

PAN AMERICAN SILVER CORP
Form 6-K
February 18, 2004

FORM 6-K
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Report of Foreign Private Issuer

Pursuant to Rule 13a-16 or 15d-16
of the Securities Exchange Act of 1934

For the month of February 17, 2004

Pan American Silver Corp

(Translation of registrant's name into English)

1500-625 HOWE STREET
VANCOUVER BC CANADA V6C 2T6

(Address of principal executive offices)

Indicate by check mark whether the registrant files or will file annual reports under cover Form 20-F or Form 40-F.

Form 20-F Form 40-F

Indicate by check mark whether the registrant by furnishing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.

Yes No ...

If "Yes" is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b):
82-_____

Index to Material Change Reports

1.

Press Release dated February 17, 2004

February 17, 2004

PAN AMERICAN SILVER REPORTS 11% PRODUCTION INCREASE IN 2003

(all amounts in US Dollars unless otherwise stated)

HIGHLIGHTS

- Silver production in the quarter up 6% to 2.12 million ounces (2.0 million in 2002). Full-year total was 8.64 million ounces, up 11% over 2002 the ninth consecutive year of silver production growth.
- Cash production costs decreased 3% to \$4.01 per ounce and total production costs decreased 4% to \$4.57 per ounce in the quarter. For 2003, cash costs declined slightly to \$4.09 per ounce and total costs declined 6% to \$4.62 per ounce.
- Net loss for the quarter declined to \$4.8 million or \$0.15 per share (2002 net loss of \$14.0 million), including non-cash charges of \$2.9 million stemming from a change in accounting rules. Net loss for 2003 totaled \$6.8 million or \$0.20 per share (2002 net loss of \$34.0 million).
- Quiruvilca generating positive cash flow. Mine life has been extended indefinitely.
- Huaron expansion study underway and 12,000 m. drill program initiated.
- Feasibility studies initiated at San Vicente in Bolivia and Manantial Espejo in Argentina.

2004 FORECAST HIGHER PRODUCTION AND LOWER COSTS

- Reserves and resources expected to increase upon completion of new reserve/ resource statement at the end of the first quarter.
- Production decision for Alamo Dorado project mid-year.
- Total production to rise 23% to 10.6 million ounces (50% to 13 million ounces including 2004 production from Morococha).
- Cash production cost to decline below \$3.50/oz.
- Total production cost to decline to approximately \$4.30/oz.
- Operating cash flow and earnings to increase significantly.

FINANCIAL RESULTS (Unaudited)

Pan American Silver Corp. (NASDAQ: PAAS; TSX: PAA) reported a net loss of \$4.8 million (\$0.15 per share) for the fourth quarter of 2003 versus a fourth quarter loss of \$14.0 million in 2002. The benefits from the surge in the price of silver and base metals seen late in the fourth quarter will begin to be realized by Pan American in the first quarter of 2004 because most of the Company's production is in the form of concentrate, which is priced an average of three months after it is produced. In addition, operations in Peru held a build-up of concentrate at year-end due to the timing of shipments and the revenue from such shipments will be recognized in the first quarter. Consolidated revenue for the fourth quarter was \$12.9 million.

The loss for the quarter included several additional accounting charges. In December, Pan American elected to early adopt CICA 3870, Stock-Based Compensation and Other Stock-Based Payments, which resulted in an expense of \$2.9 million. The Company also recognized a non-cash charge of \$1 million for additional depreciation of the Huaron mine. Excluding these

charges, the loss for the quarter was \$0.9 million, a significant improvement over the fourth quarter of 2002.

Consolidated silver production for the fourth quarter totaled 2.1 million ounces, a 6% increase over the fourth quarter of 2002. The increase was due primarily to a full year of silver production from the stockpiles operation in Peru and the expansion of La Colorada. By-product production of zinc, lead and copper was lower than in the fourth quarter of

2002 due to lower throughput at Quiruvilca and slightly lower grade at Huaron.

Cash costs of \$4.01/oz in the fourth quarter improved 3% over cash costs of \$4.15/oz in the corresponding period of 2002, while total production costs declined by 4% to \$4.57/oz. The improvement in cash cost is due primarily to the successful cost-reduction program at the Quiruvilca mine.

For the full year ended December 31, 2003 Pan American recorded a consolidated net loss of \$6.8 million. The loss in 2002 was \$34.0 million, due primarily to the write-down of the Quiruvilca mine. Consolidated revenue in 2003 was \$45.1 million and \$45.1 million in 2002.

Silver production in 2003 totaled 8.6 million ounces, an 11% increase over 2002. Zinc production of 31,797 tonnes was 19% lower than in 2002, lead production was 9% lower and copper production was 10% higher. Cash costs for 2003 declined slightly to \$4.09/oz while total production costs declined 6% to \$4.62/oz.

Capital spending in 2003 increased from \$10.9 million to \$18.9 million reflecting the construction of the La Colorada mine and sustaining capital for Huaron, which is undergoing an expansion study. Working capital at December 31, 2003 improved to \$82.0 million from \$2.4 million at December 31, 2002, due primarily to the issuance of a convertible debenture in the third quarter.

Ross Beaty, Chairman and CEO of Pan American commented that 2003 was a really positive transition year for Pan American Silver. We have put in place all the building blocks we need - the projects, the finances and the operations team - to achieve our goal of becoming the world's leading silver producer. Our focus now is on executing these ambitious plans. The addition of Morococha is an excellent fit for us, and we intend to capitalize on the growth and opportunities it provides us.

OPERATIONS AND DEVELOPMENT HIGHLIGHTS

MEXICO

The **La Colorada** mine increased production to 320,902 ounces of silver in the fourth quarter, an increase of 63% over the fourth quarter of 2002, but below forecast levels due to slower-than-expected commissioning of the mine expansion project. La Colorada's silver production in 2003 was 992,142 ounces. The mine is steadily increasing its output and is expected to reach its design capacity in mid-2004. As of January 1, 2004, for accounting purposes the mine was determined to be in commercial production and therefore, cash and total production costs will now be expensed and will decrease as production levels rise. For 2004, cash and total costs are forecast to average \$3.66/oz

and \$5.20/oz respectively.

Work has progressed steadily on the feasibility study at the **Alamo Dorado** silver project, acquired in early 2003 with the purchase of Corner Bay Silver. Permitting is underway and metallurgical testing is substantially complete. Preliminary indications suggest that a conventional mill circuit alone will yield a superior return on the project. Some additional

testwork and drilling may be required to complete the feasibility, due in mid-2004. Predicted annual production remains at 6 million ounces at an average cash cost of less than \$3.25 per equivalent ounce of silver.

PERU

The **Quiruvilca mine** achieved a significant transformation in 2003. Benefiting from the closure of the high-cost North Zone in August, the mine reduced cash costs from \$5.51/oz to \$4.11/oz and total costs from \$6.24/oz to \$4.32/oz while increasing production 7% to 618,133 ounces in the fourth quarter. The mine is now generating good cash flow and a long-term operating plan is currently being developed.

Production at the **Huaron mine** in the fourth quarter of 2003 decreased to 966,732 ounces of silver with a resulting increase in cash costs from \$3.70/oz to \$4.33/oz. Poor ground conditions in the Satellite zone continued to result in reduced tonnage and increased costs for ground support. Production levels are expected to return to normal in the second quarter as this zone is worked through and the 2004 silver production target remains at 4.4 million ounces. In 2003 the Company initiated a third-party evaluation of the potential to expand production at Huaron. As part of the feasibility study due in 2004, a \$1 million exploration drilling program was initiated to convert known mineral resources into proven and probable reserves.

In October, Pan American bought back the 3% net smelter royalty on the Huaron mine for \$2.5 million. Should an expansion to an annual production rate of 6 million ounces prove viable, the purchase of the royalty will save more than \$1 million per year in operating costs over the life of the mine.

The **Silver Stockpile Operation** continued to generate excellent cash flow, producing 217,980 ounces of silver in the fourth quarter at a cash cost of just \$2.28/oz, bringing the full year results to 790,803 ounces at a cash cost of \$2.15/oz.

The agreement to acquire the **Morococha** silver mine in Peru was announced on February 9, 2004. Morococha is immediately accretive to production, cash flow and earnings. The operation's cash production costs are expected to be \$3.10/oz in 2004 and to average \$2.50/oz over the life of the mine. Located just 80 km from Huaron, Morococha provides many administrative synergies with existing Peruvian operations as well as significant future exploration potential.

ARGENTINA

Feasibility work is progressing on the 50% owned **Manantial Espejo** silver-gold joint venture where geotechnical and environmental testing are underway to facilitate permitting. Initial scoping work indicates that at a rate of 1,500 tonnes per day, Manantial Espejo would produce 4 million ounces of silver and 70,000 ounces of gold annually. A successful program of infill drilling was completed in the fourth quarter and will be incorporated into a new resource estimate.

BOLIVIA

In November, Pan American Silver entered into an agreement with EMUSA, the Bolivian mining company that had been toll mining ore from the **San Vicente** project, giving EMUSA the right to earn a 49% interest in the project by financing the next \$2.5 million in project expenses, including a feasibility study. Current drilling to convert resources into reserves is generating positive results, which will be incorporated into the feasibility.

SILVER MARKETS

Silver prices were volatile in 2003, ranging from a low of \$4.35 per ounce to a high of \$5.98 and ending the year at \$5.92, a rise of 24% over 2002. Industrial and investment demand for silver rose sharply in 2003, while jewelry and photographic demand declined modestly, resulting in an increased silver deficit estimated at about 85 million ounces (2002 67 million ounces). This deficit was mostly filled by producer hedging and sales of Chinese government stockpiles, though the latter occurred at much reduced levels relative to recent years. World mine production of silver declined for the second consecutive year. Silver prices continue to benefit from the increasing supply deficit and renewed investor interest and we are optimistic that our shareholders will be rewarded with continuing strength in silver prices during 2004.

Pan American Silver Corp. will host a conference call on February 18, 2004 at 10:00 am Pacific Time to discuss these results as well as the Morococha purchase. North American participants please call toll-free 1-877-825-5811 and international participants call 1-973-582-2767. The call may also be accessed from the investor relations section of our website at www.panamericansilver.com or can be replayed until February 25 by dialing 1-877-519-4471 using access code 4477843.

For More Information, please contact:

Brenda Radies, Vice-President Corporate Relations (604) 806-3158

www.panamericansilver.com

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CAUTIONARY NOTE

Some of the statements in this news release are forward-looking statements, such as estimates of future production levels, expectations regarding mine production costs, expected trends in mineral prices and statements that describe Pan American's future plans, objectives or goals. Actual results and developments may differ materially from those contemplated by these statements depending on such factors as changes in general economic conditions and financial markets, changes in prices for silver and other metals, technological and operational hazards in Pan American's mining and mine development activities, uncertainties inherent in the calculation of mineral reserves, mineral resources and metal recoveries, the timing and availability of financing, governmental and other approvals, political unrest or instability in countries where Pan American is active, labor relations and other risk factors listed from time to time in Pan American's Form 40-F.

Financial & Operating Highlights

	Three Months ended		Years ended	
	December 31		December 31	
	2003	2002	2003	2002
		(Restated)		(Restated)
Consolidated Financial Highlights (unaudited - in thousands of US dollars)				
Net income (loss)	\$ (4,837)	\$ (14,040)	\$ (6,773)	\$ (33,977)
Earnings (loss) per share	(0.15)	(0.32)	(0.20)	(0.81)
Net income (loss) before unusual items	(4,837)	(1,951)	(6,773)	(6,759)
Earnings (loss) per share before unusual items	(0.15)	(0.05)	(0.20)	(0.16)
Contribution from mining operations	2,040	379	5,343	1,932
Capital spending	6,286	5,005	18,859	10,938
Exploration expense	955	629	2,543	1,206
Cash	14,191	10,185	14,191	10,185
Working capital	\$ 81,961	\$ 2,399	\$ 81,961	\$ 2,399

Consolidated Ore Milled & Metals Recovered to Concentrate

Tonnes milled	293,523	297,949	1,212,253	1,174,332
Silver metal ounces	2,123,747	2,009,787	8,641,914	7,765,154
Zinc metal tonnes	7,038	9,555	31,797	39,081
Lead metal tonnes	4,154	5,214	18,990	20,790
Copper metal tonnes	518	742	3,143	2,847

Net smelter return per tonne milled	\$ 47.97	\$ 40.13	\$ 41.68	\$ 40.23
Cost per tonne	39.69	42.78	38.38	40.44
Margin (loss) per tonne	\$ 8.28	\$ (2.66)	\$ 3.30	\$ (0.21)

Consolidated Cost per Ounce of Silver (net of by-product credits)

Total cash cost per ounce	\$ 4.01	\$ 4.15	\$ 4.09	\$ 4.16
Total production cost per ounce	\$ 4.57	\$ 4.74	\$ 4.62	\$ 4.94

In thousands of US dollars

Direct operating costs & value of metals lost

in smelting and refining	11,431	12,215	47,043	47,648
By-product credits	(4,209)	(4,694)	(15,717)	(17,984)
Cash operating costs	7,222	7,521	31,326	29,664
Depreciation, amortization & reclamation	1,015	1,079	4,001	5,557
Production costs	8,237	8,600	35,327	35,221

Ounces used in cost per ounce calculations	1,802,845	1,812,524	7,649,772	7,139,119
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Average Metal Prices

Silver - London Fixing	\$ 5.25	\$ 4.51	\$ 4.88	\$ 4.60
Zinc - LME Cash Settlement per pound	\$ 0.42	\$ 0.35	\$ 0.38	\$ 0.35
Lead - LME Cash Settlement per pound	\$ 0.29	\$ 0.20	\$ 0.23	\$ 0.21
Copper - LME Cash Settlement per pound	\$ 0.93	\$ 0.70	\$ 0.81	\$ 0.71

Average Prices Realized

Silver - per ounce (note)	\$ 5.01	\$ 4.20	\$ 4.59	\$ 4.26
Zinc - per pound	\$ 0.42	\$ 0.35	\$ 0.38	\$ 0.35
Lead - per pound	\$ 0.29	\$ 0.20	\$ 0.23	\$ 0.21
Copper - per pound (note)	\$ 0.85	\$ 0.62	\$ 0.71	\$ 0.62

Note - Pan American pays a refining charge for silver and copper

Mine Operations Highlights

	Three Months ended		Years ended	
	December 31		December 31	
	2003	2002	2003	2002
Huaron Mine				
Tonnes milled	144,220	156,305	605,790	606,300
Average silver grade - grams per tonne	235	254	251	261
Average zinc grade percent	3.49%	4.08%	3.75%	4.08%
Silver ounces	966,732	1,134,902	4,365,061	4,527,971
Zinc tonnes	3,974	5,456	18,855	20,896
Lead tonnes	2,969	3,731	14,246	14,006
Copper tonnes	282	406	1,332	1,740
Net smelter return per tonne	\$ 48.33	\$ 45.19	\$ 45.77	\$ 44.61
Cost per tonne	44.30	40.35	41.87	38.71
Margin (loss) per tonne	\$ 4.03	\$ 4.83	\$ 3.90	\$ 5.90
Total cash cost per ounce	\$ 4.33	\$ 3.70	\$ 3.92	\$ 3.66
Total production cost per ounce	\$ 5.08	\$ 4.22	\$ 4.62	\$ 4.12

In thousands of US dollars

Direct operating costs & value of metals lost				
in smelting and refining	\$ 6,762	\$ 6,927	\$ 26,821	\$ 25,992
By-product credits	\$ (2,575)	\$ (2,732)	\$ (9,692)	\$ (9,407)
Cash operating costs	4,188	4,195	17,129	16,585
Depreciation, amortization and reclamation	725	596	3,047	2,061
Production costs	\$ 4,913	\$ 4,791	\$ 20,176	\$ 18,646
Ounces for cost per ounce calculations	966,732	1,134,902	4,365,061	4,527,971

Quiruvilca Mine

Tonnes milled	89,894	119,098	442,093	508,352
Average silver grade - grams per tonne	241	171	201	176
Average zinc grade percent	3.83%	3.82%	3.30%	3.95%
Silver ounces	618,133	576,163	2,493,908	2,509,689
Zinc tonnes	2,984	3,998	12,509	17,852

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Lead - tonnes	1,095	1,398	4,361	6,468
Copper - tonnes	236	336	1,811	1,107
Net smelter return per tonne	\$ 49.86	\$ 32.72	\$ 37.24	\$ 34.39
Cost per tonne	40.30	41.58	39.20	40.01
Margin (loss) per tonne	\$ 9.56	\$ (8.86)	\$ (1.96)	\$ (5.62)
Total cash cost per ounce	\$ 4.11	\$ 5.51	\$ 5.01	\$ 5.15
Total production cost per ounce	\$ 4.34	\$ 6.24	\$ 5.18	\$ 6.52

In thousands of US dollars

Direct operating costs & value of metals lost

in smelting and refining	\$ 4,172	\$ 5,135	\$ 18,522	\$ 21,503
By-product credits	(1,634)	(1,961)	(6,025)	(8,576)
Cash operating costs	2,538	3,174	12,498	12,927
Capital spending expensed and reclamation	143	419	431	3,431
Production costs	\$ 2,681	\$ 3,593	\$ 12,928	\$ 16,358
Ounces for cost per ounce calculations	618,133	576,163	2,493,908	2,509,689

La Colorada Mine

Tonnes milled	41,195	13,528	99,115	50,662
Average silver grade - grams per tonne	409	519	435	442
Silver - ounces	320,902	197,263	992,142	626,035
Zinc - tonnes	80	101	433	333
Lead - tonnes	90	85	383	316
Net smelter return per tonne	\$ -	\$ 52.84	\$ -	\$ 48.09
Cost per tonne	-	110.04	-	72.60
Margin (loss) per tonne	\$ -	\$ (57.20)	\$ -	\$ (24.51)
Total cash cost per ounce	\$ -	\$ -	\$ -	\$ -
Total production cost per ounce	\$ -		\$ -	

	\$	-		\$	-
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In thousands of US dollars

Direct operating costs & value of metals lost

in smelting and refining	\$	-	\$	-	\$	-	\$	-
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By-product credits				-				-
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Cash operating costs		-		-		-		-
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Depreciation, amortization and reclamation				-				-
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Production costs	\$	-	\$	-	\$	-	\$	-
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Ounces for cost per ounce calculations		-		-		-		-
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Pyrite Stockpile Sales

Tonnes sold	18,214	9,018	65,255	9,018
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Average silver grade - grams per tonne	372	350	377	350
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Silver ounces	217,980	101,459	790,803	101,459
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Net smelter return per tonne	\$	\$	\$	33.84	\$
	35.78	31.13			31.13

Cost per tonne	0.15	-	0.47	-
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Margin (loss) per tonne	\$	\$	\$	33.37	\$
	35.63	31.13			31.13

Total cash cost per ounce	\$	\$	\$	2.15	\$
	2.28	1.50			1.50

Total production cost per ounce	\$	\$	\$	2.81	\$
	2.95	2.13			2.13

In thousands of US dollars

Value of metals lost in smelting and refining	\$	\$	\$	1,700	\$
	496	152			152

By-product credits	-	-	-	-
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Cash operating costs	496	152	1,700	152
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Depreciation, amortization and reclamation	146	64	523	64
Production costs	\$ 643	\$ 216	\$ 2,223	\$ 216
Ounces for cost per ounce calculations	217,980	101,459	790,803	101,459

PAN AMERICAN SILVER CORP.
Consolidated Balance Sheets
(Unaudited - in thousands of U.S. dollars)

	December 31 2003	December 31 2002
ASSETS		(Restated)
Current		
Cash and cash equivalents	\$ 14,191	\$ 10,185
Short-term investments	74,938	13
Accounts receivable	7,497	4,598
Inventories	6,611	4,637
Prepaid expenses	1,550	3,197
Total Current Assets	104,787	22,630
Mineral property, plant and equipment, net	83,877	67,426
Investment and non-producing properties	83,873	4,193
Direct smelting ore	3,901	4,303
Other assets	3,748	4,393
Total Assets	\$ 280,186	\$ 102,945
LIABILITIES		
Current		
Operating line of credit	\$ -	\$ 125
Accounts payable and accrued liabilities	10,565	15,227
Advances for metal shipments	4,537	2,158
Current portion of bank loans and capital lease	2,639	1,638
Current portion of non-current liabilities	5,085	1,083
Total Current Liabilities	22,826	20,231
Deferred revenue	864	923
Bank loans and capital lease	10,803	3,942
Liability component of convertible debenture	19,116	-

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Provision for asset retirement obligation and reclamation	21,192	20,950
Provision for future income tax	19,035	-
Severance indemnities and commitments	2,252	1,407
Total Liabilities	\$ 96,088	\$ 47,453

SHAREHOLDERS' EQUITY

Share capital

Authorized:

100,000,000 common shares of no par value

Issued:

December 31, 2002 - 43,883,454 common shares

December 31, 2003 - 53,006,558 common shares	225,133	161,108
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Equity component of convertible debentures	66,736	-
Additional paid in capital	12,753	1,327
Deficit	(120,524)	(106,943)
Total Shareholders' Equity	184,098	55,492
Total Liabilities and Shareholders' Equity	\$ 280,186	\$ 102,945

PAN AMERICAN SILVER CORP.

