Foresight Energy LP
Form 10-Q
November 12, 2015

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, DC 20549

FORM 10-Q

(Mark One)

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2015

OR

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission File Number: 001-36503

Foresight Energy LP

(Exact Name of Registrant as Specified in its Charter)

Delaware (State or other jurisdiction of incorporation or organization)	80-0778894 (I.R.S. Employer Identification No.)
211 North Broadway, Suite 2600, Saint Louis, MO (Address of principal executive offices)	63102 (Zip code)

Registrant’s telephone number, including area code: (314) 932-6160

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ¨	Accelerated filer ¨
Non-accelerated filer x (do not check if a smaller reporting company)	Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

As of November 6, 2015, the registrant had 65,190,676 common units and 64,954,691 subordinated units outstanding.

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PART I – FINANCIAL INFORMATION.

Item 1. Financial Statements.

Foresight Energy LP

Unaudited Condensed Consolidated Balance Sheets

	September 30, 2015	December 31, 2014
	(In Thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$24,993	$26,509
Accounts receivable	58,235	80,911
Due from affiliates	18,596	532
Financing receivables - affiliate	2,638	-
Inventories	89,104	92,075
Prepaid expenses	6,354	2,157
Prepaid royalties	3,957	8,380
Deferred longwall costs	26,012	23,224
Coal derivative assets	29,581	36,080
Other current assets	262	6,302
Total current assets	259,732	276,170
Property, plant, equipment and development, net	1,454,518	1,522,488
Due from affiliates	2,691	—
Financing receivables - affiliate	70,831	—
Prepaid royalties	66,210	59,967
Coal derivative assets	24,026	24,957
Other assets	29,415	32,070
Total assets	$1,907,423	$1,915,652
Liabilities and partners’ capital		
Current liabilities:		
Current portion of long-term debt and capital lease obligations	$94,567	$44,143
Accrued interest	10,685	25,136
Accounts payable	38,581	60,206
Accrued expenses and other current liabilities	35,427	37,820
Due to affiliates	6,481	15,107
Total current liabilities	185,741	182,412
Long-term debt and capital lease obligations	1,401,080	1,316,528
Sale-leaseback financing arrangements – affiliate	193,434	193,434
Asset retirement obligations	31,878	31,373
Other long-term liabilities	6,131	5,508
Total liabilities	1,818,264	1,729,255
Limited partners' capital (deficit):		
	221,446	238,925

Common unitholders (65,191 and 64,831 units outstanding as of September 30, 2015 and December 31, 2014, respectively)		
Subordinated unitholders (64,955 and 64,739 units outstanding as of September 30, 2015 and December 31, 2014, respectively)	(130,569)	(111,169)
Total limited partners' capital	90,877	127,756
Predecessor equity	—	50,710
Noncontrolling interests	(1,718)	7,931
Total partners' capital	89,159	186,397
Total liabilities and partners' capital	$1,907,423	$1,915,652

See accompanying notes.

Foresight Energy LP

Unaudited Condensed Consolidated Statements of Operations

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In Thousands, Except per Unit Data)			
Revenues				
Coal sales	$251,125	$299,964	$739,940	$809,364
Other revenues	1,941	—	3,263	—
Total revenues	253,066	299,964	743,203	809,364
Costs and expenses:				
Cost of coal produced (excluding depreciation, depletion and amortization)	128,195	123,535	360,769	323,064
Cost of coal purchased	5,055	11,940	7,063	12,672
Transportation	34,377	54,454	127,757	161,188
Depreciation, depletion and amortization	54,152	46,638	145,701	123,944
Accretion on asset retirement obligations	567	405	1,700	1,215
Selling, general and administrative	4,761	6,401	25,285	26,634
Transition and reorganization costs	5,037	—	17,288	—
Gain on commodity derivative contracts	(17,541)	(18,990)	(40,703)	(41,419)
Other operating loss (income), net	384	859	(13,872)	(1,460)
Operating income	38,079	74,722	112,215	203,526
Other expenses:				
Loss on early extinguishment of debt	—	—	—	4,979
Interest expense, net	29,891	28,202	86,591	88,156
Net income	8,188	46,520	25,624	110,391
Less: net income attributable to noncontrolling interests	118	804	652	2,819
Net income attributable to controlling interests	8,070	45,716	24,972	107,572
Less: net income attributable to predecessor equity	—	350	23	66,436
Net income attributable to limited partner units	$8,070	$45,366	$24,949	$41,136
Net income subsequent to initial public offering available to limited partner units - basic and diluted:				
Common units	$4,041	$22,691	$12,486	$20,619
Subordinated units	$4,029	$22,675	$12,463	$20,517
Net income subsequent to initial public offering per limited partner unit - basic and diluted:				
Common units	$0.06	$0.35	$0.19	$0.32
Subordinated units	$0.06	$0.35	$0.19	$0.32
Weighted average limited partner units outstanding - basic and diluted:				
Common units	65,156	64,786	65,067	64,786
Subordinated units	64,955	64,739	64,927	64,739

Distributions declared per limited partner unit	$0.38	$0.03	$1.11	$0.03

See accompanying notes.

Foresight Energy LP

Unaudited Condensed Consolidated Statement of Partners' Capital (Deficit)

	Limited Partners						
	Common Unitholders	Number of Common Units	Subordinated Unitholders	Number of Subordinated Units	Predecessor Equity	Noncontrolling Interests	Total Partners' Capital
	(In Thousands, Except Unit Data)						
Balance at January 1, 2015	$238,925	64,831,312	$(111,169)	64,738,895	$50,710	$7,931	$186,397
Net income	12,486	—	12,463	—	23	652	25,624
Capital contribution from Foresight Reserves LP	5,259	—	5,248	—	—	—	10,507
Contribution of net assets to Foresight Energy LP	25,643	—	34,988	—	(50,733)	(9,898)	—
Cash distributions	(72,246)	—	(72,099)	—	—	(403)	(144,748)
Equity-based compensation	12,897	—	—	—	—	—	12,897
Issuance of equity-based awards	—	359,364	—	215,796	—	—	—
Distribution equivalent rights on LTIP awards	(640)	—	—	—	—	—	(640)
Net settlement of withholding taxes on issued LTIP awards	(878)	—	—	—	—	—	(878)
Balance at September 30, 2015	$221,446	65,190,676	$(130,569)	64,954,691	$—	$(1,718)	$89,159

See accompanying notes.

Foresight Energy LP

Unaudited Condensed Consolidated Statements of Cash Flows

	Nine Months Ended September 30,	
	2015	2014
	(In Thousands)	
Cash flows from operating activities		
Net income	$25,624	$110,391
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	145,701	123,944
Equity-based compensation	12,897	3,257
Unrealized losses (gains) on commodity derivative contracts and cumulative prior unrealized gains realized during the period	10,853	(33,711)
Realized gains on commodity derivative contracts included in investing activities	(19,073)	—
Transition and reorganization expenses paid by Foresight Reserves LP (affiliate)	8,031	—
Noncash loss on early extinguishment of debt	—	4,681
Other	6,822	7,546
Changes in operating assets and liabilities:		
Accounts receivable	22,676	(33,655)
Due from/to affiliates, net	(25,406)	6,013
Inventories	(3,806)	(18,929)
Prepaid expenses and other current assets	2,265	(10,485)
Prepaid royalties	(1,820)	(3,443)
Commodity derivative contract assets and liabilities, net	(2,447)	(1,439)
Accounts payable	(21,625)	19,634
Accrued interest	(14,451)	(10,667)
Accrued expenses and other current liabilities	(4,085)	5,164
Other	(2,390)	(650)
Net cash provided by operating activities	139,766	167,651
Cash flows from investing activities		
Investment in property, plant, equipment and development	(69,502)	(173,946)
Investment in financing arrangements with Murray Energy (affiliate)	(75,000)	—
Settlement of certain commodity derivative contracts	19,073	—
Return of investment on financing arrangements with Murray Energy (affiliate)	1,112	—
Acquisition of an affiliate	—	(3,822)
Proceeds from sale of equipment	—	1,619
Net cash used in investing activities	(124,317)	(176,149)
Cash flows from financing activities		
Net increase in borrowings under revolving credit facility	58,000	83,500
Net increase in borrowings under A/R securitization program	50,000	—
Proceeds from other long-term debt	59,325	29,719
Payments on other long-term debt and capital lease obligations	(33,274)	(297,908)
Payments on short-term debt	(2,010)	—
Distributions paid	(144,748)	(124,267)
Proceeds from issuance of common units (net of underwriters' discount)	—	329,875
Initial public offering costs paid (other than underwriters' discount)	—	(6,976)
Debt issuance costs paid	(2,751)	(297)

Other	(1,507)	(551)
Net cash (used in) provided by financing activities	(16,965)	13,095
Net (decrease) increase in cash and cash equivalents	(1,516)	4,597
Cash and cash equivalents, beginning of period	26,509	24,787
Cash and cash equivalents, end of period	$24,993	$29,384
Supplemental information and disclosures of non-cash financing activities:		
Interest paid, net of amounts capitalized	$96,050	$93,437
Non-cash distribution	$—	$12,187
Non-cash capital contribution from Foresight Reserves LP (affiliate)	$10,507	$—
Short-term insurance financing	$2,809	$—

See accompanying notes.

Foresight Energy LP

Notes to Unaudited Condensed Consolidated Financial Statements

1. Organization, Nature of Business and Basis of Presentation

Foresight Energy LLC (“FELLC”), a perpetual-term Delaware limited liability company, was formed in September 2006 for the development, mining, transportation and sale of coal. Prior to June 23, 2014, Foresight Reserves, LP (“Foresight Reserves”) owned 99.333% of FELLC and a member of FELLC’s management owned 0.667%. In January 2012, Foresight Energy LP (“FELP”), a Delaware limited partnership, and Foresight Energy GP LLC (“general partner” or “FEGP”), a Delaware limited liability company, were formed. FELP was formed to own FELLC and FEGP was formed to be the general partner of FELP. Prior to June 23, 2014, FELP had no operating or cash flow activity, and no recorded net assets.

On June 23, 2014, in connection with the initial public offering (“IPO”) of FELP, Foresight Reserves and a member of management contributed their ownership interests in FELLC to FELP for which they were issued common and subordinated units in FELP. Because this transaction was between entities under common control, the contributed assets and liabilities of FELLC were recorded in the combined consolidated financial statements of FELP at FELLC’s historical cost. FELP has been managed by FEGP subsequent to the IPO.

During the first quarter of 2015 (the “Contribution Date”), Foresight Reserves and a member of management contributed (through their incentive distribution rights) their 100% equity interest in Sitran LLC (“Sitran”), Adena Resources LLC (“Adena”), Hillsboro Transport LLC (“Hillsboro Transport”) and Akin Energy LLC (“Akin Energy”) to FELP for no consideration (collectively, the “Contributed Companies”) (see Note 4). Because Sitran, Akin Energy and FELP were under common control, FELP’s historical results prior to the Contribution Date have been recast to combine the financial position and results of operations of Sitran and Akin Energy. Hillsboro Transport and Adena were consolidated as variable interest entities (“VIEs”) prior to the Contribution Date (see Note 14), therefore, the contribution did not result in a change in reporting entity. The equity values of Sitran and Akin Energy prior to the Contribution Date are included in predecessor equity in the statement of partners’ capital (deficit), and on the Contribution Date, the net book values of these entities were reclassified from predecessor equity to limited partners’ capital. Similarly, the equity values of Hillsboro Transport and Adena were reclassified from noncontrolling interests to limited partners’ capital on the Contribution Date.

The controlling interest net income of the Contributed Companies prior to the Contribution Date and the controlling interest net income of FELLC prior to the IPO are included in net income attributable to predecessor equity in the condensed consolidated statements of operations.

As used hereafter in this report, the terms “Foresight Energy LP,” “FELP,” the “Partnership,” “we,” “us” or like terms, refer to the combined results of Foresight Energy LP, the Contributed Companies, and FELLC and its consolidated subsidiaries and affiliates, unless the context otherwise requires or where otherwise indicated. The information presented in this Quarterly Report on Form 10-Q contains, for all periods presented, the combined financial results of Foresight Energy LP, the Contributed Companies and FELLC, and VIEs for which FELLC or its subsidiaries are the primary beneficiary.

On April 16, 2015, Murray Energy Corporation (“Murray Energy”) and Foresight Reserves completed a transaction whereby Murray Energy acquired a noncontrolling economic interest in FEGP and FELP (see Note 13).

The Partnership operates in a single reportable segment and currently operates four underground mining complexes in the Illinois Basin: Williamson Energy, LLC (“Williamson”); Sugar Camp Energy, LLC (“Sugar Camp”); Hillsboro

Energy, LLC ("Hillsboro"); and Macoupin Energy, LLC ("Macoupin"). On June 1, 2014, the second longwall system at our Sugar Camp complex transitioned from the development stage to the production stage and from that date forward was recognized in our results of operations. Mined coal is sold to a diverse customer base, including electric utility and industrial companies primarily in the eastern United States, as well as overseas markets. Intercompany transactions, including those between consolidated VIEs, the Contributed Companies, and FELP and its consolidated subsidiaries, are eliminated in consolidation.

The accompanying condensed consolidated financial statements contain all significant adjustments (consisting of normal recurring accruals) that, in the opinion of management, are necessary to present fairly, the Partnership's condensed consolidated financial position, results of operations and cash flows for all periods presented. In preparing the condensed consolidated financial statements, management used estimates and assumptions that may affect reported amounts and disclosures. To the extent there are material differences between the estimates and actual results, the impact to the Partnership's financial condition or results of operations could be material. The unaudited condensed consolidated financial statements do not include footnotes and certain financial information as required annually under U.S. generally accepted accounting principles ("U.S. GAAP") and, therefore, should be read in conjunction with the annual audited consolidated financial statements for the year ended December 31, 2014 included in our Annual Report on Form 10-K filed with the SEC on March 10, 2015. The results of operations for the three and nine months ended September 30, 2015 are not necessarily indicative of results that can be expected for any future period, including the year ending December 31, 2015.

2. New Accounting Standards

In April 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) 2014-08, Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. ASU 2014-08 changes the requirements for reporting discontinued operations by updating the criteria for determining discontinued operations and modifies the disclosure requirements of both discontinued operations and certain other disposals not defined as discontinued operations. ASU 2014-08 was adopted during the first quarter of 2015 and did not have an effect on our condensed consolidated financial statements.

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers, to clarify the principles used to recognize revenue. The initial effective date for ASU 2014-09 was scheduled for annual and interim periods beginning after December 15, 2016. In July 2015, the FASB delayed the effective date until annual and interim periods beginning after December 31, 2017. We are in the process of evaluating the effects, if any, the adoption of this guidance will have on our consolidated financial statements.

