Quarterly Report

September 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 September 30, 2015 (3Q15).

Third Quarter Highlights

- Lonestar Resources set a new production record, reporting a 42% increase in net oil and gas production to 6,614 BOEPD in 3Q15, vs. 4,669 BOEPD in 3Q14. Lonestar's 3Q15 sales volumes also represented a 14% sequential increase over 2Q15 production levels. In the third quarter, 83% of the Company's production was crude oil and NGL's.
- The Company's Eagle Ford Shale properties registered a 51% increase in net oil and gas production over 3Q14 results, to 5,969 BOEPD, which was 17% sequential growth.
- EBITDAX was $21.7 million for 3Q15 vs. $23.4 million for 3Q14, as increased production volumes and incremental revenues from crude oil hedges largely offset a 52% decrease in West Texas Intermediate oil prices. EBITDAX dropped just 2% against 2Q15 results as production growth largely offset a $12 per barrel drop in WTI. EBITDAX further benefited from the Company's ability to reduce LOE per BOE 18% sequentially.
- Lonestar reported Net Income of $7.4 million for 3Q15 vs. a Net Income of $19.1 million in 3Q14. Excluding a $10.7 million unrealized gain on commodity derivative and the associated non-cash expense, Lonestar would have reported Net Income of $0.5 million for 3Q15, equating to $0.04 per share.
- At September 30, 2015, $79 million was outstanding on the facility, leaving $101 million undrawn and available. The lead agent of its Senior Secured lender group has recommended that the borrowing base be reaffirmed at $180 million. Lonestar expects official confirmation within the next two weeks.
- Lonestar continues to build production momentum, with the Company's volumes exceeding 7,500 BOEPD in October, setting the stage for another production record in the fourth quarter of 2015.
- With the third quarter under its belt, Lonestar updates its previous 2015 guidance. Production from its Eagle Ford Shale properties is outperforming expectations. Based on a 2015 WTI price range of $50 to $60 per barrel and the expectation for the Company to drill 15 gross wells in 2015, Lonestar has increased the low end of its guidance and now forecasts production will average between 6,100 and 6,300 BOEPD, yielding EBITDAX guidance of $84 to $90 million for 2015.[1]

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

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Management's Discussion and Analysis

Lonestar Resources, Ltd. is pleased to announce its operational and unaudited financial results for the quarter ended September 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. While optimizing cash flows from its Conventional assets, Lonestar is focusing its attention and capital to continuing its growth strategy in the Eagle Ford Shale. Lonestar currently operates 100% of its 35,487 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 through 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.

THIRD 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 during 2015, Lonestar has sought to use the softening price environment to cost effectively expand its Eagle Ford leasehold and resource position in areas where it has demonstrated excellence with the drillbit. In an effort to conserve its liquidity to pursue larger scale transactions in late 2015 and early 2016, Lonestar has limited its acquisition activity to farm-ins and smaller scale primary term lease acquisitions. During the third quarter of 2015, Lonestar leased or reached agreement to lease an additional 1,127 net acres. These acquisitions add an additional 16 drilling locations in the Company's Horned Frog and South Gonzales focus areas. Including these transactions, Lonestar's Eagle Ford Shale leasehold position has increased from 30,306 net acres at yearend 2014 to 35,487 net acres presently.
- On July 28, 2015, Lonestar closed a new $500 million Senior Secured Revolving Credit Facility led by Citibank, N.A.. The initial borrowing base was set at $180 million, a 20% increase over its prior level of $150 million. At September 30, 2015, $79 million was outstanding on the facility, leaving $101 million undrawn and available. The lead agent of its Senior Secured lender group has recommended that the borrowing base be reaffirmed at $180 million. Lonestar expects official confirmation within the next two weeks.

Operational

- Lonestar set another production record in the third quarter of 2015, registering sequential production growth of 14% over 2Q15 levels. The Company's net production for the third quarter of 2015 also represented a 42% increase over 3Q14 levels, rising to 6,614 BOEPD. Lonestar's Eagle Ford Shale drilling program continues to be the driver for the Company's record-setting production. Third quarter 2015 volumes were comprised of 4,631 barrels of oil per day, 840 barrels of NGL's per day, and 6,863 Mcf of natural gas per day. Third quarter 2015 production was comprised of 83% crude oil and natural gas liquids, and 17% natural gas.
- During the third quarter of 2015, Lonestar achieved considerable improvement in its lease operating expenses. Total Company lease operating expenses were $4.8 million, marginally above results one year ago, but down 4% sequentially from second quarter 2015 results. Continued production growth and cost containment combined to reduce Lonestar's lease operating expense on a unit basis by 17% from $9.43 per BOE in 2Q15 to $7.83 per BOE in the most recent quarter. Lonestar believes that continued production growth and cost reduction efforts should further reduce LOE per BOE in the fourth quarter of 2015.
- In the third quarter of 2015, Lonestar generated EBITDAX of $21.7 million, a 7% decrease from the 3Q14 EBITDAX of $23.4 million. A 42% increase in oil and gas production and a strong hedge position largely offset a 53% decrease in wellhead price realizations. Strong production growth and reductions in lease operating costs allowed EBITDAX to remain essentially flat versus 2Q15 results, despite a 20% decrease in WTI benchmark pricing, quarter to quarter.
- 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 2,551 barrels of oil per day for the remainder of 2015 at an average strike price of $82.23 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 which provide an effective floor of $55.25 per barrel with WTI prices between $40.00 per barrel and $60.00 per barrel but also gives upside to $80.25 per barrel.

