ROYAL BANK OF CANADA
Form 424B2
August 30, 2017

RBC Capital Markets® Filed Pursuant to Rule 424(b)(2)
Registration Statement No. 333-208507

Pricing Supplement Dated August 28, 2017 To the Product Prospectus Supplement ERN-EI-1 Dated January 12, 2016, Prospectus Supplement Dated January 8, 2016, and Prospectus Dated January 8, 2016	$1,658,000 Buffered Enhanced Return Notes Linked to the S&P 500® Index, Due September 3, 2019 Royal Bank of Canada

Royal Bank of Canada is offering the Buffered Enhanced Return Notes (the "Notes") linked to the performance of the S&P 500® Index (the "Reference Asset").

The CUSIP number for the Notes is 78012K4Y0. The Notes do not pay interest. The Notes provide a 200.00% leveraged positive return if the level of the Reference Asset increases from the Initial Level to the Final Level, subject to the Maximum Redemption Amount of 15.90% of the principal amount of the Notes. Investors will lose 1% of the principal amount of the Notes for each 1% decrease from the Initial Level to the Final Level of more than 10.00%.

Any payments on the Notes are subject to our credit risk.

Issue Date: August 31, 2017

Maturity Date: September 3, 2019

The Notes will not be listed on any securities exchange.

Investing in the Notes involves a number of risks. See "Risk Factors" beginning on page S-1 of the prospectus supplement dated January 8, 2016, "Additional Risk Factors Specific to the Notes" beginning on page PS-4 of the product prospectus supplement dated January 12, 2016, and "Selected Risk Considerations" beginning on page P-6 of this pricing supplement.

The Notes will not constitute deposits insured by the Canada Deposit Insurance Corporation, the U.S. Federal Deposit Insurance Corporation or any other Canadian or U.S. government agency or instrumentality.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined that this pricing supplement is truthful or complete. Any representation to the contrary is a criminal offense.

	Per Note	Total
Price to public	100.00%	$1,658,000.00
Underwriting discounts and commissions	0.00%	$0.00
Proceeds to Royal Bank of Canada	100.00%	$1,658,000.00

The initial estimated value of the Notes as of the date of this pricing supplement is $989.25 per $1,000 in principal amount, which is less than the price to public. The actual value of the Notes at any time will reflect many factors, cannot be predicted with accuracy, and may be less than this amount. We describe our determination of the initial estimated value in more detail below.

RBC Capital Markets, LLC, which we refer to as RBCCM, acting as agent for Royal Bank of Canada, did not receive a commission in connection with the sale of the Notes. See "Supplemental Plan of Distribution (Conflicts of Interest)" on page P-14 below.

We may use this pricing supplement in the initial sale of the Notes. In addition, RBCCM or another of our affiliates may use this pricing supplement in a market-making transaction in the Notes after their initial sale. Unless we or our agent informs the purchaser otherwise in the confirmation of sale, this pricing supplement is being used in a market-making transaction.

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SUMMARY

The information in this "Summary" section is qualified by the more detailed information set forth in this pricing supplement, the product prospectus supplement, the prospectus supplement, and the prospectus.

Issuer:	Royal Bank of Canada ("Royal Bank")
Issue:	Senior Global Medium-Term Notes, Series G
Underwriter:	RBC Capital Markets, LLC ("RBCCM")
Reference Asset:	S&P 500® Index
Bloomberg Ticker:	SPX
Currency:	U.S. Dollars
Minimum Investment:	$1,000 and minimum denominations of $1,000 in excess thereof
Pricing Date:	August 28, 2017
Issue Date:	August 31, 2017
CUSIP:	78012K4Y0
Valuation Date:	July 26, 2019
Payment at Maturity (if held to maturity):	If, on the Valuation Date, the Percentage Change is positive, then the investor will receive an amount per $1,000 principal amount per Note equal to the lesser of: 1. Principal Amount + (Principal Amount x Percentage Change x Leverage Factor) and 2. Maximum Redemption Amount If, on the Valuation Date, the Percentage Change is less than or equal to 0%, but not by more than the Buffer Percentage (that is, the Percentage Change is between zero and -10.00%), then the investor will receive the principal amount only. If, on the Valuation Date, the Percentage Change is negative, by more than the Buffer Percentage (that is, the Percentage Change is between -10.01% and -100%), then the investor will receive a cash payment equal to: Principal Amount + [Principal Amount x (Percentage Change + Buffer Percentage)]
Percentage Change:	The Percentage Change, expressed as a percentage, is calculated using the following formula:
Initial Level:	2,444.24, which was the closing level of the Reference Asset on the Pricing Date.
Final Level:	The closing level of the Reference Asset on the Valuation Date.
Leverage Factor:	200.00% (subject to the Maximum Redemption Amount)

