Spark Energy, Inc.
Form 10-K
March 27, 2015

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2014,
OR
o 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: 001-36559
Spark Energy, Inc.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)		46-5453215 (I.R.S. Employer Identification No.)
2105 CityWest Blvd., Suite 100 Houston, Texas 77042	(Address and zip code of principal executive offices)	(713) 600-2600 (Registrant's telephone number, including area code)
Title of each class		Name of exchange on which registered
Class A common stock, par value $0.01 per share		The NASDAQ Global Select Market

Securities registered pursuant to Section 12(g) of the Act: none

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act
Yes o No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 of 15(d) of the Act.
Yes o No x

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 o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, 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 o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

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 o Accelerated filer o

Non-accelerated filer x (Do not check if a smaller reporting company) Smaller reporting company o

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

On July 29, 2014, the registrant’s Class A common stock began trading on the NASDAQ Global Select Market under the symbol “SPKE”. Accordingly, as of June 30, 2014 (the date of the registrant’s most recently completed second fiscal quarter), the registrant’s Class A common stock was not listed on an exchange and, therefore, the aggregate market value of the registrant’s Class A common stock held by non-affiliates cannot be reasonably determined.

There were 3,000,000 shares of Class A common stock and 10,750,000 shares of Class B common stock outstanding as of March 24, 2015.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement in connection with the 2015 Annual Meeting of Stockholders are incorporated by reference into Part III of this Form 10-K.

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Glossary

CFTC. The Commodity Futures Trading Commission.

ERCOT. The Electric Reliability Council of Texas, the independent system operator and the regional coordinator of various electricity systems within Texas.

FCM. Futures Commission Merchant, an individual or organization which does both of the following: a) solicits or accepts orders to buy or sell futures contracts, options on futures, retail off-exchange contracts or swaps and b) accepts money or other assets from customers to support such orders.

FERC. The Federal Energy Regulatory Commission, a regulatory body which regulates, among other things, the distribution and marketing of electricity and the transportation by interstate pipelines of natural gas in the United States.

ISO. An independent system operator. An ISO is similar to an RTO in that it manages and controls transmission infrastructure in a particular region.

MMBtu. One million British Thermal Units, a standard unit of heating equivalent measure for natural gas. A unit of heat equal to 1,000,000 Btus, or 1 MMBtu, is the thermal equivalent of approximately 1,000 cubic feet of natural gas.

MWh. One megawatt hour, a unit of electricity equal to 1,000 kilowatt hours (kWh), or the amount of energy equal to one megawatt of constant power expended for one hour of time.

Non-POR Market. A non-purchase of accounts receivable market.

POR Market. A purchase of accounts receivable market.

REP. A retail electricity provider.

RCE. A residential customer equivalent, refers to a natural gas customer with a standard consumption of 100 MMBtus per year or an electricity customer with a standard consumption of 10 MWHs per year.

RTO. A regional transmission organization. A RTO is a third party entity that manages transmission infrastructure in a particular region.

Cautionary Notice Regarding Forward Looking Statements

This report contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. These statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act") and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act") can be identified by the use of forward-looking terminology including "may," "should," "likely," "will," "believe," "expe "anticipate," "estimate," "continue," "plan," "intend," "projects," or other similar words. All statements, other than statements historical fact included in this report, regarding strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans, objectives and beliefs of management are forward-looking statements. Forward-looking statements appear in a number of places in this report and may include statements about business strategy and prospects for growth, customer acquisition costs, ability to pay cash dividends, cash flow generation and liquidity, availability of terms of capital, competition and government regulation and general economic conditions. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we cannot give any assurance that such expectations will prove correct.

The forward-looking statements in this report are subject to risks and uncertainties. Important factors which could cause actual results to materially differ from those projected in the forward-looking statements include, but are not limited to:

- changes in commodity prices,
- extreme and unpredictable weather conditions,
- the sufficiency of risk management and hedging policies,
- customer concentration,
- federal, state and local regulation,
- key license retention,
- increased regulatory scrutiny and compliance costs,
- our ability to borrow funds and access credit markets,
- restrictions in our debt agreements and collateral requirements,
- credit risk with respect to suppliers and customers,
- level of indebtedness,
- changes in costs to acquire customers,
- actual customer attrition rates,
- actual bad debt expense in non-POR markets,
- accuracy of internal billing systems,
- ability to successfully navigate entry into new markets,
- whether our majority shareholder or its affiliates offers us acquisition opportunities on terms that are commercially acceptable to us,
- competition, and
- the "Risk Factors" in this report.

You should review the Risk Factors in Item 1A of Part I and other factors noted throughout this report which could cause our actual results to differ materially from those contained in any forward-looking statement. All forward-looking statements speak only as of the date of this report. Unless required by law, we disclaim any obligation to publicly update or revise these statements whether as a result of new information, future events or otherwise. It is not possible for us to predict all risks, nor can we assess the impact of all factors on the business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements.

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PART I.

Item 1. Business and Properties

General

We are a growing independent retail energy services company first founded in 1999 that provides residential and commercial customers in competitive markets across the United States with an alternative choice for their natural gas and electricity. We purchase our natural gas and electricity supply from a variety of wholesale providers and bill our customers monthly for the delivery of natural gas and electricity based on their consumption at either a fixed or variable price. Natural gas and electricity are then distributed to our customers by local regulated utility companies through their existing infrastructure.

We were formed as a Delaware corporation in April 2014 to act as a holding company for the retail natural gas business and asset optimization activities and the retail electricity business of our predecessor, Spark Energy Ventures, LLC. On August 1, 2014, we completed an initial public offering of 3,000,000 shares of our Class A common stock. References to us and our business prior to August 1, 2014 refer to the combined business of our operating subsidiaries before completion of our corporate reorganization in connection with our initial public offering. See Note 1 to the audited combined and consolidated financial statements for a description of our corporate reorganization in connection with our initial public offering.

Our business consists of two operating segments:

- Retail Natural Gas Segment. We purchase natural gas supply through physical and financial transactions with market counterparts and supply natural gas to residential and commercial consumers pursuant to fixed-price, variable-price and flat-rate contracts. For the year ended December 31, 2014, approximately 45% of our retail revenues were derived from the sale of natural gas. We also identify wholesale natural gas arbitrage opportunities in conjunction with our retail procurement and hedging activities, which we refer to as asset optimization.

- Retail Electricity Segment. We purchase electricity supply through physical and financial transactions with market counterparts and independent system operators (“ISOs”) and supply electricity to residential and commercial consumers pursuant to fixed-price and variable-price contracts. For the years ended December 31, 2014 approximately 55% of our retail revenues were derived from the sale of electricity.

See Note 12 to the Company’s audited combined and consolidated financial statements in this report for financial information relating to our operating segments.

Available Information

Our principal executive offices are located at 2105 CityWest Blvd., Suite 100, Houston, Texas 77042, and our telephone number is (713) 600-2600. Our website is located at www.sparkenergy.com. We make available our periodic reports and other information filed with or furnished to the Securities and Exchange Commission (the “SEC”), free of charge through our website, as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Any materials that we have filed with the SEC may be read and copied at the SEC’s Public Reference Room at 100 F Street, NE, Washington D.C. 20549, or accessed by calling the SEC at 1-800-SEC-0330 or visiting the SEC’s website at www.sec.gov.

2014 Developments

During the fourth quarter of 2014, we entered into two purchase and sale agreements for the purchase of approximately 13,400 variable rate electricity contracts in Connecticut for a purchase price of approximately $2.2 million.

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Our Operations

As of December 31, 2014, we operated in 46 utility service territories across 16 states and had approximately 303,000 residential customers and 15,000 commercial customers, which translates to approximately 326,000 “RCE’s”. An RCE, or residential customer equivalent, is an industry standard measure of natural gas or electricity usage with each RCE representing annual consumption of 100 MMbtu of natural gas or 10 MWh of electricity. We serve natural gas customers in 14 states (Arizona, California, Colorado, Connecticut, Florida, Illinois, Indiana, Maryland, Massachusetts, Michigan, Nevada, New Jersey, New York and Ohio) and electricity customers in eight states (Connecticut, Illinois, Maryland, Massachusetts, New Jersey, New York, Pennsylvania and Texas).

Customer Contracts and Product Offerings

Fixed and variable price contracts

We offer a variety of fixed-price, which includes our flat-rate products for natural gas, and variable-price service options to our natural gas and electricity customers. Under our fixed-price service options, our customers purchase natural gas and electricity at a fixed price over the life of the customer contract, which provides our customers with protection against increases in natural gas and electricity prices. Our fixed-price contracts typically have a term of one to two years for residential customers and up to three years for commercial customers and most provide for an early termination fee in the event that the customer terminates service prior to the expiration of the contract term. Our variable-price service options carry a month-to-month term and are priced based on our forecasts of underlying commodity prices and other market factors, including the competitive landscape in the market and the regulatory environment. For instance, in a typical market, we offer fixed-price electricity plans for 6, 12 and 24 months and natural gas plans from 12 to 24 months, which may come with or without a monthly service fee and/or a termination fee. We also offer variable price natural gas and electricity plans that offer an introductory fixed price that is generally applied for a certain number of billing cycles, typically two billing cycles in our current markets, then switches to a variable price based on market conditions. Our variable plans may or may not provide for a termination fee, depending on the market and customer type.

As of December 31, 2014, approximately 45% of our natural gas RCE’s were fixed-price (including flat-rate products), and the remaining 55% of our natural gas RCE’s were variable-price. As of December 31, 2014, approximately 51% of our electricity RCE’s were fixed-price, and the remaining 49% of our electricity RCE’s were variable-price.

Green products and renewable energy credits

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We offer renewable and carbon neutral (“green”) products in certain markets. Green energy products are a growing market opportunity and typically provide increased unit margins as a result of improved customer satisfaction and less competition. Renewable electricity products allow customers to choose electricity sourced from wind, solar, hydroelectric and biofuel sources, through the purchase of renewable energy credits (“RECs”). Carbon neutral gas products give customers the option to reduce or eliminate the carbon footprint associated with their energy usage through the purchase of carbon offset credits. These products typically provide for fixed or variable prices and generally follow the terms of our other products with the added benefit of carbon reduction and reduced environmental impact. We currently offer renewable electricity in all of our electricity markets and carbon neutral natural gas in several of our gas markets. At December 31, 2014, approximately 18% of our RCE’s were on green products.

In addition to the RECs we purchase to satisfy our voluntary requirements under the terms of our contracts with our customers, we must also purchase a specified amount of RECs based on the amount of electricity we sell in a state in a year pursuant to individual state renewable portfolio standards. We forecast the price for the required RECs at the end of each month and incorporate this cost component into our customer pricing models.

Product Development Process

We identify market opportunities by developing price curves in each of the markets we serve and comparing the market prices and the price the local regulated utility is offering. We then determine if there is an opportunity in a particular market based on our ability to create an attractive customer value proposition that is also able to enhance our profitability. The attractiveness of a product from a consumer’s standpoint is based on a variety of factors, including overall pricing, price stability, contract term, sources of generation and environmental impact and whether or not the contract provides for termination and other fees. Product pricing is also based on a several other factors, including the cost to acquire customers in the market, the competitive landscape and supply issues that may affect pricing.

Customer Acquisition and Retention

Sales channels and acquisition of new customers

Once a product has been created for a particular market, we then develop a marketing campaign using a combination of sales channels, with an emphasis on door-to-door marketing and outbound telemarketing. We identify and acquire customers through a variety of additional sales channels, including our inbound customer care call center, online marketing, email, direct mail, direct sales, brokers and consultants. We typically employ eight to ten vendors under short-term contracts and have not entered into any exclusive marketing arrangements with sales vendors. Our marketing team continuously evaluates the effectiveness of each customer acquisition channel and makes adjustments in order to achieve targeted growth and customer acquisition costs. We attempt to maintain a disciplined approach to recovery of our customer acquisition costs within defined periods.

During 2014 our RCE acquisitions were generated from the following sales channels:

Door to Door	70	%
Outbound Telemarketing	10	%
Acquisitions	8	%
Web Based	7	%
Direct Sales	3	%
Brokers	1	%
Other	1	%

Retaining customers and maximizing customer lifetime value

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Our management and marketing teams devote significant attention to customer retention. We have developed a disciplined renewal communication process, which is designed to effectively reach our customers prior to the end of the contract term, and employ a team dedicated to managing this renewal communications process. Generally, customers are contacted between 45 and 60 days prior to the expiration of the customer's contract through a variety of channels, including letters, postcards, telephone calls and electronic mail. Through these contacts, we encourage retention and promote renewals.

We also apply a proprietary evaluation and segmentation process to optimize value both to us and the customer. We analyze historical usage, attrition rates and consumer behaviors to specifically tailor competitive products that aim to maximize the total expected return from energy sales to a specific customer, which we refer to as customer lifetime value.

Asset Optimization

Part of our business includes asset optimization activities in which we identify opportunities in the natural gas wholesale marketplace in conjunction with our retail procurement and hedging activities. Many of the competitive pipeline choice programs in which we participate require us and other retail energy suppliers to take assignment of and manage natural gas transportation and storage assets upstream of their respective city-gate delivery points. With respect to our allocated storage assets, we are also obligated to buy and inject gas in the summer season (April through October) and sell and withdraw gas during the winter season (November through March). These purchase and injection obligations in our allocated storage assets require us to take a seasonal long position in natural gas. Our asset optimization team determines whether market conditions justify hedging these long positions through additional derivative transactions.

Our asset optimization group utilizes these allocated transportation and storage assets for retail customer usage and to effect transactions in the wholesale market based on market conditions and opportunities. Our asset optimization group also contracts with third parties for transportation and storage capacity in the wholesale market. We are responsible for reservation and demand charges attributable to both our allocated and third-party contracted transportation and storage assets. Our asset optimization group utilizes these allocated and third-party transportation and storage assets in a variety of ways to either improve profitability or optimize supply-side counterparty credit lines.

We frequently enter into spot market transactions in which we purchase and sell natural gas at the same point or we purchase natural gas at one point or pool and ship it using our pipeline reservations for sale at another point or pool, in each case if we are able to capture a margin. We view these spot market transactions as low risk because we enter into the buy and sell transactions simultaneously, on a back-to-back basis. We will also act as an intermediary for market participants who need assistance with short-term procurement requirements. Consumers and suppliers will contact us with a need for a certain quantity of natural gas to be bought or sold at a specific location. We are able to use our contacts in the wholesale market to source the requested supply, and we will capture a margin in these transactions.

The asset optimization group historically entered into long-term transportation and storage transactions. Our risk policies are such that this business is limited to back-to-back purchase and sale transactions, or open positions subject to our aggregate net open position limits, which are not held for a period longer than two months. Further, all additional capacity procured outside of a utility allocation of retail assets must be approved by our risk committee. Hedges on our firm transportation obligations are limited to two years or less and hedging of interruptible capacity is prohibited.

We also enter into back to back wholesale transactions to optimize our credit lines with third-party energy suppliers. With each of our third-party energy suppliers, we have certain contracted credit lines, within which we are able to purchase energy supply from these counterparties. If we desire to purchase supply beyond these credit limits, we are required to post collateral, in the form of either cash or letters of credit. As we begin to approach the limits of our credit line with one supplier, we may purchase energy supply from another supplier and sell that supply to the

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original counterparty in order to reduce our net buy position with that counterparty and open up additional credit to procure supply in the future. We also perform certain gas marketing services for an affiliate, whereby we take title to natural gas from the tailgate of the affiliate's natural gas processing plant, sell the natural gas to third-parties and remit payment to the affiliate in an amount equal to that at which we sold the natural gas to third parties. Our sales of gas pursuant to these activities also enable us to optimize our credit lines with third-party energy suppliers by decreasing our net buy position with those suppliers.

Commodity Supply

We hedge and procure our energy requirements from various wholesale energy markets, including both physical and financial markets through short and long term contracts. Our in-house energy supply team is responsible for managing our commodity positions (including energy procurement, capacity, transmission, renewable energy, and resource adequacy requirements) within risk tolerances defined by our risk management policies. We procure our natural gas and electricity requirements at various trading hubs, city gates and load zones. When we procure commodities at trading hubs, we are responsible for delivery to the applicable local regulated utility for distribution.

We purchase physical natural gas supply from more than 200 counterparties in the wholesale natural gas market. We periodically adjust our portfolio of purchase/sale contracts based upon continual analysis of our forecasted load requirements. Natural gas is then delivered to the local regulated utility city-gate or other specified delivery points where the local regulated utility takes control of the natural gas and delivers it to individual customers' locations.

In most markets, we typically hedge our electricity exposure with financial products and then purchase the physical power directly from the ISO for delivery. From time to time, we use a combination of physical and financial products to hedge our electricity exposure before buying physical electricity in the day ahead real time market from the ISO. Our physical and financial electricity supply is purchased at market prices from more than 17 suppliers.

We are assessed monthly for ancillary charges such as reserves and capacity in the electricity sector by the ISOs. For instance, the ISOs will charge all retail electricity providers for monthly reserves that the ISO determines are necessary to protect the integrity of the grid. We attempt to estimate such amounts but they are difficult to estimate because they are charged in arrears by the ISOs and are subject to fluctuations based on weather and other market conditions. Many of the utilities we serve also allocate natural gas transportation and storage assets to us as a part of their competitive choice program. We are required to fill our allocated storage capacity with natural gas, which creates commodity supply and price risk. Sometimes we cannot hedge the volumes associated with these assets because they are too small compared to the much larger bulk transaction volumes required for trades in the wholesale market or it is not economically feasible to do so.

Risk Management

Our management team operates under a set of corporate risk policies and procedures relating to the purchase and sale of electricity and natural gas, general risk management and credit and collections functions. Our in-house energy supply team is responsible for managing our commodity positions (including energy procurement, capacity, transmission, renewable energy, and resource adequacy requirements) within risk tolerances defined by our risk management policies. We attempt to increase the predictability of cash flows by following our various hedging strategies.

The risk committee has control and authority over all of our risk management activities. The risk committee establishes and oversees the execution of our credit risk management policy and our commodity risk policy. The risk management policies are reviewed at least annually and the risk committee typically meets quarterly to assure that we have followed its policies. The risk committee also seeks to ensure the application of our risk management policies to new products that we may offer. The risk committee is comprised of our Chief Executive Officer, our Chief Financial Officer and our risk manager who meet on a regular basis to review the status of the risk management activities and positions. We employ a risk manager who reports directly to our Chief Financial Officer and whose compensation is unrelated to trading activity. Commodity positions are typically reviewed and updated

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daily based on information from our customer databases and pricing information sources. The risk policy sets volumetric limits on intraday and end of day long and short positions in natural gas and electricity. With respect to specific hedges, we have documented a formal delegation of authority delegating product type, volumetric, tenor and timing transaction limits to the energy supply managers. The risk manager reports to the risk committee any hedging transactions that exceed these delegated transaction limits.

Commodity Price and Volumetric Risk

Because our contracts require that we deliver full natural gas or electricity requirements to many of our customers and because our customers' usage can be impacted by factors such as weather, we may periodically purchase more or less commodity than our aggregate customer volumetric needs. In buying or selling excess volumes, we may be exposed to commodity price volatility. In order to address the potential volumetric variability of our monthly deliveries for fixed-price customers, we implement various hedging strategies to attempt to mitigate our exposure.

Our commodity risk management strategy is designed to hedge substantially all of our forecasted volumes on our fixed-price customer contracts, as well as a portion of the near-term volumes on our variable-price customer contracts. We use both physical and financial products to hedge our fixed-price exposure. The efficacy of our risk management program may be adversely impacted by unanticipated events and costs that we are not able to effectively hedge, including abnormal customer attrition and consumption, certain variable costs associated with electricity grid reliability, pricing differences in the local markets for local delivery of commodities, unanticipated events that impact supply and demand, such as extreme weather, and abrupt changes in the markets for, or availability or cost of, financial instruments that help to hedge commodity price.

Customer demand is also impacted by weather. We use utility-provided historical and/or forward projected customer volumes as a basis for our forecasted volumes and mitigate the risk of seasonal volume fluctuation for some customers by purchasing excess fixed-price hedges within our volumetric tolerances. Should seasonal demand exceed our weather-normalized projections, we may experience a negative impact on financial results.

In addition to our forward price risk management approach described above, we may take further measures to reduce price risk and optimize our returns by: (i) maximizing the use of storage in our daily balancing market areas in order to give us the flexibility to offset volumetric variability arising from changes in winter demand; (ii) entering into daily swing contracts in our daily balancing markets over the winter months to enable us to increase or decrease daily volumes if demand increases or decreases; and (iii) purchasing out-of-the-money call options for contract periods with the highest seasonal volumetric risk to protect against steeply rising prices if our customer demands exceed our forecast. Being geographically diversified in our delivery areas also permits us, from time to time, to employ assets not being used in one area to other areas, thereby mitigating potential increased prices for natural gas that we otherwise may have had to acquire at higher prices to meet increased demand.

We utilize NYMEX-settled financial instruments to offset price risk associated with volume commitments under fixed-price contracts. The NYMEX-based financial instruments are settled against each month's last trading day's closing price for natural gas listed on the NYMEX Henry Hub futures contract.

Basis Risk

We are exposed to basis risk in our operations when the commodities we hedge are sold at different delivery points from the exposure we are seeking to hedge. For example, if we hedge our natural gas commodity price with Chicago basis but physical supply must be delivered to the individual delivery points of specific utility systems around the Chicago metropolitan area, we are exposed to basis risk between the Chicago basis and the individual utility system delivery points. These differences can be significant from time to time, particularly during extreme, unforecasted cold weather conditions. Similarly, in certain of our electricity markets, customers pay the load zone price for electricity, so if we purchase supply to be delivered at a hub, we may have basis risk between the hub and the load zone electricity prices due to local congestion that is not reflected in the hub price. We attempt to hedge

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basis risk where possible, but hedging instruments are sometimes not economically feasible or available in the smaller quantities that we require.

Customer Credit Risk

Our credit risk management policies are designed to limit customer credit exposure. Credit risk is managed through participation in POR programs in utility service territories where such programs are available. In these markets, we monitor the credit ratings of the local regulated utilities and the parent companies of the utilities that purchase our customer accounts receivable. We also periodically review payment history and financial information for the local regulated utilities to ensure that we identify and respond to any deteriorating trends. In non-POR markets, we assess the creditworthiness of new applicants, monitor customer payment activities and administer an active collections program. Using risk models, past credit experience and different levels of exposure in each of the markets, we monitor our aging, bad debt forecasts and actual bad debt expenses and continually adjust as necessary.

In many of the utility services territories where we conduct business, POR programs have been established, whereby the local regulated utility offers services for billing the customer, collecting payment from the customer and remitting payment to us. This service results in substantially all of our credit risk being linked to the applicable utility and not to our end-use customer in these territories. For the year ended December 31, 2014, approximately 44% of our retail revenues were derived from territories in which substantially all of our credit risk was directly linked to local regulated utility companies, all of which had investment grade ratings as of such date. During the same period, we paid these local regulated utilities a weighted average discount of approximately 1.0% of total revenues for customer credit risk. In certain of the POR markets in which we operate, the utilities limit their collections exposure by retaining the ability to transfer a delinquent account back to us for collection when collections are past due for a specified period. If our collection efforts are unsuccessful, we return the account to the local regulated utility for termination of service. Under these service programs, we are exposed to credit risk related to payment for services rendered during the time between when the customer is transferred to us by the local regulated utility and the time we return the customer to the utility for termination of service, which is generally one to two billing periods. We may also realize a loss on fixed-price customers in this scenario due to the fact that we will have already fully hedged the customer’s expected commodity usage for the life of the contract.

In non-POR markets (and in POR markets where we may choose to direct bill our customers), we manage customer credit risk through formal credit review, in the case of commercial customers, and credit score screening, deposits and disconnection for non-payment, in the case of residential customers. Generally, new applicants in non-POR markets are subject to credit screening prior to acceptance as a customer. We also maintain an allowance for doubtful accounts, which represents our estimate of potential credit losses associated with accounts receivable from customers within non-POR markets. We assess the adequacy of the allowance for doubtful accounts through review of the aging of customer accounts receivable and general economic conditions in the markets that we serve. Our bad debt expense for the year ended December 31, 2014 was $10.2 million, or 3.2% of retail revenues. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Drivers of our Business—Customer Credit Risk” for a more detailed discussion of our bad debt expense during 2014.

We have limited exposure to high concentrations of sales volumes to individual customers. For the year ended December 31, 2014, our largest customer accounted for less than 1% of total retail energy sales volume.

Counterparty Credit Risk in Wholesale Market

We are exposed to wholesale counterparty credit risk in our retail and asset optimization activities. We do not independently produce natural gas and electricity and depend upon third parties for our supply, which exposes us to counterparty credit risk. If the counterparties to our supply contracts are unable to perform their obligations, we may suffer losses, including as a result of being unable to secure replacement supplies of natural gas or electricity on a timely and cost-effective basis or at all. At December 31, 2014, approximately 50% of our total exposure of $8.8 million was either with an investment grade customer or otherwise secured with collateral.

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Competition

The markets in which we operate are highly competitive. In markets that are open to competitive choice of retail energy suppliers, our primary competition comes from the incumbent utility and other independent retail energy companies. In the electricity sector, these competitors include larger, well-capitalized energy retailers such as Direct Energy, Inc., FirstEnergy Solutions Inc., Just Energy Group Inc. and NRG Energy. We also compete with small local retail energy providers in the electricity sector that are focused exclusively on certain markets. Each market has a different group of local retail energy providers. With respect to natural gas, our national competitors are primarily Direct Energy and Constellation Energy. Our national competitors generally have diversified energy platforms with multiple marketing approaches and broad geographic coverage similar to us. Competition in each case is based primarily on product offering, price and customer service. The number of competitors in our markets varies. In well established markets in the Northeast and Texas we have hundreds of competitors, while in others such as Southern California, the competition is limited to several participants.

The competitive landscape differs in each utility service area and within each targeted customer segment. Over the last several years, a number of utilities have spun off their retail marketing arms as part of the opening of retail competition in these markets. Markets that offer POR programs are generally more competitive than those markets in which retail energy providers bear customer credit risk. Market participants are significantly shielded from bad debt expense, thereby allowing easier entry into the market. In these markets, we face additional competition as barriers to entry are less onerous.

Our ability to compete by increasing our market share depends on our ability to convince customers to switch to our products and services. Many local regulated utilities and their affiliates may possess the advantages of name recognition, long operating histories, long-standing relationships with their customers and access to financial and other resources, which could pose a competitive challenge to us. As a result of these advantages, many customers of these local regulated utilities may decide to stay with their longtime energy provider if they have been satisfied with their service in the past.

Seasonality of our Business

Our overall operating results fluctuate substantially on a seasonal basis depending on: (i) the geographic mix of our customer base; (ii) the relative concentration of our commodity mix; (iii) weather conditions, which directly influence the demand for natural gas and electricity and affect the prices of energy commodities; and (iv) variability in market prices for natural gas and electricity. These factors can have material short-term impacts on monthly and quarterly operating results, which may be misleading when considered outside of the context of our annual operating cycle.

Our accounts payable and accounts receivable are impacted by seasonality due to the timing differences between when we pay our suppliers for accounts payable versus when we collect from our customers on accounts receivable. We typically pay our suppliers for purchases on a monthly basis. However, it takes approximately two months from the time we deliver the electricity or natural gas to our customers before we collect from our customers on accounts receivable attributable to those supplies. This timing difference could affect our cash flows, especially during peak cycles in the winter and summer months.

Natural gas accounts for approximately 45% of our retail revenues, which exposes us to a high degree of seasonality in our cash flows and income earned throughout the year as a result of the high concentration of heating load in the winter months. We utilize a considerable amount of cash from operations and borrowing capacity to fund working capital, which includes inventory purchases from April through October each year. We sell our natural gas inventory during the months of November through March of each year. We expect that the significant seasonality impacts to our cash flows and income will continue in future periods.

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Regulatory Environment

We operate in the highly regulated natural gas and electricity retail sales industry in all of our respective jurisdictions. We must comply with the legislation and regulations in these jurisdictions in order to maintain our licensed status and to continue our operations, and to obtain the necessary licenses in jurisdictions in which we plan to compete. Licensing requirements vary by state, but generally involve regular, standardized reporting in order to maintain a license in good standing with the state commission responsible for regulating retail electricity and gas suppliers. There is potential for changes to state legislation and regulatory measures addressing licensing requirements that may impact our business model in the applicable jurisdiction. In addition, as further discussed below, our marketing activities and customer enrollment procedures are subject to rules and regulations at the state and federal level, and failure to comply with requirements imposed by federal and state regulatory authorities could impact our licensing in a particular market.

In large part due to the extreme weather conditions in the first quarter of 2014 and the resulting increases in variable rate pricing by retail energy marketers, complaint levels increased significantly in 2014. State regulatory commissions opened up multiple investigations and rule making efforts in an effort to respond to the increased level of complaints. This heightened regulatory scrutiny resulted in additional obligations on retailers in various markets to provide more detailed disclosures to consumers as well as more restrictions on marketing. See “Risk Factors—Risks Related to Our Business—The retail energy business is subject to a high level of federal, state and local regulation”.

Our marketing efforts to consumers, including but not limited to telemarketing, door-to-door sales, direct mail and online marketing, are subject to consumer protection regulation including state deceptive trade practices acts, Federal Trade Commission (“FTC”) marketing standards, and state utility commission rules governing customer solicitations and enrollments, among others. By way of example, telemarketing activity is subject to federal and state do-not-call regulation and certain enrollment standards promulgated by state regulators. Door-to-door sales are governed by the FTC’s “Cooling Off” Rule as well as state-specific regulation in many jurisdictions. In markets in which we conduct customer credit checks, these checks are subject to the requirements of the Fair Credit Reporting Act. Violations of the rules and regulations governing our marketing and sales activity could impact our license to operate in a particular market, result in suspension or otherwise limit our ability to conduct marketing activity in certain markets, and potentially lead to private actions against us. Moreover, there is potential for changes to legislation and regulatory measures applicable to our marketing measures that may impact our business models.

Our participation in natural gas and electricity wholesale markets to procure supply for our retail customers and hedge pricing risk is subject to regulation by the Commodity Futures Trading Commission, including regulation pursuant to the Dodd-Frank Wall Street Reform and Consumer Protection Act. In order to sell electricity, capacity and ancillary services in the wholesale electricity markets, we are required to have market-based rate authorization, also known as “MBR Authorization”, from the Federal Energy Regulatory Commission (“FERC”). We are required to make status update filings to FERC to disclose any affiliate relationships and quarterly filings to FERC regarding volumes of wholesale electricity sales in order to maintain our MBR Authorization.

The transportation and sale for resale of natural gas in interstate commerce are regulated by agencies of the U.S. federal government, primarily FERC under the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and regulations issued under those statutes. FERC regulates interstate natural gas transportation rates and service conditions, which affects our ability to procure natural gas supply for our retail customers and hedge pricing risk. Since 1985, FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. FERC’s orders do not attempt to directly regulate natural gas retail sales. As a shipper of natural gas on interstate pipelines, we are subject to those interstate pipelines tariff requirements and FERC regulations and policies applicable to shippers.

Changes in law and to FERC policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate pipelines, and we cannot predict what future action FERC

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will take. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas marketers and local regulated utilities with which we compete.

On December 26, 2007, FERC issued Order 704, a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing. Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtus of physical natural gas in the previous calendar year, including natural gas gatherers and marketers, are required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with FERC's policy statement on price reporting. As a wholesale buyer and seller of natural gas, we are subject to the reporting requirements of Order 704.

Employees

We employed 146 people as of December 31, 2014. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory. We utilize the services of independent contractors and vendors to perform various services.

Facilities

Our corporate headquarters is located in Houston, Texas. We believe that our facilities are adequate for our current operations. We share our corporate headquarters with certain of our affiliates. Spark Energy Ventures, LLC, an indirect subsidiary of NuDevco Partners, LLC, is the lessee under the lease agreement covering these facilities. We pay the entire lease payment on behalf of Spark Energy Ventures, LLC, and we are reimbursed by our affiliates for their share of the leased space.

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Item 1A. Risk Factors

You should carefully consider the risks described below together with the other information contained in this report on Form 10-K. Our business, financial condition, cash flows, ability to pay dividends on our Class A common stock and results of operations could be adversely impacted due to any of these risks.

Risks Related to Our Business

We are subject to commodity price risk.

Our financial results are largely dependent on the prices at which we can acquire the commodities we resell. The prevailing market prices for natural gas and electricity have historically, and may continue to, fluctuate substantially over relatively short periods of time, potentially adversely impacting our results of operations, financial condition, cash flows and our ability to pay dividends to the holders of our Class A common stock. Changes in market prices for natural gas and electricity may result from many factors that are outside of our control, including the following:

- weather conditions;
- seasonality;
- demand for energy commodities and general economic conditions;
- disruption of natural gas or electricity transmission or transportation infrastructure or other constraints or inefficiencies;
- reduction or unavailability of generating capacity, including temporary outages, mothballing, or retirements;
- the level of prices and availability of natural gas and competing energy sources, including the impact of changes in environmental regulations impacting suppliers;
- the creditworthiness or bankruptcy or other financial distress of market participants;
- changes in market liquidity;
- natural disasters, wars, embargoes, acts of terrorism and other catastrophic events;
- federal, state, foreign and other governmental regulation and legislation; and
- demand side management, conservation, alternative or renewable energy sources.

Additionally, significant changes in the pricing methods in the wholesale markets in which we operate could affect our commodity prices. Regulatory policies concerning how markets are structured, how compensation is provided for service, and the kinds of different services that can or must be offered, may change and could have significant impacts on our costs of doing business. For example, the Electric Reliability Council of Texas ("ERCOT") has recently considered supplementing the existing energy and ancillary service markets with a mandate to purchase installed capacity, which could have the effect of increasing our supply costs. Similarly, ERCOT adopted a new reserve imbalance market that will increase prices in certain circumstances. Changes to the prices we pay to acquire commodities and that we are not able to pass along to our customers could materially adversely affect our operations, which could negatively impact our financial results and our ability to pay dividends to the holders of our Class A common stock.

Our financial results may be adversely impacted by weather conditions.

Weather conditions directly influence the demand for and availability of natural gas and electricity and affect the prices of energy commodities. Generally, on most utility systems, demand for natural gas peaks in the winter and demand for electricity peaks in the summer. Typically, when winters are warmer or summers are cooler, demand for energy is lower than expected, resulting in less natural gas and electricity consumption than forecasted. When demand is below anticipated levels due to weather patterns, we may be forced to sell excess supply at prices below our acquisition cost, which could result in reduced margins or even losses.

Conversely, when winters are colder or summers are warmer, consumption may outpace the volumes of natural gas and electricity against which we have hedged, and we may be unable to meet increased demand with storage or

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swing supply. In these circumstances, we may experience reduced margins or even losses if we are required to purchase additional supply at higher prices. Our failure to accurately anticipate demand due to fluctuations in weather or to effectively manage our supply in response to a fluctuating commodity price environment could negatively impact our financial results and our ability to pay dividends to the holders of our Class A common stock.

