- ***Acquire additional mineral and royalty interests in oil and natural gas properties that meet our acquisition criteria.*** We intend to continue to acquire mineral and royalty interests that have substantial resource and cost-free, or organic, growth potential. Our management team has a long history of evaluating, pursuing, and consummating acquisitions of oil and natural gas mineral and royalty interests in the United States. We believe that our large network of industry relationships provides us with a competitive advantage in pursuing potential acquisition opportunities. Since 1992, we have invested approximately $1.6 billion in 42 acquisitions. In the future, we expect to focus on relatively large acquisitions but will also continue to pursue smaller mineral packages to complement an existing position or to establish a foothold in an emerging play. We prefer acquisitions that meet the following criteria:
  - sufficient current production to create near-term accretion for our unitholders;
  - geologic support for future production and reserve growth;
  - a geographic footprint that we believe is complementary to our diverse portfolio and maximizes our potential for upside reserve and production growth from undiscovered reserves or new plays; and
  - targeted positions in high-growth resource and conventional plays.
- ***Participate in low-risk drilling opportunities in plays that generate attractive returns.*** Our ownership of mineral interests affords us the favorable position of negotiating leases that frequently provide us a unit-by-unit or well-by-well option to participate on a working-interest basis in economic, low-risk drilling opportunities. This participation program offers access to drilling opportunities in established producing trends at well-level economics, often unburdened by traditional land and exploration costs associated with acquiring prospective acreage, such as paying lease bonus, acquiring seismic data, and drilling exploratory and delineation wells. We expect to continue to actively participate in these drilling opportunities.
- ***Maintain a conservative capital structure and prudently manage the business for the long term.*** We are committed to maintaining a conservative capital structure that will afford us the financial flexibility to execute our business strategies on an ongoing basis. Upon completion of this offering, we will have no outstanding indebtedness. We believe that proceeds from this offering, internally generated cash from operations, our $600.0 million borrowing base under our credit facility, and access to the public capital markets will provide us with sufficient liquidity and financial flexibility to grow our production, reserves, and cash generated from operations through the continued development of our existing assets and accretive acquisitions of mineral and royalty interests.

Competitive Strengths

We believe that the following competitive strengths will allow us to successfully execute our business strategies and achieve our primary business objective:

- ***Significant diversified portfolio of mineral and royalty interests in mature producing basins and exposure to prospective exploration opportunities.*** We have a large-scale, diversified asset base with exposure to active, high-quality conventional and unconventional plays. With our mineral and royalty interests spanning over 16.7 million total acres across the continental United States, we have established a strong position with significant growth opportunities and exposure to potentially large new discoveries in the future. In some cases, we have built our positions in anticipation of development in a play, as we did in the Eagle Ford Shale. In other cases, we acquired diversified mineral packages in rich geologic basins with multiple prospective horizons from which subsequent resource plays, including the Bakken/ Three Forks and the Haynesville/Bossier plays, have developed. Because our asset base is large and diversified, we are able to make significant focused acquisitions in active areas within well-established resource plays, while maintaining overall diversity. Furthermore, the geographic breadth of our assets and vast quantity of our property interests expose us to potential production and reserves from new and existing plays without further required investment on our behalf. We believe that we will continue to benefit from these cost-free additions of production and reserves for the foreseeable future as a result of technological advances and continuing interest by third-party producers in exploration and development activities on our acreage.

- ***Exposure to many of the leading resource plays in the United States***. We expect our reserves and cash distributions per unit to grow organically for the next several years as our operators continue to drill new wells on the acreage we have leased to them. We believe that we have significant drilling inventory remaining in our interests in multiple resource plays.

- ***Ability to increase exposure in most economic plays through our working-interest participation program***. We frequently negotiate our leases with options to participate in wells on a working-interest basis. This working-interest option allows us to increase our exposure to plays that we find attractive when the results from prior drilling and production have substantially reduced the economic risk associated with development drilling and where we believe the probability of achieving attractive economic returns is high. We intend to continue increasing our exposure to those opportunities.

- ***Scalable business model***. We believe that our size, organizational structure, and capacity give us a relative advantage in growing our business because we are able to add large packages of mineral and royalty interests without significantly increasing our cost structure, allowing us to be more competitive when pursuing acquisition opportunities. Our land, accounting, engineering and geology, information-technology, and business-development departments have developed a scalable business model that allows us to manage our existing assets efficiently and absorb significant acquisitions without material cost increases.

- ***Exposure to natural gas supply and demand growth***. The EIA projects that U.S. natural gas demand from internal consumption is expected to increase from 25.6 trillion cubic feet in 2012 to 31.6 trillion cubic feet in 2040, driven primarily by increased electricity generation and industrial use. International demand for exports of U.S. natural gas, through pipelines and liquefied natural gas, is forecasted to grow to 5.8 trillion cubic feet per year by 2040. The EIA forecasts the total demand for U.S. natural gas to reach 37.4 trillion cubic feet in 2040. As a result of this increase in demand, the EIA projects U.S. natural gas production to increase from 24.1 trillion cubic feet in 2012 to 37.5 trillion cubic feet in 2040, a 56% increase. Almost all of this increase is due to projected growth in natural gas production from resource plays, which is projected to grow from 9.7 trillion cubic feet in 2012 to 19.8 trillion cubic feet in 2040. We have significant exposure to domestic natural gas resource plays, including the Haynesville/Bossier plays, the Fayetteville Shale, and the Barnett Shale, and we believe that these assets will provide meaningful upside in production and revenue growth as demand for natural gas increases. Our natural gas assets throughout the U.S. Gulf Coast are well positioned geographically to take advantage of the growing liquefied natural gas export market.

- ***Financial flexibility to fund expansion***. Upon the completion of this offering and the application of the net proceeds as set forth under "Use of Proceeds," we expect to have no indebtedness outstanding, approximately $13.6 million of cash on hand, and $600.0 million of undrawn borrowing capacity under our credit facility. The credit facility, combined with internally generated cash from operations and access to the public capital markets, will provide us with the financial capacity and flexibility to grow our business.

- ***Experienced and proven management team***. The members of our executive team have an average of over 25 years of industry experience and have a proven track record of executing accretive acquisitions and maximizing asset development. We expect to benefit from the longstanding relationships fostered by our management team within the industry and the decades-long track record of successful

The Offering

Common units offered to the public.	22,500,000 common units (25,875,000 common units if the underwriters exercise in full their option to purchase additional common units from us).
Units outstanding after this offering	95,133,333 common units (98,508,333 common units if the underwriters exercise in full their option to purchase additional common units from us), 95,133,333 subordinated units, and 117,980 preferred units. The preferred units are convertible into 3,579,881 common units and 4,688,839 subordinated units.
Use of proceeds	We intend to use the estimated net proceeds of approximately $421.9 million from this offering (based on an assumed initial offering price of $20.00 per common unit, the mid-point of the price range set forth on the cover page of this prospectus), after deducting the estimated underwriting discount, structuring fee, and offering expenses payable by us, to repay all of the indebtedness outstanding under our credit facility, which was $389.0 million as of March 31, 2015. We expect that at the time of completion of the offering, the outstanding balance on our credit facility will approximately equal the net proceeds of this offering. If the net proceeds should exceed the outstanding balance, this excess will be used to fund future capital expenditures. The net proceeds from any exercise of the underwriters' option to purchase additional common units (approximately $63.6 million based on an assumed initial offering price of $20.00 per common unit, the mid-point of the price range set forth on the cover page of this prospectus, after deducting the estimated underwriting discount and structuring fee, if exercised in full) will be used to fund future capital expenditures. Please read "Use of Proceeds." Affiliates of certain of our underwriters are lenders under our credit facility and, as such, may receive a portion of the proceeds from this offering. Please read "Underwriting—Relationships."
Cash distributions	Our partnership agreement generally provides that during the subordination period we will pay any distributions each quarter as follows: • *first*, to the holders of preferred units in an amount of approximately $25.00 per preferred unit (the "quarterly preferred distribution amount"); • *second*, to the holders of common units, until each common unit has received the applicable minimum quarterly distribution in the amounts specified below plus any arrearages from prior quarters; and • *third*, to the holders of subordinated units, until each subordinated unit has received the applicable minimum quarterly distribution. If the distributions to our common and subordinated unitholders exceed the applicable minimum quarterly

members of Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shale formations by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates.