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Maximum Redemption Amount:	15.90% multiplied by the principal amount
Buffer Percentage:	10.00%
Buffer Level:	2,199.82, which is 90.00% of the Initial Level (rounded to two decimal places)
Maturity Date:	September 3, 2019, subject to extension for market and other disruptions, as described in the product prospectus supplement dated January 12, 2016.
Term:	Approximately two (2) years
Principal at Risk:	The Notes are NOT principal protected. You may lose a substantial portion of your principal amount at maturity if there is a percentage decrease from the Initial Level to the Final Level of more than 10.00%.
Calculation Agent:	RBCCM
U.S. Tax Treatment:	By purchasing a Note, each holder agrees (in the absence of a change in law, an administrative determination or a judicial ruling to the contrary) to treat the Note as a pre-paid cash-settled derivative contract for U.S. federal income tax purposes. However, the U.S. federal income tax consequences of your investment in the Notes are uncertain and the Internal Revenue Service could assert that the Notes should be taxed in a manner that is different from that described in the preceding sentence. Please see the section below, “Supplemental Discussion of U.S. Federal Income Tax Consequences,” and the discussion (including the opinion of our counsel Morrison & Foerster LLP) in the product prospectus supplement dated January 12, 2016 under “Supplemental Discussion of U.S. Federal Income Tax Consequences,” which apply to the Notes.
Secondary Market:	RBCCM (or one of its affiliates), though not obligated to do so, plans to maintain a secondary market in the Notes after the Issue Date. The amount that you may receive upon sale of your Notes prior to maturity may be less than the principal amount of your Notes.
Listing:	The Notes will not be listed on any securities exchange.
Clearance and Settlement:	DTC global (including through its indirect participants Euroclear and Clearstream, Luxembourg as described under “Description of Debt Securities—Ownership and Book-Entry Issuance” in the prospectus dated January 8, 2016).
Terms Incorporated in the Master Note:	All of the terms appearing above the item captioned “Secondary Market” on pages P-2 and P-3 of this pricing supplement and the terms appearing under the caption “General Terms of the Notes” in the product prospectus supplement dated January 12, 2016, as modified by this pricing supplement.

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ADDITIONAL TERMS OF YOUR NOTES

You should read this pricing supplement together with the prospectus dated January 8, 2016, as supplemented by the prospectus supplement dated January 8, 2016 and the product prospectus supplement dated January 12, 2016, relating to our Senior Global Medium-Term Notes, Series G, of which these Notes are a part. Capitalized terms used but not defined in this pricing supplement will have the meanings given to them in the product prospectus supplement. In the event of any conflict, this pricing supplement will control. The Notes vary from the terms described in the product prospectus supplement in several important ways. You should read this pricing supplement carefully.

This pricing supplement, together with the documents listed below, contains the terms of the Notes and supersedes all prior or contemporaneous oral statements as well as any other written materials including preliminary or indicative pricing terms, correspondence, trade ideas, structures for implementation, sample structures, brochures or other educational materials of ours. You should carefully consider, among other things, the matters set forth in "Risk Factors" in the prospectus supplement dated January 8, 2016 and "Additional Risk Factors Specific to the Notes" in the product prospectus supplement dated January 12, 2016, as the Notes involve risks not associated with conventional debt securities. We urge you to consult your investment, legal, tax, accounting and other advisors before you invest in the Notes. You may access these documents on the Securities and Exchange Commission (the "SEC") website at www.sec.gov as follows (or if that address has changed, by reviewing our filings for the relevant date on the SEC website):