Our risk management policies and hedging procedures may not mitigate risk as planned, and we may fail to fully or effectively hedge our commodity supply and price risk exposure against changes in consumption volumes or market rates.

To provide energy to our customers, we purchase the relevant commodity in the wholesale energy markets, which are often highly volatile. Our commodity risk management strategy is designed to hedge substantially all of our forecasted volumes on our fixed-price customer contracts, as well as a portion of the near-term volumes on our variable-price customer contracts. We use both physical and financial products to hedge our fixed-price exposure. The efficacy of our risk management program may be adversely impacted by unanticipated events and costs that we are not able to effectively hedge, including abnormal customer attrition and consumption, certain variable costs associated with electricity grid reliability, pricing differences in the local markets for local delivery of commodities, unanticipated events that impact supply and demand, such as extreme weather, and abrupt changes in the markets for, or availability or cost of, financial instruments that help to hedge commodity price.

We are exposed to basis risk in our operations when the commodities we hedge are sold at different delivery points from the exposure we are seeking to hedge. For example, if we hedge our natural gas commodity price with Chicago basis but physical supply must be delivered to the individual delivery points of specific utility systems around the Chicago metropolitan area, we are exposed to basis risk between the Chicago basis and the individual utility system delivery points. These differences can be significant from time to time, particularly during extreme, unforecasted cold weather conditions. Similarly, in certain of our electricity markets, customers pay the load zone price for electricity, so if we purchase supply to be delivered at a hub, we may have basis risk between the hub and the load zone electricity prices due to local congestion that is not reflected in the hub price. We attempt to hedge basis risk where possible, but hedging instruments are sometimes not economically feasible or available in the smaller quantities that we require.

In addition, we incur costs monthly for ancillary charges such as reserves and capacity in the electricity sector by ISOs. For instance, the ISOs will charge all retail electricity providers for monthly reserves that the ISO determines are necessary to protect the integrity of the grid. We attempt to estimate such amounts but they are difficult to estimate because they are charged in arrears by the ISOs and are subject to fluctuations based on weather and other market conditions. We may be unable to fully pass the higher cost of ancillary reserves and reliability services through to our customers, and increases in the cost of these ancillary reserves and reliability services could negatively impact our results of operations.

Additionally, assumptions that we use in establishing our hedges may reduce the effectiveness of our hedging instruments. Considerations that may affect our hedging policies include, but are not limited to, human error, assumptions about customer attrition, the relationship of prices at different trading or delivery points, assumptions about future weather, and our load forecasting models.

Many of the natural gas utilities we serve allocate a share of transportation and storage capacity to us as a part of their competitive market operations. We are required to fill our allocated storage capacity with natural gas, which creates commodity supply and price risk. Sometimes we cannot hedge the volumes associated with these assets because they are too small compared to the much larger bulk transaction volumes required for trades in the wholesale market or it is not economically feasible to do so. In some regulatory programs or under some contracts, this capacity may be subject to recall by the utilities, which could have the effect of us being required to access the spot market to cover such recall.

In general, if we are unable to effectively manage our risk management policies and hedging procedures, our financial results and our ability to pay dividends to the holders of our Class A could be adversely affected.

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We depend on consistent regulation within a particular utility territory (or state), as well as at the federal level, to permit us to operate in restructured, competitive segments of the natural gas and electricity industries. If competitive restructuring of the natural gas and electricity utility industries is altered, reversed, discontinued or delayed, our business prospects and financial results could be materially adversely affected.

We operate in the highly regulated natural gas and electricity retail sales industry. Regulations may be revised or reinterpreted or new laws and regulations may be adopted or become applicable to us or our operations. Such changes may have a detrimental impact on our business.

In certain restructured energy markets, state legislatures, governmental agencies and/or other interested parties have made proposals to fully or partially re-regulate these markets, which would interfere with our ability to do business. If competitive restructuring of natural gas or electricity markets is altered, reversed, discontinued or delayed, our financial results and our ability to pay dividends to the holders of our Class A common stock could be adversely affected.

The regulatory structure in California, where we have operations in three markets, is in the process of changing as the California Public Utility Commission (the "CPUC") is assuming greater regulatory responsibility over the core transportation aggregation market and marketers such as ourselves that operate in the natural gas markets in California. California Senate Bill 656, which became effective on January 1, 2014, established CPUC jurisdiction over core transportation aggregators and directed the CPUC to develop and publish consumer protection standards for core transportation aggregators. The new law requires, among other things, that the CPUC must set minimum standards of consumer protection and establish a mechanism to resolve customer complaints and award reparations. The CPUC has yet to implement rules on key issues that will affect retailers in these markets, such as complaint resolution processes; minimum standards for consumer protections; notice requirements detailing the terms and conditions of service and marketing practices. There can be no assurance that the CPUC will not enact new regulations that will make marketing and operating in California more difficult or that any such new regulations and requirements will not have an adverse impact on the Company's operations in California.

The retail energy business is subject to a high level of federal, state and local regulation.

State, federal and local rules and regulations affecting the retail energy business are subject to change, which may adversely impact our business model. Our costs of doing business may fluctuate based on these regulatory changes. For example, many electricity markets have rate caps, and changes to these rate caps by regulators can impact future price exposure. Similarly, regulatory changes can result in new fees or charges that may not have been anticipated when existing retail contracts were drafted, which can create financial exposure. For example, mandates to purchase a certain quantity or type of electricity capacity can create unanticipated costs. Our ability to manage cost increases that result from regulatory changes will depend, in part, on how the "change in law provisions" of our contracts are interpreted and enforced, among other factors.

Operators of systems providing for the delivery of natural gas and electricity maintain detailed tariffs that are kept on file with regulators. These tariffs and market rules applicable to operators are often very long and complex, and often are subject to service provider proposals to change them. We may not be able to prevent adoption of adverse tariff changes. Users of energy delivery systems also have rules and obligations applicable to them that are established by regulators. For instance, transactions involving a shipper's release of interstate pipeline capacity are subject to regulation at the federal level. Our failure to abide by tariffs, market rules or other delivery system rules may result in fines, penalties and damages.

We are also subject to regulatory scrutiny in all of our markets that can give rise to compliance fees, licensing fees, or enforcement penalties. Regulations vary widely in the markets in which we operate, and these regulations change from time to time. Failure to follow prescribed regulatory guidelines could result in customer complaints and regulatory sanctions.

In addition, regulators are continuously examining certain aspects of our industry. For example, a number of public utility commissions in the northeast are investigating the impact of the harsh weather conditions during the

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2013-2014 winter season on consumers in their territories due to the number of consumer complaints attributable to high bills for the winter season and are urging FERC to investigate circumstances during that period in wholesale energy markets. This heightened regulatory scrutiny resulted in additional obligations on retailers in various markets to provide more detailed disclosures to consumers as well as additional and more stringent requirements on notifying customers when their fixed contract converts to variable pricing. These new regulations could adversely affect our customer attrition rates and cause us to incur higher compliance costs. To the extent any of these commissions takes further regulatory action to address these complaints, such as imposing limits on products, services, rates or other business limitations, our business prospects in these regions could be materially adversely affected.

In addition, door-to-door marketing and outbound telemarketing are a significant part of our marketing efforts. Each of these channels is continually under scrutiny by state and federal regulators and legislators. Additional regulation or restriction of these marketing practices could negatively impact our customer acquisition plan, and therefore our financial results and our ability to pay dividends to the holders of our Class A common stock.

Our business is dependent on retaining licenses in the markets in which we operate.

We generally must apply to the relevant state utility commission to become a retail marketer of natural gas and/or electricity in the markets that we serve. Approval by the state regulatory body is subject to our understanding of and compliance with various federal, state and local regulations that govern the activities of retail marketers. If we fail to comply with any of these regulations, we could suffer certain consequences, which may include:

- higher customer complaints and increased unanticipated attrition;
- damage to our reputation with customers and regulators; and
- increased regulatory scrutiny and sanctions, including fines and termination of our license.

Our business model is dependent on continuing to be licensed in existing markets. If we have a license revoked or are not granted renewal of a license, or if our license is adversely conditioned or modified (e.g., by increased bond posting obligations), our financial results could be materially negatively impacted, which could materially negatively impact our financial results and our ability to pay dividends to the holders of our Class A common stock.

In addition, FERC regulates the sale of wholesale electricity by requiring us and other companies who sell into the wholesale market to obtain market-based rate authority. If that authority were revoked, our financial results and our ability to pay dividends to the holders of our Class A common stock could be materially adversely affected.

Our financial results fluctuate on a seasonal and quarterly basis.

Our overall operating results fluctuate substantially on a seasonal basis depending on: (1) the geographic mix of our customer base; (2) the concentration of our product mix; (3) the impact of weather conditions on commodity pricing and demand, (4) variability in market prices for natural gas and electricity, and (5) changes in the cost of delivery of such commodities through energy delivery networks. These factors can have material short-term impacts on monthly and quarterly operating results, which may be misleading when considered outside of the context of our annual operating cycle. In addition, our accounts payable and accounts receivable are impacted by seasonality due to the timing differences between when we pay our suppliers for accounts payable versus when we collect from our customers on accounts receivable. We typically pay our suppliers for purchases on a monthly basis. However, it takes approximately two months from the time we deliver the electricity or natural gas to our customers before we collect from our customers on accounts receivable attributable to those supplies. This timing difference could affect our cash flows, especially during peak cycles in the winter and summer months. Furthermore, as a result of the seasonality of our business, we may reserve a portion of our excess cash available for distribution in the first and fourth quarters in order to fund our second and third quarter distributions. Because of the seasonal nature of our business and operating results, it may be difficult for investors to accurately and adequately value our business based on our interim result, which could materially negatively impact our financial results and our ability to pay dividends to the holders of our Class A common stock.

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Pursuant to our cash dividend policy, we distribute substantially all of our cash available for distribution through regular quarterly dividends, and our ability to grow and make acquisitions with cash on hand could be limited.

Pursuant to our cash dividend policy, we have been distributing, and intend to distribute, substantially all of our cash available for distribution through regular quarterly dividends to holders of our Class A common stock. As such, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional equity securities in connection with any acquisitions or growth capital expenditures, the payment of dividends on these additional equity securities may increase the risk that we will be unable to maintain our per share dividend rate. We may also rely upon external financing sources, including the issuance of debt and equity securities and borrowings under our new Senior Credit Facility to fund our acquisitions and growth capital expenditures. The incurrence of bank borrowings or other debt to finance our growth strategy will result in increased interest expense and the imposition of additional or more restrictive covenants, which, in turn, may impact our ability to pay dividends to holders of our Class A common stock. We may decide not to pursue otherwise attractive acquisitions if the projected short-term cash flow from the acquisition or investment is not adequate to service the capital raised to fund the acquisition or investment, after giving effect to our available cash reserves.

We may have difficulty retaining our existing customers or obtaining a sufficient number of new customers.

As of December 31, 2014, approximately 45% of our natural gas RCE's were fixed-price (including flat-rate products), and the remaining 55% of our natural gas RCE's were variable-price. As of December 31, 2014, approximately 51% of our electricity RCE's were fixed-price, and the remaining 49% of our electricity RCE's were variable-price. A significant decrease in the retail price of natural gas or electricity may cause our customers to switch retail energy service providers during their contract terms to obtain more favorable prices. Although we generally have a right to collect a termination fee from each customer on a fixed-price contract who terminates their contract following such an event, we may not be able to collect the termination fees in full or at all. Our variable-price contracts typically may be terminated by our customers at any time without penalty.

Furthermore, significant ongoing competition exists for customers in the markets where we operate, and we cannot guarantee that we will be able to retain our existing customers or obtain a sufficient number of new customers. We anticipate that we will incur significant costs as we enter new markets and pursue customers by utilizing a variety of marketing methods. In order for us to recover these expenses, we must attract and retain these customers on economic terms and for extended periods. We cannot be certain that our future efforts to retain our customers or secure additional customers will generate sufficient gross margins for us to expand into additional markets or that we will be able to prevent customer attrition and attract new customers in existing markets. If our marketing strategy is not successful, our financial results and our ability to pay dividends to the holders of our Class A common stock could be adversely affected.

We experience strong competition from local regulated utilities and other competitors.

The markets in which we compete are highly competitive, and we may not be able to compete effectively, especially against established industry competitors and new entrants with greater financial resources. We encounter significant competition from local regulated utilities or their retail affiliates and traditional and new retail energy providers with greater financial resources, well established brand names and/or large, existing installed customer bases. In most markets, our principal competitor may be the local regulated utility company or its affiliated retail arm. The local regulated utilities have the advantage of longstanding relationships with their customers, and they may have longer operating histories, better access to data, greater financial and other resources and greater name recognition in their markets than we do. Convincing customers to switch to a new company for the supply of a critical commodity such as natural gas or electricity is a challenge.

In certain markets, local regulated utilities may seek to decrease their tariffed retail rates to limit or to preclude opportunities for retail energy providers to acquire market share, and otherwise seek to establish rates, terms and conditions to the disadvantage of retail energy providers such that these retail energy providers cannot remain

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competitive in that market. Also, in states where the utility service rate is set through the procurement of energy over a period of months or years, the utility service rate will lag behind market conditions. If energy prices rise significantly above the utility service rate over a prolonged period of time, we may be forced to reduce our operating margins in order to price more competitively with the utility service rate and may experience increased customer attrition, as some customers may switch to the service offer from the utility.

In addition to competition from the local regulated utilities, we face competition from a number of other retail energy providers. We also may face competition from large corporations with similar billing and customer service capabilities, such as telecommunication service providers and nationally branded providers of consumer products and services that have a significant base of existing customers. Many of these competitors or potential competitors are larger than us and have access to more significant capital resources. For example, a larger competitor may be able to incur more costs to acquire customers if its cost of capital is lower than ours. Similarly, marketers with a larger presence in the relevant market or that have interruptible load as part of their customer base may benefit from synergies or scale economies that smaller marketers, or marketers serving only firm customers, cannot obtain. In addition, product offerings that provide a consumer with an alternative source of energy, such as a solar panel, may become more common and indirectly compete with us. If our marketing strategy is not successful, it may affect our financial results and our ability to pay dividends to the holders of our Class A common stock.

The accounting method we use for our hedging activities results in volatility in our quarterly and annual financial results.

We enter into a variety of financial derivative and physical contracts to manage commodity price risk, and we use mark-to-market accounting to account for this hedging activity. Under the mark-to-market accounting method, changes in the fair value of our hedging instruments that are not qualifying or not designated as hedges under accounting rules are recognized immediately in earnings. As a result of this accounting treatment, changes in the forward prices of natural gas and electricity cause volatility in our quarterly and annual earnings, which we are unable to fully anticipate.

We could also incur volatility from quarter to quarter associated with gains and losses on settled hedges relating to natural gas held in inventory if we choose to hedge the summer-winter spread on our retail allocated storage capacity. We typically purchase natural gas inventory and store it from April to October for withdrawal from November through March. Since a portion of the inventory is used to satisfy delivery obligations to our fixed-price customers over the winter months, we hedge the associated price risk using derivative contracts. Any gains or losses associated with settled derivative contracts are reflected in the statement of operations as a component of retail cost of sales and net asset optimization.

Increased collateral requirements in connection with our supply activities may restrict our liquidity which could limit our ability to grow our business or pay dividends.

Our contractual agreements with certain local regulated utilities and our supplier counterparties require us to maintain restricted cash balances or letters of credit as collateral for credit risk or the performance risk associated with the future delivery of natural gas or electricity. These collateral requirements may increase as we grow our customer base. Collateral requirements will increase based on the volume or cost of the commodity we purchase in any given month and the amount of capacity or service contracted for with the local regulated utility. Significant changes in market prices also can result in fluctuations in the collateral that local regulated utilities or suppliers require.

The effectiveness of our operations and future growth, and our ability to pay dividends to the holders of our Class A common stock depend in part on the amount of cash and letters of credit available to enter into or maintain these contracts. The cost of these arrangements may be affected by changes in credit markets, such as interest rate spreads in the cost of financing between different levels of credit ratings. These liquidity requirements may be greater than we anticipate or are able to meet and therefore could limit our ability to grow our business or pay dividends to the holders of shares of our Class A common stock.

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Our liquidity during 2014 was negatively impacted by the continued gradual decline in natural gas prices as we were forced to post additional cash collateral for certain of our supply contracts. If natural gas prices continue to decline, we will be forced to post additional cash collateral under certain supply contracts which will negatively impact our liquidity.

Our supply contracts expose us to counterparty credit risk.

We do not independently produce natural gas and electricity and depend upon third parties for our supply. If the counterparties to our supply contracts are unable to perform their obligations, we may suffer losses, including as a result of being unable to secure replacement supplies of natural gas or electricity on a timely and cost-effective basis or at all. If we cannot identify alternative supplies of natural gas or electricity, or secure natural gas or electricity in a timely fashion, our financial results and our ability to pay dividends to the holders of our Class A common stock could be adversely affected.

We are subject to direct credit risk for certain customers who may fail to pay their bills as they become due.

We bear direct credit risk related to our customers located in markets that have not implemented POR programs as well as indirect credit risk in those POR markets that pass collection efforts along to us after a specified non-payment period. For the year ended December 31, 2014, customers in non-POR markets represented approximately 56% of our retail revenues. We generally have the ability to terminate contracts with customers in the event of non-payment, but in most states in which we operate we cannot disconnect their natural gas or electricity gas service. In POR markets where the local regulated utility has the ability to return non-paying customers to us after specified periods, we may realize a loss for one to two billing periods until we can terminate these customers' contracts. We may also realize a loss on fixed-price customers in this scenario due to the fact that we will have already fully hedged the customer's expected commodity usage for the life of the contract. Even if we terminate service to customers who fail to pay their bill, we remain liable to our suppliers of natural gas and electricity for the cost of those commodities. Furthermore, in the Texas market, we are responsible for billing the distribution charges for the local regulated utility and are at risk for these charges, in addition to the cost of the commodity, in the event customers fail to pay their bills. Changing economic factors, such as rising unemployment rates and energy prices also result in a higher risk of customers being unable to pay their bills when due.

The Company's results of operations for 2014 were negatively impacted by increased bad debt expense in Southern California and we expect that bad debt expense will continue to be adversely impacted during the first quarter of 2015. We significantly curtailed marketing efforts in this region in the fourth quarter of 2014 as we attempt to refine our collection and retention strategies in Southern California. The Company's inability to effectively manage existing customer credit risk in Southern California and other non-POR markets could have an adverse effect on the Company's results of operations.

The failure of our customers to pay their bills or our failure to maintain adequate billing and collection procedures could adversely affect our financial results and our ability to pay dividends to the holders of our Class A common stock.

We are subject to credit, operational and financial risks related to certain local regulated utilities that provide billing services and guarantee the customer receivables for their markets.

In POR markets, we rely on the local regulated utility to purchase our customer accounts receivable and to perform timely and accurate billing. POR markets represented approximately 44% of our retail revenues for the year ended December 31, 2014. As our business grows, the portion of customers we serve in POR markets could increase. The bankruptcy of a local regulated utility could result in a default in such local regulated utility's payment obligations to us, or efforts to reject contracts for service that they have with us if they believe there is a high value alternative opportunity.

In POR markets where local regulated utilities purchase our receivables and in certain other markets, local regulated utilities are responsible for billing services. Local regulated utilities that provide billing services rely on us for

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accurate and timely communication of contract rates and other information necessary for accurate billing to customers. The number of territories within which we provide natural gas and electricity supply poses a constant challenge that demands considerable management, personnel and information system resources. Each territory requires unique and often varied electronic data interface systems. Rules that govern the exchange of data may be changed by the local regulated utilities. In certain instances, we must rely on manual processes and procedures to communicate data to local regulated utilities for inclusion in customer bills. In addition, some utilities may experience difficulty in providing accurate, timely data when changing metering equipment (e.g., from manually-read to telemetry). Failure to provide accurate data to local regulated utilities on a timely basis could result in underpayment or nonpayment by our customers, and therefore adversely affect our financial results and our ability to pay dividends to the holders of our Class A common stock.

Our indebtedness could adversely affect our ability to raise additional capital to fund our operations or pay dividends. It could also expose us to the risk of increased interest rates and limit our ability to react to changes in the economy or our industry as well as impact our cash available for distribution.

We entered into a new $70.0 million senior secured revolving credit facility in conjunction with our initial public offering in August 2014, which we refer to as our Senior Credit Facility. We have $33.0 million of indebtedness outstanding under our Senior Credit Facility and $10.7 million in issued letters of credit as of December 31, 2014. Debt we incur under our Senior Credit Facility or otherwise could have important negative consequences on our financial condition, including:

- increasing our vulnerability to general economic and industry conditions;
- requiring cash flow from operations to be dedicated to the payment of principal and interest on our indebtedness, therefore reducing our ability to pay dividends to holders of our Class A common stock or to use our cash flow to fund our operations, capital expenditures and future business opportunities;
- limiting our ability to fund operations or future acquisitions;
- restricting our ability to make certain distributions with respect to our capital stock and the ability of our subsidiaries to make certain distributions to us, in light of restricted payment and other financial covenants, including requirements to maintain certain financial ratios, in our credit facilities and other financing agreements;
- exposing us to the risk of increased interest rates because borrowings under our new Senior Credit Facility will be at variable rates of interest; and
- limiting our ability to obtain additional financing for working capital including collateral postings, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes.

Our Senior Credit Facility contains financial and other restrictive covenants that may limit our ability to return capital to stockholders or otherwise engage in activities that may be in our long-term best interests. Our inability to satisfy certain financial covenants could prevent us from paying cash dividends, and our failure to comply with those and other covenants could result in an event of default which, if not cured or waived, may entitle the lenders to demand repayment or enforce their security interests, which could negatively impact our financial results and our ability to pay dividends to the holders of our Class A common stock.

We depend on the accuracy of data in our billing systems. Inaccurate data could have a negative impact on our results of operations, financial condition, cash flows and reputation with customers and/or regulators.

We depend on the accuracy and timeliness of customer billing, collections and consumption information in our information systems. We rely on many internal and external sources for this information, including:

- our internal marketing, pricing and customer operations functions; and
- various local regulated utilities and ISOs for volume or meter read information, certain billing rates and billing types (e.g., budget billing) and other fees and expenses.

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Inaccurate or untimely information, which may be outside of our direct control, could result in:
- inaccurate and/or untimely bills sent to customers;
- inaccurate accounting and reporting of customer revenues, gross margin and accounts receivable activity;
- inaccurate measurement of usage rates, throughput and imbalances;
- customer complaints; and
- increased regulatory scrutiny.

We may become liable for incorrectly calculating taxes, and certain of our charges may become uncollectable due to billing errors. Although customers are responsible for the payment of taxes related to the sales of natural gas and electricity, we estimate the amount of taxes they owe and invoice our customers through our billing process. We subsequently remit those taxes to the relevant taxing authorities. If we were to later determine that the amount we billed them for taxes was insufficient, we would not be able to recover the difference from them and would ultimately be responsible for those costs. Additionally, some of the markets in which we operate require us to bill customers within a specific period of time. If we do not bill our customer within that period of time, the customer may not be obligated to pay us.

Regulations in the restructured markets in which we operate require that meter reading be performed by the local regulated utility; and we are required to rely on the local regulated utility to provide us with our customers' information regarding energy usage. Our inability to obtain this usage information or confirm information received from the utilities could negatively impact our billing systems and reputation with customers and, therefore, our financial results and our ability to pay dividends to the holders of our Class A common stock.

Information management systems could prove unreliable.

We operate in a high volume business with an extensive array of data interchanges and market requirements. We are highly dependent on our information management systems to track, monitor and correct or otherwise verify a high volume of data to ensure the reported financial results and our forecasting efforts are accurate. Our information management systems are designed to help us forecast new customer enrollments and their energy requirements, which helps ensure that we are able to supply new customers estimated average energy requirements without exposing us to excessive commodity price risk.

We may be subject to disruptions in our information flow arising out of events beyond our control, such as natural disasters, epidemics, failures in hardware or software, power fluctuations, telecommunications and other similar disruptions. In addition, our information management systems may be vulnerable to computer viruses, incursions by intruders or hackers and cyber terrorists and other similar disruptions. The failure of our information management systems to perform as anticipated for any reason or any significant breach of security could disrupt our business and result in numerous adverse consequences, including reduced effectiveness and efficiency of our operations, inappropriate disclosure of confidential information and increased overhead costs, all of which could impact our financial results and our ability to pay dividends to the holders of our Class A common stock.

The Company's business is subject to cyber-attacks and data breaches, including the risk that sensitive customer data may be compromised, which could result in an adverse impact to its reputation and results of operations.

The Company is dependent on information technology systems that we own and that are owned and managed by third parties. Parties that wish to disrupt the Company's operations could view our computer systems or networks and those of our third party outsourced providers as attractive targets for cyber-attack. Our business requires access to sensitive customer data in the ordinary course of business. Examples of sensitive customer data are names, addresses, account information, historical electricity usage, expected patterns of use, payment history, credit bureau data, credit and debit card account numbers, drivers' license numbers, social security numbers and bank account information. The Company provides sensitive customer data to vendors and service providers who require access to this information in order to provide billing and transaction services.

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A successful cyber-attack on the systems that control the Company's billing and transaction and customer information systems could severely disrupt business operations, preventing the Company from serving customers or collecting revenues. A cyber-attack or security breach on us or our third party outsourced system providers could result in significant expenses to investigate and repair security breaches or system damage and could lead to litigation, fines, other remedial action, heightened regulatory scrutiny and damage to the Company's reputation. In addition, the misappropriation, corruption or loss of personally identifiable information and other confidential data could lead to significant breach notification expenses and mitigation expenses such as credit monitoring. The Company does not maintain cyber-liability insurance that covers certain damage caused by potential cyber incidents. A significant cyber incident could materially and adversely affect the Company's business, financial condition and results of operations.

We depend on local transportation and transmission facilities of third parties to supply our customers. Our financial results may be adversely impacted if transportation and transmission availability is limited or unreliable.

We depend on transportation and transmission facilities owned and operated by local regulated utilities and other energy companies to deliver the natural gas and electricity we sell to customers. Under the regulatory structures adopted in most jurisdictions, we are required to enter into agreements with regulated local regulated utilities for use of the local distribution systems and to establish functional data interfaces necessary to serve our customers. Any delay in the negotiation of such agreements or inability to enter into reasonable agreements could delay or negatively impact our ability to serve customers in those jurisdictions. Additionally, failure to coordinate upstream and downstream receipts and deliveries on an energy transportation network can result in significant penalties. Any of these factors could have an adverse impact on our financial results and our ability to pay dividends to the holders of our Class A common stock.

We also depend on local regulated utilities for maintenance of the infrastructure through which we deliver natural gas and electricity to our customers. We are unable to control the level of service the utilities provide to our customers, including the timeliness and effectiveness of upkeep and repairs to infrastructure. Any infrastructure failure that interrupts or impairs delivery of electricity or natural gas to our customers could cause customer dissatisfaction, which could adversely affect our business. If transportation or transmission/distribution is disrupted, or if transportation or transmission/distribution capacity is inadequate, our ability to sell and deliver products may be hindered. Such disruptions could also hinder our providing electricity or natural gas to our customers and adversely impact our risk management policies, hedge contracts, our financial results and our ability to pay dividends to the holders of our Class A common stock.

In addition, the power generation and transmission/distribution infrastructure in the United States is very complex. Maintaining reliability of the infrastructure requires appropriate oversight by regulatory agencies, careful planning and design, trained and skilled operators, sophisticated information technology and communication systems, ongoing monitoring and, where necessary, improvements to various components of the infrastructure, including with regard to security. Major electric power blackouts are possible, which could disrupt electrical service for extended periods of time to large geographic regions of the United States. If such a major blackout were to occur, we may be unable to deliver electricity to our customers in the affected region, which would have an adverse impact our financial results and our ability to pay dividends to the holders of our Class A common stock.

The adoption of derivatives legislation by Congress will continue to have an adverse impact on our ability to hedge risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Act"), enacted on July 21, 2010, established federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. Although we qualify for the end-user exception to the mandatory clearing and uncleared swap margin requirements for swaps to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, has changed the cost and availability of the swaps that we use for hedging.

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The full impact of the Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. The Act and any new regulations could significantly increase the cost of derivative transactions, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks that we encounter, or reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives as a result of the Act and related regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Any of these consequences could have a material adverse effect our financial results and our ability to pay dividends to the holders of our Class A common stock.

We intend to grow our business in part through strategic acquisition opportunities from third parties and potentially from affiliates of our majority shareholder. If we are unable to make acquisitions on economically acceptable terms or we cannot consummate acquisitions due to capital constraints, our future growth may be limited.

Our ability to grow depends in part on our ability to make acquisitions that are accretive to our Adjusted EBITDA. If we are unable to make accretive acquisitions, whether because we are (i) unable to identify attractive acquisition candidates or negotiate commercially acceptable terms for such acquisitions, (ii) unable to obtain financing for these acquisitions on economically feasible terms, or (iii) outbid by competitors, then our future growth may be limited to organic growth. We may also enter into transactions with NuDevco, our majority shareholder, or its affiliates in which we acquire assets and businesses from NuDevco and its affiliates in related party transactions. We can provide no assurance that NuDevco will offer us acquisition opportunities, or if it does offer us any acquisition opportunities, that it will do so on commercially reasonable terms. Neither NuDevco nor any of its affiliates is obligated to offer us any acquisition opportunities. Further, we may not decide to accept any such opportunities presented by NuDevco or its affiliates on the terms being offered. Any transaction between us and any of NuDevco or its affiliates would be subject to review and approval of a special committee of independent directors. Investors should not place any reliance on any intention of NuDevco and its affiliates to offer us acquisition opportunities.

We may not be able to manage our growth successfully, which could strain our liquidity and other resources and lead to poor customer satisfaction with our services.

The growth of our operations will depend upon our ability to expand our customer base in our existing markets and to enter new markets in a timely manner at reasonable costs. As we expand our operations, we may encounter difficulties implementing new product offerings or integrating new customers and employees as well as any legacy systems of acquired entities.

We may experience difficulty managing the growth of a portfolio of customers that is diverse with respect to the types of service offerings, applicable market rules and the infrastructure for product delivery. We also may experience difficulty integrating an acquired company's personnel and operations, or key personnel of the acquired company may decide not to work for us. Furthermore, if we acquire the residential or commercial businesses of an incumbent local regulated utility or other energy provider in a particular market, the customers of that business may not be under any obligation to use our services. These difficulties could disrupt our ongoing business, distract our management and employees, increase our expenses and adversely affect our cash flows.

Expanding our operations could result in increased liquidity needs to support working capital for the purchase of natural gas and electricity supply to meet our customers' needs, for the credit requirements of forward physical supply and for generally higher operating expenses. Expanding our operations also may require continued development of our operating and financial controls and may place additional stress on our management and operational resources. If we are unable to manage our growth and development successfully, this could affect our financial results and our ability to pay dividends to the holders of our Class A common stock.

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Our success depends on key members of our management, the loss of whom could disrupt our business operations.
We depend on the continued employment and performance of key management personnel. A number of our senior executives have substantial experience in consumer and energy markets that have undergone regulatory restructuring and have extensive risk management and hedging expertise. We believe their experience is important to our continued success. We do not maintain key life insurance policies for our executive officers. If our key executives do not continue in their present roles and are not adequately replaced, our financial results and our ability to pay dividends to the holders of our Class A common stock could be adversely affected.
We rely on a capable, well-trained workforce to operate effectively. Retention of employees with strong industry or operational knowledge is essential to our ongoing success.
Many of the employee positions within our customer operations, energy supply, information systems, pricing, marketing, risk management and finance functions require extensive industry, operational, regulatory or financial experience or skills that may not be easily replaced if an employee were to leave employment with us. While some normal employee turnover is expected, high turnover could strain our ability to manage our ongoing operations as well as inhibit organic and acquisition growth.

We rely on a third party vendor for our customer billing and transactions platform which exposes us to third party performance risk.
We have outsourced our back office customer billing and transactions functions to a third party, and we rely heavily on the continued performance of that vendor under the outsourcing agreement. Failure of our vendor to operate in accordance with the terms of the outsourcing agreement or the vendor's bankruptcy or other event that prevents it from performing under our outsourcing agreement could have a material adverse effect on our financial results and our ability to pay dividends to the holders of our Class A common stock.
The failures or questionable activities of various local regulated utilities and other retail marketers within the markets that we serve adversely impact us.
A general positive perception on the part of customers and regulators of utilities and retail energy providers in general, and of us in particular, is essential for our continued growth and success. Questionable pricing, billing, collections, marketing or customer service practices on the part of any utility or retail marketer, or unsuccessful implementation of competitive energy programs can damage the reputation of all market participants, which could result in lower customer renewals and impact our ability to sign-on new customers. Any utility or retail marketer that defaults on its obligations to its customers, suppliers, lenders, hedge counterparties, or employees can have similar impacts on the retail energy industry as a whole and on our operations in particular. Any of these factors could affect our financial results and our ability to pay dividends to the holders of our Class A common stock.
A large portion of our current customers are concentrated in a limited number of states, making us vulnerable to customer concentration risks.
As of December 31, 2014, approximately 79% of our RCE's were located in five states. Specifically, 27%, 19%, 19%, 8% and 6% of our customers were located in Illinois, California, Texas, Connecticut and Indiana, respectively. If we are unable to increase our market share across other competitive markets or enter into new competitive markets effectively, we may be subject to continued or greater customer concentration risk. In addition, if any of the states that contain a large percentage of our customers were to reverse regulatory restructuring or change the regulatory environment in a manner that causes us to be unable to economically operate in that state, our financial results and our ability to pay dividends to the holders of our Class A common stock could be adversely affected.

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Increases in state renewable portfolio standards or an increase in the cost of renewable energy credit and carbon offsets may adversely impact the price, availability and marketability of our products.

Pursuant to state renewable portfolio standards, we must purchase a specified amount of renewable energy credits, or RECs, based on the amount of electricity we sell in a state in a year. In addition, we have contracts with certain customers which require us to purchase RECs or carbon offsets. If a state increases its renewable portfolio standards, the demand for RECs within that state will increase and therefore the market price for RECs could increase. We attempt to forecast the price for the required RECs and carbon offsets at the end of each month and incorporate this forecast into our customer pricing models, but the price paid for RECs and carbon offsets may be higher than forecasted. We may be unable to fully pass the higher cost of RECs through to our customers, and increases in the price of RECs may decrease our results of operations and affect our ability to compete with other energy retailers that have not contracted with customers to purchase RECs or carbon offsets. Further, a price increase for RECs or carbon offsets may require us to decrease the renewable portion of our energy products, which may result in a loss of customers. A further reduction in benefits received by local regulated utilities from production tax credits in respect of renewable energy may adversely impact the availability to us, and marketability by us, of renewable energy under our brands. Accordingly, such decrease may result in reduced revenue and may negatively impact our financial results and our ability to pay dividends to the holders of our Class A common stock.

The suppliers from which we purchase our natural gas and electricity are subject to environmental laws and regulations that impose extensive and increasingly stringent requirements on their operations.