Consolidated Statements of Operations

(Unaudited - in thousands of U.S. dollars, except for shares and per share amounts)

	Three months ended		Twelve months ended	
	December 31		December 31	
	2003	2002	2003	2002
		(Restated)		(Restated)
Revenue	\$ 12,857	\$ 12,084	\$ 45,122	\$ 45,093
Expenses				
Operating	10,817	11,705	39,779	43,161
General and administration	1,183	209	2,731	1,445
Stock-based compensation	2,871	572	2,871	572
Depreciation and amortization	1,961	692	3,326	4,872
Reclamation	72	215	303	860

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Exploration	955	629	2,543	1,206
Interest and financing costs	142	223	1,157	988
Write-down of mineral properties	-	12,089	-	27,218
	18,011	26,334	52,710	80,322
Net loss from operations	(5,144)	(14,250)	(7,588)	(35,229)
Other income and expenses	307	210	815	1,252
Net loss for the period	\$ (4,837)	\$ (14,040)	\$ (6,773)	\$ (33,977)
Basic & fully diluted loss per share	\$ (0.15)	\$ (0.32)	\$ (0.20)	\$ (0.81)
Weighted average shares outstanding	52,641,955	43,308,203	51,058,212	41,849,413

PAN AMERICAN SILVER CORP.

Consolidated Statements of Cash Flows - Indirect Method

For the twelve months ended December 31, 2003 and 2002

(Unaudited - in thousands of U.S. dollars)

	Three months ended		Twelve months ended	
	December 31		December 31	
	2003	2002	2003	2002
Operating activities		(Restated)		(Restated)
Net loss for the period	\$ (4,837)	\$ (14,040)	\$ (6,773)	\$ (33,977)
Items not involving cash				
Depreciation and amortization	1,960	692	3,325	4,872
Reclamation	72	215	303	860
Operating cost provisions	477	(789)	1,326	(658)
Gain on sale of marketable securities	(153)	-	(318)	-
Stock-based compensation	2,871	572	2,871	572
Write-down of mineral properties	-	12,089	-	27,218
Changes in non-cash operating working capital items	(1,650)	(566)	(4,719)	371
	(1,260)	(1,827)	(3,985)	(742)
Financing activities				
Shares issued for cash	2,713	113	8,351	22,759

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Shares issue costs	-	(6)	-	(900)
Proceeds from convertible debentures	-	-	86,250	-
Convertible debenture issue costs	(273)	-	(3,273)	-
Repayment of line of credit	-	(595)	(125)	(1,265)
Proceeds from bank loans	1,500	-	9,500	-
Repayment of bank loans and capital lease	(270)	(459)	(1,639)	(2,060)
	3,670	(947)	99,064	18,534
Investing activities				
Mineral property, plant and equipment expenditures	(5,207)	(4,843)	(16,851)	(9,612)
Investment and non-producing properties expenditures	(514)	(396)	(1,383)	(1,158)
Acquisition of cash of subsidiary	-	-	2,393	-
Purchases of marketable securities	(74,772)	-	(74,607)	-
Other	(565)	234	(625)	(168)
	(81,058)	(5,005)	(91,073)	(10,938)
Increase (decrease) in cash and cash equivalents for the period	(78,648)	(7,779)	4,006	6,854
Cash and cash equivalents, beginning of period	92,839	17,964	10,185	3,331
Cash and cash equivalents, end of period	\$ 14,191	\$ 10,185	\$ 14,191	\$ 10,185

Signatures

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Pan American Silver Corp

(Registrant)

By: /s/ Ross Beaty

(Signature)

Date: February 18, 2004

D>

Net cash provided by (used in) investing activities

148,787 (5,367) (24,894)

CASH FLOWS FROM FINANCING ACTIVITIES:

Borrowings under revolving credit facility

135,000

Repayments under revolving credit facility

(179,536) (291,191)

Senior note repurchases

(5,528)

Distributions paid to shareholders/unitholders

(12,578)

Net proceeds from issuance of common limited partner units

204

Deferred financing costs, distribution equivalent rights and other

(991) (150) (8,044)

Net cash used in financing activities

(180,527) (150) (182,137)

Net change in cash and cash equivalents

(2,865) 3,881 14,075

Cash and cash equivalents, beginning of period

24,446 15,428 1,353

Cash and cash equivalents, end of period

\$21,581 \$19,309 \$15,428

See accompanying notes to condensed consolidated financial statements.

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TITAN ENERGY, LLC

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

NOTE 1 ORGANIZATION

We are a publicly traded (OTCQX: TTEN) Delaware limited liability company and an independent developer and producer of natural gas, crude oil and NGLs with operations in basins across the United States but primarily focused on the horizontal development of resource potential from the Eagle Ford Shale in South Texas. As discussed further below, we are the successor to the business and operations of Atlas Resource Partners, L.P. (ARP). Unless the context otherwise requires, references to Titan Energy, LLC, Titan, the Company, we, us, and our, refer to Titan Energy and our consolidated subsidiaries (and our predecessor, where applicable).

Titan Energy Management, LLC (Titan Management) manages us and holds our Series A Preferred Share, which entitles Titan Management to receive 2% of the aggregate of distributions paid to shareholders (as if it held 2% of our members' equity, subject to dilution as discussed below) and to appoint four of our seven directors. Titan Management is a wholly owned subsidiary of Atlas Energy Group, LLC (ATLS ; OTCQX: ATLS), which is a publicly traded company.

In addition to its preferred member interest in us, ATLS also holds general and limited partner interests in Atlas Growth Partners, L.P. (AGP), a Delaware limited partnership and an independent developer and producer of natural gas, oil and NGLs, with operations primarily focused in the Eagle Ford Shale, and in Lightfoot Capital Partners, L.P. and Lightfoot Capital Partners GP, LLC, which incubate new MLPs and invest in existing MLPs.

At September 30, 2017, we had 5,427,547 common shares representing limited liability company interests issued and outstanding.

ARP Restructuring and Emergence from Chapter 11 Proceedings

On July 25, 2016, ARP and certain of its subsidiaries and ATLS, solely with respect to certain sections thereof, entered into a Restructuring Support Agreement (the Restructuring Support Agreement) with certain of their lenders (the Restructuring Support Parties) to support ARP's restructuring pursuant to a pre-packaged plan of reorganization (the Plan).

On July 27, 2016, ARP and certain of its subsidiaries filed voluntary petitions for relief under Chapter 11 in the United States Bankruptcy Court for the Southern District of New York (the Bankruptcy Court, and the cases commenced thereby, the Chapter 11 Filings). The cases commenced thereby were jointly administered under the caption In re: ATLAS RESOURCE PARTNERS, L.P., et al.

On August 26, 2016, an order confirming the Plan was entered by the Bankruptcy Court. On September 1, 2016, (the Plan Effective Date), pursuant to the Plan, the following occurred:

ARP's first lien lenders received cash payment of all obligations owed to them by ARP pursuant to the senior secured revolving credit facility (other than \$440 million of principal and face amount of letters of credit)

and became lenders under our first lien exit facility credit agreement, composed of a \$410 million conforming reserve-based tranche and a \$30 million non-conforming tranche (the First Lien Credit Facility) (refer to Note 5 Debt for further information regarding terms and provisions).

ARP's second lien lenders received a pro rata share of our second lien exit facility credit agreement with an aggregate principal amount of \$252.5 million (the Second Lien Credit Facility) (refer to Note 5 Debt for further information regarding terms and provisions). In addition, ARP's second lien lenders received a pro rata share of 10% of our common shares, subject to dilution by a management incentive plan.

ARP's senior note holders, in exchange for 100% of the \$668 million aggregate principal amount of senior notes outstanding plus accrued but unpaid interest as of the commencement of the Chapter 11 Filings, received 90% of our common shares, subject to dilution by a management incentive plan.

All of ARP's preferred limited partnership units and common limited partnership units were cancelled without the receipt of any consideration or recovery.

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ARP transferred all of its assets and operations to us as a new holding company and ARP dissolved. As a result, we became the successor issuer to ARP for purposes of and pursuant to Rule 12g-3 of the Securities Exchange Act of 1934, as amended.

Titan Management, a wholly owned subsidiary of ATLS, received a Series A Preferred Share, which entitles Titan Management to receive 2% of the aggregate of distributions paid to shareholders (as if it held 2% of our members' equity, subject to dilution if catch-up contributions are not made with respect to future equity issuances, other than pursuant to the management incentive plan) and certain other rights as provided for in the Restructuring Support Agreement. Four of the seven initial members of the board of directors were designated by Titan Management (the Titan Class A Directors). For so long as Titan Management holds such preferred share, the Titan Class A Directors will be appointed by a majority of the Titan Class A Directors then in office. We have a continuing right to purchase the preferred share at fair market value (as determined pursuant to the methodology provided for in our limited liability company agreement), subject to the receipt of certain approvals, including the holders of at least 67% of the outstanding common shares of us unaffiliated with Titan Management voting in favor of the exercise of the right to purchase the preferred share.

NOTE 2 BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States (U.S. GAAP) and the applicable rules and regulations of the Securities and Exchange Commission regarding interim financial reporting and include all adjustments that are necessary for a fair presentation of our consolidated results of operations, financial condition and cash flows for the periods shown, including normal, recurring accruals and other items. The consolidated results of operations for the interim periods presented are not necessarily indicative of results for the full year. The year-end condensed consolidated balance sheet was derived from audited financial statements but does not include all disclosures required by U.S. GAAP. For a more complete discussion of our accounting policies and certain other information, refer to our consolidated financial statements included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2016.

In connection with the Chapter 11 Filings, we were subject to the provisions of the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 852 *Reorganizations* (ASC 852).

Upon emergence from bankruptcy on the Plan Effective Date, we adopted fresh-start accounting in accordance with ASC 852. Upon adoption of fresh-start accounting, our assets and liabilities were recorded at their fair values as of the Plan Effective Date, which differed materially from the recorded values of ARP's assets and liabilities.

As a result, our condensed consolidated statement of operations subsequent to the Plan Effective Date is not comparable to ARP's condensed consolidated statement of operations prior to the Plan Effective Date. Our condensed consolidated financial statements and related footnotes are presented with a black line division which delineates the lack of comparability between amounts presented on or after the Plan Effective Date and dates prior. Our financial results for future periods following the application of fresh-start accounting will be different from historical trends and the differences may be material.

References to Successor relate to the Company on and subsequent to the Plan Effective Date. References to Predecessor refer to the Company prior to the Plan Effective Date. The condensed consolidated financial statements of

the Successor have been prepared assuming that the Company will continue as a going concern and contemplate the realization of assets and the satisfaction of liabilities in the normal course of business.

Reclassifications

Certain reclassifications have been made to our condensed consolidated financial statements for the prior year periods to conform to classifications used in the current year, specifically related to our discontinued operations (see Note 3) and our segment information on the condensed consolidated statement of operations and segment footnote disclosures (see Note 11).

Principles of Consolidation

Our condensed consolidated financial statements include our accounts and the accounts of our wholly-owned subsidiaries. Transactions between us and other ATLS managed operations have been identified in the condensed consolidated financial statements as transactions between affiliates, where applicable. All material intercompany transactions have been eliminated.

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We sponsored and continue to manage tax-advantaged investment partnerships (the *Drilling Partnerships*), in which we coinvested, to finance a portion of our natural gas, crude oil and NGL production activities. In accordance with established practice in the oil and gas industry, our condensed consolidated financial statements include our pro-rata share of assets, liabilities, income and lease operating and general and administrative costs and expenses of the *Drilling Partnerships* in which we have an interest. Such interests generally approximate 10-30%. Our condensed consolidated financial statements do not include proportional consolidation of the depletion or impairment expenses of the *Drilling Partnerships*. Rather, we calculate these items specific to our own economics.

Liquidity and Capital Resources and Ability to Continue as a Going Concern

Since the Plan Effective Date, we have funded our operations through cash flows generated from our operations and cash on hand. We currently do not have the capacity to access additional liquidity from our First Lien Credit Facility and our ability to access public equity and debt markets may be limited. Our future cash flows are subject to a number of variables, including oil and natural gas prices. Prices for oil and natural gas began to decline significantly during the fourth quarter of 2014 and continue to remain low in 2017. These lower commodity prices have negatively impacted our revenues, earnings and cash flows, which has negatively impacted our ability to remain in compliance with the covenants under our credit facilities. Sustained low commodity prices could have a material and adverse effect on our liquidity position.

Even following the amendments described below, we continue to face liquidity issues and are currently considering, and are likely to make, changes to our capital structure to maintain sufficient liquidity, meet our debt obligations and manage and strengthen our balance sheet. If we are not able to enter into further amendments with our lenders prior to the expiration of the standstill period, we may be forced to seek further options as described below.

We were not in compliance with certain of the financial covenants under our credit facilities as of December 31, 2016, as well as the requirement to deliver audited financial statements without a going concern qualification. As a result of the amendment referenced below, our financial covenants will not be tested again until the quarter ending December 31, 2017. We do not currently have sufficient liquidity to repay all of our outstanding indebtedness, and as a result, there is substantial doubt regarding our ability to continue as a going concern. We have classified \$538.1 million of outstanding indebtedness under our credit facilities, which is net of \$1.7 million of deferred financing costs, as current portion of long term debt, net within our condensed consolidated balance sheet as of September 30, 2017, based on the occurrence of the event of default, the lenders under our credit facilities, as applicable, could elect to declare all amounts outstanding immediately due and payable and the lenders could terminate all commitments to extend further credit.

On April 19, 2017, we entered into an amendment to our First Lien Credit Facility (which has been superseded by subsequent amendments as described further below). This amendment provided for, among other things, waivers of our non-compliance, increases in certain financial covenant ratios and scheduled decreases in our borrowing base (refer to Note 5 *Debt* for further information regarding the specific amended terms and provisions). As part of our overall business strategy, we have continued to execute on our sales of non-core assets, which has included the sale of our Appalachia and Rangely operations. The proceeds of the consummated asset sales were used to repay borrowings under our First Lien Credit Facility. Our strategy is to continue to sell non-core assets to reduce our leverage position, which will also help us to comply with the requirements of our First Lien Credit Facility amendments.

In addition to the amendments to the financial ratio covenants, the First Lien Credit Facility lenders waived certain defaults by us with respect to the fourth quarter of 2016, including compliance with the ratios of Total Debt to EBITDA and First Lien Debt to EBITDA, as well as our obligation to deliver financial statements without a going concern qualification. The First Lien Credit Facility lenders' waivers were subject to revocation in certain

circumstances, including the exercise of remedies by junior lenders (including pursuant to our Second Lien Credit Facility), the failure to extend the standstill period under the intercreditor agreement at least 15 business days prior to its expiration, and the occurrence of additional events of default under the First Lien Credit Facility.

On April 21, 2017, the lenders under the our Second Lien Credit Facility delivered a notice of events of default and reservation of rights, pursuant to which they noticed events of default related to financial covenants and the failure to deliver financial statements without a going concern qualification. The delivery of such notice began the 180-day standstill period under the intercreditor agreement, during which the lenders under the Second Lien Credit Facility were prevented from pursuing remedies against the collateral securing our obligations under the Second Lien Credit Facility. The lenders have not accelerated the payment of amounts outstanding under the Second Lien Credit Facility.

On May 4, 2017, we entered into a definitive agreement to sell our conventional Appalachia and Marcellus assets to Diversified Gas & Oil, PLC (Diversified) for \$84.2 million. The transaction included the sale of approximately 8,400 oil and gas wells across Pennsylvania, Ohio, Tennessee, New York and West Virginia, along with the associated infrastructure (the Appalachian Assets). We retained our Utica Shale position, Indiana assets and West Virginia CBM assets in the region. On June 30, 2017, we completed a majority of the Appalachian Assets sale for net cash proceeds of \$65.6 million, which included customary preliminary purchase price adjustments, all of which was used to repay a portion of the outstanding indebtedness under our First Lien Credit Facility.

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On June 12, 2017, we entered into a definitive agreement to sell our 25% interest in Rangely Field to an affiliate of Merit Energy Company, LLC for \$105 million. Rangely is a CO₂ flood located in Rio Blanco County, Colorado, and operated by Chevron. The transaction includes the sale of our interest in Rangely Field, its 22% interest in Raven Ridge Pipeline, a CO₂ transportation line, as well as surrounding acreage in Rio Blanco and Moffat Counties, Colorado (collectively, the Rangely Assets). On August 7, 2017, we completed the Rangely Assets sale for net cash proceeds of \$103.5 million, which included customary preliminary purchase price adjustments, all of which was used to repay a portion of the outstanding indebtedness under our First Lien Credit Facility and achieve compliance with the requirement to reduce our First Lien Credit Facility borrowings below \$360 million, as required by August 31, 2017.

On September 27, 2017, the lenders under our Second Lien Credit Facility entered into a letter agreement with us and the lenders under our First Lien Credit Facility (the Extension Letter) (which has been superseded by subsequent amendments as described further below). Pursuant to the Extension Letter, the Second Lien Credit Facility lenders agreed to extend the 180-day standstill period under the intercreditor agreement (during which the lenders under the Second Lien Credit Facility were prevented from pursuing remedies against the collateral securing the Company's obligations under the Second Lien Credit Facility) by an additional 35 days from October 18, 2017 to November 22, 2017. In addition, the extension of the standstill period extends the waiver of certain defaults under the First Lien Credit Facility, which terminates 15 business days prior to the expiration of the standstill period. The parties agreed to extend the standstill period to provide the Company with additional time to negotiate proposed amendments to each of the First Lien Credit Facility and the Second Lien Credit Facility.

On September 29, 2017, we completed the remainder of the Appalachia Assets sale for additional cash proceeds of \$10.4 million, all of which was used to repay a portion of outstanding borrowings under our First Lien Credit Facility.

On November 6, 2017, we entered into a fourth amendment to our First Lien Credit Facility. The fourth amendment has an effective date of October 31, 2017 and confirms the conforming and non-conforming tranches of the borrowing base at \$228.7 million and \$30 million, respectively, but requires us to take actions (which can include asset sales and equity offerings) to reduce the conforming tranche of the borrowing base to \$190 million by December 8, 2017 and to \$150 million by August 31, 2018. The maturity date of the non-conforming tranche of the borrowing base was confirmed as May 1, 2018. We are required to use proceeds from asset sales to make prepayments.