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 the remainder of 2015 or 2016.
- **Beall Ranch-** In Dimmit County, Lonestar drilled and completed the Beall Ranch #26H-#28H during the third quarter of 2015. 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 feet. Lonestar achieved completed well costs of $3.3 million versus our pre-drill AFE of $3.7 million. While Lonestar has been developing Beall Ranch for over four years now, the Company continues to strive for improved results. Based on advanced log analysis, the #26H-28H wells were drilled in a narrower, refined target zone within the Eagle Ford Shale, and were fracked with markedly tighter stage spacing, achieving an average proppant concentration of 1,654 pounds per foot. The 3 new wells registered average Max-30 production rates of 329 bopd and 389 Mcfgpd, or a 3-stream rate of 419 BOEPD, on a 18/64" choke. Recent rates, achieved in the wells' 105th day of production were still averaging 365 BOEPD per well. To date, Lonestar's refinements to its targeting and stimulation designs appear to be achieving material improvements in recovery rates, with the #26H-28H producing 43% more oil per perforated foot than the #32-#34H, which are immediate offsets, and were completed in 2014.
- **Burns Ranch Area-** In northern La Salle County, Lonestar drilled and completed the Burns Ranch Eagle Ford Unit A #1H-3H wells with an average perforated interval of 7,970 feet. The three new wells, which were pad-drilled and zipper fracked with an average proppant concentration of 1,570 pounds per foot, 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' 180th day of production, were still averaging 390 BOEPD per well without artificial lift. Lonestar is extremely pleased with the results of its initial long laterals on the Burns Ranch and currently plans to drill additional wells on this property in 2016 which are currently categorized as Probable Undeveloped.
- **Horned Frog-** In La Salle County, Lonestar drilled and completed the Horned Frog A #1H & B #1H with an average perforated interval of 8,233 feet. The two new wells were fracked with an average proppant concentration of 1,556 pounds per foot. The Horned Frog A #1H tested 275 bopd and 5,527 Mcfgpd, or 1,542 BOEPD on a processed three-stream basis on a 20/64" choke and registered a 30-day production rate of 1,438 BOEPD. The Horned Frog B #1H tested 286 bopd and 5,311 Mcfgpd, or 1,658 BOEPD on a processed three-stream basis on a 20/64" choke and registered a 30-day production rate of 1,315 BOEPD. Lonestar continues to expand its leasehold position in the Horned Frog area. Since last report, Lonestar leased an additional 465 net acres, spending less than $0.5 million on lease bonuses to acquire these interests. Lonestar's current net leasehold stands at 4,402 gross / 4,063 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. Lonestar is currently drilling the Horned Frog D #1H & E #1H utilizing the IOG Capital Joint Venture in order to secure the aforementioned additional acreage. The Horned Frog D#1H & E #1H have been drilled and cased to an average total measured depth of 19,400 feet equating to an average perforated interval of 9,100 feet. Fracture stimulation is scheduled for mid-November with flowback expected to commence in early December. Lonestar is paying 10% of the well costs and will have an initial 15.0% working interest in these wells. Upon achievement of a specified IRR, Lonestar's working interest would increase to 57.5%.

EAGLE FORD SHALE TREND- CENTRAL REGION

- **Pirate Area-** In southwest Wilson County, Lonestar has drilled the Pirate #M1H and Pirate #N1H wells and cased them to an average measured depth of approximately 16,100 feet. Lonestar has a 100% working interest and an average 76.4% net revenue interest in these two wells. 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. These wells are awaiting fracture stimulation at a date which has yet to be determined.
- **Southern Gonzales County**- In Gonzales County, Lonestar's Harvey Johnson #1H-#6H continue to perform extremely well, with production from the six wells averaging 2,201 gross / 826 net BOEPD in the third quarter of 2015. Lonestar recently reached agreement to lease a total of 662 net acres which will accommodate 10 gross laterals with average lateral lengths of 7,200 feet. Lonestar is actively evaluating additional leasehold opportunities in the area.

EAGLE FORD SHALE TREND- EASTERN REGION

- **Brazos & Robertson Counties** - In Brazos Central County, Lonestar has permitted two 8,000-foot laterals. These wells are currently scheduled to be drilled on its Wildcat project in December, 2015. Lonestar has assembled a lease position while allowing other operators to drill and produce wells in the area, which reduces risk. The Company is encouraged by the results of offset drilling by a leading operator, who recently announced impressive production rates on four wells immediately offsetting Lonestar's leasehold. It has been reported that the 5,527' Rae #3H registered 30-day rates of 1,587 BOEPD while the 5,494' Rae #4H produced 1,520 BOEPD. The nearest of these wells are approximately 3,000 feet east of Lonestar's drilling locations. Additionally, it has been reported that the 6,841' Walker Family #1H registered 30-day rates of 1,897 BOEPD while the 6,841' Walker Family #3H produced 1,973 BOEPD. The nearest of these wells are 3,300 feet northeast of Lonestar's drilling locations.

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 October 2015, Lonestar received approval of the Stone Turtle Indian Exploratory unit by the Bureau of Land Management (BLM) and Bureau of Indian Affairs (BIA), which it has downsized to cover 44,084 gross / 28,655 net acres, with additional leasehold around the Unit's periphery. The unit establishes a 5-year primary term on all leasehold in the unit, in exchange for drilling activity. The long-awaited unit approval opens the door for development of the block either by Lonestar or a farm-in partner.

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, 2 of which it expects to complete in late 2015 that should see first production in 2016, as well as 3 wells which were drilled and completed in 2014 and turned to production in early 2015.

- 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 began production in July 2015. The Company completed two 8,000' laterals at Horned Frog (100% WI) (A#1H & B#1H) in La Salle County, which were fracked in August and commenced flowback in September.
- 4Q15- The Company has drilled the Pirate M#1H and N#1H in Wilson County. With production rates running ahead of budget and the Company keenly focused on matching capital spending and cash flow, Lonestar has deferred the fracture stimulation of the Pirate wells. Lonestar is currently drilling two wells on its Horned Frog acreage (15% WI) (D#1H & E#1H). The company also currently plans to spud 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.

While its 2016 budget will be confirmed at the Company's December 2015 meeting of its Board of Directors, Lonestar's preliminary plans would be to complete 14 to 16 Eagle Ford Shale wells at a budget of $70 to $80 million.