Prospectus dated January 8, 2016:
http://www.sec.gov/Archives/edgar/data/1000275/000121465916008810/j18160424b3.htm
Prospectus Supplement dated January 8, 2016:
http://www.sec.gov/Archives/edgar/data/1000275/000121465916008811/p14150424b3.htm
Product Prospectus Supplement ERN-EI-1 dated January 12, 2016:
https://www.sec.gov/Archives/edgar/data/1000275/000114036116047560/form424b5.htm

Our Central Index Key, or CIK, on the SEC website is 1000275. As used in this pricing supplement "we," "us," or "our" refers to Royal Bank of Canada.

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HYPOTHETICAL RETURNS

The examples set out below are included for illustration purposes only. The hypothetical Percentage Changes of the Reference Asset used to illustrate the calculation of the Payment at Maturity (rounded to two decimal places) are not estimates or forecasts of the Final Level or the level of the Reference Asset on any trading day prior to the Maturity Date. All examples are based on the Buffer Percentage of 10.00% (resulting in a Buffer Level of 90.00% of the Initial Level), the Leverage Factor of 200.00%, the Maximum Redemption Amount of 115.90% of the principal amount, and assume that the holder purchased Notes with an aggregate principal amount of $1,000 and that no market disruption event occurs on the Valuation Date.

Example 1—Calculation of the Payment at Maturity where the Percentage Change is positive.

Percentage Change: 5%

Payment at Maturity: $1,000 + ($1,000 x 5% x 200.00%) = $1,000 + $100.00 = $1,100.00

On a $1,000 investment, a 5% Percentage Change results in a Payment at Maturity of $1,100.00, a 10.00% return on the Notes.

Example 2—Calculation of the Payment at Maturity where the Percentage Change is positive (and the Payment at Maturity is subject to the Maximum Redemption Amount).

Percentage Change: 20.00%

Payment at Maturity: $1,000 + ($1,000 x 20% x 200.00%) = $1,000 + $400.00 = $1,400.00
However, the Maximum Redemption Amount is $1,159.00

On a $1,000 investment, a 20.00% Percentage Change results in a Payment at Maturity of $1,159.00, a 15.90% return on the Notes.

Example 3—Calculation of the Payment at Maturity where the Percentage Change is negative (but not by more than the Buffer Percentage).

Percentage Change: -8%

Payment at Maturity: At maturity, if the Percentage Change is negative BUT not by more than the Buffer Percentage, then the Payment at Maturity will equal the principal amount.

On a $1,000 investment, a -8% Percentage Change results in a Payment at Maturity of $1,000, a 0% return on the Notes.

Example 4—Calculation of the Payment at Maturity where the Percentage Change is negative (by more than the Buffer Percentage).

Percentage Change: -35%

Payment at Maturity: $1,000 + [$1,000 x (-35% + 10.00%)] = $1,000 - $250.00 = $750.00

On a $1,000 investment, a -35% Percentage Change results in a Payment at Maturity of $750.00, a -25.00% return on the Notes.

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SELECTED RISK CONSIDERATIONS

An investment in the Notes involves significant risks. Investing in the Notes is not equivalent to investing directly in the Reference Asset. These risks are explained in more detail in the section "Additional Risk Factors Specific to the Notes," beginning on page PS-4 of the product prospectus supplement. In addition to the risks described in the prospectus supplement and the product prospectus supplement, you should consider the following:

- Principal at Risk – Investors in the Notes could lose a substantial portion of their principal amount if there is a decline in the level of the Reference Asset. You will lose 1% of the principal amount of your Notes for each 1% that the Final Level is less than the Initial Level by more than 10.00%.
- The Notes Do Not Pay Interest and Your Return May Be Lower than the Return on a Conventional Debt Security of Comparable Maturity – There will be no periodic interest payments on the Notes as there would be on a conventional fixed-rate or floating-rate debt security having the same maturity. The return that you will receive on the Notes, which could be negative, may be less than the return you could earn on other investments. Even if your return is positive, your return may be less than the return you would earn if you bought a conventional senior interest bearing debt security of Royal Bank.
- Your Potential Payment at Maturity Is Limited – The Notes will provide less opportunity to participate in the appreciation of the Reference Asset than an investment in a security linked to the Reference Asset providing full participation in the appreciation, because the payment at maturity will not exceed the Maximum Redemption Amount. Accordingly, your return on the Notes may be less than your return would be if you made an investment in a security directly linked to the positive performance of the Reference Asset.
- Payments on the Notes Are Subject to Our Credit Risk, and Changes in Our Credit Ratings Are Expected to Affect the Market Value of the Notes – The Notes are Royal Bank's senior unsecured debt securities. As a result, your receipt of the amount due on the maturity date is dependent upon Royal Bank's ability to repay its obligations at that time. This will be the case even if the level of the Reference Asset increases after the Pricing Date. No assurance can be given as to what our financial condition will be at the maturity of the Notes.
- There May Not Be an Active Trading Market for the Notes—Sales in the Secondary Market May Result in Significant Losses – There may be little or no secondary market for the Notes. The Notes will not be listed on any securities exchange. RBCCM and other affiliates of Royal Bank may make a market for the Notes; however, they are not required to do so. RBCCM or any other affiliate of Royal Bank may stop any market-making activities at any time. Even if a secondary market for the Notes develops, it may not provide significant liquidity or trade at prices advantageous to you. We expect that transaction costs in any secondary market would be high. As a result, the difference between bid and asked prices for your Notes in any secondary market could be substantial.
- You Will Not Have Any Rights to the Securities Included in the Reference Asset – As a holder of the Notes, you will not have voting rights or rights to receive cash dividends or other distributions or other rights that holders of securities included in the Reference Asset would have. The Final Level will not reflect any dividends paid on the securities included in the Reference Asset, and accordingly, any positive return on the Notes may be less than the potential positive return on those securities.
- The Initial Estimated Value of the Notes Is Less than the Price to the Public – The initial estimated value set forth on the cover page of this pricing supplement does not represent a minimum price at which we, RBCCM or any of our affiliates would be willing to purchase the Notes in any secondary market (if any exists) at any time. If you attempt to sell the Notes prior to maturity, their market value may be lower than the price you paid for them and the initial estimated value. This is due to, among other things, changes in the level of the Reference Asset, the borrowing rate we pay to issue securities of this kind, and the inclusion in the price to the public of the estimated costs relating to our hedging of the Notes. These factors, together with various credit, market and economic factors over the term of the

Notes, are expected to reduce the price at which you may be able to sell the Notes in any secondary market and will affect the value of the Notes in complex and unpredictable ways. Assuming no change in market conditions or any other relevant factors, the price, if any, at which you may be able to sell your Notes prior to maturity may be less than your original purchase price, as any such sale price would not be expected to include the hedging costs relating to the Notes. In addition to bid-ask spreads, the value of the Notes determined for any secondary market price is expected to be based on the secondary rate rather than the internal funding rate used to price the Notes and determine the initial estimated value. As a result, the secondary price will be less than if the internal funding rate was used. The Notes are not designed to be short-term trading instruments. Accordingly, you should be able and willing to hold your Notes to maturity.

- The Initial Estimated Value of the Notes Is an Estimate Only, Calculated as of the Time the Terms of the Notes Were Set –The initial estimated value of the Notes is based on the value of our obligation to make the payments on the Notes, together with the mid-market value of the derivative embedded in the terms of the Notes. See "Structuring the Notes" below. Our estimate is based on a variety of assumptions, including our credit spreads, expectations as to dividends, interest rates and volatility, and the expected term of the Notes. These assumptions are based on certain forecasts about future events, which may prove to be incorrect. Other entities may value the Notes or similar securities at a price that is significantly different than we do.

The value of the Notes at any time after the Pricing Date will vary based on many factors, including changes in market conditions, and cannot be predicted with accuracy. As a result, the actual value you would receive if you sold the Notes in any secondary market, if any, should be expected to differ materially from the initial estimated value of your Notes.