In addition to the requirements above, the First Lien Credit Facility lenders also agreed to a limited waiver of certain existing defaults with respect to financial covenants, required repayments of borrowings and other related matters. The waiver terminates upon the earliest of (i) December 8, 2017, (ii) the occurrence of additional events of default under the First Lien Credit Facility and (iii) the exercise of remedies under our Second Lien Credit Facility. Pursuant to the fourth amendment, we are required to hedge at least 50% and 80% of our 2019 projected proved developed producing production by December 31, 2017 and March 31, 2018, respectively.

In connection with, and as a condition to, the effectiveness of the fourth amendment to our First Lien Credit Facility, the lenders under our Second Lien Credit Facility agreed to extend the standstill period under the intercreditor agreement (during which the lenders under the Second Lien Credit Facility are prevented from pursuing remedies against the collateral securing our obligations under the Second Lien Credit Facility) until December 29, 2017.

We continually review and may make changes to our capital structure from time to time, with the goal of strengthening our balance sheet and meeting our debt service obligations. We could pursue options such as refinancing, restructuring or reorganizing our indebtedness or capital structure or seek to raise additional capital through debt or equity financing to address our liquidity concerns and high debt levels. We are evaluating various options, but there is no certainty that we will be able to implement any such options, and we cannot provide any

assurances that any refinancing or changes in our debt or equity capital structure would be possible or that additional equity or debt financing could be obtained on acceptable terms, if at all, and such options may result in a wide range of outcomes for our stakeholders.

We cannot assure you that we will be able to implement the above actions, if necessary, on commercially reasonable terms, or at all, in a manner that will be permitted under the terms of our debt instruments or in a manner that does not negatively impact the price of our securities. Additionally, there can be no assurance that the above actions will allow us to meet our debt obligations and capital requirements.

Table of Contents*Use of Estimates*

The preparation of our condensed consolidated financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities that exist at the date of our condensed consolidated financial statements, as well as the reported amounts of revenue and costs and expenses during the reporting periods. Our condensed consolidated financial statements are based on a number of significant estimates, including revenue and expense accruals, depletion of gas and oil properties, fair value of derivative instruments, and the fair value of assets held for sale. The oil and gas industry principally conducts its business by processing actual transactions as many as 60 days after the month of delivery. Consequently, the most recent two months' financial results were recorded using estimated volumes and contract market prices. Actual results could differ from those estimates.

Assets Held For Sale

Assets are classified as held for sale when we commit to a plan to sell the assets and there is reasonable certainty the sale will take place within one year. Upon classification as held for sale, long-lived assets are no longer depreciated or depleted, and a measurement for impairment is performed to identify and expense any excess of carrying value over fair value less estimated costs to sell. Any subsequent changes to the fair value less estimated costs to sell impact the measurement of assets held for sale, with any gain or loss reflected in the loss on divestitures line item in our condensed consolidated statements of operations. See Note 3 for additional disclosures regarding assets held for sale.

Discontinued Operations

A disposal of a component of our entity is classified as discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on our operations and financial results. For components classified as discontinued operations, the balance sheet amounts and results of operations are reclassified from their historical presentation to assets and liabilities held for sale on the condensed consolidated balance sheet and to net income (loss) from discontinued operations on the condensed consolidated statement of operations for all periods presented. The gains or losses associated with these divested components are recorded in net income (loss) from discontinued operations on the condensed consolidated statement of operations. See Note 3 for additional disclosures regarding discontinued operations.

Predecessor's Reorganization Items, Net

Incremental costs incurred as a result of the Chapter 11 Filings, net gain on settlement of liabilities subject to compromise and reorganization adjustments, and net impact of fresh start adjustments are classified as Reorganization items, net in the Predecessor's condensed consolidated statement of operations. The following table summarizes the reorganization items:

Professional fees and other	\$ (33,065)
Accelerated amortization of deferred financing costs	(9,565)
Net gain on reorganization adjustments	361,479
Net loss on fresh start adjustments	(335,463)
Total reorganization items, net	\$ (16,614)

Income Taxes

Our effective tax rates for the Successor three and nine months ended September 30, 2017 were 1.27% and 0.74%, respectively, which represent our expected Texas Franchise Tax liability. Our income tax provision differs from the provision computed by applying the U.S. Federal statutory corporate income tax rate of 35% primarily due to the valuation allowance on our deferred tax assets. For the Successor three and nine months ended September 30, 2017, we recognized a provision for income taxes of \$0.2 million and \$11.5 million, respectively, in net income (loss) from discontinued operations on our condensed consolidated statement of operations. For the Successor three and nine months ended September 30, 2017, we recognized a corresponding income tax benefit of \$0.2 million and \$11.5 million, respectively, in net income (loss) from continuing operations on our condensed consolidated statement of operations, which represents a direct offset of the provision for income taxes included within our discontinued operations.

Successor's Management Incentive Plan

Pursuant to the Titan Energy, LLC Management Incentive Plan (the "MIP") plan, participants are allowed to withhold or surrender shares for the payment of taxes. These shares are available for re-issuance under the MIP. For the three months ended September 30, 2017, 91,710 shares under the MIP became unrestricted. Of these shares, 42,251 were withheld for taxes, which resulted in \$0.2 million recognized in our consolidated statement of changes in members equity. For the nine months ended

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September 30, 2017, 91,710 shares under the MIP became unrestricted and 37,324 shares were granted and vested immediately. Of these shares, 57,562 were withheld for taxes, which resulted in \$0.3 million recognized in our consolidated statement of changes in members' equity. For the Successor period September 1, 2016 through September 30, 2016, 138,750 shares were granted and vested immediately.

Predecessor's 2012 Long-Term Incentive Plan

On May 12, 2016, due to the income tax ramifications of the potential options our Predecessor was considering, our Predecessor's Board of Directors delayed the vesting date of approximately 110,000 units granted to employees, directors and officers until March 2017. The phantom units were set to vest between May 15, 2016 and August 31, 2016. The delayed vesting schedule did not have a significant impact on the compensation expense recorded in general and administrative expenses on the condensed consolidated statement of operations for the Predecessor period from January 1, 2016 through August 31, 2016 or our Predecessor's remaining unrecognized compensation expense related to such awards. As a result of the Chapter 11 Filings, our Predecessor's 2012 LTIP phantom units were cancelled. The remaining unrecognized compensation cost of \$0.8 million was recognized upon the cancellation and was recorded in general and administrative expenses on the condensed consolidated statement of operations for the Predecessor period from July 1, 2016 through August 31, 2016.

Successor's Net Income Attributable to Common Shareholders Per Share

The Successor's basic net income attributable to common shareholders per share is computed by dividing net income attributable to our common shareholders by the weighted-average number of common shares outstanding, excluding any unvested restricted shares, for the period. The Successor's diluted net income attributable to common shareholders per share is similarly calculated except that the common shares outstanding for the period are increased using the treasury stock method to reflect the potential dilution that could occur if outstanding share based awards were vested at the end of the applicable period. Anti-dilutive shares represent potentially dilutive securities that are excluded from the computation of diluted net income attributable to common shareholders per share as their impact would be anti-dilutive. We determine if potentially dilutive shares are anti-dilutive based on their impact to net income (loss) from continuing operations.

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The following is a reconciliation of net income attributable to our Successor's common shareholders for purposes of calculating net income attributable to our Successor's common shareholders per share (in thousands):

	Successor		
	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2017	Period from September 1, 2016 through September 30, 2016
Net loss from continuing operations	\$ (19,706)	\$ (15,084)	\$ (7,364)
Less: Series A Preferred member interest in loss from continuing operations	(394)	(302)	(147)
Net loss from continuing operations utilized in the calculation of net loss attributable to common shareholders per share	\$ (19,312)	\$ (14,782)	\$ (7,217)
Net income (loss) from discontinued operations	\$ 2,156	\$ 20,945	\$ (167)
Less: Series A Preferred member interest in net income (loss) from discontinued operations	43	419	(4)
Net income (loss) from discontinued operations utilized in the calculation of net income (loss) attributable to common shareholders per share	\$ 2,113	\$ 20,526	\$ (163)

The following table is a reconciliation of the Successor's basic and diluted weighted average number of common shares used to calculate basic and diluted net income attributable to common shareholders per share (in thousands):

	Successor		
	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2017	Period from September 1, 2016 through September 30, 2016
Weighted average number of common shares - basic ⁽¹⁾	5,208	5,186	5,139
Add dilutive effect of share based awards at end of period ⁽²⁾			
Weighted average number of common shares - diluted	5,208	5,186	5,139

- (1) For the three and nine months ended September 30, 2017, 186,000 and 278,000 restricted common shares outstanding, respectively, were excluded from the calculation of basic weighted average number of common shares because they were not vested. For the Successor period from September 1, 2016 through September 30, 2016, 278,000 restricted common shares outstanding were excluded from the calculation of basic weighted average number of common shares because they were not vested.
- (2) We determine if potentially dilutive shares are anti-dilutive based on their impact to net income (loss) from continuing operations. Since all of the periods presented resulted in net loss from continuing operations attributable to common shareholders, potentially dilutive shares were excluded because their inclusion would have been anti-dilutive.

Table of Contents*Predecessor's Net Income (Loss) Per Common Unit*

The following is a reconciliation of net income (loss) allocated to our Predecessor's common limited partners for purposes of calculating net income (loss) attributable to our Predecessor's common limited partners per unit (in thousands):

	Predecessor	
	Period From July 1 through August 31, 2016	Period From January 1 through August 31, 2016
Net loss from continuing operations	\$ (36,772)	\$ (147,239)
Preferred limited partner dividends		(4,013)
Net loss from continuing operations attributable to common limited partners and the general partner	(36,772)	(151,252)
Less: General partner's interest in net loss from continuing operations	(736)	(3,025)
Net loss from continuing operations attributable to common limited partners	(36,036)	(148,227)
Less: Net income from continuing operations attributable to participating securities phantom units		
Net loss from continuing operations utilized in the calculation of net loss attributable to common limited partners per unit Basic	(36,036)	(148,227)
Plus: Convertible preferred limited partner dividends ⁽¹⁾		
Net loss from continuing operations utilized in the calculation of net loss attributable to common limited partners per unit Diluted	\$ (36,036)	\$ (148,227)
Net loss from discontinued operations attributable to common limited partners and the general partner	\$ (11,852)	\$ (30,191)
Less: General partner's interest in net loss from discontinued operations	(237)	(604)
Net loss from discontinued operations attributable to common limited partners	(11,615)	(29,587)
Less: Net income from discontinued operations attributable to participating securities phantom units		
Net loss from discontinued operations utilized in the calculation of net loss attributable to common limited	(11,615)	(29,587)

partners per unit Basic

Plus: Convertible preferred limited partner dividends⁽¹⁾

Net loss from discontinued operations utilized in the
calculation of net loss attributable to common limited

partners per unit Diluted	\$ (11,615)	\$ (29,587)
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- (1) For the periods presented, distributions on our Predecessor's Class C convertible preferred units were excluded, because the inclusion of such preferred distributions would have been anti-dilutive.

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The following table sets forth the reconciliation of our Predecessor's weighted average number of common limited partner units used to compute basic net income (loss) attributable to our Predecessor's common limited partners per unit with those used to compute diluted net income attributable to our Predecessor's common limited partners per unit (in thousands):

	Predecessor	
	Period From July 1 through August 31, 2016	Period From January 1 through August 31, 2016
Weighted average number of common limited partner units - basic	104,366	102,912
Add effect of dilutive incentive awards ⁽¹⁾		
Add effect of dilutive convertible preferred limited partner units ⁽²⁾		
Weighted average number of common limited partner units - diluted	104,366	102,912

- (1) For the Predecessor periods from July 1, 2016 through August 31, 2016 and from January 1, 2016 through August 31, 2016, 247,000 and 274,000 phantom units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive.
- (2) For the periods presented, potential common limited partner units issuable upon (a) conversion of our Predecessor's Class C preferred units and (b) exercise of the common unit warrants issued with our Predecessor's Class C preferred units were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such units would have been anti-dilutive. As our Predecessor's Class D and Class E preferred units were convertible only upon a change of control event, they were not considered dilutive securities for earnings per unit purposes.

Recently Issued Accounting Standards

In February 2016, the FASB updated the accounting guidance related to leases. The updated accounting guidance requires lessees to recognize a lease asset and liability at the commencement date of all leases (with the exception of short-term leases), initially measured at the present value of the lease payments. The updated guidance is effective for us as of January 1, 2019 and requires a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest period presented. We are currently in the process of determining the impact that the updated accounting guidance will have on our condensed consolidated financial statements.

In May 2014, the FASB updated the accounting guidance related to revenue recognition. The updated accounting guidance provides a single, contract-based revenue recognition model to help improve financial reporting by providing clearer guidance on when an entity should recognize revenue, and by reducing the number of standards to which an entity has to refer. In July 2015, the FASB voted to defer the effective date by one year to December 15, 2017 for annual reporting periods beginning after that date. We have made progress on our contract reviews and

documentation. Substantially all of our revenue is earned pursuant to agreements under which we have currently interpreted one performance obligation, which is satisfied at a point-in-time. We are currently unable to reasonably estimate the expected financial statement impact; however, we do not believe the new accounting guidance will have a material impact on our financial position, results of operations or cash flows. We intend to adopt the new accounting guidance using the modified retrospective method. The new accounting guidance will require that our revenue recognition policy disclosures include further detail regarding our performance obligations as to the nature, amount, timing, and estimates of revenue and cash flows generated from our contracts with customers.

NOTE 3 DISCONTINUED OPERATIONS AND DIVESTITURES

Appalachia Divestiture Discontinued Operations

As disclosed in Note 2, on June 30, 2017, we completed a majority of the Appalachian Assets sale for net cash proceeds of \$65.6 million, which included customary preliminary purchase price adjustments, all of which was used to repay a portion of the outstanding indebtedness under our First Lien Credit Facility. On September 29, 2017, we completed the remainder of the Appalachian Assets sale for additional cash proceeds of \$10.4 million, all of which was used to repay a portion of outstanding borrowings under our First Lien Credit Facility.

We determined the Appalachian Assets represent discontinued operations as they constitute a disposal of a group of components and a strategic shift that will have a major effect on our operations and financial results. We evaluated the Appalachian Assets sale on our gas and oil production and Drilling Partnership management segments' results of operations and cash flows, as well as expected

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asset retirement obligations, and concluded the impact will have a major effect on our expected operations and financial results. As a result, we reclassified the Appalachian Assets from their historical presentation to assets and liabilities held for sale on the condensed consolidated balance sheet and to net income (loss) from discontinued operations on the condensed consolidated statement of operations for all periods presented.

We determined that the carrying value of the remainder of our Appalachian Assets exceeded the fair value less costs to sell, which resulted in an impairment of \$4.3 million recognized in net income (loss) from discontinued operations on our condensed consolidated statement of operations during the nine months ended September 30, 2017.

The following table reconciles the major classes of line items from the discontinued operations of the Appalachian Assets included within net income (loss) from discontinued operations, in thousands:

	Successor			Predecessor	
	Three Months	Nine Months	Period From	Period From	Period
	Ended	Ended	September 1	July 1 to	From
	September 30,	September 30,	to	August 31,	January 1 to
	2017	2017	September 30,	2016	August 31,
	2017	2017	2016	2016	2016
Revenues:					
Gas and oil production	\$ 288	\$ 21,213	\$ 1,197	\$ 2,917	\$ 10,037
Drilling partnership management		5,114	1,320	3,621	12,100
Gain (loss) on mark-to-market derivatives		4,955	750	875	(667)
Total revenues	288	31,282	3,267	7,413	21,470
Costs and expenses:					
Gas and oil production	\$ 924	\$ 9,091	\$ 760	\$ 1,454	\$ 6,244
Drilling partnership management	597	5,824	1,074	2,312	9,801
Depreciation, depletion and amortization		4,842	869	2,693	9,059
General and administrative	298	4,378	395	12,044	16,974
Gain on sale of assets	(4,319)	(32,921)	(4)	(50)	(72)
Impairment on assets held for sale		4,272			
Interest expense	115	2,769	340	842	3,529
Other (income) loss	541	541		(30)	6,126
Total costs and expenses	\$ (1,844)	\$ (1,204)	\$ 3,434	\$ 19,265	\$ 51,661
Income (loss) from discontinued operations before income taxes	2,132	32,486	(167)	(11,852)	(30,191)
Income tax provision (benefit)	(24)	11,541			
Net income (loss) from discontinued operations	\$ 2,156	\$ 20,945	\$ (167)	\$ (11,852)	\$ (30,191)

We allocated First Lien Credit Facility interest expense to our discontinued operations based on the relative proportion of the net cash proceeds from the sale of the Appalachian Assets used to repay outstanding indebtedness under our

First Lien Credit Facility to the total outstanding indebtedness under our First Lien Credit Facility for the periods presented.

We allocated gain (loss) on mark-to-market natural gas commodity derivatives to our discontinued operations based on the relative proportion of the Appalachian Assets' natural gas production volumes to our total natural gas production volumes for the periods presented.

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The following table details the major classes of assets and liabilities of the Appalachian Assets discontinued operations classified as held for sale for the prior period presented, in thousands:

	December 31, 2016
Current assets:	
Accounts receivable	\$ 7,254
Prepaid expenses and other	1,017
Total current assets	8,271
Property, plant and equipment, net	113,956
Other assets	449
Total non-current assets	114,405
Total assets classified as held for sale	\$ 122,676
Current liabilities:	
Accounts payable	\$ 2,516
Current portion of derivative liability	4,279
Accrued liabilities and other	2,666
Total current liabilities	9,461
Long-term derivative liability	1,407
Asset retirement obligations	60,316
Other long-term liabilities	682
Total non-current liabilities	62,405
Total liabilities classified as held for sale	\$ 71,866

We allocated natural gas commodity derivatives assets and liabilities to our discontinued operations held for sale based on the relative proportion of the Appalachian Assets natural gas production volumes to our total natural gas production volumes as of December 31, 2016.

Rangely Divestiture

As disclosed in Note 2, on August 7, 2017, we completed the Rangely Assets sale for net cash proceeds of \$103.5 million, which included customary preliminary purchase price adjustments, all of which was used to repay a portion of the outstanding indebtedness under our First Lien Credit Facility. We determined that the carrying value of the Rangely Assets exceeded the fair value less costs to sell, which resulted in an impairment of \$38.2 million recognized in loss on divestiture on our condensed consolidated statement of operations during the Successor nine months ended September 30, 2017. We recognized a \$5.2 million loss on asset sale from the closing of the Rangely Assets sale during the Successor three and nine months ended September 30, 2017 resulting from final negotiations

and settlement of working capital adjustments in connection with the preliminary purchase price adjustments.

We considered the Rangely Assets to be an individually significant component of our operations. The following table presents the net income (loss) before income taxes of the Rangely Assets for the periods presented, in thousands:

	Successor			Predecessor	
	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2017	Period From September 1, 2016 to September 30, 2016	Period From July 1, 2016 to August 31, 2016	Period From January 1, 2016 to August 31, 2016
Income (loss) before income taxes ⁽¹⁾	\$ (4,292)	\$ (38,379)	\$ 532	\$ 1,253	\$ 2,011

- (1) Income (loss) before income taxes reflects gas and oil production revenues less gas and oil production expenses, general and administrative expenses, depletion, depreciation, and amortization expenses for all periods presented. The Successor three and nine months ended September 30, 2017 include \$5.2 million of loss on asset sale resulting from the closing of the Rangely Asset sale. The Successor nine months ended September 30, 2017 also includes \$38.2 million loss on divestiture resulting from the carrying value of the Rangely Assets exceeding the fair value less costs to sell as disclosed above.