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	2	-	2	10	-	10
Western Eagle Ford	**3**	-	**3**	**3**	-	**3**	**5**	-	**5**	**2**	-	**2**	**13**	-	**13**
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**	**4**	-	**6**	**18**	-	**20**

Management's Discussion and Analysis

Net Production (after royalties)

		Three months ended September 30, 2015	2014	% Change	Nine Months Ended September 30, 2015	2014	% Change
Western Eagle Ford Shale							
Crude Oil	(bbls/day)	**2,735**	2,010	36%	**2,359**	1,779	33%
Natural Gas Liquids	(bbls/day)	**738**	457	61%	**594**	384	55%
Natural Gas	(Mcf/day)	**4,799**	3,588	34%	**4,097**	2,998	37%
Oil Equivalent	**(BOE/day)**	**4,273**	**3,066**	**39%**	**3,636**	**2,662**	**37%**
Central Eagle Ford Shale							
Crude Oil	(bbls/day)	**1,117**	705	58%	**973**	515	89%
Natural Gas Liquids	(bbls/day)	**50**	1	6293%	**32**	0	11854%
Natural Gas	(Mcf/day)	**184**	3	5331%	**146**	1	10314%
Oil Equivalent	**(BOE/day)**	**1,198**	**706**	**70%**	**1,029**	**515**	**100%**
Eastern Eagle Ford Shale							
Crude Oil	(bbls/day)	**423**	167	153%	**572**	179	221%
Natural Gas Liquids	(bbls/day)	**38**	12	203%	**37**	11	232%
Natural Gas	(Mcf/day)	**225**	81	179%	**200**	77	160%
Oil Equivalent	**(BOE/day)**	**498**	**193**	**158%**	**643**	**203**	**217%**
Total Eagle Ford Shale							
Crude Oil	(bbls/day)	**4,275**	2,883	48%	**3,904**	2,472	58%
Natural Gas Liquids	(bbls/day)	**826**	470	76%	**663**	395	68%
Natural Gas	(Mcf/day)	**5,208**	3,673	42%	**4,442**	3,076	44%
Oil Equivalent	**(BOE/day)**	**5,969**	**3,965**	**51%**	**5,307**	**3,380**	**57%**
Conventional							
Crude Oil	(bbls/day)	**356**	405	-12%	**381**	453	-16%
Natural Gas Liquids	(bbls/day)	**14**	19	-26%	**14**	8	67%
Natural Gas	(Mcf/day)	**1,655**	1,678	-1%	**1,743**	1,222	43%
Oil Equivalent	**(BOE/day)**	**645**	**704**	**-8%**	**685**	**665**	**3%**
Total Company							
Crude Oil	(bbls/day)	**4,631**	3,288	41%	**4,285**	2,925	46%
Natural Gas Liquids	(bbls/day)	**840**	489	72%	**676**	404	68%
Natural Gas	(Mcf/day)	**6,863**	5,350	28%	**6,185**	4,298	44%
Oil Equivalent	**(BOE/day)**	**6,614**	**4,669**	**42%**	**5,992**	**4,045**	**48%**

Lonestar established a new company production record in the third quarter of 2015, with volumes averaging 6,614 BOE per day (BOEPD), representing a 42% increase over year-ago results and a 14% increase sequentially over 2Q15 results. Third quarter 2015 volumes were comprised of 4,631 barrels of oil per day, 840 barrels of NGL's per day, and 6,863 Mcf of natural gas per day, with 83% of the Company's sales volumes derived from liquids, and 70% of total volumes coming from crude oil. Lonestar's drilling program, which has generated excellent results across its portfolio, is responsible for the Company's continued growth in production.

- Third quarter 2015 Eagle Ford Shale volumes represented an increase of 51% compared to the third quarter of 2014 and a 17% sequential increase over second quarter 2015 volumes. Lonestar's net production from its Eagle Ford Shale assets averaged a record 5,969 BOEPD during the third quarter of 2015, and was comprised of 4,275 barrels of oil per day, 826 barrels of NGL's per day, and 5,208 Mcf of natural gas per day. For the quarter, 85% of the Company's Eagle Ford production was derived from liquid hydrocarbons, 72% of which was derived from crude oil.
- Lonestar's net production from its Conventional assets averaged 645 BOEPD during the third quarter of 2015, and was comprised of 356 barrels of oil per day, 14 barrels of NGL's per day, and 1,655 Mcf of natural gas per day. 57% of the Company's Conventional production was from liquid hydrocarbons. Third quarter volumes represented an decrease of 8% compared to the third quarter of 2014 and due to natural declines and the fact that Lonestar is not conducting drilling operations on its Conventional assets, limiting capital to workover and well optimizations.