In February 2015, the FASB issued ASU 2015-02, Amendments to the Consolidation Analysis. ASU 2015-02 changes the requirements and analysis required when determining the reporting entity’s need to consolidate an entity, including modifying the evaluation of limited partnership variable interest status, the presumption that a general partner should consolidate a limited partnership and the consolidation criterion applied by a reporting entity involved with variable interest entities. ASU 2015-02 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2015 and shall be applied retrospectively to each period presented. Early adoption is permitted. We are currently evaluating the effect of adopting ASU 2015-02.

In April 2015, the FASB issued ASU 2015-06, Effects on Historical Earnings per Unit of Master Limited Partnership Dropdown Transactions. ASU 2015-06 specifies that for purposes of calculating historical earnings per unit under the two-class method, the earnings of a transferred business before the date of a dropdown transaction should not be allocated to the limited partnership and therefore earnings per unit of the limited partners would not change as a result of the dropdown transaction. ASU 2015-06 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2015 and shall be applied retrospectively to each period presented. At this time, we do not expect that ASU 2015-06 will have a significant effect on our consolidated financial statements or related disclosures.

In April 2015, the FASB issued ASU 2015-03, Interest - Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs. ASU 2015-03 requires, effective for fiscal years and interim periods beginning after December 15, 2015, that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. Retrospective application is required and early adoption is permitted. The adoption of ASU 2015-03 only impacts balance sheet classification; therefore, it will not have a significant effect on our consolidated financial statements or related disclosures.

In July 2015, the FASB issued ASU 2015-11, Inventory: Simplifying the Measurement of Inventory, which simplifies the measurement of inventories valued under most methods. Under this new guidance, inventories valued under these methods would be valued at the lower of cost and net realizable value, with net realizable value defined as the estimated selling price less reasonable costs to sell the inventory. The new guidance is effective prospectively for fiscal periods starting after December 15, 2016 and early adoption is permitted. We do not expect the adoption of ASU 2015-11 to have a significant effect on our consolidated financial statements or related disclosures.

No other new accounting pronouncement issued or effective during the fiscal year which were not previously disclosed in our Annual Report on Form 10-K had, or is expected to have, a material impact on our consolidated financial statements or related disclosures.

3. Transition and Reorganization Costs

Transition and reorganization costs were $5.0 million and $17.3 million for the three and nine months ended September 30, 2015, respectively. In connection with Murray Energy acquiring a noncontrolling ownership interest in the Partnership and its general partner (see Note 13), we entered into a management services agreement (“MSA”) with Murray American Coal Inc., an affiliate of Murray Energy, with the intent of optimizing and reorganizing certain corporate administrative functions and generating synergies between the two companies through the elimination of headcount and duplicate selling, general and administrative expenses. The costs are comprised of retention compensation to certain employees during the transition period and termination benefits to employees whose positions were replaced during the current period by Murray Energy employees under the MSA. Included in these costs for the nine months ended September 30, 2015 were $8.0 million of costs paid by Foresight Reserves which were recorded as capital contributions (an additional $2.5 million was paid and deferred and will be expensed over the required remaining retention period),

$3.9 million of equity-based compensation for the accelerated vesting of certain equity awards and $0.6 million of legal and various other one-time charges related to the Murray Energy transaction.

4. Contributions by Foresight Reserves

During the nine months ended September 30, 2015, Foresight Reserves paid $10.5 million of one-time employee compensation costs classified as transition and reorganization costs for which it will not seek reimbursement from the Partnership. The noncash contribution from Foresight Reserves increased the Partnership's limited partners' capital accounts. Of the $10.5 million contribution amount, $2.5 million was deferred as a prepaid expense and will be amortized over the required retention period.

During the first quarter of 2015, Foresight Reserves and a member of management contributed to FELP, for no consideration, the following entities:

- Sitran – a barge terminal on the Ohio River,
- Hillsboro Transport – Hillsboro's coal loadout facility,
- Adena – an entity that provides certain water and other miscellaneous rights to FELP's mines, and
- Akin Energy – an entity holding certain permits and development costs for a natural gas power generation facility.

As described in Note 1, because Sitran and Akin Energy were under common control, the Partnership's historical financial statements have been retrospectively adjusted to combine their financial position at historical cost and their results of operations. The equity values of Sitran and Akin Energy prior to the Contribution Date are included in predecessor equity in the statement of partners' capital (deficit). Hillsboro Transport and Adena were previously consolidated by the Partnership as VIEs, therefore the contribution did not result in a change in reporting entity (see Note 14). On the Contribution Date, the net book values of the Contributed Companies were reclassified from either predecessor equity or noncontrolling interest, as applicable, to limited partners' capital in the statement of partners' capital (pro rata between the common and subordinated units based on the number of units held by the contributing parties on the Contribution Date). The aggregate net book value of the Contributed Companies on the Contribution Date was $60.6 million.

5. Commodity Derivative Contracts

We have commodity price risk for our coal sales as a result of changes in the market value of our coal. To minimize this risk, we enter into long-term, fixed price coal supply sales agreements and coal derivative swap contracts. As of September 30, 2015 and December 31, 2014, we had outstanding coal derivative contracts to fix the selling price on 1.4 million tons and 3.4 million tons, respectively. Swaps are designed so that we receive or make payments based on a differential between fixed and variable prices for coal. The coal derivative contracts are economic hedges to certain future unpriced (indexed) sales commitments through 2017. The coal derivative contracts are indexed to the Argus API 2 price index, the benchmark price for coal exported to northwest Europe. The coal derivative contracts are accounted for as freestanding derivatives and any gains or losses resulting from adjusting these contracts to fair value are recorded into earnings.

We have diesel fuel price exposure in our transportation and production processes and therefore are subject to commodity price risk as a result of changes in the market value of diesel fuel. Beginning in 2015, to limit our exposure to diesel fuel price volatility, we entered into swap agreements with financial institutions which provide a fixed price per unit for the volume of purchases being hedged. As of September 30, 2015, we had swap agreements outstanding to hedge the variable cash flows related to 19% of anticipated diesel fuel exposure for the remainder of 2015 and calendar year 2016. The diesel fuel derivative contracts are accounted for as freestanding derivatives and any gains or losses resulting from adjusting these contracts to fair value are recorded into earnings.

We have master netting arrangements with all of our counterparties that allow for the settlement of contracts in an asset position with contracts in a liability position. We manage counterparty risk through the utilization of investment grade commercial banks, diversification of counterparties and our counterparty netting arrangements. We record the fair value of all derivative positions with a given counterparty on a gross basis in the condensed consolidated balance sheets (see Note 17).

A summary of the unrealized and realized (gains) losses recorded on commodity derivative contracts for the three and nine months ended September 30, 2015 and 2014 is as follows:

	Three Months Ended		Nine Months Ended	
	September 30, 2015	September 30, 2014	September 30, 2015	September 30, 2014
	(In Thousands)			
Unrealized (gain) loss on commodity derivative contracts and prior cumulative unrealized gains realized during the period	$(6,616)	$(16,001)	$10,853	$(33,711)
Realized (gain) loss on commodity derivative contracts	(10,925)	(2,989)	(51,556)	(7,708)
Gain on commodity derivative contracts	$(17,541)	$(18,990)	$(40,703)	$(41,419)

We received $19.1 million in proceeds during the nine months ended September 30, 2015 from the settlement of derivatives that were reclassified from an operating cash flow activity to an investing activity in the condensed consolidated statement of cash flows because the derivative contracts were settled prior to the expiration of their contractual maturities and prior to the delivery date of the underlying sales contracts.

6. Accounts Receivable

Accounts receivable consist of the following:

	September 30, 2015	December 31, 2014
	(In Thousands)	
Trade accounts receivable	$51,802	$ 72,835
Other receivables	6,433	8,076
Total accounts receivable	$58,235	$ 80,911

7. Inventories

Inventories consist of the following:

September 30, 2015	December 31, 2014
(In Thousands)	

Parts and supplies	$27,448	$ 32,156
Raw coal	4,189	6,200
Clean coal	57,467	53,719
Total inventories	$89,104	$ 92,075

8. Property, Plant, Equipment and Development, Net

Property, plant, equipment and development, net consist of the following:

	September 30, 2015	December 31, 2014
	(In Thousands)	
Land, land rights and mineral rights	$100,384	$108,892
Machinery and equipment	1,132,391	1,094,631
Machinery and equipment under capital leases	126,401	126,401
Buildings and structures	248,450	246,617
Development costs	737,262	713,301
Other	9,619	9,239
Property, plant, equipment and development	2,354,507	2,299,081
Less: accumulated depreciation, depletion and amortization	(899,989)	(776,593)
Property, plant, equipment and development, net	$1,454,518	$1,522,488

9. Accrued Expenses and Other Current Liabilities

Accrued expenses and other current liabilities consist of the following:

	September 30, 2015	December 31, 2014
	(In Thousands)	
Employee compensation, benefits and payroll taxes	$12,018	$13,163
Taxes other than income	5,684	5,668
Asset retirement obligations	4,207	4,207
Royalties (non-affiliate)	4,087	2,975
Short-term insurance financing	797	—
Liquidated damages (non-affiliate)	2,836	7,315
Other	5,798	4,492
Total accrued expenses and other current liabilities	$35,427	$37,820

10. Long-Term Debt and Capital Lease Obligations

Long-term debt and capital lease obligations consist of the following:

	September 30, 2015	December 31, 2014
	(In Thousands)	
2021 Senior Notes	$596,548	$596,213
Term Loan	295,446	235,822
Revolving Credit Facility	377,500	319,500
Trade A/R Securitization	50,000	—
5.78% longwall financing arrangement	56,025	61,628
5.555% longwall financing arrangement	51,562	61,875
Capital lease obligations	68,566	85,633
Total long-term debt and capital lease obligations	1,495,647	1,360,671
Less: current portion	(94,567)	(44,143)
Long-term debt and capital lease obligations	$1,401,080	$1,316,528

In May 2015, we entered into the Incremental Amendment No. 1 to the Second Amended and Restated Credit Agreement (the “Credit Agreement”), which increased lender commitments under the Revolving Credit Facility by $50.0 million and provided $60.0 million of incremental Term Loan borrowings. The additional commitments under the Revolving Credit Facility and the Term Loan borrowings have the same terms as the existing borrowings under the Credit Agreement.

The Revolving Credit Facility, as amended, has a total borrowing capacity of $550.0 million. At September 30, 2015, we had borrowings of $377.5 million outstanding under the Revolving Credit Facility and $6.5 million outstanding in letters of credit. There was $166.0 million of remaining capacity under the Revolving Credit Facility as of September 30, 2015 and the weighted-average effective interest rate on borrowings was 2.9%.

As of September 30, 2015 and December 31, 2014, Chris Cline, the Cline Trust Company, LLC and another director of the Partnership’s general partner had independently acquired and owned, in aggregate, $58.5 million and $12.0 million, respectively, of the outstanding notional principal on the Partnership’s 2021 Senior Notes. See Note 13.

Trade A/R Securitization

In January 2015, Foresight Energy LP and certain of its wholly-owned subsidiaries, entered into a $70 million receivables securitization program (the “Securitization Program”). Under this Securitization Program, our subsidiaries sell all of their customer trade receivables (the “Receivables”), on a revolving basis, to Foresight Receivables LLC, a wholly-owned and consolidated special purpose subsidiary of Foresight Energy LP (the “SPV”). The SPV then pledges its interests in the Receivables to the securitization program lenders, which either make loans or issue letters of credit to, or on behalf of, the SPV. The maximum amount of advances and letters of credit outstanding under the program may not exceed $70 million. The amount eligible for borrowing is determined by the qualified receivable balances outstanding. The Securitization Program has a three-year maturity which expires on January 12, 2018. The borrowings under the Securitization Program are variable-rate and also carry a commitment fee for unutilized commitments. As of September 30, 2015, we had borrowings outstanding of $50.0 million under the Securitization Program included within the current portion of long-term debt and capital lease obligations.

11. Sale-Leaseback Financing Arrangements – Affiliate

In 2009, Macoupin sold certain of its coal reserves and rail facilities to WPP, LLC (“WPP”), a subsidiary of Natural Resource Partners, LP (“NRP”), and leased them back. The gross proceeds from this transaction were $143.5 million. In 2012, Sugar Camp sold certain rail facilities to HOD, LLC (“HOD”), a subsidiary of NRP, and leased them back. The gross proceeds from this transaction were $50.0 million. NRP is an affiliated entity to the Partnership (see Note 13). In both transactions, because we had continuing involvement in the assets sold, the transactions were treated as sale-leaseback financing arrangements.

In 2013, an agreement was reached between FELLC, Foresight Reserves and HOD that allows for the existing agreement with Sugar Camp to be amended in the future to include coal produced from Sugar Camp’s second longwall on what is expected to be materially consistent terms as the original agreement. Pursuant to such an amendment occurring, the consideration paid by HOD for including coal produced by Sugar Camp's second longwall was to be paid directly to Foresight Reserves. In April 2015, in connection with Murray Energy acquiring a noncontrolling ownership interest in the Partnership and its general partner (see Note 13), Foresight Reserves assigned its right to receive the proceeds from HOD back to the Partnership (net of any taxes incurred by Foresight Reserves on the transaction).

As of September 30, 2015, the outstanding principal balance on the Macoupin and Sugar Camp sale-leaseback financing arrangements were $143.5 million and $50.0 million, respectively.

The implied effective interest rate as of September 30, 2015 on the Macoupin sale-leaseback financing arrangement and the Sugar Camp sale-leaseback financing arrangement was 14.0% and 13.3%, respectively. If there is a material change to the mine plans, the impact of a change in the effective interest rate to the condensed consolidated statement of operations could be significant. Interest expense recorded on the Macoupin sale-leaseback was $5.9 million and $5.2 million for each of the three months ended September 30, 2015 and 2014, respectively, and $15.9 million and $14.8 million for the nine months ended September 30, 2015 and 2014, respectively. Interest expense recorded on the Sugar Camp sale-leaseback was $0.9 million and $1.4 million for the three months ended September 30, 2015 and 2014, respectively, and $3.9 million and $4.9 million for the nine months ended September 30, 2015 and 2014, respectively. As of September 30, 2015 and December 31, 2014, interest totaling $3.1 million and $5.6 million, respectively, was accrued in the condensed consolidated balance sheets for the Macoupin and Sugar Camp sale-leaseback financing arrangements.

