5**	$14.0	-10%	**$20.0**	$29.2	-31%
Natural Gas Liquids	($MM)	**$0.7**	$0.8	-13%	**$1.4**	$2.0	-34%
Natural Gas	($MM)	**$0.8**	$1.0	-16%	**$1.7**	$2.2	-22%
Western Eagle Ford Shale Revenues	**($MM)**	**$14.1**	**$15.8**	**-11%**	**$23.1**	**$33.4**	**-31%**
Central Eagle Ford Shale							
Crude Oil	($MM)	**$3.9**	$4.5	-13%	**$8.1**	$7.4	10%
Natural Gas Liquids	($MM)	**$0.1**	$0.0	-	**$0.1**	$0.0	-
Natural Gas	($MM)	**$0.0**	$0.0	-	**$0.1**	$0.0	22986%
Central Eagle Ford Shale Revenues	**($MM)**	**$4.0**	**$4.5**	**-11%**	**$8.2**	**$7.4**	**12%**
Eastern Eagle Ford Shale							
Crude Oil	($MM)	**$3.0**	$1.6	92%	**$5.9**	$3.2	87%
Natural Gas Liquids	($MM)	**$0.0**	$0.0	3%	**$0.1**	$0.1	24%
Natural Gas	($MM)	**$0.0**	$0.0	67%	**$0.1**	$0.0	87%
Eastern Eagle Ford Shale Revenues	**($MM)**	**$3.1**	**$1.6**	**90%**	**$6.1**	**$3.3**	**85%**
Total Eagle Ford Shale							
Crude Oil	($MM)	**$19.5**	$20.1	-3%	**$34.0**	$39.7	-14%
Natural Gas Liquids	($MM)	**$0.8**	$0.9	-7%	**$1.5**	$2.1	-28%
Natural Gas	($MM)	**$0.9**	$1.0	-11%	**$1.8**	$2.2	-18%
Total Eagle Ford Shale Revenues	**($MM)**	**$21.2**	**$21.9**	**-3%**	**$37.4**	**$44.0**	**-15%**
Conventional							
Crude Oil	($MM)	**$1.9**	$4.0	-53%	**$3.5**	$8.0	-56%
Natural Gas Liquids	($MM)	**$0.0**	$0.0	80%	**$0.0**	$0.0	35%
Natural Gas	($MM)	**$0.4**	$0.6	-32%	**$0.9**	$1.2	-26%
Conventional Revenues	**($MM)**	**$2.3**	**$4.6**	**-50%**	**$4.5**	**$9.2**	**-51%**
Total Company Wellhead							
Crude Oil	($MM)	**$21.3**	$24.1	-11%	**$37.6**	$47.7	-21%
Natural Gas Liquids	($MM)	**$0.8**	$0.9	-5%	**$1.6**	$2.1	-27%
Natural Gas	($MM)	**$1.3**	$1.6	-19%	**$2.8**	$3.5	-21%
Total Company Wellhead Revenues	**($MM)**	**$23.5**	**$26.6**	**-12%**	**$41.9**	**$53.3**	**-21%**
Total Company Hedging Revenues							
Crude Oil	($MM)	**$7.4**	($1.9)	296%	**$18.2**	($2.9)	521%
Hedging Revenues	**($MM)**	**$7.4**	**($1.9)**	**296%**	**$18.2**	**($2.9)**	**521%**
Total Company Net Oil & Gas Revenues							
Crude Oil	($MM)	**$28.7**	$22.2	29%	**$55.7**	$44.7	25%
Natural Gas Liquids	($MM)	**$0.8**	$0.9	-5%	**$1.6**	$2.1	-27%
Natural Gas	($MM)	**$1.3**	$1.6	-19%	**$2.8**	$3.5	-21%
Net Oil & Gas Revenues	**($MM)**	**$30.9**	**$24.7**	**25%**	**$60.0**	**$50.4**	**19%**

Lonestar's net oil and gas revenues for 2Q15 increased 25% to $30.9 million, versus $24.7 million a year ago, while oil and gas revenues climbed 6% sequentially over 1Q15 results. Lonestar's ability to increase revenues was driven primary by a 61% increase in oil and gas production, year-over-year, partially offset by a 45% decline in realized wellhead prices. The decline in prices was mitigated by Lonestar's favorable hedge position, which added $7.4 million to revenues in the second quarter of 2015.