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The following is a summary of property, plant and equipment at the dates indicated (in thousands):

	September 30, 2017	December 31, 2016
Natural gas and oil properties:		
Proved properties	\$ 519,147	\$ 608,901
Unproved properties	52,767	73,057
Support equipment and other	8,690	8,081
Total natural gas and oil properties	580,604	690,039
Less accumulated depreciation, depletion and amortization	(53,207)	(19,270)
Total property, plant and equipment, net	\$ 527,397	\$ 670,769

During the Successor nine months ended September 30, 2017, the Successor period from September 1, 2016 through September 30, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016, we recognized \$0.7 million, \$3.5 million and \$19.6 million, respectively, of non-cash investing activities capital expenditures, which was reflected within the changes in accounts payable and accrued liabilities on our condensed consolidated statements of cash flows.

We capitalize interest on borrowed funds related to capital projects only for periods that activities are in progress to bring these projects to their intended use. The weighted average interest rate used to capitalize interest on borrowed funds during the Successor three and nine months ended September 30, 2017, the Successor period September 1, 2016 through September 30, 2016, and the Predecessor periods from July 1, 2016 through August 31, 2016 and January 1, 2016 through August 31, 2016 were 9.5%, 8.4%, 7.6%, 6.0% and 6.5%, respectively. The aggregate amount of interest capitalized during the Successor three and nine months ended September 30, 2017, the Successor period September 1, 2016 through September 30, 2016, and the Predecessor periods from July 1, 2016 through August 31, 2016 and January 1, 2016 through August 31, 2016 were \$0.2 million, \$0.4 million, \$0.7 million, \$1.7 million and \$6.5 million, respectively.

For the Successor three and nine months ended September 30, 2017, the Successor period September 1, 2016 through September 30, 2016, and the Predecessor periods from July 1, 2016 through August 31, 2016 and January 1, 2016 through August 31, 2016, we recorded \$0.4 million, \$1.1 million, \$0.5 million, \$1.3 million and \$4.6 million, respectively, of accretion expense related to our asset retirement obligations within depreciation, depletion and amortization in our condensed consolidated statements of operations.

NOTE 5 DEBT

Total debt consists of the following at the dates indicated (in thousands):

September 30,	December 31,
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	2017	2016
First Lien Credit Facility	\$ 256,273	\$ 435,809
Second Lien Credit Facility	283,523	261,022
Deferred financing costs, net of accumulated amortization of \$686 and \$172, respectively	(1,711)	(2,021)
Total debt, net	538,085	694,810
Less current maturities	(538,085)	(694,810)
Total long-term debt, net	\$	\$

Cash Interest. Total cash payments for interest for the Successor three and nine months ended September 30, 2017, the Successor period September 1, 2016 through September 30, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016, were \$7.3 million, \$21.2 million, \$0.5 million and \$53.7 million, respectively. There were no cash payments for interest for the Predecessor period from July 1, 2016 through August 31, 2016 due to our Predecessor's Chapter 11 Filings.

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First Lien Credit Facility

On September 1, 2016, we entered into our \$440 million First Lien Credit Facility with Wells Fargo Bank, National Association (Wells Fargo), as administrative agent, and the lenders party thereto. A summary of the key provisions of the First Lien Credit Facility is as follows (of which certain provisions have been modified through subsequent amendments as described further below):

Borrowing base of a \$410 million conforming reserve based tranche plus a \$30 million non-conforming tranche.

Provides for the issuance of letters of credit, which reduce borrowing capacity.

Obligations are secured by mortgages on substantially all of our oil and gas properties and first priority security interests in substantially all of our assets and are guaranteed by certain of our material subsidiaries, and any non-guarantor subsidiaries of ours are minor.

Borrowings bear interest at our election at either LIBOR plus an applicable margin between 3.00% and 4.00% per annum or the alternate base rate plus an applicable margin between 2.00% and 3.00% per annum, which fluctuates based on utilization. We are also required to pay a fee of 0.50% per annum on the unused portion of the borrowing base. At September 30, 2017, the weighted average interest rate on outstanding borrowings under the First Lien Credit Facility was 5.2%.

Contains covenants that limit our ability to incur additional indebtedness, grant liens, make loans or investments, make distributions, merge into or consolidate with other persons, enter into commodity or interest rate swap agreements that do not conform to specified terms or that exceed specified amounts, or engage in certain asset dispositions including a sale of all or substantially all of our assets.

Requires us to enter into commodity hedges covering at least 80% of our expected 2019 production prior to December 31, 2017.

We were not in compliance with certain of the financial covenants under our credit facilities as of December 31, 2016, as well as the requirement to deliver audited financial statements without a going concern qualification. On April 19, 2017, we, Titan Energy Operating, LLC (our wholly owned subsidiary), as borrower, and certain subsidiary guarantors entered into a third amendment to the First Lien Credit Facility with Wells Fargo, as administrative agent, and the lenders party thereto. Pursuant to the third amendment, certain of the financial ratio covenants were revised upwards. Specifically, beginning December 31, 2017, we will be required to maintain a ratio of Total Debt to EBITDA (each as defined in the First Lien Credit Facility) of not more than 5.50 to 1.00 for each fiscal quarter through December 31, 2018 and of not more than 5.00 to 1.00 thereafter. We will also be required, beginning December 31, 2017, to maintain a ratio of First Lien Debt (as defined in the First Lien Credit Facility) to EBITDA of not more than 4.00 to 1.00 for each fiscal quarter through December 31, 2018 and of not more than 3.50 to 1.00 thereafter.

In addition to the amendments to the financial ratio covenants, the First Lien Credit Facility lenders waived certain defaults by us with respect to the fourth quarter of 2016, including compliance with the ratios of Total Debt to EBITDA and First Lien Debt to EBITDA, as well as our obligation to deliver financial statements without a going concern qualification. The First Lien Credit Facility lenders' waivers were subject to revocation in certain circumstances, including the exercise of remedies by junior lenders (including pursuant to our second lien credit facility), the failure to extend the 180-day standstill period under the intercreditor agreement at least 15 business days prior to its expiration, and the occurrence of additional events of default under the First Lien Credit Facility.

The third amendment to the First Lien Credit Facility confirmed the conforming and non-conforming tranches of the borrowing base at \$410 million and \$30 million, respectively, but required us to take actions (which included asset sales) to reduce the conforming tranche of the borrowing base to \$330 million by August 31, 2017 and to \$190 million by October 1, 2017 (subject to extension at the administrative agent's option to October 31, 2017). Similarly, the non-conforming tranche of the borrowing base was required to be reduced to \$10 million by November 1, 2017. In addition, we were required to use excess asset sale proceeds (after application in accordance with the existing terms of the First Lien Credit Facility) to repay outstanding borrowings and reduce the applicable borrowing base to the required level.

On June 30, 2017, we completed a majority of the Appalachian Assets sale for net cash proceeds of \$65.6 million, which included customary preliminary purchase price adjustments, all of which was used to repay a portion of the outstanding indebtedness under our First Lien Credit Facility. On August 7, 2017, we completed the Rangely Assets sale for net cash proceeds of \$103.5 million, which included customary preliminary purchase price adjustments, all of which was used to repay a portion of the outstanding indebtedness under our First Lien Credit Facility and achieve compliance with the requirement to reduce our First Lien Credit Facility borrowings below \$360 million, as required by August 31, 2017. On September 29, 2017, we completed the remainder of the Appalachia Assets sale for additional cash proceeds of \$10.4 million, all of which was used to repay a portion of outstanding borrowings under our First Lien Credit Facility.

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On November 6, 2017, we entered into a fourth amendment to our First Lien Credit Facility. The fourth amendment has an effective date of October 31, 2017 and confirms the conforming and non-conforming tranches of the borrowing base at \$228.7 million and \$30 million, respectively, but requires us to take actions (which can include asset sales and equity offerings) to reduce the conforming tranche of the borrowing base to \$190 million by December 8, 2017 and to \$150 million by August 31, 2018. The maturity date of the non-conforming tranche of the borrowing base was confirmed as May 1, 2018. We are required to use proceeds from asset sales to make prepayments.

In addition to the requirements above, the First Lien Credit Facility lenders also agreed to a limited waiver of certain existing defaults with respect to financial covenants, required repayments of borrowings and other related matters. The waiver terminates upon the earliest of (i) December 8, 2017, (ii) the occurrence of additional events of default under the First Lien Credit Facility and (iii) the exercise of remedies under our Second Lien Credit Facility. Pursuant to the fourth amendment, we are required to hedge at least 50% and 80% of our 2019 projected proved developed producing production by December 31, 2017 and March 31, 2018, respectively.

Second Lien Credit Facility

On September 1, 2016, we entered into our Second Lien Credit Facility with Wilmington Trust, National Association, as administrative agent, and the lenders party thereto for an aggregate principal amount of \$252.5 million maturing on February 23, 2020. A summary of the key provisions of the Second Lien Credit Facility is as follows (of which certain provisions have been modified through subsequent amendments as described further below):

Until May 1, 2017, interest will be payable at a rate of 2% in cash plus paid-in-kind interest at a rate equal to the Adjusted LIBO Rate (as defined in the Second Lien Credit Facility) plus 9% per annum. During the subsequent 15-month period, cash and paid-in-kind interest will vary based on a pricing grid tied to our leverage ratio under the First Lien Credit Facility. After such 15-month period, interest will accrue at a rate equal to the Adjusted LIBO Rate plus 9% per annum and will be payable in cash.

All prepayments are subject to the following premiums, plus accrued and unpaid interest:

4.5% of the principal amount prepaid for prepayments prior to February 23, 2017;

2.25% of the principal amount prepaid for prepayments on or after February 23, 2017 and prior to February 23, 2018; and

no premium for prepayments on or after February 23, 2018.

Obligations are secured on a second priority basis by security interests in the same collateral securing the First Lien Credit Facility and are guaranteed by certain of our material subsidiaries, and any non-guarantor subsidiaries of ours are minor.

Contains covenants that limit our ability to make restricted payments, take on indebtedness, issue preferred stock, grant liens, conduct sales of assets and subsidiary stock, make distributions from restricted subsidiaries, conduct affiliate transactions, engage in other business activities, and other covenants substantially similar to those in the First Lien Credit Facility, including, among others, restrictions on swap agreements, debt of unrestricted subsidiaries, drilling and operating agreements and the sale or discount of receivables.

Requires us to maintain certain financial ratios (the financial ratios used an annualized EBITDA measurement for periods prior to June 30, 2017):

EBITDA to Interest Expense (each as defined in the Second Lien Credit Facility) of not less than 2.50 to 1.00;

Total Leverage Ratio (as defined in the Second Lien Credit Facility) of no greater than 5.5 to 1.0 prior to December 31, 2017 and no greater than 5.0 to 1.0 thereafter; and

Current assets to current liabilities (each as defined in the Second Lien Credit Facility) of not less than 1.0 to 1.0.

On April 21, 2017, the lenders under the our Second Lien Credit Facility delivered a Notice, pursuant to which they noticed events of default related to financial covenants and the failure to deliver financial statements without a going concern qualification. The delivery of the Notice began the 180-day standstill period under the intercreditor agreement, during which the lenders under the Second Lien Credit Facility were prevented from pursuing remedies against the collateral securing our obligations under the Second Lien Credit Facility. The lenders have not accelerated the payment of amounts outstanding under the Second Lien Credit Facility.

On September 27, 2017, the lenders under our Second Lien Credit Facility entered into the Extension Letter with us and the lenders under our First Lien Credit Facility. Pursuant to the Extension Letter, the Second Lien Credit Facility lenders agreed to extend the 180-day standstill period under the intercreditor agreement (during which the lenders under the Second Lien Credit Facility were prevented from pursuing remedies against the collateral securing the Company's obligations under the Second Lien Credit Facility) by

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an additional 35 days from October 18, 2017 to November 22, 2017. In addition, the extension of the standstill period extends the waiver of certain defaults under the First Lien Credit Facility, which terminates 15 business days prior to the expiration of the standstill period. The parties agreed to extend the standstill period to provide the Company with additional time to negotiate proposed amendments to each of the First Lien Credit Facility and the Second Lien Credit Facility.

In connection with, and as a condition to, the effectiveness of the fourth amendment to our First Lien Credit Facility, on November 6, 2017, the lenders under our Second Lien Credit Facility agreed to extend the standstill period under the intercreditor agreement (during which the lenders under the Second Lien Credit Facility are prevented from pursuing remedies against the collateral securing our obligations under the Second Lien Credit Facility) until December 29, 2017.

NOTE 6 DERIVATIVE INSTRUMENTS

We use a number of different derivative instruments, principally swaps and options, in connection with our commodity price risk management activities. We do not apply hedge accounting to any of our derivative instruments. As a result, gains and losses associated with derivative instruments are recognized in earnings.

We enter into commodity future option contracts to achieve more predictable cash flows by hedging our exposure to changes in commodity prices. At any point in time, such contracts may include regulated New York Mercantile Stock Exchange (NYMEX) futures and options contracts and non-regulated over-the-counter futures contracts with qualified counterparties. NYMEX contracts are generally settled with offsetting positions, but may be settled by the physical delivery of the commodity. Crude oil contracts are based on a West Texas Intermediate (WTI) index. NGL fixed price swaps are priced based on a WTI crude oil index, while ethane, propane, butane and iso butane contracts are priced based on the respective Mt. Belvieu price. These contracts were recorded at their fair values.

Pursuant to the Restructuring Support Agreement, our Predecessor completed the sale of substantially all of its commodity hedge positions on July 25, 2016 and July 26, 2016 and used the proceeds to repay \$233.5 million of borrowings outstanding under the Predecessor's first lien credit facility.

The following table summarizes the commodity derivative activity and presentation in our condensed consolidated statements of operations for the periods indicated (in thousands):

	Successor			Predecessor	
	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2017	Period from September 1, 2016 through September 30, 2016	Period from July 1, 2016 through August 31, 2016	Period from January 1, 2016 through August 31, 2016
Portion of settlements associated with gains previously recognized within accumulated other comprehensive income, net of prior year offsets ⁽¹⁾⁽²⁾	\$	\$	\$	\$ 1,461	\$ 10,387
Portion of settlements attributable to subsequent mark to market gains (losses) ⁽²⁾	1,666	(2,309)	191	3,440	80,604

Total cash settlements on commodity derivative contracts ⁽²⁾	\$ 1,666	\$ (2,309)	\$ 191	\$ 4,901	\$ 90,991
Gains (losses) recognized on cash settlement ⁽³⁾	\$ 195	\$ 20,409	\$ (43)	\$ 9,381	\$ (9,444)
Gains (losses) recognized on open derivative contracts ⁽³⁾	(4,263)	16,516	(2,036)	(7,028)	(13,804)
Gains (losses) on mark-to-market derivatives	\$ (4,068)	\$ 36,925	\$ (2,079)	\$ 2,353	\$ (23,248)

(1) Recognized in gas and oil production revenue.

(2) The Predecessor periods presented exclude the effects of the \$214.9 million and the \$20.4 million allocated to discontinued operations (see Note 3), net of \$8.2 million in hedge monetization fees, paid directly to the First Lien Credit Facility lenders upon the sale of substantially all of our Predecessor's commodity hedge positions on July 25, 2016 and July 26, 2016. The \$8.2 million in hedge monetization fees was not allocated to discontinued operations as this was recorded in reorganization items, net on the condensed consolidated statements of operations.

(3) Recognized in gain (loss) on mark-to-market derivatives.

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The following table summarizes the gross fair values of our derivative instruments, presenting the impact of offsetting the derivative assets and liabilities included on our condensed consolidated balance sheets for the periods indicated (in thousands):

	Gross Amounts Recognized	Gross Amounts Offset	Net Amount Presented
<u>Offsetting Derivatives as of September 30, 2017</u>			
Current portion of derivative assets	\$ 2,038	\$ (2,006)	\$ 32
Long-term portion of derivative assets	168	(168)	
Total derivative assets	\$ 2,206	\$ (2,174)	\$ 32
Current portion of derivative liabilities	\$ (5,635)	\$ 2,006	\$ (3,629)
Long-term portion of derivative liabilities	(1,064)	168	(896)
Total derivative liabilities	\$ (6,699)	\$ 2,174	\$ (4,525)
<u>Offsetting Derivatives as of December 31, 2016</u>			
Current portion of derivative assets	\$ 7	\$ (7)	\$
Long-term portion of derivative assets	677	(677)	
Total derivative assets	\$ 684	\$ (684)	\$
Current portion of derivative liabilities	\$ (30,526)	\$ 7	\$ (30,519)
Long-term portion of derivative liabilities	(13,885)	677	(13,208)
Total derivative liabilities	\$ (44,411)	\$ 684	\$ (43,727)

At September 30, 2017, we had the following commodity derivatives instruments:

Type	Production Period Ending December 31,	Volumes ⁽¹⁾	Average Fixed Price ⁽²⁾	Fair Value Asset / (Liability) (in thousands) ⁽²⁾	Total Type (in thousands)
Natural Gas Fixed Price Swaps	2017 ⁽³⁾	12,919,900	\$ 3.140	\$ 693	
	2018	43,947,300	\$ 2.959	\$ (3,458)	\$ (2,765)
Crude Oil Fixed Price Swaps	2017 ⁽³⁾	196,500	\$ 47.441	\$ (766)	
	2018	588,500	\$ 50.286	\$ (936)	
	2019	73,000	50.630	(26)	\$ (1,728)
				Total net liability	\$ (4,493)

- (1) Volumes for natural gas are stated in million British Thermal Units. Volumes for crude oil are stated in barrels.
- (2) Fair value for natural gas fixed price swaps are based on forward NYMEX natural gas prices, as applicable. Fair value of crude oil fixed price swaps are based on forward West Texas Intermediate (WTI) index crude oil prices, as applicable.
- (3) The production volumes for 2017 include the remaining three months of 2017 beginning October 1, 2017.

NOTE 7 FAIR VALUE OF FINANCIAL INSTRUMENTS

Assets and Liabilities Measured on a Recurring Basis

We use a market approach fair value methodology to value our outstanding derivative contracts. The fair value of a financial instrument depends on a number of factors, including the availability of observable market data over the contractual term of the underlying instrument. We separate the fair value of our financial instruments into the three level hierarchy (Levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine fair value. As of September 30, 2017 and December 31, 2016, all of our derivative financial instruments were classified as Level 2.

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Information for financial instruments measured at fair value were as follows (in thousands):

Derivatives, Fair Value, as of September 30, 2017	Level 1	Level 2	Level 3	Total
Assets, gross				
Commodity swaps	\$	\$ 2,206	\$	\$ 2,206
Total derivative assets, gross		2,206		2,206
Liabilities, gross				
Commodity swaps		(6,699)		(6,699)
Total derivative liabilities, gross		(6,699)		(6,699)
Total derivatives, fair value, net	\$	\$ (4,493)	\$	\$ (4,493)
Derivatives, Fair Value, as of December 31, 2016	Level 1	Level 2	Level 3	Total
Assets, gross				
Commodity swaps	\$	\$ 684	\$	\$ 684
Total derivative assets, gross		684		684
Liabilities, gross				
Commodity swaps		(44,411)		(44,411)
Total derivative liabilities, gross		(44,411)		(44,411)
Total derivatives, fair value, net	\$	\$ (43,727)	\$	\$ (43,727)

Other Financial Instruments

Our other current assets and liabilities on our condensed consolidated balance sheets are considered to be financial instruments. The estimated fair values of these instruments approximate their carrying amounts due to their short-term nature and thus are categorized as Level 1. The estimated fair value of our long-term debt at September 30, 2017, which consists of our First Lien Credit Facility and Second Lien Credit Facility, approximated carrying value of \$539.8 million. At September 30, 2017, the carrying value of outstanding borrowings under our First Lien Credit Facility, which bears interest at variable interest rates, approximated estimated fair value. The estimated fair value of our Second Lien Credit Facility was based upon the market approach and calculated using yields of our Second Lien Credit Facility as provided by financial institutions and thus were categorized as Level 3 values.