Several states, including Texas, have adopted or are considering adopting regulations that could restrict or prohibit hydraulic fracturing in certain circumstances or require the disclosure of the composition of hydraulic-fracturing fluids. For example, the Texas Railroad Commission has adopted rules and regulations requiring that well operators disclose the list of chemical ingredients subject to the requirements of the federal Occupational Safety and Health Act to state regulators and on a public internet website. We expect our operators to use hydraulic fracturing extensively in connection with the development and production of our oil and natural gas properties, and any increased federal, state, or local regulation of hydraulic fracturing could reduce the volumes of oil and natural gas that our operators can economically recover, which could materially and adversely affect our revenues and results of operations. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where our operators conduct operations, our operators may incur substantial costs to comply with these requirements, which may be significant in nature, experience delays, or curtailment in the pursuit of exploration, development, or production activities and perhaps even be precluded from the drilling of wells.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, impacts on drinking water supplies, use of water, and the potential for impacts to surface water, groundwater, and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic-fracturing practices. If new laws or regulations are adopted that significantly restrict hydraulic fracturing, those laws could make it more difficult or costly for our operators to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing is further regulated at the federal or state level, fracturing activities on our properties could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements, and also to attendant permitting delays and potential increases in costs. Legislative changes could cause operators to incur substantial compliance costs. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal or state legislation governing hydraulic fracturing.

Our credit facility has substantial restrictions and financial covenants that may restrict our business and financing activities and our ability to pay distributions.

Our credit facility limits the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion based on their valuation of our proved reserves and their internal criteria. The borrowing base is redetermined at least semi-annually, and the available borrowing amount could be further decreased as a result of such redeterminations. Decreases in the available borrowing amount could result from declines in oil and natural gas prices, operating difficulties or increased costs, declines in reserves, lending requirements, or regulations or certain other circumstances. As of March 31, 2015, we had outstanding borrowings of $389.0 million and the aggregate maximum credit amounts of the lenders were $1.0 billion. As a result of the steep decline in oil and natural gas prices in of the second half of 2014, our borrowing base was decreased by the lenders under our credit facility in April 2015 to $600.0 million. A future decrease in our borrowing base could be substantial and could be to a level below our then-outstanding borrowings. Outstanding borrowings in excess of the borrowing base are required to be repaid in five equal monthly payments, or we are required to pledge other oil and natural gas properties as additional collateral, within 30 days following notice from the administrative agent of the new or adjusted borrowing base. If we do

USE OF PROCEEDS

We intend to use the estimated net proceeds of approximately $421.9 million from this offering (based on an assumed initial offering price of $20.00 per common unit, the mid-point of the price range set forth on the cover page of this prospectus), after deducting the estimated underwriting discount, structuring fee, and offering expenses payable by us, to repay all of the indebtedness outstanding under our credit facility, which was $389.0 million as of March 31, 2015. We expect that at the time of completion of the offering, the outstanding balance on our credit facility will approximately equal the net proceeds of this offering. If the net proceeds should exceed the outstanding balance, this excess will be used to fund future capital expenditures.

The net proceeds from any exercise of the underwriters' option to purchase additional common units (approximately $63.6 million, if exercised in full, based on an assumed initial offering price of $20.00 per common unit, the mid-point of the price range set forth on the cover of this prospectus, after deducting the estimated underwriting discount and structuring fee) will be used to fund future capital expenditures.

Borrowings under our credit facility were primarily made for the acquisition of properties and other general business purposes. As of March 31, 2015, we had borrowings outstanding of $389.0 million under our credit facility. Indebtedness under our credit facility bore interest at a weighted average rate of approximately 2.4% during the year ended December 31, 2014. The maturity date of our credit facility is February 3, 2017. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations—Credit Facility."

Affiliates of certain of our underwriters are lenders under our credit facility and, as such, may receive a portion of the proceeds from this offering. Please read "Underwriting—Relationships."

- We may lack sufficient cash to pay distributions to our unitholders due to shortfalls in cash generated from operations attributable to a number of operational, commercial, or other factors as well as increases in our operating or general and administrative expenses, principal and interest payments on our outstanding debt, working-capital requirements, and anticipated cash needs.

We expect to generally distribute a substantial majority of our cash from operations to our unitholders on a quarterly basis, after, among other things, the establishment of cash reserves. To fund our growth, we may eventually need capital in excess of the amounts we may retain in our business or borrow under our credit facility. To the extent efforts to access capital externally are unsuccessful, our ability to grow will be significantly impaired.

Any distributions paid on our common and subordinated units with respect to a quarter will be paid within 60 days after the end of such quarter. Our first distribution will be for the period from the closing of this offering through June 30, 2015, and our partnership agreement will prorate the minimum quarterly distribution based on the actual length of the period. Please read "Cash Distribution Policy and Restrictions on Distributions."

Minimum Quarterly Distribution

Upon completion of this offering, our partnership agreement provides for an initial minimum quarterly distribution of $0.2625 per unit, or $1.05 per unit on an annualized basis, on all of the common and subordinated units outstanding through March 31, 2016. The payment of the full initial minimum quarterly distribution on all of the common units and subordinated units to be outstanding after completion of this offering would require us to have cash generated from operations available for distribution of approximately $202.6 million on an annualized basis. Our ability to make cash distributions at the applicable minimum quarterly distribution rate will be subject to the factors described above under "—General—Limitations on Cash Distributions and Our Ability to Change Our Cash Distribution Policy." The table below sets forth the amount of common units and subordinated units that will be outstanding after this offering, assuming the underwriters do not exercise their option to purchase additional common units, and the cash generated from operations available for distribution needed to pay the aggregate initial minimum quarterly distribution on all of such units for a single fiscal quarter and a four-quarter period (dollars in thousands):

		Aggregate Minimum Quarterly Distributions for the Three Months Ending				
	Number of Units(1)	**March 31, 2016**	**December 31, 2015**	**September 30, 2015**	**June 30, 2015**	**Annualized**
Common units issued in this offering	22,500,000	$ 5,907	$ 5,906	$ 5,906	$ 5,906	$ 23,625
Common units issued or issuable as equity-based compensation(2)	1,954,939	514	513	513	513	2,053
Common units issued in the merger(3)	72,633,333	19,067	19,066	19,066	19,066	76,265
Subordinated units issued in the merger(4)	95,133,333	24,974	24,972	24,972	24,972	99,890
Preferred units to be converted into common units as of January 1, 2016	1,193,294	313	—	—	—	313
Preferred units to be converted into subordinated units as of January 1, 2016	1,562,946	410	—	—	—	410
Total	194,997,845	$51,185	$50,457	$50,457	$50,457	$202,556

(1) Reflects preferred units to be converted into common and subordinated units on January 1, 2016, which will be entitled to the minimum quarterly distribution for the three months ending March 31, 2016 and thereafter.

(2) Includes 60,000 common units, 936,661 restricted common units, and 958,278 common-unit-settled performance units expected to be issued as equity-based compensation after the offering.

(3) Includes 1,190,148 common units to be issued in the merger resulting from the conversion of preferred units into BSMC common units in January 2015 and 230,983 restricted common units (net of withholding for vesting awards) to be issued in the merger resulting from equity-based compensation awards granted in February 2015.
(4) Includes 1,558,826 subordinated units to be issued in the merger resulting from the conversion of preferred units into BSMC common units in January 2015 and 302,536 restricted subordinated units (net of withholding for vesting awards) to be issued in the merger resulting from equity-based compensation awards granted in February 2015.

The preferred units are convertible into common units and subordinated units. If all of our preferred units converted as of March 31, 2015, these units would convert into 3,579,881 common and 4,688,839 subordinated units. If our preferred units fully converted into common and subordinated units as of March 31, 2015, we would need $8.0 million of additional cash to pay the applicable minimum quarterly distribution on all of our common and subordinated units outstanding after this offering, which would be more than offset by the $10.8 million of distributions on the preferred units. If the underwriters exercise their option to purchase additional common units, we will need $3.5 million additional cash to pay the applicable minimum quarterly distribution on our common units outstanding after the offering.