- Market Disruption Events and Adjustments – The payment at maturity and the Valuation Date are subject to adjustment as described in the product prospectus supplement. For a description of what constitutes a market disruption event as well as the consequences of that market disruption event, see "General Terms of the Notes—Market Disruption Events" in the product prospectus supplement.

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INFORMATION REGARDING THE REFERENCE ASSET

All disclosures contained in this pricing supplement regarding the Reference Asset, including, without limitation, its make up, method of calculation, and changes in its components, have been derived from publicly available sources. The information reflects the policies of, and is subject to change by, S&P Dow Jones Indices LLC ("S&P"). S&P, which owns the copyright and all other rights to the Reference Asset, has no obligation to continue to publish, and may discontinue publication of, the Reference Asset. The consequences of S&P discontinuing publication of the Reference Asset are discussed in the section of the product prospectus supplement entitled "General Terms of the Notes—Unavailability of the Level of the Reference Asset on a Valuation Date." Neither we nor RBCCM accepts any responsibility for the calculation, maintenance or publication of the Reference Asset or any successor index.

The Reference Asset is intended to provide an indication of the pattern of common stock price movement. The calculation of the level of the Reference Asset is based on the relative value of the aggregate market value of the common stocks of 500 companies as of a particular time compared to the aggregate average market value of the common stocks of 500 similar companies during the base period of the years 1941 through 1943.

S&P chooses companies for inclusion in the Reference Asset with the aim of achieving a distribution by broad industry groupings that approximates the distribution of these groupings in the common stock population of its Stock Guide Database of over 10,000 companies, which S&P uses as an assumed model for the composition of the total market. Relevant criteria employed by S&P include the viability of the particular company, the extent to which that company represents the industry group to which it is assigned, the extent to which the market price of that company's common stock generally is responsive to changes in the affairs of the respective industry, and the market value and trading activity of the common stock of that company. S&P from time to time, in its sole discretion, may add companies to, or delete companies from, the Reference Asset to achieve the objectives stated above.

S&P calculates the Reference Asset by reference to the prices of the constituent stocks of the Reference Asset without taking account of the value of dividends paid on those stocks. As a result, the return on the Notes will not reflect the return you would realize if you actually owned the Reference Asset constituent stocks and received the dividends paid on those stocks.

Effective with the September 2015 rebalance, consolidated share class lines will no longer be included in the Reference Asset. Each share class line will be subject to public float and liquidity criteria individually, but the company's total market capitalization will be used to evaluate each share class line. This may result in one listed share class line of a company being included in the Reference Asset while a second listed share class line of the same company is excluded.

Computation of the Reference Asset

While S&P currently employs the following methodology to calculate the Reference Asset, no assurance can be given that S&P will not modify or change this methodology in a manner that may affect the Payment at Maturity.

Historically, the market value of any component stock of the Reference Asset was calculated as the product of the market price per share and the number of then outstanding shares of such component stock. In March 2005, S&P began shifting the Reference Asset halfway from a market capitalization weighted formula to a float-adjusted formula, before moving the Reference Asset to full float adjustment on September 16, 2005. S&P's criteria for selecting stocks for the Reference Asset did not change with the shift to float adjustment. However, the adjustment affects each company's weight in the Reference Asset.

Under float adjustment, the share counts used in calculating the Reference Asset reflect only those shares that are available to investors, not all of a company's outstanding shares. Float adjustment excludes shares that are closely held by control groups, other publicly traded companies or government agencies.

In September 2012, all shareholdings representing more than 5% of a stock's outstanding shares, other than holdings by "block owners," were removed from the float for purposes of calculating the Reference Asset. Generally, these "control holders" will include officers and directors, private equity, venture capital and special equity firms, other publicly traded companies that hold shares for control, strategic partners, holders of restricted shares, ESOPs, employee and family trusts, foundations associated with the company, holders of unlisted share classes of stock, government entities at all levels (other than government retirement/pension funds) and any individual person who controls a 5% or greater stake in a company as reported in regulatory filings. However, holdings by block owners, such as depositary banks, pension funds, mutual funds and ETF providers, 401(k) plans of the company, government retirement/pension funds, investment funds of insurance companies, asset managers and investment funds, independent foundations and savings and investment plans, will ordinarily be considered part of the float.