The assets of the suppliers from which we purchase natural gas and electricity are subject to numerous and significant federal, state and local laws, including statutes, regulations, guidelines, policies, directives and other requirements governing or relating to, among other things: protection of wildlife, including threatened and endangered species; air emissions; discharges into water; water use; the storage, handling, use, transportation and distribution of dangerous goods and hazardous, residual and other regulated materials, such as chemicals; the prevention of releases of hazardous materials into the environment; the prevention, presence and remediation of hazardous materials in soil and groundwater, both on and offsite; land use and zoning matters; and workers' health and safety matters. Environmental laws and regulations have generally become more stringent over time. Significant costs may be incurred for capital expenditures under environmental programs to keep the assets compliant with such environmental laws and regulations, which could have a material adverse impact on the businesses of our producers, which may increase the prices they charge us for natural gas and electricity and have a material adverse effect on our financial results and our ability to pay dividends to the holders of our Class A common stock.

Technological improvements and changing consumer preferences could reduce demand and alter consumption patterns.

Technological improvements in energy efficiency could potentially reduce the overall demand for natural gas and electricity. Additionally, increased competitiveness of alternative energy sources or consumer preferences that alter fuel choices could potentially reduce the demand for natural gas and electricity. A prolonged decrease in demand for natural gas and electricity in the retail energy markets would adversely affect our financial results and our ability to pay dividends to the holders of our Class A common stock.

We employ independent contractors to broker sales for which they receive residual commissions. The residual commissions paid to independent contractors could adversely affect our operating margins and financial performance, particularly if our costs rise and we do not adjust our pricing strategy.

Some of our independent contractors earn ongoing residual commissions. Residual commissions are calculated based on a fixed percentage of revenues attributable to a customer's energy consumption, without regard to our wholesale supply costs. Should our supply costs rise, our operating margins, financial results and our ability to pay dividends to the holders of our Class A common stock could be adversely affected.

Our access to marketing channels may be contingent upon the viability of our telemarketing and door-to-door agreements with our vendors.

Our vendors are essential to our telemarketing and door-to-door sales activities. Our ability to increase revenues in the future will depend significantly on our access to high quality vendors. If we are unable to attract new vendors and retain existing vendors to achieve our marketing targets, our growth may be materially reduced. There can be no assurance that competitive conditions will allow these vendors and their independent contractors to continue to successfully sign up new customers. Further, if our products are not attractive to, or do not generate sufficient revenue for our vendors, we may lose our existing relationships, which would have a material adverse effect on our business, revenues, results of operations and financial condition, as well as our ability to pay dividends to the holders of our Class A common stock. In addition, the decline in landlines reduces the number of potential customers that may be reached by our telemarketing efforts and as a result our telemarketing sales channel may become less viable, which may materially impact our financial results and our ability to pay dividends to the holders of our Class A common stock.

Our vendors may expose us to risks.

We are subject to reputational risks that may arise from the actions of our vendors and their independent contractors that are wholly or partially beyond our control, such as violations of our marketing policies and procedures as well as any failure to comply with applicable laws and regulations. If our vendors engage in marketing practices that are not in compliance with local laws and regulations, we may be in breach of applicable laws and regulations which may result in regulatory proceeding, disadvantageous conditioning of our energy retailer license, or the revocation of our energy retailer license. These risks would materially impact our financial results and our ability to pay dividends to the holders of our Class A common stock.

Unauthorized activities in connection with sales efforts by agents of our vendors, including calling consumers in violation of the Telephone Consumer Protection Act and predatory door-to-door sales tactics and fraudulent misrepresentation could subject the Company to class action lawsuits against which the Company will be required to defend. Such defense efforts will be costly and time consuming.

In addition, the independent contractors of our vendors may consider us to be their employer and seek compensation.

Risks Related to our Class A Common Stock

We may have shortfalls of cash available for distribution from operating cash flows in certain quarters, and we may not be able to continue paying our targeted quarterly dividend to the holders of our Class A common stock in the future.

The amount of our cash available for distribution principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- changes in commodity prices, which may be driven by a variety of factors, including, but not limited to, weather conditions, seasonality and demand for energy commodities and general economic conditions;
- the level and timing of customer acquisition costs we incur;
- the level of our operating and general and administrative expenses;
- seasonal variations in revenues generated by our business;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions contained in our debt agreements (including our new Senior Credit Facility);
- management of customer credit risk;
- abrupt changes in regulatory policies; and,

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~~ot~~her business risks affecting our cash flows.
As a result of these and other factors, we cannot guarantee that we will have sufficient cash generated from operations to pay a specific level of cash dividends to holders of our Class A common stock.
Due to the seasonality of our retail natural gas business, we generate the substantial majority of our cash available for distribution in the first and fourth quarters of each year. As a result of seasonality and our customer acquisition costs, we may not have sufficient cash available for distribution to cover quarterly dividends for certain quarters. Furthermore, holders of our Class A common stock should be aware that the amount of cash available for distribution depends primarily on our cash flow, and is not solely a function of profitability, which is affected by non-cash items. We may incur other expenses or liabilities during a period that could significantly reduce or eliminate our cash available for distribution and, in turn, impair our ability to pay dividends to holders of our Class A common stock during the period. Because we are a holding company, our ability to pay dividends on our Class A common stock is limited by restrictions on the ability of our subsidiaries to pay dividends or make other distributions to us. We are entitled to pay cash dividends to the holders of the Class A common stock and Spark HoldCo is entitled to make cash distributions to NuDevco and us so long as: (a) no default exists or would result from such a payment; (b) Spark HoldCo, SE and SEG are in pro forma compliance with all financial covenants before and after giving effect to such payment and (c) the outstanding amount of all loans and letters of credit does not exceed borrowing base limits. Finally, dividends to holders of our Class A common stock are paid at the discretion of our board of directors. Our board of directors may decrease the level of or entirely discontinue payment of dividends.
We are a holding company. Our sole material asset is our equity interest in Spark HoldCo and we are accordingly dependent upon distributions from Spark HoldCo to pay dividends, pay taxes, make payments under the Tax Receivable Agreement and cover our corporate and other overhead expenses under the Spark HoldCo LLC Agreement.
We are a holding company and have no material assets other than our equity interest in Spark HoldCo. We have no independent means of generating revenue. The Spark HoldCo LLC Agreement provides, to the extent Spark HoldCo has available cash and is not prevented by restrictions in any of its credit agreements, for distributions pro rata to its unitholders, including us, such that we receive an amount of cash sufficient to pay the estimated taxes payable by us, the targeted quarterly dividend we intend to pay holders of our Class A common stock, and payments under the Tax Receivable Agreement we entered into with Spark HoldCo, NuDevco Retail Holdings and NuDevco Retail. In addition, Spark HoldCo pays for our corporate and other overhead expenses pursuant to the Spark HoldCo LLC Agreement. To the extent that we need funds and Spark HoldCo or its subsidiaries are restricted from making such distributions under applicable law or regulation or under the terms of their financing arrangements, or are otherwise unable to provide such funds, it could materially adversely affect our financial results and our ability to pay dividends to the holders of our Class A common stock.

Market interest rates may have an effect on the value of our Class A common stock.
One of the factors that influences the price of shares of our Class A common stock is the effective dividend yield of such shares (i.e., the yield as a percentage of the then market price of our shares) relative to market interest rates. An increase in market interest rates, which are currently at low levels relative to historical rates, may lead prospective purchasers of shares of our Class A common stock to expect a higher dividend yield, and our inability to increase our dividend as a result of an increase in borrowing costs, insufficient cash available for distribution or otherwise, could result in selling pressure on, and a decrease in the market price of, our Class A common stock as investors seek alternative investments with higher yield.

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An active, liquid and orderly trading market for our Class A common stock may not be maintained, and our stock price may be volatile.

An active, liquid and orderly trading market for our Class A common stock may not be maintained. Active, liquid and orderly trading markets usually result in less price volatility and more efficiency in carrying out investors' purchase and sale orders. The market price of our Class A common stock could vary significantly as a result of a number of factors, some of which are beyond our control. In the event of a drop in the market price of our Class A common stock, you could lose a substantial part or all of your investment in our Class A common stock.

The stock markets in general have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our Class A common stock. Securities class action litigation has often been instituted against companies following periods of volatility in the overall market and in the market price of a company's securities. Such litigation, if instituted against us, could result in very substantial costs, divert our management's attention and resources and negatively impact our financial results and our ability to pay dividends to the holders of our Class A common stock.

Our principal shareholder holds a substantial majority of the voting power of our common stock.

Holders of Class A common stock and Class B common stock vote together as a single class on all matters presented to our stockholders for their vote or approval, except as otherwise required by applicable law or our certificate of incorporation and bylaws. NuDevco Retail Holdings, LLC and its subsidiary, NuDevco Retail, LLC (together, "NuDevco") own all of our Class B common stock (representing 78.18% of our combined voting power).

NuDevco is entitled to act separately in its own interest with respect to its investment in us. NuDevco has the ability to elect all of the members of our board of directors, and thereby to control our management and affairs. In addition, NuDevco is able to determine the outcome of all matters requiring shareholder approval, including mergers and other material transactions, and is able to cause or prevent a change in the composition of our board of directors or a change in control of our company that could deprive our stockholders of an opportunity to receive a premium for their Class A common stock as part of a sale of our company. The existence of a significant shareholder may also have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may deem to be in the best interests of our company.

So long as NuDevco continues to control a significant amount of our common stock, it will continue to be able to strongly influence all matters requiring shareholder approval, regardless of whether other stockholders believe that a potential transaction is in their own best interests. In any of these matters, the interests of NuDevco may differ or conflict with the interests of our other stockholders. Moreover, this concentration of stock ownership may also adversely affect the trading price of our Class A common stock to the extent investors perceive a disadvantage in owning stock of a company with a controlling shareholder.

We are a "controlled company" under NASDAQ Global Market rules, and as such we are entitled to an exemption from certain corporate governance standards of the NASDAQ Global Market, and you may not have the same protections afforded to shareholders of companies that are subject to all of the NASDAQ Global Market corporate governance requirements.

We qualify as a "controlled company" within the meaning of Nasdaq Global Market corporate governance standards because NuDevco controls more than 50% of our voting power. Under NASDAQ Global Market rules, a company of which more than 50% of the voting power is held by an individual, a group or another company is a "controlled company" and may elect not to comply with certain corporate governance requirements, including (i) the requirement that a majority of the board of directors consist of independent directors, (ii) the requirement to have a nominating/corporate governance committee composed entirely of independent directors and a written charter addressing the committee's purpose and responsibilities, (iii) the requirement to have a compensation committee composed entirely of independent directors and a written charter addressing the committee's purpose and

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responsibilities and (iv) the requirement of an annual performance evaluation of the nominating/corporate governance and compensation committees.

In light of our status as a controlled company, our board of directors has determined to take partial advantage of the controlled company exemption. Our board of directors has determined not to have a nominating and corporate governance committee and that our compensation committee will not consist entirely of independent directors. As a result, non-independent directors may among other things, appoint future members of our board of directors, resolve corporate governance issues, establish salaries, incentives and other forms of compensation for officers and other employees and administer our incentive compensation and benefit plans.

Accordingly, in the future, you may not have the same protections afforded to shareholders of companies that are subject to all of NASDAQ Global Market corporate governance requirements.

We engage in transactions with our affiliates and expect to do so in the future. The terms of such transactions and the resolution of any conflicts that may arise may not always be in our or our stockholders' best interests.

We have engaged in transactions and expect to continue to engage in transactions with affiliated companies. We will continue to enter into back-to-back transactions for the sale of natural gas from an affiliate. We will also continue to pay certain expenses on behalf of several of our affiliates for which we will seek reimbursement. We will also continue to share our corporate headquarters with certain affiliates. We cannot assure that our affiliates will reimburse us for the costs we have incurred on their behalf or perform their obligations under any of these contracts.

Our amended and restated certificate of incorporation and amended and restated bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our Class A common stock.

Our amended and restated certificate of incorporation authorizes our board of directors to issue preferred stock without shareholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us.

In addition, some provisions of our amended and restated certificate of incorporation and amended and restated bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders. Among other things, our amended and restated certificate of incorporation and amended and restated bylaws:

— provide for our board of directors to be divided into three classes of directors, with each class as nearly equal in number as possible, serving staggered three year terms. Our staggered board may tend to discourage a third party from making a tender offer or otherwise attempting to obtain control of us, because it generally makes it more difficult for shareholders to replace a majority of the directors;

— provide that the authorized number of directors may be changed only by resolution of the board of directors;

— provide that all vacancies in our board, including newly created directorships, may, except as otherwise required by law or, if applicable, the rights of holders of a series of preferred stock, be filled by the affirmative vote of a majority of directors then in office, even if less than a quorum;

— provide our board of directors the ability to authorize undesignated preferred stock. This ability makes it possible for our board of directors to issue, without shareholder approval, preferred stock with voting or other rights or preferences that could impede the success of any attempt to change control of us. These and other provisions may have the effect of deferring hostile takeovers or delaying changes in control or management of our company;

— provide that at any time after the first date upon which W. Keith Maxwell III no longer beneficially owns more than fifty percent of the outstanding Class A common stock and Class B common stock, any action required or permitted to be taken by the shareholders must be effected at a duly called annual or special meeting of shareholders and may not be effected by any consent in writing in lieu of a meeting of such shareholders, subject to the rights of the holders of any series of preferred stock with respect to such

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series (prior to such time, such actions may be taken without a meeting by written consent of holders of the outstanding stock having not less than the minimum number of votes that would be necessary to authorize or take such action at a meeting);

- provide that at any time after the first date upon which W. Keith Maxwell III no longer beneficially owns more than fifty percent of the outstanding Class A common stock and Class B common stock, special meetings of our shareholders may only be called by the board of directors, the chief executive officer or the chairman of the board (prior to such time, special meetings may also be called by our Secretary at the request of holders of record of fifty percent of the outstanding Class A common stock and Class B common stock);
- provide that our amended and restated certificate of incorporation and amended and restated bylaws may be amended by the affirmative vote of the holders of at least two-thirds of our outstanding stock entitled to vote thereon;
- provide that our amended and restated bylaws can be amended by the board of directors; and
- establish advance notice procedures with regard to shareholder proposals relating to the nomination of candidates for election as directors or new business to be brought before meetings of our shareholders. These procedures provide that notice of shareholder proposals must be timely given in writing to our corporate secretary prior to the meeting at which the action is to be taken. These requirements may preclude shareholders from bringing matters before the shareholders at an annual or special meeting.

In addition, in our amended and restated certificate of incorporation, we have elected not to be subject to the provisions of Section 203 of the Delaware General Corporation Law (the “DGCL”) regulating corporate takeovers until the date on which W. Keith Maxwell III no longer beneficially owns in the aggregate more than fifteen percent of the outstanding Class A common stock and Class B common stock. On and after such date, we will be subject to the provisions of Section 203 of the DGCL.

In addition, certain change of control events have the effect of accelerating the payment due under our Tax Receivable Agreement, which could be substantial and accordingly serve as a disincentive to a potential acquirer of our company.

Our amended and restated certificate of incorporation designates the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders’ ability to obtain a favorable judicial forum for disputes with us or our directors, officers, employees or agents.

Our amended and restated certificate of incorporation provides that, unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware will, to the fullest extent permitted by applicable law, be the sole and exclusive forum for (i) any derivative action or proceeding brought on our behalf, (ii) any action asserting a claim of breach of a fiduciary duty owed by any of our directors, officers, employees or agents to us or our stockholders, (iii) any action asserting a claim against us or any director or officer or other employee of ours arising pursuant to any provision of the DGCL, our amended and restated certificate of incorporation or our bylaws, or (iv) any action asserting a claim against us or any director or officer or other employee of ours that is governed by the internal affairs doctrine, in each such case subject to such Court of Chancery having personal jurisdiction over the indispensable parties named as defendants therein. Any person or entity purchasing or otherwise acquiring any interest in shares of our capital stock will be deemed to have notice of, and consented to, the provisions of our amended and restated certificate of incorporation described in the preceding sentence. This choice of forum provision may limit a stockholder’s ability to bring a claim in a judicial forum that it finds favorable for disputes with us or our directors, officers, employees or agents, which may discourage such lawsuits against us and such persons. Alternatively, if a court were to find these provisions of our amended and restated certificate of incorporation inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, financial condition or results of operations.

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Future sales of our Class A common stock in the public market could reduce our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute your ownership in us.

Subject to certain limitations and exceptions, NuDevco may exchange its Spark HoldCo units (together with a corresponding number of shares of Class B common stock) for shares of Class A common stock (on a one-for-one basis, subject to conversion rate adjustments for stock splits, stock dividends and reclassification and other similar transactions) and then sell those shares of Class A common stock. Additionally, we may issue additional shares of Class A common stock or convertible securities in subsequent public offerings. We have 3,000,000 outstanding shares of Class A common stock and 10,750,000 outstanding shares of Class B common stock. NuDevco owns 10,750,000 shares of Class B common stock, representing approximately 78.18% of our total Class A and B common stock. All such shares are restricted from immediate resale under the federal securities laws but may be sold into the market in the future. NuDevco Retail Holdings and NuDevco Retail are each a party to a registration rights agreement with us that requires us to effect the registration of their shares in certain circumstances. Subject to compliance with the Securities Act or exemptions therefrom, employees may sell their shares into the public market.

We cannot predict the size of future issuances of our Class A common stock or securities convertible into Class A common stock or the effect, if any, that future issuances or sales of shares of our Class A common stock will have on the market price of our Class A common stock. Sales of substantial amounts of our Class A common stock (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our Class A common stock. Our amended and restated certificate of incorporation allows us to issue up to an additional 186,250,000 shares of equity securities, including securities ranking senior to our Class A common stock.

We will be required to make payments under the Tax Receivable Agreement for certain tax benefits we may claim, and the amounts of such payments could be significant.

We are party to a Tax Receivable Agreement with Spark HoldCo, NuDevco Retail Holdings and NuDevco Retail. This agreement generally provide for the payment by us to NuDevco of 85% of the net cash savings, if any, in U.S. federal, state and local income tax or franchise tax that we actually realize (or are deemed to realize in certain circumstances) in periods after our initial public offering on August 1, 2014 as a result of (i) any tax basis increase resulting from the purchase by Spark Energy, Inc. of Spark HoldCo units from NuDevco Retail Holdings prior to or in connection with the initial public offering, (ii) any tax basis increases resulting from the exchange of Spark HoldCo units for shares of Class A common stock pursuant to the Spark Holdco LLC Agreement (or resulting from an exchange of Spark HoldCo units for cash pursuant to the Spark Holdco LLC Agreement) and (iii) imputed interest deemed to be paid by us as a result of, and additional tax basis arising from, any payments we make under the Tax Receivable Agreement. In addition, payments we make under the Tax Receivable Agreement will be increased by any interest accrued from the due date (without extensions) of the corresponding tax return.

Spark Energy, Inc. may be required to defer or partially defer any payment due to holders of rights under the Tax Receivable Agreement in certain circumstances during the five-year period commencing on October 1, 2014. Following the expiration of the five-year deferral period, Spark Energy, Inc. will be obligated to pay any outstanding deferred TRA Payments. While this payment obligation is subject to certain limitations, the obligation may nevertheless be significant and could adversely affect our liquidity and ability to pay dividends to the holders of our Class A common stock.

The payment obligations under the Tax Receivable Agreement are our obligations and not obligations of Spark HoldCo. For purposes of the Tax Receivable Agreement, cash savings in tax generally are calculated by comparing our actual tax liability to the amount we would have been required to pay had we not been able to utilize any of the tax benefits subject to the Tax Receivable Agreement. The term of the Tax Receivable Agreement continues until all such tax benefits have been utilized or expired, unless we exercise our right to terminate the Tax Receivable Agreement by making the termination payment specified in the agreement.

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The actual increase in tax basis, as well as the amount and timing of any payments under the Tax Receivable Agreement, will vary depending upon a number of factors, including the timing of the exchanges of Spark HoldCo units, the price of Class A common stock at the time of each exchange, the extent to which such exchanges are taxable, the amount and timing of the taxable income we generate in the future and the tax rate then applicable, and the portion of our payments under the Tax Receivable Agreement constituting imputed interest or depletable, depreciable or amortizable basis. We expect that the payments that we will be required to make under the Tax Receivable Agreement could be substantial.

The payments under the Tax Receivable Agreement will not be conditioned upon a holder of rights under the Tax Receivable Agreement having a continued ownership interest in either Spark HoldCo or us.

In certain cases, payments under the Tax Receivable Agreement may be accelerated and/or significantly exceed the actual benefits, if any, we realize in respect of the tax attributes subject to the Tax Receivable Agreement.

If we elect to terminate the Tax Receivable Agreement early or it is terminated early due to certain mergers or other changes of control, we would be required to make an immediate payment equal to the present value of the anticipated future tax benefits subject to the Tax Receivable Agreement, which calculation of anticipated future tax benefits will be based upon certain assumptions and deemed events set forth in the Tax Receivable Agreement, including the assumption that we have sufficient taxable income to fully utilize such benefits and that any Spark HoldCo units that NuDevco or its permitted transferees own on the termination date are deemed to be exchanged on the termination date. Any early termination payment may be made significantly in advance of the actual realization, if any, of such future benefits.

In these situations, our obligations under the Tax Receivable Agreement could have a substantial negative impact on our liquidity and could have the effect of delaying, deferring or preventing certain mergers, asset sales, other forms of business combinations or other changes of control due to the additional transaction cost a potential acquirer may attribute to satisfying such obligations. For example, if the Tax Receivable Agreement had been terminated immediately after our initial public offering, the estimated termination payment would be approximately $66.9 million (calculated using a discount rate equal to the LIBOR, plus 200 basis points). The foregoing number is merely an estimate and the actual payment could differ materially. There can be no assurance that we will be able to finance our obligations under the Tax Receivable Agreement.

Payments under the Tax Receivable Agreement will be based on the tax reporting positions that we will determine.

The holders of rights under the Tax Receivable Agreement will not reimburse us for any payments previously made under the Tax Receivable Agreement if such basis increases or other benefits are subsequently disallowed, except that excess payments made to any such holder will be netted against payments otherwise to be made, if any, to such holder after our determination of such excess. As a result, in such circumstances, we could make payments that are greater than our actual cash tax savings, if any, and may not be able to recoup those payments, which could adversely affect our liquidity.

We may issue preferred stock whose terms could adversely affect the voting power or value of our Class A common stock.

Our certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our Class A common stock respecting dividends and distributions, as our board of directors may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our Class A common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the Class A common stock.

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We incur increased costs as a result of being a public company.

As a publicly traded company with listed equity securities, we are required to comply with laws, regulations and requirements, including corporate governance provisions of the Sarbanes-Oxley Act of 2002, and rules and regulations of the SEC and the NASDAQ. Additional or new regulatory requirements may be adopted in the future. The requirements of existing and potential future rules and regulations increase our legal, accounting and financial compliance costs, make some activities more difficult, time-consuming or costly and may also place undue strain on our personnel, systems and resources, which could adversely affect our business, financial condition and ability to pay dividends to the holders of our Class A common stock.

For as long as we are an emerging growth company, we will not be required to comply with certain reporting requirements, including those relating to accounting standards and disclosure about our executive compensation, that apply to other public companies.

In April 2012, President Obama signed into law the JOBS Act. We are classified as an “emerging growth company” under the JOBS Act. For as long as we are an emerging growth company, which may be up to five full fiscal years, unlike other public companies, we will not be required to, among other things, (i) provide an auditor’s attestation report on management’s assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act, (ii) comply with any new requirements adopted by the PCAOB requiring mandatory audit firm rotation or a supplement to the auditor’s report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer, (iii) provide certain disclosure regarding executive compensation required of larger public companies or (iv) hold nonbinding advisory votes on executive compensation. We will remain an emerging growth company for up to five years, although we will lose that status sooner if we have more than $1.0 billion of revenues in a fiscal year, have more than $700 million in market value of our Class A common stock held by non-affiliates, or issue more than $1.0 billion of non-convertible debt over a three-year period.

To the extent that we rely on any of the exemptions available to emerging growth companies, you will receive less information about our executive compensation and internal control over financial reporting than issuers that are not emerging growth companies. If some investors find our common stock to be less attractive as a result, there may be a less active trading market for our common stock and our stock price may be more volatile.

As a result of becoming a public company, we are obligated to design and operate proper and effective internal control over financial reporting and to report our financial results in a timely fashion. If our internal control over financial reporting is determined to be ineffective or we fail to meet financial reporting deadlines, investor confidence in our company, and our Class A common stock price, may be adversely affected.

We are required to comply with certain of the SEC’s rules that implement Section 404 of the Sarbanes-Oxley Act which require management to certify financial and other information in our quarterly and annual reports and provide an annual management report on the effectiveness of our internal control over financial reporting commencing with our second annual report. This assessment will need to include the disclosure of any material weakness in internal control over financial reporting identified by our management and our independent registered public accounting firm. A “material weakness” is a deficiency, or combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis. Also, prior to our initial public offering, we were not previously required to prepare quarterly financial statements, nor were we required to generate financial statements in the time frames mandated for public companies by the Commission’s reporting requirements.

Our independent registered public accounting firm will not be required to formally attest to the effectiveness of our internal control over financial reporting until the end of the fiscal year after we are no longer an “emerging growth company” under the JOBS Act, which may be for up to five fiscal years after the completion of our initial public offering.

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Upon our further review and analysis of information related to our unaudited interim condensed combined and consolidated financial statements as of and for the three months ended March 31, 2014, included in our previous Form S-1 as filed with the Securities and Exchange Commission, we identified errors in our retail revenues and retail cost of revenues due to inaccurate data and assumptions used in estimating the recorded amounts of retail sales, retail costs of revenues and related imbalances for the three months ended March 31, 2014. We also determined there is a material weakness in our internal control over financial reporting as of March 31, 2014 due to the lack of internal controls designed to ensure that estimated retail revenues, cost of revenues and related imbalances are based on complete and accurate data and assumptions on a timely basis.

We are continuing to implement further controls to more precisely estimate and validate our recorded estimated retail revenues, retail cost of revenues and related imbalances as of December 31, 2014 in accordance with U.S. GAAP and on a timeline that ensures we can prepare our financial statements on a timely basis in compliance with reporting timelines under the Exchange Act, however, there is no guarantee that these controls are, or will be, effective. We also believe that we need to expand our accounting resources, including the size and expertise of our internal accounting team, to effectively execute a quarterly close process on an appropriate time frame for a public company. In the event that our internal control over financial reporting is perceived as inadequate, or that we are unable to produce timely or accurate financial statements, investors may lose confidence in our operating results and the trading price of our Class A common stock could decline.

Our amended and restated certificate of incorporation limits the fiduciary duties of one of our directors and certain of our affiliates and restricts the remedies available to our stockholders for actions taken by Mr. Maxwell or certain of our affiliates that might otherwise constitute breaches of fiduciary duty.

Our amended and restated certificate of incorporation contains provisions that we renounce any interest in existing and future investments in other entities by, or the business opportunities of, NuDevco Partners, LLC, NuDevco Partners Holdings, LLC and W. Keith Maxwell III, or any of their officers, directors, agents, shareholders, members, affiliates and subsidiaries (other than a director or officer of the Company who is presented an opportunity solely in his capacity as a director or officer). Because of this provision, these persons and entities have no obligation to offer us those investments or opportunities that are offered to them in any capacity other than solely as an officer or director of the Company. If one of these persons or entities pursues a business opportunity instead of presenting the opportunity to the Company, we will not have any recourse against such person or entity for a breach of fiduciary duty.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Information regarding our properties is included in “Item 1. Business and Properties” above.

Item 3. Legal Proceedings

We are the subject of lawsuits and claims arising in the ordinary course of business from time to time. Management cannot predict the ultimate outcome of such lawsuits and claims. While the lawsuits and claims are asserted for amounts that may be material should an unfavorable outcome occur, management does not currently expect that these matters will have a material adverse effect on our financial position or results of operations. See Note 10 to the audited combined and consolidated financial statements, which are incorporated herein by reference to Part II, Item 8 “Financial Statements and Supplementary Data” of this Form 10-K.

Item 4. Mine Safety Disclosures.

Not applicable.

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PART II

Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

We completed our initial public offering on August 1, 2014. Our Class A common stock began trading on the NASDAQ Global Select Market on July 29, 2014.

Our Class A common stock is traded on the NASDAQ Global Select Market under the symbol “SPKE”. On March 24, 2015, the closing price of our stock was $14.44, and we had one holder of record of our Class A common stock and two holders of record of our Class B common stock, excluding stockholders for whom shares are held in “nominee” or “street name”. The following table presents the high and low sales prices for closing market transactions as reported on the NASDAQ for the periods presented.

	Range of Market Prices	
Quarter Ended	Low	High
September 30, 2014 (beginning July 29, 2014)	15.77	17.96
December 31, 2014	13.06	17.72

Dividends

We declared a dividend on our Class A common stock of $0.2404 per share (prorated from the date of the closing of our initial public offering through September 30, 2014) on November 11, 2014 for the third quarter of 2014, which was paid on December 15, 2014 to holders of the Class A common stock as of November 28, 2014.

We declared a dividend on our Class A common stock of $0.3625 per share on February 16, 2015 for the fourth quarter of 2014, which was paid on March 16, 2015 to holders of the Class A common stock as of March 2, 2015.

We intend to pay a cash dividend each quarter to holders of our Class A common stock to the extent we have cash available for distribution to do so.

Issuer Purchases of Equity Securities

We have not repurchased any equity securities since our initial public offering, which closed on August 1, 2014.

Recent Sales of Unregistered Equity Securities

We have not sold any unregistered equity securities during the period ended December 31, 2014, other than as previously reported.

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Stock Performance Graph

The following graph compares, since the initial public offering, the monthly performance of our Class A common stock to the NASDAQ Composite Index (NASDAQ Composite) and the Dow Jones U.S. Utilities Index (IDU). The chart assumes that the value of the investment in our Class A common stock and each index was $100 at August 1, 2014, and that all dividends were reinvested. The stock performance shown on the graph below is not indicative of future price performance.

The performance graph above and related information shall not be deemed “soliciting material” or to be “filed” with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act or the Exchange Act, except to the extent that we specifically incorporate by reference.

Item 6. Selected Financial Data

The following table sets forth selected historical financial information for each of the years in the three year period ended December 31, 2014. Selected financial data is presented for the three years in accordance with the reporting requirements applicable to the Company as an “emerging growth company”.

This information is derived from our combined and consolidated financial statements and should be read in conjunction with “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Financial Statements and Supplementary Data”.

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(in thousands, except per share and volumetric data)	Year Ended December 31, 2014	2013	2012
Statement of Operations Data:			
Revenues:			
Retail revenues (including retail revenues—affiliates of $2,170, $4,022 and $1,382 for the years ended December 31, 2014, 2013 and 2012, respectively)	$320,558	$316,776	$380,198
Net asset optimization revenues (expenses) (including asset optimization revenues-affiliates of $12,842, $14,940 and $8,334 for the years ended December 31, 2014, 2013 and 2012, respectively, and asset optimization revenues affiliates cost of revenues of $30,910, $15,928 and $568 for the years ended December 31, 2014, 2013 and 2012, respectively)	2,318	314	(1,136)
Total Revenues	322,876	317,090	379,062
Operating Expenses:			
Retail cost of revenues (including retail cost of revenues-affiliates of $13, $55 and $254 for the years December 31, 2014, 2013 and 2012)	258,616	233,026	279,506
General and administrative (including general and administrative expense-affiliates of less than $100, less than $100 and $800 for the years ended December 31, 2014, 2013 and 2012, respectively)	45,880	35,020	47,321
Depreciation and amortization	22,221	16,215	22,795
Total Operating Expenses	326,717	284,261	349,622
Operating (loss) income	(3,841)	32,829	29,440
Other (expense)/income:			
Interest expense	(1,578)	(1,714)	(3,363)
Interest and other income	263	353	62
Total other expenses	(1,315)	(1,361)	(3,301)
(Loss) income before income tax expense	(5,156)	31,468	26,139
Income tax expense	(891)	56	46
Net (loss) income	(4,265)	31,412	26,093
Less: Net (loss) income attributable to non-controlling interests	(4,211)	—	—
Net (loss) income attributable to Spark Energy, Inc. stockholders	$(54)	$31,412	$26,093
Other comprehensive (loss) income:			
Deferred gain (loss) from cash flow hedges	—	2,620	(10,243)
Reclassification of deferred gain (loss) from cash flow hedges into net income	—	(84)	17,942
Comprehensive (loss) income	$(4,265)	$33,948	$33,792
Net loss income attributable to Spark Energy, Inc. per share of Class A common stock			
Basic	$(0.02)	N/A(1)	N/A(1)
Diluted	$(0.02)	N/A(1)	N/A(1)
Weighted average common shares outstanding		N/A(1)	N/A(1)
Basic	3,000	N/A(1)	N/A(1)
Diluted	3,000	N/A(1)	N/A(1)
Balance Sheet Data:			
Current assets	$105,989	$101,291	$104,246
Current liabilities	$92,816	$73,142	$67,297
Total liabilities and equity	$138,397	$109,073	$129,278

Cash Flow Data:			
Cash flows from operating activities	$5,874	$44,480	$44,076
Cash flows used in investing activities	$(3,040)	$(1,481)	$(1,643)
Cash flows used in financing activities	$(5,664)	$(42,369)	$(39,904)
Other Financial Data:			
Adjusted EBITDA (2)	$11,324	$33,533	$40,659
Retail gross margin (2)	$76,944	$81,668	$93,219
Distributions paid to Class B non-controlling unit holders and dividends paid to Class A common shareholders	$(3,305)	$—	$—
Other Operating Data:			
Customers (thousands)	318	211	237
Natural gas volumes (MMBtu)	15,724,708	16,598,751	17,527,252
Electricity volumes (MWh)	1,526,652	1,829,657	2,698,084

(1) EPS and other per share data is not meaningful prior to the Company's initial public offering, effective August 1, 2014, as the Company operated under a sole-member ownership structure.
(2) Adjusted EBITDA and retail gross margin are non-GAAP financial measures. For a definition and reconciliation of each of Adjusted EBITDA and retail gross margin to their most directly comparable financial measures calculated and presented in accordance with GAAP, please see “Management's Discussion and Analysis of Financial Condition and Results of Operations-How We Evaluate Our Operations”.

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ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the combined and consolidated financial statements and the related notes thereto included elsewhere in this report. In this report, the terms "Spark Energy," "Company," "we," "us" and "our" refer collectively to (i) the combined business and assets of the retail natural gas business and asset optimization activities of Spark Energy Gas, LLC and the retail electricity business of Spark Energy, LLC before the completion of our corporate reorganization in connection with the initial public offering of Spark Energy, Inc., which closed on August 1, 2014 (the "Offering") and (ii) Spark Energy, Inc. and its subsidiaries as of the Offering and thereafter.

Overview

We are a growing independent retail energy services company first founded in 1999 that provides residential and commercial customers in competitive markets across the United States with an alternative choice for their natural gas and electricity. We purchase our natural gas and electricity supply from a variety of wholesale providers and bill our customers monthly for the delivery of natural gas and electricity based on their consumption at either a fixed or variable-price. Natural gas and electricity are then distributed to our customers by local regulated utility companies through their existing infrastructure. As of December 31, 2014, we operated in 46 utility service territories across 16 states.