- Lonestar's net wellhead oil and gas revenues from its Eagle Ford Shale assets fell a modest 3% to $21.2 million for the second quarter of 2015 versus $21.9 million a year ago. 2Q15 revenues were bolstered by a 70% increase in production, which was offset by a 43% 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, Lonestar generated a 31% increase in wellhead net oil and gas revenues over 1Q15 results, as BOE price realizations rose 22% and production increased by 6%.
- Lonestar's net wellhead oil and gas revenues from its Conventional assets totaled $2.3 million during the second quarter of 2015, a 50% decrease over the second quarter of 2014. The decrease in revenue was driven by a 56% decrease in wellhead price realizations per BOE partially offset by a 14% increase in production. Crude oil contributed 81% of revenues while natural gas liquids contributed 1% of revenues and natural gas contributed 18% of revenues.

Management's Discussion and Analysis

Field Operating Expenses

		Three months ended June 30, 2015	2014	% Change	Six Months Ended June 30, 2015	2014	% Change
Western Eagle Ford Shale							
Lease Operating Expense	($/BOE)	**$8.32**	$10.41	-20%	**$7.91**	$9.12	-13%
Production Taxes	($/BOE)	**$2.59**	$4.68	-45%	**$2.50**	$4.54	-45%
Western Eagle Ford Shale	**($/BOE)**	**$10.92**	**$15.08**	**-28%**	**$10.41**	**$13.66**	**-24%**
Central Eagle Ford Shale							
Lease Operating Expense	($/BOE)	**$10.50**	$12.10	-13%	**$7.90**	$11.18	-29%
Production Taxes	($/BOE)	**$3.95**	$6.45	-39%	**$3.74**	$5.88	-36%
Central Eagle Ford Shale	**($/BOE)**	**$14.45**	**$18.55**	**-22%**	**$11.64**	**$17.05**	**-32%**
Eastern Eagle Ford Shale							
Lease Operating Expense	($/BOE)	**$7.78**	$6.40	22%	**$6.31**	$6.36	-1%
Production Taxes	($/BOE)	**$3.34**	$7.89	-58%	**$2.98**	$6.06	-51%
Eastern Eagle Ford Shale	**($/BOE)**	**$11.11**	**$14.29**	**-22%**	**$9.29**	**$12.42**	**-25%**
Total Eagle Ford Shale							
Lease Operating Expense	($/BOE)	**$8.60**	$10.41	-17%	**$7.68**	$9.21	-17%
Production Taxes	($/BOE)	**$2.90**	$5.19	-44%	**$2.80**	$4.82	-42%
Total Eagle Ford Shale	**($/BOE)**	**$11.50**	**$15.60**	**-26%**	**$10.48**	**$14.04**	**-25%**
Conventional							
Lease Operating Expense	($/BOE)	**$15.62**	$22.16	-30%	**$14.50**	$19.44	-25%
Production Taxes	($/BOE)	**$2.05**	$7.91	-74%	**$2.43**	$5.71	-57%
Conventional	**($/BOE)**	**$17.67**	**$30.07**	**-41%**	**$16.93**	**$25.15**	**-33%**
Total Company							
Lease Operating Expense	($/BOE)	**$9.43**	$12.38	-24%	**$8.53**	$10.98	-22%
Production Taxes	($/BOE)	**$2.80**	$5.65	-50%	**$2.75**	$4.98	-45%
Total Company	**($/BOE)**	**$12.24**	**$18.02**	**-32%**	**$11.28**	**$15.96**	**-29%**

Lonestar's field operating expenses for the second quarter of 2015 were $6.5 million, an increase of 9% over 2Q14 field operating expenses of $5.9 million. More importantly, however, the Company reduced total field operating expenses by 32% on a unit of production basis from 2Q14 to $12.24 per BOE. Lease Operating Expense ("LOE") was $5.0 million for 2Q15, rising 22% over 2Q14 levels on an absolute dollar basis, but decreasing 24% on a BOE basis to $9.43 per BOE. Lonestar's field operating expenses were inflated during the second quarter of 2015 by the start-up of several gas sweetening facilities on our Eagle Ford properties. Production taxes were $1.5 million for the second quarter of 2015, a 20% decrease over comparable levels in 2014, and a 50% decrease to $2.80 on a unit of production basis.