Further, our partnership agreement provides for an increase in the applicable minimum quarterly distribution on each of April 1, 2016, 2017, and 2018. To fund those increases in the minimum quarterly distribution on our outstanding common and subordinated units, our cash generated from operations available for distribution, assuming (i) no change in distribution coverage, (ii) the preferred units fully converted on March 31, 2015, (iii) the underwriters exercise their option to purchase additional common units in full, and (iv) no additional common or subordinated units are issued, would have to increase by $23.2 million, $46.4 million, and $69.6 million for each of the twelve months ending March 31, 2017, 2018, and 2019, respectively, compared to the twelve months ending March 31, 2016.

The table below sets forth the amounts required to pay the minimum quarterly distribution of $0.3375 applicable for the twelve months ending March 31, 2019, assuming (unlike the immediately preceding table) that (i) the preferred units have fully converted and (ii) the underwriters exercised their option to purchase additional units to cover over-allotments in full with respect to this offering (dollars in thousands):

		Aggregate Minimum Quarterly Distributions for the Three Months Ending				
	Number of Units	**March 31, 2019**	**December 31, 2018**	**September 30, 2018**	**June 30, 2018**	**Annualized**
Common units issued in this offering	25,875,000	$ 8,732	$ 8,733	$ 8,733	$ 8,733	$ 34,931
Common units issued or issuable as equity-based compensation	1,954,939	659	660	660	660	2,639
Common units issued in the merger	72,633,333	24,513	24,514	24,514	24,514	98,055
Subordinated units issued in the merger	95,133,333	32,109	32,107	32,107	32,107	128,430
Preferred units convertible into common units	3,579,881	1,209	1,208	1,208	1,208	4,833
Preferred units convertible into subordinated units	4,688,839	1,584	1,582	1,582	1,582	6,330
Total	203,865,325	$68,806	$68,804	$68,804	$68,804	$275,218

	Year Ended December 31, 2014
	(unaudited) (in thousands, except per unit data)
Adjustments to reconcile to pro forma cash generated from operations:	
Less:	
Deferred revenue	(2,589)
Incremental general and administrative(6)	(1,475)
Cash interest expense(3)	(2,665)
Capital expenditures(7)	(101,110)
Pro forma cash generated from operations	277,866
Less:	
Cash paid to noncontrolling interests(8)	(294)
Preferred unit distributions(9)(10)	(15,720)
Pro forma cash generated from operations available for distribution on common and subordinated units and reinvestment in our business	261,852
Initial minimum quarterly distribution per common and subordinated unit	1.05
Aggregate distributions to:	
Common units issued in this offering	23,625
Common units issued or issuable as equity-based compensation	2,053
Common units issued in the merger	75,015
Subordinated units issued in the merger	98,254
Total distributions on common and subordinated units(10)	198,947
Excess(11)	$ 62,905

(1) Includes revenues from our mineral and royalty interests and working interests.

(2) The impairment primarily resulted from decreasing commodity prices and changes in projections based on the recent historical operating characteristics at the field level. For more information, please read the historical financial statements of BSMC included elsewhere in this prospectus.

(3) Interest expense includes cash expenses of commitment fees and agency fees and non-cash amortization of debt issuance costs. Cash interest expense does not include non-cash amortization of debt issuance costs.

(4) For more information, please read "Summary—Summary Historical and Pro Forma Financial Data—Non-GAAP Financial Measures."

(5) Represents compensation expense that is settled in common and subordinated units and would not reduce the amount of cash generated from operations.

(6) Reflects incremental general and administrative expenses that we expect to incur as a result of operating as a publicly traded partnership that are not reflected in our pro forma financial statements. Does not include expected nonrecurring expenses of approximately $1.4 million related to compliance with the Sarbanes-Oxley Act.

(7) Our capital expenditures during 2014 were funded with cash generated from our operations.

(8) Reflects cash distributions made to unaffiliated third-party limited partners in a consolidated, but not wholly owned, partnership. For additional information, please read Note 16 to the consolidated financial statements of BSMC included elsewhere in this prospectus.

(9) Reflects distributions paid on our preferred units assuming no optional conversion. For more information regarding conversion of the preferred units, please read "Description of Our Preferred Units—Conversion of the Preferred Units." If all outstanding preferred units had been converted to common and subordinated units at the beginning of the period, no preferred unit distributions would have been paid. Pro forma cash generated from operations available for distribution on common and subordinated units would have increased to $277.6 million for the year ended December 31, 2014 and total distributions on common and subordinated units would have increased by $11.6 million.

(10) Does not reflect the conversion of 35,589 preferred units into 1,190,148 common units and 1,558,826 subordinated units on January 1, 2015, which would eliminate $3.9 million in preferred unit distributions, increase the estimated quarterly distributions to common and subordinated units by $2.9 million for the same period, and increase the excess by $1.0 million.

(11) Assuming the underwriters' option to purchase additional common units to cover over-allotments is exercised in full, and all of our preferred units converted into 4,770,029 common and 6,247,665 subordinated units as of the year ended December 31, 2014, the excess for the year ended December 31, 2014 would have increased to $63.5 million.

If we do not distribute cash from operations in any quarter sufficient to pay the full applicable minimum quarterly distribution on all common units, then holders of the subordinated units will not be entitled to receive any distribution until the common units have received the applicable minimum quarterly distribution for such quarter plus any arrearages in the payment of the applicable minimum quarterly distribution from prior quarters. Subordinated units will not accrue arrearages.

The following table illustrates the excess in the amount of cash generated from operations available for distribution on common and subordinated units and reinvestment in our business on a pro forma basis for the year ended December 31, 2014 assuming (i) the minimum quarterly distribution per unit was $0.3375, which is the minimum quarterly distribution applicable after March 31, 2018 and (ii) all preferred units outstanding as of December 31, 2014 have converted into 4,770,029 common units and 6,247,665 subordinated units pursuant to their terms.

	Pro Forma Year Ended December 31, 2014
	(in thousands, except per unit data)
Pro forma cash generated from operations available for distribution on common and subordinated units and reinvestment in our business	$277,572
Minimum quarterly distribution per common and subordinated unit	1.35
Aggregate distributions to:	
Common units issued in this offering	30,375
Common units issued or issuable as equity-based compensation	2,639
Common units issued in the merger	98,055
Subordinated units issued in the merger	128,430
Preferred units convertible into common units	6,440
Preferred units convertible into subordinated units	8,434
Total distributions on common and subordinated units	274,373
Excess	$ 3,199

Based on the immediately preceding table and assuming the underwriters' option to purchase additional common units to cover over-allotments was exercised in full, we would have had a shortfall of $1.4 million, and we would have been able to pay 100% of the aggregate minimum quarterly distribution on all common units and 99.0% of the aggregate minimum quarterly distribution on all the subordinated units.

Based on our preliminary operating results and assuming the formation transactions occurred as of January 1, 2015, we believe that we will generate sufficient cash from operations to pay the aggregate initial minimum quarterly distributions on all common units and subordinated units outstanding at the completion of this offering for the three months ended March 31, 2015.

Estimated Cash Generated from Operations for the Twelve Months Ending March 31, 2016

For the twelve months ending March 31, 2016, we estimate that we will generate $241.6 million of cash from operations. In "—Assumptions and Considerations" below, we discuss the major assumptions underlying this estimate. The cash generated from operations discussed in the forecast should not be viewed as management's projection of the actual cash that we will generate during the twelve months ending March 31, 2016. We can give you no assurance that our assumptions will be realized or that we will generate any cash, in which event we will not be able to pay the full initial minimum quarterly cash distribution on all of our common and subordinated units during such period.

When considering our ability to generate cash and how we calculate forecasted cash generated from operations, please keep in mind all of the risk factors and other cautionary statements under the headings "Risk Factors" and "Forward-Looking Statements," which discuss factors that could cause our results of operations and cash generated from operations to vary significantly from our estimates.

The following table illustrates the amount of cash that we estimate that we will generate for the twelve months ending March 31, 2016 that would be available for distribution to our common and subordinated unitholders and reinvestment in our business.