12. Asset Retirement Obligations

The change in the carrying amount of our asset retirement obligations was as follows for the nine months ended September 30, 2015:

	September 30, 2015 (In Thousands)
Balance at January 1, 2015 (including current portion)	$ 35,580
Accretion expense	1,700
Expenditures for reclamation activities	(1,195)
Balance at September 30, 2015 (including current portion)	36,085
Less: current portion of asset retirement obligations	(4,207)
Noncurrent portion of asset retirement obligations	$ 31,878

13. Related-Party Transactions

The chairman of our general partner's board of directors and the controlling member of Foresight Reserves, Chris Cline, directly and indirectly beneficially owns a 31% and 4% interest in the general and limited partner interests of NRP, respectively. Additionally, Donald R. Holcomb, who serves as a director on NRP's board, is the member for the Cline Trust Company LLC, which owns 20.3 million of the Partnership's common limited partner units. We routinely engage in transactions in the normal course of business with NRP and its subsidiaries and Foresight Reserves and its affiliates. These transactions include production royalties, transportation services, administrative arrangements, coal handling and storage services, supply agreements, service agreements, land leases and sale-leaseback financing arrangements (see Note 11, sale-leaseback financing arrangements are excluded from the discussion and tables below). We also acquire, from time to time, mining equipment from Foresight Reserves and affiliated entities.

On April 16, 2015, Foresight Reserves and Murray Energy executed a purchase and sale agreement whereby Murray Energy paid Foresight Reserves $1.37 billion to acquire a 34% voting interest in FEGP, 77.5% of FELP's incentive distribution rights ("IDR") and nearly 50% of the outstanding limited partner units in FELP, including all of the outstanding subordinated units. FEGP will continue to govern the Partnership subsequent to this transaction. As part of the transaction, Murray Energy obtained an option, subject to certain conditions described below, to purchase an additional 46% of the voting interests in FEGP for $25 million during a five-year period. Murray Energy's ability to exercise the option is conditioned upon (i) the exercise of the call option with respect to Colt LLC, a wholly-owned subsidiary of Foresight Reserves and (ii) the refinancing of the FELP notes and FELP's existing credit facilities on terms reasonably acceptable to Foresight Reserves, or any other transaction (whether by amendment, waiver or a consent solicitation) that would have the effect of eliminating the "change of control" provisions of the FELP notes and

FELP's existing credit facilities with respect to the exercise of the option.

Murray Management Services Agreement

On April 16, 2015, a MSA was executed between FEGP and Murray American Coal, Inc. (the "Manager"), a wholly-owned subsidiary of Murray Energy, pursuant to which the Manager will provide certain management and administration services to FELP for a quarterly fee of $3.5 million ($14.0 million on an annual basis), subject to contractual adjustments. To the extent that FELP or FEGP directly incurs costs for any services covered under the MSA, then the Manager's quarterly fee is reduced accordingly. Also, to the extent that the Manager utilizes outside service providers to perform any of the services under the MSA, then the Manager is responsible for those outside service provider costs. The initial term of the MSA extends through December 31, 2022 and is subject to termination provisions. After taking into account the contractual adjustments for direct costs incurred by FELP, the amount of net expense due to the Manager for the three and nine months ended September 30, 2015 was $1.9 million and $3.4 million, respectively.

Murray Energy Transport Lease and Overriding Royalty Agreements

On April 16, 2015, American Century Transport LLC ("American Transport"), a newly created subsidiary of the Partnership, entered into a purchase and sale agreement (the "PSA") with American Energy Corporation ("American Energy"), a subsidiary of Murray Energy, pursuant to which American Energy sold to American Transport certain mining and transportation assets for $63.0 million. Concurrent with the PSA, American Transport entered into a lease agreement (the "Transport Lease") with American Energy pursuant to which (i) American Transport will lease to American Energy a tract of real property, two coal preparation plants and related coal handling facilities at the Transport Mine situated in Belmont and Monroe Counties, Ohio and (ii) American Transport will receive from American Energy a fee ranging from $1.15 to $1.75 for every ton of coal mined, processed and/or transported using such assets, subject to a quarterly recoupable minimum fee of $1.7 million. The Transport Lease is being accounted for as a direct financing lease. The total remaining minimum payments under the Transport Lease was $100.4 million at September 30, 2015, with unearned income equal to $38.8 million. The unearned income will be reflected as other revenue over the term of the lease using the effective interest method. Any amounts in excess of the contractual minimums will be recorded as other revenue when earned. As of September 30, 2015, the outstanding Transport Lease financing receivable was $61.6 million, of which $2.5 million was classified as current in the condensed consolidated balance sheet.

Also, on April 16, 2015, American Century Minerals LLC (“Minerals”), a newly created subsidiary of the Partnership, entered into an overriding royalty agreement (“ORRA”) with Murray Energy subsidiaries’ American Energy and Consolidated Land Company (collectively, “AEC”), pursuant to which AEC granted to Minerals an overriding royalty interest ranging from $0.30 to $0.50 for each ton of coal mined, removed and sold from certain coal reserves situated near the Century Mine in Belmont and Monroe Counties, Ohio for $12.0 million. The ORRA is subject to a minimum recoupable quarterly fee of $0.5 million. This overriding royalty was accounted for as a financing arrangement. The payments the Partnership receives with respect to the ORRA will be reflected partially as a return of the initial investment (reduction in the affiliate financing receivable) and partially as other revenue over the life of the agreement using the effective interest method. Any amounts in excess of the contractual minimums will be recorded as other revenue when earned. The total remaining minimum payments under the ORRA was $34.5 million at September 30, 2015, with unearned income equal to $22.7 million. As of September 30, 2015, the outstanding ORRA financing receivable was $11.8 million, of which $0.1 million was classified as current in the condensed consolidated balance sheet.

Other Murray Transactions

During the three and nine months ended September 30, 2015, we purchased $1.2 million and $1.6 million, respectively, in equipment, supplies and rebuild services from affiliates of Murray Energy.

During the three and nine months ended September 30, 2015, we purchased $5.1 million and $7.0 million, respectively, in coal from Murray Energy to meet quality specifications under certain customer contracts and we sold $8.7 million of coal to Murray Energy during the three and nine months ended September 30, 2015.

During the three and nine months ended September 30, 2015, Murray Energy transported coal under our transportation agreement with a third party rail company resulting in usage fees owed to the third-party rail company of $7.5 million and $7.7 million, respectively. These usage fees have been fully billed to Murray Energy, resulting in no impact to our condensed consolidated statement of operations. The usage of the railway line with this third-party rail company by Murray Energy counts towards the minimum annual throughput volumes with the third-party rail company, thereby reducing the Partnership’s exposure to contractual liquidated damage charges.

Convent Marine Terminal Amendment

Effective May 1, 2015, the Partnership amended its material handling agreement with Raven Energy LLC, a former affiliate of The Cline Group, to reduce the minimum annual throughput volume at Convent Marine Terminal to 5.0 million tons for 2015 and through the duration of the contract.

2021 Senior Notes

On August 23, 2013, Cline Resource and Development Company ("CRDC") acquired $16.5 million of outstanding principal amounts of our 2021 Senior Notes (the "Original Purchase"), which bear interest at the rate of 7.875% annually. During September and October 2013, CRDC sold the Original Purchase primarily to affiliates, including $8.0 million to Chris Cline, $4.0 million to an entity controlled by John F. Dickinson, a director of our general partner's board of directors, and $3.8 million to two former executives of the Partnership. Additional amounts were acquired independently in 2015 by Chris Cline and The Cline Trust Company LLC, as discussed below.

As of September 30, 2015 and December 31, 2014, Chris Cline owned $44.5 million and $8.0 million, respectively, of the outstanding principal on our 2021 Senior Notes. Chris Cline acquired $8.0 million in principal of the Original Purchase and during the nine months ended September 30, 2015, acquired an additional $36.5 million in principal from third parties in open market transactions. During the three months ended September 30, 2015 and 2014, $1.6 million and $0.3 million, respectively, of interest on the 2021 Senior Notes was paid to Chris Cline and $1.9 million and $0.6 million during the nine months ended September 30, 2015 and 2014, respectively. As of September 30, 2015 and December 31, 2014, $0.4 million and $0.2 million, respectively, of interest on the 2021 Senior Notes was accrued.

The entity controlled by Mr. Dickinson owned $4.0 million of the outstanding principal on our 2021 Senior Notes as of September 30, 2015 and December 31, 2014, all of which was acquired from the Original Purchase. During the three months ended September 30, 2015 and 2014, $0.2 million of interest on the 2021 Senior Notes was paid to Mr. Dickinson and during the nine months ended September 30, 2015 and 2014, $0.3 million of interest on the 2021 Senior Notes was paid to Mr. Dickinson. As of September 30, 2015 and December 31, 2014, $0.1 million of interest on the 2021 Senor Notes was accrued.

As of September 30, 2015, The Cline Trust Company LLC owned $10.0 million in principal of our 2021 Senior Notes, all of which was acquired during the nine months ended September 30, 2015. During the three and nine months ended September 30, 2015, no interest had been paid to The Cline Trust Company LLC. As of September 30, 2015, $0.1 million of interest on the 2021 Senior Notes was accrued.

Also, Michael Beyer, the former chief executive officer of FELP, who resigned in May 2015, and Drexel Short, a former executive of our predecessor, who retired in March 2014, acquired $3.2 million and $0.5 million, respectively, from the Original Purchase. Mr. Beyer disposed of his 2021 Senior Notes in September of 2015. These former executives were no longer affiliates of the Partnership subsequent to their termination dates. During the three months ended September 30, 2015 and 2014, $0.1 million of interest on the 2021 Senior Notes was paid to Mr. Beyer. During the nine months ended September 30, 2015, $0.3 million of interest was paid to Mr. Beyer and during the nine months ended September 30, 2014, $0.3 million of interest was paid to Mr. Beyer and Mr. Short, collectively.

Limited Partnership Agreement

The Partnership's general partner manages the Partnership's operations and activities as specified in the partnership agreement. The general partner of the Partnership is managed by its board of directors, which is controlled by Foresight Reserves. Foresight Reserves and Murray Energy have the right to select the directors of the general partner. The members of the board of directors of the general partner are not elected by the unitholders and are not subject to reelection by the unitholders. The officers of the general partner govern the day-to-day affairs of the Partnership's business. The partnership agreement provides that the Partnership will reimburse its general partner for all direct and indirect expenses incurred or payments made by the general partner on behalf of the Partnership. No amounts were incurred by the general partner or reimbursed under the partnership agreement during the three and nine months ended September 30, 2015 and 2014.

The following table summarizes certain affiliate amounts included in our condensed consolidated balance sheets:

Affiliated Company	Balance Sheet Location	September 30, 2015	December 31, 2014
		(In Thousands)	
Foresight Reserves and affiliated entities	Due from affiliates - current	$165	$ 345
Murray Energy and affiliated entities	Due from affiliates - current	18,310	—
NRP and affiliated entities	Due from affiliates - current	121	187
Total		$18,596	$ 532
Murray Energy and affiliated entities	Financing receivables - affiliate - current	$2,638	$ —
Total		$2,638	$ —
Murray Energy and affiliated entities	Due from affiliates - noncurrent	$2,691	$ —

Total		$2,691	$ —
Murray Energy and affiliated entities	Financing receivables - affiliate - noncurrent	$70,831	$ —
Total		$70,831	$ —
Foresight Reserves and affiliated entities	Prepaid royalties - current and noncurrent	$52,300	$ 53,671
NRP and affiliated entities	Prepaid royalties - current and noncurrent	12,324	11,071
Total		$64,624	$ 64,742
Foresight Reserves and affiliated entities	Due to affiliates - current	$939	$ 7,959
Murray Energy and affiliated entities	Due to affiliates - current	2,274	—
NRP and affiliated entities	Due to affiliates - current	3,268	7,148
Total		$6,481	$ 15,107

A summary of certain expenses (income) incurred with affiliated entities is as follows for the three and nine months ended September 30, 2015 and 2014:

	Three Months Ended		Nine Months Ended	
	September 30, 2015	September 30, 2014	September 30, 2015	September 30, 2014
	(In Thousands)			
Coal sales – Murray Energy and affiliated entities (1)	$(8,727)	$ —	$(8,727)	$ —
Overriding royalty and lease revenues – Murray Energy and affiliated entities (2)	$(1,941)	$ —	$(3,263)	$ —
Royalty expense – NRP and affiliated entities (3)	$5,210	$ 11,755	$23,367	$ 37,779
Royalty expense – Foresight Reserves and affiliated entities (3)	$419	$ 2,477	$2,382	$ 6,403
Loadout services – NRP and affiliated entities (3)	$1,695	$ 2,175	$6,318	$ 7,609
Purchased goods and services – Murray Energy and affiliated entities (3)	$1,230	$ —	$1,570	$ —
Purchased coal - Murray Energy and affiliated entities (4)	$5,055	$ —	$6,957	$ —
Land leases - Foresight Reserves and affiliated entities (3)	$100	$ 100	$100	$ 100
Terminal fees – Foresight Reserves and affiliated entities (5)	$1,500	$ 10,903	$19,327	$ 32,408
Management services – Murray Energy and affiliated entities (6)	$1,855	$ —	$3,362	$ —
Administrative fee income – Foresight Reserves and affiliated entities (7)	$—	$ (60)	$(52)	$ (196)

Location in the condensed consolidated statements of operations:

(1) – Coal sales

(2) – Other revenues

(3) – Cost of coal produced (excluding depreciation, depletion and amortization)

(4) – Cost of coal purchased

(5) – Transportation

(6) – Selling, general and administrative

(7) – Other operating income, net

We also purchased $4.4 million and $5.8 million in mining supplies from an affiliated joint venture under a supply agreement during the three months ended September 30, 2015 and 2014, respectively, and $11.8 million and $13.4 million for the nine months ended September 30, 2015 and 2014, respectively (see Note 14).

14. Variable Interest Entities (VIEs)

Our financial statements include VIEs for which the Partnership or one of its subsidiaries is the primary beneficiary. Among those VIEs consolidated by the Partnership and its subsidiaries are Mach Mining, LLC; M-Class Mining, LLC; MaRyan Mining LLC; Patton Mining LLC; Viking Mining LLC; Coal Field Construction Company LLC; Coal Field Repair Services LLC; and LD Labor Company LLC (collectively, the “Contractor VIEs”). Each of the Contractor VIEs holds a contract to provide one or more of the following services to a Partnership subsidiary: contract mining, processing and loading services, or construction and maintenance services. Each of the Contractor VIEs generally receives a nominal per ton fee ($0.01 to $0.02 per ton) above its cost of operations as compensation for services performed. All of these entities were determined not to have sufficient equity at risk and are therefore VIEs. The Partnership was determined to be the primary beneficiary of each of these entities given it controls these entities under a contractual cost-plus arrangement. During each of the three months ended September 30, 2015 and 2014, in aggregate, the Contractor VIEs earned income of $0.1 million under the contractual arrangements with the Partnership which was recorded as net income attributable to noncontrolling interests in the condensed consolidated statements of operations. During each of the nine months ended September 30, 2015 and 2014, in aggregate, the Contractor VIEs earned income of $0.4 million under the contractual arrangements with the Partnership which was classified as net income attributable to noncontrolling interests in the condensed consolidated statements of operations.