- Lonestar's field operating expenses from its Eagle Ford Shale assets totaled $5.4 million during the second quarter of 2015, a 25% increase over the second quarter of 2014. However, on a unit of production basis, field operating expenses decreased 26% to $11.50 per BOE, year-over-year. Direct lease operating expenses totaled $4.0 million in 2Q15, or $8.60 per BOE, a reduction of 18% on a per unit basis. Production taxes were $1.4 million, or $2.90 per BOE, compared to $1.4 million, or $5.19 per BOE in the year-ago quarter.
- Lonestar's field operating expenses from its Conventional assets totaled $1.1 million during the second quarter of 2015, a 33% decrease versus the second quarter of 2014. On a unit of production basis, field operating expenses decreased 30% to $15.62 per BOE. Lonestar was able to achieve substantial reductions in Lease Operating Expense, both on an absolute-dollar and per-unit basis. In total, LOE was $1.0 million, or $15.62 per BOE, compared to $1.2 million, or $22.16 per BOE in 2Q14. Production taxes were $0.1 million, or $2.05 per BOE, compared to $0.4 million, or 7.91 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 June 30, 2015	Three months ended June 30, 2014	% Change	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014	% Change
Western Eagle Ford Shale							
Production Revenue	($/BOE)	$42.32	$75.41	-44%	$38.50	$75.55	-49%
Lease Operating Expenses	($/BOE)	$8.32	$10.41	-20%	$7.91	$9.12	-13%
Production Taxes	($/BOE)	$2.59	$4.68	-45%	$2.50	$4.54	-45%
Field Netback	**($/BOE)**	**$31.41**	**$60.33**	**-48%**	**$28.09**	**$61.89**	**-55%**
Field Netback	**($MM)**	**$10.4**	**$12.6**	**-17%**	**$16.8**	**$27.4**	**-38%**
Central Eagle Ford Shale							
Production Revenue	($/BOE)	$54.20	$99.79	-46%	$48.28	$98.01	-51%
Lease Operating Expenses	($/BOE)	$10.50	$12.10	-13%	$7.90	$11.18	-29%
Production Taxes	($/BOE)	$3.95	$6.45	-39%	$3.74	$5.88	-36%
Field Netback	**($/BOE)**	**$39.75**	**$81.24**	**-51%**	**$36.64**	**$80.96**	**-55%**
Field Netback	**($MM)**	**$2.9**	**$3.7**	**-20%**	**$6.3**	**$6.1**	**3%**
Eastern Eagle Ford Shale							
Production Revenue	($/BOE)	$52.86	$86.17	-39%	$46.68	$87.47	-47%
Lease Operating Expenses	($/BOE)	$7.78	$6.40	22%	$6.31	$6.36	-1%
Production Taxes	($/BOE)	$3.34	$7.89	-58%	$2.98	$6.06	-51%
Field Netback	**($/BOE)**	**$41.74**	**$71.89**	**-42%**	**$37.39**	**$75.05**	**-50%**
Field Netback	**($MM)**	**$2.5**	**$1.4**	**80%**	**$4.8**	**$2.8**	**73%**
Total Eagle Ford Shale							
Production Revenue	($/BOE)	$45.54	$80.19	-43%	$41.53	$79.40	-48%
Lease Operating Expenses	($/BOE)	$8.60	$10.41	-17%	$7.68	$9.21	-17%
Production Taxes	($/BOE)	$2.90	$5.19	-44%	$2.80	$4.82	-42%
Field Netback	**($/BOE)**	**$34.04**	**$64.59**	**-47%**	**$31.05**	**$65.36**	**-52%**
Field Netback	**($MM)**	**$15.8**	**$17.7**	**-10%**	**$27.9**	**$36.3**	**-23%**
Conventional							
Production Revenue	($/BOE)	$36.69	$84.01	-56%	$35.28	$79.58	-56%
Lease Operating Expenses	($/BOE)	$15.62	$22.16	-30%	$14.50	$19.44	-25%
Production Taxes	($/BOE)	$2.05	$7.91	-74%	$2.43	$5.71	-57%
Field Netback	**($/BOE)**	**$19.02**	**$53.93**	**-65%**	**$18.35**	**$54.43**	**-66%**
Field Netback	**($MM)**	**$1.2**	**$3.0**	**-60%**	**$2.3**	**$6.3**	**-63%**
Total Company							
Production Revenue	($/BOE)	$44.49	$80.83	-45%	$40.76	$79.43	-49%
Lease Operating Expenses	($/BOE)	$9.43	$12.38	-24%	$8.53	$10.98	-22%
Production Taxes	($/BOE)	$2.80	$5.65	-50%	$2.75	$4.98	-45%
Field Netback	**($/BOE)**	**$32.25**	**$62.80**	**-49%**	**$29.47**	**$63.47**	**-54%**
Field Netback	**($MM)**	**$17.0**	**$20.6**	**-18%**	**$30.3**	**$42.6**	**-29%**