Assets and Liabilities Measured at Fair Value on a Non-Recurring Basis

We estimated the fair value less estimated costs to sell of our remaining Appalachia Assets and Rangely Assets held for sale (see Note 3) based on the respective negotiated purchase prices that were derived from discounted cash flow models, which considered the estimated remaining lives of the wells based on reserve estimates, future operating and development costs of the assets, the respective natural gas, oil and natural gas liquids forward price curves, external

estimates of recovery values, and other market multiples. These estimates of fair value are Level 3 measurements as they are based on unobservable inputs.

Our Predecessor's management estimated the fair values of natural gas and oil properties transferred to our Predecessor upon consolidation of certain Drilling Partnerships (see Note 8) based on a discounted cash flow model, which considered the estimated remaining lives of the wells based on reserve estimates, our Predecessor's future operating and development costs of the assets, the respective natural gas, oil and natural gas liquids forward price curves and estimated salvage values using our historical experience and external estimates of recovery values. These estimates of fair value were Level 3 measurements as they were based on unobservable inputs.

Our Predecessor's management estimated the fair value of asset retirement obligations transferred to our Predecessor upon consolidation of certain Drilling Partnerships (see Note 8) based on discounted cash flow projections using our Predecessor's historical experience in plugging and abandoning wells, the estimated remaining lives of those wells based on reserve estimates, external estimates as to the cost to plug and abandon the wells in the future considering inflation rates, federal and state regulatory requirements, and our Predecessor's assumed credit-adjusted risk-free interest rate. These estimates of fair value were Level 3 measurements as they were based on unobservable inputs.

We estimated the fair value of our enterprise value and reorganizational value of assets and liabilities upon our emergence from bankruptcy through fresh-start accounting (see Note 2) utilizing the discounted cash flow method for both our gas and oil production business and our partnership management business based on the financial projections in our disclosure statement. The resulting fair value of our equity was used to value shares issued under our incentive plan. These estimates of fair value are Level 3 measurements as they are based on unobservable inputs.

Table of Contents**NOTE 8 CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS**

Relationship with ATLS. Except for our named executive officers, we do not directly employ any persons to manage or operate our business. These functions are provided by employees of ATLS and/or its affiliates. As of September 30, 2017, we had a \$1.8 million payable to ATLS for payroll and benefit costs related to ATLS employees managing and operating our business, which was recorded as a current liability within advances from affiliates on our condensed consolidated balance sheet. As of September 30, 2017 we reclassified \$15.1 million of receivables from ATLS originating prior to our Chapter 11 Filings to non-current due to the uncertainty of collecting this balance within the next twelve months, which was recorded within non-current advances to affiliates on our condensed consolidated balance sheet. As of December 31, 2016, we had net receivables of \$3.3 million from ATLS related to the timing of funding cash accounts related to general and administrative expenses, such as payroll and benefits, and amounts originating prior to our Chapter 11 Filings, which was recorded as a net current asset within in advances to affiliates in our condensed consolidated balance sheets.

Relationship with Drilling Partnerships. We conduct certain activities through, and a portion of our revenues are attributable to, sponsorship of the Drilling Partnerships. We serve as general partner and operator of the Drilling Partnerships and assume customary rights and obligations for the Drilling Partnerships. As the general partner, we are liable for the Drilling Partnerships' liabilities and can be liable to limited partners of the Drilling Partnerships if we breach our responsibilities with respect to the operations of the Drilling Partnerships. We are entitled to receive management fees, reimbursement for administrative costs incurred and to share in the Drilling Partnership's revenue and costs and expenses according to the respective partnership agreements. On June 30, 2017, in connection with the completion of the sale of the majority of the Appalachian Assets, we delegated the operational activities to an affiliate of Diversified for all the Drilling Partnerships' natural gas and oil wells in Pennsylvania and Tennessee.

In March 2016, our Predecessor transferred \$36.7 million of investor capital raised and \$13.3 million of accrued well drilling and completion costs incurred by our Predecessor to the Atlas Eagle Ford 2015 L.P. private drilling partnership for activities directly related to their program. In June 2016, our Predecessor transferred \$3.8 million of funds to certain of the Drilling Partnerships that were projected to make monthly or quarterly distributions to their limited partners over the next several months and/or quarters to ensure accessible distribution funding coverage in accordance with the respective Drilling Partnerships' operations and partnership agreements in the event that our Predecessor experienced a prolonged restructuring period as our Predecessor performed all administrative and management functions for the Drilling Partnerships.

During the Predecessor period from January 1, 2016 to August 31, 2016, our Predecessor recorded \$7.2 million and \$12.4 million of gas and oil properties and asset retirement obligations, respectively, transferred to our Predecessor as a result of certain Drilling Partnership consolidations. The gas and oil properties and asset retirement obligations were recorded at their fair values on the respective dates of the Drilling Partnerships' consolidation and transfer to our Predecessor (see Note 7) and resulted in a non-cash loss of \$6.1 million, net of consolidation and transfer adjustments, for the Predecessor period from January 1, 2016 through August 31, 2016, which was recorded in net income (loss) from discontinued operations in the consolidated statements of operations.

During the Predecessor periods from July 1, 2016 to August 31, 2016 and from January 1, 2016 to August 31, 2016, we recognized a \$10.9 million provision for losses on Drilling Partnership receivables related to the write down of certain receivables to their estimated net realizable values, which is recorded in loss from discontinued operations on our consolidated statement of operations. As of December 31, 2016, we had trade receivables of \$0.1 million from certain of the Drilling Partnerships, which were recorded in accounts receivable in our condensed consolidated balance sheet. As of September 30, 2017 and December 31, 2016, we had trade payables of \$3.2 million and \$5.6 million, respectively, to certain of the Drilling Partnerships, which were recorded in accounts payable in our

condensed consolidated balance sheets.

Relationship with AGP. At the direction of ATLS, we charge direct costs, such as salaries and wages, and allocate indirect costs, such as rent and other general and administrative costs, to AGP based on the number of ATLS employees who devoted time to AGP's activities. As of September 30, 2017 and December 31, 2016, we had receivables of \$0.1 million and \$0.8 million, respectively, from AGP related to AGP's direct costs and indirect cost allocation, which was recorded in advances to affiliates in our condensed consolidated balance sheets.

Other Relationships. We have other related party transactions with regard to certain funds advised and sub-advised by GSO Capital Partners LP and its affiliates (GSO) as GSO funds are majority lenders under our Second Lien Credit Facility and GSO funds hold an excess of ten-percent of our common shares.

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NOTE 9 COMMITMENTS AND CONTINGENCIES

Drilling Partnership Commitments

As of September 30, 2017, we are committed to expend approximately \$2.8 million, principally on a new enterprise resource planning system and drilling and completion expenditures.

Environmental Matters

We and our subsidiaries are subject to various federal, state and local laws and regulations relating to the protection of the environment. We have established procedures for the ongoing evaluation of our and our subsidiaries' operations, to identify potential environmental exposures and to comply with regulatory policies and procedures. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations and do not contribute to current or future revenue generation are expensed. Liabilities are recorded when environmental assessments and/or clean-ups are probable, and the costs can be reasonably estimated. We and our subsidiaries maintain insurance which may cover in whole or in part certain environmental expenditures. We and our subsidiaries had no environmental matters requiring specific disclosure or requiring the recognition of a liability as of September 30, 2017 and December 31, 2016.

Legal Proceedings

We are party to various routine legal proceedings arising out of the ordinary course of our business. We believe that none of these actions, individually or in the aggregate, will have a material adverse effect on our financial condition, results of operations or cash flows.

NOTE 10 PREDECESSOR CASH DISTRIBUTIONS

Our Predecessor had a monthly cash distribution program whereby it distributed all of its available cash (as defined in its partnership agreement) for that month to its unitholders within 45 days from the month end. If our Predecessor's common unit distributions in any quarter exceed specified target levels, ATLS received between 13% and 48% of such distributions in excess of the specified target levels.

During the Predecessor period from January 1, 2016 through August 31, 2016, our Predecessor paid four monthly cash distributions totaling \$5.1 million to its common limited partners (\$0.0125 per unit per month); \$2.5 million to its Preferred Class C limited partners (\$0.0125 per unit per month); and \$0.2 million to its General Partner Class A holder (\$0.0125 per unit per month).

During the Predecessor period from January 1, 2016 through August 31, 2016, our Predecessor paid two distributions totaling \$4.4 million to its Class D Preferred limited partners (\$0.5390625 per unit) for the period October 15, 2015 through April 14, 2016. During the Predecessor period from January 1, 2016 through August 31, 2016, our Predecessor paid two distributions totaling \$0.3 million to its Class E Preferred limited partners (\$0.671875 per unit) for the period October 15, 2015 through April 14, 2016. On June 16, 2016, our Predecessor's Board of Directors elected to suspend its quarterly distributions on its Class D Preferred Units and our Class E Preferred Units, beginning with the second quarter 2016 distribution, due to the continued lower commodity price environment. The Class D Preferred Units and Class E Preferred Units accrued distributions of \$3.4 million and \$0.3 million, respectively, from April 15, 2016 through August 31, 2016. However, due to the distribution suspension and our Predecessor's Chapter 11 filings, these amounts were not earned as the preferred units were cancelled without receipt of any consideration on the Plan Effective Date.

NOTE 11 OPERATING SEGMENT INFORMATION

Our operations include two reportable operating segments: gas and oil production and Drilling Partnership management. The Drilling Partnership management segment includes all of our managing and operating activities specific to the Drilling Partnerships including well construction and completion, administration and oversight, well services, and gathering and processing. These operating segments reflect the way we manage our operations and make business decisions.

We previously presented three reportable operating segments; however, due to the decline in investor capital funds raised in recent years, anticipated lower levels of future investor capital fund raise, and the consolidation of certain historical Drilling Partnerships in 2016, we aggregated our well construction and completion segment with our other partnership management segment to report all of our Drilling Partnership management activities in one combined segment as they do not meet the quantitative threshold for reporting individual segment information. As a result of this change, we have restated our prior year condensed consolidated statements of operations and segment footnote disclosures to conform to our current presentation.

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Operating segment data for the periods indicated were as follows (in thousands):

	Successor Three Months Period Ended September 1 September 30, through 2017	September 1 30, 2016	Predecessor Period July 1 through August 31, 2016
Gas and oil production:			
Gas and oil production revenues ⁽¹⁾	\$ 43,356	\$ 15,182	\$ 38,643
Gas and oil production costs	(21,633)	(9,854)	(18,577)
Depreciation, depletion and amortization	(11,646)	(4,882)	(14,723)
Loss on divestiture	(5,177)		
Segment income	\$ 4,900	\$ 446	\$ 5,343
Drilling partnership management:⁽²⁾			
Drilling partnership management revenues	\$ 1,997	\$ 2,074	\$ 18,778
Drilling partnership management expenses	(248)	(1,266)	(16,121)
Depreciation, depletion and amortization expense	(288)	(270)	(5,862)
Segment income (loss)	\$ 1,461	\$ 538	\$ (3,205)
Reconciliation of segment income (loss) to net loss:			
Segment income (loss):			
Gas and oil production	\$ 4,900	\$ 446	\$ 5,343
Drilling partnership management ⁽²⁾	1,461	538	(3,205)
Total segment income	6,361	984	2,138
General and administrative expenses ⁽³⁾	(10,142)	(4,530)	(5,128)
Interest expense ⁽³⁾	(15,268)	(3,470)	(14,087)
Gain (loss) on asset sales and disposal ⁽³⁾	(82)	5	(18)
Reorganization items, net ⁽³⁾		(353)	(16,614)
Other income (loss) ⁽³⁾	(777)		(3,063)
Income tax (provision) benefit ⁽³⁾	202		
Net loss	\$ (19,706)	\$ (7,364)	\$ (36,772)
Reconciliation of segment revenues to total revenues:			
Gas and oil production ⁽¹⁾	\$ 43,356	\$ 15,182	\$ 38,643
Drilling partnership management	1,997	2,074	18,778
Total revenues	\$ 45,353	\$ 17,256	\$ 57,421

Capital expenditures:

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Gas and oil production	\$ 4,279	\$ 5,464	\$ 5,529
Drilling partnership management		(115)	496
Corporate and other	325	18	49
Total capital expenditures	\$ 4,604	\$ 5,367	\$ 6,074

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	Successor		Predecessor
	Nine Months Ended September 30, 2017	Period September 1 through 30, 2016	Period January 1 through August 31, 2016
Gas and oil production:			
Gas and oil production revenues ⁽¹⁾	\$ 197,855	\$ 15,182	\$ 105,829
Gas and oil production costs	(74,355)	(9,854)	(80,988)
Depreciation, depletion and amortization	(37,455)	(4,882)	(62,142)
Loss on divestiture	(43,369)		
Segment income (loss)	\$ 42,676	\$ 446	\$ (37,301)
Drilling partnership management:⁽²⁾			
Drilling partnership management revenues	\$ 17,387	\$ 2,074	\$ 24,446
Drilling partnership management expenses	(10,026)	(1,266)	(17,427)
Depreciation, depletion and amortization expense	(947)	(270)	(11,130)
Segment income (loss)	\$ 6,414	\$ 538	\$ (4,111)
Reconciliation of segment income (loss) to net loss:			
Segment income (loss):			
Gas and oil production ⁽¹⁾	\$ 42,676	\$ 446	\$ (37,301)
Drilling partnership management	6,414	538	(4,111)
Total segment income (loss)	49,090	984	(41,412)
General and administrative expenses ⁽³⁾	(32,961)	(4,530)	(41,038)
Interest expense ⁽³⁾	(41,816)	(3,470)	(71,059)
Gain on early extinguishment of debt ⁽³⁾			26,498
Gain (loss) on asset sales and disposal ⁽³⁾	25	5	(551)
Reorganization items, net ⁽³⁾		(353)	(16,614)
Other income (loss) ⁽³⁾	(925)		(3,063)
Income tax (provision) benefit ⁽³⁾	11,503		
Net loss	\$ (15,084)	\$ (7,364)	\$ (147,239)
Reconciliation of segment revenues to total revenues:			
Gas and oil production ⁽¹⁾	\$ 197,855	\$ 15,182	\$ 105,829
Drilling partnership management	17,387	2,074	24,446
Total revenues	\$ 215,242	\$ 17,256	\$ 130,275
Capital expenditures:			
Gas and oil production	\$ 36,191	\$ 5,464	\$ 22,684
Drilling partnership management	521	(115)	2,046
Corporate and other	527	18	164

Total capital expenditures	\$ 37,239	\$ 5,367	\$ 24,894
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- (1) Includes gain (loss) on mark-to-market derivatives. The Predecessor period from January 1, 2016 through August 31, 2016 includes a \$23.2 million loss on mark-to-market derivatives related to increases in commodity future prices relative to our commodity fixed price swaps.
- (2) Includes revenues and expenses from our Drilling Partnership management activities, including well construction and completion, well services, gathering and processing, administration and oversight that do not meet the quantitative threshold for reporting individual segment information.
- (3) General and administrative expenses, interest expense, gain on early extinguishment of debt, gain (loss) on asset sales and disposal, reorganization items, net,, other income (loss) and income tax (provision) benefit have not been allocated to reportable segments as it would be impracticable to reasonably do so for the periods presented.

	September 30, 2017	December 31, 2016
Balance sheet:		
Total assets:		
Gas and oil production	\$ 556,607	\$ 703,243
Drilling partnership management	5,476	11,786
Corporate and other ⁽¹⁾	43,342	44,129
Assets held for sale		122,676
Total assets	\$ 605,425	\$ 881,834

- (1) Corporate and other primarily consists of cash and cash equivalents, advances to affiliates and other assets, net, which have not been allocated to reportable segments.

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ITEM 2: MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

BUSINESS OVERVIEW

We are a publicly traded (OTCQX: TTEN) Delaware limited liability company and an independent developer and producer of natural gas, crude oil and NGLs with operations in basins across the United States but primarily focused on the horizontal development of resource potential from the Eagle Ford Shale in South Texas. As discussed further below, we are the successor to the business and operations of Atlas Resource Partners, L.P. (ARP). Unless the context otherwise requires, references to Titan Energy, LLC, Titan, the Company, we, us, and our, refer to Titan Energy and our consolidated subsidiaries (and our predecessor, where applicable).

Titan Energy Management, LLC (Titan Management) manages us and holds our Series A Preferred Share, which entitles Titan Management to receive 2% of the aggregate of distributions paid to shareholders (as if it held 2% of our members' equity, subject to dilution as discussed below) and to appoint four of our seven directors. Titan Management is a wholly owned subsidiary of Atlas Energy Group, LLC (ATLS ; OTCQX: ATLS), which is a publicly traded company.

In addition to its preferred member interest in us, ATLS also holds general and limited partner interests in Atlas Growth Partners, L.P. (AGP), a Delaware limited partnership and an independent developer and producer of natural gas, oil and NGLs, with operations primarily focused in the Eagle Ford Shale, and in Lightfoot Capital Partners, L.P. and Lightfoot Capital Partners GP, LLC, which incubate new MLPs and invest in existing MLPs.

ARP Restructuring and Emergence from Chapter 11 Proceedings

On July 25, 2016, ARP and certain of its subsidiaries and ATLS, solely with respect to certain sections thereof, entered into a Restructuring Support Agreement (the Restructuring Support Agreement) with certain of their lenders (the Restructuring Support Parties) to support ARP's restructuring pursuant to a pre-packaged plan of reorganization (the Plan).

On July 27, 2016, ARP and certain of its subsidiaries filed voluntary petitions for relief under Chapter 11 in the United States Bankruptcy Court for the Southern District of New York (the Bankruptcy Court, and the cases commenced thereby, the Chapter 11 Filings). The cases commenced thereby were jointly administered under the caption In re: ATLAS RESOURCE PARTNERS, L.P., et al.

On August 26, 2016, an order confirming the Plan was entered by the Bankruptcy Court. On September 1, 2016, (the Plan Effective Date), pursuant to the Plan, the following occurred:

ARP's first lien lenders received cash payment of all obligations owed to them by ARP pursuant to the senior secured revolving credit facility (other than \$440 million of principal and face amount of letters of credit) and became lenders under our first lien exit facility credit agreement, composed of a \$410 million conforming reserve-based tranche and a \$30 million non-conforming tranche (the First Lien Credit Facility).

ARP's second lien lenders received a pro rata share of our second lien exit facility credit agreement with an aggregate principal amount of \$252.5 million (the Second Lien Credit Facility). In addition, ARP's second lien lenders received a pro rata share of 10% of our common shares, subject to dilution by a management

incentive plan.

ARP's senior note holders, in exchange for 100% of the \$668 million aggregate principal amount of senior notes outstanding plus accrued but unpaid interest as of the commencement of the Chapter 11 Filings, received 90% of our common shares, subject to dilution by a management incentive plan.

all of ARP's preferred limited partnership units and common limited partnership units were cancelled without the receipt of any consideration or recovery.

ARP transferred all of its assets and operations to us as a new holding company and ARP dissolved. As a result, we became the successor issuer to ARP for purposes of and pursuant to Rule 12g-3 of the Securities Exchange Act of 1934, as amended.