On August 23, 2013, FELLC effected a reorganization pursuant to which certain transportation assets were distributed to its members (the “2013 Reorganization”). Among the assets distributed were Adena and Hillsboro Transport. Subsequent to the 2013 Reorganization, both of these entities were identified as VIEs and continued to be consolidated by FELLC. During the first quarter of 2015, Adena and Hillsboro Transport were contributed to the Partnership by Foresight Reserves and a member of management (see Note 4) and are therefore no longer consolidated as VIEs. The aggregate net book values of Adena and Hillsboro Transport of $9.9 million was reclassified from noncontrolling interest equity to limited partners’ capital on the Contribution Date.

The liabilities recognized as a result of consolidating the VIEs do not necessarily represent additional claims on the general assets of the Partnership outside of the VIEs; rather, they represent claims against the specific assets of the consolidated VIEs. Conversely, assets recognized as a result of consolidating these VIEs do not necessarily represent additional assets that could be used to satisfy claims against the Partnership’s general assets. There are no restrictions on the VIE assets that are reported in the Partnership’s general assets. The total consolidated VIE assets and liabilities reflected in the Partnership’s condensed consolidated balance sheets are as follows:

	September 30, 2015	December 31, 2014
	(In Thousands)	
Assets:		
Current assets	$ 8,500	$ 4,939
Long-term assets	—	1,554
Total assets	$ 8,500	$ 6,493
Liabilities:		
Current liabilities	$ 12,974	$ 10,145
Long-term liabilities	1,947	1,131
Total liabilities	$ 14,921	$ 11,276

In May 2013, an affiliate owned by The Cline Group and a third-party supplier of mining supplies formed a joint venture whose purpose is the manufacture and sale of supplies primarily for use by the Partnership in the conduct of its mining operations. The agreement obligates the Partnership’s coal mines to purchase at least 90% of their aggregate annual requirements for certain mining supplies from the supplier parties, subject to exceptions as set forth in the agreement. The initial term of the amended agreement is five years and expires in April 2018. The supplies sold under this arrangement result in an agreed-upon, fixed-profit percentage for the joint venture. This joint venture was determined to be a VIE given that the equity holders do not have the obligation to absorb the expected losses or the right to receive the expected residual returns of the joint venture as a result of the Partnership effectively guaranteeing a fixed-profit percentage on the supplies it purchases from the joint venture. We are not the primary beneficiary of this joint venture and, therefore, do not consolidate the joint venture, given that the power over the joint venture is conveyed through the board of directors of the joint venture and no party controls the board of directors.

15. Equity-Based Compensation

Long-Term Incentive Plan

The Partnership has a Long-Term Incentive Plan ("LTIP") for employees, directors, officers and certain key third-parties (collectively, the "Participants") which allows for the issuance of equity-based compensation. The LTIP awards granted thus far are phantom units, which upon satisfaction of vesting requirements, entitle the LTIP participant to receive FELP units. The board of directors of FEGP authorized 7.0 million common units to be granted under the LTIP, with 6.3 million remaining units available for issuance as of September 30, 2015.

Our equity-based compensation expense, net of estimated forfeitures, was $1.3 million and $1.1 million during the three months ended September 30, 2015 and 2014, respectively, and was $12.9 million and $3.3 million during the nine months ended September 30, 2015 and 2014, respectively. During the nine months ended September 30, 2015, 575,160 limited partner units were issued and 75,490 units were settled in cash to satisfy the individual statutory minimum tax obligations of the Participants. In conjunction with our reorganization (see Note 3), the Partnership modified certain employees' equity awards to accelerate vesting during the transition and reorganization period. Approximately 30% of the Partnership's equity-based compensation during the nine months ended September 30, 2015 was reported in the condensed consolidated statement of operations as transition and reorganization costs, 60% as selling, general and administrative expenses and the remaining 10% recorded as cost of coal produced. Included in the selling, general and administrative expense for the nine months ended September 30, 2015 was $7.1 million of stock compensation expense for 215,954 common units and 215,796 subordinated units issued to the former chief executive officer of the Partnership which were fully-vested on the date of grant. All non-vested phantom awards include tandem distribution incentive rights, which provide for the right to accrue quarterly cash distributions in an amount equal to the cash distributions the Partnership makes to unitholders during the vesting period and will be settled in cash upon vesting. The Partnership has $0.6 million accrued for this liability as of September 30, 2015. Any distributions accrued to a Participants' account will be forfeited if the related phantom award fails to vest according to the relevant vesting conditions.

A summary of LTIP award activity for the nine months ended September 30, 2015 is as follows:

	Number of Units	Weighted Average Grant Date Fair Value per Unit
Non-vested grants at January 1, 2015	601,109	$ 19.99
Granted	622,993	$ 16.06
Vested	(650,654)	$ 17.25
Forfeited	(99,105)	$ 18.48
Non-vested grants at September 30, 2015	474,343	$ 18.91

16. Earnings per Limited Partner Unit

Limited partners' interest in net income (loss) attributable to the Partnership and basic and diluted earnings per unit reflect net income attributable to the Partnership from the closing date of the IPO. We compute earnings per unit ("EPU") using the two-class method for master limited partnerships as prescribed in ASC 260, Earnings Per Share. The two-class method requires that securities that meet the definition of a participating security be considered for inclusion in the computation of basic EPU. In addition to the common and subordinated units, we have also identified the general partner interest and IDRs as participating securities. Under the two-class method, EPU is calculated as if all of the earnings for the period were distributed under the terms of the partnership agreement, regardless of whether the general partner has discretion over the amount of distributions to be made in any particular period, whether those earnings would actually be distributed during a particular period from an economic or practical perspective, or whether the general partner has other legal or contractual limitations on its ability to pay distributions that would prevent it from distributing all of the earnings for a particular period.

The Partnership's net income is allocated to the limited partners, including the holders of the subordinated units, in accordance with their respective ownership percentages, after giving effect to any special income or expense allocations and incentive distributions paid to the general partner, if any. The IDR holders have the right to receive increasing percentages of quarterly distributions from operating surplus after certain distribution levels defined in the partnership agreement have been achieved. The general partner has no obligation to make distributions; therefore, undistributed earnings of the Partnership are not allocated to the IDR holder. Basic EPU is computed by dividing net earnings attributable to unitholders by the weighted-average number of units outstanding during each period. Diluted EPU reflects the potential dilution of common equivalent units that could occur if equity participation units are converted into common units.

The following table illustrates the Partnership's calculation of net income per common and subordinated unit for the three month periods indicated:

	Three Months Ended September 30,					
	2015			2014		
	Common Units	Subordinated Units	Total	Common Units	Subordinated Units	Total
	(In Thousands, Except Per Unit Data)					
Numerator:						
Net income available to limited partner units	$4,041	$ 4,029	$8,070	$22,691	$ 22,675	$45,366
Denominator:						
Weighted-average units to calculate basic EPU	65,156	64,955	130,111	64,786	64,739	129,525
Less: effect of dilutive securities [1]	—	—	—	—	—	—
Weighted-average units to calculate diluted EPU	65,156	64,955	130,111	64,786	64,739	129,525
Basic net income per unit	$0.06	$ 0.06	$0.06	$0.35	$ 0.35	$0.35
Diluted net income per unit	$0.06	$ 0.06	$0.06	$0.35	$ 0.35	$0.35

(1) - Diluted EPU gives effect to all dilutive potential common units outstanding during the period using the treasury stock method. Diluted EPU excludes all dilutive potential units calculated under the treasury stock method if their effect is anti-dilutive. For the three months ended September 30, 2015 and 2014, approximately 0.5 million and 0.7 million phantom units, respectively, were anti-dilutive, and therefore excluded from the diluted EPU calculation.

The following table illustrates the Partnership's calculation of net income per common and subordinated unit for the nine month periods indicated:

	Nine Months Ended September 30,					
	2015			2014		
	Common Units	Subordinated Units	Total	Common Units	Subordinated Units	Total
	(In Thousands, Except Per Unit Data)					
Numerator:						
Net income available to limited partner units	$12,486	$ 12,463	$24,949	$20,619	$ 20,517	$41,136

Denominator:						
Weighted-average units to calculate basic EPU	65,067	64,927	129,994	64,786	64,739	129,525
Less: effect of dilutive securities [(1)]	—	—	—	—	—	—
Weighted-average units to calculate diluted EPU	65,067	64,927	129,994	64,786	64,739	129,525
Basic net income per unit	$0.19	$ 0.19	$0.19	$0.32	$ 0.32	$0.32
Diluted net income per unit	$0.19	$ 0.19	$0.19	$0.32	$ 0.32	$0.32

(1) - Diluted EPU gives effect to all dilutive potential common units outstanding during the period using the treasury stock method. Diluted EPU excludes all dilutive potential units calculated under the treasury stock method if their effect is anti-dilutive. For the nine months ended September 30, 2015 and 2014, approximately 0.5 million and 0.7 million phantom units, respectively, were anti-dilutive, and therefore excluded from the diluted EPU calculation.

17. Fair Value of Financial Instruments

The table below sets forth, by level, the Partnership's net financial assets and liabilities for which fair value is measured on a recurring basis:

	Fair Value at September 30, 2015			
	Total	Level 1	Level 2	Level 3
	(In Thousands)			
Coal derivative contracts	$53,607	$ —	$53,607	$ —
Diesel derivative contracts	(977)	—	(977)	—
Total	$52,630	$ —	$52,630	$ —

	Fair Value at December 31, 2014			
	Total	Level 1	Level 2	Level 3
	(In Thousands)			
Coal derivative contracts	$61,037	$ —	$61,037	$ —
Total	$61,037	$ —	$61,037	$ —

The Partnership's commodity derivative contracts are valued based on direct broker quotes and corroborated with market pricing data.

The classification and amount of the Partnership's financial instruments measured at fair value on a recurring basis, which are presented on a gross basis in the condensed consolidated balance sheets as of September 30, 2015 and December 31, 2014, are as follows:

	Fair Value at September 30, 2015			
	Current – Coal Derivative Assets	Long-Term – Coal Derivative Assets	Accrued Expenses	Other Long-Term Liabilities
	(In Thousands)			
Coal derivative contracts	$29,581	$ 24,026	$ —	$ —
Diesel derivative contracts	—	—	(859)	(118)
Total	$29,581	$ 24,026	$ (859)	$ (118)

	Fair Value at December 31, 2014			
	Current – Coal Derivative Assets	Long-Term – Coal Derivative Assets	Accrued Expenses	Other Long-Term Liabilities
	(In Thousands)			
Coal derivative contracts	$36,080	$ 24,957	$ —	$ —

Total	$36,080	$ 24,957	$ —	$ —

The following is a reconciliation of the beginning and ending balances for assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) during the nine months ended September 30, 2014:

	Liability Award (In Thousands)
Balance at January 1, 2014	$ 11,700
Recorded fair value losses (gains):	
Included in earnings	690
Purchases, issuances and settlements	(12,390)
Balance at September 30, 2014	$ —

The liability award represents a phantom equity award (“Liability Award”) to a retired executive for which the value was determined based on the fair value, as defined in the agreement, of Foresight Reserves as of the employee’s retirement date and was adjusted for distributions made to Foresight Reserves’ members. This Liability Award fully vested in 2010 and was granted principally for services performed to develop the Partnership’s longwall mines. Prior to March 31, 2014, the Liability Award was Level 3 in the fair value hierarchy given Foresight Reserves was a private company; therefore, there was no liquid market to determine the fair value of Foresight Reserves’ equity. The fair value of the Liability Award was determined using a discounted cash flow model and corroborated with recent equity transactions at Foresight Reserves. Effective March 31, 2014, the Liability Award amount was negotiated between the Partnership and the employee to be $12.4 million; therefore, the value of this liability was contracted and therefore no longer a Level 3 liability. As of September 30, 2015, $0.4 million of the unpaid balance is recorded in accrued expenses and other current liabilities for required payments over the next year, and the remaining $3.5 million is recorded in other long-term liabilities, which will be paid out ratably through 2024. The note payable to the retired executive currently bears interest at 3.5%.

During the three and nine months ended September 30, 2015 and 2014, there were no assets or liabilities that were transferred between Level 1 and Level 2.

Long-Term Debt

The fair value of long-term debt as of September 30, 2015 and December 31, 2014 was $1,306.0 million and $1,279.7 million, respectively. The fair value of long-term debt was calculated based on the amount of future cash flows associated with each debt instrument discounted at the Partnership’s current estimated credit-adjusted borrowing rate for similar debt instruments with comparable terms. This is considered a Level 3 fair value measurement.

18. Contingencies

In July 2015, we provided notice to WPP, a subsidiary of NRP, declaring a force majeure event at our Hillsboro mine due to elevated carbon monoxide levels as a result of a mine fire, which has required the stoppage of mining operations since March 2015. As a result of the force majeure event, we have not made $9.2 million in minimum deficiency payments to WPP in accordance with the force majeure provisions of the royalty agreement. NRP is disputing our claim that the stoppage of mining operations at our Hillsboro mine as a result of the mine fire and elevated carbon monoxide levels constitutes a force majeure event. While we believe this event meets the force majeure provision of the royalty agreement, should our position not prevail, we would be responsible for funding any minimum deficiency payment amounts during the shutdown period to WPP.

In May 2015, the trustee for the bondholders of our 2021 Senior Notes filed suit in the Delaware Court of Chancery alleging that Murray Energy’s acquisition of a 34% noncontrolling interest in FEGP and of an option to purchase an additional 46% interest in FEGP triggered a change of control of the 2021 Senior Notes pursuant to its indenture, thereby requiring FELP to make an offer to purchase the 2021 Senior Notes at 101% of the principal amount tendered plus any accrued and unpaid interest thereon. We believe this suit is without merit and have filed a motion for judgment on the pleadings, seeking judgment in our favor. Oral arguments are scheduled to begin in November 2015.

In March 2015, we entered into a settlement agreement with Murray Energy resolving litigation between the Partnership and Murray Energy for an aggregate payment of $14.0 million. Of the $14.0 million settlement amount, $10.0 million was due and payable to us immediately and the remainder is due in increments of $1.0 million over each of the next four years. We recorded the $13.5 million net present value of the settlement amount to other operating income, net in the condensed consolidated statement of operations during the nine months ended September 30, 2015.