Lonestar's field netback rose sequentially 29% to $17.0 million and increased sequentially 22% to $32.25 per BOE in 2Q15. Year-over-year, Lonestar's field netback for the second quarter of 2015 was $17.0 million, a decrease of 18% over the field netback of $20.6 million in 2Q14. On a per BOE basis, field netbacks declined 49% to $32.25 in the second quarter of 2015 vs. $62.80 in the second quarter of 2014. The decrease in the per BOE field netback is associated primarily with a 44% decrease in WTI pricing and a 41% decrease in Henry Hub pricing compared to 2Q14, and in spite of significant reductions in the Company's unit operating costs.

- Lonestar's Eagle Ford Shale field netback rose sequentially 30% to $15.8 million and increased sequentially 18% to $34.04 per BOE in 2Q15. Year-over-year, Lonestar's Eagle Ford Shale field netback represented a 10% decrease in the field netback compared to the $17.7 million reported in the second quarter of 2014. On a BOE basis, field netbacks declined 47% to $34.04 in second quarter of 2015 vs. $64.59 in 2Q14, largely influenced by a 44% reduction in WTI and a 41% reduction in Henry Hub.
- Lonestar's Conventional field netback rose sequentially 9% to $1.2 million and increased sequentially 7% to $19.02 per BOE in 2Q15. Year-over-year, Lonestar's field netback from its Conventional assets represented a 60% decrease in field netbacks compared to the $3.0 million reported in the second quarter of 2014. On a BOE basis, field netbacks declined 65% largely due to a 44% reduction in crude oil prices and a 41% reduction in Henry Hub.

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

Management's Discussion and Analysis

Depreciation and Depletion

		Three months ended June 30, 2015	2014	% Change	Six Months Ended June 30, 2015	2014	% Change
Total Expense	($MM)	$13.3	$9.7	38%	$26.1	$17.5	49%
Depreciation & Depletion	($/BOE)	$25.20	$29.42	-14%	$25.45	$26.15	-3%

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 second quarter of 2015 was $13.3 million, or $25.20 per BOE compared to $9.7 million, or $29.42 per BOE reported in the second quarter of 2014. This increase in D,D&A in absolute terms is due to a 38% increase in production compared to 2Q14 levels, while the 14% decrease in unit terms is a function of improved well costs.

General and Administrative Expenses

		Three months ended June 30, 2015	2014	% Change	Six Months Ended June 30, 2015	2014	% Change
Total Expense	($MM)	$2.4	$2.1	13%	$4.6	$3.9	20%
General & Administrative	($/BOE)	$4.46	$6.32	-29%	$4.52	$5.76	-22%

Lonestar reported General & Administrative expenses of $2.4 million for the second quarter of 2015, a 13% increase over the $2.1 million of General & Administrative expenses reported in the second quarter of 2014. However on a sequential basis, second quarter 2015 General & Administrative expenses are only up 3% in absolute dollar terms when compared to the first quarter of 2015. On a BOE basis, the Company achieved a 29% decrease in G&A per BOE to $4.46, compared to $6.32 per BOE reported in the second quarter of 2014.