Titan Management, a wholly owned subsidiary of ATLS, received a Series A Preferred Share, which entitles Titan Management to receive 2% of the aggregate of distributions paid to shareholders (as if it held 2% of our members' equity, subject to dilution if catch-up contributions are not made with respect to future equity issuances, other than pursuant to the management incentive plan) and certain other rights as provided for in the Restructuring Support Agreement. Four of the seven initial members of the board of directors were designated by Titan Management (the Titan Class A Directors). For so long as Titan Management holds such preferred share, the Titan Class A Directors will be appointed by a majority of the Titan Class A Directors then in office. We have a continuing right to purchase the preferred share at fair market

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value (as determined pursuant to the methodology provided for in our limited liability company agreement), subject to the receipt of certain approvals, including the holders of at least 67% of the outstanding common shares of us unaffiliated with Titan Management voting in favor of the exercise of the right to purchase the preferred share.

LIQUIDITY AND ABILITY TO CONTINUE AS A GOING CONCERN

Since the Plan Effective Date, we have funded our operations through cash flows generated from our operations and cash on hand. We currently do not have the capacity to access additional liquidity from our First Lien Credit Facility and our ability to access public equity and debt markets may be limited. Our future cash flows are subject to a number of variables, including oil and natural gas prices. Prices for oil and natural gas began to decline significantly during the fourth quarter of 2014 and continue to remain low in 2017. These lower commodity prices have negatively impacted our revenues, earnings and cash flows, which has negatively impacted our ability to remain in compliance with the covenants under our credit facilities. Sustained low commodity prices could have a material and adverse effect on our liquidity position.

Even following the amendments described below, we continue to face liquidity issues and are currently considering, and are likely to make, changes to our capital structure to maintain sufficient liquidity, meet our debt obligations and manage and strengthen our balance sheet. If we are not able to enter into further amendments with our lenders prior to the expiration of the standstill period, we may be forced to seek further options as described below.

We were not in compliance with certain of the financial covenants under our credit facilities as of December 31, 2016, as well as the requirement to deliver audited financial statements without a going concern qualification. As a result of the amendment referenced below, our financial covenants will not be tested again until the quarter ending December 31, 2017. We do not currently have sufficient liquidity to repay all of our outstanding indebtedness, and as a result, there is substantial doubt regarding our ability to continue as a going concern. We have classified \$538.1 million of outstanding indebtedness under our credit facilities, which is net of \$1.7 million of deferred financing costs, as current portion of long term debt, net within our condensed consolidated balance sheet as of September 30, 2017, based on the occurrence of the event of default, the lenders under our credit facilities, as applicable, could elect to declare all amounts outstanding immediately due and payable and the lenders could terminate all commitments to extend further credit.

On April 19, 2017, we entered into an amendment to our First Lien Credit Facility (which has been superseded by subsequent amendments as described further below). This amendment provided for, among other things, waivers of our non-compliance, increases in certain financial covenant ratios and scheduled decreases in our borrowing base (*refer to Note 5 of our condensed consolidated financial statements for further information regarding the specific amended terms and provisions*). As part of our overall business strategy, we have continued to execute on our sales of non-core assets, which has included the sale of our Appalachia and Rangely operations (*see Recent Developments*). The proceeds of the consummated asset sales were used to repay borrowings under our First Lien Credit Facility. Our strategy is to continue to sell non-core assets to reduce our leverage position, which will also help us to comply with the requirements of our First Lien Credit Facility amendments.

In addition to the amendments to the financial ratio covenants, the First Lien Credit Facility lenders waived certain defaults by us with respect to the fourth quarter of 2016, including compliance with the ratios of Total Debt to EBITDA and First Lien Debt to EBITDA, as well as our obligation to deliver financial statements without a going concern qualification. The First Lien Credit Facility lenders' waivers were subject to revocation in certain circumstances, including the exercise of remedies by junior lenders (including pursuant to our Second Lien Credit Facility), the failure to extend the standstill period under the intercreditor agreement at least 15 business days prior to its expiration, and the occurrence of additional events of default under the First Lien Credit Facility.

On April 21, 2017, the lenders under the our Second Lien Credit Facility delivered a notice of events of default and reservation of rights, pursuant to which they noticed events of default related to financial covenants and the failure to deliver financial statements without a going concern qualification. The delivery of such notice began the 180-day standstill period under the intercreditor agreement, during which the lenders under the Second Lien Credit Facility were prevented from pursuing remedies against the collateral securing our obligations under the Second Lien Credit Facility. The lenders have not accelerated the payment of amounts outstanding under the Second Lien Credit Facility.

On September 27, 2017, the lenders under our Second Lien Credit Facility entered into a letter agreement with us and the lenders under our First Lien Credit Facility (the Extension Letter) (which has been superseded by subsequent amendments as described further below). Pursuant to the Extension Letter, the Second Lien Credit Facility lenders agreed to extend the 180-day standstill period under the intercreditor agreement (during which the lenders under the Second Lien Credit Facility were prevented from pursuing remedies against the collateral securing the Company s obligations under the Second Lien Credit Facility) by an additional 35 days from October 18, 2017 to November 22, 2017. In addition, the extension of the standstill period extended the waiver of certain defaults under the First Lien Credit Facility, which terminates 15 business days prior to the expiration of the standstill period. The parties agreed to extend the standstill period to provide the Company with additional time to negotiate proposed amendments to each of the First Lien Credit Facility and the Second Lien Credit Facility.

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On September 29, 2017, we completed the remainder of the Appalachia Assets sale for additional cash proceeds of \$10.4 million, all of which was used to repay a portion of outstanding borrowings under our First Lien Credit Facility.

On November 6, 2017, we entered into a fourth amendment to our First Lien Credit Facility. The fourth amendment has an effective date of October 31, 2017 and confirms the conforming and non-conforming tranches of the borrowing base at \$228.7 million and \$30 million, respectively, but requires us to take actions (which can include asset sales and equity offerings) to reduce the conforming tranche of the borrowing base to \$190 million by December 8, 2017 and to \$150 million by August 31, 2018. The maturity date of the non-conforming tranche of the borrowing base was confirmed as May 1, 2018. We are required to use proceeds from asset sales to make prepayments.

In addition to the requirements above, the First Lien Credit Facility lenders also agreed to a limited waiver of certain existing defaults with respect to financial covenants, required repayments of borrowings and other related matters. The waiver terminates upon the earliest of (i) December 8, 2017, (ii) the occurrence of additional events of default under the First Lien Credit Facility and (iii) the exercise of remedies under our Second Lien Credit Facility. Pursuant to the fourth amendment, we are required to hedge at least 50% and 80% of our 2019 projected proved developed producing production by December 31, 2017 and March 31, 2018, respectively.

In connection with, and as a condition to, the effectiveness of the fourth amendment to our First Lien Credit Facility, the lenders under our Second Lien Credit Facility agreed to extend the standstill period under the intercreditor agreement (during which the lenders under the Second Lien Credit Facility are prevented from pursuing remedies against the collateral securing our obligations under the Second Lien Credit Facility) until December 29, 2017.

We continually review and may make changes to our capital structure from time to time, with the goal of strengthening our balance sheet and meeting our debt service obligations. We could pursue options such as refinancing, restructuring or reorganizing our indebtedness or capital structure or seek to raise additional capital through debt or equity financing to address our liquidity concerns and high debt levels. We are evaluating various options, but there is no certainty that we will be able to implement any such options, and we cannot provide any assurances that any refinancing or changes in our debt or equity capital structure would be possible or that additional equity or debt financing could be obtained on acceptable terms, if at all, and such options may result in a wide range of outcomes for our stakeholders.

We cannot assure you that we will be able to implement the above actions, if necessary, on commercially reasonable terms, or at all, in a manner that will be permitted under the terms of our debt instruments or in a manner that does not negatively impact the price of our securities. Additionally, there can be no assurance that the above actions will allow us to meet our debt obligations and capital requirements.

RECENT DEVELOPMENTS

Appalachia Divestiture

On May 4, 2017, we entered into a definitive agreement to sell our conventional Appalachia and Marcellus assets to Diversified Gas & Oil, PLC (Diversified) for \$84.2 million. The transaction includes the sale of approximately 8,400 oil and gas wells across Pennsylvania, Ohio, Tennessee, New York and West Virginia, along with the associated infrastructure (the Appalachian Assets). We retained our Utica Shale position, Indiana assets and West Virginia CBM assets in the region. On June 30, 2017, we completed a majority of the Appalachian Assets sale for net cash proceeds of \$65.6 million, which included customary preliminary purchase price adjustments, all of which was used to repay a portion of the outstanding indebtedness under our First Lien Credit Facility.

On September 29, 2017, we completed the remainder of the Appalachia Assets sale for additional cash proceeds of \$10.4 million, all of which was used to repay a portion of outstanding borrowings under our First Lien Credit Facility.

Rangely Divestiture

On June 12, 2017, we entered into a definitive agreement to sell our 25% interest in Rangely Field to an affiliate of Merit Energy Company, LLC for \$105 million. Rangely is a CO₂ flood located in Rio Blanco County, Colorado, and operated by Chevron. The transaction includes the sale of our interest in Rangely Field, its 22% interest in Raven Ridge Pipeline, a CO₂ transportation line, as well as surrounding acreage in Rio Blanco and Moffat Counties, Colorado (collectively, the Rangely Assets). On August 7, 2017, we completed the Rangely Assets sale for net cash proceeds of \$103.5 million, which included customary preliminary purchase price adjustments, all of which was used to repay a portion of the outstanding indebtedness under our First Lien Credit Facility and achieve compliance with the requirement to reduce our First Lien Credit Facility borrowings below \$360 million, as required by August 31, 2017.

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GENERAL TRENDS AND OUTLOOK

We expect our business to be affected by key trends in natural gas and oil production markets. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about or interpretations of available information prove to be incorrect, our actual results may vary materially from our expected results.

The natural gas, oil and natural gas liquids commodity price markets have suffered significant declines since the fourth quarter of 2014 and continue to remain low in 2017. The causes of these declines are based on a number of factors, including, but not limited to, a significant increase in natural gas, oil and NGL production. While we anticipate continued high levels of exploration and production activities over the long-term in the areas in which we operate, fluctuations in energy prices can greatly affect production rates and investments in the development of new natural gas, oil and NGL reserves.

Our future gas and oil reserves, production, cash flow, and our ability to make payments on our debts, depend on our success in producing our current reserves efficiently, developing our existing acreage and acquiring additional proved reserves economically. We face the challenge of natural production declines and volatile natural gas, oil and NGL prices. As initial reservoir pressures are depleted, natural gas and oil production from particular wells decrease. We attempt to overcome this natural decline by drilling to find additional reserves and acquiring more reserves than we produce. To the extent we do not have sufficient capital, our ability to drill and acquire more reserves will be negatively impacted. Based on current market conditions, we believe that a reduction in our debt and cash interest obligations is needed to improve our financial position and flexibility and to position us to take advantage of opportunities that may arise out of the current industry downturn.

RESULTS OF OPERATIONS

We sponsored and continue to manage tax-advantaged investment partnerships (the *Drilling Partnerships*), in which we coinvested, to finance a portion of our natural gas, crude oil and NGL production activities.

Matters Impacting Comparability of Results

Fresh Start Accounting. Upon our emergence from bankruptcy, we adopted fresh-start accounting in accordance with ASC 852. We qualified for fresh-start accounting because (i) the reorganization value of our assets immediately prior to the confirmation was less than the post-petition liabilities and allowed claims and (ii) the holders of existing voting shares of our predecessor company received less than 50% of the voting shares of the post-emergence successor entity.

As a result of the application of fresh start accounting, at the Plan Effective Date, our assets and liabilities were recorded at their estimated fair values which, in some cases, are significantly different than amounts included in our financial statements prior to the Plan Effective Date. Accordingly, our financial condition, results of operations, and cash flows on and after the Plan Effective Date are not comparable to our financial condition, results of operations, and cash flows prior to the Plan Effective Date. References to *Successor* relate to Titan on and subsequent to the Plan Effective Date. References to *Predecessor* refer to ARP prior to the Plan Effective Date. We have presented our financial condition, results of operations, and cash flows with a black line division to delineate the lack of comparability between the amounts presented on or after September 1, 2016 and dates prior.

Reclassifications. Certain reclassifications have been made to our condensed consolidated financial statements for the prior year periods to conform to classifications used in the current year, specifically related to our Appalachian Assets

presented as discontinued operations in the condensed consolidated financial statements and footnote disclosures and our segment information on the condensed consolidated statement of operations and segment footnote disclosures.

Discontinued operations. We determined the Appalachian Assets represent discontinued operations as they constitute a disposal of a group of components and a strategic shift that will have a major effect on our operations and financial results. We evaluated the Appalachian Assets sale on our gas and oil production and Drilling Partnership management segments' results of operations and cash flows, as well as expected asset retirement obligations, and concluded the impact will have a major effect on our expected operations and financial results. As a result, we reclassified the Appalachian Assets from their historical presentation to assets and liabilities held for sale on the condensed consolidated balance sheet and to net income (loss) from discontinued operations on the condensed consolidated statement of operations for all periods presented.

Segments. Our operations include two reportable operating segments: gas and oil production and Drilling Partnership management. The Drilling Partnership management segment includes all of our managing and operating activities specific to the Drilling Partnerships including well construction and completion, administration and oversight, well services, and gathering and processing. These operating segments reflect the way we manage our operations and make business decisions.

We previously presented three reportable operating segments; however, due to the decline in investor capital funds raised in recent years, anticipated lower levels of future investor capital fund raise, and the consolidation of certain historical Drilling

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Partnerships in 2016, we aggregated our well construction and completion segment with our other partnership management segment to report all of our Drilling Partnership management activities in one combined segment as they do not meet the quantitative threshold for reporting individual segment information. As a result of this change, we have restated our prior year condensed consolidated statements of operations and segment footnote disclosures to conform to our current presentation.

GAS AND OIL PRODUCTION

Production Profile. Currently, we have natural gas, crude oil and NGL production operations in various plays throughout the United States. We have established production positions in the following operating areas:

the Eagle Ford Shale in south Texas, in which we acquired acreage and producing wells in November 2014;

Coalbed Methane producing natural gas assets in (1) the Raton Basin in northern New Mexico and southern Colorado, acquired in 2013; (2) the Black Warrior Basin in central Alabama, acquired in 2013; (3) the Central Appalachia Basin in West Virginia and Virginia, acquired in 2014; and (4) the Arkoma Basin in eastern Oklahoma, acquired in 2015;

the Appalachia Basin assets, including the Utica Shale, and the New Albany Shale in southwestern Indiana; and

the Mid-Continent assets, including Barnett Shale and Marble Falls plays, both in the Fort Worth Basin in northern Texas and acquired in 2012, and the Mississippi Lime and Hunton plays in northwestern Oklahoma.

We also had a production position in the Rangely field in northwest Colorado, a mature tertiary CO₂ flood with low-decline oil production, where we had a 25% non-operated net working interest position which we acquired in 2014 and subsequently sold in August 2017.

The following table presents the number of wells we drilled and the number of wells we turned in line, both gross and for our interest, during the periods indicated:

	Successor Period Three Months Ended September 30, 2017	Predecessor Period July 1 through August 31, 2016
Gross wells drilled⁽³⁾:		
Eagle Ford		2
Net wells drilled⁽¹⁾:		
Eagle Ford		2

Gross wells turned in line⁽²⁾⁽³⁾:		
Eagle Ford		4
Net wells turned in line⁽¹⁾⁽²⁾⁽³⁾:		
Eagle Ford		1
	Successor Period Nine Months Ended September 2017	Predecessor Period January 1 through August 31, 2016
Gross wells drilled⁽³⁾:		
Eagle Ford	4	2
Net wells drilled⁽¹⁾:		
Eagle Ford	3	2
Gross wells turned in line⁽²⁾⁽³⁾:		
Eagle Ford	4	4
Net wells turned in line⁽¹⁾⁽²⁾⁽³⁾:		
Eagle Ford	3	1

- (1) Includes (i) our percentage interest in the wells in which we have had a direct ownership interest and (ii) our percentage interest in the wells based on our percentage ownership in the Drilling Partnerships.
- (2) Wells turned in line refers to wells that have been drilled, completed, and connected to a gathering system.

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(3) There were no exploratory wells drilled during the periods presented. There were no gross or net dry wells within any of our operating areas during the periods presented.

Production Volumes. The following table presents our total net natural gas, crude oil, and NGL production volumes per day in each of our operating areas and total production for each of the periods indicated:

	Successor Period Three Months Ended September 30, 2017	September 1, through September 30, 2016	Predecessor Period July 1, through August 31, 2016
Production volumes per day:⁽¹⁾⁽²⁾			
Eagle Ford:			
Natural gas (Mcfed)	613	423	457
Oil (Bpd)	2,218	1,025	1,028
NGLs (Bpd)	136	88	95
Total (Mcfed)	14,736	7,102	7,197
Coal-bed Methane:			
Natural gas (Mcfed)	103,673	114,030	114,100
Oil (Bpd)			
NGLs (Bpd)			
Total (Mcfed)	103,673	114,030	114,100
Utica / Indiana:			
Natural gas (Mcfed)	3,914	4,841	5,136
Oil (Bpd)	20	43	43
NGLs (Bpd)	15	23	25
Total (Mcfed)	4,121	5,240	5,540
Mid-Continent:			
Natural gas (Mcfed)	30,674	34,508	34,499
Oil (Bpd)	193	299	325
NGLs (Bpd)	1,190	1,447	1,440
Total (Mcfed)	38,970	44,985	45,091
Rangely:⁽³⁾			
Natural gas (Mcfed)			
Oil (Bpd)	817	2,229	2,214
NGLs (Bpd)	34	232	242
Total (Mcfed)	5,103	14,766	14,736

Total production volumes per day:			
Natural gas (Mcfed)	138,873	153,802	154,192
Oil (Bpd)	3,247	3,597	3,611
NGLs (Bpd)	1,374	1,790	1,801
Total (Mcfed)	166,602	186,122	186,664
Total production:⁽¹⁾⁽²⁾			
Natural gas (MMcf)	12,776	4,614	9,560
Oil (MBbls)	299	108	224
NGLs (MBbls)	126	54	112
Total (MMcfe)	15,327	5,584	11,573

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	Successor Period Nine Months Ended September 30, 2017	September 1, through September 30, 2016	Predecessor Period January 1, through August 31, 2016
Production volumes per day:⁽¹⁾⁽²⁾			
Eagle Ford:			
Natural gas (Mcfed)	621	423	437
Oil (Bpd)	2,072	1,025	1,212
NGLs (Bpd)	137	88	91
Total (Mcfed)	13,874	7,102	8,257
Coal-bed Methane: ⁽³⁾			
Natural gas (Mcfed)	105,835	114,030	117,491
Oil (Bpd)			
NGLs (Bpd)			
Total (Mcfed)	105,835	114,030	117,491
Utica / Indiana:			
Natural gas (Mcfed)	4,163	4,841	5,748
Oil (Bpd)	26	43	47
NGLs (Bpd)	17	23	25
Total (Mcfed)	4,417	5,240	6,182
Mid-Continent:			
Natural gas (Mcfed)	31,229	34,508	38,111
Oil (Bpd)	225	299	432
NGLs (Bpd)	1,224	1,447	1,654
Total (Mcfed)	39,927	44,985	50,627
Rangely ⁽³⁾ :			
Natural gas (Mcfed)			
Oil (Bpd)	1,648	2,229	2,287
NGLs (Bpd)	153	232	244
Total (Mcfed)	10,802	14,766	15,187
Total production volumes per day:			
Natural gas (Mcfed)	141,848	153,802	161,786
Oil (Bpd)	3,971	3,597	3,979
NGLs (Bpd)	1,530	1,790	2,014
Total (Mcfed)	174,855	186,122	197,745

Total production:⁽¹⁾⁽²⁾

Natural gas (MMcf)	38,725	4,614	39,476
Oil (MBbls)	1,084	108	971
NGLs (MBbls)	418	54	491
Total (MMcfe)	47,735	5,584	48,250

- (1) Production quantities consist of the sum of (i) our proportionate share of production from wells in which we have a direct interest, based on our proportionate net revenue interest in such wells, and (ii) our proportionate share of production from wells owned by the Drilling Partnerships in which we have an interest, based on our equity interest in each such Drilling Partnership and based on each Drilling Partnership's proportionate net revenue interest in these wells.
- (2) MMcf represents million cubic feet; MMcfe represent million cubic feet equivalents; Mcfd represents thousand cubic feet per day; Mcfed represents thousand cubic feet equivalents per day; and Bbls and Bpd represent barrels and barrels per day. Barrels are converted to Mcfe using the ratio of approximately 6 Mcf to one barrel.
- (3) We sold our interest in Rangely on August 7, 2017 (see Recent Developments).