Our business consists of two operating segments:

- Retail Natural Gas Segment. We purchase natural gas supply through physical and financial transactions with market counterparts and supply natural gas to residential and commercial consumers pursuant to fixed-price, variable-price and flat-rate contracts. For the years ended December 31, 2014, 2013 and 2012, approximately 45%, 39% and 32%, respectively, of our retail revenues were derived from the sale of natural gas. We also identify wholesale natural gas arbitrage opportunities in conjunction with our retail procurement and hedging activities, which we refer to as asset optimization.

- Retail Electricity Segment. We purchase electricity supply through physical and financial transactions with market counterparts and ISOs and supply electricity to residential and commercial consumers pursuant to fixed-price and variable-price contracts. For the years ended December 31, 2014, 2013 and 2012, approximately 55%, 61% and 68%, respectively, of our retail revenues were derived from the sale of electricity.

Spark Energy, Inc. was formed in April 2014 and only has historical financial operating results for the portions of the periods covered by this report that are subsequent to the closing of the Offering on August 1, 2014. The following discussion analyzes our historical combined financial condition and results of operations before the Offering, which is the combined businesses and assets of the retail natural gas business and asset optimization activities of Spark Energy Gas, LLC ("SEG") and the retail electricity business of Spark Energy, LLC ("SE") and the consolidated results of operations and financial condition of Spark Energy, Inc. and its subsidiaries after the Offering. SE and SEG are the operating subsidiaries through which we have historically operated our retail energy business and were commonly controlled by NuDevco Partners, LLC prior to the Offering.

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Drivers of our Business

Customer Growth

(In thousands)	Retail Electricity	Retail Natural Gas	Total	% Annual Increase (Decrease)
Customers at 12/31/2011	210	109	319	
Additions	50	32	82	
Attrition	118	46	164	
Customers at 12/31/2012	142	95	237	(26)%
Additions	34	31	65	
Attrition	55	36	91	
Customers at 12/31/2013	121	90	211	(11)%
Additions	94	189	283	
Attrition	70	106	176	
Customers at 12/31/2014	145	173	318	51%

Customer growth is a key driver of our operations. We attempt to grow our customer base by offering customers competitive pricing, price certainty or green product offerings. We manage growth on a market-by-market basis by developing price curves in each of the markets we serve and comparing the market prices to the price the local regulated utility is offering. We then determine if there is an opportunity in a particular market based on our ability to create a competitive product on economic terms that satisfies our profitability objectives and provides customer value. We develop marketing campaigns using a combination of sales channels, with an emphasis on door-to-door marketing and outbound telemarketing given their flexibility and historical effectiveness. We identify and acquire customers through a variety of additional sales channels, including our inbound customer care call center, online marketing, email, direct mail, affinity programs, direct sales, brokers and consultants. Our marketing team continuously evaluates the effectiveness of each customer acquisition channel and makes adjustments in order to achieve desired growth and profitability targets.

Our 51% net customer growth in 2014 reflects the overall success of our marketing campaigns relaunched in the second half of 2013 that continued throughout 2014. Although we do not expect growth to continue at these levels, we are committed to growing and diversifying our customer base through changing market conditions. The 2014 growth was primarily organic but includes two acquisitions of customer contracts in Connecticut. See Note 14 to the Company’s audited combined and consolidated financial statements for a discussion of these acquisitions.

In 2012, our previous owner made the determination to invest excess cash flows from our operations in other affiliated businesses. As a result, we significantly reduced our spending on customer acquisition costs, including completely discontinuing some marketing channels, and focused our efforts on integrating and optimizing our existing expanded customer base. As such, our customer attrition out-paced additions and our customer count was reduced by 26%. In mid-2013, we began reactivating our marketing channels and reinvested in customer acquisitions. By late 2013 the customer book was increasing but ended 2013 down from 2012 by 11%.

Customer Acquisition Spending

(In thousands)	Year Ended 12/31/14	Year Ended 12/31/13	Year Ended 12/31/12
Total Customer Acquisition Spending	$26,191	$8,257	$6,322
Without Southern California	16,355	8,257	6,322

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Management of customer acquisition costs is a key component to our profitability. We attempt to maintain a disciplined approach to recovery of our customer acquisition costs within defined periods. We capitalize and amortize our customer acquisition costs over a two year period, which is based on the expected average length of a customer relationship. We factor in the recovery of customer acquisition costs in determining which markets we enter and the pricing of our products in those markets. Accordingly, our results are significantly influenced by our customer acquisition spending. Customer acquisition spending per customer in 2014 is in line with historical experience and management expectations.

We invested $9.8 million acquiring customers in Southern California in 2014, or approximately 37% of total customer acquisition costs of $26.2 million in 2014. Given the abnormally high early termination and disconnect for non-payment attrition rates we faced in this market, this expenditure yielded significantly less net customer growth than in our other markets. As a result, we have determined that a portion of our unamortized capitalized customer acquisition costs in Southern California in 2014 have been impaired, and we accelerated amortization of these costs by $6.5 million for the year ended December 31, 2014 to reflect the estimated future cash flows of the Southern California customer contracts.

The $16.4 million customer acquisition costs outside of Southern California were invested in acquiring gas and electricity customers across our various other markets with economics that met or exceeded our targeted return thresholds.

In 2012, our previous owner made the determination to invest excess cash flows from our operations in other affiliated businesses. As a result, we significantly reduced our spending on customer acquisition costs, including completely discontinuing some marketing channels, and focused our efforts on integrating and optimizing our existing expanded customer base. In mid-2013, we began reactivating our marketing channels and reinvested in customer acquisitions resulting in an increase in customer acquisition costs in 2013.

Our Ability to Manage Customer Attrition

	Year Ended 12/31/14	Year Ended 12/31/13	Year Ended 12/31/12
Total Attrition	5.5%	3.6%	4.6%
Without Southern California	4.8%	3.6%	4.6%

Customer attrition is primarily due to: (i) customer initiated switches; (ii) residential moves and (iii) disconnection for customer payment defaults. Our rate of attrition during 2014 increased significantly due to higher than expected customer attrition in the Northeast due to extreme weather patterns experienced during the 2013-2014 winter season. Additionally, we saw high early tenure attrition and disconnects for non-payment in the Southern California gas market where we offered flat and fixed rate gas products in a largely unpenetrated and minimally competitive market. Finally, as expected, we experienced early tenure churn in several markets where we aggressively relaunched our marketing efforts in late 2013 and 2014. We anticipate first quarter 2015 attrition to remain at elevated levels before returning to more normal levels as the elevated levels of attrition in Southern California portfolio continue due primarily to disconnects for non-payment. See “—Southern California Market Entry” below for a more detailed discussion of our attrition rates in Southern California.

Customer attrition in 2013 was benefited by the minimal customer acquisition spending throughout 2012 and most of 2013 as early tenure attrition was negligible. However, the overall customer count continued to shrink until the marketing channels were relaunched in late 2013. Customer attrition in 2012 was slightly elevated compared to 2011 levels due to the large number of customer additions in 2011, when the customer base grew by approximately 63%, or 123,000 customers.

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Customer Credit Risk

	12/31/2014	12/31/2013	12/31/2012
Total Non-POR Bad Debt as % of Revenue	5.7 %	1.8 %	1.1 %
Total Non-POR Bad Debt as % of Revenue, excluding Southern California	3.2 %	1.8 %	1.1 %

In many of the utility service territories where we conduct business, purchase of receivables ("POR") programs have been established, whereby the local regulated utility offers services for billing the customer, collecting payment from the customer and remitting payment to us. This service results in substantially all of our credit risk being linked to the applicable utility and not to our end-use customer in these territories. Approximately 44%, 47% and 55% of our retail revenues were derived from territories in which substantially all of our credit risk was directly linked to local regulated utility companies as of December 31, 2014, 2013 and 2012, respectively, all of which had investment grade ratings as of such date. During the same periods, we paid these local regulated utilities a weighted average discount of approximately 1.0% of total revenues for customer credit risk protection. In certain of the POR markets in which we operate, the utilities limit their collections exposure by retaining the ability to transfer a delinquent account back to us for collection when collections are past due for a specified period. If our collection efforts are unsuccessful, we return the account to the local regulated utility for termination of service. Under these service programs, we are exposed to credit risk related to payment for services rendered during the time between when the customer is transferred to us by the local regulated utility and the time we return the customer to the utility for termination of service, which is generally one to two billing periods. We may also realize a loss on fixed-price customers in this scenario due to the fact that we will have already fully hedged the customer's expected commodity usage for the life of the contract.

In non-POR markets (and in POR markets where we may choose to direct bill our customers), we manage customer credit risk through formal credit review in the case of commercial customers, and credit screening, deposits, disconnection for non-payment and collection efforts in the case of residential customers.
Our bad debt expense for the year ended December 31, 2014, 2013 and 2012 was approximately 5.7%, 1.8% and 1.1% of non-POR market retail revenues, respectively. Bad debt expense has increased in 2014 as a result of several factors, one of which was our focus on customer acquisition in the Southern California gas market in which we bear customer credit risk. A larger than anticipated percentage of new customers in this market have been terminating service between 30 and 90 days of coming on flow or have not been paying their invoices resulting in disconnect for non-payment, which has left the Company attempting to recoup one to three months of outstanding balances from these customers. Our ability to manage customer credit risk in this market is primarily through disconnection and aggressive collection efforts. See "—Southern California Market Entry" below. Bad debt expense attributable to the Northeast Region has also increased in 2014 as we have experienced greater difficulty in collecting higher than normal bills from commercial and residential customers following the extreme weather patterns in that region during the 2014 winter season.

We recorded accounts receivable, net of allowance, for non-POR markets of $24.6 million and $24.8 million for the years ended December 31, 2014 and 2013, respectively. As of December 31, 2014 and 2013, we had recorded accounts receivable, net of allowance, of $0.9 million and zero for Southern California.

Our bad debt expense in 2013 and 2012 was in line with industry averages and primarily resulted from Texas, which was our largest non-POR market during both years.

Southern California Market Entry

The Company's results for 2014 were negatively impacted by our market entry into Southern California. Starting in the second quarter of 2014 we accelerated our growth by acquiring carbon neutral gas customers in Southern California. Although we were successful in our acquisition of customers, the campaign faced significant challenges. These challenges resulted in higher than estimated customer attrition and bad debt expense. We attribute our high customer

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attrition and non-payment rates in the Southern California gas market to confusion and lack of awareness by consumers in an early stage competitive market that is also a “dual bill” market for which customers receive two bills, one from the local distribution utility for delivery and one from the retail energy provider for the product. These factors were exacerbated by the lack of an immediate savings from the utility price as the products that we are offering provided carbon natural gas at a neutral fixed price rather than an immediate savings claim. As a result, our monthly attrition in the Southern California gas market averaged 11.4% during the time we were actively marketing there (April 2014 to December 2014), as compared to an average attrition rate of 4.8% for the rest of the Company’s markets during 2014. Our bad debt expense in this market is heavily impacted by early stage customer attrition and non-payment rates. As noted above, a much larger than anticipated percentage of new customers in this market terminated or had their services disconnected for non-payment between 30 and 90 days of coming on flow which has left the Company attempting to recoup one to three months of outstanding balances from these customers. Our ability to manage customer credit risk in this market is primarily through disconnection and aggressive collection efforts. Our bad debt expense in the Southern California gas market during 2014 was $4.8 million, or an average of 51.0%, as compared to $5.4 million, or an average of 3.2%, for all other markets.

During the third quarter, we began responding to the initial negative results in the Southern California gas market by reducing customer acquisition spending in this market, revamping our products, renegotiating our compensation structure with our primary sales vendor, and increasing our efforts to train the vendor and educate the customer, all with the goal of improving the overall economics for this market. By the end of the third quarter, we had significantly reduced customer acquisition spending as the mitigation efforts taken in the quarter were not providing the desired results. In the fourth quarter, we took further steps to reduce our sales in Southern California, such that we substantially ceased marketing efforts by the end of the year. We continue to focus our efforts on aggressive collection initiatives. We invested $9.8 million acquiring customers in Southern California in 2014, or approximately 37% of total customer acquisition spending of $26.2 million in 2014. We have determined that a portion of our unamortized customer acquisition costs in Southern California in 2014 has been impaired, resulting in accelerated amortization of these costs of $6.5 million during the year ended December 31, 2014. Additionally, although marketing efforts in Southern California substantially ceased by the end of 2014, new customers continue to come on-flow in the first quarter of 2015. We anticipate attrition and bad debt expense to remain high during the first quarter of 2015 as a result of these issues.

Weather Conditions

Weather conditions directly influence the demand for natural gas and electricity and affect the prices of energy commodities. Our hedging strategy is based on forecasted customer energy usage, which can vary substantially as a result of weather patterns deviating from historical norms. We are particularly sensitive to this variability because of our current substantial concentration and focus on growth in the residential customer segment in which energy usage is highly sensitive to weather conditions that impact heating and cooling demand. The extreme weather patterns during the 2013 and 2014 winter season caused commodity demand and prices to rise significantly beyond industry forecasts. As a result, the retail energy industry generally charged higher prices to its variable-price customers resulting in increased attrition and bad debt expense and was subject to decreased margins on fixed-price contracts due to unanticipated increases in volumetric demand that had to be purchased in the spot market at high prices. Our results during the first quarter of 2014 suffered as a result of this severe weather abnormality. After the first quarter 2014 extreme weather conditions, our major markets returned to historical norms for the remainder of the year.

Asset Optimization

Our natural gas business includes opportunistic transactions in the natural gas wholesale marketplace in conjunction with our retail procurement and hedging activities. Asset optimization opportunities primarily arise during the winter heating season when demand for natural gas is the highest. As such, the majority of our asset optimization profits are made in the winter. Given the opportunistic nature of these activities we experience variability in our earnings from our asset optimization activities from year to year. As these activities are accounted for using mark-to-market accounting, the timing of our revenue recognition often differs from the actual cash settlement.

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During 2014, we were obligated to pay demand charges of approximately $2.8 million under certain long-term legacy transportation assets that our predecessor entity acquired prior to 2013. Although these demand payments will decrease over time, the related capacity agreements extend through 2028. Net asset optimization results were a gain of $2.3 million, a gain of $0.3 million and a loss of $1.1 million for the year ended December 31, 2014, 2013 and 2012, respectively, primarily due to arbitrage opportunities we captured during the extreme weather pattern in the Northeast during the first quarter offset by our legacy capacity charges.

Factors Affecting Comparability of Historical Financial Results

Tax Receivable Agreement. The Tax Receivable Agreement between us and NuDevco Retail Holdings, LLC, NuDevco Retail, LLC and Spark HoldCo provides for the payment by Spark Energy, Inc. to NuDevco Retail Holdings of 85% of the net cash savings, if any, in U.S. federal, state and local income tax or franchise tax that Spark Energy, Inc. actually realizes (or is deemed to realize in certain circumstances) in periods after the Offering as a result of (i) any tax basis increases resulting from the purchase by Spark Energy, Inc. of Spark HoldCo units from NuDevco Retail Holdings prior to or in connection with the Offering, (ii) any tax basis increases resulting from the exchange of Spark HoldCo units for shares of Class A common stock pursuant to the exchange right set forth in the limited liability company agreement of Spark HoldCo (or resulting from an exchange of Spark HoldCo units for cash under the Spark HoldCo limited liability agreement) and (iii) any imputed interest deemed to be paid by us as a result of, and additional tax basis arising from, any payments we make under the Tax Receivable Agreement. In addition, payments we make under the Tax Receivable Agreement will be increased by any interest accrued from the due date (without extensions) of the corresponding tax return. We have recorded 85% of the estimated tax benefit as an increase to amounts payable under the Tax Receivable Agreement as a liability. We will retain the benefit of the remaining 15% of these tax savings.

Executive Compensation Programs. On August 1, 2014, we granted restricted stock units to our employees, non-employee directors, and certain employees of our affiliates who perform services for us under our long-term incentive plan. The initial restricted stock unit awards generally vest ratably over approximately one, three or four years commencing May 4, 2015 and include tandem dividend equivalent rights that will vest upon the same schedule as the underlying restricted stock unit.

Financing. The total amounts outstanding under our Seventh Amended Credit Agreement as of December 31, 2013 and until the Offering included amounts used to fund equity distributions to our common control owner to fund operations of an affiliated company. As such, historical borrowings under our Seventh Amended Credit Agreement may not provide an accurate indication of what we need to operate our natural gas and electricity business. Concurrently with the closing of the Offering, we entered into a new $70.0 million Senior Credit Facility, and the Seventh Amended Credit Agreement was terminated.

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How We Evaluate Our Operations

(in thousands)	Year Ended December 31, 2014	2013	2012
Adjusted EBITDA	$11,324	$33,533	$40,659
Retail Gross Margin	$76,944	$81,668	$93,219

Adjusted EBITDA. We define "Adjusted EBITDA" as EBITDA less (i) customer acquisition costs incurred in the current period, (ii) net gain (loss) on derivative instruments, and (iii) net current period cash settlements on derivative instruments, plus (iv) non-cash compensation expense and (v) other non-cash operating items. EBITDA is defined as net income (loss) before provision for income taxes, interest expense and depreciation and amortization. We deduct all current period customer acquisition costs in the Adjusted EBITDA calculation because such costs reflect a cash outlay in the year in which they are incurred, even though we capitalize such costs and amortize them over two years in accordance with our accounting policies. The deduction of current period customer acquisition costs is consistent with how we manage our business, but the comparability of Adjusted EBITDA between periods may be affected by varying levels of customer acquisition costs. For example, our Adjusted EBITDA is lower in years of customer growth reflecting larger customer acquisition spending. We deduct our net gains (losses) on derivative instruments, excluding current period cash settlements, from the Adjusted EBITDA calculation in order to remove the non-cash impact of net gains and losses on derivative instruments. We also deduct non-cash compensation expense as a result of restricted stock units that are issued under our long-term incentive plan.

We believe that the presentation of Adjusted EBITDA provides information useful to investors in assessing our liquidity and financial condition and results of operations and that Adjusted EBITDA is also useful to investors as a financial indicator of a company's ability to incur and service debt, pay dividends and fund capital expenditures. Adjusted EBITDA is a supplemental financial measure that management and external users of our combined and consolidated financial statements, such as industry analysts, investors, commercial banks and rating agencies, use to assess the following:

- our operating performance as compared to other publicly traded companies in the retail energy industry, without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate earnings sufficient to support our proposed cash dividends; and
- our ability to fund capital expenditures (including customer acquisition costs) and incur and service debt.

Retail Gross Margin. We define retail gross margin as operating income (loss) plus (i) depreciation and amortization expenses and (ii) general and administrative expenses, less (i) net asset optimization revenues, (ii) net gains (losses) on non-trading derivative instruments, and (iii) net current period cash settlements on non-trading derivative instruments. Retail gross margin is included as a supplemental disclosure because it is a primary performance measure used by our management to determine the performance of our retail natural gas and electricity business by removing the impacts of our asset optimization activities and net non-cash income (loss) impact of our economic hedging activities. As an indicator of our retail energy business' operating performance, retail gross margin should not be considered an alternative to, or more meaningful than, operating income (loss), its most directly comparable financial measure calculated and presented in accordance with GAAP.

The GAAP measures most directly comparable to Adjusted EBITDA are net income (loss) and net cash provided by operating activities. The GAAP measure most directly comparable to Retail Gross Margin is operating income (loss). Our non-GAAP financial measures of Adjusted EBITDA and Retail Gross Margin should not be considered as alternatives to net income (loss), net cash provided by operating activities, or operating income (loss). Adjusted EBITDA and Retail Gross Margin are not presentations made in accordance with GAAP and have important limitations as analytical tools. You should not consider Adjusted EBITDA or Retail Gross Margin in isolation or as a substitute for analysis of our results as reported under GAAP. Because Adjusted EBITDA and Retail Gross Margin exclude some, but not all, items that affect net income (loss) and net cash provided by operating activities,

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and are defined differently by different companies in our industry, our definition of Adjusted EBITDA and Retail Gross Margin may not be comparable to similarly titled measures of other companies.
Management compensates for the limitations of Adjusted EBITDA and Retail Gross Margin as analytical tools by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these data points into management's decision-making process.

The following table presents a reconciliation of Adjusted EBITDA to net (loss) income for each of the periods indicated.

	Year Ended December 31,		
(in thousands)	2014	2013	2012
Reconciliation of Adjusted EBITDA to Net (Loss) Income:			
Net (loss) income	$(4,265)	$31,412	$26,093
Depreciation and amortization	22,221	16,215	22,795
Interest expense	1,578	1,714	3,363
Income tax expense	(891)	56	46
EBITDA	18,643	49,397	52,297
Less:			
Net, Gains (losses) on derivative instruments	(14,535)	6,567	(21,485)
Net, Cash settlements on derivative instruments	(3,479)	1,040	26,801
Customer acquisition costs	26,191	8,257	6,322
Plus:			
Non-cash compensation expense	858	—	—
Adjusted EBITDA	$11,324	$33,533	$40,659

The following table presents a reconciliation of Adjusted EBITDA to net cash provided by operating activities for each of the periods indicated.

	Year Ended December 31,		
(in thousands)	2014	2013	2012
Reconciliation of Adjusted EBITDA to net cash provided by operating activities:			
Net cash provided by operating activities	$5,874	$44,480	$44,076
Amortization and write off of deferred financing costs	(631)	(678)	(919)
Allowance for doubtful accounts and bad debt expense	(10,164)	(3,101)	(1,835)
Interest expense	1,578	1,714	3,363
Income tax (benefit) expense	(891)	56	46
Changes in operating working capital			
Accounts receivable, prepaids, current assets	13,332	(17,790)	(12,737)
Inventory	3,711	599	(3,442)
Accounts payable and accrued liabilities	(2,466)	7,879	12,689
Other	981	374	(582)
Adjusted EBITDA	$11,324	$33,533	$40,659

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The following table presents a reconciliation of Retail Gross Margin to operating (loss) income for each of the periods indicated.

(in thousands)	Year Ended December 31, 2014	2013	2012
Reconciliation of Retail Gross Margin to Operating (Loss) Income:			
Operating (loss) income	$(3,841)	$32,829	$29,440
Depreciation and amortization	22,221	16,215	22,795
General and administrative	45,880	35,020	47,321
Less:			
Net asset optimization revenue	2,318	314	(1,136)
Net, Gains (losses) on non-trading derivative instruments	(8,713)	1,429	(19,016)
Net, Cash settlements on non-trading derivative instruments	(6,289)	653	26,489
Retail Gross Margin	$76,944	$81,668	$93,219

Combined and Consolidated Results of Operations

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

In Thousands	Year Ended December 31, 2014	2013	Change
Revenues:			
Retail revenues	$320,558	$316,776	$3,782
Net asset optimization revenues	2,318	314	2,004
Total Revenues	322,876	317,090	5,786
Operating Expenses:			
Retail cost of revenues	258,616	233,026	25,590
General and administrative	45,880	35,020	10,860
Depreciation and amortization	22,221	16,215	6,006
Total Operating Expenses	326,717	284,261	42,456
Operating (loss) income	(3,841)	32,829	(36,670)
Other (expense)/income:			
Interest expense	(1,578)	(1,714)	136
Interest and other income	263	353	(90)
Total other (expenses)/income	(1,315)	(1,361)	46
(Loss) income before income tax expense	(5,156)	31,468	(36,624)
Income tax (benefit) expense	(891)	56	(947)
Net (loss) income	$(4,265)	$31,412	$(35,677)
Adjusted EBITDA (1)	$11,324	$33,533	$(22,209)
Retail Gross Margin (1)	$76,944	$81,668	$(4,724)
Customer Acquisition Costs	$26,191	$8,257	$17,934
Customer Attrition	5.5%	3.6%	1.9%
Distributions paid to Class B non-controlling unit holders and dividends paid to Class A common shareholders	$3,305	$—	$3,305

(1) Adjusted EBITDA and Retail Gross Margin are non-GAAP financial measures. See "How We Evaluate Our Operations" for a reconciliation of Adjusted EBITDA and Retail Gross Margin to their most directly comparable financial measures presented in accordance with GAAP.

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Total Revenues. Total revenues for the year ended December 31, 2014 were approximately $322.9 million, an increase of approximately $5.8 million, or 2%, from approximately $317.1 million for the year ended December 31, 2013. This increase was primarily due to overall higher customer pricing across both commodities, in part due to increased supply costs, which resulted in an increase in total revenues of $38.1 million, as well as a $2.0 million increase in net asset optimization revenues. This increase was offset by a decrease of $34.3 million due to customer sales volumes which were lower, primarily due to the shift of the concentration of our marketing efforts from commercial customers to residential customers.

Net Asset Optimization Revenues. Net asset optimization revenues for the year ended December 31, 2014 were approximately $2.3 million, an increase of approximately $2.0 million, or 667%, from $0.3 million in the prior year. This increase was primarily due to physical gas arbitrage opportunities in the Northeast that arose due to extreme winter weather conditions in 2014 and losses we recognized in 2013 from a hedge strategy involving interruptible transportation that did not repeat in 2014.

Retail Cost of Revenues. Total retail cost of revenues for the year ended December 31, 2014 was approximately $258.6 million, an increase of approximately $25.6 million, or 11%, from approximately $233.0 million for the year ended December 31, 2013. This increase was primarily due to increased supply costs arising from capacity constraints from the extreme weather conditions in the Northeast during the first quarter of 2014, which resulted in an increase of total retail cost of revenues of $35.6 million, as well as an increase of $17.0 million due to a change in the value of our non-trading derivative portfolio used for hedging. This increase was offset by a decrease of $27.0 million due to customer sales volumes which were lower, primarily due to the strategic shift of the concentration of our marketing efforts from commercial customers to residential customers.

General and Administrative Expense. General and administrative expense for the year ended December 31, 2014 was approximately $45.9 million, an increase of approximately $10.9 million, or 31%, as compared to $35.0 million for the year ended December 31, 2013. This increase was primarily due to an increase of bad debt expense of $7.1 million, which was $10.2 million for the year ended December 31, 2014 compared to $3.1 million for the year ended December 31, 2013, as well as increased costs associated with being a public company and increased billing and other variable costs associated with increased customers.

Depreciation and Amortization Expense. Depreciation and amortization expense for the year ended December 31, 2014 was approximately $22.2 million, an increase of approximately $6.0 million, or 37%, from approximately $16.2 million for the year ended December 31, 2013. This increase was primarily due to the accelerated amortization of capitalized customer acquisition costs in Southern California and Massachusetts of $6.5 million and $0.2 million, respectively, in the fourth quarter of 2014 offset by lower depreciation for certain software assets that were fully depreciated in 2013.

Customer Acquisition Cost. Customer acquisition cost for the year ended December 31, 2014 was approximately $26.2 million, an increase of approximately $17.9 million from approximately $8.3 million for the year ended December 31, 2013. This increase was due to our increased marketing efforts to grow our customer base beginning in the second half of 2013 and continuing during 2014 including spending in California of $15.4 million, spending in Illinois of $6.4 million and spending in New York for $1.1 million for the year ended December 31, 2014.

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Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

In Thousands	Year Ended December 31, 2013	2012	Change
Revenues:			
Retail revenues	$316,776	$380,198	$(63,422)
Net asset optimization revenues	314	(1,136)	1,450
Total Revenues	317,090	379,062	(61,972)
Operating Expenses:			
Retail cost of revenues	233,026	279,506	(46,480)
General and administrative	35,020	47,321	(12,301)
Depreciation and amortization	16,215	22,795	(6,580)
Total Operating Expenses	284,261	349,622	(65,361)
Operating (loss) income	32,829	29,440	3,389
Other (expense)/income:			
Interest expense	(1,714)	(3,363)	1,649
Interest and other income	353	62	291
Total other (expenses)/income	(1,361)	(3,301)	1,940
(Loss) income before income tax expense	31,468	26,139	5,329
Income tax expense	56	46	10
Net (loss) income	$31,412	$26,093	$5,319
Adjusted EBITDA (1)	$33,533	$40,659	$(7,126)
Retail Gross Margin (1)	$81,668	$93,219	$(11,551)
Customer Acquisition Costs	$8,257	$6,322	$1,935
Customer Attrition	3.6%	4.6%	(1.0)%

(1) Adjusted EBITDA and Retail Gross Margin are non-GAAP financial measures. See “How We Evaluate Our Operations” for a reconciliation of Adjusted EBITDA and Retail Gross Margin to their most directly comparable financial measures presented in accordance with GAAP.

Total Revenues. Total revenues for the year ended December 31, 2013 were approximately $317.1 million, a decrease of approximately $62.0 million, or 16%, from approximately $379.1 million for the year ended December 31, 2012. This decrease was primarily due to lower customer sales volumes, which resulted in a decrease in total revenues of $89.2 million. This decrease was offset by an increase of total revenues of $25.7 million due to increased customer pricing and a $1.5 million increase in net asset optimization revenues.

Net Asset Optimization Revenues. Net asset optimization revenues for the year ended December 31, 2013 were approximately $0.3 million, an increase of approximately $1.4 million, or 128%, from $(1.1) million in the same period in the prior year. We recognized losses in late 2012 and early 2013 on a hedge strategy involving interruptible transportation, partially offset by increased arbitrage opportunities in the fourth quarter of 2013 in the northeast United States.

Retail Cost of Revenues. Total retail cost of revenues for the year ended December 31, 2013 was approximately $233.0 million, a decrease of approximately $46.5 million, or 17%, from approximately $279.5 million for the year ended December 31, 2012. This decrease was primarily due to lower customer sales volumes, which resulted in a decrease in total retail cost of revenues of $70.0 million. This decrease was offset by an increase of total retail cost of revenues of $18.1 million due to energy supply prices and a $5.4 million decrease in net gains on non-trading derivative instruments, net of cash settlements.

General and Administrative Expense. General and administrative expense for the year ended December 31, 2013 was approximately $35.0 million, a decrease of approximately $12.3 million or 26%, as compared to $47.3 million

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for the year ended December 31, 2012. Approximately $8.0 million of the decrease in our general and administrative expenses was due to a companywide initiative to reduce costs and realize operational efficiencies in conjunction with our shift in focus from increasing our customer base to optimizing our customer base. Additionally, approximately $2.7 million was attributable to a decrease in sales and marketing expenses.

Depreciation and Amortization Expense. Depreciation and amortization expense for the year ended December 31, 2013 was approximately $16.2 million, a decrease of approximately $6.6 million, or 29%, from approximately $22.8 million in the same period in the prior year. This decrease was primarily due to the amortization in 2011 of a portion of higher customer acquisition costs that were incurred in 2011.

Interest Expense. Interest expense for the year ended December 31, 2013 was approximately $1.7 million, a decrease of approximately $1.7 million, or 50%, from approximately $3.4 million in the same period in the prior year. This decrease was primarily due to reduced interest expense due to lower average borrowing amounts during the year as a result of reduced customer acquisition expenses in connection with the strategic initiative to optimize our customer base in 2012 discussed above.

Customer Acquisition Cost. Customer acquisition cost for the year ended December 31, 2013 was approximately $8.3 million, an increase of approximately $2.0 million, or 31%, from approximately $6.3 million in the prior year. This increase was primarily due to increasing our marketing efforts during the second half of 2013 to grow our customer base.

Operating Segment Results

	Year Ended December 31,		
	2014	2013	2012
	(in millions, except volume and per unit operating data)		
Retail Natural Gas Segment			
Total Revenues	$146.5	$125.2	$122.7
Retail Cost of Revenues	109.2	83.1	77.0
Less: Net Asset Optimization Revenues	2.3	0.3	(1.1)
Less: Net Gains (Losses) on non-trading derivatives, net of cash settlements	(9.3)	(0.6)	6.3
Retail Gross Margin-Gas	$44.3	$42.4	$40.5
Volumes-Gas (MMBtu's)	15,724,708	16,598,751	17,527,252
Retail Gross Margin-Gas per MMBtu	$2.82	$2.55	$2.31
Retail Electricity Segment			
Total Revenues	$176.4	$191.9	$256.4
Retail Cost of Revenues	149.5	149.9	202.5
Less: Net Gains (Losses) on non-trading derivatives, net of cash settlements	(5.7)	2.7	1.2
Retail Gross Margin—Electricity	$32.6	$39.3	$52.7
Volumes - Electricity (MWh's)	1,526,652	1,829,657	2,698,084
Retail Gross Margin—Electricity per MWh	$21.37	$21.48	$19.55

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

Retail Natural Gas Segment

Retail revenues for the Retail Natural Gas Segment for the year ended December 31, 2014 were approximately $146.5 million, an increase of approximately $21.3 million, or 17%, from approximately $125.2 million for the year ended December 31, 2013. This increase was primarily due to higher customer pricing implemented in part to capture increased supply costs, which resulted in an increase of $21.9 million, as well as a $2.0 million increase in net optimization revenues. This increase was offset by a decrease of $2.6 million due to decreased customer sales volumes.

Retail cost of revenues for the Retail Natural Gas Segment for the year ended December 31, 2014 were approximately $109.2 million, an increase of approximately $26.1 million, or 31%, from approximately $83.1 million for the year ended December 31, 2013. This increase was primarily due to increased supply costs resulting from the extreme weather conditions experienced across the United States during the first quarter of 2014, which resulted in an increase of $19.2 million, as well as a $8.6 million increase due to a change in the value of our non-trading derivative portfolio used for hedging. This increase was offset primarily by a $1.7 million decrease due to decreased customer sales volumes.

Retail gross margin for the Retail Natural Gas Segment for the year ended December 31, 2014 was approximately $44.3 million, an increase of approximately $1.9 million, or 4%, as compared to $42.4 million for the year ended December 31, 2013, as indicated in the table below (in millions).

Increase in unit margin per MMBtu	$2.9	
Decrease in volumes sold	(1.0	)
Decrease in retail natural gas segment retail gross margin	$1.9	

The volumes of natural gas sold decreased from 16,598,751 MMBtu for the year ended December 31, 2013 to 15,724,708 MMBtu for the year ended December 31, 2014. This decrease was primarily due to the shift in our customer base to lower volume, higher margin residential gas users, primarily in Southern California.

Retail Electricity Segment

Retail revenues for the Retail Electricity Segment for the year ended December 31, 2014 were approximately $176.4 million, a decrease of approximately $15.5 million, or 8%, from approximately $191.9 million for the year ended December 31, 2013. This decrease was primarily due to lower customer sales volumes, which resulted in a decrease of $31.7 million. This decrease was offset by an increase of retail revenues of $16.2 million due to higher customer pricing implemented in part to capture increased supply costs.

Retail cost of revenues for the Retail Electricity Segment for the year ended December 31, 2014 were approximately $149.5 million, a decrease of approximately $0.4 million, or 0%, from approximately $149.9 million for the year ended December 31, 2013. This decrease was primarily due to lower customer sales volumes, which resulted in a decrease of approximately $25.1 million. This decrease was offset by increased supply costs resulting from the extreme weather conditions experienced across the United States during the first quarter of 2014, which resulted in an increase in retail cost of revenues of $16.4 million, as well as an $8.3 million increase due to a change in the value of our non-trading derivative portfolio used for hedging.