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 September 30, 2015	2014	% Change	Nine Months Ended September 30, 2015	2014	% Change
Western Eagle Ford Shale							
Crude Oil	($/bbl)	**$44.02**	$95.39	-54%	$48.29	$96.73	-50%
Natural Gas Liquids	($/bbl)	**$11.04**	$31.58	-65%	$12.96	$32.30	-60%
Natural Gas	($/Mcf)	**$2.67**	$3.84	-30%	$2.58	$4.25	-39%
Western Eagle Ford Shale	**($/BOE)**	**$33.09**	**$71.76**	**-54%**	**$36.36**	**$74.08**	**-51%**
Central Eagle Ford Shale							
Crude Oil	($/bbl)	**$44.91**	$95.46	-53%	$47.86	$96.84	-51%
Natural Gas Liquids	($/bbl)	**$17.43**	$25.08	-30%	$18.88	$25.08	-25%
Natural Gas	($/Mcf)	**$3.23**	$4.02	-20%	$2.89	$3.98	-27%
Central Eagle Ford Shale	**($/BOE)**	**$43.11**	**$95.33**	**-55%**	**$46.25**	**$96.77**	**-52%**
Eastern Eagle Ford Shale							
Crude Oil	($/bbl)	**$44.48**	$96.01	-54%	$48.84	$95.55	-49%
Natural Gas Liquids	($/bbl)	**$9.53**	$32.68	-71%	$10.97	$32.96	-67%
Natural Gas	($/Mcf)	**$1.85**	$2.80	-34%	$2.06	$2.88	-29%
Eastern Eagle Ford Shale	**($/BOE)**	**$39.31**	**$86.41**	**-55%**	**$44.75**	**$87.13**	**-49%**
Total Eagle Ford Shale							
Crude Oil	($/bbl)	**$44.30**	$95.44	-54%	$48.26	$96.67	-50%
Natural Gas Liquids	($/bbl)	**$11.36**	$31.60	-64%	$13.13	$32.31	-59%
Natural Gas	($/Mcf)	**$2.66**	$3.82	-30%	$2.57	$4.21	-39%
Total Eagle Ford Shale	**($/BOE)**	**$35.62**	**$76.68**	**-54%**	**$39.29**	**$78.32**	**-50%**
Conventional							
Crude Oil	($/bbl)	**$43.54**	$92.98	-53%	$47.74	$92.78	-49%
Natural Gas Liquids	($/bbl)	**$21.03**	$31.76	-34%	$19.55	$39.92	-51%
Natural Gas	($/Mcf)	**$2.72**	$5.21	-48%	$2.80	$6.16	-55%
Conventional	**($/BOE)**	**$31.42**	**$66.83**	**-53%**	**$34.05**	**$75.01**	**-55%**
Total Company Wellhead							
Crude Oil	($/bbl)	**$44.24**	$95.14	-53%	$48.22	$96.07	-50%
Natural Gas Liquids	($/bbl)	**$11.52**	$31.61	-64%	$13.26	$32.47	-59%
Natural Gas	($/Mcf)	**$2.67**	$4.26	-37%	$2.63	$4.77	-45%
Total Company Wellhead	**($/BOE)**	**$35.21**	**$75.19**	**-53%**	**$38.69**	**$77.78**	**-50%**
Total Company Hedging Revenues							
Crude Oil	($/bbl)	**$20.69**	($1.15)	-1901%	$23.05	($4.11)	-661%
Hedging Revenues	**($/BOE)**	**$14.48**	**($0.81)**	**-1890%**	**$16.48**	**($2.97)**	**-655%**
Total Company Net Oil & Gas Revenues							
Crude Oil	($/bbl)	**$64.93**	$93.99	-31%	$71.27	$91.96	-23%
Natural Gas Liquids	($/bbl)	**$11.52**	$31.61	-64%	$13.26	$32.47	-59%
Natural Gas	($/Mcf)	**$2.67**	$4.26	-37%	$2.63	$4.77	-45%
Net Oil & Gas Revenues	**($/BOE)**	**$49.69**	**$74.38**	**-33%**	**$55.18**	**$74.80**	**-26%**

Lonestar's average wellhead commodity price realization for 3Q15 was $35.21 per BOE, which was 53% lower than the $75.19 per BOE average price realized in the third quarter of 2014. Reported wellhead realizations were driven lower by large declines in both the crude oil and natural gas benchmarks. Year-over-year, West Texas Intermediate fell 52%, or $50.74 per barrel to $46.43 per barrel while Henry Hub natural gas prices were 31% lower, falling $1.22 per Mcf to $2.74 per Mcf . While benchmark prices fell sharply, Lonestar's revenues were bolstered by its crude oil hedge positions, which added $20.69 per barrel to its crude oil realizations of $64.93 per barrel.

- On its Eagle Ford Shale assets, Lonestar recorded energy equivalent wellhead price realization of $35.62 per BOE during 3Q15, a 54% decrease compared to 3Q14. When compared to 2Q15, Lonestar registered a 22% sequential decline in Eagle Ford BOE realizations driven entirely by a 20% lower crude oil prices.
- On its Conventional assets, Lonestar recorded an average wellhead price realization of $31.42 per BOE during 3Q15, down 53% versus 2Q14. Reduced West Texas Intermediate pricing was primarily 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 September 30, 2015	2014	% Change	Nine Months Ended September 30, 2015	2014	% Change
Western Eagle Ford Shale							
Crude Oil	($MM)	**$11.1**	$17.6	-37%	**$31.1**	$46.8	-34%
Natural Gas Liquids	($MM)	**$0.7**	$1.3	-44%	**$2.1**	$3.4	-38%
Natural Gas	($MM)	**$1.2**	$1.3	-7%	**$2.9**	$3.5	-17%
Western Eagle Ford Shale Revenues	**($MM)**	**$13.0**	**$20.2**	**-36%**	**$36.1**	**$53.6**	**-33%**
Central Eagle Ford Shale							
Crude Oil	($MM)	**$4.6**	$6.2	-25%	**$12.7**	$13.6	-6%
Natural Gas Liquids	($MM)	**$0.1**	$0.0	4344%	**$0.2**	$0.0	8930%
Natural Gas	($MM)	**$0.1**	$0.0	4264%	**$0.1**	$0.0	7505%
Central Eagle Ford Shale Revenues	**($MM)**	**$4.7**	**$6.2**	**-23%**	**$13.0**	**$13.6**	**-4%**
Eastern Eagle Ford Shale							
Crude Oil	($MM)	**$1.7**	$1.5	17%	**$7.6**	$4.6	64%
Natural Gas Liquids	($MM)	**$0.0**	$0.0	-12%	**$0.1**	$0.1	11%
Natural Gas	($MM)	**$0.0**	$0.0	85%	**$0.1**	$0.1	86%
Eastern Eagle Ford Shale Revenues	**($MM)**	**$1.8**	**$1.5**	**17%**	**$7.9**	**$4.8**	**64%**
Total Eagle Ford Shale							
Crude Oil	($MM)	**$17.4**	$25.3	-31%	**$51.4**	$65.0	-21%
Natural Gas Liquids	($MM)	**$0.9**	$1.4	-37%	**$2.4**	$3.5	-32%
Natural Gas	($MM)	**$1.3**	$1.3	-1%	**$3.1**	$3.5	-12%
Total Eagle Ford Shale Revenues	**($MM)**	**$19.6**	**$28.0**	**-30%**	**$56.9**	**$72.0**	**-21%**
Conventional							
Crude Oil	($MM)	**$1.4**	$3.5	-59%	**$5.0**	$11.4	-57%
Natural Gas Liquids	($MM)	**$0.0**	$0.1	-51%	**$0.1**	$0.1	-18%
Natural Gas	($MM)	**$0.4**	$0.8	-49%	**$1.3**	$2.0	-35%
Conventional Revenues	**($MM)**	**$1.9**	**$4.3**	**-57%**	**$6.4**	**$13.6**	**-53%**
Total Company Wellhead							
Crude Oil	($MM)	**$18.8**	$28.8	-35%	**$56.4**	$76.4	-26%
Natural Gas Liquids	($MM)	**$0.9**	$1.4	-37%	**$2.4**	$3.6	-31%
Natural Gas	($MM)	**$1.7**	$2.1	-19%	**$4.4**	$5.6	-20%
Total Company Wellhead Revenues	**($MM)**	**$21.4**	**$32.3**	**-34%**	**$63.3**	**$85.6**	**-26%**
Total Company Hedging Revenues							
Crude Oil	($MM)	**$8.8**	($0.3)	2436%	**$27.0**	($3.3)	725%
Hedging Revenues	**($MM)**	**$8.8**	**($0.3)**	**2436%**	**$27.0**	**($3.3)**	**725%**
Total Company Net Oil & Gas Revenues							
Crude Oil	($MM)	**$27.7**	$28.4	-3%	**$83.4**	$73.2	14%
Natural Gas Liquids	($MM)	**$0.9**	$1.4	-37%	**$2.4**	$3.6	-31%
Natural Gas	($MM)	**$1.7**	$2.1	-19%	**$4.4**	$5.6	-20%
Net Oil & Gas Revenues	**($MM)**	**$30.2**	**$32.0**	**-5%**	**$90.3**	**$82.3**	**10%**