Treasury stock, stock options, equity participation units, warrants, preferred stock, convertible stock, and rights are not part of the float. Shares held in a trust to allow investors in countries outside the country of domicile, such as depositary shares and Canadian exchangeable shares are normally part of the float unless those shares form a control block. If a company has multiple classes of stock outstanding, shares in an unlisted or non-traded class are treated as a control block.

For each stock, an investable weight factor ("IWF") is calculated by dividing the available float shares by the total shares outstanding. As of September 21, 2012, available float shares are defined as the total shares outstanding less shares held by control holders. This calculation is subject to a 5% minimum threshold for control blocks. For example, if a company's officers and directors hold 3% of the company's shares, and no other control group holds 5% of the company's shares, S&P would assign that company an IWF of 1.00, as no control group meets the 5% threshold. However, if a company's officers and directors hold 3% of the company's shares and another control group holds 20% of the company's shares, S&P would assign an IWF of 0.77, reflecting the fact that 23% of the company's outstanding shares are considered to be held for control. For companies with multiple classes of stock, S&P calculates the weighted average IWF for each stock using the proportion of the total company market capitalization of each share class as weights.

The Reference Asset is calculated using a base-weighted aggregate methodology. The level of the Reference Asset reflects the total market value of all 500 component stocks relative to the base period of the years 1941 through 1943. An indexed number is used to represent the results of this calculation in order to make the level easier to use and track over time. The actual total market value of the component stocks during the base period of the years 1941 through 1943 has been set to an indexed level of 10. This is often indicated by the notation 1941-43 = 10. In practice, the daily calculation of the Reference Asset is computed by dividing the total market value of the component stocks by the "index divisor." By itself, the index divisor is an arbitrary number. However, in the context of the calculation of the Reference Asset, it serves as a link to the original base period level of the Reference Asset. The index divisor keeps the Reference Asset comparable over time and is the manipulation point for all adjustments to the Reference Asset, which is index maintenance.

Index Maintenance

Index maintenance includes monitoring and completing the adjustments for company additions and deletions, share changes, stock splits, stock dividends, and stock price adjustments due to company restructuring or spinoffs. Some corporate actions, such as stock splits and stock dividends, require changes in the common shares outstanding and the stock prices of the companies in the Reference Asset, and do not require index divisor adjustments.

To prevent the level of the Reference Asset from changing due to corporate actions, corporate actions which affect the total market value of the Reference Asset require an index divisor adjustment. By adjusting the index divisor for the change in market value, the level of the Reference Asset remains constant and does not reflect the corporate actions of individual companies in the Reference Asset. Index divisor adjustments are made after the close of trading and after the calculation of the Reference Asset closing level.

Changes in a company's shares outstanding of 5.00% or more due to mergers, acquisitions, public offerings, tender offers, Dutch auctions, or exchange offers are made as soon as reasonably possible. Share changes due to mergers or acquisitions of publicly held companies that trade on a major exchange are implemented when the transaction occurs even if both of the companies are not in the same headline index, and regardless of the size of the change. All other changes of 5.00% or more (due to, for example, company stock repurchases, private placements, redemptions, exercise of options, warrants, conversion of preferred stock, notes, debt, equity participation units, at the market offerings, or other recapitalizations) are made weekly and are announced on Fridays for implementation after the close of trading on the following Friday. Changes of less than 5.00% are accumulated and made quarterly on the third Friday of March, June, September, and December, and are usually announced two to five days prior.

If a change in a company's shares outstanding of 5.00% or more causes a company's IWF to change by five percentage points or more, the IWF is updated at the same time as the share change. IWF changes resulting from partial tender offers are considered on a case-by-case basis.