Retail gross margin for the Retail Electricity Segment for the year ended December 31, 2014 was approximately $32.6 million, a decrease of approximately $6.7 million, or 17%, as compared to $39.3 million for the year ended December 31, 2013, as indicated in the table below (in millions).

Decrease in unit margin per MWh	$(0.2	)
Decrease in volumes sold	(6.5	)
Decrease in retail electricity segment retail gross margin	$(6.7	)

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The volumes of electricity sold decreased from 1,829,657 MWh for the year ended December 31, 2013 to 1,526,652 MWh for the year ended December 31, 2014. This decrease was primarily due to a decreased focus on higher volume but lower margin commercial customers. Electric unit margins expanded in 2014 with our shift to higher margin residential customers but were negatively impacted by the increased supply cost during the extreme weather patterns in the first quarter.

Year Ended December 31, 2013 Compared to the Year Ended December 31, 2012

Retail Natural Gas Segment

Retail revenues for the Retail Natural Gas Segment for the year ended December 31, 2013 were approximately $125.2 million, an increase of approximately $2.5 million, or 2%, from approximately $122.7 million in the prior year. This increase was primarily due to increased customer pricing, which resulted in an increase of $7.6 million, as well as an increase of $1.5 million due to net asset optimization revenue. This increase was offset by a decrease of $6.6 million due to lower customer sales volumes.

Retail cost of revenues for the Retail Natural Gas Segment for the year ended December 31, 2013 was approximately $83.1 million, an increase of approximately $6.1 million, or 8%, from approximately $77.0 million in the prior year. This increase was primarily due to a $6.9 million decrease in the value of our non-trading derivative portfolio used for hedging, as well as increased commodity prices, which resulted in an increase of $3.6 million. This increase was offset by a decrease of retail cost of revenues of $4.4 million due to lower customer sales volumes.

Retail gross margin for the Retail Natural Gas Segment for the year ended December 31, 2013 was approximately $42.4 million, an increase of approximately $1.9 million, or 5%, from approximately $40.5 million for the year ended December 31, 2012, as indicated in the table below (in millions).

Increase in unit margin per MMBtu	$4.0	
Decrease in volumes sold	(2.1	)
Increase in retail natural gas segment retail gross margin	$1.9	

The volumes of natural gas sold decreased from 17,527,252 MMBtu during the year ended December 31, 2012 to 16,598,751 MMBtu during the year ended December 31, 2013, due to our natural gas customer attrition outpacing natural gas customer acquisition attributable to the shift in our strategic focus, coupled with a decreased focus on higher-volume but lower margin commercial customers.

Retail Electricity Segment

Retail revenues for the Retail Electricity Segment for the year ended December 31, 2013 were approximately $191.9 million, a decrease of approximately $64.5 million, or 25%, from approximately $256.4 million in the prior year. This decrease was primarily due to lower customer sales volumes, which resulted in a decrease of $82.5 million. This decrease was offset by an increase of retail revenues of $18.0 million due to increased customer pricing.

Retail cost of revenues for the Retail Electricity Segment for the year ended December 31, 2013 was approximately $149.9 million, a decrease of approximately $52.6 million, or 26%, from approximately $202.5 million in the prior year. This decrease was primarily due to lower customer sales volumes, which resulted in a decrease in retail cost of revenues of $65.6 million and a $1.5 million increase in the value of our non-trading derivative portfolio used for hedging. This decrease was offset by an increase of retail cost of revenues of $14.5 million due to increased commodity prices.

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Retail gross margin for the Retail Electricity Segment for the year ended December 31, 2013 was approximately $39.3 million, a decrease of approximately $13.4 million, or 25%, as compared to $52.7 million for the year ended December 31, 2012, as indicated in the table below (in millions).

Increase in unit margin per MWh	$3.6	
Decrease in volumes sold	(17.0	)
Decrease in retail electricity segment retail gross margin	$(13.4	)

The volumes of electricity sold decreased from 2,698,084 MWh during the year ended December 31, 2012 to 1,829,657 MWh during the year ended December 31, 2013, due to our electricity customer attrition outpacing electricity customer acquisition attributable to the shift in our strategic focus, coupled with a decreased focus on higher-volume but lower margin commercial customers.

Liquidity and Capital Resources

Our liquidity requirements fluctuate with our customer acquisition cost spending level, acquisitions, collateral posting requirements on our hedge portfolio, distributions, the effects of the timing between payments of payables and receipt of receivables, including bad debt receivables, and our general working capital needs for ongoing operations. Our credit facility borrowings are also subject to material variations on a seasonal basis due to the timing of commodity purchases to satisfy required natural gas inventory purchases and to meet customer demands during periods of peak usage. Moreover, estimating our liquidity requirements is highly dependent on then-current market conditions, including forward prices for natural gas and electricity, and market volatility.

Our primary sources of liquidity are cash generated from operations and borrowings under our Senior Credit Facility. We believe that cash generated from these sources will be sufficient to sustain operations, to finance anticipated expansion plans and growth initiatives, and to pay required taxes and quarterly cash distributions. However, in the event our liquidity is insufficient, we may be required to limit our spending on future growth or other business opportunities or to rely on external financing sources, including additional commercial bank borrowings and the issuance of debt and additional equity securities, to fund our growth.

Based upon our current plans, level of operations and business conditions, we believe that our cash on hand, cash generated from operations, and available borrowings under our credit facility will be sufficient to meet our capital requirements and working capital needs for the foreseeable future.

The following table details our total liquidity as of the period presented:

($ in thousands)	December 31, 2014
Cash and cash equivalents	$4,359
Senior Credit Facility Availability [1]	26,260
Total Liquidity	$30,619

[1] Subject to Senior Credit Facility borrowing base restrictions.

Capital expenditure in 2014 included approximately $26.2 million on customer acquisitions and $3.0 million related to information systems improvements, including $2.0 million related to our outsourced customer information system.

The Spark HoldCo, LLC Agreement provides, to the extent cash is available, for distributions pro rata to the holders of Spark HoldCo units such that we receive an amount of cash sufficient to cover the estimated taxes payable by us, the targeted quarterly dividend we intend to pay to holders of our Class A common stock, and payments under the

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Tax Receivable Agreement we have entered into with Spark HoldCo, NuDevco Retail Holdings and NuDevco Retail. We paid a regular quarterly dividend on our Class A common stock of $0.3625 per share in 2014, or approximately $1.45 per share or $4.4 million on an annualized basis, which was prorated from the Offering date of August 1, 2014 for the third quarter 2014 dividend. No dividends on our Class A common stock will accrue in arrears. Our ability to pay dividends in the future will depend on many factors, including the performance of our business in the future and restrictions under our new Senior Credit Facility. In order to pay these dividends to holders of our Class A common stock and corresponding distributions to holders of our Class B common stock, we expect that Spark HoldCo will be required to distribute approximately $19.9 million on an annualized basis to holders of Spark HoldCo units. If our business does not generate enough cash for Spark HoldCo to make such distributions, we may have to borrow to pay our dividend. If our business generates cash in excess of the amounts required to pay an annual dividend of $1.45 per share of Class A common stock, we currently expect to reinvest any such excess cash flows in our business and not increase the distributions payable to holders of our Class A common stock. However, our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including the results of our operations, our financial condition, capital requirements and investment opportunities. On November 11, 2014, our Board of Directors declared a quarterly dividend for the third quarter of 2014 to holders of the Class A common stock on November 28, 2014. This dividend was paid on December 15, 2014. On February 16, 2015, our Board of Directors declared a quarterly dividend for the fourth quarter of 2014 to holders of the Class A common stock of record on March 2, 2015. This dividend will be paid on March 16, 2014.
In addition, we expect to make payments pursuant to the Tax Receivable Agreement that we have entered into with NuDevco Retail Holdings, NuDevco Retail and Spark HoldCo in connection with the Offering. Except in cases where we elect to terminate the Tax Receivable Agreement early (the Tax Receivable Agreement is terminated early due to certain mergers or other changes of control) or we have available cash but fail to make payments when due, generally we may elect to defer payments due under the Tax Receivable Agreement if we do not have available cash to satisfy our payment obligations under the Tax Receivable Agreement or if our contractual obligations limit our ability to make these payments. Any such deferred payments under the Tax Receivable Agreement generally will accrue interest. If we were to defer substantial payment obligations under the Tax Receivable Agreement on an ongoing basis, the accrual of those obligations would reduce the availability of cash for other purposes, but we would not be prohibited from paying dividends on our Class A common stock. See “Risk Factors—Risks Related to our Class A Common Stock” for risks related to the Tax Receivable Agreement.

Cash Flows
Year Ended December 31, 2014 Compared to the Year Ended December 31, 2013
Our cash flows were as follows for the respective periods (in millions):

	Year Ended December 31,		
	2014	2013	Change
Net cash provided by operating activities	$5.9	$44.5	$(38.6)
Net cash used in investing activities	$(3.0)	$(1.5)	$(1.5)
Net cash used in financing activities	$(5.7)	$(42.4)	$36.7

Cash Flows Provided by Operating Activities. Cash flows provided by operating activities for the year ended December 31, 2014 decreased by $38.6 million compared to the year ended December 31, 2013. The decrease was primarily due to increased customer acquisition cost spending primarily in California, Illinois and New York during the year ended December 31, 2014. In addition, the decrease in cash flows provided by operating activities was due to a decrease in retail gross margin due to the cost of supply in the first quarter of 2014 and an increase in general and administrative expenses, including bad debt expense, as discussed in “—Operating Segment Results”.

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Cash Flows Used in Investing Activities. Cash flows used in investing activities increased by $1.5 million for the year ended December 31, 2014 which was driven by a increase in capital expenditures related to the Company's new customer billing and information system.

Cash Flows Used in Financing Activities. Cash flows used in financing activities decreased by $36.7 million for the year ended December 31, 2014 due primarily to a $17.0 million increase in our borrowings, net of payments, under our credit facilities due to cash funding for operations and a $23.0 million decrease in net member distributions prior to the Offering, offset by a $3.3 million distribution and dividend paid in December 2014.

Year Ended December 31, 2013 Compared to the Year Ended December 31, 2012

Our cash flows were as follows for the respective periods (in millions):

	Year Ended December 31,		
	2013	2012	Change
Net cash provided by operating activities	$44.5	$44.1	$0.4
Net cash used in investing activities	$(1.5)	$(1.6)	$0.1
Net cash used in financing activities	$(42.4)	$(39.9)	$(2.5)

Cash Flows Provided by Operating Activities. Net cash provided by operating activities was $44.1 million for the year ended December 31, 2012 and $44.5 million for the year ended December 31, 2013. Decreases in account receivable levels were generally offset by decreases in accounts payable, resulting in an immaterial impact on cash flow provided by operating activities. These decreases were primarily a result of lower retail sales volume offset by higher retail and wholesale prices. Net decreases in affiliate receivables increased operating cash flow by $21.1 million. Overall increases in commodity prices led to decreased operating cash flows, as both our inventory values and deposits required to transact in the wholesale market, which are recorded in other assets, increased with commodity prices.

Cash Flows Used in Investing Activities. Net cash used in investing activities was $1.6 million for the year ended December 31, 2012 and $1.5 million for the year ended December 31, 2013. The $0.1 million decrease in cash used in investing activities was primarily attributable to decreased capital expenditures.

Cash Flows Used in Financing Activities. Net cash used in financing activities was $39.9 million for the year ended December 31, 2012 and $42.4 million for the year ended December 31, 2013. The increase was primarily attributable to increased member distributions of $48.9 million partially offset by increased borrowings of $40.5 million on our working capital credit facility.

Credit Facility

Prior to the Offering, SE and SEG were co-borrowers under an $80 million revolving working capital credit facility with a maturity date of July 31, 2015. The total amounts outstanding under this facility prior to the Offering include distributions to the common control owner to fund unrelated operations of an affiliate.

In connection with the Offering, Spark HoldCo, SE and SEG (the "Co-Borrowers") and Spark Energy, Inc., as guarantor, entered into a new $70.0 million senior secured revolving working capital credit facility (the "Senior Credit Facility"). The Senior Credit Facility has a maturity date of August 1, 2016. If no event of default has occurred, the Co-Borrowers have the right, subject to approval by the administrative agent and certain lenders, to increase the borrowing capacity under the new Senior Credit Facility to up to $120.0 million, which is available to fund expansions, acquisitions and working capital requirements for our operations and general corporate purposes, including distributions.

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We borrowed approximately $10.0 million under the new Senior Credit Facility at the closing of the Offering to repay in full the outstanding indebtedness under our previous credit facility that SEG and SE had agreed to be responsible for pursuant to the interborrower agreement. The remainder of indebtedness outstanding under our previous credit facility was paid off by our affiliate with its own funds in connection with the closing of the Offering pursuant to the terms of the interborrower agreement. Following this repayment, our previous credit facility was terminated. We had $33.0 million outstanding on the Senior Credit Facility at December 31, 2014 and had approximately $10.7 million in letters of credit issued as of December 31, 2014.

At our election, interest under the Senior Credit Facility is generally determined by reference to:

- the Eurodollar rate plus an applicable margin of up to 3.0% per annum (based upon the prevailing utilization);
- the alternate base rate plus an applicable margin of up to 2.0% per annum (based upon the prevailing utilization). The alternate base rate is equal to the highest of (i) Société Générale's prime rate, (ii) the federal funds rate plus 0.5% per annum, or (iii) the reference Eurodollar rate plus 1.0%; or
- the rate quoted by Société Générale as its cost of funds for the requested credit plus 2.25% to 2.50% per annum.

The interest rate is generally reduced by 25 basis points if utilization under the Senior Credit Facility is below fifty percent. The Senior Credit Facility allows us to issue letters of credit, which reduce availability under Senior Credit Facility, at a cost of 2.00% to 2.50% per annum of aggregate letters of credit issued.

We pay an annual commitment fee of 0.375% or 0.5% on the unused portion of the Senior Credit Facility depending upon the unused capacity. The lending syndicate under the Senior Credit Facility is entitled to several additional fees including an upfront fee, annual agency fee, and fronting fees based on a percentage of the face amount of letters of credit payable to any syndicate member that issues a letter a credit.

The Senior Credit Facility is secured by the membership interests of SE, SEG and the equity of the Co-Borrowers' present and future subsidiaries, all of the Co-Borrowers' and their subsidiaries' present and future property and assets, including accounts receivable, inventory and liquid investments, and control agreements relating to bank accounts.

The Senior Credit Facility contains covenants that, among other things, require the maintenance of specified ratios or conditions as follows:

Maximum Leverage Ratio. Spark Energy, Inc. must maintain a consolidated maximum senior secured leverage ratio, consisting of total liabilities to tangible net worth of not more than 7.0 to 1.0, at any time.

Minimum Net Working Capital. Spark Energy, Inc. must maintain minimum consolidated net working capital at all times equal to the greater of (i) 20% of the aggregate commitments under the Senior Credit Facility, and (ii) $12,000,000.

Minimum Tangible Net Worth. Spark Energy, Inc. must maintain a minimum consolidated tangible net worth at all times equal to the net book value of property, plant and equipment as of the closing date of the Senior Credit Facility plus the greater of (i) 20% of aggregate commitments under the Senior Credit Facility and (ii) $12,000,000.

The borrowing base, which is recalculated and reported monthly, is calculated primarily based on 80 to 90% of the value of eligible accounts receivable and unbilled product sales (depending on the credit quality of the counterparties) and inventory and other working capital assets. The Co-borrowers under the Senior Credit Facility must prepay any amounts outstanding under the Senior Credit Facility in excess of the borrowing base (up to the maximum availability amount).

In addition, the Senior Credit Facility contains customary affirmative covenants. The covenants include delivery of financial statements and other information (including any filings made with the SEC), maintenance of property and insurance, maintenance of holding company status at Spark Energy, Inc., payment of taxes and obligations, material

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compliance with laws, inspection of property, books and records and audits, use of proceeds, payments to bank blocked accounts, notice of defaults and certain other customary matters. The Senior Credit Facility also contains additional negative covenants that limits our ability to, among other things, do any of the following:

- incur certain additional indebtedness,
- grant certain liens,
- engage in certain asset dispositions,
- merge or consolidate,
- make certain payments, distributions (as noted below), investments, acquisitions or loans,
- enter into transactions with affiliates,
- make certain changes in our lines of business or accounting practices, except as required by GAAP or its successor,
- store inventory in certain locations,
- place certain amounts of cash in accounts not subject to control agreements,
- amend or modify billing services agreements and documents,
- engage in certain prohibited transactions,
- enter into burdensome agreements, and
- act as a transmitting utility or as a utility.

Certain of the negative covenants listed above are subject to certain permitted exceptions and allowances.

Spark Energy, Inc. is entitled to pay cash dividends to the holders of the Class A common stock and Spark HoldCo is entitled to make cash distributions to NuDevco and us so long as: (a) no default exists or would result from such a payment; (b) the Co-Borrowers are in pro forma compliance with all financial covenants (as defined above) before and after giving effect to such payment and (c) the outstanding amount of all loans and letters of credit does not exceed the borrowing base limits. Spark HoldCo's inability to satisfy certain financial covenants or the existence of an event of default, if not cured or waived, under the Senior Credit Facility could prevent us from paying dividends to holders of our Class A common stock.

The Senior Credit Facility contains certain customary representations and warranties and events of default. Events of default include, among other things, payment defaults, breaches of representations and warranties, covenant defaults, cross-defaults and cross-acceleration to certain indebtedness, certain events of bankruptcy, certain events under ERISA, material judgments in excess of $2.5 million, certain events with respect to material contracts, actual or asserted failure of any guaranty or security document supporting the Senior Credit Facility to be in full force and effect and changes of control. If such an event of default occurs, the lenders under the Senior Credit Facility are entitled to take various actions, including the acceleration of amounts due under the facility and all actions permitted to be taken by a secured creditor.

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Summary of Contractual Obligations

The following table discloses aggregate information about our contractual obligations and commercial commitments as of December 31, 2014 (in millions):

	Total	2015	2016	2017	2018	2019	> 5 years
Operating leases (1)	$1.1	$1.1	$—	$—	$—	$—	$—
Purchase obligations:							
Natural gas and electricity related purchase obligations (2)	8.4	4.7	3.7	—	—	—	—
Pipeline transportation agreements	18.1	5.5	3.1	2.6	1.0	0.8	5.1
Other purchase obligations (3)	9.4	3.9	3.8	1.7	—	—	—
Total purchase obligations	$37.0	$15.2	$10.6	$4.3	$1.0	$0.8	$5.1
Debt	$33.0	$33.0	$—	$—	$—	$—	$—

(1) Included in the total amount are future minimum payments for office and other operating leases.
(2) The amounts represent the notional value of natural gas and electricity related purchase contracts that are not accounted for as derivative financial instruments recorded at fair market value as the company has elected the normal purchase normal sale exception, and therefore are not recognized as liabilities on the combined and consolidated balance sheet.
(3) The amounts presented here include contracts for billing services and other software agreements.

Off-Balance Sheet Arrangements

As of December 31, 2014 we had no material off-balance sheet arrangements.

Related Party Transactions

For a discussion of related party transactions see Note 11 “Transactions with Affiliates” in the Company’s audited combined and consolidated financial statements.

Critical Accounting Policies and Estimates

Our significant accounting policies are described in Note 2 to our audited combined and consolidated financial statements. We prepare our financial statements in conformity with accounting principles generally accepted in the United States of America and pursuant to the rules and regulations of the SEC, which require us to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying footnotes. Actual results could differ from those estimates. We consider the following policies to be the most critical in understanding the judgments that are involved in preparing our financial statements and the uncertainties that could impact our financial condition and results of operations.

Revenue Recognition

Our revenues are derived primarily from the sale of natural gas and electricity to retail customers. We also record revenues from sales of natural gas and electricity to wholesale counterparties, including affiliates. Revenues are recognized by using the following criteria: (1) persuasive evidence of an exchange arrangement exists, (2) delivery has occurred or services have been rendered, (3) the buyer’s price is fixed or determinable and (4) collection is reasonably assured. Utilizing these criteria, revenue is recognized when the natural gas or electricity is delivered. Similarly, cost of revenues is recognized when the commodity is delivered.

Revenues for natural gas and electricity sales are recognized upon delivery under the accrual method. Natural gas and electricity sales that have been delivered but not billed by period end are estimated. Accrued unbilled revenues are based on estimates of customer usage since the date of the last meter read provided by the utility. Volume

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estimates are based on forecasted volumes and estimated customer usage by class. Unbilled revenues are calculated by multiplying these volume estimates by the applicable rate by customer class. Estimated amounts are adjusted when actual usage is known and billed.

The cost of natural gas and electricity for sale to retail customers is based on estimated supply volumes for the applicable reporting period. In estimating supply volumes, we consider the effects of historical customer volumes, weather factors and usage by customer class. Transmission and distribution delivery fees, where applicable, are estimated using the same method used for sales to retail customers. In addition, other load related costs, such as ISO fees, ancillary services and renewable energy credits are estimated based on historical trends, estimated supply volumes and initial utility data. Volume estimates are then multiplied by the supply rate and recorded as retail cost of revenues in the applicable reporting period. Estimated amounts are adjusted when actual usage is known and billed.

Our asset optimization activities, which primarily include natural gas physical arbitrage and other short term storage and transportation opportunities, meet the definition of trading activities and are recorded on a net basis in the combined and consolidated statements of operations in net asset optimization revenues as required by the Financial Accounting Standards Board (“FASB”) Accounting Standards Codification (“ASC”) Topic 815, Derivatives and Hedging.

Accounts Receivable

We accrue an allowance for doubtful accounts based upon estimated uncollectible accounts receivable considering historical collections, accounts receivable aging analysis, credit risk and other factors. We write off accounts receivable balances against the allowance for doubtful accounts when the accounts receivable is deemed to be uncollectible.

We conduct business in many utility service markets where the local regulated utility is responsible for billing the customer, collecting payment from the customer and remitting payment to the Company (“POR programs”). This POR service results in substantially all of our credit risk being linked to the applicable utility in these territories, which generally has an investment-grade rating, and not to the end-use customer. We monitor the financial condition of each utility and currently believe that our susceptibility to an individually significant write-off as a result of concentrations of customer accounts receivable with those utilities is remote.

In markets that do not offer POR services or when we choose to directly bill our customers, certain accounts receivable are billed and collected by us. We bear the credit risk on these accounts and record an appropriate allowance for doubtful accounts to reflect any losses due to non-payment by customers. Our customers are individually insignificant and geographically dispersed in these markets. We write off customer balances when we believe that amounts are no longer collectible and when we have exhausted all means to collect these receivables.

Capitalized Customer Acquisition Costs

Capitalized customer acquisition costs consist primarily of hourly and commission based telemarketing costs, door-to-door agent commissions and other direct advertising costs associated with proven customer generation, and are capitalized and amortized over the estimated two-year average life of a customer in accordance with the provisions of FASB ASC 340-20, Capitalized Advertising Costs.

Recoverability of customer acquisition costs is evaluated based on a comparison of the carrying amount of the customer acquisition costs to the future net cash flows expected to be generated by the customers acquired, considering specific assumptions for customer attrition, per unit gross profit, and operating costs. These assumptions are based on forecasts and historical experience.

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Accounting for Derivative and Hedging Activities

We use derivative instruments such as futures, swaps, forwards and options to manage the commodity price risks of our business operations.

All derivatives, other than those for which an exception applies, are recorded in the combined and consolidated balance sheets at fair value. Derivative instruments representing unrealized gains are reported as derivative assets while derivative instruments representing unrealized losses are reported as derivative liabilities. We have elected to offset amounts on the combined and consolidated balance sheets for recognized derivative instruments executed with the same counterparty under a master netting arrangement. One of the exceptions to fair value accounting, normal purchases and normal sales, has been elected by us for certain derivative instruments when the contract satisfies certain criteria, including a requirement that physical delivery of the underlying commodity is probable and is expected to be used in normal course of business. Retail revenues and retail cost of revenues resulting from deliveries of commodities under normal purchase contracts and normal sales contracts are included in earnings at the time of contract settlement.

To manage commodity price risk, we hold certain derivative instruments that are not held for trading purposes and are not designated as hedges for accounting purposes. However, to the extent we do not hold offsetting positions for such derivatives, we believe these instruments represent economic hedges that mitigate our exposure to fluctuations in commodity prices. As part of our strategy to optimize our assets and manage related commodity risks, we also manage a portfolio of commodity derivative instruments held for trading purposes. We use established policies and procedures to manage the risks associated with price fluctuations in these energy commodities and use derivative instruments to reduce risk by generally creating offsetting market positions.

Changes in the fair value of and amounts realized upon settlement of derivative instruments not held for trading purposes are recognized currently in earnings in retail revenues or retail costs of revenues, respectively.

Changes in the fair value of and amounts realized upon settlement of derivative instruments held for trading purposes are recognized currently in earnings in net asset optimization revenues.

We have historically designated a portion of our derivative instruments as cash flow hedges for accounting purposes. For all hedging transactions, we formally documented the hedging transaction and its risk management objective and strategy for undertaking the hedge, the hedging instrument, the nature of the risk being hedged, how the hedging instrument’s effectiveness in offsetting the hedged risk was assessed prospectively and retrospectively, and a description of the method used to measure ineffectiveness. We also formally assessed, both at the inception of the hedging transaction and on an ongoing basis, whether the derivatives used in hedging transactions were highly effective in offsetting changes in cash flows of hedged transactions. For derivative instruments that were designated and qualified as part of a cash flow hedging transaction, the effective portion of the gain or loss on the derivative was reported as a component of other comprehensive income and reclassified into earnings in the same period or periods during when the hedged transaction affected earnings. Gains and losses on the derivative representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness were recognized in current earnings. Hedge accounting was discontinued prospectively for derivatives that ceased to be highly effective hedges or when the occurrence of the forecasted transaction was no longer probable.

Effective July 1, 2013, we elected to discontinue hedge accounting prospectively and began to record the changes in fair value recognized in the combined and consolidated statement of operations in the period of change. Because the underlying transactions were still probable of occurring, the related accumulated other comprehensive income was frozen and recognized in earnings as the underlying hedged item was delivered. As of December 31, 2014 and 2013, we had no gains or losses on derivatives that were designated as qualifying cash flow hedging transactions recorded as a component of accumulated other comprehensive income, as all previously deferred gains and losses on qualifying hedge transactions were reclassified into earnings during the year ended December 31, 2013 when the associated hedged transactions were recorded into earnings.

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Recent Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2014-09, Revenue from Contracts with Customers, which requires an entity to recognize the amount of revenue to which it expects to be entitled for the transfer of promised goods or services to customers. ASU 2014-09 will replace most existing revenue recognition guidance in GAAP when it becomes effective on January 1, 2017. Early application is not permitted. The standard permits the use of either the retrospective or cumulative effect transition method. The Company is evaluating the effect that ASU 2014-09 will have on its financial statements and related disclosures. The Company has not yet selected a transition method nor has it determined the effect of the standard on its ongoing financial reporting.

In August 2014, the FASB issued ASU No. 2014-15, Presentation of Financial Statements - Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern ("ASU 2014-15"). The new guidance clarifies management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and to provide related footnote disclosure. ASU 2014-15 is effective for annual periods ending after December 15, 2016 and for annual periods and interim periods thereafter. Early adoption is permitted. The Company does not expect the adoption to have a material effect on the combined or consolidated financial statements.

In November 2014, the FASB issued ASU No. 2014-16, Derivatives and Hedging, which clarifies how current GAAP should be interpreted in evaluating the economic characteristics and risks of a host contract in a hybrid financial instrument that is issued in the form of a share. The amendments in this Update are effective for public business entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. Early adoption, including adoption in an interim period, is permitted. The Update does not change the current criteria in GAAP for determining when separation of certain embedded derivative features in a hybrid financial instrument is required. The Company does not believe the adoption of this ASU to have a material impact on the combined and consolidated financial statements.

In February 2015, the FASB issued ASU No. 2015-02, Consolidation (Topic 810) ("ASU 2015-02"). The new guidance changes the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. ASU 2015-02 is effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted, including adoption at an interim period. The Company has not yet determined the effect of the standard on its ongoing financial reporting.

Contingencies

In the ordinary course of business, we may become party to lawsuits, administrative proceedings and governmental investigations, including regulatory and other matters. As of December 31, 2014, management does not believe that any of our outstanding lawsuits, administrative proceedings or investigations could result in a material adverse effect. Liabilities for loss contingencies arising from claims, assessments, litigation, fines, penalties and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

Emerging Growth Company Status

We are an "emerging growth company" within the meaning of the federal securities laws. For as long as we are an emerging growth company, we will not be required to comply with certain requirements that are applicable to other public companies that are not "emerging growth companies" including, but not limited to, not being required to comply with the auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act, the reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements and the exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and shareholder approval of any golden parachute payments not previously approved. In addition, Section 107 of the JOBS Act provides that an emerging growth company can take advantage of the extended transition period provided in Section 7(a)(2)(B) of

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the Securities Act for complying with new or revised accounting standards, but we have irrevocably opted out of the extended transition period and, as a result, we will adopt new or revised accounting standards on the relevant dates on which adoption of such standards is required for other public companies.

We intend to take advantage of these exemptions until we are no longer an emerging growth company. We will cease to be an "emerging growth company" upon the earliest of: (i) the last day of the fiscal year in which we have $1.0 billion or more in annual revenues; (ii) the date on which we become a "large accelerated filer" (the fiscal year-end on which the total market value of our common equity securities held by non-affiliates is $700 million or more as of June 30); (iii) the date on which we issue more than $1.0 billion of non-convertible debt over a three-year period; or (iv) the last day of the fiscal year following the fifth anniversary of the Offering.

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ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risks relating to our operations result primarily from changes in commodity prices and interest rates, as well as counterparty credit risk. We employ established policies and procedures to manage our exposure to these risks.

Commodity Price Risk

We hedge and procure our energy requirements from various wholesale energy markets, including both physical and financial markets and through short and long term contracts. Our financial results are largely dependent on the margin we are able to realize between the wholesale purchase price of natural gas and electricity plus related costs and the retail sales price we charge our customers. We actively manage our commodity price risk by entering into various derivative or non-derivative instruments to hedge the variability in future cash flows from fixed-price forecasted sales and purchases of natural gas and electricity in connection with our retail energy operations. These instruments include forwards, futures, swaps, and option contracts traded on various exchanges, such as NYMEX and Intercontinental Exchange, or ICE, as well as over-the-counter markets. These contracts have varying terms and durations, which range from a few days to a few years, depending on the instrument. Our asset optimization group utilizes similar derivative contracts in connection with its trading activities to attempt to generate incremental gross margin by effecting transactions in markets where we have a retail presence. Generally, any of such instruments that are entered into to support our retail electricity and natural gas business are categorized as having been entered into for non-trading purposes, and instruments entered into for any other purpose are categorized as having been entered into for trading purposes. Our net loss on non-trading derivative instruments net of cash settlements was $15.0 million for the year ended December 31, 2014. This non-cash loss was due to a decline in wholesale gas and electricity market prices against our fixed price hedge portfolio. As this future supply has been sold to customers at fixed prices, changes in the value of the hedge portfolio should have no impact on future margin. Additionally, the decline in market prices led to a cash collateral posting to our FCM, Futures Commission Merchant, of $7.4 million as of December 31, 2014 compared to $2.0 million as of December 31, 2013.

We have adopted risk management policies to measure and limit market risk associated with our fixed-price portfolio and our hedging activities. For additional information regarding our commodity price risk and our risk management policies, see "Item 1A - Risk Factors".

We measure the commodity risk of our non-trading energy derivatives using a sensitivity analysis on our net open position. As of December 31, 2014, our Gas Non-Trading Fixed Price Open Position (hedges net of retail load) was a long position of 429,395 MMBtu, due primarily to our retail choice storage being close to full as we approach winter. An increase in 10% in the market prices (NYMEX) from their December 31, 2014 levels would have increased the fair market value of our net non-trading energy portfolio by $0.4 million. Likewise, a decrease in 10% in the market prices (NYMEX) from their December 31, 2014 levels would have decreased the fair market value of our non-trading energy derivatives by $0.4 million. As of December 31, 2014, our Electricity Non-Trading Fixed Price Open Position (hedges net of retail load) was a short position of 53,509 MWhs. An increase in 10% in the forward market prices from their December 31, 2014 levels would have decreased the fair market value of our net non-trading energy portfolio by $0.4 million. Likewise, a decrease in 10% in the forward market prices from their December 31, 2014 levels would have increased the fair market value of our non-trading energy derivatives by $0.4 million.

We measure the commodity risk of our trading energy derivatives using a sensitivity analysis on our net open position. As of December 31, 2014, our Gas Trading Fixed Price Open Position was a long position of 17,715 MMBtu. An increase in 10% in the market prices (NYMEX) from their December 31, 2014 levels would have increased the fair market value of our trading energy derivatives by less than $0.1 million. Likewise, a decrease in 10% in the market prices (NYMEX) from their December 31, 2014 levels would have decreased the fair market value of our trading energy derivatives by less than $0.1 million.

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Credit Risk

In many of the utility services territories where we conduct business, POR programs have been established, whereby the local regulated utility offers services for billing the customer, collecting payment from the customer and remitting payment to us. This service results in substantially all of our credit risk being linked to the applicable utility and not to our end-use customer in these territories. Approximately 44%, 47% and 55% of our retail revenues were derived from territories in which substantially all of our credit risk was directly linked to local regulated utility companies as of December 31, 2014, 2013 and 2012, respectively, all of which had investment grade ratings as of such date. During the same period, we paid these local regulated utilities a weighted average discount of approximately 1.0% of total revenues for customer credit risk. In certain of the POR markets in which we operate, the utilities limit their collections exposure by retaining the ability to transfer a delinquent account back to us for collection when collections are past due for a specified period. If our collection efforts are unsuccessful, we return the account to the local regulated utility for termination of service. Under these service programs, we are exposed to credit risk related to payment for services rendered during the time between when the customer is transferred to us by the local regulated utility and the time we return the customer to the utility for termination of service, which is generally one to two billing periods.

In non-POR markets (and in POR markets where we may choose to direct bill our customers), we manage customer credit risk through formal credit review in the case of commercial customers, and credit screening, deposits, disconnection for non-payment and collection efforts in the case of residential customers. Our bad debt expense for the year ended December 31, 2014, 2013 and 2012 was approximately 5.7%, 1.8% and 1.1% of non-POR market retail revenues, respectively. Economic conditions may affect our customers' ability to pay bills in a timely manner, which could increase customer delinquencies and may lead to an increase in bad debt expense. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Drivers of our Business—Customer Credit Risk" for an analysis of our bad debt expense related to non-POR markets during 2014.

We are exposed to wholesale counterparty credit risk in our retail and asset optimization activities. We manage this risk at a counterparty level and secure our exposure with collateral or guarantees when needed. At December 31, 2014 and 2013, approximately 50% and 82% of our total exposure of $8.8 million and $12.5 million, respectively, was either with an investment grade customer or otherwise secured with collateral. The credit worthiness of the remaining exposure with other customers was evaluated with no material allowance recorded at December 31, 2014, 2013 and 2012.