Lonestar's 42% increase in production and robust hedge book allowed the Company to register a modest 5% decrease in net oil and gas revenues in the third quarter of 2015, which totaled $30.2 million. On a wellhead basis, Lonestar's net oil and gas revenues for 3Q15 decreased 34% to $21.4 million, versus $32.3 million a year ago. The precipitous decline in oil and gas prices was mitigated by Lonestar's favorable crude oil hedge position, which added $8.8 million to revenues in the third quarter of 2015.

- Lonestar's net wellhead oil and gas revenues from its Eagle Ford Shale assets fell 30% to $19.6 million for the third quarter of 2015 versus $28.0 million a year ago. 3Q15 revenues were bolstered by a 51% increase in production, which was offset by a 54% decrease in wellhead price realizations per BOE. Crude oil contributed 89% of revenues, while natural gas liquids contributed 4% of revenues and natural gas contributed 7% of revenues. Sequentially, Lonestar generated a modest 8% decrease in wellhead net oil and gas revenues over 2Q15 results, as BOE price realizations fell 22% and production increased by 17%.
- Lonestar's net wellhead oil and gas revenues from its Conventional assets totaled $1.9 million during the third quarter of 2015, a 57% decrease over the third quarter of 2014. The decrease in revenue was driven by a 53% decrease in wellhead price realizations per BOE coupled with an 7% decrease in production. Crude oil contributed 76% of revenues while natural gas liquids contributed 1% of revenues and natural gas contributed 23% of revenues.

Management's Discussion and Analysis

Field Operating Expenses

		Three months ended September 30, 2015	2014	% Change	Nine Months Ended September 30, 2015	2014	% Change
Western Eagle Ford Shale							
Lease Operating Expense	($/BOE)	**$7.41**	$7.73	-4%	**$7.71**	$8.58	-10%
Production Taxes	($/BOE)	**$1.93**	$4.25	-54%	**$2.27**	$4.43	-49%
Western Eagle Ford Shale	**($/BOE)**	**$9.35**	**$11.98**	**-22%**	**$9.99**	**$13.00**	**-23%**
Central Eagle Ford Shale							
Lease Operating Expense	($/BOE)	**$5.68**	$10.29	-45%	**$7.03**	$10.77	-35%
Production Taxes	($/BOE)	**$2.86**	$5.17	-45%	**$3.40**	$5.55	-39%
Central Eagle Ford Shale	**($/BOE)**	**$8.54**	**$15.47**	**-45%**	**$10.42**	**$16.32**	**-36%**
Eastern Eagle Ford Shale							
Lease Operating Expense	($/BOE)	**$8.17**	$13.07	-37%	**$6.80**	$8.53	-20%
Production Taxes	($/BOE)	**$2.59**	$6.31	-59%	**$2.88**	$6.14	-53%
Eastern Eagle Ford Shale	**($/BOE)**	**$10.77**	**$19.38**	**-44%**	**$9.68**	**$14.67**	**-34%**
Total Eagle Ford Shale							
Lease Operating Expense	($/BOE)	**$7.13**	$8.44	-16%	**$7.47**	$8.91	-16%
Production Taxes	($/BOE)	**$2.18**	$4.52	-52%	**$2.56**	$4.70	-45%
Total Eagle Ford Shale	**($/BOE)**	**$9.30**	**$12.96**	**-28%**	**$10.03**	**$13.61**	**-26%**
Conventional							
Lease Operating Expense	($/BOE)	**$14.36**	$20.12	-29%	**$14.46**	$19.68	-27%
Production Taxes	($/BOE)	**$2.99**	$5.60	-47%	**$2.61**	$5.67	-54%
Conventional	**($/BOE)**	**$17.35**	**$25.72**	**-33%**	**$17.06**	**$25.36**	**-33%**
Total Company							
Lease Operating Expense	($/BOE)	**$7.83**	$10.20	-23%	**$8.27**	$10.68	-23%
Production Taxes	($/BOE)	**$2.26**	$4.68	-52%	**$2.57**	$4.86	-47%
Total Company	**($/BOE)**	**$10.09**	**$14.88**	**-32%**	**$10.84**	**$15.54**	**-30%**