Black Stone Minerals, L.P.
Estimated Cash Generated from Operations

	Twelve Months Ending March 31, 2016
	(unaudited) (in thousands, except per unit data)
Revenue:	
Oil and condensate sales	$145,272
Natural gas and natural gas liquids sales	125,644
Gain on commodity derivative instruments	33,587
Lease bonus and other income	40,200
Total revenue	344,703
Operating expense:	
Lease operating expense and other	21,058
Production and ad valorem taxes	24,377
Depreciation, depletion, and amortization	113,684
General and administrative	78,007
Accretion of asset retirement obligations	1,060
Total operating expense	238,186
Income from operations	106,517
Other expense:	
Interest expense	(4,119)
Total other expense	(4,119)
Net income	102,398
Adjustments to reconcile to Adjusted EBITDA:	
Add:	
Depreciation, depletion, and amortization	113,684
Interest expense	4,119
EBITDA(1)	220,201
Add:	
Accretion of asset retirement obligations	1,060
Equity-based compensation expense(2)	24,318
Adjusted EBITDA(1)	245,579
Adjustments to reconcile to estimated cash generated from operations:	
Add:	
Borrowings to fund future capital expenditures(3)	47,027
Less:	
Deferred revenue(4)	(863)
Cash interest expense	(3,143)
Capital expenditures	(47,027)
Estimated cash generated from operations	241,573
Less:	
Cash paid to noncontrolling interests(5)	(179)
Preferred unit distributions(6)(7)	(10,844)
Estimated cash generated from operations available for distribution on common and subordinated units and reinvestment in our business	230,550
Initial minimum quarterly distribution per common and subordinated unit	1.05
Estimated annual distributions to:	
Common units issued in this offering	23,625
Common units issued or issuable as equity-based compensation	2,053
Common units issued in the merger	76,265
Subordinated units issued in the merger	99,890
Preferred units to be converted into common units as of January 1, 2016(7)	313
Preferred units to be converted into subordinated units as of January 1, 2016(7)	410
Total distributions on common and subordinated units	202,556
Excess(8)	**$ 27,994**

(1) For more information, please read "Summary—Summary Historical and Pro Forma Financial Data—Non-GAAP Financial Measures."
(2) Represents compensation expense that is settled in common and subordinated units and would not impact estimated cash generated from operations.
(3) Assumes borrowings under our credit facility are incurred when the capital expenditures are made.
(4) Represents working-interest owners' recoupment of advance royalty payments, which results in a reduction of cash received from production revenues.
(5) Reflects cash distributions made to unaffiliated third-party limited partners in a consolidated, but not wholly owned, partnership. For additional information, please read Note 16 to the consolidated financial statements of BSMC included elsewhere in this prospectus.
(6) Reflects distributions paid on our preferred units assuming no optional conversion. For more information regarding conversion of the preferred units, please read "Description of Our Preferred Units—Conversion of the Preferred Units." If all outstanding preferred units had been converted to common and subordinated units at the beginning of the period, no preferred unit distributions would have been paid, estimated cash generated from operations available for distribution on common and subordinated units would have increased to $241.4 million, and total distributions on common and subordinated units would have increased by $8.0 million for the twelve months ending March 31, 2016.
(7) Reflects conversion of 35,684 preferred units into 1,193,294 common units and 1,562,946 subordinated units on January 1, 2016, which eliminates $1.0 million of preferred unit distributions for the quarter ending March 31, 2016, increases the estimated quarterly distributions to common and subordinated units by $0.7 million for the same period, and increases the excess by $0.3 million.
(8) Assuming the underwriters' option to purchase additional common units to cover over-allotments is exercised in full and all of our preferred units converted into 3,579,881 common and 4,688,839 subordinated units as of March 31, 2015, the excess for the twelve months ending March 31, 2016 would have decreased to $27.3 million. In addition, assuming the underwriters' option to purchase additional common units to cover over-allotments is not exercised and all of our preferred units converted into common and subordinated units as of March 31, 2015, the excess for the twelve months ending March 31, 2016 would have increased to $30.9 million.

If we do not distribute cash from operations in any quarter sufficient to pay the full applicable minimum quarterly distribution on all common units, then holders of the subordinated units will not be entitled to receive any distribution until the common units have received the applicable minimum quarterly distribution for such quarter plus any arrearages in the payment of the applicable minimum quarterly distribution from prior quarters. Subordinated units will not accrue arrearages.

The following table illustrates the shortfall in our estimated amount of cash generated from operations available for distribution on common and subordinated units and reinvestment in our business for the twelve months ending March 31, 2016 assuming (i) the minimum quarterly distribution per unit was $0.3375, which is the minimum quarterly distribution applicable after March 31, 2018 and (ii) all preferred units outstanding as of March 31, 2015 have converted into 3,579,881 common units and 4,688,839 subordinated units pursuant to their terms.

	Estimated Twelve Months Ending March 31, 2016
	(in thousands, except per unit data)
Estimated cash generated from operations available for distribution on common and subordinated units and reinvestment in our business	$241,394
Minimum quarterly distribution per common and subordinated unit	1.35
Aggregate distributions to:	
Common units issued in this offering	30,375
Common units issued or issuable as equity-based compensation	2,639
Common units issued in the merger	98,055
Subordinated units issued in the merger	128,430
Preferred units convertible into common units	4,833
Preferred units convertible into subordinated units	6,330
Total distributions on common and subordinated units	270,662
Shortfall	$ (29,268)

Based on the immediately preceding table and assuming the underwriters' option to purchase additional common units to cover over-allotments was exercised in full, we would have had a shortfall of $33.8 million, and we would have been able to pay 100% of the aggregate minimum quarterly distribution on all common units and 74.9% of the aggregate minimum quarterly distribution on all the subordinated units.

	Three Months Ending			
	March 31, 2016	December 31, 2015	September 30, 2015	June 30, 2015
	(unaudited) (in thousands)			
Adjustments to reconcile to estimated cash generated from operations:				
Add:				
Borrowings to fund future capital expenditures	11,313	11,336	11,712	12,666
Less:				
Deferred revenue	(266)	(259)	(258)	(80)
Cash interest expense	(718)	(638)	(606)	(1,181)
Capital expenditures	(11,313)	(11,336)	(11,712)	(12,666)
Estimated cash generated from operations	53,456	61,662	63,007	63,448
Less:				
Cash paid to noncontrolling interests(2)	(46)	(45)	(44)	(44)
Preferred unit distributions(3)	(1,956)	(2,974)	(2,974)	(2,940)
Estimated cash generated from operations available for distribution on common and subordinated units and reinvestment in our business	51,454	58,643	59,989	60,464
Initial minimum quarterly distribution per common and subordinated unit	0.2625	0.2625	0.2625	0.2625
Estimated quarterly distributions to:				
Common units issued in this offering	5,907	5,906	5,906	5,906
Common units issued or issuable as equity-based compensation	514	513	513	513
Common units issued in the merger	19,067	19,066	19,066	19,066
Subordinated units issued in the merger	24,974	24,972	24,972	24,972
Preferred units to be converted into common units as of January 1, 2016(3)	313	—	—	—
Preferred units to be converted into subordinated units as of January 1, 2016(3)	410	—	—	—
Total	51,185	50,457	50,457	50,457
Excess	$ 269	$ 8,186	$ 9,532	$ 10,007

(1) Lease bonus income can vary from quarter to quarter. Historically, lease bonus income has been higher in the third and fourth quarters relative to the first and second quarters.

(2) Reflects cash distributions made to unaffiliated third-party limited partners in a consolidated, but not wholly owned, partnership. For additional information, please read Note 16 to the consolidated financial statements of BSMC included elsewhere in this prospectus.

(3) Reflects conversion of 35,684 preferred units into 1,193,294 common units and 1,562,946 subordinated units on January 1, 2016, which eliminates $1.0 million of preferred unit distributions for the quarter ending March 31, 2016, increases the estimated quarterly distributions to common and subordinated units by $0.7 million for the same period, and increases the excess by $0.3 million.

Cash Flows

The following table shows our cash flows for the periods presented (in thousands):

	Year Ended December 31, 2014	Year Ended December 31, 2013
Cash flows provided by operating activities	$ 396,125	$ 320,764
Cash flows used in investing activities	$(101,110)	$(195,631)
Cash flows used in financing activities	$(310,335)	$(142,311)

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

Operating Activities. Our operating cash flow is dependent, in large part, on our production, realized commodity prices, leasing revenues, and operating expenses. For the year ended December 31, 2014, cash flows from operating activities increased by $75.4 million as compared to the same period in 2013 due to increased realized natural gas prices, higher oil and condensate volumes, and higher lease bonus revenue.