Finance Expenses

		Three months ended June 30, 2015	2014	% Change	Six Months Ended June 30, 2015	2014	% Change
Interest Expense	($MM)	$5.4	$6.1	-11%	$10.8	$7.5	44%
Amortization of Finance Costs	($MM)	$0.5	$1.2	-56%	$1.0	$1.4	-25%
Total Finance Costs	**($MM)**	**$6.0**	**$7.3**	**-19%**	**$11.8**	**$8.9**	**33%**
Finance Costs	($/BOE)	$11.31	$22.33	**-49%**	$11.50	$13.26	**-13%**

Lonestar reported Finance expenses of $6.0 million for the second quarter of 2015, a 19% decrease over the $7.3 million of Finance expenses reported in the second quarter of 2014. On a BOE basis, the Company reported Finance expenses of $11.31, a 49% decrease compared to $22.33 per BOE reported in the second 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 $77.8 million during the quarter with interest expense averaging 2.73% 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 June 30,			Six Months Ended June 30,		
		2015	2014	% Change	2015	2014	% Change
Crude Oil	($MM)	**$7.4**	($1.9)	296%	**$18.2**	($2.9)	521%
Natural Gas Liquids	($MM)	**$0.0**	$0.0	-	**$0.0**	$0.0	-
Natural Gas	($MM)	**$0.0**	$0.0	-	**$0.0**	$0.0	-
Hedging Revenues (Expenses)	**($MM)**	**$7.4**	**($1.9)**	**296%**	**$18.2**	**($2.9)**	**521%**
Hedging Revenues (Expenses)	($/BOE)	**$14.03**	($5.68)		**$17.67**	($4.36)	

- Lonestar realized crude oil hedge revenues of $7.4 million in the second quarter of 2015 vs. a crude oil hedge expense of $1.9 million reported in the second quarter of 2014. As of June 30, 2015 the Mark to Market value of Lonestar's remaining hedge contracts totaled $22.6 million.

Derivative Commodity Contracts

Commodity	Quantity	Term			Reference	Strike	Put	Call	Option Traded
Crude Oil	117,500	Jul 1, 2015	-	Dec 31, 2015	WTI	$87.00	-	-	Swap
Crude Oil	128,800	Jul 1, 2015	-	Dec 31, 2015	WTI	$81.25	-	-	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	73,600	Jul 1, 2015	-	Dec 31, 2015	WTI	$59.52	-	-	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	$85.00	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 2,593 barrels of oil per day for the remainder of 2015 at an average strike price of $82.58 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

LONESTAR RESOURCES

UNAUDITED INTERIM FINANCIAL REPORT

For the three months ended June 30, 2015

Consolidated statements of comprehensive income

For the three months ended June 30, 2015 and 2014

(US $MM)	*As Reported* Three months ended June 30, 2015	*As Reported* Three months ended June 30, 2014	*As Reported* Six Months Ended June 30, 2015	*As Reported* Six Months Ended June 30, 2014
Revenues (Net of Royalties)				
Crude Oil	21.3	24.1	37.6	47.7
Natural Gas Liquids	0.8	0.9	1.6	2.1
Natural Gas	1.4	1.6	2.8	3.5
Revenues (Net of Royalties)	**23.5**	**26.6**	**41.9**	**53.3**
Hedge Revenues (Expenses)	7.4	(1.9)	18.1	(2.9)
Net Revenue From Ordinary Activities	**30.9**	**24.7**	**60.0**	**50.4**
Operating Expenses				
Lease Operating Expenses	(5.0)	(4.1)	(8.8)	(7.4)
Severance Taxes	(1.0)	(1.3)	(1.9)	(2.5)
Ad Valorem Taxes	(0.4)	(0.6)	(1.0)	(0.9)
Depreciation, Depletion & Amortization	(13.3)	(9.7)	(26.1)	(17.5)
General & Administrative	(2.4)	(2.1)	(4.6)	(3.9)
Total Operating Expenses	**(22.1)**	**(17.7)**	**(42.4)**	**(32.1)**
Gross Profit from Operating Activities	**8.8**	**7.0**	**17.6**	**18.2**
Other Income (Expense)	0.0	0.5	(0.6)	0.5
Impairment of O&G properties	0.0	0.0	0.0	0.0
Stock based compensation	(0.4)	(0.9)	(0.9)	(1.3)
Non-recurring expenses	(0.1)	(0.6)	(0.1)	(1.1)
Interest & Other Finance Expenses	(6.0)	(7.3)	(11.8)	(8.9)
Fair Value Gain (Loss) on derivatives	(14.9)	(6.1)	(18.6)	(8.3)
Profit (Loss) before taxes	**(12.6)**	**(7.5)**	**(14.4)**	**(0.9)**
Income tax (expense) benefit	4.2	0.5	5.3	(1.0)
Net Income (Loss)	**(8.4)**	**(7.0)**	**(9.1)**	**(1.9)**
EBITDAX	**22.1**	**16.7**	**43.8**	**35.8**