In January 2014, the Illinois Environmental Protection Agency (the “IEPA”) issued Sugar Camp a violation notice regarding construction of an underground injection well without issuance of an appropriate permit (“January Notice”). Sugar Camp is working with the IEPA to finalize its permit application, which has been in process since May 2013. The IEPA determined not to enter into a compliance commitment agreement with respect to the January Notice and referred the January Notice to the Illinois Attorney General for enforcement. While Sugar Camp believes this referral may result in the assessment of a penalty, we believe any such penalty will be immaterial.

Sugar Camp continues to work with the IEPA to identify and permit a sustainable solution for the future disposal of water at the mine in compliance with its permits. Sugar Camp has spent $34.1 million on water treatment infrastructure to prospectively comply with its permits.

In November 2012, six citizens filed requests for administrative review of Revision No. 1 to Permit No. 399 for the Hillsboro mine. Revision No. 1 allowed for conversion of the currently permitted coal refuse disposal facility from a non-impounding to an impounding structure. Shortly after the filing of Revision No. 1, one citizen withdrew his request. Following a hearing on both the Illinois Department of Natural Resources’ (“IDNR”) and Hillsboro’s motion to dismiss, the hearing officer dismissed the claims of two of the remaining five petitioners and also limited some of the issues remaining for administrative review. In June 2014, two of the remaining three petitioners dismissed their requests. A final hearing on the merits began in June 2015. The hearing officer granted Hillsboro's motion for reconsideration of his decision denying its motion for summary decision on two grounds. The hearing officer's decision on reconsideration disposed of the entire administrative proceeding in Hillsboro's favor. On October 5, 2015, the petitioner filed an appeal of the hearing officer's decision in the Circuit Court of Montgomery County, Illinois. Hillsboro intends to continue its defense of the issuance of the permit in the Circuit Court proceeding.

FELLC acquired the Shay No. 1 Mine at Macoupin ("Shay Mine") in 2009. Prior to this acquisition, in 2003, ExxonMobil Coal USA, Inc. ("Exxon"), the prior owner of the Shay Mine, enrolled the mine in the IEPA's Site Remediation Program ("SRP") to address some concerns regarding groundwater contamination from the refuse areas. In 2011, Macoupin proposed, and the IEPA accepted, a compliance commitment agreement ("CCA") with remediation steps designed to respond to the groundwater contamination concerns. Further, in May 2013, Macoupin submitted a corrective action plan ("CAP") with groundwater modeling to the IEPA to address the long-term compliance and corrective measures planned for the cleanup of groundwater contamination issues. In June 2013, the IEPA referred the CCA to the Illinois Attorney General's Office for enforcement on the basis that the compliance period for the CCA extended for too long of a period for the IEPA to monitor. The CAP has been approved by the IEPA. On July 24, 2015, the Illinois Attorney General's Office filed a formal complaint against Macoupin in Macoupin County Circuit Court to effectuate a settlement and entry of a negotiated consent order. On September 14, 2015, the Circuit Court approved the settlement and entered the consent order. Macoupin has begun to effectuate the CAP and has made all the required civil penalty payments of $0.1 million to the IEPA and $0.2 million in environmental project payments. As of September 30, 2015, we have recorded an asset retirement obligation of $6.7 million as the costs relate to ongoing mining operations at Macoupin. However, there can be no assurance that the ultimate costs will not exceed this amount.

Certain railcar lessors have asserted claims under their railcar leases with us for damage to railcars allegedly caused by our use of the railcars during the lease terms. We are currently investigating these claims and intend to defend these matters vigorously.

We are also party to various other litigation matters, in most cases involving ordinary and routine claims incidental to our business. We cannot reasonably estimate the ultimate legal and financial liability with respect to all pending litigation matters. However, we believe, based on our examination of such matters, that the ultimate liability will not have a material adverse effect on our consolidated financial position, results of operations or cash flows. As of September 30, 2015, we have $2.2 million accrued, in aggregate, for various litigation matters.

Performance Bonds

We had outstanding surety bonds with third parties of $71.9 million as of September 30, 2015 to secure reclamation and other performance commitments. In November 2015, a demand notice was issued by our insurer requesting that we post collateral, either in the form of a letter of credit or cash, for our outstanding surety bonds. We have not been required to post collateral in the past and we are currently in discussions with our insurer to eliminate or negotiate lower the amount required, which we believe will not have a material impact on our liquidity.

19. Subsequent Events

Hillsboro Mine

On March 26, 2015, as a result of a mine fire, carbon monoxide readings in excess of actionable levels (a mine-specific carbon monoxide threshold requiring mine management to evacuate the mine) were detected at

Hillsboro. All underground employees were safely evacuated. The Mine Safety and Health Administration ("MSHA") approved reentry into the mine on May 6, 2015 to complete an evaluation of the affected area and the longwall. No damage to our mining equipment was noted. Elevated carbon monoxide levels required us to evacuate the mine shortly after reentry. In July 2015, MSHA approved restoration of power to a portion of the mine to allow our personnel re-entry into the mine to evaluate the ventilation and longwall mining systems, to address any needed rehabilitation to the underground facilities to allow us to operate the longwall in the current panel until we reach a point in the panel where the longwall equipment can be safely recovered. Elevated carbon monoxide levels required us to evacuate the mine again in August 2015. On October 14, 2015, personnel reentered the mine and began the construction of underground ventilation control stoppings intended to assist in adjusting ventilation within the mine and to allow personnel to complete the current longwall move. Upon completion of this longwall move, we intend to seal the current longwall district, where the combustion event occurred and the resultant elevated carbon monoxide levels were located. We continue to work with regulatory agencies for the purpose of completing this longwall move and fully resuming normal longwall mining operations at the mine. Coal deliveries have not been interrupted as a result of this event as sufficient inventory existed at the mine.

Declared Distribution

On October 29, 2015, we declared a quarterly distribution of $0.17 per unit payable on November 25, 2015 to all common unitholders of record on November 13, 2015, while suspending the distribution on all subordinated units. Chris Cline and one additional common unitholder elected to forego the $0.17 per common unit distribution on their collective 21.2 million common units.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

You should read the following discussion and analysis together with the financial statements and the notes thereto included elsewhere in this report. This discussion may contain statements about our business, operations and industry that constitute forward-looking statements. Forward-looking statements involve risks and uncertainties, such as statements regarding our plans, objectives, expectations and intentions. You can identify these forward-looking statements by the use of forward-looking words such as "outlook," "intends," "plans," "estimates," "believes," "expects," "potential," "continues," "may," "will," "should," "seeks," "approximately," "predicts," "anticipates," "foresees," or the nega of these words or other comparable words and phrases. Any forward-looking statements contained in this report are based upon our historical performance and on our current plans, estimates and expectations as of the filing date of this report. Our future results and financial condition and our ability to pay distributions may differ materially from those we currently anticipate as a result of various factors. Among those factors that could cause actual results to differ materially are the following:

- The market price for coal;
- The supply of, and demand for, domestic and foreign coal;
- Competition from other coal suppliers;
- The cost of using, and the availability of, other fuels, including the effects of technological developments;
- Advances in power technologies;
- The efficiency of our mines;
- The amount of coal we are able to produce from our properties, which could be adversely affected by, among other things, operating difficulties and unfavorable geologic conditions;
- The pricing terms contained in our long-term contracts;
- Cancellation or renegotiation of contracts;
- Legislative, regulatory and judicial developments, including those related to the release of greenhouse gases;
- The strength of the U.S. dollar;

- Air emission, wastewater discharge and other environmental standards for coal-fired power plants or coal mines;
- Delays in the receipt of, failure to receive, or revocation of, necessary government permits;
- Inclement or hazardous weather conditions and natural disasters;
- Availability and cost or interruption of fuel, equipment and other supplies;
- Transportation costs;
- Availability of transportation infrastructure, including flooding and railroad derailments;
- Cost and availability of our contract miners;
- Availability of skilled employees; and
- Work stoppages or other labor difficulties.

The above factors should be read in conjunction with the risk factors included in our Annual Report on Form 10-K filed with the U.S. Securities and Exchange Commission ("SEC") on March 10, 2015.

Company Overview

Foresight Energy LLC (“FELLC”), a limited liability company, was formed in September 2006 for the development, mining, transportation and sale of coal. Prior to June 23, 2014, Foresight Reserves, L.P. (“Foresight Reserves”) owned 99.333% of FELLC and a member of management owned 0.667%. In January 2012, Foresight Energy LP (“FELP”) and Foresight Energy GP LLC (“general partner” or “FEGP”) were formed. FELP was formed to own FELLC and FEGP was formed to be the general partner of FELP. On June 23, 2014, in connection with the initial public offering (“IPO”) of FELP, Foresight Reserves and a member of management contributed their ownership interests in FELLC to FELP for which they were issued common and subordinated units in FELP. Because this transaction was between entities under common control, the contributed assets and liabilities of FELLC were recorded in the combined consolidated financial statements at FELLC’s historical cost. FELP has been managed by FEGP subsequent to the IPO.

As used hereafter in this report, the terms “Foresight Energy LP,” “FELP,” the “Partnership,” “we,” “us” or like terms, refer to the combined results of Foresight Energy LP, the Contributed Companies (discussed below), and FELLC and its consolidated subsidiaries and affiliates, unless the context otherwise requires or where otherwise indicated.

We control over 3 billion tons of coal reserves, almost all of which exist in three large, contiguous blocks of coal: two in central Illinois and one in southern Illinois. Since our inception, we have invested significantly in capital expenditures to develop what we believe are industry-leading, geologically-similar, low-cost and highly productive mines and related infrastructure. We currently operate under one reportable segment with four underground mining complexes in the Illinois Basin: Williamson, Sugar Camp and Hillsboro, all three of which are longwall operations, and Macoupin, which is currently a continuous miner operation. The Williamson and Hillsboro complexes are each operating with one longwall mining system and Sugar Camp is operating with two longwall mining systems, the second of which emerged from development on June 1, 2014. The timing of additional development is dependent on several factors, including market demand, permitting, access to capital, equipment availability and the committed sales position at our existing mining operations.

Our operations are strategically located near multiple rail and river transportation access points giving us cost-competitive transportation options. We own a barge loading facility on the Ohio River and have contractual agreements for export terminal capacity in the Gulf of Mexico. We have developed infrastructure that provides each of our four mining complexes with multiple transportation outlets including direct and indirect access to five Class I railroads. Our access to competing rail carriers as well as access to truck and barge transport provides us with operating flexibility and minimizes transportation costs.

Our coal is sold to a diverse customer base, including electric utility and industrial companies in the eastern United States and overseas. We generally sell a majority of our coal to customers at delivery points other than our mines, including, but not limited to, river terminals on the Ohio and Mississippi Rivers and at two ports in New Orleans. As such, we generally bear the transportation cost and risk to and through these facilities and we therefore do not report coal sales and transportation revenue separately in our consolidated statements of operations.

Recent Transactions and Developments

Murray Energy Transactions

On April 16, 2015, Foresight Reserves and Murray Energy Corporation (“Murray Energy”) executed a purchase and sale agreement whereby Murray Energy paid Foresight Reserves $1.37 billion to acquire a noncontrolling 34% voting interest in FEGP, 77.5% of FELP’s incentive distribution rights and all of FELP’s outstanding subordinated units. FEGP will continue to govern the Partnership subsequent to this transaction. As part of the transaction, Murray Energy obtained an option, subject to certain conditions, to purchase an additional 46% of the voting interests in FEGP for $25 million during a five-year period, which would allow Murray Energy to control FEGP. Also in connection with this transaction, Michael J. Beyer resigned from his position as President and Chief Executive Officer of FEGP and as a director on the board of directors of FEGP, effective May 30, 2015, and Robert D. Moore (“Mr. Moore”) was appointed President and Chief Executive Officer of FEGP, effective May 31, 2015, and to the board of directors, effective April 16, 2015. Mr. Moore has served as the Executive Vice President, Chief Operating Officer and Chief Financial Officer of Murray Energy since September 2007 and will continue to serve these roles for Murray Energy.

A management services agreement (“MSA”) was executed, effective April 30, 2015, between FEGP and Murray American Coal, Inc. (the ”Manager”), a wholly-owned subsidiary of Murray Energy, pursuant to which the Manager will provide certain management and administration services to FELP for a quarterly fee of $3.5 million, subject to contractual adjustments. The initial term of the MSA extends through December 31, 2022 and is subject to termination provisions.

In April 2015, American Century Transport LLC ("American Transport"), a newly created subsidiary of the Partnership, entered into a purchase and sale agreement (the "PSA") with American Energy Corporation ("American Energy"), a subsidiary of Murray Energy, pursuant to which American Energy sold to American Transport certain mining and transportation assets for $63.0 million. American Transport then entered into a lease agreement with American Energy pursuant to which (i) American Transport will lease to American Energy a tract of real property, two coal preparation plants and related coal handling facilities at the Transport Mine situated in Belmont and Monroe Counties, Ohio and (ii) American Transport will receive from American Energy a fee ranging from $1.15 to $1.75 for each ton of coal mined, processed and/or transported using such assets, subject to a quarterly minimum fee of $1.7 million.

Also, in April 2015, American Century Minerals LLC ("Minerals"), a newly created subsidiary of the Partnership, entered into an overriding royalty agreement with Murray Energy subsidiaries' American Energy and Consolidated Land Company (collectively "AEC") pursuant to which AEC granted to Minerals an overriding royalty interest ranging from $0.30 to $0.50 for each ton of coal mined, removed and sold from certain coal reserves situated near the Century Mine in Belmont and Monroe Counties, Ohio for $12.0 million. The overriding royalty agreement is subject to a minimum quarterly fee of $0.5 million.

We expect that these Murray Energy agreements will be accretive to future earnings and Adjusted EBITDA.

Contributions by Foresight Reserves

During the first quarter of 2015 (the "Contribution Date"), Foresight Reserves and a member of management contributed their 100% equity interest in Sitran LLC, a river transloading terminal on the Ohio River; Adena Resources LLC, an entity that provides water and other miscellaneous rights to the FELP mines; Hillsboro Transport LLC, Hillsboro's coal loadout facility; and Akin Energy LLC, an entity holding certain permits for a natural gas facility, to FELP for no consideration (collectively, the "Contributed Companies"). Because Sitran, Akin Energy and FELP were entities under common control, FELP's historical results prior to the Contribution Date have been recast to combine the financial position and results of operations of Sitran and Akin Energy. Hillsboro Transport and Adena were consolidated as variable interest entities prior to the Contribution Date therefore the contribution did not result in a change in reporting entity. We expect that the Contributed Companies will be accretive to future earnings and Adjusted EBITDA.