License Agreement

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The Notes are not sponsored, endorsed, sold or promoted by S&P Dow Jones Indices LLC, Standard & Poor's Financial Services LLC or any of their respective affiliates (collectively, "S&P Dow Jones Indices"). S&P Dow Jones Indices make no representation or warranty, express or implied, to the holders of the Notes or any member of the public regarding the advisability of investing in securities generally or in the Notes particularly or the ability of the Reference Asset to track general market performance. S&P Dow Jones Indices' only relationship to us with respect to the Reference Asset is the licensing of the Reference Asset and certain trademarks, service marks and/or trade names of S&P Dow Jones Indices and/or its third party licensors. The Reference Asset is determined, composed and calculated by S&P Dow Jones Indices without regard to us or the Notes. S&P Dow Jones Indices have no obligation to take our needs or the needs of holders of the Notes into consideration in determining, composing or calculating the Reference Asset. S&P Dow Jones Indices are not responsible for and have not participated in the determination of the prices, and amount of the Notes or the timing of the issuance or sale of the Notes or in the determination or calculation of the equation by which the Notes are to be converted into cash. S&P Dow Jones Indices have no obligation or liability in connection with the administration, marketing or trading of the Notes. There is no assurance that investment products based on the Reference Asset will accurately track index performance or provide positive investment returns. S&P Dow Jones Indices LLC and its subsidiaries are not investment advisors. Inclusion of a security or futures contract within an index is not a recommendation by S&P Dow Jones Indices to buy, sell, or hold such security or futures contract, nor is it considered to be investment advice. Notwithstanding the foregoing, CME Group Inc. and its affiliates may independently issue and/or sponsor financial products unrelated to the Notes currently being issued by us, but which may be similar to and competitive with the Notes. In addition, CME Group Inc. and its affiliates may trade financial products which are linked to the performance of the Reference Asset. It is possible that this trading activity will affect the value of the Notes.

S&P DOW JONES INDICES DO NOT GUARANTEE THE ADEQUACY, ACCURACY, TIMELINESS AND/OR THE COMPLETENESS OF THE REFERENCE ASSET OR ANY DATA RELATED THERETO OR ANY COMMUNICATION, INCLUDING BUT NOT LIMITED TO, ORAL OR WRITTEN COMMUNICATION (INCLUDING ELECTRONIC COMMUNICATIONS) WITH RESPECT THERETO. S&P DOW JONES INDICES SHALL NOT BE SUBJECT TO ANY DAMAGES OR LIABILITY FOR ANY ERRORS, OMISSIONS, OR DELAYS THEREIN. S&P DOW JONES INDICES MAKE NO EXPRESS OR IMPLIED WARRANTIES, AND EXPRESSLY DISCLAIMS ALL WARRANTIES, OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE OR USE OR AS TO RESULTS TO BE OBTAINED BY US, HOLDERS OF THE NOTES, OR ANY OTHER PERSON OR ENTITY FROM THE USE OF THE REFERENCE ASSET OR WITH RESPECT TO ANY DATA RELATED THERETO. WITHOUT LIMITING ANY OF THE FOREGOING, IN NO EVENT WHATSOEVER SHALL S&P DOW JONES INDICES BE LIABLE FOR ANY INDIRECT, SPECIAL, INCIDENTAL, PUNITIVE, OR CONSEQUENTIAL DAMAGES INCLUDING BUT NOT LIMITED TO, LOSS

OF PROFITS, TRADING LOSSES, LOST TIME OR GOODWILL, EVEN IF THEY HAVE BEEN ADVISED OF THE POSSIBILITY OF SUCH DAMAGES, WHETHER IN CONTRACT, TORT, STRICT LIABILITY, OR OTHERWISE. THERE ARE NO THIRD PARTY BENEFICIARIES OF ANY AGREEMENTS OR ARRANGEMENTS BETWEEN S&P DOW JONES INDICES AND US, OTHER THAN THE LICENSORS OF S&P DOW JONES INDICES.

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Historical Information

The graph below sets forth the information relating to the historical performance of the Reference Asset. In addition, below the graph is a table setting forth the intra-day high, intra-day low and period-end closing levels of the Reference Asset. The information provided in this table is for the four calendar quarters of 2012, 2013, 2014, 2015 and 2016, the first and second calendar quarters of 2017, and for the period from July 1, 2017 through August 28, 2017.

We obtained the information regarding the historical performance of the Reference Asset in the chart below from Bloomberg Financial Markets.