Interest Rate Risk

We are exposed to fluctuations in interest rates under our variable-price debt obligations. At December 31, 2014 we have a $70 million variable rate Senior Credit Facility under which $33.0 million of variable rate indebtedness was outstanding. Based on the average amount of our variable rate indebtedness outstanding during the year ended December 31, 2014, a 1% percent increase in interest rates would have resulted in additional annual interest expense of approximately $0.3 million. We do not currently employ interest rate hedges, although we may choose to do so in the future.

Item 8. Financial Statements and Supplementary Data

ITEM 8. FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Spark Energy, Inc.:

We have audited the accompanying combined and consolidated balance sheets of Spark Energy, Inc. as of December 31, 2014 and 2013, and the related combined and consolidated statements of operations and comprehensive (loss) income, changes in equity, and cash flows for each of the years in the three year period ended December 31, 2014. These combined and consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these combined and consolidated financial statements based on our audits.
We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.
In our opinion, the combined and consolidated financial statements referred to above present fairly, in all material respects, the financial position of Spark Energy, Inc. as of December 31, 2014 and 2013, and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles.
/s/ KPMG LLP
Houston, Texas
March 27, 2015

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AUDITED COMBINED AND CONSOLIDATED FINANCIAL STATEMENTS

SPARK ENERGY, INC.
COMBINED AND CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2014 AND DECEMBER 31, 2013
(in thousands)

	December 31, 2014	December 31, 2013
Assets		
Current assets:		
Cash and cash equivalents	$4,359	$7,189
Restricted cash	707	—
Accounts receivable, net of allowance for doubtful accounts of $8.0 million and $1.2 million as of December 31, 2014 and 2013, respectively	63,797	62,678
Accounts receivable-affiliates	1,231	6,794
Inventory	8,032	4,322
Fair value of derivative assets	216	8,071
Customer acquisition costs, net	12,369	4,775
Intangible assets - customer acquisitions, net	486	—
Prepaid assets	1,236	1,032
Deposits	10,569	3,529
Other current assets	2,987	2,901
Total current assets	105,989	101,291
Property and equipment, net	4,221	4,817
Fair value of derivative assets	—	6
Customer acquisition costs	2,976	2,901
Intangible assets - customer acquisitions	1,015	—
Deferred tax assets	24,047	—
Other assets	149	58
Total Assets	$138,397	$109,073
Liabilities and Stockholders’ Equity		
Current liabilities:		
Accounts payable	$38,210	$36,971
Accounts payable-affiliates	1,017	—
Accrued liabilities	7,195	6,838
Fair value of derivative liabilities	11,526	1,833
Note payable	33,000	27,500
Other current liabilities	1,868	—
Total current liabilities	92,816	73,142
Long-term liabilities:		
Fair value of derivative liabilities	478	18
Payable pursuant to tax receivable agreement-affiliates	20,767	—
Other long-term liabilities	219	—
Total liabilities	114,280	73,160
Commitments and contingencies (Note 10)		
Stockholders' equity:		
Member's equity	—	35,913
Common Stock:		
	30	—

Class A common stock, par value $0.01 per share, 120,000,000 shares authorized, 3,000,000 issued and outstanding at December 31, 2014 and zero authorized, issued and outstanding at December 31, 2013		
Class B common stock, par value $0.01 per share, 60,000,000 shares authorized, 10,750,000 issued and outstanding at December 31, 2014 and zero authorized, issued and outstanding at December 31, 2013	108	—
Preferred Stock:		
Preferred stock, par value $0.01 per share, 20,000,000 shares authorized, zero issued and outstanding at December 31, 2014 and zero authorized, issued and outstanding at December 31, 2013	—	—
Additional paid-in capital	9,296	—
Retained deficit	(775)	—
Total stockholders' equity	8,659	35,913
Non-controlling interest in Spark HoldCo, LLC	15,458	—
Total equity	24,117	35,913
Total Liabilities and Stockholders' Equity	$138,397	$109,073

The accompanying notes are an integral part of the combined and consolidated financial statements.

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SPARK ENERGY, INC.
COMBINED AND CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE (LOSS) INCOME FOR THE YEARS ENDED DECEMBER 31, 2014, 2013 and 2012
(in thousands, except per share data)

	Year Ended December 31, 2014	2013	2012
Revenues:			
Retail revenues (including retail revenues—affiliates of $2,170, $4,022 and $1,382 for the years ended December 31, 2014, 2013 and 2012, respectively)	$320,558	$316,776	$380,198
Net asset optimization revenues (expenses) (including asset optimization revenues-affiliates of $12,842, $14,940 and $8,334 for the years ended December 31, 2014, 2013 and 2012, respectively, and asset optimization revenues affiliates cost of revenues of $30,910, $15,928 and $568 for the years ended December 31, 2014, 2013 and 2012, respectively)	2,318	314	(1,136)
Total Revenues	322,876	317,090	379,062
Operating Expenses:			
Retail cost of revenues (including retail cost of revenues-affiliates of $13, $55 and $254 for the years December 31, 2014, 2013 and 2012, respectively)	258,616	233,026	279,506
General and administrative (including general and administrative expense-affiliates of less than $100, less than $100 and $800 for the years ended December 31, 2014, 2013 and 2012, respectively)	45,880	35,020	47,321
Depreciation and amortization	22,221	16,215	22,795
Total Operating Expenses	326,717	284,261	349,622
Operating (loss) income	(3,841)	32,829	29,440
Other (expense)/income:			
Interest expense	(1,578)	(1,714)	(3,363)
Interest and other income	263	353	62
Total other expenses	(1,315)	(1,361)	(3,301)
(Loss) income before income tax expense	(5,156)	31,468	26,139
Income tax (benefit) expense	(891)	56	46
Net (loss) income	(4,265)	31,412	26,093
Less: Net (loss) attributable to non-controlling interests	(4,211)	—	—
Net (loss) income attributable to Spark Energy, Inc. stockholders	$(54)	$31,412	$26,093
Other comprehensive (loss) income:			
Deferred gain (loss) from cash flow hedges	—	2,620	(10,243)
Reclassification of deferred gain (loss) from cash flow hedges into net income (Note 6)	—	(84)	17,942
Comprehensive (loss) income	$(4,265)	$33,948	$33,792
Net loss attributable to Spark Energy, Inc. per common share			
Basic	$(0.02)		
Diluted	$(0.02)		
Weighted average commons shares outstanding			
Basic	3,000		

Diluted	3,000

The accompanying notes are an integral part of the combined and consolidated financial statements.

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SPARK ENERGY, INC.
COMBINED AND CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2014, 2013 and 2012
(in thousands)

	Member's Equity	Issued Shares of Class A Common Stock	Issued Shares of Class B Common Stock	Issued Shares of Preferred Stock	Class A Common Stock	Class B Common Stock	Accumulated Other Comprehensive Income	Additional Paid In Capital	Retained Deficit	Total Stockholders Equity	Non-controlling Interest	Total Equity
Balance at 12/31/2011:	$48,180	—	—	—	$—	$—	$ (10,235)	$—	$—	$—	$ —	$37,945
Capital contributions from member	10,060	—	—	—	—	—	—	—	—	—	—	10,060
Distributions to member	(20,495)	—	—	—	—	—	—	—	—	—	—	(20,495)
Net income	26,093	—	—	—	—	—	—	—	—	—	—	26,093
Deferred loss from cash flow hedges	—	—	—	—	—	—	(10,243)	—	—	—	—	(10,243)
Reclassification of deferred gain from cash flow hedges into net income	—	—	—	—	—	—	17,942	—	—	—	—	17,942
Balance at 12/31/2012:	63,838	—	—	—	—	—	(2,536)	—	—	—	—	61,302
Capital contributions from member	12,400	—	—	—	—	—	—	—	—	—	—	12,400
Distributions to member	(71,737)	—	—	—	—	—	—	—	—	—	—	(71,737)
Net income	31,412	—	—	—	—	—	—	—	—	—	—	31,412
Deferred gain from cash flow hedges	—	—	—	—	—	—	2,620	—	—	—	—	2,620
Reclassification of deferred loss from cash flow hedges into net income	—	—	—	—	—	—	(84)	—	—	—	—	(84)
Balance at 12/31/2013:	35,913	—	—	—	—	—	—	—	—	—	—	35,913
Capital contributions from member and liabilities retained by	54,201	—	—	—	—	—	—	—	—	—	—	54,201

affiliate												
Distributions to member	(61,607)	—	—	—	—	—	—	—	—	—	—	(61,607)
Net loss prior to the Offering	(21)	—	—	—	—	—	—	—	—	—	—	(21)
Balance prior to Corporate Reorganization and the Offering:	28,486	—	—	—	—	—	—	—	—	—	—	28,486
Reorganization Transaction:												
Issuance of Class B common stock	(28,486)	—	10,750	—	—	108	—	28,378	—	28,486	—	—
Offering Transactions:												
Offering costs paid	—	—	—	—	—	—	—	(2,667)	—	(2,667)	—	(2,667)
Issuance of Class A Common Stock, net of underwriters discount	—	3,000	—	—	30	—	—	50,190	—	50,220	—	50,220
Distribution of Offering proceeds and payment of note payable to affiliate	—	—	—	—	—	—	—	(47,604)	—	(47,604)	—	(47,604)
Initial allocation of non-controlling interest of Spark Energy, Inc. effective on date of Offering	—	—	—	—	—	—	—	(22,232)	—	(22,232)	22,232	—

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Tax benefit from tax receivable agreement	—	—	—	—	—	—	—	23,636	—	23,636	—	23,636
Liability due to tax receivable agreement	—	—	—	—	—	—	—	(20,915)	—	(20,915)	—	(20,915)
Balance at inception of public company (8/1/2014):	—	3,000	10,750	—	30	108	—	8,786	—	8,924	22,232	31,156
Stock based compensation	—	—	—	—	—	—	—	510	—	510	—	510
Consolidated net loss subsequent to the Offering	—	—	—	—	—	—	—	—	(54)	(54)	(4,190)	(4,244)
Distributions paid to Class B non-controlling unit holders	—	—	—	—	—	—	—	—	—	—	(2,584)	(2,584)
Dividends paid to Class A common shareholders	—	—	—	—	—	—	—	—	(721)	(721)	—	(721)
Balance at 12/31/2014:	$—	3,000	10,750	—	$30	$108	$—	$9,296	$(775)	$8,659	$15,458	$24,117

The accompanying notes are an integral part of the combined and consolidated financial statements.

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SPARK ENERGY, INC.
COMBINED AND CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2014, 2013 AND 2012
(in thousands)

	Year Ended December 31,		
	2014	2013	2012
Cash flows from operating activities:			
Net (loss) income	$(4,265)	$31,412	$26,093
Adjustments to reconcile net (loss) income to net cash flows provided by operating activities:			
Depreciation and amortization expense	22,221	16,215	22,795
Deferred income taxes	(1,064)	—	—
Stock based compensation	858	—	—
Amortization and write off of deferred financing costs	631	678	919
Bad debt expense	10,164	3,101	1,835
(Gain) loss on derivatives, net	14,535	(6,567)	21,485
Current period cash settlements on derivatives, net	3,479	(1,040)	(26,801)
Changes in assets and liabilities:			
Increase in restricted cash	(707)	—	—
(Increase) decrease in accounts receivable	(11,283)	6,338	12,019
(Increase) decrease in accounts receivable-affiliates	5,563	13,369	(7,787)
(Increase) decrease in inventory	(3,711)	(599)	3,442
Increase in customer acquisition costs	(26,191)	(8,257)	(6,322)
(Increase) decrease in prepaid and other current assets	(6,905)	(1,917)	8,505
(Increase) decrease in other assets	(90)	144	345
Increase in intangible assets - customer acquisitions	(1,545)	—	—
Increase (decrease) in accounts payable and accrued liabilities	1,449	(7,879)	(11,394)
Increase (decrease) in accounts payable-affiliates	1,017	—	(1,295)
Increase (decrease) in other current liabilities	1,867	(518)	237
Decrease in other non-current liabilities	(149)	—	—
Net cash provided by operating activities	5,874	44,480	44,076
Cash flows from investing activities:			
Purchases of property and equipment	(3,040)	(1,481)	(2,220)
Sale of property, plant and equipment-affiliates	—	—	577
Net cash used in investing activities	(3,040)	(1,481)	(1,643)
Cash flows from financing activities:			
Borrowings on notes payable	78,500	80,000	39,500
Payments on notes payable	(44,000)	(62,500)	(68,528)
Deferred financing costs	(402)	(532)	(441)
Member contribution (distributions), net	(36,406)	(59,337)	(10,435)
Proceeds from issuance of Class A common stock	50,220	—	—
Distributions of proceeds from Offering to affiliate	(47,554)	—	—
Payment of note payable to NuDevco	(50)	—	—
Offering costs	(2,667)	—	—
Payment of distributions to Class B non-controlling unit holders	(2,584)	—	—
Payment of dividends to Class A common shareholders	(721)	—	—
Net cash used in financing activities	(5,664)	(42,369)	(39,904)
Decreases in cash and cash equivalents	(2,830)	630	2,529
Cash and cash equivalents—beginning of period	7,189	6,559	4,030

Cash and cash equivalents—end of period	$4,359	$7,189	$6,559
Supplemental Disclosure of Cash Flow Information:			
Non cash items:			
Issuance of Class B common stock	$28,486	$—	$—
Liabilities retained by affiliate	$29,000	$—	$—
Tax benefit from tax receivable agreement	$23,636	$—	$—
Liability due to tax receivable agreement	$20,767	$—	$—
Initial allocation of non-controlling interest	$22,232	$—	$—
Property and equipment purchase accrual	$19	$—	$—
Cash paid during the period for:			
Interest	$860	$879	$2,686
Taxes	$85	$195	$318

The accompanying notes are an integral part of the combined and consolidated financial statements.

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SPARK ENERGY, INC.
NOTES TO COMBINED AND CONSOLIDATED FINANCIAL STATEMENTS
1. Formation and Organization
Organization

Spark Energy, Inc. (the “Company”) is an independent retail energy services company that provides residential and commercial customers in competitive markets across the United States with an alternative choice for natural gas and electricity. The Company is a holding company whose sole material asset consists of units in Spark HoldCo, LLC (“Spark HoldCo”). Spark HoldCo owns all of the outstanding membership interests in each of Spark Energy, LLC (“SE”) and Spark Energy Gas, LLC (“SEG”), the operating subsidiaries through which the Company operates. The Company is the sole managing member of Spark HoldCo, is responsible for all operational, management and administrative decisions relating to Spark HoldCo’s business and consolidates the financial results of Spark HoldCo and its subsidiaries.

The Company is a Delaware corporation formed on April 22, 2014 by Spark Energy Ventures, LLC (“Spark Energy Ventures”) for the purpose of succeeding to Spark Energy Ventures’ ownership in SE and SEG. Spark Energy Ventures, a single member limited liability company formed on October 8, 2007 under the Texas Limited Liability Company Act (“TLLCA”) is an affiliate of NuDevco Retail Holdings, LLC (“NuDevco Retail Holdings”), a single member Texas limited liability company formed by Spark Energy Ventures on May 19, 2014 under the Texas Business Organizations Code (“TBOC”). NuDevco Retail Holdings was formed by Spark Energy Ventures to hold its investment in Spark HoldCo, LLC, our subsidiary and the direct parent of SEG and SE. NuDevco Retail Holdings is currently a direct wholly owned subsidiary of Spark Energy Ventures, which is wholly owned by NuDevco Partners Holdings, LLC, which is wholly owned by NuDevco Partners, LLC (“NuDevco Partners”), which is wholly owned by W. Keith Maxwell III. NuDevco Retail Holdings formed NuDevco Retail, LLC (“NuDevco Retail” and, together with NuDevco Retail Holdings, “NuDevco”), a single member limited liability company, on May 29, 2014 and it holds a 1% interest in Spark HoldCo formerly held by NuDevco Retail Holdings.

Prior to the closing of the Company’s initial public offering of 3,000,000 shares of Class A common stock, par value $0.01 per share (the “Class A common stock”), representing a 21.82% interest in the Company, on August 1, 2014 (the “Offering”), Spark Energy Ventures contributed all of its interest in each of SE and SEG to NuDevco Retail Holdings. NuDevco Retail Holdings in turn contributed all of its interest in each of SE and SEG to Spark HoldCo. The contribution of the interests in SE and SEG to Spark HoldCo is not considered a business combination accounted for under the purchase method, as it was a transfer of assets and operations under common control, and accordingly, balances were transferred at their historical cost. The Company’s historical combined financial statements prior to the Offering are prepared using SE’s and SEG’s historical basis in the assets and liabilities, and include all revenues, costs, assets and liabilities attributed to the retail natural gas and asset optimization and retail electricity businesses of SE and SEG.

SE is a licensed retail electric provider in multiple states. SE provides retail electricity services to end-use retail customers, ranging from residential and small commercial customers to large commercial and industrial users. SE was formed on February 5, 2002 under the Texas Revised Limited Partnership Act (as recodified by the TBOC) and was converted to a Texas limited liability company on May 21, 2014.

SEG is a retail natural gas provider and asset optimization business competitively serving residential, commercial and industrial customers in multiple states. SEG was formed on January 17, 2001 under the Texas Revised Limited Partnership Act (as recodified by the TBOC) and was converted to a Texas limited liability company on May 21, 2014.

As a company with less than $1.0 billion in revenues during its last fiscal year, the Company qualifies as an “emerging growth company” as defined in the Jumpstart Our Business Startups Act of 2012, or the JOBS Act. An emerging growth company may take advantage of specified reduced reporting and other regulatory requirements.

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The Company will remain an “emerging growth company” for up to five years, or until the earliest of (i) the last day of the fiscal year in which the Company has $1.0 billion or more in annual revenues; (ii) the date on which the Company becomes a “large accelerated filer” (the fiscal year-end on which the total market value of the Company’s common equity securities held by non-affiliates is $700 million or more as of June 30); (iii) the date on which the Company issues more than $1.0 billion of non-convertible debt over a three-year period; or (iv) the last day of the fiscal year following the fifth anniversary of the Offering.
As a result of the Company's election to avail itself of certain provisions of the JOBS Act, the information that the Company provides may be different than what you may receive from other public companies in which you hold an equity interest.
Initial Public Offering of Spark Energy, Inc.

On August 1, 2014, the Company completed the Offering of 3,000,000 shares of its Class A common stock for $18.00 per share, representing a 21.82% voting interest in the Company.

Net proceeds from the Offering were $47.6 million, after underwriting discounts and commissions, structuring fees and offering expenses. The net proceeds from the Offering were used to acquire units of Spark HoldCo (the “Spark HoldCo units”) representing approximately 21.82% of the outstanding Spark HoldCo units after the Offering from NuDevco Retail Holdings and to repay a promissory note from the Company in the principal amount of $50,000 (the “NuDevco Note”). The Company did not retain any of the net proceeds from the Offering. The Company recorded $2.7 million of previously deferred incremental costs directly attributable to the Offering as a reduction in equity at the Offering date, which were funded by the Offering proceeds.

The Company also issued 10,750,000 shares of Class B common stock, par value 0.01 per share (the “Class B common stock”) to Spark HoldCo, 10,612,500 of which Spark HoldCo distributed to NuDevco Retail Holdings, and 137,500 of which Spark HoldCo distributed to NuDevco Retail.

At the consummation of the Offering, the Company's outstanding common stock is summarized in the table below:

	Shares of common stock		
	Number	Percent Voting Interest	
Publicly held Class A common stock	3,000,000	21.82	%
Class B common stock held by NuDevco Retail Holdings, LLC and NuDevco Retail, LLC	10,750,000	78.18	%
Total	13,750,000	100.00	%

Credit Facility
Concurrently with the closing of the Offering, the Company entered into a new $70.0 million senior secured credit facility (“Senior Credit Facility”). See Note 4 “Long-Term Debt” for further discussion.
Exchange and Registration Rights
NuDevco has the right to exchange (the “Exchange Right”) all or a portion of its Spark HoldCo units (together with a corresponding number of shares of Class B common stock) for Class A common stock (or cash at Spark Energy, Inc.’s or Spark HoldCo’s election (the “Cash Option”)) at an exchange ratio of one share of Class A common stock for each Spark HoldCo unit (and corresponding share of Class B common stock) exchanged. In addition, NuDevco has the right, under certain circumstances, to cause the Company to register the offer and resale of NuDevco's shares of Class A common stock obtained pursuant to the Exchange Right.

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Tax Receivable Agreement

Concurrently with the closing of the Offering, the Company entered into a Tax Receivable Agreement with Spark HoldCo, NuDevco Retail Holdings and NuDevco Retail. See Note 11 “Transactions with Affiliates” for further discussion.

Other Transactions in Connection with the Consummation of the Offering
In connection with the Offering the following restructuring transactions occurred:

- SEG and SE were converted from limited partnerships into limited liability companies;
- SEG, SE and an affiliate entered into an interborrower agreement, pursuant to which such affiliate agreed to be solely responsible for $29.0 million of the outstanding indebtedness. SE and SEG repaid their outstanding indebtedness of $10.0 million and borrowed $10.0 million under the Company's Senior Credit Facility,
- NuDevco Retail Holdings contributed all of its interests in SEG and SE to Spark HoldCo in exchange for all of the outstanding units of Spark HoldCo and transferred 1% of those Spark HoldCo units to NuDevco Retail;
- NuDevco Retail Holdings transferred Spark HoldCo units to the Company for the $50,000 NuDevco Note and the limited liability company agreement of Spark HoldCo was amended and restated to admit the Company as its sole managing member.

Following the Offering, the Company purchased 2,997,222 Spark HoldCo units from NuDevco Retail Holdings and repaid the NuDevco Note. The 2,997,222 Spark Holdco units we purchased with the proceeds from the Offering, together with the 2,778 Spark HoldCo units we purchased in exchange for the NuDevco Note prior to the Offering, represent a 21.82% ownership interest in Spark HoldCo. After giving effect to these transactions and the Offering, the Company owns an approximate 21.82% interest in Spark HoldCo. NuDevco Retail Holdings owns an approximate 77.18% interest in Spark HoldCo and 10,612,500 shares of Class B common stock, and NuDevco Retail owns a 1% interest in Spark HoldCo and 137,500 shares of Class B common stock.

Each share of Class B common stock, all of which is held by NuDevco, has no economic rights but entitles its holder to one vote on all matters to be voted on by shareholders generally. Holders of Class A common stock and Class B common stock vote together as a single class on all matters presented to our shareholders for their vote or approval, except as otherwise required by applicable law or by our certificate of incorporation.
2. Basis of Presentation and Summary of Significant Accounting Policies

The accompanying combined and consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (“GAAP”) and pursuant to the rules and regulations of the Securities and Exchange Commission (“SEC”). All significant intercompany transactions and balances have been eliminated in the combined and consolidated financial statements.
The accompanying combined and consolidated financial statements have been prepared in accordance with Regulation S-X, Article 3, General Instructions as to Financial Statements and Staff Accounting Bulletin (“SAB”) Topic 1-B, Allocations of Expenses and Related Disclosures in Financial Statements of Subsidiaries, Divisions or Lesser Business Components of Another Entity on a stand-alone basis and are derived from SE’s and SEG’s historical basis in the assets and liabilities before the Offering and Spark Energy Inc.’s financial results after the Offering, and include all revenues, costs, assets and liabilities attributable to the retail natural gas and asset optimization and retail electricity businesses of SE and SEG for the periods prior to the Offering that are specifically identifiable or have been allocated to the Company. Management has made certain assumptions and estimates in order to allocate a reasonable share of expenses to the Company, such that the Company’s combined and consolidated financial statements reflect substantially all of its costs of doing business. The Company also enters into transactions with and pays certain costs on behalf of affiliates under common control in order to reduce

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risk, reduce administrative expense, create economies of scale, create strategic alliances and supply goods and services to these related parties. The Company direct bills certain expenses incurred on behalf of affiliates or allocates certain overhead expenses to affiliates associated with general and administrative services based on services provided, departmental usage, or headcount, which are considered reasonable by management. The allocations and related estimates and assumptions are described more fully in Note 11 “Transactions with Affiliates”. These costs are not necessarily indicative of the cost that the Company would have incurred had it operated as an independent stand-alone entity prior to the Offering. Affiliates have also relied upon Spark Energy Ventures as a participant in the credit facility for periods prior to the Offering as described more fully in Note 4 “Long-Term Debt”. As such, the Company’s combined and consolidated financial statements do not fully reflect what the Company’s financial position, results of operations and cash flows would have been had the Company operated as an independent stand-alone company prior to the Offering. As a result, historical financial information prior to the Offering is not necessarily indicative of what the Company’s results of operations, financial position and cash flows will be in the future. The Company’s combined and consolidated financial statements include all wholly-owned and controlled subsidiaries.

Cash and Cash Equivalents

Cash and cash equivalents consist of all unrestricted demand deposits and funds invested in highly liquid instruments with original maturities of three months or less. The Company periodically assesses the financial condition of the institutions where these funds are held and believes that its credit risk is minimal with respect to these institutions.

Restricted Cash

Restricted cash consists of cash that has been placed in escrow for a contractually designated future use. As of December 31, 2014, the Company had $0.7 million in restricted cash related to future required payments for customer acquisitions as described in more detail in Note 13 “Customer Acquisitions”. The restricted cash is classified as current as the payments for these customers are expected to be made in the first quarter of 2015. There was no restricted cash as of December 31, 2013.

Accounts Receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. Accounts receivable in the combined and consolidated balance sheets are net of allowance for doubtful accounts of $8.0 million and $1.2 million as of December 31, 2014 and 2013, respectively.

The Company accrues an allowance for doubtful accounts based upon estimated uncollectible accounts receivable considering historical collections, accounts receivable aging analysis, credit risk and other factors. The Company writes off accounts receivable balances against the allowance for doubtful accounts when the accounts receivable is deemed to be uncollectible. Bad debt expense of $10.2 million, $3.1 million and $1.8 million was recorded in general and administrative expense in the combined and consolidated statements of operations for the years ended December 31, 2014, 2013 and 2012, respectively.

The Company conducts business in many utility service markets where the local regulated utility is responsible for billing the customer, collecting payment from the customer and remitting payment to the Company (“POR programs”). This POR service results in substantially all of the Company’s credit risk being linked to the applicable utility, which generally has an investment-grade rating, and not to the end-use customer. The Company monitors the financial condition of each utility and currently believes that its susceptibility to an individually significant write-off as a result of concentrations of customer accounts receivable with those utilities is remote. Trade accounts receivable that are part of a local regulated utility’s POR program are recorded on a gross basis in accounts receivable in the combined and consolidated balance sheets. The discount paid to the local regulated utilities is recorded in general and administrative expense in the combined and consolidated statements of operations.

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In markets that do not offer POR services or when the Company chooses to directly bill its customers, certain receivables are billed and collected by the Company. The Company bears the credit risk on these accounts and records an appropriate allowance for doubtful accounts to reflect any losses due to non-payment by customers. The Company's customers are individually insignificant and geographically dispersed in these markets. The Company writes off customer balances when it believes that amounts are no longer collectible and when it has exhausted all means to collect these receivables.

Inventory

Inventory consists of natural gas used to fulfill and manage seasonality for fixed and variable-price retail customer load requirements and is valued at the lower of weighted average cost or market. Purchased natural gas costs are recognized in the combined and consolidated statements of operations, within retail cost of revenues, when the natural gas is sold and delivered out of the storage facility. There were no inventory impairments recorded for the years ended December 31, 2014, 2013 and 2012. When natural gas is sold costs are recognized in the combined and consolidated statements of operations, within retail cost of revenues, at the weighted average cost value at the time of the sale.

Customer Acquisition Costs

The Company has retail natural gas and electricity customer acquisition costs, net of $12.4 million and $4.8 million recorded in current assets and $3.0 million and $2.9 million recorded in noncurrent assets representing direct response advertising costs as of December 31, 2014 and 2013, respectively. Customer acquisition costs is spending for organic customer acquisitions and does not include customer acquisitions through merger and acquisition activities, which are recorded as intangible assets. Amortization of customer acquisition costs, recorded in depreciation and amortization in the combined and consolidated statements of operations, was $18.5 million, $10.1 million and $16.4 million for the years ended December 31, 2014, 2013 and 2012, respectively. Capitalized direct response advertising costs consist primarily of hourly and commission based telemarketing costs, door-to-door agent commissions and other direct advertising costs associated with proven customer generation, and are capitalized and amortized over the estimated two-year average life of a customer in accordance with the provisions of FASB ASC 340-20, Capitalized Advertising Costs.

Recoverability of customer acquisition costs is evaluated based on a comparison of the carrying amount of the customer acquisition costs to the future net cash flows expected to be generated by the customers acquired, considering specific assumptions for customer attrition, per unit gross profit, and operating costs. These assumptions are based on forecasts and historical experience.

Based on the analysis described above, for the year ended December 31, 2014, the Company recorded accelerated amortization of such costs of $6.5 million associated with capitalized customer acquisition costs in California and $0.2 million associated with capitalized customer acquisition costs in Massachusetts. This accelerated amortization expense is included in "depreciation and amortization" on the statement of operations. There were no such accelerated amortization charges recorded for the year ended December 31, 2013 and 2012.

Intangibles - Customer Acquisitions

Customer acquisitions through merger and acquisition activities are recorded as intangible assets and represent customer contract acquisitions not acquired through the direct response advertising discussed above at "Customer Acquisition Costs". The Company has recorded $1.5 million, net of amortization, as of December 31, 2014 related to these intangible assets. These intangibles are amortized over the estimated three-year average life of the related customer contracts acquired.

We review intangible assets for impairment whenever events or changes in business circumstances indicate the carrying value of the intangible assets may not be recoverable. Impairment is indicated when the undiscounted cash flows estimated to be generated by the intangible assets are less than their respective carrying value. If an impairment exists, a loss would be recognized for the difference between the fair value and carrying value of the intangible assets. No impairments of intangible assets were recorded in 2014, 2013 and 2012.

Deferred Financing Costs

Costs incurred in connection with the issuance of long-term debt are capitalized and amortized to interest expense using the straight-line method over the life of the related long-term debt due to the variable nature of the Company's long-term debt.

Property and Equipment

The Company records property and equipment at historical cost. Depreciation expense is recorded on a straight-line method based on estimated useful lives. When assets are placed into service, management makes estimates with respect to useful lives and salvage values of the assets.

When items of property and equipment are sold or otherwise disposed of, any gain or loss is recorded in the combined and consolidated statements of operations.

The Company capitalizes costs associated with internal-use software projects in accordance with FASB ASC Topic 350-40, Internal-Use Software. Capitalized costs are the costs incurred during the application development stage of the internal-use software project such as software configuration, coding, installation of hardware and testing. Costs incurred during the preliminary or post-implementation stage of the internal-use software project are expensed in the period incurred. These types of costs include formulation of ideas and alternatives, training and application maintenance. After internal-use software projects are completed, the associated capitalized costs are depreciated over the estimated useful life of the related asset. Interest costs incurred while developing internal-use software projects are capitalized in accordance with FASB ASC Topic 835-20, Capitalization of Interest. Capitalized interest costs for the years ended December 31, 2014, 2013 and 2012 were not material.

Segment Reporting

The FASB ASC Topic 280, Segment Reporting, established standards for entities to report information about the operating segments and geographic areas in which they operate. The Company operates two segments, retail natural gas and retail electricity, and all of its operations are located in the United States.

Revenues and Cost of Revenues

The Company's revenues are derived primarily from the sale of natural gas and electricity to retail customers. The company also records revenue from sales of natural gas and electricity to wholesale counterparties, including affiliates. Revenues are recognized by the Company using the following criteria: (1) persuasive evidence of an exchange arrangement exists, (2) delivery has occurred or services have been rendered, (3) the buyer's price is fixed or determinable and (4) collection is reasonably assured. Utilizing these criteria, revenue is recognized when the natural gas or electricity is delivered. Similarly, cost of revenues is recognized when the commodity is delivered.

Revenues for natural gas and electricity sales are recognized upon delivery under the accrual method. Natural gas and electricity sales that have been delivered but not billed by period end are estimated. Accrued unbilled revenues are based on estimates of customer usage since the date of the last meter read provided by the utility. Volume estimates are based on forecasted volumes and estimated customer usage by class. Unbilled revenues are calculated by multiplying these volume estimates by the applicable rate by customer class. Estimated amounts are adjusted when actual usage is known and billed.

The Company records gross receipts taxes on a gross basis in retail revenues and retail cost of revenues. During the years ended December 31, 2014, 2013 and 2012, the Company's retail revenues and retail cost of revenues included gross receipts taxes of $3.0 million, $3.5 million and $5.1 million, respectively.

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Costs for natural gas and electricity sales are recognized as the commodity is delivered to the customer under the accrual method. Natural gas and electricity costs that have not been billed to the Company by suppliers but have been incurred by period end are estimated. The Company estimates volumes for natural gas and electricity delivered based on the forecasted revenue volumes, estimated transportation cost volumes and estimation of other costs associated with retail load which varies by commodity utility territory. These costs include items like ISO fees, ancillary services and renewable energy credits. Estimated amounts are adjusted when actual usage is known and billed.

The Company's asset optimization activities, which primarily include natural gas physical arbitrage and other short term storage and transportation opportunities, meet the definition of trading activities and are recorded on a net basis in the combined and consolidated statements of operations in net asset optimization revenues pursuant to FASB ASC 815, Derivatives and Hedging. The Company recorded asset optimization revenues, primarily related to physical sales or purchases of commodities, of $284.6 million, $192.4 million and $248.6 million for the years ended December 31, 2014, 2013 and 2012, respectively, and recorded asset optimization costs of revenues of $282.3 million, $192.1 million and $249.7 million for the years ended December 31, 2014, 2013 and 2012, respectively, which are presented on a net basis in asset optimization revenues.

Natural Gas Imbalances

The combined and consolidated balance sheets include natural gas imbalance receivables and payables, which primarily results when customers consume more or less gas than has been delivered by the Company to local distribution companies ("LDCs"). The settlement of natural gas imbalances varies by LDC, but typically the natural gas imbalances are settled in cash or in kind on a monthly, quarterly, semi-annual or annual basis. The imbalances are valued at an estimated net realizable value. The Company recorded an imbalance receivable of $1.4 million and $0.7 million recorded in other current assets on the combined and consolidated balance sheets as of December 31, 2014 and 2013, respectively. The Company recorded an imbalance payable of $0.6 million and zero recorded in other current liabilities on the combined and consolidated balance sheets as of December 31, 2014 and 2013, respectively.

Fair Value

FASB ASC 820, Fair Value Measurement, established a single authoritative definition of fair value, set out a framework for measuring fair value, and requires disclosures about fair value measurements. The standard clarifies that fair value is an exit price, representing the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. The standard utilizes a fair value hierarchy that prioritizes the inputs to the valuation techniques used to measure fair value into three broad levels based on quoted prices in active market, observable market prices, and unobservable market prices.