Key Metrics

We assess the performance of our business using certain key metrics, which are described below and analyzed on a period-to -period basis. These key metrics include Adjusted EBITDA, production, tons sold, coal sales realization per ton sold, netback to mine realization per ton sold and cash cost per ton sold.

Adjusted EBITDA is defined as net income (loss) attributable to controlling interests before interest, income taxes, depreciation, depletion, amortization and accretion. Adjusted EBITDA is also adjusted for equity-based compensation, unrealized gains or losses on derivatives, cumulative unrealized gains and losses from prior periods which were realized during the current period, early debt extinguishment costs, transition and reorganization costs and material nonrecurring or other items which may not reflect the trend of results. Adjusted EBITDA is not a measure of performance defined in accordance with U.S. GAAP. However, management believes that Adjusted EBITDA is useful to investors in evaluating our performance because it is a commonly used financial analysis tool for measuring and comparing companies in our industry in areas of operating performance. Management believes that the disclosure of Adjusted EBITDA offers an additional view of our operations that, when coupled with our U.S. GAAP results and the reconciliation to U.S. GAAP results, provides a more complete understanding of our results of operations and the factors and trends affecting our business. Adjusted EBITDA should not be considered as an alternative to net income. The primary limitation associated with the use of Adjusted EBITDA as compared to U.S GAAP results are (i) it may not be comparable to similarly titled measures used by other companies in our industry, and (ii) it excludes financial information that some consider important in evaluating our performance. We compensate for these limitations by providing a reconciliation of Adjusted EBITDA to U.S. GAAP results to enable users to perform their own analysis of our operating results.

Results of Operations

Comparison of Three Months Ended September 30, 2015 to Three Months Ended September 30, 2014

Coal Sales. The following table summarizes coal sales information during the three months ended September 30, 2015 and 2014.

	Three Months Ended September 30,

	2015	2014	Variance	
	(In Thousands, Except Per Ton Data)			
Coal sales	$251,125	$299,964	$(48,839)	-16.3%
Tons sold	5,708	6,021	(313)	-5.2 %
Coal sales realization per ton sold[1]	$44.00	$49.82	$(5.82)	-11.7%
Netback to mine realization per ton sold[2]	$37.97	$40.78	$(2.81)	-6.9 %

(1) - Coal sales realization per ton sold is defined as coal sales divided by tons sold.
(2) - Netback to mine realization per ton sold is defined as coal sales less transportation expense divided by tons sold.

The decrease in coal sales from the third quarter of the prior year was due to a decline in coal sales realization per ton sold as well as a decrease in sales volumes during the current year quarter. The decline in coal sales realization was due to continued weak coal market conditions, particularly in international markets where pricing fell substantially from the prior year period. The decline in tons sold from the prior year period was due to a 0.7 million ton decrease in tons sold to international markets due to unfavorable market pricing. The decline in tons sold to international market resulted in a corresponding decline in transportation expense during the current year period, therefore, the netback to mine realization per ton sold decreased to a lesser extent than the coal sales realization per ton sold.

Other Revenues.

Other revenues of $1.9 million recorded during the three months ended September 30, 2015 were overriding royalty and lease revenues earned on the agreements entered into with American Energy in April 2015.

Cost of Coal Produced (Excluding Depreciation, Depletion and Amortization). The following table summarizes cost of coal produced (excluding depreciation, depletion and amortization) information for the three months ended September 30, 2015 and 2014.

	Three Months Ended September 30,			
	2015	2014	Variance	
	(In Thousands, Except Per Ton Data)			
Cost of coal produced (excluding depreciation, depletion and amortization)	$128,195	$123,535	$4,660	3.8%
Produced tons sold	5,588	5,744	(156)	-2.7%
Cash cost per ton sold(1)	$22.94	$21.51	$1.43	6.7%
Tons produced	4,884	6,218	(1,334)	-21.5%

(1) - Cash cost per ton sold is defined as cost of coal produced (excluding depreciation, depletion and amortization) divided by produced tons sold.

The increase in cost of coal produced during the current period was driven by an, increase in cash cost per ton sold offset partially by a decrease in sales volumes. The increase in cash cost per ton sold during the current quarter was principally driven by the direct and indirect costs associated with the Hillsboro combustion event and higher operating costs at our Williamson mine. Partially offsetting these higher costs were synergies realized as a result of the transaction with Murray Energy. Coal production during the three months ended September 30, 2015 declined 1.3 million tons from the prior year period primarily as a result of the Hillsboro production outage, however, we were able to satisfy all sales commitments during this period from inventories and production from our other mines.

Transportation.

Transportation expense declined $20.1 million, or $3.02 per ton sold, from the prior year period due to a decrease in tons sold to international markets.

Depreciation, Depletion and Amortization.

The increase in depreciation, depletion and amortization expense of $7.5 million during the three months ended September 30, 2015 was primarily due to the reduction of coal inventory during the current year quarter.

Selling, General and Administrative.

Selling, general and administrative expenses decreased $1.6 million, or 25.6%, from the prior year third quarter due primarily to synergies from the Murray Energy transaction and a significant component of our selling, general and administrative costs are subject to a fixed quarterly fee of $3.5 million under the MSA with Murray Energy.

Transition and Reorganization Costs.

Transition and reorganization costs were $5.0 million for the three months ended September 30, 2015. As part of the Murray Energy transaction, Foresight entered into a MSA with Murray Energy with the intent of optimizing and reorganizing certain corporate administrative functions and generating synergies between the two companies through the elimination of headcount and duplicate selling, general and administrative costs. The costs for the current period are comprised of retention compensation to certain employees during the transition period and termination benefits to employees whose positions were replaced by Murray Energy employees under the MSA. Included in these costs were $2.3 million of costs paid by Foresight Reserves which were recorded as capital contributions and $1.3 million of equity-based compensation for the accelerated vesting of certain equity awards. An additional $2.5 million in costs paid by Foresight Reserves were deferred and will be expensed over the employee retention period.

Gain on Commodity Derivative Contracts.

We recorded a gain on our commodity derivative contracts of $17.5 million for the three months ended September 30, 2015 compared to a $19.0 million gain for the three months ended September 30, 2014. The gains recorded during both periods were primarily due to a decrease in the API 2 coal index forward curve. During the three months ended September 30, 2015, we realized a net gain of $10.9 million on commodity derivative contracts, as compared to a realized net gain of $3.0 million in the prior year period.

Adjusted EBITDA.

Adjusted EBITDA decreased $14.9 million from the comparable prior year period to $91.1 million for the three months ended September 30, 2015 due to a decrease in tons sold, a lower netback to mine realization per ton sold and a higher cash cost per ton sold during the current year period. Partially offsetting the above was a $7.9 million incremental benefit from realized commodity derivative contracts during the current year period and lower selling, general and administrative costs driven primarily by synergies with Murray Energy. The table below reconciles net income attributable to controlling interests to Adjusted EBITDA for the three months ended September 30, 2015 and 2014.

	Three Months Ended September 30,	
	2015	2014
	(In Thousands)	
Net income attributable to controlling interests	$8,070	$45,716
Interest expense, net	29,891	28,202
Depreciation, depletion and amortization	54,152	46,638
Accretion on asset retirement obligations	567	405
Transition and reorganization costs (excluding amounts included in equity-based compensation below)[1]	3,784	—
Equity-based compensation	1,258	1,077
Unrealized gain on commodity derivative contracts and prior cumulative unrealized gains realized during the period	(6,616)	(16,001)
Adjusted EBITDA	$91,106	$106,037

(1)– Equity-based compensation of $1.3 million was recorded in transition and reorganization costs in the condensed consolidated statement of operations for the three months ended September 30, 2015.

For a discussion on Adjusted EBITDA, please read Item 2.“Management’s Discussion and Analysis of Financial Condition and Results of Operations—Key Metrics.”

Comparison of Nine Months Ended September 30, 2015 to Nine Months Ended September 30, 2014

Coal Sales. The following table summarizes coal sales information during the nine months ended September 30, 2015 and 2014.

	Nine Months Ended September 30,			
	2015	2014	Variance	
	(In Thousands, Except Per Ton Data)			
Coal sales	$739,940	$809,364	$(69,424)	-8.6 %
Tons sold[1]	16,440	16,153	287	1.8 %
Coal sales realization per ton sold[2]	$45.01	$50.11	$(5.10)	-10.2%
Netback to mine realization per ton sold[3]	$37.24	$40.13	$(2.89)	-7.2 %

(1) - Excludes tons sold of 0.2 million during the nine months ended September 30, 2014 for our mine under development.
(2) - Coal sales realization per ton sold is defined as coal sales divided by tons sold.
(3) - Netback to mine realization per ton sold is defined as coal sales less transportation expense divided by tons sold.

Coal sales decreased $69.4 million from the prior year period due to a decline in coal sales realization per ton sold of $5.10 offset partially by a 1.8% increase in sales volumes during the nine months ended September 30, 2015. The decline in coal sales realization was due to a lower mix of international shipments as well as a decline in realization per ton on both our domestic and international sales driven by weak coal market conditions. Increased domestic shipments during the current year period more than offset the 1.1 million ton decrease in sales volumes to international markets from the year ago period. The decline in tons sold to the international market resulted in a corresponding decline in transportation expense during the current year period, therefore, the netback to mine realization per ton sold decreased to a lesser extent than the coal sales realization per ton sold.

Other Revenues.

Other revenues of $3.3 million recorded during the nine months ended September 30, 2015 were overriding royalty and lease revenues earned on the agreements entered into with American Energy in April 2015.

Cost of Coal Produced (Excluding Depreciation, Depletion and Amortization). The following table summarizes cost of coal produced (excluding depreciation, depletion and amortization) information for the nine months ended September 30, 2015 and 2014.

	Nine Months Ended September 30,			
	2015	2014	Variance	
	(In Thousands, Except Per Ton Data)			
Cost of coal produced (excluding depreciation, depletion and amortization)	$360,769	$323,064	$37,705	11.7%
Produced tons sold[(1)]	16,278	15,859	419	2.6%
Cash cost per ton sold[(2)]	$22.16	$20.37	$1.79	8.8%
Tons produced[(3)]	16,193	16,856	(663)	-3.9%

(1) - Excludes tons sold of 0.2 million during the nine months ended September 30, 2014 for our mine under development.
(2) - Cash cost per ton sold is defined as cost of coal produced (excluding depreciation, depletion and amortization) divided by produced tons sold.
(3) - Excludes production of 0.2 million tons during the nine months ended September 30, 2014 for our mine under development.

The increase in cost of coal produced during the current period was driven by a $1.79 per ton increase in cash cost per ton sold and a 2.6% increase in sales volumes. Increased costs at our Williamson mine and the impact of the Hillsboro mine combustion event primarily accounted for the increase in the cash cost per ton sold. The higher cash cost per ton sold at Williamson was driven by higher repairs, maintenance and longwall costs during the current year period and by decreased production due to a longwall move during the first quarter. The direct and indirect costs from the combustion event at our Hillsboro mine were partially offset by an $8 million favorable adjustment related to a refund from our utility provider during the second quarter of 2015.

Transportation.

Transportation expense declined $33.4 million, or $2.21 per ton sold, from the prior year period due to a decrease in international sales as well as lower charges during the current year period for shortfalls against contractual minimum volumes as a result of a favorable contractual amendment to reduce the required minimum volumes through the Convent Marine Terminal.

Depreciation, Depletion and Amortization.

The increase in depreciation, depletion and amortization expense of $21.8 million from the prior year period was primarily due to the second longwall at our Sugar Camp complex coming out of development in June 2014 and from a reduction of coal inventory during the current year period.

Transition and Reorganization Costs.

Transition and reorganization costs were $17.3 million for the nine months ended September 30, 2015. As part of the Murray Energy transaction, Foresight entered into a MSA with Murray Energy with the intent of optimizing and reorganizing certain corporate administrative functions and generating synergies between the two companies through the elimination of headcount and duplicate selling, general and administrative costs. The costs for the current period are comprised of retention compensation to certain employees during the transition period and termination benefits to employees whose positions were replaced by Murray Energy employees under the MSA. Included in these costs were $8.0 million of costs paid by Foresight Reserves which were recorded as capital contributions and $3.9 million of equity-based compensation for the accelerated vesting of certain equity awards.

Gain on Commodity Derivative Contracts.

We recorded a gain on our commodity derivative contracts of $40.7 million for the nine months ended September 30, 2015 compared to a $41.4 million gain for the nine months ended September 30, 2014. The API 2 coal index forward price curve declined significantly during both periods. During the nine months ended September 30, 2015, we realized net gains of $51.6 million on commodity derivative contracts, of which $19.1 million were for coal derivative contracts settled prior to their contractual maturities.

Other Operating Income, Net.

Other operating income, net increased $12.4 million from the prior year period primarily due to a $13.5 million favorable legal settlement with Murray Energy during the first quarter of 2015 (see "Item 1. Financial Statements –Note 18 Contingencies" of this Quarterly Report on Form 10-Q).

Loss on Early Extinguishment of Debt.

The $5.0 million loss on the early extinguishment of debt recognized during the nine months ended September 30, 2014 was due to the write-off of $2.8 million of debt issuance costs and $1.9 million in unamortized debt discount as a result of the prepayment of $210.0 million of principal on our term loan.

Adjusted EBITDA.

Adjusted EBITDA remained materially consistent with the prior year period as the lower netback to mine realization per ton sold and the higher cash cost per ton sold during the nine months ended September 30, 2015 were offset by $43.8 million of incremental realized gains on commodity derivative contracts and a favorable $13.5 million legal settlement with Murray Energy. The table below reconciles net income attributable to controlling interests to Adjusted EBITDA for the nine months ended September 30, 2015 and 2014.

	Nine Months Ended September 30,	
	2015	2014
	(In Thousands)	
Net income attributable to controlling interests	$24,972	$107,572
Interest expense, net	86,591	88,156
Depreciation, depletion and amortization	145,701	123,944
Accretion on asset retirement obligations	1,700	1,215
Transition and reorganization costs (excluding amounts included in equity-based compensation below)(1)	13,388	—
Loss on early extinguishment of debt	—	4,979
Equity-based compensation	12,897	3,257
Unrealized loss (gain) on commodity derivative contracts and prior cumulative unrealized gains realized during the period	10,853	(33,711)
Adjusted EBITDA	$296,102	$295,412

(1) – Equity-based compensation of $3.9 million was recorded in transition and reorganization costs in the condensed consolidated statement of operations for the nine months ended September 30, 2015.