Lonestar's field operating expenses for the third quarter of 2015 were $6.1 million, a decrease of 4% over 3Q14 field operating expenses of $6.4 million. Combined with increased volumes, the Company reduced total field operating expenses by 32% on a unit of production basis from 3Q14 to $10.09 per BOE. Lonestar's 3Q15 results also represent a 18% sequential reduction in field operating expenses. Lease Operating Expense ("LOE") was $4.8 million for 3Q15, only marginally above 3Q14 levels on an absolute dollar basis, but decreased 23% on a BOE basis to $7.83 per BOE. Production taxes were $1.4 million for the third quarter of 2015, a 32% decrease over comparable levels in 2014, and a 52% decrease to $2.26 per BOE.

- Lonestar's field operating expenses from its Eagle Ford Shale assets totaled $5.1 million during the third quarter of 2015, an 8% increase over the third quarter of 2014. However, on a unit of production basis, field operating expenses decreased 28% to $9.30 per BOE, year-over-year. Direct lease operating expenses totaled $3.9 million in 3Q15, or $7.13 per BOE, a reduction of 16% on a per unit basis. 3Q15 Lease Operating Expenses included $0.2 million of non-recurring workover expenses on 12 Austin Chalk wells in La Salle County, equating to $0.38 per BOE. Production taxes were $1.2 million, or $2.18 per BOE, compared to $1.6 million, or $4.52 per BOE in the year-ago quarter. More importantly, Lonestar was successful in sequentially reducing Eagle Ford Shale lease operating expenses in absolute terms by 2% vs. 2Q15 results, and by 17% on a per-BOE unit basis.
- Lonestar's field operating expenses from its Conventional assets totaled $1.0 million during the third quarter of 2015, a 38% decrease versus the third quarter of 2014. On a unit of production basis, field operating expenses decreased 33% to $17.35 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 $0.9 million, or $14.36 per BOE, compared to $1.3 million, or $20.12 per BOE in 3Q14. Production taxes were $0.2 million, or $2.99 per BOE, compared to $0.4 million, or $5.60 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 September 30, 2015	2014	% Change	Nine Months Ended September 30, 2015	2014	% Change
Western Eagle Ford Shale							
Production Revenue	($/BOE)	$33.09	$71.76	-54%	$36.36	$74.08	-51%
Lease Operating Expenses	($/BOE)	$7.41	$7.73	-4%	$7.71	$8.58	-10%
Production Taxes	($/BOE)	$1.93	$4.25	-54%	$2.27	$4.43	-49%
Field Netback	**($/BOE)**	**$23.74**	**$59.79**	**-60%**	**$26.37**	**$61.07**	**-57%**
Field Netback	**($MM)**	**$9.3**	**$16.9**	**-45%**	**$26.2**	**$44.2**	**-41%**
Central Eagle Ford Shale							
Production Revenue	($/BOE)	$43.11	$95.33	-55%	$46.25	$96.77	-52%
Lease Operating Expenses	($/BOE)	$5.68	$10.29	-45%	$7.03	$10.77	-35%
Production Taxes	($/BOE)	$2.86	$5.17	-45%	$3.40	$5.55	-39%
Field Netback	**($/BOE)**	**$34.57**	**$79.86**	**-57%**	**$35.83**	**$80.45**	**-55%**
Field Netback	**($MM)**	**$3.8**	**$5.2**	**-27%**	**$10.1**	**$11.3**	**-11%**
Eastern Eagle Ford Shale							
Production Revenue	($/BOE)	$39.31	$86.41	-55%	$44.75	$87.13	-49%
Lease Operating Expenses	($/BOE)	$8.17	$13.07	-37%	$6.80	$8.53	-20%
Production Taxes	($/BOE)	$2.59	$6.31	-59%	$2.88	$6.14	-53%
Field Netback	**($/BOE)**	**$28.55**	**$67.03**	**-57%**	**$35.08**	**$72.46**	**-52%**
Field Netback	**($MM)**	**$1.3**	**$1.2**	**10%**	**$6.2**	**$4.0**	**54%**
Total Eagle Ford Shale							
Production Revenue	($/BOE)	$35.62	$76.68	-54%	$39.29	$78.32	-50%
Lease Operating Expenses	($/BOE)	$7.13	$8.44	-16%	$7.47	$8.91	-16%
Production Taxes	($/BOE)	$2.18	$4.52	-52%	$2.56	$4.70	-45%
Field Netback	**($/BOE)**	**$26.32**	**$63.72**	**-59%**	**$29.26**	**$64.71**	**-55%**
Field Netback	**($MM)**	**$14.5**	**$23.2**	**-38%**	**$42.4**	**$59.5**	**-29%**
Conventional							
Production Revenue	($/BOE)	$31.42	$66.83	-53%	$34.05	$75.01	-55%
Lease Operating Expenses	($/BOE)	$14.36	$20.12	-29%	$14.46	$19.68	-27%
Production Taxes	($/BOE)	$2.99	$5.60	-47%	$2.61	$5.67	-54%
Field Netback	**($/BOE)**	**$14.07**	**$41.11**	**-66%**	**$16.99**	**$49.66**	**-66%**
Field Netback	**($MM)**	**$0.8**	**$2.7**	**-69%**	**$3.2**	**$9.0**	**-65%**
Total Company							
Production Revenue	($/BOE)	$35.21	$75.19	-53%	$38.69	$77.78	-50%
Lease Operating Expenses	($/BOE)	$7.83	$10.20	-23%	$8.27	$10.68	-23%
Production Taxes	($/BOE)	$2.26	$4.68	-52%	$2.57	$4.86	-47%
Field Netback	**($/BOE)**	**$25.12**	**$60.31**	**-58%**	**$27.86**	**$62.24**	**-55%**
Field Netback	**($MM)**	**$15.3**	**$25.9**	**-41%**	**$45.6**	**$68.5**	**-33%**

Lonestar's field netback for the third quarter of 2015 was $15.3 million, a decrease of 41% over the field netback of $25.9 million in 3Q14. Despite strong volume growth and meaningful field-level cost reductions, field netbacks declined 58% to $25.12 per BOE in the third quarter of 2015 vs. $60.31 in the third quarter of 2014. The decrease in the per BOE field netback is entirely driven by a 52% decrease in WTI pricing and a 31% decrease in Henry Hub pricing compared to 3Q14, and in spite of a 32% reduction in the Company's unit operating costs.