When the Company is required to measure fair value, and there is not a quoted or observable market price for a similar asset or liability, the Company utilizes the cost, income, or market valuation approach depending on the quality of information available to support management's assumptions.

Derivative Instruments

The Company uses derivative instruments such as futures, swaps, forwards and options to manage the commodity price risks of its business operations.

All derivatives, other than those for which an exception applies, are recorded in the combined and consolidated balance sheets at fair value. Derivative instruments representing unrealized gains are reported as derivative assets while derivative instruments representing unrealized losses are reported as derivative liabilities. The Company has elected to offset amounts in the combined and consolidated balance sheets for derivative instruments executed with the same counterparty under a master netting arrangement. One of the exceptions to fair value accounting, normal

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purchases and normal sales, has been elected by the Company for certain derivative instruments when the contract satisfies certain criteria, including a requirement that physical delivery of the underlying commodity is probable and is expected to be used in normal course of business. Retail revenues and retail cost of revenues resulting from deliveries of commodities under normal purchase contracts and normal sales contracts are included in earnings at the time of contract settlement.

To manage commodity price risk, the Company holds certain derivative instruments that are not held for trading purposes and are not designated as hedges for accounting purposes. However, to the extent the Company does not hold offsetting positions for such derivatives, they believe these instruments represent economic hedges that mitigate their exposure to fluctuations in commodity prices. As part of the Company’s strategy to optimize its assets and manage related commodity risks, it also manages a portfolio of commodity derivative instruments held for trading purposes. The Company uses established policies and procedures to manage the risks associated with price fluctuations in these energy commodities and uses derivative instruments to reduce risk by generally creating offsetting market positions.

Changes in the fair value of and amounts realized upon settlement of derivative instruments not held for trading purposes are recognized currently in earnings in retail revenues or retail costs of revenues, respectively.

Changes in the fair value of and amounts realized upon settlement of derivative instruments held for trading purposes are recognized currently in earnings in net asset optimization revenues.

The Company has historically designated a portion of our derivative instruments as cash flow hedges for accounting purposes. For all hedging transactions, the Company formally documented the hedging transaction and its risk management objective and strategy for undertaking the hedge, the hedging instrument, the nature of the risk being hedged, how the hedging instrument’s effectiveness in offsetting the hedged risk was assessed prospectively and retrospectively, and a description of the method used to measure ineffectiveness. The Company also formally assessed, both at the inception of the hedging transaction and on an ongoing basis, whether the derivatives used in hedging transactions were highly effective in offsetting changes in cash flows of hedged transactions. For derivative instruments that were designated and qualified as part of a cash flow hedging transaction, the effective portion of the gain or loss on the derivative was reported as a component of other comprehensive income and reclassified into earnings in the same period or periods during when the hedged transaction affected earnings. Gains and losses on the derivative representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness were recognized in current earnings. Hedge accounting was discontinued prospectively for derivatives that ceased to be highly effective hedges or when the occurrence of the forecasted transaction was no longer probable.

Effective July 1, 2013, the Company elected to discontinue hedge accounting prospectively and began to record the changes in fair value recognized in the combined and consolidated statement of operations in the period of change. Because the underlying transactions were still probable of occurring, the related accumulated OCI was frozen and recognized in earnings as the underlying hedged item was delivered. As of December 31, 2014 and 2013, the Company has no gains or losses on derivatives that were designated as qualifying cash flow hedging transactions recorded as a component of accumulated OCI, as all previously deferred gains and losses on qualifying hedge transactions were reclassified into earnings during the year ended December 31, 2013 and 2012 when the associated hedged transactions were recorded into earnings.

Income Taxes

The Company recognizes the amount of taxes payable or refundable for the year. In addition, the Company follows the asset and liability method of accounting for income taxes where deferred tax assets and liabilities are recognized for the expected future tax consequences of events that have been recognized in the financial statements or tax returns and operating loss carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in those years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in the tax rates is recognized in

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income in the period that includes the enactment date. A valuation allowance is provided for deferred tax assets if it is more likely than not that these items will not be realized.

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the projected future taxable income and tax planning strategies in making this assessment. Based upon the level of historical taxable income and projections for future taxable income over the periods in which the deferred tax assets are deductible, management believes it is more likely than not that we will realize the benefits of these deductible differences.

The Company recognizes interest and penalties related to unrecognized tax benefits within the provision for income taxes on continuing operations in our consolidated statements of operations.

Earnings per Share

Basic earnings per share ("EPS") is computed by dividing net income attributable to shareholders (the numerator) by the weighted-average number of Class A common shares outstanding for the period (the denominator). Class B common shares are not included in the calculation of basic earnings per share because they have no economic interest in the Company. Diluted earnings per share is similarly calculated except that the denominator is increased (1) using the treasury stock method to determine the potential dilutive effect of the Company's outstanding unvested restricted stock units and (2) using the if-converted method to determine the potential dilutive effect of the Company's Class B common stock. The Company has omitted earnings per share prior to the Offering because the Company operated under a sole member equity structure for those periods.

Non-controlling Interest

As a result of the Offering, the Company acquired a 21.82% economic interest in Spark HoldCo, and is the sole managing member in Spark HoldCo, with NuDevco Retail Holdings, LLC and NuDevco Retail, LLC (collectively, "NuDevco") retaining a 78.18% economic interest in Spark HoldCo. As a result, the Company has consolidated the financial position and results of operations of Spark HoldCo and reflected the economic interest retained by NuDevco as a non-controlling interest. Net income attributable to non-controlling interest for the year ended December 31, 2014 represents the net income attributable to NuDevco prior to the Offering and NuDevco's retained interest subsequent to the Offering.

Commitments and Contingencies

The Company enters into various firm purchase and sale commitments for natural gas, storage, transportation, and electricity that do not meet the definition of a derivative instrument or for which the Company has elected the normal purchase or normal sales exception. Management does not anticipate that such commitments will result in any significant gains or losses based on current market conditions.

Liabilities for loss contingencies arising from claims, assessments, litigation, fines, penalties and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Legal costs incurred in connection with loss contingencies are expensed as incurred.

Transactions with Affiliates

The Company enters into transactions with and incurs certain costs on behalf of affiliates that are commonly controlled by NuDevco Partners Holdings in order to reduce risk, reduce administrative expense, create economies of scale, create strategic alliances and supply goods and services to these related parties. These transactions include, but are not limited to, certain services to the affiliated companies associated with the Company's debt facility prior to the Offering, employee benefits provided through the Company's benefit plans, insurance plans, leased office

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space, and administrative salaries for accounting, tax, legal, or technology services. As such, the accompanying combined and consolidated financial statements include costs that have been incurred by the Company and then directly billed or allocated to affiliates and are recorded net in general and administrative expense on the combined and consolidated statements of operations with a corresponding accounts receivable-affiliates recorded in the combined and consolidated balance sheets. Additionally, the Company enters into transactions with certain affiliates for sales or purchases of natural gas and electricity, which are recorded in retail revenues, retail cost of revenues, and net asset optimization revenues in the combined and consolidated statements of operations with a corresponding accounts receivable-affiliate or accounts payable-affiliate in the combined and consolidated balance sheets. See Note 11, “Transactions with Affiliates” for further discussion.

Use of Estimates and Assumptions

The preparation of the Company’s combined and consolidated financial statements requires estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the combined financial statements and the reported amounts of revenues and expenses during the period. Actual results could materially differ from those estimates. Significant items subject to such estimates by the Company’s management include estimates for unbilled revenues and related cost of revenues, provisions for uncollectible receivables, valuation of customer acquisition costs, estimated useful lives of property and equipment, valuation of derivatives and reserves for contingencies.

Subsequent Events

Subsequent events have been evaluated through the date these financial statements are issued. Any material subsequent events that occurred prior to such date have been properly recognized or disclosed in the combined and consolidated financial statements. See Note 14 “Subsequent Events” for further discussion.

Recent Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) No. 2014-09, Revenue from Contracts with Customers, which requires an entity to recognize the amount of revenue to which it expects to be entitled for the transfer of promised goods or services to customers. ASU 2014-09 will replace most existing revenue recognition guidance in GAAP when it becomes effective on January 1, 2017. Early application is not permitted. The standard permits the use of either the retrospective or cumulative effect transition method. The Company is evaluating the effect that ASU 2014-09 will have on its financial statements and related disclosures. The Company has not yet selected a transition method nor has it determined the effect of the standard on its ongoing financial reporting.

In August 2014, the FASB issued ASU No. 2014-15, Presentation of Financial Statements - Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity’s Ability to Continue as a Going Concern (“ASU 2014-15”). The new guidance clarifies management’s responsibility to evaluate whether there is substantial doubt about an entity’s ability to continue as a going concern and to provide related footnote disclosure. ASU 2014-15 is effective for annual periods ending after December 15, 2016 and for annual periods and interim periods thereafter. Early adoption is permitted. The Company does not expect the adoption to have a material effect on the combined or consolidated financial statements.

In November 2014, the FASB issued ASU No. 2014-16, Derivatives and Hedging, which clarifies how current GAAP should be interpreted in evaluating the economic characteristics and risks of a host contract in a hybrid financial instrument that is issued in the form of a share. The amendments in this Update are effective for public business entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. Early adoption, including adoption in an interim period, is permitted. The Update does not change the current criteria in GAAP for determining when separation of certain embedded derivative features in a hybrid financial instrument is required. The Company does not believe the adoption of this ASU to have a material impact on the combined and consolidated financial statements.

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In February 2015, the FASB issued ASU No. 2015-02, Consolidation (Topic 810) (“ASU 2015-02”). The new guidance changes the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. ASU 2015-02 is effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted, including adoption at an interim period. The Company has not yet determined the effect of the standard on its ongoing financial reporting.

3. Property and Equipment

Property and equipment consist of the following amounts as of (in thousands):

	Estimated useful lives (years)	December 31, 2014	December 31, 2013
Information technology	2 – 5	$25,588	$22,529
Leasehold improvements	2 – 5	4,568	4,568
Furniture and fixtures	2 – 5	998	998
Total		31,154	28,095
Accumulated depreciation		(26,933)	(23,278)
Property and equipment—net		$4,221	$4,817

Information technology assets include software and consultant time used in the application, development and implementation of various systems including customer billing and resource management systems. As of December 31, 2014 and 2013, information technology includes $0.4 million and $1.3 million, respectively, of costs associated with assets not yet placed into service.

Depreciation expense recorded in the combined and consolidated statements of operations was $3.7 million, $6.1 million and $6.4 million for the years ended December 31, 2014, 2013 and 2012, respectively.

4. Long-Term Debt

In October 2007, Spark Energy Ventures and all of its subsidiaries (collectively, the “Borrowers”), entered into a credit agreement, consisting of a working capital facility, a term loan and a revolving credit facility (the “Credit Agreement”), with SE and SEG as co-borrowers under which they were jointly and severally liable for amounts Borrowers borrowed under the Credit Agreement. The Credit Agreement was secured by substantially all of the assets of Spark Energy Ventures and its subsidiaries.

The Credit Agreement was amended on May 30, 2008 to provide for a $177.5 million working capital facility, a $100 million term loan, and a $35 million revolving credit facility. On January 24, 2011, the Borrowers amended and restated the Credit Agreement (the “Fifth Amended Credit Agreement”) to decrease the working capital facility to $150 million, to increase the term loan to $130 million and to eliminate the revolving credit facility.

On December 17, 2012, the Borrowers amended and restated the Fifth Amended Credit Agreement to decrease the working capital facility to $70 million, to decrease the term loan to $125 million and to reinstate the revolving credit facility in the amount of $30 million (the “Sixth Amended Credit Agreement”).

On July 31, 2013 and in conjunction with the initial public offering of Marlin Midstream Partners, LP (“Marlin”), which was formerly a wholly owned subsidiary of Spark Energy Ventures, the Sixth Amended Credit Agreement was amended and restated to increase the working capital facility to $80 million and eliminate the term loan and revolving credit facility (the “Seventh Amended Credit Agreement”) and to remove Marlin as a party to the Credit Agreement. The Seventh Amended Credit Agreement continued to be secured by the assets of Spark Energy Ventures and its subsidiaries through completion of the Offering.

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Although SE and SEG, as wholly owned subsidiaries of Spark Energy Ventures, were jointly and severally liable for Marlin's borrowing under the Sixth Amended Credit Agreement prior to the Marlin initial public offering, SE and SEG did not historically have access to or use the term loan and the revolving credit facility utilized by Marlin. SE and SEG were the primary recipients of the proceeds from the working capital facility.

The Company adopted ASU 2013-04, which prescribes the accounting for joint and several liability arrangements early and applied the accounting in the guidance combined and consolidated financial statements prior to the Offering as required by the standard. This guidance requires an entity to measure its obligation resulting from joint and several liability arrangements for which the total amount under the arrangement is fixed at the reporting date, as the sum of the amount the reporting entity agreed to pay on the basis of its arrangement among its co-obligors and any additional amount the reporting entity expects to pay on behalf of its co-obligors. Based on the Sixth Amended Credit Agreement prior to the Marlin initial public offering and understanding among the Borrowers, the term loan and the revolving credit facility were assigned specifically to Marlin. The Company has recognized the proceeds from the working capital facility in its combined financial statements prior to the Offering, which represented the amounts the Company with the other Borrowers agreed to pay, and the amounts the Company expected to pay.

Working Capital Facility

The working capital facility was $150 million in 2012 under the Fifth Amended Credit Agreement and was later amended to $70 million on December 17, 2012 under the Sixth Amended Credit Agreement. On July 31, 2013, and in conjunction with the Seventh Amended Credit Agreement, the working capital facility was increased to $80 million. The working capital facility was available for use by Spark Energy Ventures and its affiliates to finance the working capital requirements related to the purchase and sale of natural gas, electricity, and other commodity products not related to the retail natural gas and asset optimization and retail electricity businesses of the Company. The Company's combined financial statements include the total amounts outstanding under the working capital facility of $27.5 million as of December 31, 2013, which is classified as current in the combined and consolidated balance sheet as the working capital facility was drawn upon and repaid on a monthly basis to fund working capital needs. Portions of the borrowings were used to fund equity distributions to the sole member of the Company to fund unrelated operations of an affiliate under the common control of the sole member prior to the Offering. The total amounts outstanding under the facility as of December 31, 2013 and through the Offering date included $29.0 million that was retained and paid off by an affiliate in connection with the Offering.

Further, through the issuance of letters of credit, the Company was able to secure payment to suppliers. No obligation is recorded for such outstanding letters of credit unless they are drawn upon by the suppliers and in the event a supplier draws on a letter of credit, repayment is due by the earlier of demand by the bank or at the expiration of the applicable Credit Agreement. Letters of credit issued and outstanding as of December 31, 2013 were $10.0 million. Under the working capital facility, the Company paid a fee with respect to each letter of credit issued and outstanding. For the years ended December 31, 2014, 2013 and 2012, the Company incurred fees on letters of credit issued and outstanding totaling $0.4 million, $0.5 million and $0.6 million, respectively, which is recorded in interest expense in the combined and consolidated statements of operations.

Under the Sixth Amended Credit Agreement, the Company was able to elect to have loans under the working credit facility bear interest either (i) at a Eurodollar-based rate plus a margin ranging from 3.00% to 3.75% depending on the Company's consolidated funded indebtedness ratio then in effect, or (ii) at a base rate loan plus a margin ranging from 2.00% to 2.75% depending on the Company's consolidated funded indebtedness ratio then in effect. The Company also paid a nonutilization fee equal to 0.50% per annum.

Under the Seventh Amended Credit Agreement, the Company was able to elect to have loans under the working capital facility bear interest (i) at a Eurodollar-based rate plus a margin ranging from 3.00% to 3.25%, depending on the Spark Energy Ventures' aggregate amount outstanding then in effect, (ii) at a base rate loan plus a margin

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ranging from 2.00% to 2.25%, depending on Spark Energy Ventures' aggregate amount outstanding then in effect or (iii) a cost of funds rate loan plus a margin ranging from 2.50% to 2.75%, depending on Spark Energy Ventures' aggregate amount outstanding then in effect. Each working capital loan made as a result of a drawing under a letter of credit bears interest on the outstanding principal amount thereof from the date funded at a floating rate per annum equal to the cost of funds rate plus the applicable margin until such loan has been outstanding for more than two business days and, thereafter, bears interest on the outstanding principal amount thereof at a floating rate per annum equal to the base rate plus the applicable margin, plus two percent 2.00% per annum. The Company incurred interest expense related to our revolving credit facilities of $0.4 million, $0.3 million and $1.3 million for the years ended December 31, 2014, 2013 and 2012, respectively, which is recorded in interest expense in the combined and consolidated statements of operations.

The Company also paid a commitment fee equal to 0.50% per annum. The Company incurred commitment fees from the prior and current facilities totaling $0.1 million, $0.2 million and $0.5 million for the years ended December 31, 2014, 2013 and 2012, which is recorded in interest expense in the combined and consolidated statements of operations.

Deferred Financing Costs

Deferred financing costs were $0.3 million (all of which represents capitalized financing costs related to the new Senior Credit Facility entered into on August 1, 2014) and $0.5 million as of December 31, 2014 and 2013, respectively. Of these amounts, $0.2 million and $0.4 million is recorded in other current assets in the combined and consolidated balance sheets as of December 31, 2014 and 2013, respectively, and $0.1 million and $0.1 million is recorded in other assets in the combined and consolidated balance sheets as of December 31, 2014 and 2013, respectively, based on the terms of the working capital facilities.

Amortization and write offs of deferred financing costs were $0.6 million (which included $0.3 million of deferred financing costs written off upon extinguishment of the Seventh Amended Credit Facility), $0.7 million (which included $0.1 million of deferred financing costs written off in connection with the execution of the Seventh Amended Credit Facility), and $0.9 million (which included $0.3 million of deferred financing costs written off in connection with the execution of the Sixth Amended Credit Facility), for the years ended December 31, 2014, 2013 and 2012, respectively, which is recorded in interest expense in the combined and consolidated statements of operations.

NuDevco Note

NuDevco Retail Holdings transferred Spark HoldCo units to the Company for the $50,000 NuDevco Note, and the limited liability company agreement of Spark HoldCo was amended and restated to admit Spark Energy, Inc. as its sole managing member. This promissory note was repaid in connection with proceeds from the Offering.

New Credit Facility

Concurrently with the closing of the Offering, the Company entered into the $70.0 million Senior Credit Facility, which matures on August 1, 2016. If no event of default has occurred, the Company has the right, subject to approval by the administrative agent and each issuing bank, to increase the commitments under the Senior Credit Facility up to $120.0 million. The Company borrowed approximately $10.0 million under the Senior Credit Facility at the closing of the Offering to repay in full the outstanding indebtedness under the Seventh Amended Credit Agreement that SEG and SE agreed to be responsible for pursuant to an interborrower agreement between SEG, SE and an affiliate. The remaining $29.0 million of indebtedness outstanding under the Seventh Amended Credit Agreement at the Offering date was paid down by our affiliate with its own funds concurrent with the closing of the Offering pursuant to the terms of the interborrower agreement. Following this repayment, the Seventh Amended Credit Agreement was terminated. The Company had $15 million in letters of credit issued under the Senior Credit Facility at inception. As of December 31, 2014, the Company had $33.0 million outstanding under the Senior Credit Facility and $10.7 million in letters of credit issued. The Senior Credit Facility is available to fund expansions, acquisitions and working capital requirements for operations and general corporate purposes.

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At our election, interest under the Senior Credit Facility is generally determined by reference to:

- the Eurodollar-based rate plus a margin ranging from 2.75% to 3.00%, depending on the overall utilization of the working capital facility;
- the alternate base rate loan plus a margin ranging from 1.75% to 2.00%, depending on the overall utilization of the working capital facility; or
- a cost of funds rate loan plus a margin ranging from 2.25% to 2.50%, depending on the overall utilization of the working capital facility.

The interest rate is generally reduced by 25 basis points if utilization under the Senior Credit Facility is below fifty percent.

Each working capital loan made as a result of a drawing under a letter of credit or a reducing letter of credit borrowing bears interest on the outstanding principal amount thereof from the date funded at a floating rate per annum equal to the base rate plus the applicable margin until such loan has been outstanding for more than two business days and, thereafter, bears interest on the outstanding principal amount thereof at a floating rate per annum equal to the base rate plus the applicable margin, plus two percent (2.00%) per annum. Additionally, the Company is charged a letter of credit fee for letters of credit outstanding. Our fee is from 2.00% to 2.50% per annum, depending on the overall utilization of the working capital facility and what type of transaction it supports.

We pay an annual commitment fee of 0.375% or 0.5% on the unused portion of the Senior Credit Facility depending upon the unused capacity. The lending syndicate under the Senior Credit Facility is entitled to several additional fees including an upfront fee, annual agency fee, and fronting fees based on a percentage of the face amount of letters of credit payable to any syndicate member that issues a letter a credit. Commitment fees were immaterial for the year ended December 31, 2014. The Company paid no commitment fees related to the Senior Credit Facility for the years ended December 31, 2013 and 2012.

The Company incurred total interest expense related to prior and current credit facilities of $1.6 million, $1.7 million and $3.4 million for the years ended December 31, 2014, 2013 and 2012, respectively.

The Senior Credit Facility is secured by the membership interests of SE, SEG and the equity of the Co-Borrowers' present and future subsidiaries, all of the Co-Borrowers' and their subsidiaries' present and future property and assets, including accounts receivable, inventory and liquid investments, and control agreements relating to bank accounts. The Senior Credit Facility contains covenants which, among other things, require the Company to maintain certain financial ratios or conditions. At all times, the Company must maintain net working capital, tangible net worth and a leverage ratio to a certain threshold. The Senior Credit Facility also contains negative covenants that limit our ability to, among other things, make certain payments, distributions, investments, acquisitions or loans.
In addition, the Senior Credit Facility contains affirmative covenants that are customary for credit facilities of this type. The covenants include delivery of financial statements, including any filings made with the SEC, maintenance of property and insurance, payment of taxes and obligations, material compliance with laws, inspection of property, books and records and audits, use of proceeds, payments to bank blocked accounts, notice of defaults and certain other customary matters.

5. Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (exit price) in an orderly transaction between market participants at the measurement date. Fair values are based on assumptions that market participants would use when pricing an asset or liability, including assumptions about risk and the risks inherent in valuation techniques and the inputs to valuations. This includes not only the credit standing of

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counterparties involved and the impact of credit enhancements but also the impact of the Company's own nonperformance risk on its liabilities.

The Company applies fair value measurements to its commodity derivative instruments based on the following fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value into three broad levels:

- Level 1—Quoted prices in active markets for identical assets and liabilities. Instruments categorized in Level 1 primarily consist of financial instruments such as exchange-traded derivative instruments.
- Level 2—Inputs other than quoted prices recorded in Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means. Instruments categorized in Level 2 primarily include non-exchange traded derivatives such as over-the-counter commodity forwards and swaps and options.
- Level 3—Unobservable inputs for the asset or liability, including situations where there is little, if any, observable market activity for the asset or liability.

As the fair value hierarchy gives the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3), the Company maximizes the use of observable inputs and minimizes the use of unobservable inputs when measuring fair value. In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. In these cases, the lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy.

Non-Derivative Financial Instruments

The carrying amount of cash and cash equivalents, accounts receivable, accounts receivable-affiliates, accounts payable, accounts payable-affiliates, and accrued liabilities recorded in the combined and consolidated balance sheets approximate fair value due to the short-term nature of these items. The carrying amount of long-term debt recorded in the combined and consolidated balance sheets approximates fair value because of the variable rate nature of the Company's long-term debt. The fair value of the payable pursuant to tax receivable agreement-affiliate is not determinable due to the affiliate nature and terms of the associated agreement with the affiliate.

Derivative Instruments

The following tables present assets and liabilities measured and recorded at fair value in the Company's combined and consolidated balance sheets on a recurring basis by and their level within the fair value hierarchy as of (in thousands):

	Level 1	Level 2	Level 3	Total
December 31, 2014				
Non-trading commodity derivative assets	$—	$80	$—	$80
Trading commodity derivative assets	—	136	—	136
Total commodity derivative assets	$—	$216	$—	$216
Non-trading commodity derivative liabilities	$(6,810)	$(5,017)	$—	$(11,827)
Trading commodity derivative liabilities	(32)	(145)	—	(177)
Total commodity derivative liabilities	$(6,842)	$(5,162)	$—	$(12,004)

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	Level 1	Level 2	Level 3	Total
December 31, 2013				
Non-trading commodity derivative assets	$—	$4,672	$—	$4,672
Trading commodity derivative assets	—	3,405	—	3,405
Total commodity derivative assets	$—	$8,077	$—	$8,077
Non-trading commodity derivative liabilities	$(563)	$(854)	$—	$(1,417)
Trading commodity derivative liabilities	147	(581)	—	(434)
Total commodity derivative liabilities	$(416)	$(1,435)	$—	$(1,851)

The Company had no financial instruments measured using level 3 at December 31, 2014 and 2013. The Company had no transfers of assets or liabilities between any of the above levels during the year ended December 31, 2014 and 2013.

The Company's derivative contracts include exchange-traded contracts fair valued utilizing readily available quoted market prices and non-exchange-traded contracts fair valued using market price quotations available through brokers or over-the-counter and on-line exchanges. In addition, in determining the fair value of the Company's derivative contracts, the Company applies a credit risk valuation adjustment to reflect credit risk which is calculated based on the Company's or the counterparty's historical credit risks. As of December 31, 2014 and December 31, 2013, the credit risk valuation adjustment was not material.

6. Accounting for Derivative Instruments

The Company is exposed to the impact of market fluctuations in the price of electricity and natural gas and basis costs, storage and ancillary capacity charges from independent system operators. The Company uses derivative instruments to manage exposure to these risks, and historically designated certain derivative instruments as cash flow hedges for accounting purposes. For derivatives designated in a qualifying cash flow hedging relationship, the effective portion of the change in fair value is recognized in accumulated other comprehensive income ("OCI") and reclassified to earnings in the period in which the hedged item affects earnings. Any ineffective portion of the derivative's change in fair value is recognized currently in earnings.

The Company also holds certain derivative instruments that are not held for trading purposes but are also not designated as hedges for accounting purposes. These derivative instruments represent economic hedges that mitigate the Company's exposure to fluctuations in commodity prices. For these derivative instruments, changes in the fair value are recognized currently in earnings in retail revenues or retail costs of revenues, respectively.

As part of the Company's strategy to optimize its assets and manage related risks, it also manages a portfolio of commodity derivative instruments held for trading purposes. The Company's commodity trading activities are subject to limits within the Company's Risk Management Policy. For these derivative instruments, changes in the fair value are recognized currently in earnings in net asset optimization revenues.

Derivative assets and liabilities are presented net in the Company's combined and consolidated balance sheets when the derivative instruments are executed with the same counterparty under a master netting arrangement. The Company's derivative contracts include transactions that are executed both on an exchange and centrally cleared as well as over-the-counter, bilateral contracts that are transacted directly with a third party. To the extent the Company has paid or received collateral related to the derivative assets or liabilities, such amounts would be presented net against the related derivative asset or liability's fair value. As of December 31, 2014 and 2013, the Company had not paid or received any collateral amounts. The specific types of derivative instruments the Company may execute to manage the commodity price risk include the following:

- Forward contracts, which commit the Company to purchase or sell energy commodities in the future;
- Futures contracts, which are exchange-traded standardized commitments to purchase or sell a commodity or financial instrument;

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•Swap agreements, which require payments to or from counterparties based upon the differential between two prices for a predetermined notional quantity; and,
•Option contracts, which convey to the option holder the right but not the obligation to purchase or sell a commodity.
The Company has entered into other energy-related contracts that do not meet the definition of a derivative instrument or qualify for the normal purchase or normal sale exception and are therefore not accounted for at fair value including the following:

•Forward electricity and natural gas purchase contracts for retail customer load; and,
•Natural gas transportation contracts and storage agreements.
Volumetric Underlying Derivative Transactions
The following table summarizes the net notional volume buy/(sell) of the Company's open derivative financial instruments accounted for at fair value, broken out by commodity, as of:
Non-trading

Commodity	Notional	December 31, 2014	December 31, 2013
Natural Gas	MMBtu	9,690	3,513
Natural Gas Basis	MMBtu	2,710	373
Electricity	MWh	607	465

Trading

Commodity	Notional	December 31, 2014	December 31, 2013
Natural Gas	MMBtu	(155)	2,259
Natural Gas Basis	MMBtu	(56)	1,443

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Gains (Losses) on Derivative Instruments

Gains (losses) on derivative instruments, net and current period settlements on derivative instruments were as follows for the periods indicated (in thousands):

	Year Ended December 31,		
	2014	2013	2012
Loss on non-trading derivatives—cash flow hedges, net (including ineffectiveness gain (loss) of ($288) and $930 for the years ended December 31, 2013 and 2012, respectively.)	$—	$84	$(17,942)
Gain (loss) on non-trading derivatives, net	(8,713)	1,345	(1,074)
Gain (loss) on trading derivatives, net (including gain on trading derivatives—affiliates, net of $203, $1,509 and $506 for the years ended December 31, 2014, 2013 and 2012, respectively)	(5,822)	5,138	(2,469)
Gain (loss) on derivatives, net	$(14,535)	$6,567	$(21,485)
Current period settlements on non-trading derivatives—cash flow hedges	$—	$(1,180)	$18,707
Current period settlements on non-trading derivatives	(6,289)	1,833	7,782
Current period settlements on trading derivatives (including current period settlements on trading derivatives—affiliates, net of $315, ($1,780) and $87 for the years ended December 31, 2014, 2013 and 2012, respectively)	2,810	387	312
Total current period settlements on derivatives	$(3,479)	$1,040	$26,801

Gains (losses) on trading derivative instruments are recorded in net asset optimization revenues and gains (losses) on non-trading derivative instruments are recorded in retail revenues or retail cost of revenues on the combined and consolidated statements of operations.

Fair Value of Derivative Instruments

The following tables summarize the fair value and offsetting amounts of the Company's derivative instruments by counterparty and collateral received or paid as of (in thousands):

	December 31, 2014				
Description	Gross Assets	Gross Amounts Offset	Net Assets	Cash Collateral Offset	Net Amount Presented
Non-trading commodity derivatives	$3,642	$(3,562)	$80	$—	$80
Trading commodity derivatives	234	(98)	136	—	136
Total Current Derivative Assets	3,876	(3,660)	216	—	216
Non-trading commodity derivatives	313	(313)	—	—	—
Total Non-current Derivative Assets	313	(313)	—	—	—
Total Derivative Assets	$4,189	$(3,973)	$216	$—	$216

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	December 31, 2014				
Description	Gross Liabilities	Gross Amounts Offset	Net Liabilities	Cash Collateral Offset	Net Amount Presented
Non-trading commodity derivatives	$(14,911)	$3,562	$(11,349)	$—	$(11,349)
Trading commodity derivatives	(275)	98	(177)	—	(177)
Total Current Derivative Liabilities	(15,186)	3,660	(11,526)	—	(11,526)
Non-trading commodity derivatives	(791)	313	(478)	—	(478)
Total Non-current Derivative Liabilities	(791)	313	(478)	—	(478)
Total Derivative Liabilities	$(15,977)	$3,973	$(12,004)	$—	$(12,004)

	December 31, 2013				
Description	Gross Assets	Gross Amounts Offset	Net Assets	Cash Collateral Offset	Net Amount Presented
Non-trading commodity derivatives	$11,564	$(6,898)	$4,666	$—	$4,666
Trading commodity derivatives	3,949	(544)	3,405	—	3,405
Total Current Derivative Assets	15,513	(7,442)	8,071	—	8,071
Non-trading commodity derivatives	100	(94)	6	—	6
Trading commodity derivatives	14	(14)	—	—	—
Total Non-current Derivative Assets	114	(108)	6	—	6
Total Derivative Assets	$15,627	$(7,550)	$8,077	$—	$8,077

	December 31, 2013				
Description	Gross Liabilities	Gross Amounts Offset	Net Liabilities	Cash Collateral Offset	Net Amount Presented
Non-trading commodity derivatives	$(8,289)	$6,898	$(1,391)	$—	$(1,391)
Trading commodity derivatives	(986)	544	(442)	—	(442)
Total Current Derivative Liabilities	(9,275)	7,442	(1,833)	—	(1,833)
Non-trading commodity derivatives	(120)	94	(26)	—	(26)
Trading commodity derivatives	(6)	14	8	—	8
Total Non-current Derivative Liabilities	(126)	108	(18)	—	(18)
Total Derivative Liabilities	$(9,401)	$7,550	$(1,851)	$—	$(1,851)

Accumulated Other Comprehensive Income

The following table summarizes the effects on the Company's accumulated OCI balance attributable to cash flow hedge derivative instruments for the periods indicated (in thousands):

	Year Ended December 31,	
	2014	2013
Accumulated OCI balance, beginning of period	$—	$(2,536)
Deferred gain (loss) on cash flow hedge derivative instruments	—	2,620
Reclassification of accumulated OCI net to income	—	(84)
Accumulated OCI balance, end of period	$—	$—

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The amounts reclassified from accumulated OCI into income and any amounts recognized in income from the ineffective portion of cash flow hedges are recorded in retail cost of revenues. In June 2013, the Company elected to discontinue cash flow hedge accounting.

7. Equity

Class A Common Stock

The Company has a total of 3,000,000 shares of its Class A common stock outstanding at December 31, 2014. Each share of Class A common stock holds economic rights and entitles its holder to one vote on all matters to be voted on by shareholders generally.

Class B Common Stock

The Company has a total of 10,750,000 shares of its Class B common stock outstanding at December 31, 2014. Each share of Class B common stock, all of which is held by NuDevco, has no economic rights but entitles its holder to one vote on all matters to be voted on by shareholders generally.

Holders of Class A common stock and Class B common stock vote together as a single class on all matters presented to our shareholders for their vote or approval, except as otherwise required by applicable law or by our certificate of incorporation.

Preferred Stock

The Company has 20,000,000 shares of authorized preferred stock for which there are no issued and outstanding shares at December 31, 2014.

Earnings Per Share

The Company's unvested restricted stock units were not recognized in dilutive earnings per share as they would have been antidilutive. The Class B common stock conversion to Class A common stock was not recognized in dilutive earnings per share for the year ended December 31, 2014 as the effect of the conversion would be antidilutive.

The following table presents the computation of earnings per share for the year ended December 31, 2014 (in thousands, except per share data):

	Year Ended December 31, 2014
Net loss attributable to Spark Energy, Inc. stockholders	$(54)
Basic weighted average Class A common shares outstanding [1]	3,000
Basic EPS attributable to Spark Energy, Inc. stockholders	$(0.02)
Net loss attributable to Spark Energy, Inc. stockholders	$(54)
Effect of conversion of Class B common stock to shares of Class A common stock	—
Diluted net loss attributable to Spark Energy, Inc. stockholders	(54)
Basic weighted average Class A common shares outstanding [1]	3,000
Effect of dilutive Class B common stock [1]	—
Effect of dilutive restricted stock units	—
Diluted weighted average shares outstanding	3,000
Diluted EPS attributable to Spark Energy, Inc. stockholders	$(0.02)

(1) Based on outstanding shares for the period from the Offering date of August 1, 2014 to December 31, 2014.