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Production Revenues, Prices and Costs. Our production revenues and estimated gas and oil reserves are substantially dependent on prevailing market prices for natural gas and oil. The following table presents our production revenues and average sales prices for our natural gas, oil, and natural gas liquids production, along with our average production costs, which include lease operating expenses, taxes, and transportation costs, for each of the periods indicated:

	Successor Three Months Ended September 30, 2017	Period September 1 through September 30, 2016	Predecessor Period July 1 through August 31, 2016
Production revenues (in thousands):⁽¹⁾			
Eagle Ford:			
Natural gas revenue	\$ 155	\$ 35	\$ 92
Oil revenue	9,699	1,306	1,960
Natural gas liquids revenue	253	45	86
Total revenues	\$ 10,107	\$ 1,386	\$ 2,138
Coal-bed Methane:			
Natural gas revenue	\$ 26,256	\$ 9,628	\$ 22,077
Oil revenue			
Natural gas liquids revenue			
Total revenues	\$ 26,256	\$ 9,628	\$ 22,077
Utica / Indiana:			
Natural gas revenue	\$ 920	\$ 339	\$ 736
Oil revenue	66	50	91
Natural gas liquids revenue	19	7	15
Total revenues	\$ 1,005	\$ 396	\$ 842
Mid-Continent:			
Natural gas revenue	\$ 5,816	\$ 2,165	\$ 5,252
Oil revenue	814	362	624
Natural gas liquids revenue	2,007	609	1,070
Total revenues	\$ 8,637	\$ 3,136	\$ 6,946
Rangely: ⁽⁷⁾			
Natural gas revenue	\$	\$	\$
Oil revenue	2,599	2,843	4,393
Natural gas liquids revenue	118	214	452
Total revenues	\$ 2,717	\$ 3,057	\$ 4,845

Total production revenues:			
Natural gas revenue	\$ 33,147	\$ 12,167	\$ 28,157
Oil revenue	13,178	4,561	7,068
Natural gas liquids revenue	2,397	875	1,623
Subordinated revenue ⁽²⁾	(1,298)	(342)	(558)
Total revenues	\$ 47,424	\$ 17,261	\$ 36,290
Average sales price:			
Natural gas (per Mcf): ⁽³⁾			
Total realized price, after hedge ^{(4) (1)}	\$ 2.74	\$ 2.70	\$ 3.06
Total realized price, before hedge ⁽⁴⁾	\$ 2.60	\$ 2.61	\$ 2.53
Oil (per Bbl): ⁽³⁾			
Total realized price, after hedge ⁽¹⁾	\$ 43.55	\$ 39.92	\$ 41.09
Total realized price, before hedge	\$ 44.05	\$ 42.21	\$ 41.68
Natural gas liquids (per Bbl): ⁽³⁾			
Total realized price, after hedge ⁽¹⁾	\$ 18.96	\$ 16.30	\$ 14.53
Total realized price, before hedge	\$ 18.96	\$ 16.30	\$ 14.53

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	Successor Three Months Ended September 30, 2017	Period September 1 through September 30, 2016	Predecessor Period July 1 through August 31, 2016
Production costs (per Mcfe):⁽³⁾			
Eagle Ford:			
Lease operating expenses	\$ 1.22	\$ 2.03	\$ 1.58
Production taxes	0.39	0.49	0.48
Transportation and compression	0.05	0.14	0.16
	\$ 1.66	\$ 2.66	\$ 2.23
Coal-bed Methane:			
Lease operating expenses	\$ 1.08	\$ 1.06	\$ 0.97
Production taxes	0.20	0.24	0.21
Transportation and compression	0.10	0.19	0.18
	\$ 1.37	\$ 1.48	\$ 1.37
Utica / Indiana:			
Lease operating expenses	\$ 0.54	\$ 0.46	\$ 0.34
Production taxes	0.12	0.06	0.06
Transportation and compression	0.08	0.12	0.11
	\$ 0.74	\$ 0.65	\$ 0.51
Mid-Continent:			
Lease operating expenses	\$ 0.90	\$ 0.99	\$ 0.85
Production taxes	0.15	0.20	0.19
Transportation and compression	0.18	0.23	0.25
	\$ 1.23	\$ 1.42	\$ 1.29
Rangely: ⁽⁷⁾			
Lease operating expenses	\$ 4.53	\$ 4.59	\$ 4.22
Production taxes	0.12	0.62	0.60
Transportation and compression	0.02	0.01	0.01
	\$ 4.67	\$ 5.22	\$ 4.82
Total production costs:			
Lease operating expenses ⁽⁵⁾	\$ 1.14	\$ 1.34	\$ 1.20
Production taxes	0.20	0.27	0.24
Transportation and compression	0.11	0.18	0.18
	\$ 1.45	\$ 1.79	\$ 1.63

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	Successor Nine Months Ended September 30, 2017	Period September 1 through September 30, 2016	Predecessor Period January 1 through August 31, 2016
Production revenues (in thousands):⁽¹⁾			
Eagle Ford:			
Natural gas revenue	\$ 504	\$ 35	\$ 298
Oil revenue	27,253	1,306	14,622
Natural gas liquids revenue	701	45	305
Total revenues	\$ 28,458	\$ 1,386	\$ 15,225
Coal-bed Methane:			
Natural gas revenue	\$ 83,342	\$ 9,628	\$ 69,358
Oil revenue			
Natural gas liquids revenue			
Total revenues	\$ 83,342	\$ 9,628	\$ 69,358
Utica / Indiana:			
Natural gas revenue	\$ 3,213	\$ 339	\$ 2,520
Oil revenue	301	50	392
Natural gas liquids revenue	94	7	56
Total revenues	\$ 3,608	\$ 396	\$ 2,968
Mid-Continent			
Natural gas revenue	\$ 18,182	\$ 2,165	\$ 11,188
Oil revenue	2,820	362	1,839
Natural gas liquids revenue	5,788	609	4,010
Total revenues	\$ 26,790	\$ 3,136	\$ 17,037
Rangely: ⁽⁷⁾			
Natural gas revenue	\$	\$	\$
Oil revenue	20,501	2,843	23,883
Natural gas liquids revenue	1,516	214	1,557
Total revenues	\$ 22,017	\$ 3,057	\$ 25,440
Total production revenues:			
Natural gas revenue	\$ 105,241	\$ 12,167	\$ 83,364
Oil revenue	50,875	4,561	40,736
Natural gas liquids revenue	8,099	875	5,928
Subordinated revenue ⁽²⁾	(3,285)	(342)	(951)

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Total revenues	\$ 160,930	\$ 17,261	\$ 129,077
Average sales price:			
Natural gas (per Mcf): ⁽³⁾			
Total realized price, after hedge ⁽⁴⁾ (1)	\$ 2.70	\$ 2.70	\$ 3.39
Total realized price, before hedge ⁽⁴⁾	\$ 2.71	\$ 2.61	\$ 1.96
Oil (per Bbl): ⁽³⁾			
Total realized price, after hedge ⁽¹⁾	\$ 44.90	\$ 39.92	\$ 72.44
Total realized price, before hedge	\$ 46.76	\$ 42.21	\$ 36.94
Natural gas liquids (per Bbl): ⁽³⁾			
Total realized price, after hedge ⁽¹⁾	\$ 19.32	\$ 16.30	\$ 13.55
Total realized price, before hedge	\$ 19.32	\$ 16.30	\$ 13.55
Production costs (per Mcfe): ⁽³⁾			
Eagle Ford:			
Lease operating expenses	\$ 1.17	\$ 2.03	\$ 1.71
Production taxes	0.44	0.49	0.43
Transportation and compression	0.07	0.14	0.13
	\$ 1.68	\$ 2.66	\$ 2.27

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	Successor Nine Months Ended September 2017	Period September 1 through September 30, 2016	Predecessor Period January 1 through August 31, 2016
Coal-bed Methane:			
Lease operating expenses	\$ 1.03	\$ 1.06	\$ 1.00
Production taxes	0.23	0.24	0.17
Transportation and compression	0.12	0.19	0.25
	\$ 1.39	\$ 1.48	\$ 1.43
Utica / Indiana:			
Lease operating expenses	\$ 0.47	\$ 0.46	\$ 0.38
Production taxes	0.11	0.06	0.06
Transportation and compression	0.11	0.12	0.11
	\$ 0.69	\$ 0.65	\$ 0.55
Mid-Continent:			
Lease operating expenses	\$ 0.93	\$ 0.99	\$ 0.96
Production taxes	0.15	0.20	0.17
Transportation and compression	0.13	0.23	0.25
	\$ 1.21	\$ 1.42	\$ 1.38
Rangely: ⁽⁷⁾			
Lease operating expenses	\$ 4.76	\$ 4.59	\$ 4.33
Production taxes	0.48	0.62	0.59
Transportation and compression	0.01	0.01	0.01
	\$ 5.24	\$ 5.22	\$ 4.92
Total production costs:			
Lease operating expenses ⁽⁵⁾	\$ 1.23	\$ 1.34	\$ 1.27
Production taxes	0.24	0.27	0.12
Transportation and compression	0.11	0.18	0.22
	\$ 1.58	\$ 1.79	\$ 1.61

- (1) For the Predecessor periods from July 1, 2016 through August 31, 2016 and January 1, 2016 through August 31, 2016, production revenue includes the portion of settlements associated with gains and losses on commodity derivative contracts previously recognized within accumulated other comprehensive income following our Predecessor's decision to de-designate hedges beginning on January 1, 2015, consisting of \$1.5 million for natural gas for the Predecessor period from July 1, 2016 through August 31, 2016, and \$2.3 million for natural gas and

- \$8.1 million for oil for the Predecessor period from January 1, 2016 through August 31, 2016.
- (2) Represents the amount of subordination of our production revenue to investor partners within certain of our Drilling Partnerships. In addition to recognizing subordinated revenues, we also subordinate a corresponding proportionate share of subordinated lease operating expenses to investor partners within certain of our Drilling Partnerships, which lowers our overall production costs. The corresponding subordinated lease operating expenses for the Successor three and nine months ended September 30, 2017 and period from September 1 through September 30, 2016 were \$0.7 million, \$1.6 million and \$0.1 million, respectively, and for the Predecessor periods from July 1, 2016 through August 31, 2016 and from January 1, 2016 through August 31, 2016 were \$0.3 million and \$0.6 million, respectively.
 - (3) Mcf represents thousand cubic feet; Mcfe represents thousand cubic feet equivalents; and Bbl represents barrels.
 - (4) For the Successor three months and nine months ended September 30, 2017, and period from September 1, 2016 through September 30, 2016, calculation includes the impact of cash settlements on commodity derivative contracts, consisting of \$1.8 million in receipts for natural gas derivative contracts and \$0.1 million in payments for crude oil derivative contracts for the Successor three months ended September 30, 2017, \$0.5 million in payments for natural gas derivative contracts and \$1.8 million in payments for crude oil derivative contracts for the Successor nine months ended September 30, 2017, and \$0.4 million in receipts for natural gas derivative contracts and \$0.2 million in payments for crude oil derivative contracts for the Successor period from September 1, 2016 through September 30, 2016. For the Predecessor periods from July 1, 2016 through August 31, 2016 and from January 1, 2016 through August 31, 2016, calculation includes the impact of cash settlements on commodity derivative contracts not previously included within accumulated other comprehensive income following our Predecessor's decision to de-designate hedges beginning on January 1, 2015, consisting of \$3.6 million and \$54.2 million in receipts associated with natural gas derivative contracts and \$0.1 million in payments and \$26.4 million in receipts associated with crude oil derivative contracts.
 - (5) Calculation excludes the impact of subordination of our production revenue to investor partners within our Drilling Partnerships for each of the periods presented. Including the effect of this subordination, the average realized gas sales price was \$2.64 per Mcf (\$2.49 per Mcf before the effects of financial hedging), \$2.78 per Mcf (\$2.62 per Mcf before the effects of financial hedging), \$2.63 per Mcf (\$2.53 per Mcf before the effects of financial hedging), \$3.00 per Mcf (\$2.47 per Mcf before the effects of financial hedging) and \$3.37 per Mcf (\$1.94 per Mcf before the effects of financial hedging) for the Successor three months ended September 30, 2017, the nine months ended September 30, 2017 and the period from September 1, 2016 through September 30, 2016 and for the Predecessor periods from July 1, 2016 through August 31, 2016 and from January 1, 2016 through August 31, 2016, respectively.
 - (6) Excludes the effects of our proportionate share of lease operating expenses associated with subordination of our production revenue to investor partners within our Drilling Partnerships for each of the periods presented. Including the effects of these costs, total lease operating expenses per Mcfe were \$1.10 per Mcfe (\$1.41 per Mcfe for total production costs), \$1.20 per Mcfe (\$1.55 per Mcfe for total production costs), \$1.32 per Mcfe (\$1.76 per Mcfe for total production costs), \$1.18 per Mcfe (\$1.61 per Mcfe for total production costs) and \$1.25 per Mcfe (\$1.60 per Mcfe for total production costs) for the Successor periods three months ended September 30, 2017, nine months ended September 30, 2017, and the period from September 1, 2016 through September 30, 2016 and the Predecessor periods from July 1, 2016 through January 31, 2016 and from January 1, 2016 through August 31, 2016, respectively.
 - (7) We sold our interest in Rangely on August 7, 2017 (see Recent Developments).

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	Successor Period Three Months Ended September 30, 2017	September 1 through September 30, 2016	Predecessor Period July 1 through August 31, 2016
(in thousands)			
Gas and oil production revenues	\$ 47,424	\$ 17,261	\$ 36,290
Gas and oil production costs	\$ (21,633)	\$ (9,854)	\$ (18,577)

	Successor Period Nine Months Ended September 30, 2017	September 1 through September 30, 2016	Predecessor Period January 1 through August 31, 2016
(in thousands)			
Gas and oil production revenues	\$ 160,930	\$ 17,261	\$ 129,077
Gas and oil production costs	\$ (74,355)	\$ (9,854)	\$ (80,988)

Our gas and oil production revenues were lower during in the current quarter than the Successor period from September 1, 2016 through September 30, 2016 and the Predecessor period from July 1, 2016 through August 31, 2016 due to decreases in production volumes at our operating areas due to natural declines and cost control operating decisions and the sale of our interests in Rangely, partially offset by an increase in volumes at our Eagle Ford operating area due to 15 wells turned inline since the end of the third quarter 2016 and higher average realized sales prices before hedging activities resulting from the improved commodity pricing environment.

Our gas and oil production revenues were higher in the nine months ended September 30, 2017 than the Successor period from September 1, 2016 through September 30, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016 due to higher average realized sales prices before hedging activities resulting from the improved commodity pricing environment and an increase in volumes at our Eagle Ford operating area due to 15 wells turned inline since the end of the third quarter 2016, partially offset by decreases in production volumes at our operating areas due to natural declines and cost control operating decisions and the sale of our interests in Rangely.

Our total production costs were lower in the current quarter than the Successor period from September 1, 2016 through September 30, 2016 and the Predecessor period from July 1, 2016 through August 31, 2016 primarily due to a decrease in lease operating expenses related to lower labor costs from employee reductions and other production cost control measures in each of our operating areas, a decrease in transportation costs due to contract negotiations for lower rates, a decrease in property taxes, and the sale of our interests in Rangely.

Our total production costs were lower in the nine months ended September 30, 2017 than the Successor period from September 1, 2016 through September 30, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016 primarily due to a decrease in lease operating expenses related to lower labor costs from employee reductions and other production cost control measures in each of our operating areas, a decrease in transportation costs due to contract negotiations for lower rates, and the sale of our interests in Rangely; partially offset by an increase in production taxes due to higher realized sales prices.

DRILLING PARTNERSHIP MANAGEMENT

We sponsored and continue to manage tax-advantaged investment partnerships (the "Drilling Partnerships"), in which we coinvested, to finance a portion of our natural gas, crude oil and NGL production activities and generated revenues as the manager and operator of the Drilling Partnerships. Drilling Partnership investor capital raised by us is deployed to drill and complete wells included within the partnership. As we deploy Drilling Partnership investor capital, we recognize certain management fees we are entitled to receive, including well construction and completion revenues and a portion of administration and oversight revenues. At each period end, if we have Drilling Partnership investor capital that has not yet been deployed, we recognize a current liability titled "Liabilities Associated with Drilling Contracts" on our condensed consolidated balance sheet. After the Drilling Partnership well is completed and turned in line, we are entitled to receive additional well services and operating fee revenues, administration and oversight fee revenues, and gathering and processing fee revenues on a monthly basis while the well is operating and as the services are performed.

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In addition, we are also entitled to our pro-rata share of Drilling Partnership gas and oil production revenue, which generally approximates 10-30%, which is recognized in our gas and oil production segment.

	Successor Period Three Months Ended September 1 September 30, 2017		Predecessor Period July 1 through August 31, 2016
(in thousands)			
Drilling partnership management revenues	\$ 1,997	\$ 2,074	\$ 18,778
Drilling partnership management expenses	248	1,266	16,121

	Successor Period Nine Months Ended September 1 September 30, 2017		Predecessor Period January 1 through August 31, 2016
(in thousands)			
Drilling partnership management revenues	\$ 17,387	\$ 2,074	\$ 24,446
Drilling partnership management expenses	10,026	1,266	17,427

Drilling partnership management revenues. Our Drilling partnership management revenues were lower in the current quarter and in the nine months ended September 30, 2017 compared to each of our Successor period from September 1, 2016 and the Predecessor periods from July 1, 2016 through August 31, 2016 and from January 1, 2016 through August 31, 2016 primarily due to a decrease in well construction and completion revenues related to the timing of drilling and completion activities for the partnership wells, which are recognized on a cost plus basis.

Drilling partnership management expenses. Our drilling partnership management expenses were lower in the current quarter and in the nine months ended September 30, 2017 compared to each of our Successor period from September 1, 2016 and the Predecessor periods from July 1, 2016 through August 31, 2016 and from January 1, 2016 through August 31, 2016 due to a decrease in well construction and completion expenses related to the timing of drilling and completion activities for the partnership wells, which are recognized on a percentage of completion basis.