For a discussion on Adjusted EBITDA, please read Item 2.“Management’s Discussion and Analysis of Financial Condition and Results of Operations—Key Metrics.”

Liquidity and Capital Resources

Our primary uses of cash include, but are not limited to, the cash costs of coal production, capital expenditures, coal reserve lease and royalty payments, production taxes, debt service costs (interest and principal), lease obligations, transportation costs and distributions to our unitholders. We expect that our cash flows from operations and available capacity under our Revolving Credit Facility will continue to support our existing operations for the next 12 months.

Since inception, we have made significant investments in capital expenditures to develop our four mining complexes and related transportation infrastructure which were funded with debt and cash generated from operations. Our operations are capital intensive, requiring investments to expand, maintain or enhance existing operations and to meet environmental and operational regulations. Our future capital spending will be determined by the board of directors of our general partner. Our capital requirements consist of maintenance and expansion capital expenditures. Maintenance capital expenditures are cash expenditures made to maintain our then-current operating capacity or net income as they exist at such time as the capital expenditures are made. Our maintenance capital expenditures can be irregular, causing the amount spent to differ materially from period to period.

Expansion capital expenditures are cash expenditures made to increase, over the long-term, our operating capacity or net income as it exists at such time as the capital expenditures are made. Development of the second longwall at our Sugar Camp complex was substantially completed with the start-up of the longwall on June 1, 2014. As a result, expansion capital expenditures have declined significantly from prior periods. Future longwall development and the associated expansion capital expenditures will be dependent upon several factors, including permitting, demand, access to capital, equipment availability and the committed sales position at our existing mining operations. We are currently incurring limited capital costs to pursue permits that would enable us to install our third and fourth longwall mines and related infrastructure at our Sugar Camp complex. In the event that market conditions are unsatisfactory for expansion, we are not obligated or committed to use cash for expansion capital expenditures and would look to dropdown transactions from Murray Energy and other acquisitions instead. We will look to the capital markets (debt and/or equity) to raise the required funding necessary to fund growth through dropdown transactions with Murray Energy or for material organic growth.

As of September 30, 2015, the total amount outstanding under our long-term debt and capital lease obligations was $1,495.6 million, compared to $1,360.7 million at December 31, 2014. As of September 30, 2015, we had $191.0 million of liquidity comprised of $25.0 million in cash and availability for borrowing under our Revolving Credit Facility of $166.0 million.

The following is a summary of cash provided by or used in each of the indicated types of activities:

	Nine Months Ended	
	September 30, 2015	September 30, 2014
	(In Thousands)	
Net cash provided by operating activities	$139,766	$167,651
Net cash used in investing activities	$(124,317)	$(176,149)
Net cash (used in) provided by financing activities	$(16,965)	$13,095

Net cash provided by operating activities declined $27.9 million to $139.8 million for the nine months ended September 30, 2015 primarily due to lower net income, excluding non-cash items, during the current year period and to a lesser extent unfavorable variances in working capital accounts from the prior year period.

Net cash used in investing activities was $124.3 million for the nine months ended September 30, 2015, compared to $176.1 million for the nine months ended September 30, 2014. The decline in net cash used in investing activities was primarily due to a $104.4 million reduction in capital expenditures as a result of the second longwall mine at our Sugar Camp complex emerging from development in June 2014 as well as the receipt of $19.1 million in proceeds during the current year period from the settlement of certain outstanding coal derivative contracts. The cash receipts on these contracts were recorded as an investing activity given they were settled prior to the economically hedged sale transaction occurring. Offsetting the items above was a $75.0 million investment in the Murray Energy transport lease and overriding royalty agreements (see “Item 1. Financial Statements – Note 13. Related-Party Transactions” of this Quarterly Report on Form 10-Q).

Net cash used in financing activities was $17.0 million for the nine months ended September 30, 2015, compared to $13.1 million provided by financing activities for the nine months ended September 30, 2014. During the nine months ended September 30, 2015, we received net proceeds from our A/R securitization program of $50.0 million, increased our borrowings under our Revolving Credit Facility by $58.0 million and received proceeds from incremental term loan borrowings of $59.3 million. Also, during the current year period, we repaid $33.2 million under our longwall financing and capital lease arrangements, repaid $2.0 million in short-term insurance financing, paid $2.8 million in debt issuance costs and paid $144.7 million in distributions to our limited partners and noncontrolling interests. The increased borrowings during the current year period were due in part to the $75.0 million invested in the Murray Energy transport lease and overriding royalty agreements.

Distributions

Our partnership agreement provides that our general partner make a determination as whether to make a distribution, but our partnership agreement does not require us to pay distributions at any time or at any amount. To the extent the quarterly distribution is below the minimum quarterly distribution (“MQD”) of $0.3375 per unit, as defined in the partnership agreement, then common unitholders would accrue an arrearage equal to the shortfall amount to the MQD that would carry forward to future quarters and must be paid to common unitholders before any distributions from operating surplus to the subordinated unitholder are made.

In February 2015, May 2015, and August 2015, we paid quarterly cash distributions of $0.36, $0.37 and $0.38 per unit, respectively, to all limited partner unitholders.

On October 29, 2015, we declared a quarterly distribution of $0.17 per unit payable on November 25, 2015 to all common unitholders of record on November 13, 2015, while suspending the distribution to the subordinated unitholders. Chris Cline and one additional common unitholder elected to forego the $0.17 per common unit distribution on their collective 21.2 million common units.

The decision by the board of directors of our general partner to reduce the distribution during the current quarter was a proactive effort to improve both long-term liquidity and our leverage in this difficult and unpredictable coal market.

Long-Term Debt, Capital Lease Obligations and Sale-Leaseback Financing Arrangements

2021 Senior Notes

On August 23, 2013, FELLC issued $600.0 million of 7.875% senior notes due August 15, 2021 (the “2021 Senior Notes”) and redeemed the outstanding 2017 senior notes. The 2021 Senior Notes are guaranteed on a senior unsecured basis by all of the domestic operating subsidiaries of FELLC, other than Foresight Energy Finance Corporation, co-issuer of the notes. Interest is due semiannually on February 15 and August 15 of each year. The 2021 Senior Notes were issued at an initial discount of $4.3 million, which is being amortized using the effective interest method over the term of the notes.

Revolving Credit Facility and Term Loan

In August 2010, FELLC entered into a $285.0 million revolving credit facility (the “Revolving Credit Facility”), which was amended in December 2011 to increase the capacity to $400.0 million. In August 2013, FELLC executed the second amendment to its credit agreement (the “Credit Agreement”) to increase the borrowing capacity under the Revolving Credit Facility from $400.0 million to $500.0 million and extend the maturity date to August 23, 2018. In May 2015, FELLC entered into the Incremental Amendment No. 1 to the Credit Agreement which increased lender commitments under the Revolving Credit Facility by $50.0 million to $550.0 million. The Revolving Credit Facility is guaranteed by the Partnership and all of its domestic operating subsidiaries except Foresight Energy Finance Corporation. Interest on borrowings under the amended Revolving Credit Facility is based, at our election, on the London Interbank Offered Rate (“LIBOR”) plus an applicable margin or at a defined prime rate plus an applicable margin. The applicable margin is determined based on our consolidated net leverage ratio, as defined in the Credit Agreement. The weighted-average effective interest rate on borrowings under the Revolving Credit Facility as of September 30, 2015 was 2.9%. We are also required to pay a 0.5% commitment fee for unutilized capacity. At September 30, 2015, we had borrowings of $377.5 million outstanding under the Revolving Credit Facility and $6.5 million outstanding in letters of credit, resulting in $166.0 million of remaining capacity.

The Credit Agreement was also amended on August 23, 2013 to incorporate the issuance of a $450.0 million senior secured term loan (the “Term Loan”). The Term Loan required quarterly principal payments of approximately $1.1 million, which commenced on December 31, 2013. In June 2014, we repaid $210.0 million of principal with proceeds from the IPO, which was applied against the prospective scheduled quarterly principal payments. In May 2015, FELLC entered into the Incremental Amendment No. 1 to the Credit Agreement, which in addition to increasing our capacity under the Revolving Credit Facility, allowed for the borrowing of $60.0 million of additional Term Loan principal. No scheduled principal payments are due until the Term Loan matures on August 23, 2020, at which point all remaining unpaid principal is due. The Term Loan bears interest at LIBOR plus 4.5%, subject to a 1% LIBOR floor. As of September 30, 2015, the interest rate on the Term Loan was 5.5% and the principal balance outstanding, excluding the unamortized debt discount of $2.3 million, was $297.8 million.

The Revolving Credit Facility is subject to customary debt covenants, including a consolidated interest coverage ratio and a consolidated net senior secured leverage ratio. As of September 30, 2015, our consolidated interest coverage ratio and consolidated net senior secured leverage ratio was 3.81x and 2.14x, respectively. Our covenants required a consolidated interest coverage ratio of greater than 2.00x and a consolidated net senior secured leverage ratio of less than 2.75x as of September 30, 2015. In addition, both the Credit Agreement and 2021 Senior Notes carry limitations on restricted payments, which may impact the timing and amount of cash distributions.

Trade A/R Securitization

In January 2015, Foresight Energy LP and certain of its wholly-owned subsidiaries entered into a $70 million receivables securitization program (the “Securitization Program”). Under this Securitization Program, our subsidiaries sell their customer trade receivables (the “Receivables”), on a revolving basis, to Foresight Receivables LLC, a wholly-owned consolidated special-purpose subsidiary of Foresight Energy LP (the “SPV”). The SPV then pledges its interests in the Receivables to the securitization program lenders, which either make loans or issue letters of credit to, or on behalf of, the SPV. The maximum amount of advances and letters of credit outstanding under the program may not exceed $70 million. The amount eligible for borrowing is determined by the qualified receivable balances outstanding. The Securitization Program has a three-year maturity and expires on January 12, 2018. The borrowings under the Securitization Program are variable-rate and the Securitization Program also carries a commitment fee for unutilized commitments. As of September 30, 2015, we had borrowings outstanding of $50.0 million under the Securitization Program.

Longwall Financing Arrangements and Capital Lease Obligations

In November 2014, we entered into a sale-leaseback financing arrangement with a financial institution under which we sold a set of longwall shields and related equipment for $55.9 million and leased the shields back under three individual leases. We account for these leases as capital lease obligations since ownership of the longwall shields and related equipment transfer back to us upon the completion of the leases. These capital lease obligations bear interest at 5.762% and principal and interest payments are due monthly over the five-year terms of the leases. Aggregate termination payments of $2.8 million are due at the end of the lease terms. As of September 30, 2015, $48.1 million was outstanding under these capital lease obligations.

In March 2012, we entered into a finance agreement with a financial institution to fund the manufacturing of longwall equipment. Upon taking possession of the longwall equipment, the interim longwall finance agreement was converted into six individual capital leases with maturities of four and five years beginning on September 1, 2012. These capital lease obligations bear interest ranging from 5.4% to 6.3%, and principal and interest payments are due monthly over the terms of the leases. As of September 30, 2015, $20.5 million was outstanding under these capital lease obligations.

In May 2010, we entered into a credit agreement with a financial institution to provide financing for longwall equipment and related parts and accessories. The financing agreement also provided for financing of loan fees and eligible interest during the construction of the longwall equipment. The financing arrangement is collateralized by the longwall equipment. Interest accrues on the note at a fixed rate per annum of 5.555% and is due semiannually in March and September until maturity. Principal is due in 17 equal semiannual payments through September 30, 2020. The outstanding balance as of September 30, 2015 was $51.6 million.

In January 2010, we entered into a credit agreement with a financial institution to provide financing for longwall equipment and related parts and accessories. The financing agreement also provided for financing of the loan fees and eligible interest during the construction of the longwall equipment. The financing arrangement is collateralized by the longwall equipment. Interest accrues on the note at a fixed rate per annum of 5.78% and is due semiannually in June and December until maturity. Principal is due in 17 equal semiannual payments through June 30, 2020. The outstanding balance as of September 30, 2015 was $56.0 million.

The guaranty agreements with the lender under both the 5.555% and 5.78% longwall financing arrangements contain certain financial covenants consistent with those of our Revolving Credit Facility.

Sale-Leaseback Financing Arrangements - Affiliate

In 2009, Macoupin sold certain of its coal reserves and rail facility assets to WPP LLC, a subsidiary of Natural Resources Partners LP (“NRP”), and leased them back. The gross proceeds from this transaction were $143.5 million. As Macoupin has continuing involvement in the assets sold, the transaction is treated as a financing arrangement. At September 30, 2015, the outstanding balance of the sale-leaseback financing arrangement was $143.5 million and the effective interest rate was 14.0%.

In 2012, Sugar Camp sold certain rail facility assets to HOD LLC, a subsidiary of NRP, and leased them back. The gross proceeds from this transaction were $50.0 million. As Sugar Camp has continuing involvement in the assets sold, the transaction is treated as a financing arrangement. At September 30, 2015, the outstanding balance of the sale-leaseback financing arrangement was $50.0 million and the effective interest rate was 13.3%.

Off-Balance Sheet Arrangements

In the normal course of business, we are a party to certain off-balance sheet arrangements, including operating leases, coal reserve leases, take-or-pay transportation obligations, indemnifications and financial instruments with off-balance sheet risk, such as bank letters of credit and surety bonds. Liabilities related to these arrangements are generally not reflected in our consolidated balance sheets and, except for the coal reserve leases, take-or-pay transportation obligations and operating leases, we do not expect any material impact on our cash flows, results of operations or financial condition to result from these off-balance sheet arrangements.

In May 2015, we amended our material handling agreement with Raven Energy LLC, a former affiliate of The Cline Group, to reduce the minimum annual throughput volume at CMT, beginning in 2015, to 5.0 million tons per year over the remaining duration of the agreement. The amendment reduced our remaining aggregate contractual commitments by $126.9 million and decreased our annual commitments by $18.1 million, on average, through 2021.

From time to time, we use bank letters of credit to secure our obligations for certain contracts and other obligations. At September 30, 2015, we had $6.5 million of letters of credit outstanding.

We had outstanding surety bonds with third parties of $71.9 million as of September 30, 2015 to secure reclamation and other performance commitments. In November 2015, a demand notice was issued by our insurer requesting that we post collateral, either in the form of a letter of credit or cash, for our outstanding surety bonds. We have not been required to post collateral in the past and we are currently in discussions with our insurer to eliminate or negotiate lower the amount required, which we believe will not have a material impact on our liquidity.

Related-Party Transactions

See “Item 1. Financial Statements – Note 13. Related-Party Transactions” and “Item 1. Financial Statements – Note 11. Sale-Leaseback Financing Arrangements” of this Quarterly Report on Form 10-Q. See also “Certain Relationships and Related-Party Transactions” in the Annual Report on Form 10-K filed with the SEC on March 10, 2015.