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8. Stock-Based Compensation

Restricted Stock Units

In connection with the Offering, the Company adopted the Spark Energy, Inc. Long-Term Incentive Plan (the “LTIP”) for the employees, consultants and directors of the Company and its affiliates who perform services for the Company. The purpose of the LTIP is to provide a means to attract and retain individuals to serve as directors, employees and consultants who provide services to the Company by affording such individuals a means to acquire and maintain ownership of awards, the value of which is tied to the performance of the Company’s Class A common stock. The LTIP provides for grants of cash payments, stock options, stock appreciation rights, restricted stock or units, bonus stock, dividend equivalents, and other stock-based awards with the total number of shares of stock available for issuance under the LTIP not to exceed 1,375,000 shares.

On August 1, 2014, the Company granted restricted stock units to our employees, non-employee directors and certain employees of our affiliates who perform services for the Company. The restricted stock unit awards vest over a nine month period for non-employee directors and ratably over approximately three or four years for officers, employees, and employees of affiliates, depending on years of service at the grant date, with the initial vesting date occurring on May 4, 2015 and each subsequent vesting date occurring each May 4 thereafter. Each restricted stock unit is entitled to receive a dividend equivalent when dividends are declared and distributed to shareholders of Class A common stock. These dividend equivalents shall be retained by the Company, reinvested in additional restricted stock units effective as of the record date of such dividends and vested upon the same schedule as the underlying restricted stock unit. One dividend was declared and paid during the year ended December 31, 2014, and the dividends associated with unvested restricted stock units resulted in additional restricted stock units issued. In accordance with ASC 718, Compensation - Stock Compensation (“ASC 718”), the Company measures the cost of awards classified as equity awards based on the grant date fair value of the award, and the Company measures the cost of awards classified as liability awards at the fair value of the award at each reporting period. The Company has utilized an estimated 6% annual forfeiture rate of restricted stock units in determining the fair value for all awards excluding those issued to executive level recipients and non-employee directors, for which no forfeitures are estimated to occur. The Company has elected to recognize related compensation expense on a straight-line basis over the associated vesting periods. Although the restricted stock units allow for cash settlement of the awards at the sole discretion of management of the Company, management intends to settle the awards by issuing shares of the Company’s Class A common stock.

Equity Classified Restricted Stock Units

Restricted stock units issued to employees and officers of the Company are classified as equity awards. The fair value of the equity classified restricted stock units was based on the Company’s Class A common stock price as of the grant date, and the Company recognized stock based compensation expense of $0.5 million for the year ended December 31, 2014 in general and administrative expense with a corresponding increase to additional paid in capital. No compensation expense was recorded for the same periods in 2013 and 2012 as there were no LTIP awards outstanding.

The following table summarizes equity classified restricted stock unit activity and unvested restricted stock units for the year ended December 31, 2014:

	Number of Shares	Weighted Average Grant Date Fair Value
Unvested at December 31, 2013	—	—
Granted	264,150	$ 18.00
Dividend reinvestment issuances	4,334	14.01
Vested	—	—

Forfeited	(11,600	) 18.00
Unvested at December 31, 2014	256,884	$ 17.93

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As of December 31, 2014, there was $4.1 million of total unrecognized compensation cost related to the Company's equity classified restricted stock units, which is expected to be recognized over a weighted average period of approximately 3.2 years.

Liability Classified Restricted Stock Units

Restricted stock units issued to non-employee directors of the Company and employees of certain of our affiliates are classified as liability awards in accordance with ASC 718 as the awards are either to a) non-employee directors that allow for the recipient to choose net settlement for the amount of withholding taxes dues upon vesting or b) to employees of certain affiliates of the Company and are therefore not deemed to be employees of the Company. The fair value of the liability classified restricted stock units was based on the Company's Class A common stock price as of the reported period ending date, and the Company recognized stock based compensation expense of $0.3 million for year ended December 31, 2014 in general and administrative expense with a corresponding increase to liabilities. As of December 31, 2014, the Company's liabilities related to these restricted stock units recorded in other current liabilities and other non-current liabilities was $0.1 million and $0.2 million, respectively. No compensation expense was recorded for the same periods in 2013 and 2012 as there were no LTIP awards outstanding.

The following table summarizes liability classified restricted stock unit activity and unvested restricted stock units for the year ended December 31, 2014:

	Number of Shares	Weighted Average Reporting Date Fair Value
Unvested at December 31, 2013	—	—
Granted	122,000	$14.09
Dividend reinvestment issuances	2,093	14.09
Vested	—	—
Forfeited	—	—
Unvested at December 31, 2014	124,093	$14.09

As of December 31, 2014, there was $1.4 million of total unrecognized compensation cost related to the Company's liability classified restricted stock units, which is expected to be recognized over a weighted average period of approximately 2.2 years.

9. Income Taxes

The Company is subject to U.S. federal income tax as a corporation. Spark HoldCo and its subsidiaries are treated as flow-through entities for U.S. federal income tax purposes, and as such, are generally not subject to U.S. federal income tax at the entity level. Rather, the tax liability with respect to their taxable income is passed through to their members or partners. Accordingly, the Company is subject to U.S. federal income taxation on its allocable share of Spark Holdco's net U.S. taxable income.

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The (benefit) provision for income taxes included the following components:

(in thousands)	2014	2013	2012
Current:			
Federal	$—	$—	$—
State	173	56	46
Total Current	173	56	46
Deferred:			
Federal	(957)	—	—
State	(107)	—	—
Total Deferred	(1,064)	—	—
(Benefit) provision for income taxes	$(891)	$56	$46

For the year ended December 31, 2013 and 2012, income taxes relate solely to the Company's Texas franchise tax liability, which is computed on a modified gross margin. The Company does not do business in any other state where a similar tax is applied.

The effective income tax rate was 17.3% for the year ended December 31, 2014. The following table reconciles the income tax benefit included in the combined and consolidated statement of operations with income tax expense that would result from application of the statutory federal tax rate, 34%, to loss before income tax expense:

(in thousands)	2014
Expected benefit at federal statutory rate	$(1,753)
Increase (decrease) resulting from:	
Noncontrolling interest	1,451
Corporate costs	(607)
State income taxes, net of federal income tax effect	69
Other	(51)
Benefit for income taxes	$(891)

For the year ended December 31, 2013 and 2012, the rate reconciliation calculation is not applicable as the Company was not subject to federal income taxes prior to the Offering.

The Company accounts for income taxes using the assets and liabilities method. Deferred tax assets and liabilities are recognized for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and those assets and liabilities tax bases. The Company applies existing tax law and the tax rate that the Company expects to apply to taxable income in the years in which those differences are expected to be recovered or settled in calculating the deferred tax assets and liabilities. Effects of changes in tax rates on deferred tax assets and liabilities are recognized in income in the period of the tax rate enactment. A valuation allowance is recorded when it is not more likely than not that some or all of the benefit from the deferred tax asset will be realized.

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The components of the Company’s deferred tax assets as of December 31, 2014 are as follows:

(in thousands)	2014
Current deferred tax assets:	
Net operating loss carryforward	$654
Non-current deferred tax assets:	
Investment in Spark HoldCo	16,171
Benefit of TRA liability	7,817
Net operating loss carryforward	59
Total non-current deferred tax assets	24,047
Total deferred tax assets	$24,701

Current deferred tax assets are recorded in other current assets in the combined and consolidated financial statements. The Company had no material deferred tax assets or liabilities as of December 31, 2013 and 2012.

On the Offering date, the Company recorded a net deferred tax asset related to the step up in tax basis resulting from the purchase by the Company of Spark HoldCo units from NuDevco. In addition, the Company recorded a long-term liability to record the effect of the Tax Receivable Agreement liability (See Note 11 “Transactions with Affiliates” for further discussion) and a corresponding long-term deferred tax asset. The payable pursuant to the Tax Receivable Agreement and the deferred tax assets were recorded with a corresponding offset to additional paid-in capital.

The Company has a federal net operating loss carry forward totaling $1.9 million expiring in 2034 and a state net operating loss of $1.8 million expiring through 2034. No valuation allowance has been recorded as management believes that there will be sufficient future taxable income to fully utilize deferred tax assets.

The Company periodically assesses whether it is more likely than not that it will generate sufficient taxable income to realize its deferred income tax assets. In making this determination, the Company considers all available positive and negative evidence and makes certain assumptions. The Company considers, among other things, its deferred tax liabilities, the overall business environment, its historical earnings and losses, current industry trends, and its outlook for future years. The Company believes it is more likely than not that the deferred tax assets will be utilized.

Separate federal and state income tax returns are filed for Spark Energy, Inc. and Spark HoldCo. The tax years 2010 through 2013 remain open to examination by the major taxing jurisdictions to which the Company is subject to income tax. NuDevco would be responsible for any audit adjustments incurred in connection with transactions occurring up to July 31, 2014. The last closed audit period of exam was for the 2011 Spark Energy, LLC’s federal tax return and resulted in no adjustments by the IRS. The Company is not currently under any income tax audits.

Accounting for uncertainty in income taxes prescribes a recognition threshold and measurement methodology for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. As of December 31, 2014, 2013 and 2012 there was no liability or expense recorded for interest and penalties associated with uncertain tax positions or unrecognized tax positions. Additionally, the Company does not have unrecognized tax benefits as of December 31, 2014, 2013 and 2012.

10. Commitments and Contingencies

From time to time, the Company may be involved in legal, tax, regulatory and other proceedings in the ordinary course of business. Management does not believe that we are a party to any litigation, claims or proceedings that will have a material impact on the Company’s combined and consolidated financial condition or results of operations.

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11. Transactions with Affiliates

The Company enters into transactions with and pays certain costs on behalf of affiliates that are commonly controlled in order to reduce risk, reduce administrative expense, create economies of scale, create strategic alliances and supply goods and services to these related parties. The Company also sells and purchases natural gas and electricity with affiliates. The Company presents receivables and payables with the same affiliate on a net basis in the combined and consolidated balance sheets as all affiliate activity is with parties under common control.

Accounts Receivable and Payable-Affiliates

The Company recorded current accounts receivable-affiliates of $1.2 million and $6.8 million as of December 31, 2014 and 2013, respectively, and current accounts payable-affiliates of $1.0 million as of December 31, 2014 for certain direct billings and cost allocations for services the Company provided to affiliates and sales or purchases of natural gas and electricity with affiliates.

Revenues and Cost of Revenues-Affiliates

Prior to Marlin’s initial public offering on July 31, 2013, the Company provided natural gas to Marlin, who is a processing service provider, whereby Marlin gathered natural gas from the Company and other third parties, extracted NGLs, and redelivered the processed natural gas to the Company and other third parties. Marlin replaced energy used in processing due to the extraction of liquids, compression and transportation of natural gas, and fuel by making a payment to the Company at market prices. Revenues-affiliates, recorded in net asset optimization revenues in the combined and consolidated statements of operations, related to Marlin’s payments to the Company for replaced energy for the years ended December 31, 2013 and 2012 were $3.0 million and $8.3 million, respectively.

Beginning on August 1, 2013, the Marlin processing agreement was terminated and the Company and another affiliate entered into an agreement whereby the Company purchased natural gas from the affiliate at the tailgate of the Marlin plant. Cost of revenues-affiliates, recorded in net asset optimization revenues in the combined and consolidated statements of operations for the years ended December 31, 2014 and 2013 related to this agreement were $30.3 million and $17.7 million, respectively.

The Company also purchased natural gas at a nearby third party plant inlet which was then sold to the affiliate. Revenues-affiliates, recorded in net asset optimization revenues in the combined and consolidated statements of operations for the years ended December 31, 2014 and 2013 related to these sales were $12.8 million and $11.9 million, respectively. There was no such activity in 2012.

Additionally, the Company entered into a natural gas transportation agreement with Marlin, at Marlin’s pipeline, whereby the Company transports retail natural gas and pays the higher of (i) a minimum monthly payment or (ii) a transportation fee per MMBtu times actual volumes transported. The current transportation agreement was set to expire on February 28, 2013, but was extended for three additional years at a fixed rate per MMBtu without a minimum monthly payment. Included in the Company’s results are cost of revenues-affiliates, recorded in retail cost of revenues in the combined and consolidated statements of operations related to this activity, which was less than $0.1 million, $0.1 million and $0.3 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Prior to the Offering, the Company also purchased electricity for an affiliate and sold the electricity to the affiliate at the same market price that the Company paid to purchase the electricity. Sales of electricity to the affiliate were $2.2 million, $4.0 million and $1.4 million for the years ended December 31, 2014, 2013 and 2012, respectively, which is recorded in retail revenues-affiliate in the combined and consolidated statements of operations.

Also included in the Company’s results are cost of revenues-affiliates related to derivative instruments, recorded in net asset optimization revenues in the combined and consolidated statements of operations, is a loss of $0.6 million,

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a gain of $1.8 million and a loss of $0.6 million for the years ended December 31, 2014, 2013 and 2012, respectively.
Cost Allocations
The Company paid certain expenses on behalf of affiliates, which are reimbursed by the affiliates to the Company, including costs that can be specifically identified and certain allocated overhead costs associated with general and administrative services, including executive management, facilities, banking arrangements, professional fees, insurance, information services, human resources and other support departments to the affiliates. Where costs incurred on behalf of the affiliate could not be determined by specific identification for direct billing, the costs were primarily allocated to the affiliated entities based on percentage of departmental usage, wages or headcount. The total amount direct billed and allocated to affiliates was $5.1 million, $7.4 million and $4.1 million for the years ended December 31, 2014, 2013 and 2012, respectively, which is recorded as a reduction in general and administrative expenses in the combined and consolidated statements of operations.
The Company pays residual commissions to an affiliate for all customers enrolled by the affiliate who pay their monthly retail gas or retail electricity bill. Commissions paid to the affiliate was less than $0.1 million for the years ended December 31, 2014 and 2013, respectively, and $0.8 million for the year ended December 31, 2012, which is recorded in general and administrative expense in the combined and consolidated statements of operations. This agreement with the affiliate was terminated in May 2014.
Member Distributions and Contributions
During the years ended December 31, 2014, 2013 and 2012, the Company made net capital distributions to W. Keith Maxwell III of $36.4 million, $59.3 million and $10.4 million, respectively. In contemplation of the Company's initial public offering, the Company entered into an agreement with an affiliate in April 2014 to permanently forgive all net outstanding accounts receivable balances from the affiliate through the Offering date. As such, the accounts receivable balances from the affiliate have been eliminated and presented as a distribution to W. Keith Maxwell III for 2014, 2013 and 2012.
Property and Equipment Sold
In 2012, the Company sold a field office facility, vehicles and computer and other equipment to affiliates for $0.6 million. The assets were sold at the Company's historical cost basis at the time of the sale, as the transactions were between affiliates under common control.

Tax Receivable Agreement

Concurrently with the closing of the Offering, the Company entered into a Tax Receivable Agreement with Spark HoldCo, NuDevco Retail Holdings and NuDevco Retail. This agreement generally provides for the payment by the Company to NuDevco of 85% of the net cash savings, if any, in U.S. federal, state and local income tax or franchise tax that the Company actually realizes (or is deemed to realize in certain circumstances) in future periods as a result of (i) any tax basis increases resulting from the purchase by the Company of Spark HoldCo units from NuDevco Retail Holdings in connection with the Offering, (ii) any tax basis increases resulting from the exchange of Spark HoldCo units for shares of Class A common stock pursuant to the Exchange Right (or resulting from an exchange of Spark HoldCo units for cash pursuant to the Cash Option) and (iii) any imputed interest deemed to be paid by the Company as a result of, and additional tax basis arising from, any payments the Company makes under the Tax Receivable Agreement. In addition, payments we make under the Tax Receivable Agreement will be increased by any interest accrued from the due date (without extensions) of the corresponding tax return. The Company retains the benefit of the remaining 15% of these tax savings. See Note 9 "Taxes" for further discussion of amounts recorded in connection with the Offering.

In certain circumstances, the Company may defer or partially defer any payment due (a "TRA Payment") to the holders of rights under the Tax Receivable Agreement, which are currently NuDevco Retail Holdings and NuDevco

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Retail. No TRA Payment was made during 2014, and any future TRA Payments due with respect to a given taxable year are expected to be paid in December of the subsequent calendar year.

During the five-year period commencing October 1, 2014, the Company will defer all or a portion of any TRA Payment owed pursuant to the Tax Receivable Agreement to the extent that Spark HoldCo does not generate sufficient Cash Available for Distribution (as defined below) during the four-quarter period ending September 30th of the applicable year in which the TRA Payment is to be made in an amount that equals or exceeds 130% (the "TRA Coverage Ratio") of the Total Distributions (as defined below) paid in such four-quarter period by Spark HoldCo. For purposes of computing the TRA Coverage Ratio:

- "Cash Available for Distribution" is generally defined as the Adjusted EBITDA of Spark HoldCo for the applicable period, less (i) cash interest paid by Spark HoldCo, (ii) capital expenditures of Spark HoldCo (exclusive of customer acquisition costs) and (iii) any taxes payable by Spark HoldCo; and
- "Total Distributions" are defined as the aggregate distributions necessary to cause the Company to receive distributions of cash equal to (i) the targeted quarterly distribution the Company intends to pay to holders of its Class A common stock payable during the applicable four-quarter period, plus (ii) the estimated taxes payable by the Company during such four-quarter period, plus (iii) the expected TRA Payment payable during the calendar year for which the TRA Coverage Ratio is being tested.

In the event that the TRA Coverage Ratio is not satisfied in any calendar year, the Company will defer all or a portion of the TRA Payment to NuDevco under the Tax Receivable Agreement to the extent necessary to permit Spark HoldCo to satisfy the TRA Coverage Ratio (and Spark HoldCo is not required to make and will not make the pro rata distributions to its members with respect to the deferred portion of the TRA Payment). If the TRA Coverage Ratio is satisfied in any calendar year, the Company will pay NuDevco the full amount of the TRA Payment.

Following the five-year deferral period, the Company will be obligated to pay any outstanding deferred TRA Payments to the extent such deferred TRA Payments do not exceed (i) the lesser of the Company's proportionate share of aggregate Cash Available for Distribution of Spark HoldCo during the five-year deferral period or the cash distributions actually received by the Company during the five-year deferral period, reduced by (ii) the sum of (a) the aggregate target quarterly dividends (which, for the purposes of the Tax Receivable Agreement, will be $0.3625 per share per quarter) during the five-year deferral period, (b) the Company's estimated taxes during the five-year deferral period, and (c) all prior TRA Payments and (y) if with respect to the quarterly period during which the deferred TRA Payment is otherwise paid or payable, Spark HoldCo has or reasonably determines it will have amounts necessary to cause the Company to receive distributions of cash equal to the target quarterly distribution payable during that quarterly period. Any portion of the deferred TRA Payments not payable due to these limitations will no longer be payable.

12. Segment Reporting

The Company's determination of reportable business segments considers the strategic operating units under which the Company makes financial decisions, allocates resources and assesses performance of its retail and asset optimization businesses.

The Company's reportable business segments are retail natural gas and retail electricity. The retail natural gas segment consists of natural gas sales to, and natural gas transportation and distribution for, residential and commercial customers. Asset optimization activities, considered an integral part of securing the lowest price natural gas to serve retail gas load, are part of the retail natural gas segment. The Company recorded asset optimization revenues of $284.6 million, $192.4 million and $248.6 million and asset optimization cost of revenues of $282.3 million, $192.1 million and $249.7 million for the years ended December 31, 2014, 2013 and 2012, respectively, which are presented on a net basis in asset optimization revenues. The retail electricity segment consists of electricity sales and transmission to residential and commercial customers. Corporate and other consists of expenses and assets of the retail natural gas and retail electricity segments that are managed at a consolidated level such as general and administrative expenses.

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To assess the performance of the Company's operating segments, the chief operating decision maker analyzes retail gross margin. The Company defines retail gross margin as operating income plus (i) depreciation and amortization expenses and (ii) general and administrative expenses, less (i) net asset optimization revenues, (ii) net gains (losses) on non-trading derivative instruments, and (iii) net current period cash settlements on non-trading derivative instruments. The Company deducts net gains (losses) on non-trading derivative instruments, excluding current period cash settlements, from the retail gross margin calculation in order to remove the non-cash impact of net gains and losses on non-trading derivative instruments.

Retail gross margin is a primary performance measure used by our management to determine the performance of our retail natural gas and electricity business by removing the impacts of our asset optimization activities and net non-cash income (loss) impact of our economic hedging activities. As an indicator of our retail energy business' operating performance, retail gross margin should not be considered an alternative to, or more meaningful than, operating income, as determined in accordance with GAAP. Below is a reconciliation of retail gross margin to (loss) income before income tax expense.

	Years Ended December 31,		
(in thousands)	2014	2013	2012
Reconciliation of Retail Gross Margin to (Loss)income before taxes			
(Loss) income before income tax expense	$(5,156)	$31,468	$26,139
Interest and other income	(263)	(353)	(62)
Interest expense	1,578	1,714	3,363
Operating Income	(3,841)	32,829	29,440
Depreciation and amortization	22,221	16,215	22,795
General and administrative	45,880	35,020	47,321
Less:			
Net asset optimization revenue	2,318	314	(1,136)
Net, Gains (losses) on non-trading derivative instruments	(8,713)	1,429	(19,016)
Net, Cash settlements on non-trading derivative instruments	(6,289)	653	26,489
Retail Gross Margin	$76,944	$81,668	$93,219

The Company uses retail gross margin and net asset optimization revenues as the measure of profit or loss for its business segments. This measure represents the lowest level of information that is provided to the chief operating decision maker for our reportable segments.

Financial data for business segments are as follows (in thousands):

Year Ended December 31, 2014	Retail Electricity	Retail Natural Gas	Corporate and Other	Eliminations	Total Spark Retail
Total Revenues	$176,406	$146,470	$—	$—	$322,876
Retail cost of revenues	149,452	109,164	—	—	258,616
Less:					
Net asset optimization revenues	—	2,318	—	—	2,318
Net, Gains (losses) on non-trading derivative instruments	(518)	(8,195)	—	—	(8,713)
Current period settlements on non-trading derivatives	(5,145)	(1,144)	—	—	(6,289)
Retail gross margin	$32,617	$44,327	$—	$—	$76,944
Total Assets	$46,848	$101,711	$27,285	$(37,447)	$138,397

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Year Ended December 31, 2013	Retail Electricity	Retail Natural Gas	Corporate and Other	Eliminations	Total Spark Retail
Total Revenues	$191,872	$125,218	$—	$—	$317,090
Retail cost of revenues	149,885	83,141	—	—	233,026
Less:					
Net asset optimization revenues	—	314	—	—	314
Net, Gains (losses) on non-trading derivative instruments	1,336	93	—	—	1,429
Current period settlements on non-trading derivatives	1,349	(696)	—	—	653
Retail gross margin	$39,302	$42,366	$—	$—	$81,668
Total Assets	$41,879	$87,985	$953	$(21,744)	$109,073

Year Ended December 31, 2012	Retail Electricity	Retail Natural Gas	Corporate and Other	Eliminations	Spark Retail
Total Revenues	$256,357	$122,705	$—	$—	$379,062
Retail cost of revenues	202,440	77,066	—	—	279,506
Less:					
Net asset optimization revenues	—	(1,136)	—	—	(1,136)
Net, Gains (losses) on non-trading derivative instruments	(17,400)	(1,616)	—	—	$(19,016)
Current period settlements on non-trading derivatives	18,577	7,912	—	—	26,489
Retail gross margin	$52,740	$40,479	$—	$—	$93,219

Significant Customers

For the years ended December 31, 2014, 2013 and 2012, we had one significant customer that individually accounted for more than 10% of the Company’s combined and consolidated net asset optimization revenues.

Significant Suppliers

For the years ended December 31, 2014, 2013 and 2012, we had one significant supplier that individually accounted for more than 10% of the Company’s combined and consolidated net asset optimization revenues cost of revenues.

For the years ended December 31, 2014, and 2013, the Company had three and one significant suppliers that individually accounted for more than 10% of the Company’s combined and consolidated retail electricity retail cost of revenues, respectively. There were no significant suppliers for retail electricity in 2012.

13. Customer Acquisitions

During the fourth quarter of 2014, the Company entered into two purchase and sale agreements for the purchase of approximately 13,400 variable rate electricity contracts in Connecticut for a purchase price of approximately $2.2 million. The purchase prices are capitalized as intangible assets - customer acquisitions to be amortized over a three year period as customers begin using electricity under a contract with the Company. As of December 31, 2014 the Company had paid and capitalized approximately $1.5 million related to these purchases.

14. Subsequent Events

On February 16, 2015, the Company declared a dividend of $0.3625 per share to holders of record of our Class A common stock on March 2, 2015 which was paid on March 16, 2015.

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On March 3, 2015, the Company entered into a purchase and sale agreement for the purchase of approximately 33,500 residential and commercial natural gas contracts in Northern California for a purchase price of approximately $2.8 million, depending on the number of contracts that come on flow. The transaction is expected to close in April 2015 subject to certain closing conditions.

Supplemental Quarterly Financial Data (unaudited)

Summarized unaudited quarterly financial data is as follows:

	Quarter Ended 2014			
	December 31	September 30	June 30	March 31
	(In thousands, except per share data)			
Total Revenues	$82,742	$68,217	$65,941	$105,976
Operating (loss) income	(12,786)	1,607	555	6,783
Net (loss) income	(11,394)	419	201	6,509
Net (loss) income attributable to Spark Energy, Inc. stockholders	(1,115)	1,061	—	—
Net (loss) income attributable to Spark Energy, Inc. per common share - basic	(0.37)	0.35	N/A*	N/A*
Net (loss) income attributable to Spark Energy, Inc. per common share - diluted	(0.37)	0.03	N/A*	N/A*

*Per share data is not meaningful prior to the Company's initial public offering, effective August 1, 2014, as the Company operated under a sole-member ownership structure.

	Quarter Ended 2013			
	December 31	September 30	June 30	March 31
	(In thousands, except per share data)			
Total Revenues	$82,414	$69,899	$65,481	$99,296
Operating income (loss)	19,587	(1,110)	(646)	14,998
Net income (loss)	19,344	(1,597)	(946)	14,611
Net income (loss) attributable to Spark Energy, Inc. stockholders	19,344	(1,597)	(946)	14,611
Net income attributable to Spark Energy, Inc. per common share - basic	N/A*	N/A*	N/A*	N/A*
Net income attributable to Spark Energy, Inc. per common share - diluted	N/A*	N/A*	N/A*	N/A*

*Per share data is not meaningful prior to the Company's initial public offering, effective August 1, 2014, as the Company operated under a sole-member ownership structure.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

ITEM 9A. Controls and Procedures

Our management, with the participation of our Chief Executive Officer and our Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures as of the end of the period covered by this Annual Report on Form 10-K. The term “disclosure controls and procedures,” as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), means controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC’s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is accumulated and communicated to the company’s management, including its principal executive and principal financial officers or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. Management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving their objectives and management necessarily applies its judgment in evaluating the cost benefit relationship of possible controls and procedures.

Based on this evaluation, management concluded that our disclosure controls and procedures were not effective as of December 31, 2014 at the reasonable assurance level due to a material weakness in our internal control over financial reporting. In connection with the preparation of our restated financial statements for the quarter ended March 31, 2014, we concluded there was a material weakness in the design and operating effectiveness of our internal control over financial reporting. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis. The primary factors contributing to the material weakness, which relates to our financial statement close process, was that we did not have adequate policies and procedures in place to ensure that estimated retail revenues, cost of revenues and related imbalances for the three months ended March 31, 2014 were based on complete and accurate data and assumptions on a timely basis.

With the oversight of senior management, we have taken steps and plan to take additional measures to remediate the underlying causes of the material weakness, primarily through the development and implementation of formal policies, improved processes and documented procedures to more precisely estimate and validate our recorded estimated retail revenues, retail cost of revenues and related imbalances in accordance with U.S. GAAP and on a timeline that ensures we can prepare our financial statements on a timely basis in compliance with reporting timelines under the Exchange Act, however, there is no guarantee that these controls are or will be effective. We also believe that we need to expand our accounting resources, including the size and expertise of our internal accounting team, to effectively execute a quarterly close process on an appropriate time frame for a public company.

Notwithstanding the identified material weakness, management believes the combined and consolidated financial statements included in this Annual Report on Form 10-K fairly represent in all material respects our financial condition, results of operations and cash flows at and for the periods presented in accordance with U.S. GAAP.

Management’s Report Regarding Internal Control

This Form 10-K does not include a report of management’s assessment regarding internal control over financial reporting or an attestation report of our independent registered public accounting firm due to a transition period established by rules of the SEC. We will be required to include management’s assessment regarding internal controls in our December 31, 2015 annual report filed with the SEC in 2016 regarding the effectiveness of our internal control over financial reporting.

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Changes in Internal Control over Financial Reporting

Other than as described above, there was no change in our internal control over financial reporting identified in connection with the evaluation required by Rule 13a-15(d) and 15d-15(d) of the Exchange Act that occurred during the three months ended December 31, 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

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PART III.

Item 10. Directors, Executive Officers and Corporate Governance

Information as to Item 10 will be set forth in the Proxy Statement for the 2015 Annual Meeting of Shareholders (the “Annual Meeting”) and is incorporated herein by reference.

Item 11. Executive Compensation

Information as to Item 11 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information as to Item 12 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information as to Item 13 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services

Information as to Item 14 will be set forth in the Proxy Statement for the Annual Meeting and is incorporated herein by reference.

PART IV.

Item 15. Exhibits, Financial Statement Schedules

(1) The combined and consolidated financial statements of Spark Energy, Inc. and its subsidiaries and the report of the independent registered public accounting firm are included in Part II, Item 8 of this Form 10-K.

(2) All schedules have been omitted because they are not required under the related instructions, are not applicable or the information is presented in the combined and consolidated financial statements or related notes.

(3) The exhibits listed on the accompanying Exhibit Index on page 109 are filed as part of, or incorporated by reference into, this Form 10-K.

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SIGNATURES

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

March 27, 2015

Spark Energy, Inc.

By: /s/ Georganne Hodges
Georganne Hodges
Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant in the capacities indicated on March 27, 2015:

By: /s/ Nathan Kroeker
Nathan Kroeker
Director, President and Chief Executive Officer

/s/ W. Keith Maxwell III
W. Keith Maxwell III
Chairman of the Board of Directors, Director

/s/ Georganne Hodges
Georganne Hodges
Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)

/s/ James G. Jones II
James G. Jones II
Director

/s/ John Eads
John Eads
Director

/s/ Kenneth M. Hartwick
Kenneth M. Hartwick
Director

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INDEX TO EXHIBITS

		Incorporated by Reference			
Exhibit	Exhibit Description	Form	Exhibit Number	Filing Date	SEC File No.
3.1	Amended and Restated Certificate of Incorporation of Spark Energy, Inc.	8-K	3.1	8/4/2014	001-36559
3.2	Amended and Restated Bylaws of Spark Energy, Inc.	8-K	3.2	8/4/2014	001-36559
4.1	Class A Common Stock Certificate	S-1	4.1	6/30/2014	333-196375
10.1	Credit Agreement, dated as of August 1, 2014, by and among Spark Energy, Inc., as parent, Spark HoldCo, LLC, Spark Energy, LLC, and Spark Energy Gas, LLC, as co-borrowers, SG Americas Securities, LLC, as sole lead arranger and sole bookrunner, Natixis, New York Branch, Cooperatieve Centrale Raiffeisen-Boerenleenbank B.A., New York Branch, and RB International Finance (USA) LLC, as co-documentation agent and Compass Bank, as senior managing agent.	8-K	10.1	8/4/2014	001-36559
10.2	Tax Receivable Agreement, dated as of August 1, 2014, by and among Spark Energy, Inc., NuDevco Retail Holdings, LLC, NuDevco Retail, LLC and W. Keith Maxwell III Gas, LLC, as co-borrowers and the lenders and other parties thereto.	8-K	10.2	8/4/2014	001-36559
10.3†	Spark Energy, Inc. Long-Term Incentive Plan	S-8	4.3	7/31/2014	333-197738
10.4†	Form of Restricted Stock Unit Agreement	S-1	10.4	6/30/2014	333-196375
10.5†	Form of Notice of Grant of Restricted Stock Unit	S-1	10.5	6/30/2014	333-196375
10.6	Spark HoldCo, LLC Second Amended and Restated Limited Liability Agreement, dated as of August 1, 2014, by and among Spark Energy, Inc., NuDevco Retail Holdings and NuDevco Retail.	8-K	10.3	8/4/2014	001-36559
10.7	Indemnification Agreement, dated August 1, 2014, by and between Spark Energy, Inc. and W. Keith Maxwell III.	8-K	10.5	8/4/2014	001-36559
10.8	Indemnification Agreement, dated August 1, 2014, by and between Spark Energy, Inc. and Nathan Kroeker.	8-K	10.6	8/4/2014	001-36559
10.9	Indemnification Agreement, dated August 1, 2014, by and between Spark Energy, Inc. and Allison Wall.	8-K	10.7	8/4/2014	001-36559
10.10		8-K	10.8	8/4/2014	001-36559

	Indemnification Agreement, dated August 1, 2014, by and between Spark Energy, Inc. and Georganne Hodges.				
10.11	Indemnification Agreement, dated August 1, 2014, by and between Spark Energy, Inc. and Gil Melman.	8-K	10.9	8/4/2014	001-36559
10.12	Indemnification Agreement, dated August 1, 2014, by and between Spark Energy, Inc. and James G. Jones II.	8-K	10.10	8/4/2014	001-36559
10.13	Indemnification Agreement, dated August 1, 2014, by and between Spark Energy, Inc. and John Eads.	8-K	10.11	8/4/2014	001-36559
10.14	Indemnification Agreement, dated August 1, 2014, by and between Spark Energy, Inc. and Kenneth M. Hartwick.	8-K	10.12	8/4/2014	001-36559

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10.15	Registration Rights Agreement, dated as of August 1, 2014, by and among Spark Energy, Inc., NuDevco Retail Holdings and NuDevco Retail.	8-K	10.4	8/4/2014	001-36559
10.16	Transaction Agreement II, dated as of July 30, 2014, by and among Spark Energy, Inc., Spark HoldCo, LLC, NuDevco Retail LLC, NuDevco Retail Holdings, LLC, Spark Energy Ventures, LLC, NuDevco Partners Holdings, LLC and Associated Energy Services, LP.	8-K	4.1	8/4/2014	001-36559
21.1*	List of Subsidiaries of Spark Energy, Inc.				
23.1*	Consent of KPMG				
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.				
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.				
32**	Certifications pursuant to 18 U.S.C. Section 1350.				
101.INS*	XBRL Instance Document.				
101.SCH*	XBRL Schema Document.				
101.CAL*	XBRL Calculation Document.				
101.LAB*	XBRL Labels Linkbase Document.				
101.PRE*	XBRL Presentation Linkbase Document.				
101.DEF*	XBRL Definition Linkbase Document.				

* Filed herewith
** Furnished herewith
† Compensatory plan or arrangement