- Lonestar's Eagle Ford Shale field netback was $14.5 million and $26.32 per BOE in 3Q15. Year-over-year, Lonestar's Eagle Ford Shale field netback represented a 38% decrease in the field netback compared to the $23.2 million reported in the third quarter of 2014. On a BOE basis, field netbacks declined 59% to $26.32 in third quarter of 2015 vs. $63.72 in 3Q14, caused by a 52% reduction in WTI and a 31% reduction in Henry Hub and in spite of a 28% reduction in the Eagle Ford's unit operating costs.

- Lonestar's Conventional field netback was $0.8 million and $14.07 per BOE in 3Q15. Year-over-year, Lonestar's field netback from its Conventional assets represented a 69% decrease in field netbacks compared to the $2.7 million reported in the third quarter of 2014. On a BOE basis, field netbacks declined 66% largely due to a 52% reduction in crude oil prices and a 31% reduction in Henry Hub in spite of a 33% reduction in the Eagle Ford's unit operating costs.

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

Management's Discussion and Analysis

Depreciation and Depletion

		Three months ended September 30, 2015	2014	% Change	Nine Months Ended September 30, 2015	2014	% Change
Total Expense	($MM)	$13.0	$9.2	41%	$39.2	$26.8	46%
Depreciation & Depletion	($/BOE)	$21.40	$21.46	0%	$23.94	$24.32	-2%

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 third quarter of 2015 was $13.0 million, or $21.40 per BOE compared to $9.2 million, or $21.46 per BOE reported in the third quarter of 2014. This increase in D,D&A in absolute dollar terms is due to a 41% increase in production compared to 3Q14 levels, while Depreciation and Amortization remained flat on a unit of production basis.

General and Administrative Expenses

		Three months ended September 30, 2015	2014	% Change	Nine Months Ended September 30, 2015	2014	% Change
Total Expense	($MM)	$2.4	$2.2	10%	$7.0	$6.1	16%
General & Administrative	($/BOE)	$3.95	$5.09	-22%	$4.31	$5.50	-22%

Lonestar reported General & Administrative expenses of $2.4 million for the third quarter of 2015, a 10% increase over the $2.2 million of General & Administrative expenses reported in the third quarter of 2014. However on a sequential basis, third quarter 2015 General & Administrative expenses are only up 2% in absolute dollar terms when compared to the second quarter of 2015. As it scales it's business, the Company achieved a 22% decrease in G&A per BOE to $3.95, compared to $5.09 per BOE reported in the third quarter of 2014.

Finance Expenses

		Three months ended September 30, 2015	2014	% Change	Nine Months Ended September 30, 2015	2014	% Change
Interest Expense	($MM)	$5.4	$5.1	7%	$16.2	$12.6	29%
Amortization of Finance Costs	($MM)	$1.2	$0.3	345%	$2.3	$1.7	36%
Total Finance Costs	**($MM)**	**$6.7**	**$5.3**	**25%**	**$18.5**	**$14.2**	**30%**
Finance Costs	($/BOE)	$10.95	$12.45	**-12%**	$11.30	$12.94	**-13%**

Lonestar reported Finance expenses of $6.7 million for the third quarter of 2015, a 25% increase over the $5.3 million of Finance expenses reported in the third quarter of 2014. On a BOE basis, the Company reported Finance expenses of $10.95 per BOE, a 12% decrease compared to $12.45 per BOE reported in the third quarter of 2014. The increase in Finance Expenses was primarily driven by a non-cash write-off of approximately $0.7 million of deferred financing costs associated with the extinguishment of our previous Senior Secured Revolving Credit Facility which was replaced by a Citibank-led facility on July 28, 2015. Interest Expense grew a modest 7% in the third quarter of 2015. The Company's borrowings from its senior unsecured notes were $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 $180.0 million Senior Secured Revolving Credit Facility averaged $83.7 million during the quarter with interest expense averaging 2.50% 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 September 30, 2015	2014	% Change	Nine Months Ended September 30, 2015	2014	% Change
Crude Oil	($MM)	**$8.8**	($0.3)	2436%	**$27.0**	($3.3)	725%
Natural Gas Liquids	($MM)	**$0.0**	$0.0	-	**$0.0**	$0.0	-
Natural Gas	($MM)	**$0.0**	$0.0	-	**$0.0**	$0.0	-
Hedging Revenues (Expenses)	**($MM)**	**$8.8**	**($0.3)**	**2436%**	**$27.0**	**($3.3)**	**725%**
Hedging Revenues (Expenses)	($/BOE)	**$14.48**	($0.81)		**$16.48**	($2.97)	

- Lonestar realized crude oil hedge revenues of $8.8 million in the third quarter of 2015 vs. a crude oil hedge expense of $0.3 million reported in the third quarter of 2014. As of September 30, 2015 the Mark to Market value of Lonestar's remaining hedge contracts totaled $33.3 million.