Newly Adopted Accounting Standards and Accounting Standards Not Yet Implemented

See “Item 1. Financial Statements – Note 2. New Accounting Standards” of this Quarterly Report on Form 10-Q.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with U.S. GAAP requires us to make estimates and assumptions in certain circumstances that affect amounts reported in the accompanying condensed consolidated financial statements and related footnotes. In preparing these financial statements, we have made our best estimates of certain amounts included in the financial statements. Application of these accounting policies and estimates, however, involves the exercise of judgment and use of assumptions as to future uncertainties, and as a result, actual results could differ from these estimates. In arriving at our critical accounting estimates, factors we consider include how accurate the estimates or assumptions have been in the past, how much the estimates or assumptions have changed and how reasonably likely such change may have a material impact. Our critical accounting policies and estimates are more fully described in “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in the Annual Report on Form 10-K filed with the SEC on March 10, 2015. There have been no significant changes to our prior critical accounting policies and estimates subsequent to December 31, 2014, or new accounting pronouncements impacting our results.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

We define market risk as the risk of economic loss as a consequence of the adverse movement of market rates and prices. We believe our principal market risks include commodity price risk and interest rate risk, which are disclosed below.

Commodity Price Risk

We have commodity price risk as a result of changes in the market value of our coal. We try to minimize this risk by entering into fixed price coal supply agreements and, from time to time, commodity hedge agreements. As of October 23, 2015, we had the following contracted sales commitments for the years ending December 31, 2016 and 2017:

	Priced	Unpriced (or Index-Based)	Total
	(Tons, in Millions)		
Year ending December 31, 2016	18.6	0.9	19.5
Year ending December 31, 2017	11.6	2.3	13.9

As of September 30, 2015, we have 1.4 million tons economically hedged with forward coal derivative contracts tied to the API 2 coal price index to partially mitigate coal price risk through 2017. The impact of our economic hedges to fix the selling price on unpriced (or index-based) coal sales contracts and forecasted sales is not reflected in the table above. A 10% change in the API 2 index would result in a $7.8 million change in the fair value of these derivative contracts.

We have diesel fuel price exposure in our transportation and production processes and therefore are subject to commodity price risk as a result of changes in the market value of diesel fuel. To limit our exposure to price volatility, we have entered into swap agreements with financial institutions which allows us to pay a fixed price and receive a floating price, which provides a fixed price per unit for the volume of purchases being hedged. As of September 30, 2015, we have 1.8 million gallons of diesel fuel hedged through 2016. A 10% change in the price of diesel fuel would result in a $0.6 million change in the fair value of these derivative contracts.

Interest Rate Risk

We are exposed to market risk associated with interest rates due to our existing level of indebtedness. At September 30, 2015, of our $1.5 billion in long-term debt and capital lease obligations outstanding, $725.3 million of outstanding borrowings have interest rates that fluctuate based on changes in market interest rates. A one percentage point increase in the interest rates related to variable interest borrowings would result in an annualized increase in interest expense of approximately $5.2 million.

Item 4. Controls and Procedures.

We evaluated, under the supervision and with the participation of our management, including our chief executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of September 30, 2015. Based on that evaluation, our management, including our chief executive officer and principal financial officer, concluded that the disclosure controls and procedures were effective in ensuring that information required to be disclosed in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and is accumulated and communicated to our management to allow timely decisions regarding required disclosure. There were no changes in our internal control over financial reporting during the fiscal quarter to which this report relates that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION.

Item 1. Legal Proceedings.

See Note 18, "Contingencies," to the condensed consolidated financial statements included in this report relating to certain legal proceedings, which information is incorporated by reference herein. See also "Legal Proceedings" in our Annual Report on Form 10-K filed with the SEC on March 10, 2015.

Item 1A. Risk Factors.

The risk factor below is an update to certain risk factors previously discussed under the heading "Risk Factors" in our Annual Report on Form 10-K filed with the SEC on March 10, 2015.

Recent developments in the regulation of GHG emissions and coal ash could materially adversely affect our customers' demand for coal and our results of operations, cash flows and financial condition.

Coal-fired power plants produce carbon dioxide and other GHGs as a by-product of their operations. GHG emissions have received increased scrutiny from local, state, federal and international government bodies. Future regulation of GHGs could occur pursuant to U.S. treaty obligations or statutory or regulatory change. The EPA and other regulators are using existing laws, including the federal Clean Air Act, to limit emissions of carbon dioxide and other GHGs from major sources, including coal-fired power plants that may require the use of "best available control technology." For example, in 2011, the EPA issued regulations, including permitting requirements, restricting GHG emissions from any new U.S. power plants, and from any existing U.S. power plants that undergo major modifications that increase their GHG emissions. In response to a recent Supreme Court decision, the EPA is scaling back its GHG permitting program in part and plans to finalize a rule by the end of 2015 to rescind certain permits issued under the Clean Air Act triggered solely because of GHG emissions. In addition, the EPA, in September 2013, also proposed new source performance standards for GHG emissions for new coal and oil-fired power plants, which could require partial carbon capture and sequestration. The EPA is expected to issue a final regulation by mid-summer 2015. In addition, in June 2013, President Obama announced additional initiatives intended to reduce greenhouse gas emissions globally, including curtailing U.S. government support for public financing of new coal-fired power plants overseas and promoting fuel switching from coal to natural gas or renewable energy sources. Global treaties are also being considered that place restrictions on carbon dioxide and other GHG emissions. On August 3, 2015, President Obama and the EPA announced the Clean Power Plan (CPP), which includes final emission guidelines for States to follow in developing plans to reduce greenhouse gas (GHG) emissions from existing fossil fuel-fired electric generating units (EGUs) as well as limits on GHG emission rates for new, modified and reconstructed EGUs. Under the CPP, nationwide carbon dioxide emissions would be reduced by 32% by 2030, while offering states and utilities flexibility in achieving these reductions. In addition, state and regional climate change initiatives to regulate GHG emissions, such as the RGGI of certain northeastern and Mid-Atlantic states, the Western Climate Initiative, the Midwestern Greenhouse Gas Reduction Accord and the California Global Warming Solutions Act, either have already taken effect or may take effect before federal action. Further, governmental agencies have been providing grants or other financial incentives to entities developing or selling alternative energy sources with lower levels of GHG emissions, which may lead to more competition from those entities. There have also been several public nuisance lawsuits brought against power, coal, oil and gas companies alleging that their operations are contributing to climate change. The plaintiffs are seeking various remedies, including punitive and compensatory damages and injunctive relief. While the U.S. Supreme Court recently determined that such claims cannot be pursued under federal law, plaintiffs may seek to proceed under state common law.

In December 2014, the EPA announced that it had determined to regulate coal combustion wastes, sometimes referred to as coal ash, as a nonhazardous substance under Subtitle D of the RCRA. While classifying coal combustion waste as a hazardous waste under Subtitle C of the RCRA would have led to more stringent requirements, the new rule could still increase customers' operating costs and may make coal less attractive for electric utilities.

The enactment of these and other laws or regulations regarding emissions from the combustion of coal or other actions to limit such emissions, could result in electricity generators switching from coal to other fuel sources thereby reducing demand for our coal.

Significant public opposition has also been raised with respect to the proposed construction of certain new coal-fueled electricity generating plants and certain new export transloading facilities due to the potential for increased air emissions. Such opposition, as well as any corporate or investor policies against coal-fired generation plants could also reduce the demand for our coal. Further, policies limiting available financing for the development of new coal-fueled power plants could adversely impact the global demand for coal in the future. The potential impact on us of future laws, regulations or other policies or circumstances will depend upon the degree to which any such laws, regulations or other policies or circumstances force electricity generators to diminish their reliance on coal as a fuel source. In view of the significant uncertainty surrounding each of these factors, it is not possible for us to reasonably predict the impact that any such laws, regulations or other policies may have on our results of operations, cash flows and financial condition as well as our ability to pay distributions to our unitholders. However, such impacts could have a material adverse effect on our results of operations, cash flows and financial condition as well as our ability to pay distributions to our unitholders.

We may be unable to obtain, maintain or renew permits necessary for our operations and to mine all of our coal reserves, which would materially and adversely affect our production, cash flow and profitability.

In order to develop our economically recoverable coal reserves, we must regularly obtain, maintain or renew a number of permits that impose strict requirements on various environmental and operational matters in connection with coal mining. These include permits issued by various federal, state and local agencies and regulatory bodies. Permitting rules, and the interpretations of these rules, are complex, change frequently, and are often subject to discretionary interpretations by regulators, all of which may make compliance more difficult or impractical and could result in the discontinuance of mine development or the development of future mining operations. The public, including non-governmental organizations, anti-mining groups and individuals, have certain statutory rights to comment upon and submit objections to requested permits and environmental impact statements prepared in connection with applicable regulatory processes, and otherwise engage in the permitting process, including bringing citizens' claims to challenge the issuance or renewal of permits, the validity of environmental impact statements or performance of mining activities. Our mining operations are currently, and may become in the future, subject to legal challenges before administrative or judicial bodies contesting the validity of our environmental permits under SMCRA and the CWA, among other statutory provisions. Accordingly, required permits may not be issued in a timely fashion or renewed at all, or permits issued or renewed may not be maintained, may be challenged or may be conditioned in a manner that may restrict our ability to efficiently and economically conduct our mining activities, any of which would materially reduce our production, cash flow, and profitability as well as our ability to pay distributions to our unitholders.

We make no assurances that we will be able to obtain, maintain or renew any of the governmental permits that we need to continue developing our proven and probable coal reserves. Further, new legislation or administrative regulations or new judicial interpretations or administrative enforcement of existing laws and regulations, including proposals related to the protection of the environment and to human health and safety that would further regulate and tax the coal industry may also require us to change operations significantly or incur increased costs. For example, in July 2015, the OSM issued a new proposed revision to its Stream Buffer Zone Rule that would require extensive baseline data on hydrology, geology and aquatic biology in permit applications, define the "material damage" that would be prohibited outside permitted areas, require additional monitoring during mining and reclamation and expand restoration and stream protection requirements for both surface and underground mines. OSM, in the preamble to this proposed rule, states that the rule will "prohibit mining operations that would result in dewatering of a stream to the extent that the stream would no longer be able to support existing or reasonably foreseeable uses or designated uses of the stream under the Clean Water Act and for which there are no viable measures to prevent this impact." If this prohibition is interpreted to exclude longwall mining beneath streams, then our ability to fully mine our reserves with the longwall method could be materially diminished. If finalized in 2016, as currently anticipated, the proposed rule would also likely add costs and delays to the SMCRA permitting process and add costs to our operations and reclamation activities.

On June 29, 2015, the EPA published its final rule expanding the definition of "Waters of the United States" ("WOTUS Rule") that expands the jurisdiction of the EPA and the United States Army Corps of Engineers to regulate waters not previously regulated. The WOTUS Rule becomes effective on August 28, 2015 and will likely add an additional layer of permitting to activities involving previously non-jurisdictional waters and likely cause states that have jurisdiction over their own waters to enhance their already robust regulatory programs, adding unwarranted delays to the permitting process and extending review times even further for regulatory agencies already under resourced. On October 9, 2015, the United States Court of Appeals for the Sixth Circuit issued a temporary nationwide stay of the effectiveness of the WOTUS rule while litigation regarding its legality progresses. The temporary stay could be lifted at any time. This rule, if it becomes final, could impact our ability to timely obtain necessary permits. Such changes could have a material adverse effect on our financial condition and results of operations as well as our ability to pay distributions to our unitholders.

In March 2014, the Illinois State Attorney General, the Illinois Department of Natural Resources and others entered into an order which has potentially far-reaching effects on the permitting process for mines in Illinois. While the final rules have yet to be promulgated, and thus the impact on the permitting process cannot yet be determined, it could have the effect of extending the permit review and approval process. The inability to conduct mining operations or obtain, maintain or renew permits may have a material adverse effect on our results of operations, business and financial position, as well as the ability to pay distributions to our unitholders.

The benefits of reduced costs associated with joint management with Murray Energy may not be realized and key personnel may experience conflicts of interest.

We may not realize the reduction in selling, general and administrative costs which we expect under the management services agreement with Murray Energy or the expected procurement synergies resulting from increased purchasing power with third party vendors and lower pricing on equipment acquired from Murray Energy's manufacturing facilities. Additionally, we share key personnel with Murray Energy and there may be a conflict of interest in the duties of such personnel as they relate to Murray Energy and us. Such personnel have fiduciary duties to Murray Energy which may cause them to pursue business strategies that disproportionately benefit Murray Energy or which otherwise are not in the best interest of our unitholders. As a result, there may be instances where a conflict of interest arises between Murray Energy and us that could have an adverse effect on our business.

In addition to the other information set forth in this Quarterly Report on Form 10-Q, you should carefully consider the risk factors discussed under the heading "Risk Factors" in our Annual Report on Form 10-K filed with the SEC on March 10, 2015, which risks could have a material adverse effect on our business, financial condition, or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing us. Additional risks and uncertainties not currently known to us, or that we currently deem to be immaterial, also may have a material adverse effect on our business, operations, financial condition or future results.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

None.

Item 3. Defaults Upon Senior Securities.

None.

Item 4. Mine Safety Disclosures.

Information concerning mine safety violations or other regulatory matters required by SEC regulations is included in Exhibit 95.1 of this Form 10-Q.

Item 5. Other Information

None.

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 on November 12, 2015.

Foresight Energy LP

By: Foresight Energy GP LLC,
its general partner

/s/ Robert D. Moore
Robert D. Moore
President, Chief Executive Officer and Director

/s/ James T. Murphy
James T. Murphy
Principal Financial Officer and Chief Accounting Officer

Item 6. Exhibits.

Exhibit Number	Exhibit Description
3.1	Certificate of Limited Partnership of Foresight Energy LP (f/k/a Foresight Energy Partners LP) (incorporated herein by reference to Exhibit 3.1 to the Registrant's Registration Statement on Form S-1 filed on February 2, 2012 (SEC File No. 333-179304)).
3.2	Partnership Agreement of Foresight Energy LP (incorporated herein by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed on June 23, 2014 (SEC File No. 001-36503)).
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended.

31.2*	Certification of Principal Financial Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended.
32.1**	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2012.
32.2**	Certification of Principal Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2012.
95.1*	Mine Safety Disclosure Exhibit.
101*	Interactive Data File (Form 10-Q for the quarter ended September 30, 2015 filed in XBRL. The financial information contained in the XBRL-related documents is "unaudited" and "unreviewed".
*	Filed herewith.
**	Furnished.

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