Table of Contents**OTHER REVENUES AND EXPENSES**

	Successor Period from Three Months Ended September 30, 2017	September 1, 2016 through September 30, 2016	Predecessor Period from July 1, 2016 through August 31, 2016
(in thousands)			
<u>Other Revenues</u>			
Gain (loss) on mark-to-market derivatives	\$ (4,068)	\$ (2,079)	\$ 2,353
<u>Other Expenses</u>			
General and administrative	\$ 10,142	\$ 4,530	\$ 5,128
Depreciation, depletion and amortization	11,934	5,152	20,585
Loss on divestiture	(5,177)		
Interest expense	15,268	3,470	14,087
Gain (loss) on asset sales and disposal	(82)	5	(18)
Reorganization items, net		353	16,614
Other income (loss)	(777)		(3,063)
Income tax benefit	(202)		

	Successor Period from Nine Months Ended September 30, 2017	September 1, 2016 through September 30, 2016	Predecessor Period from January 1, 2016 through August 31, 2016
(in thousands)			
<u>Other Revenues</u>			
Gain (loss) on mark-to-market derivatives	\$ 36,925	\$ (2,079)	\$ (23,248)
<u>Other Expenses</u>			
General and administrative	\$ 32,961	\$ 4,530	\$ 41,038
Depreciation, depletion and amortization	38,402	5,152	73,272
Loss on divestiture	(43,369)		
Interest expense	41,816	3,470	71,059
Gain (loss) on asset sales and disposal	25	5	(551)
Gain on extinguishment of debt			26,498
Reorganization items, net		353	16,614
Other income (loss)	(925)		(3,063)
Income tax benefit	(11,503)		

Gain (Loss) on Mark-to-Market Derivatives. We recognize changes in the fair value of our derivatives immediately within gain (loss) on mark-to-market derivatives on our condensed consolidated statements of operations. The gains on mark-to-market derivatives during the Successor nine months ended September 30, 2017 and the Predecessor

period from July 1, 2016 through August 31, 2016 were due to decreases in commodity future prices relative to our derivative positions as of the respective prior period end. The losses on mark-to-market derivatives during the Successor three months ended September 30, 2017, the Successor period from September 1, 2016 through September 30, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016 were due to increases in commodity future prices relative to our Successor's and our Predecessor's derivative positions as of the respective prior period end.

General and Administrative. General and administrative expenses during the three months ended September 30, 2017 as compared to the Predecessor period from July 1, 2016 through August 31, 2016 and the Successor period from September 1, 2016 through September 30, 2016 reflect increases in non-recurring transaction costs and salaries, wages and benefits, partially offset by decreases in stock compensation, syndication expense, and other corporate activities.

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General and administrative expenses during the nine months ended September 30, 2017 as compared to the Predecessor period from January 1, 2016 through August 31, 2016 and the Successor period from September 1, 2016 through September 30, 2016 reflect decreases in non-recurring transaction costs, salaries, wages and benefits, syndication expense, and other corporate activities.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization expenses decreased in the current quarter as compared to the Successor period from September 1, 2016 through December 31, 2016 and the Predecessor period from July 1, 2016 through August 31, 2016 due to the application of fresh-start accounting to our proved properties on September 1, 2016, which reduced the depletable cost basis of our proved gas and oil properties resulting in lower depletion expense, lower production volumes, and the sale of our interests in Rangely.

Our depreciation, depletion and amortization expenses were lower in the nine months ended September 30, 2017 as compared to the Successor period from September 1, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through August 31, 2016 due to the application of fresh-start accounting to our proved properties on September 1, 2016, which reduced the depletable cost basis of our proved gas and oil properties resulting in lower depletion expense, lower production volumes, and the sale of our interests in Rangely.

Loss on Divestiture. We determined that the carrying value of the Rangely Assets exceeded the fair value less costs to sell, which resulted in an impairment of \$38.2 million recognized in loss on divestiture on our condensed consolidated statement of operations during the nine months ended September 30, 2017. We recognized a \$5.2 million loss on asset sale from the closing of the Rangely Assets sales during the Successor three and nine months ended September 30, 2017 resulting from final negotiations and settlement of working capital adjustments in connection with the preliminary purchase price adjustments.

Interest Expense. Interest expense during the Successor three months ended September 30, 2017 primarily consisted of \$10.1 million related to our Second Lien Credit Facility, \$4.0 million related to our First Lien Credit Facility, and \$1.4 million related to amortization of deferred financing costs, partially offset by \$0.2 million in capitalized interest. Interest expense during the Successor period from September 1, 2016 through September 30, 2016 consisted of \$2.5 million related to our Second Lien Credit Facility, \$1.5 million related to our First Lien Credit Facility and \$0.1 million related to amortization of deferred financing costs, partially offset by \$0.6 million in capitalized interest. Interest expense during the Predecessor period from July 1, 2016 through August 31, 2016 consisted of \$4.8 million related to our Predecessor's second lien term loan, \$4.1 million related to our Predecessor's senior notes, \$3.6 million related to our Predecessor's first lien credit facility and \$3.3 million related to amortization of deferred financing costs and debt discounts, partially offset by \$1.7 million in capitalized interest.

Interest expense during the Successor nine months ended September 30, 2017 primarily consisted of \$26.6 million related to our Second Lien Credit Facility, \$13.1 million related to our First Lien Credit Facility, and \$2.5 million related to amortization of deferred financing costs, partially offset by \$0.4 million in capitalized interest. Interest expense during the Successor period from September 1, 2016 through September 30, 2016 consisted of \$2.5 million related to our Second Lien Credit Facility, \$1.5 million related to our First Lien Credit Facility and \$0.1 million related to amortization of deferred financing costs, partially offset by \$0.6 million in capitalized interest. Interest expense during the Predecessor period from January 1, 2016 through August 31, 2016 consisted of \$32.6 million related to our Predecessor's senior notes, \$17.4 million related to our Predecessor's second lien term loan, \$14.5 million related to amortization of deferred financing costs and debt discounts and \$13.1 million related to our Predecessor's first lien credit facility, partially offset by \$6.5 million in capitalized interest.

Gain on Early Extinguishment of Debt. The gain on early extinguishment of debt for the Predecessor period from January 1, 2016 through August 31, 2016 represents a \$26.5 million gain related to the repurchase of a portion of our

Predecessor's senior notes. Of the \$26.5 million gain, \$27.4 million related to the gain from the redemption of the principal values and accrued interest, partially offset by \$0.9 million related to the accelerated amortization of the related deferred financing costs.

Reorganization Items, Net. Incremental costs incurred as a result of the Chapter 11 Filings, net gain on settlement of liabilities subject to compromise and reorganization adjustments, and net impact of fresh start adjustments are classified as Reorganization items, net in the Predecessor's condensed consolidated statement of operations. The following table summarizes the reorganization items:

Professional fees and other	\$ (33,065)
Accelerated amortization of deferred financing costs	(9,565)
Net gain on reorganization adjustments	361,479
Net loss on fresh start adjustments	(335,463)
Total reorganization items, net	\$ (16,614)

Other income (loss). The \$0.8 million loss for the Successor three months ended September 30, 2017, includes a \$1.3 million adjustment to net realizable value related to a settled escrow account receivable, partially offset by \$0.6 million in transition service

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agreement fees related to the Appalachian Assets sale. The \$0.9 million loss for the Successor nine months ended September 30, 2017, represents a \$1.3 million adjustment to net realizable value related to a settled escrow account and the \$0.6 million write-off of promotional items, partially offset by \$0.6 million in transition service agreement fees related to the Appalachian Assets sale and \$0.4 million sales tax refund for equipment purchased for our Texas operations. The \$3.0 million loss for the Predecessor periods from July 1, 2016 through August 31, 2016 and from January 1, 2016 through August 31, 2016 represent non-cash losses for the write-off of notes receivables with certain investors of our Drilling Partnerships.

Income Tax Provision (Benefit). For the Successor nine months ended September 30, 2017, we recorded a full valuation allowance against our net deferred tax asset balance, which reduced our effective tax rate to 0.74%. We continue to monitor facts and circumstances in the reassessment of the likelihood that operating loss carryforwards, credits and other deferred tax assets will be utilized prior to their expiration. Our effective tax rate fluctuates as a result of the impact of state income taxes and permanent differences between our accounting for certain revenue or expense items and their corresponding treatment for income tax purposes. Our effective tax rate for the nine months ended September 30, 2017 was 0.74%, which represents our expected Texas Franchise Tax liability. Our income tax provision differs from the provision computed by applying the U.S. Federal statutory corporate income tax rate of 35% primarily due to the valuation allowance on our deferred tax assets.

LIQUIDITY AND CAPITAL RESOURCES

See Liquidity and Ability to Continue as a Going Concern for additional disclosures.

Cash Flows

	Successor		Predecessor
	Period from		Period from
	September 1, 2016		January 1, 2016
	Nine Months Ended through		through
	September 30,		August 31, 2016
	2017	2016	
Net cash provided by operating activities	\$ 28,875	\$ 9,398	\$ 221,106
Net cash provided by (used in) investing activities	148,787	(5,367)	(24,894)
Net cash used in financing activities	(180,527)	(150)	(182,137)

Cash Flows From Operating Activities:

Successor Period from January 1, 2017 through September 30, 2017

consists of \$46.5 million of net cash provided by continuing operating activities and \$5.9 million of net cash provided by discontinued operating activities for cash receipts and disbursements attributable to our normal monthly operating cycle for gas and oil production and Drilling Partnership management revenues, and collections net of payments for royalties, lease operating expenses, gathering, processing and transportation expenses, severance taxes, Drilling Partnership management expenses, and general and administrative expenses; partially offset by

\$21.2 million of cash paid for interest primarily due to our First Lien Credit Facility; and

cash settlement payments of \$2.3 million on commodity derivative contracts.

Successor Period from September 1, 2016 through September 30, 2016

consists of \$5.8 million net cash provided by continuing operating activities and \$4.3 million of net cash provided by discontinued operating activities for cash receipts and disbursements attributable to our normal monthly operating cycle for gas and oil production and Drilling Partnership management revenues, and collections net of payments for royalties, lease operating expenses, gathering, processing and transportation expenses, severance taxes, Drilling Partnership management expenses, and general and administrative expenses; and

cash settlement receipts of \$0.2 million on commodity derivative contracts; partially offset by

reorganization costs of \$0.9 million representing incremental costs incurred as a result of our Predecessor's Chapter 11 Filings.

Predecessor Period from January 1, 2016 through August 31, 2016

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consists of \$214.4 million received from the sale of substantially all of our Predecessor's commodity hedge positions on July 25, 2016 and July 26, 2016 pursuant to our Predecessor's Restructuring Support Agreement;

cash settlement receipts of \$91.0 million on commodity derivative contracts; partially offset by

\$20.6 million of net cash used in continuing operating activities and \$15.6 million of net cash provided by discontinued operating activities for cash receipts and disbursements attributable to our Predecessor's normal monthly operating cycle for gas and oil production and partnership management revenues, and collections net of payments for royalties, well construction and completion activities, Drilling Partnership administrative and oversight and well services activities, lease operating expenses, gathering, processing and transportation expenses, severance taxes, general and administrative expenses, and interest payments;

reorganization costs of \$37.4 million incurred as a result of our Predecessor's Chapter 11 Filings;

\$36.7 million of investor capital raised transferred by our Predecessor to the Atlas Eagle Ford 2015 L.P. private drilling partnership for activities directly related to their program; and

\$5.2 million of funds transferred to certain Drilling Partnerships.

Cash Flows From Investing Activities:

Successor Nine Months Ended September 30, 2017

consists of \$109.1 million in net cash provided by continuing investing activities for the sale of our Rangely Assets; and

\$77.0 million in net proceeds from discontinued operations for the majority of the sale of our Appalachian Assets; partially offset by

\$37.2 million in capital expenditures paid related to our drilling activities.

Successor Period from September 1, 2016 through September 30, 2016

\$5.4 million in capital expenditures paid related to our drilling activities.

Predecessor Period from January 1, 2016 through August 31, 2016

\$24.9 million in capital expenditures paid related to our Predecessor's drilling activities.

Cash Flows From Financing Activities:

Successor Nine Months Ended September 30, 2017

consists of \$179.5 million in repayments under our First Lien Credit Facility; and

\$1.0 million in deferred financing costs primarily related to our First Lien Credit Facility amendments.

Predecessor Period from January 1, 2016 through August 31, 2016

consists of \$156.2 million in net repayments on our Predecessor's revolving credit facility;

\$12.6 million in distributions paid to our Predecessor's unitholders;

\$8.0 million in deferred financing costs primarily related to our Predecessor's revolving credit facility; and

\$5.5 million related to our Predecessor's senior note repurchases.

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Capital Requirements

At September 30, 2017, the capital expenditures of our natural gas and oil production assets primarily consist of discretionary expenditures to maintain or increase production margin in future periods, as well as land, gathering and processing, and other non-drilling capital expenditures.

As of September 30, 2017, we are committed to expend approximately \$2.8 million on a new enterprise resource planning system and drilling and completion and other capital expenditures. We expect to fund these capital expenditure commitments with our cash flows from operations.

OFF BALANCE SHEET ARRANGEMENTS

As of September 30, 2017, our off-balance sheet arrangements were limited to our letters of credit outstanding of \$2.8 million and commitments to spend \$2.8 million related to a new enterprise resource planning system and our drilling and completion and capital expenditures.

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

There have been no material changes to our contractual obligations and commercial commitments from those disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2016, except for our well drilling and completion commitments is \$0.4 million as of September 30, 2017 as compared to \$19.4 million as of December 31, 2016, and our commitments for a new enterprise resource planning system of \$1.9 million at September 30, 2017 as compared to zero as of December 31, 2016.

CREDIT FACILITIES

First Lien Credit Facility

On September 1, 2016, we entered into our \$440 million First Lien Credit Facility with Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto. See Note 5 to our condensed consolidated financial statements for a summary of the key provisions of our First Lien Credit Facility and subsequent amendments.

Second Lien Credit Facility

On September 1, 2016, we entered into our Second Lien Credit Facility with Wilmington Trust, National Association, as administrative agent, and the lenders party thereto for an aggregate principal amount of \$252.5 million. See Note 5 to our condensed consolidated financial statements for a summary of the key provisions of our Second Lien Credit Facility and subsequent amendments.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

For a more complete discussion of the accounting policies and estimates that we have identified as critical in the preparation of our condensed consolidated financial statements, please refer to our Management's Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report on Form 10-K for the fiscal year ended December 31, 2016.

Recently Issued Accounting Standards

See Note 2 to our condensed consolidated financial statements for additional information related to recently issued accounting standards.

ITEM 3: QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in interest rates and commodity prices. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonable possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of the market risk-sensitive instruments were entered into for purposes other than trading.

We are exposed to various market risks, principally fluctuating interest rates and changes in commodity prices. These risks can impact our results of operations, cash flows and financial position. We manage these risks through regular operating and financing activities and periodic use of derivative financial instruments such as forward contracts and interest rate cap and swap agreements. The following analysis presents the effect on our results of operations as if the hypothetical changes in market risk factors occurred on September 30, 2017. Only the potential impact of hypothetical assumptions was analyzed. The analysis does not consider other possible effects that could impact our business.

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Interest Rate Risk. At September 30, 2017, \$256.3 million was outstanding under our First Lien Credit Facility and \$283.5 million was outstanding under our Second Lien Credit Facility. Holding all other variables constant, a hypothetical 1% change in variable interest rates would change our condensed consolidated interest expense for the twelve-month period ending September 30, 2018 by approximately \$5.4 million.

Commodity Price Risk. Holding all other variables constant, including the effect of commodity derivatives, a 10% change in average commodity prices would result in a change to our condensed consolidated operating income for the twelve-month period ending September 30, 2018 of approximately \$0.3 million.

At September 30, 2017, we had the following commodity derivatives:

Type		Production Period Ending December 31,	Volumes⁽¹⁾	Average Fixed Price⁽¹⁾
Natural Gas	Fixed Price Swaps	2017 ⁽²⁾	12,919,900	\$ 3.140
		2018	43,947,300	\$ 2.959
Crude Oil	Fixed Price Swaps	2017 ⁽²⁾	196,500	\$ 47.441
		2018	588,500	\$ 50.286
		2019	73,000	

(1) Volumes for natural gas are stated in million British Thermal Units. Volumes for crude oil are stated in barrels.

(2) The production volumes for 2017 include the remaining three months of 2017 beginning October 1, 2017.

ITEM 4: CONTROLS AND PROCEDURES**Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures**

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in our Securities Exchange Act of 1934 reports is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating the disclosure controls and procedures, our management recognized that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

Under the supervision of our Chief Executive Officer and Chief Financial Officer and with the participation of our disclosure committee appointed by such officers, we have carried out an evaluation of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as of September 30, 2017, our disclosure controls and procedures were effective at the reasonable assurance level.

There have been no changes in our internal control over financial reporting during our most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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Exhibit	
Number	Description of Exhibit
3.1(a)	Certification of Conversion of Titan Energy, LLC (incorporated by reference to Exhibit 3.1(a) to our Registration Statement on Form S-1 (File No. 333-214850) filed on November 30, 2016)
3.1(b)	Certificate of Formation of Titan Energy, LLC (incorporated by reference to Exhibit 3.1(b) to our Registration Statement on Form S-1 (File No. 333-214850) filed on November 30, 2016)
3.2	Amended and Restated Limited Liability Company Agreement of Titan Energy, LLC, dated as of September 1, 2016 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed September 7, 2016)
10.1	Extension Letter, dated as of September 27, 2017, among Wilmington Trust, National Association, as Second Lien Collateral Agent, Wells Fargo Bank, National Association, as First Lien Collateral Agent, and Titan Energy, LLC (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed September 27, 2017)
10.2	Fourth Amendment to Third Amended and Restated Credit Agreement, dated effective as of October 31, 2017, among Titan Energy Operating, LLC, as borrower, Titan Energy, LLC, as parent, the subsidiary guarantors party thereto, the lenders party thereto, and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed November 6, 2017)
31.1*	Rule 13(a)-14(a)/15(d)-14(a) Certification
31.2*	Rule 13(a)-14(a)/15(d)-14(a) Certification
32.1*	Section 1350 Certification
32.2*	Section 1350 Certification
101.INS**	XBRL Instance Document
101.SCH**	XBRL Schema Document
101.CAL**	XBRL Calculation Linkbase Document
101.LAB**	XBRL Label Linkbase Document
101.PRE**	XBRL Presentation Linkbase Document
101.DEF**	XBRL Definition Linkbase Document

* Provided herewith.

** Attached as Exhibit 101 to this report are documents formatted in XBRL (Extensible Business Reporting Language). The financial information contained in the XBRL-related documents is unaudited or unreviewed.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

TITAN ENERGY, LLC

Date: November 28, 2017

By: /s/ Daniel C. Herz
Daniel C. Herz
Chief Executive Officer and Director

Date: November 28, 2017

By: /s/ Jeffrey M. Slotterback
Jeffrey M. Slotterback
Chief Financial Officer

Date: November 28, 2017

By: /s/ Matthew J. Finkbeiner
Matthew J. Finkbeiner
Chief Accounting Officer

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EXHIBIT 31.1

CERTIFICATION

I, Daniel C. Herz, certify that:

1. I have reviewed this quarterly report on Form 10-Q for the quarter ended September 30, 2017 of Titan Energy, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
- (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ DANIEL C. HERZ

Daniel C. Herz

Chief Executive Officer of Titan Energy, LLC

November 28, 2017

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EXHIBIT 31.2

CERTIFICATION

I, Jeffrey M. Slotterback, certify that:

1. I have reviewed this quarterly report on Form 10-Q for the quarter ended September 30, 2017 of Titan Energy, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
- (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ JEFFREY M. SLOTTBACK

Jeffrey M. Slotterback

Chief Financial Officer of Titan Energy, LLC

November 28, 2017

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EXHIBIT 32.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Titan Energy, LLC (the Company) on Form 10-Q for the quarter ended September 30, 2017 as filed with the Securities and Exchange Commission on the date hereof (the Report), I, Daniel C. Herz, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

- (1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ DANIEL C. HERZ
Daniel C. Herz
Chief Executive Officer of Titan Energy, LLC
November 28, 2017

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EXHIBIT 32.2

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Titan Energy, LLC (the Company) on Form 10-Q for the quarter ended September 30, 2017 as filed with the Securities and Exchange Commission on the date hereof (the Report), I, Jeffrey M. Slotterback, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

- (1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ JEFFREY M. SLOTTERBACK
Jeffrey M. Slotterback
Chief Financial Officer of Titan Energy, LLC
November 28, 2017