Derivative Commodity Contracts

Commodity	Quantity	Term			Reference	Strike	Put	Call	Option Traded
Crude Oil	58,000	Oct 1, 2015	-	Dec 31, 2015	WTI	$87.00	-	-	Swap
Crude Oil	64,400	Oct 1, 2015	-	Dec 31, 2015	WTI	$81.25	-	-	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	36,800	Oct 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 2,551 barrels of oil per day for the fourth quarter of 2015 at an average strike price of $82.23 per barrel, equating to 60 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 2016 at an average strike price of $77.15 per barrel, equating to 51 to 57% of currently budgeted oil production.
- **2017**- Lonestar's 2017 oil hedge position consists of 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 September 30, 2015

Consolidated statements of comprehensive income

For the three and nine months ended September 30, 2015 and 2014

(US $MM)	*As Reported* Three months ended September 30,		*As Reported* Nine Months Ended September 30,	
	2015	2014	2015	2014
Revenues (Net of Royalties)				
Crude Oil	18.8	28.8	56.4	76.4
Natural Gas Liquids	0.9	1.4	2.5	3.6
Natural Gas	1.7	2.1	4.4	5.6
Revenues (Net of Royalties)	**21.4**	**32.3**	**63.3**	**85.6**
Hedge Revenues (Expenses)	8.8	(0.3)	27.0	(3.3)
Net Revenue From Ordinary Activities	**30.2**	**32.0**	**90.3**	**82.3**
Operating Expenses				
Lease Operating Expenses	(4.8)	(4.4)	(13.5)	(11.7)
Severance Taxes	(1.0)	(1.5)	(2.8)	(4.0)
Ad Valorem Taxes	(0.4)	(0.5)	(1.4)	(1.4)
Depreciation, Depletion & Amortization	(13.0)	(9.2)	(39.2)	(26.8)
General & Administrative	(2.4)	(2.2)	(7.1)	(6.1)
Total Operating Expenses	**(21.6)**	**(17.8)**	**(64.0)**	**(49.9)**
Gross Profit from Operating Activities	**8.6**	**14.2**	**26.3**	**32.4**
Other Income (Expense)	(0.0)	(0.0)	(0.7)	0.4
Impairment of O&G properties	0.0	0.0	(19.3)	0.0
Stock based compensation	(0.9)	(0.6)	(1.7)	(2.0)
Non-recurring expenses	(0.0)	(0.4)	(0.1)	(1.6)
Interest & Other Finance Expenses	(6.7)	(5.3)	(18.5)	(14.2)
Fair Value Gain (Loss) on derivatives	10.7	13.0	(8.0)	4.6
Profit (Loss) before taxes	**11.7**	**20.6**	**(22.0)**	**19.7**
Income tax (expense) benefit	(4.4)	(1.5)	7.8	(2.6)
Net Income (Loss)	**7.4**	**19.1**	**(14.2)**	**17.1**
EBITDAX	**21.7**	**23.4**	**65.5**	**59.2**

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

Consolidated statements of financial position

As of September 30, 2015

(US $MM)	September 30, 2015	*As Reported* As of June, 2015	December 31, 2014
Assets			
Current Assets			
Cash and cash equivalents	5.0	4.4	10.0
Trade and other receivables	12.9	16.1	17.5
Derivative financial instruments	29.7	20.1	31.0
Other assets	1.4	1.2	0.7
Total current assets	**49.0**	**41.8**	**59.3**
Non-current assets			
Oil and gas properties	499.5	493.6	477.2
Intangible assets	-	-	-
Property, plant and equipment	2.2	2.3	2.4
Oil and Gas Properties & Equipment	501.7	495.9	479.5
Deferred tax assets	0.3	0.4	0.1
Derivative financial instruments	6.5	6.2	12.7
Other non-current assets	3.9	3.4	3.7
Total non-current assets	**512.4**	**505.9**	**496.1**
Total Assets	**561.4**	**547.7**	**555.5**
Liabilities			
Current liabilities			
Trade and other payables	31.4	32.6	35.7
Revenue payable	5.3	5.1	5.0
Accrued expenses	1.7	1.4	2.4
Derivative financial instruments	-	0.6	-
Total current liabilities	**38.4**	**39.8**	**43.0**
Non-current liabilities			
Long-term Debt	295.4	292.1	264.6
Deferred tax liablilities	24.0	19.7	26.0
Other non-current liabilities	8.3	9.1	7.8
Total non-current liabilities	**327.8**	**320.9**	**298.5**
Total Liabilities	**366.2**	**360.7**	**341.5**
Net assets	**195.2**	**187.0**	**214.0**
Equity			
Contributed equity	142.6	142.6	142.6
Reserves	8.7	7.8	6.9
Retained Earnings	43.9	36.5	64.3
Total Equity	**195.2**	**187.0**	**213.8**

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

Consolidated statements of cash flows
For the nine months ended September 30, 2015 and 2014

(US $MM)	*As Reported* Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income (loss)	(14.2)	17.2
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	39.0	26.6
Impairment	19.3	-
Increase in retirement provision	0.2	0.1
Deferred taxes	(7.8)	3.2
Share based payments	1.7	2.0
Loss (Gain) on sale of equipment	0.6	-
Non-cash interest expense	0.8	0.6
Net (increase) decrease in derivatives	7.6	(5.5)
Changes in operating assets and liabilities:	-	-
Accounts receivable	4.6	(7.5)
Other assets	(0.9)	(2.9)
Accounts payable and provisions	(9.0)	22.2
Net cash inflow from operating activities	41.9	55.5
CASH FLOWS FROM INVESTING ACTIVITIES		
Payments for oil and gas property, plant & equipment	(69.9)	(108.0)
Acquisition of oil and gas properties	(7.0)	(71.0)
Proceeds from sales of oil and gas properties	-	3.2
Net cash (outflow) from investing activities	(76.9)	(175.8)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net change in borrowings	30.0	(87.0)
Proceeds from issuance of long term bonds	-	214.5
Net cash inflow from financing activities	30.0	127.5
Net increase / (Decrease) in cash held	(5.0)	7.2
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	5.0	13.9

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.

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.