Investing Activities. The net cash used in investing activities decreased by $94.5 million in 2014 as compared to 2013 primarily due to reduced capital spent on acquisitions and lower capital expenditures under our working-interest participation program. For the year ended December 31, 2014, our cash expenditures for acquisitions totaled $45.6 million versus $121.6 million for the same period in 2013. Capital expenditures for our working interests, net of sale proceeds, decreased by $13.4 million for the year ended December 31, 2014 versus the comparable period of 2013.

Financing Activities. For the year ended December 31, 2014, the net cash used in financing activities increased $168.0 million compared to the same period in 2013. During 2014, we made distributions to common equity owners of $224.9 million, dividends on preferred units of $15.7 million, $57.0 million of credit facility repayments, and common equity repurchases of $5.2 million, and we paid $7.6 million of consulting and other costs directly related to our initial public offering. During 2013, we received $191.6 million in equity contributions as a result of our exchange offer and borrowed $134.0 million under our credit facility. These activities were partially offset by distributions to common equity owners of $225.7 million, dividends on preferred units of $15.7 million, common equity repurchases of $118.1 million, repayments under our credit facility of $46.1 million, and purchases of noncontrolling interests of $60.7 million. Please read the notes to the historical consolidated financial statements of BSMC included elsewhere in this prospectus for additional information regarding the exchange and equity offering.

Capital Expenditures

During 2014, we spent approximately $45.6 million on three cash acquisitions and completed another acquisition for $2.3 million with an issuance of equity securities. In 2014, we spent approximately $67.7 million on drilling and completion costs. Our 2015 capital budget for drilling expenditures is approximately $40.1 million. Approximately 65% and 14% of our drilling capital budget will be spent in the Haynesville/Bossier and Bakken/Three Forks plays, respectively, with the remainder spent in various plays including the Wilcox and Granite Wash plays.

Credit Facility

As of January 23, 2015, we amended and restated our $1.0 billion senior secured revolving credit agreement. Under this third amended and restated credit facility, the commitment of the lenders equals the lesser of the aggregate maximum credit amounts of the lenders and the borrowing base (which is determined based on the value of our oil and natural gas properties). As of March 31, 2015, we had outstanding borrowings of $389.0 million. As a result of the steep decline in oil and natural gas prices in the second half of 2014, our borrowing base was decreased by the lenders under our credit facility in April 2015 to $600.0 million. We do not believe the decrease in our borrowing base

Off-Balance Sheet Arrangements

At December 31, 2014, we did not have any material off-balance sheet arrangements.

Critical Accounting Policies and Related Estimates

The discussion and analysis of our financial condition and results of operations are based upon the historical financial statements of BSMC, which have been prepared in accordance with GAAP. Certain of our accounting policies involve judgments and uncertainties to such an extent that there is a reasonable likelihood that materially different amounts would have been reported under different conditions, or if different assumptions had been used. The following discussions of critical accounting estimates, including any related discussion of contingencies, address all important accounting areas where the nature of accounting estimates or assumptions could be material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change. Below, we have provided expanded discussion of our more significant accounting estimates.

Please read the notes to the historical consolidated financial statements of BSMC included elsewhere in this prospectus for additional information regarding our accounting policies.

Successful Efforts Method of Accounting

We use the successful efforts method of accounting for oil and natural gas operations. Under this method, costs to acquire interests in oil and natural gas properties are capitalized. The cost of property acquisitions, successful exploratory wells, development costs, and support equipment and facilities are initially capitalized when incurred. DD&A of producing oil and natural gas properties is recorded based on a units-of-production methodology. Acquisition costs of proved properties are amortized on the basis of all proved reserves, developed and undeveloped, and capitalized development costs are amortized on the basis of proved developed reserves. Proved reserves are quantities of oil and natural gas that can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, under existing economic conditions, operating methods, and government regulations. A sustained low price environment could decrease our estimate of proved reserves, which would increase the rate at which we record depletion expense and reduce net income. Additionally, a decline in proved reserve estimates may impact the outcome of our assessment of producing properties for impairment. The recent decline in oil and natural gas prices increases the uncertainty as to the impact of commodity prices on our estimated proved reserves. We are unable to predict future commodity prices with any greater precision than the futures market. The impact of commodity prices can be illustrated as follows. If we used the NYMEX forward strip prices as of December 31, 2014 to determine our proved reserves, our estimated proved reserves as of December 31, 2014 on a Boe basis would have declined by approximately 1%. If we assume that the spot prices as of April 1, 2015 were held constant, our estimated proved reserves as of December 31, 2014 on a Boe basis would have declined by approximately 13%.

Other exploratory costs, including annual delay rentals and geological and geophysical costs, are expensed when incurred. Mineral and royalty interests and working interests are recorded at cost at the time of acquisition. Upon sale or retirement of depreciable or depletable property, the cost and related accumulated DD&A are eliminated from the accounts and the resulting gain or loss is recognized.

The costs of unproved leaseholds and mineral interests are capitalized as unproved properties pending the results of exploration efforts. As unproved leaseholds are determined to be producing, the related costs are transferred to producing properties. The remaining net book values associated with unproved leaseholds that have expired are charged to exploration expense. Non-producing property costs are assessed periodically, on a property-by-property basis, and a loss is recognized to the extent, if any, the recorded value has been impaired. Any impairment will generally be based on geographic or geologic data.

Mineral interests are recorded at cost at the time of acquisition. Mineral interests are assessed for impairment annually via comparison to third-party valuation information and a loss is recognized to the extent fair value is below the recorded value.

We evaluate impairment of producing properties in accordance with Accounting Standards Codification ("ASC") 360 *Property, Plant, and Equipment*. This standard requires that long-lived assets that are held and used by an entity be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. We estimate the undiscounted future cash flows expected in connection with the properties and compare such undiscounted future cash flows to the carrying amount of the terms that are designed to encourage more exploration. Through our control of large blocks of contiguous acreage throughout the country, we provide exploration and production companies with an extensive acreage inventory from which to generate prospects and search for new opportunities. In addition, our in-house geological and geophysical team uses our extensive seismic library to assist exploration and production companies in the identification of emerging plays and potential drilling locations. In this prospectus, we define identified potential drilling locations as locations specifically identified by management based on evaluation of applicable geologic and engineering data accrued over our multi-year historical drilling activities. When leasing acreage, we consider the potential lessee's operational track record to ensure that we maximize the pace of development. Our leases often contain provisions which provide us the option to participate on a working-interest (cost-bearing) basis in the operators' third-party drilling programs. Typically, this option is structured to allow us to elect to participate after the operator has demonstrated repeatable attractive economics, thereby allowing us to increase our exposure to a play after the risks of failure or poor returns have been substantially reduced.

- ***Acquire additional mineral and royalty interests in oil and natural gas properties that meet our acquisition criteria.*** We intend to continue to acquire mineral and royalty interests that have substantial resource and cost-free, or organic, growth potential. Our management team has a long history of evaluating, pursuing, and consummating acquisitions of oil and natural gas mineral and royalty interests in the United States. We believe that our large network of industry relationships provides us with a competitive advantage in pursuing potential acquisition opportunities. Since 1992, we have invested approximately $1.6 billion in 42 acquisitions. In the future, we expect to focus on relatively large acquisitions but will also continue to pursue smaller mineral packages to complement an existing position or to establish a foothold in an emerging play. We prefer acquisitions that meet the following criteria:
  - sufficient current production to create near-term accretion for our unitholders;
  - geologic support for future production and reserve growth;
  - a geographic footprint that we believe is complementary to our diverse portfolio and maximizes our potential for upside reserve and production growth from undiscovered reserves or new plays; and
  - targeted positions in high-growth resource and conventional plays.
- ***Participate in low-risk drilling opportunities in plays that generate attractive returns.*** Our ownership of mineral interests affords us the favorable position of negotiating leases that frequently provide us a unit-by-unit or well-by-well option to participate on a working-interest basis in economic, low-risk drilling opportunities. This participation program offers access to drilling opportunities in established producing trends at well-level economics, often unburdened by traditional land and exploration costs associated with acquiring prospective acreage, such as paying lease bonus, acquiring seismic data, and drilling exploratory and delineation wells. We expect to continue to actively participate in these drilling opportunities.
- ***Maintain a conservative capital structure and prudently manage the business for the long term.*** We are committed to maintaining a conservative capital structure that will afford us the financial flexibility to execute our business strategies on an ongoing basis. Upon completion of this offering, we will have no outstanding indebtedness. We believe that proceeds from this offering, internally generated cash from operations, our $600.0 million borrowing base under our credit facility, and access to the public capital markets will provide us with sufficient liquidity and financial flexibility to grow our production, reserves, and cash generated from operations through the continued development of our existing assets and accretive acquisitions of mineral and royalty interests.

plays, which is projected to grow from 9.7 trillion cubic feet in 2012 to 19.8 trillion cubic feet in 2040. We have significant exposure to domestic natural gas resource plays, including the Haynesville/Bossier plays, the Fayetteville Shale, and the Barnett Shale, and we believe that these assets will provide meaningful upside in production and revenue growth as demand for natural gas increases. Our natural gas assets throughout the U.S. Gulf Coast are well positioned geographically to take advantage of the growing liquefied natural gas export market.