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

Consolidated statements of financial position
As of June 30, 2015

(US $MM)	June 30, 2015	*As Reported* As of March 31, 2015	December 31, 2014
Assets			
Current Assets			
Cash and cash equivalents	4.4	3.6	10.0
Trade and other receivables	16.1	10.9	17.5
Derivative financial instruments	20.1	30.7	31.0
Other assets	1.2	1.0	0.7
Total current assets	**41.8**	**46.3**	**59.3**
Non-current assets			
Oil and Gas Properties & Equipment	515.2	496.4	479.5
Deferred tax assets	0.4	0.3	0.1
Derivative financial instruments	6.2	10.9	12.7
Other non-current assets	3.4	3.8	3.7
Total non-current assets	**525.2**	**511.4**	**496.1**
Total Assets	**567.0**	**557.7**	**555.3**
Liabilities			
Current liabilities			
Trade and other payables	32.6	28.5	35.7
Revenue payable	5.2	4.9	5.0
Accrued expenses	1.4	0.8	2.4
Derivative financial instruments	0.6	0.0	-
Total current liabilities	**39.8**	**34.1**	**43.0**
Non-current liabilities			
Long-term Debt	292.1	276.9	264.6
Deferred tax liablilities	26.5	30.7	26.0
Other non-current liabilities	9.1	8.5	7.8
Total non-current liabilities	**327.7**	**316.1**	**298.5**
Total Liabilities	**367.5**	**350.3**	**341.5**
Net assets	**199.4**	**207.4**	**213.8**
Equity			
Contributed equity	142.6	142.6	142.6
Reserves	7.8	7.4	6.9
Retained Earnings	49.1	57.4	64.3
Total Equity	**199.5**	**207.4**	**213.8**

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

Consolidated statements of cash flows
For the six months ended June 30, 2015 and 2014

(US $MM)	*As Reported* Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income (loss)	(9.1)	(1.9)
Adjustments to reconcile profit/(loss) to net cash provided by operating activities:		
(Gain) / Loss on sale of oil and gas properties	-	(0.5)
Depreciation, depletion, amortisation	26.0	17.4
Increase in retirement provision	0.1	0.1
Deferred taxes	(5.4)	1.2
Share based payments	0.9	1.3
Loss (Gain) on sale of equipment	0.6	-
Non-cash interest expense	0.6	0.3
Changes in operating assets and liabilities:	-	-
Accounts receivable	1.4	(10.3)
Other assets	(0.2)	(2.7)
Accounts payable and provisions	(8.2)	18.3
Net cash inflow from operating activities	6.7	23.3
CASH FLOWS FROM INVESTING ACTIVITIES		
Payments for oil and gas property, plant & equipment	(54.7)	(63.2)
Acquisition of oil and gas properties	(3.5)	(71.0)
Net (increase) decrease in derivatives	18.9	9.1
Proceeds from sales of oil and gas properties	-	3.2
Net cash (outflow) from investing activities	(39.3)	(122.0)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net change in borrowings	27.0	(109.0)
Proceeds from issuance of long term bonds	-	214.5
Net cash inflow from financing activities	27.0	105.5
Net increase / (Decrease) in cash held	(5.6)	6.8
Cash and cash equivalents at the beginning of the financial period	10.0	6.7
Cash and cash equivalents at the end of the financial period	4.4	13.5

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 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.

Oil and Gas Properties & Equipment
As is our practice, an evaluation of our assets is in progress in conjunction with a review of our accounts by our independent auditors for the preparation of the Half Year financial statements and Appendix 4D to be filed with the Australian Stock Exchange by August 31, 2015.

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 second-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."