- ***Financial flexibility to fund expansion.*** Upon the completion of this offering and the application of the net proceeds as set forth under "Use of Proceeds," we expect to have no indebtedness outstanding, approximately $13.6 million of cash on hand, and $600.0 million of undrawn borrowing capacity under our credit facility. The credit facility, combined with internally generated cash from operations and access to the public capital markets, will provide us with the financial capacity and flexibility to grow our business.

- ***Experienced and proven management team.*** The members of our executive team have an average of over 25 years of industry experience and have a proven track record of executing accretive acquisitions and maximizing asset development. We expect to benefit from the longstanding relationships fostered by our management team within the industry and the decades-long track record of successful acquisitions of mineral and royalty interests. We believe the experience of our management team in acquiring and managing mineral and royalty interests will allow us to continue to grow our production, reserves, and distributions.

Our Properties

Material Basins and Producing Regions

The following is an overview of the U.S. basins and regions we consider most material to our current and future business.

- ***Louisiana-Mississippi Salt Basins***. The Louisiana-Mississippi Salt Basins region ranges from northern Louisiana and southern Arkansas through south central and southern Mississippi, southern Alabama, and the Florida Panhandle. The Haynesville/Bossier plays, which have been extensively delineated through drilling, are the most prospective unconventional plays for natural gas production and reserves within this region. Approximately half of the Haynesville/Bossier plays' prospective acreage is within the Louisiana-Mississippi Salt Basins region, where we own significant mineral and royalty interests and working interests. The Tuscaloosa Marine Shale play is the region's most significant emerging unconventional oil play, extending through southwestern Mississippi and southeastern Louisiana on the eastern end of the play and westward across central Louisiana to the Texas border. The play is in the early stage of development and has been actively drilled and tested recently by several operators. We have a significant mineral-and-royalty-interest position across the entire region, with material exposure to the Tuscaloosa Marine Shale. There are a number of additional active conventional and unconventional plays in the basins in which we hold considerable mineral and royalty interests, including the Brown Dense, Cotton Valley, Hosston, Norphlet, Smackover, and Wilcox plays.

- ***Western Gulf (onshore)***. The Western Gulf region, which ranges from South Texas through southeastern Louisiana, includes a variety of both conventional and unconventional plays. We have extensive exposure to the Eagle Ford Shale in South Texas, where we are experiencing a significant level of development drilling on our mineral interests within the oil and rich-gas condensate areas of the play. We also have significant exposure to the Tuscaloosa Marine Shale in central and southeastern Louisiana, which is one of the most prospective emerging oil shale plays in the region and has been actively drilled and tested recently by several operators in the Western Gulf region. In addition to the Eagle Ford Shale and Tuscaloosa Marine Shale plays, there are a number of other active conventional and unconventional plays to which we have exposure to in the region, including the Austin Chalk, Buda, Eaglebine (or Maness) Shale, Frio, Glenrose, Olmos, Woodbine, Vicksburg, Wilcox, and Yegua plays.

Severance Agreements

Following the closing of this offering, our general partner intends to cause one of our affiliates to enter into a severance agreement with each of our executive officers that, among other things, will provide for the payment of cash severance payments and benefits in the event the executive officer's employment is terminated under certain circumstances. The description of the severance agreements set forth below is a summary of the material anticipated features of the severance agreements. This summary, however, does not purport to be a complete description of all of the anticipated provisions of the severance agreements and is qualified in its entirety by reference to the severance agreements, the forms of which are filed as exhibits to this registration statement.

We anticipate that the severance agreements will provide that if the applicable executive officer's employment is terminated without "cause" or the executive officer resigns for "good reason," then so long as the officer executes (and does not revoke within any time provided to do so) a release in a form satisfactory to the officer's employer within the applicable time period specified in the severance agreement, the officer will receive the following severance payments and benefits: (a) a lump sum cash severance payment equal to the sum of: (i) an amount equal to 1.0 (or, in the case of Mr. Carter, 2.0) times the sum of the executive officer's annualized base salary and target annual bonus as in effect on the date of such termination (or, if such termination occurs within 24 months following a "change in control," an amount equal to 2.0 (or, in the case of Mr. Carter, 3.0) times the sum of the executive officer's annualized base salary and target annual bonus as in effect on the date of such termination); (ii) a pro-rated portion of the executive officer's target bonus for the calendar year that includes the date of such termination; and (iii) any earned but unpaid bonus for the calendar year preceding the calendar year that includes the date of such termination; and (b) monthly cash reimbursement for the amount the executive officer pays for continuation coverage under our affiliates' group health plans for up to 12 months following such termination (or, if such termination occurs within 24 months following a change in control, for up to 24 months following such termination).

Under the severance agreements, "cause" is expected to generally mean a determination by two-thirds of the board of directors of our general partner that the applicable executive officer has: (a) willfully and continually failed to substantially perform the officer's duties; (b) willfully engaged in conduct that is demonstrably and materially injurious to us or any of our affiliates; (c) been convicted of, or has plead guilty or nolo contendere to, a misdemeanor involving moral turpitude or a felony; (d) committed an act of fraud, or material embezzlement or material theft; or (e) materially breached any of the officer's obligations under the severance agreement or any other written agreement entered into between the officer and us or any of our affiliates. In addition, we anticipate that "good reason" will generally be defined as the occurrence of any of the following events without the applicable executive officer's written consent: (i) a reduction in the officer's total compensation other than a general reduction in compensation that affects all similarly situated employees in substantially the same proportions; (ii) a relocation of the officer's principal place of employment by more than 50 miles; (iii) a material breach by us or any of our affiliates of the severance agreement or any other written agreement with the officer; (iv) a material, adverse change in the officer's title, authority, duties or responsibilities; (v) a material adverse change in the reporting structure applicable to the officer; (vi) following a change in control, the failure to continue (or the taking of any action that adversely affects the officer's participation in) any benefit plan or compensation arrangement in which the officer was participating immediately prior to such change in control; or (vii) in the case of Mr. Carter, our general partner's failure to nominate Mr. Carter for election to the board of directors of our general partner and to use its best efforts to have Mr. Carter elected and re-elected, as applicable. We expect that a "change in control" will generally mean (1) the acquisition of beneficial ownership of more than 50% of our common units and subordinated units; (2) the complete liquidation of the partnership; (3) the sale of all or substantially all of our assets to any person other than one of our affiliates; (4) the occurrence of a transaction resulting in our general partner or one of its affiliates ceasing to be the sole general partner of the partnership; (5) the failure of the individuals who constitute the "incumbent board" of our general partner to constitute at least a majority of the board; or (6) the occurrence of a transaction resulting in the partnership ceasing to own, directly or indirectly, 100% of the outstanding equity interests of our general partner.

We expect that the severance agreements will also contain certain restrictive covenants pursuant to which our executive officers will recognize an obligation to comply with, among other things, certain confidentiality covenants as well as covenants not to compete in a defined market area with us or any of our affiliates or solicit any of our affiliates' employees, in each case, during the term of the agreement and for a period of one year (or, in the case of Mr. Carter, two years) thereafter.

Please read "Management—Executive Officers and Directors of Our General Partner" for information regarding the individuals who will be serving as the executive officers of our general partner upon the consummation of this offering.

Long-Term Incentive Plan

Prior to the closing of this offering, our general partner intends to adopt the LTIP, pursuant to which non-employee directors of our general partner and certain employees and consultants of our general partner and our affiliates will be eligible to receive awards with respect to our common or subordinated units. As described above, in connection with this offering, the outstanding restricted common units in our predecessor will be exchanged for restricted common units and restricted subordinated units under the LTIP. Following the closing of this offering, our general partner currently intends to grant new awards under the LTIP only with respect to our common units. The description of the LTIP set forth below is a summary of the material anticipated features of the LTIP. This summary, however, does not purport to be a complete description of all of the anticipated provisions of the LTIP and is qualified in its entirety by reference to the LTIP, the form of which is filed as an exhibit to this registration statement.

The LTIP will provide for the grant, from time to time, at the discretion of the board of directors of our general partner or a committee thereof, of unit options, unit appreciation rights, restricted units, phantom units, unit awards, distribution equivalent rights ("DERs"), cash awards, and other unit-based awards. Subject to adjustment in the event of certain transactions or changes in capitalization, an aggregate of 15,221,333 units may be delivered pursuant to awards under the LTIP. Units subject to awards that are forfeited, cancelled, exercised, paid, or otherwise terminated without the delivery of units, and units held back to cover the exercise price or tax withholding applicable to an award, will be available for delivery pursuant to other awards under the LTIP. Under the LTIP, the maximum aggregate grant date fair value of awards granted to a non-employee director of our general partner during any calendar year will not exceed $500,000 (or $600,000 in the first year in which an individual becomes a non-employee director). The LTIP will be administered by the board of directors of our general partner or a committee thereof, either of which we refer to herein as the "committee." The LTIP will be designed to promote our interests, as well as the interests of our unitholders and to encourage superior performance, by rewarding the directors of our general partner and employees and consultants of our general partner and our affiliates, as well as by strengthening our general partner's and our affiliates' abilities to attract, retain, and motivate individuals who are essential for our growth and profitability.

Unit Options and Unit Appreciation Rights

The LTIP will permit the grant of unit options and unit appreciation rights covering common or subordinated units. Unit options represent the right to purchase a number of common or subordinated units at a specified exercise price. Unit appreciation rights represent the right to receive the appreciation in the value of a number of common or subordinated units as of the exercise date over a specified exercise price, either in cash, common or subordinated units, or a combination thereof, as determined in the discretion of the committee. Unit options and unit appreciation rights may be granted to such eligible individuals and with such terms as the committee may determine, consistent with the terms of the LTIP; however, the exercise price of a unit option or unit appreciation right may not be less than the fair market value of a common or subordinated unit on the date such unit option or unit appreciation right is granted.

Restricted Units and Phantom Units

The LTIP will also permit the grant of restricted units and phantom units. A restricted unit is a common or subordinated unit that is subject to forfeiture. Upon vesting, the forfeiture restrictions lapse and the participant holds a common or subordinated unit that is not subject to forfeiture. A phantom unit is a notional unit that

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table presents information regarding the beneficial ownership of our common and subordinated units following this offering and the other formation transactions by:

- our general partner;
- each of our general partner's directors and named executive officers;
- each unitholder known by us to beneficially hold 5% or more of our common units, on an as-converted basis; and
- all of our general partner's directors and executive officers as a group.

Beneficial ownership is determined under the rules of the SEC and generally includes voting or investment power with respect to securities. Unless otherwise noted, the address for each beneficial owner listed below is 1001 Fannin Street, Suite 2020, Houston, Texas 77002.

The following table does not include any units that may be purchased pursuant to our directed unit program. Please read "Underwriting—Directed Unit Program."

Name of Beneficial Owner	Common Units Beneficially Owned(1)	Percentage of Common Units Beneficially Owned(1)	Subordinated Units Beneficially Owned(1)	Percentage of Subordinated Units Beneficially Owned(1)	Percentage of Common and Subordinated Units Beneficially Owned(1)
Black Stone Minerals G.P., L.L.C.(2)	—	—	—	—	—
Camden Energy Limited Partnership(3)	8,118,065	8.1%	10,632,841	10.7%	9.4%
Thomas L. Carter, Jr.(3)(4)(5)	8,676,679	8.6%	11,364,502	11.4%	10.0%
Marc Carroll(5)(6)	161,474	*	211,496	*	*
Holbrook F. Dorn(5)(7)	147,604	*	193,330	*	*
William G. Bardel(8)	118,233	*	148,311	*	*
Carin M. Barth(8)	5,000	*	—	—	*
D. Mark DeWalch(8)(9)	77,761	*	95,309	*	*
Ricky J. Haeflinger(8)(10)	2,987,973	3.0%	3,907,028	3.9%	3.4%
Jerry V. Kyle, Jr.(8)(11)	317,406	*	409,187	*	*
Michael C. Linn(8)	33,445	*	37,258	*	*
John H. Longmaid(8)(12)	1,380,736	1.4%	1,801,906	1.8%	1.6%
William N. Mathis(8)(13)	1,855,370	1.8%	2,423,576	2.4%	2.1%
Richard N. Papert(8)	250,781	*	321,925	*	*
Robert E.W. Sinclair(8)(14)	1,706,620	1.7%	2,228,747	2.2%	2.0%
Alexander D. Stuart(8)(15)	4,077,124	4.1%	5,333,579	5.3%	4.7%
Allison K. Thacker(8)(16)	2,350,872	2.3%	3,072,569	3.1%	2.7%
Directors and executive officers as a group (18 people)	26,168,143	26.0%	31,713,923	31.8%	28.9%

* Less than 1%

(1) Reflects conversion of our preferred units. Preferred units may be converted at the conversion rate of 30.3431 common units and 39.7427 subordinated units per preferred unit at any time subsequent to the consummation of this offering and are mandatorily convertible in annual tranches from January 1, 2016 to January 1, 2018. Upon the consummation of this offering, our 117,980 preferred units will represent 3.6% of our common units and 4.7% of our subordinated units outstanding on an as-converted basis. Except with respect to certain matters requiring the approval of the holders of preferred units, each preferred unit is entitled to vote as a single class with the common and subordinated units on an as-converted basis. For a detailed discussion of our preferred units, please read "Description of Our Preferred Units." Percentages also include 60,000 units expected to be issued to the non-employee directors after the offering as director compensation and an aggregate of 1,894,939 units expected to be issued as restricted common units and common-unit-settled performance units to management after the offering.

(2) Black Stone Minerals G.P., L.L.C., our general partner, owns 733,670 common units and 960,943 subordinated units; these units are not included in the beneficial ownership table or in total units outstanding because this entity is a wholly owned subsidiary of the Partnership.
(3) Camden Energy Limited Partnership is a family partnership, of which our Chairman, Chief Executive Officer, and President, Thomas L. Carter, Jr., serves as the general partner.
(4) Includes all units held by Camden Energy Limited Partnership, described above, over which Mr. Carter has sole voting power. Mr. Carter also has sole voting and investment power over 91,029 common units and 119,229 subordinated units held by Preference Partners LP, whose general partner he controls. He shares voting control and investment power over an aggregate of 257,974 common units and 337,888 subordinated units owned by a nonprofit institution on whose board he serves, and he disclaims beneficial ownership of those units. Mr. Carter's ownership also includes 112,439 unvested restricted common units and 147,270 unvested restricted subordinated units previously issued as equity-based compensation.
(5) Does not include an aggregate of 1,894,939 units expected to be issued to our management team immediately after the offering and that are subject to performance and time vesting.
(6) Includes 51,136 unvested restricted common units and 66,978 unvested restricted subordinated units previously issued as equity-based compensation.
(7) Includes 46,920 unvested restricted common units and 61,456 unvested restricted subordinated units previously issued as equity-based compensation.
(8) Includes 5,000 common units expected to be issued immediately after the offering to each non-employee director as director compensation.
(9) Mr. DeWalch has shared voting and investment power over 15,350 common units and 20,109 subordinated units held by a trust, of which he serves as co-trustee.
(10) Mr. Haeflinger has shared voting and investment power over an aggregate of 2,987,973 common units and 3,907,028 subordinated units owned by Mayo Clinic and Mayo Clinic Master Retirement Trust.
(11) Mr. Kyle has shared voting and investment power over an aggregate of 259,881 common units and 340,389 subordinated units held by two trusts, of which he serves as co-trustee and beneficiary.
(12) Mr. Longmaid has sole voting and investment power over 1,027,084 common units and 1,338,701 subordinated units held in a trust of which he is the trustee and shares investment and voting power over 353,652 common units and 463,205 subordinated units held in a trust of which he is a beneficiary.
(13) Mr. Mathis has sole voting and investment power over an aggregate of 1,637,346 common units and 2,144,561 subordinated units held by WM Capital Partners, L.P., Conti Street Partners, L.P., and Conti Street Minerals, L.P. He has shared voting and investment power of aggregate of 189,117 common units and 247,701 subordinated units held by the estate of a family member, of which he serves as co-executor.
(14) Mr. Sinclair has sole voting and investment power over of an aggregate of 1,677,713 common units and 2,197,433 subordinated units owned by Caddis Minerals, Ltd., Castleton Energy Fund I, Ltd., Leone, Ltd., Shiprock Minerals, Ltd., and San Miguel River Partners.
(15) Mr. Stuart has sole voting and investment power over an aggregate of 3,619,946 common units and 4,741,322 subordinated units owned by North Star Oil & Gas, Topsfield Energy, Ltd., and RDS Investments, L.P. He also shares voting and investment power over 123,779 common units and 162,125 subordinated units owned by a trust, of which he serves as co-trustee and which are pledged to a bank as collateral for a loan to the trust.
(16) Ms. Thacker has shared voting and investment power over 2,337,173 common units and 3,061,173 subordinated units held by William Marsh Rice University. Ms. Thacker serves as Chief Investment Officer of an affiliate of that entity.

BLACK STONE MINERALS, L.P.
UNAUDITED PRO FORMA CONSOLIDATED STATEMENT OF OPERATIONS
For the Year Ended December 31, 2014
(in thousands, except per unit amounts)

	Predecessor Historical	Pro Forma Adjustments	Pro Forma
REVENUE			
Oil and condensate sales	$ 257,390	$ —	$ 257,390
Natural gas and natural gas liquids sales	207,456	—	207,456
Gain on commodity derivative instruments	37,336	—	37,336
Lease bonus and other income	46,139	—	46,139
TOTAL REVENUE	548,321	—	548,321
OPERATING EXPENSE			
Lease operating expense and other	23,288	—	23,288
Production and ad valorem taxes	49,575	—	49,575
Depreciation, depletion, and amortization	111,962	—	111,962
Impairment of oil and natural gas properties	117,930	—	117,930
General and administrative	62,765	—	62,765
Accretion of asset retirement obligations	1,060	—	1,060
Loss on disposal of assets	32	—	32
TOTAL OPERATING EXPENSE	366,612	—	366,612
INCOME FROM OPERATIONS	181,709	—	181,709
OTHER INCOME (EXPENSE)			
Interest and investment income	28	—	28
Interest expense	(13,509)	9,879(e)(f)	(3,630)
Other income	959	—	959
TOTAL OTHER EXPENSE	(12,522)	9,879	(2,643)
NET INCOME	169,187	9,879	179,066
LESS: NET LOSS ATTRIBUTABLE TO NONCONTROLLING INTERESTS	1,164	—	1,164
NET INCOME ATTRIBUTABLE TO BLACK STONE MINERALS, L.P.	170,351	9,879	180,230
LESS: DIVIDENDS ON PREFERRED UNITS	(15,720)	—	(15,720)
NET INCOME ATTRIBUTABLE TO GENERAL PARTNER	—	—	—
NET INCOME ATTRIBUTABLE TO LIMITED PARTNER UNITS			
Common units	$ 154,631	$ (72,184)(g)	$ 82,447
Subordinated units	—	82,063(g)	82,063
EARNINGS PER UNIT (BASIC AND DILUTED)			
Common units	$ 0.07	$ 0.81	$ 0.88
Subordinated units	—	0.88	0.88
WEIGHTED AVERAGE UNITS OUTSTANDING (BASIC AND DILUTED)			
Common units	2,129,812	(2,036,089)(g)	93,723
Subordinated units	—	93,286(g)	93,286

The accompanying notes to unaudited pro forma consolidated financial statements are an integral part of these financial statements.

BLACK STONE MINERALS, L.P.
NOTES TO UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Basis of Presentation

The unaudited pro forma consolidated balance sheet of the Partnership as of December 31, 2014, and the related unaudited pro forma consolidated statement of operations for the year ended December 31, 2014 are derived from the historical consolidated financial statements of the Predecessor.

Upon completion of this offering, the Partnership anticipates incurring incremental general and administrative expenses of approximately $1.5 million as a result of being a publicly traded partnership, consisting of costs associated with SEC reporting requirements, including annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, Sarbanes-Oxley Act compliance, NYSE listing, independent registered public accounting firm fees, legal fees, investor-relations activities, registrar and transfer agent fees, director-and-officer insurance, and additional compensation. The unaudited pro forma financial statements do not reflect these incremental general and administrative expenses.

The unaudited pro forma adjustments included herein assume no exercise of the underwriters' option to purchase additional common units. Any net proceeds received from the exercise of this option will be used to fund future capital expenditures.

Note 2—Unaudited Pro Forma Adjustments and Assumptions

A summary of the unaudited pro forma adjustments to effect the transactions is as follows:

(a) Reflects the issuance and sale of common units by the Partnership at an assumed initial public offering price of $20.00 per common unit, net of an underwriting discount, structuring fee and offering expenses of $28.1 million, and the receipt of the estimated net proceeds therefrom.

(b) Reflects the use of the net proceeds from the Offering to repay all of the debt outstanding under the credit facility with any remaining net proceeds reflected as an addition to cash.

(c) Reflects the elimination of capitalized payments incurred related to the Partnership's planned initial public offering. These capitalized payments will be netted against proceeds received.

(d) Reflects adjustments to capital balances and units outstanding as a result of the issuance of common units in the Offering and common and subordinated units to existing unitholders of the Predecessor at a ratio of 0.4329 common units and 0.5671 subordinated units of the Partnership for 12.9465 common units of the Predecessor as part of the formation transactions. The adjustment of $45.4 million to partners' equity attributable to common units comprises the contribution of $414.3 million related to the issuance of common units in the Offering, net of underwriting discounts, structuring fees, and offering expenses, and a reduction of $368.9 million related to the conversion of 56.71% of Predecessor equity into subordinated units. Common units outstanding as of December 31, 2014 reflect both the aforementioned conversion of Predecessor units into common and subordinated units of the Partnership and the issuance and sale of 22,500,000 common units in the Offering.

(e) Reflects the elimination of interest expense after repayment of all of the debt outstanding under the credit facility discussed in (b) above.

(f) Reflects the commitment fee related to the credit facility of 0.375% on the $700.0 million borrowing base as well as the agency fees and amortization of debt issuance costs related to the credit facility.

(g) Reflects adjustments to net income allocations and weighted-average units outstanding as a result of the issuance of common units in the Offering and common and subordinated units to existing unitholders of the Predecessor in the merger at a ratio of 0.4329 common units and 0.5671 subordinated units of the Partnership for 12.9465 common units of the Predecessor. The aforementioned conversion results in weighted-average units outstanding of 22,500,000 common units issued in the Offering, 71,223,025 common units issued in the merger, and 93,286,147 subordinated units issued in the merger. Pro forma net income attributable to limited partner units of $164.5 million was allocated $19.8 million to common units in the Offering, $62.6 million to common units in the merger, and $82.1 million to subordinated units in the merger. If the outstanding preferred units were converted to common units, their effect would be anti-dilutive; therefore, the preferred units are not included in the pro forma dilutive EPU calculation.

Note 3—Unaudited Pro Forma Net Income Per Unit

Pro forma net income per unit is determined by dividing the pro forma net income available to common and subordinated unitholders by the weighted-average common units expected to be issued in the Offering and common and subordinated units to be issued to the limited partners of BSMC prior to the Offering. All units from the Offering were assumed to have been outstanding since the beginning of the period presented. The outstanding preferred units would not have been eligible to participate in earnings beyond their quarterly preferred distribution.