We have not independently verified the accuracy or completeness of the information obtained from Bloomberg Financial Markets. The historical performance of the Reference Asset should not be taken as an indication of its future performance, and no assurance can be given as to the Final Level of the Reference Asset. We cannot give you assurance that the performance of the Reference Asset will result in any positive return on your initial investment.

S&P 500® Index ("SPX")

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Period-Start Date	Period-End Date	High Intra-Day Level of the Reference Asset	Low Intra-Day Level of the Reference Asset	Period-End Closing Level of the Reference Asset
1/1/2012	3/31/2012	1,419.15	1,258.86	1,408.47
4/1/2012	6/30/2012	1,422.38	1,266.74	1,362.16
7/1/2012	9/30/2012	1,474.51	1,325.41	1,440.67
10/1/2012	12/31/2012	1,470.96	1,343.35	1,426.19
1/1/2013	3/31/2013	1,570.28	1,426.19	1,569.19
4/1/2013	6/30/2013	1,687.18	1,536.03	1,606.28
7/1/2013	9/30/2013	1,729.86	1,604.57	1,681.55
10/1/2013	12/31/2013	1,849.44	1,646.47	1,848.36
1/1/2014	3/31/2014	1,883.97	1,737.92	1,872.34
4/1/2014	6/30/2014	1,968.17	1,814.36	1,960.23
7/1/2014	9/30/2014	2,019.26	1,904.78	1,972.29
10/1/2014	12/31/2014	2,093.55	1,820.66	2,058.90
1/1/2015	3/31/2015	2,119.59	1,980.90	2,067.89
4/1/2015	6/30/2015	2,134.72	2,048.38	2,063.11
7/1/2015	9/30/2015	2,132.82	1,867.01	1,920.03
10/1/2015	12/31/2015	2,116.48	1,893.70	2,043.94
1/1/2016	3/31/2016	2,072.21	1,810.10	2,059.74
4/1/2016	6/30/2016	2,120.55	1,991.68	2,098.86
7/1/2016	9/30/2016	2,193.81	2,074.02	2,168.27
10/1/2016	12/31/2016	2,277.53	2,083.79	

Other Assets:				
Intangible assets, net of accumulated amortization of $11,512 in 2008 and $8,929 in 2007		155,701		77,804
Long-term assets from risk management activities		708		-
Other, net of accumulated amortization of debt issuance costs of $3,146 in 2008 and $2,488 in 2007		41,469		13,529
Goodwill		298,580		94,075
Total other assets		496,458		185,408
TOTAL ASSETS	$	2,153,933	$	1,278,410
LIABILITIES & PARTNERS' CAPITAL				
Current Liabilities:				
Accounts payable, trade	$	55,710	$	48,904
Accrued cost of gas and liquids		113,974		96,026

Related party payables		10		50
Escrow payable		14,568		6,029
Liabilities from risk management activities		35,584		37,852
Other current liabilities		27,646		9,397
Total current liabilities		247,492		198,258
Long-term liabilities from risk management activities		14,033		15,073
Other long-term liabilities		16,075		15,393
Long-term debt		1,090,500		481,500
Minority interest in consolidated subsidiary		885		4,893
Commitments and contingencies				
Partners' Capital:				
Common units (41,277,082 and 41,283,079 units authorized; 40,700,898 and 40,514,895 units issued and outstanding at March 31, 2008 and December 31, 2007)		481,455		490,351
Class D common units (7,276,506 units authorized, issued and outstanding at March 31, 2008)		219,590		-
Class E common units (4,701,034 units authorized, issued and outstanding at March 31, 2008 and December 31, 2007)		92,962		92,962
Subordinated units (19,103,896 units authorized, issued and outstanding at March 31, 2008 and December 31, 2007)		2,438		7,019
General partner interest		19,227		11,286
Accumulated other comprehensive loss		(30,724)		(38,325)
Total partners' capital		784,948		563,293
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$	2,153,933	$	1,278,410

See accompanying notes to condensed consolidated financial statements

* Recast to reflect an acquisition accounted for in a manner similar to a pooling of interests.

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Regency Energy Partners LP
Condensed Consolidated Statements of Operations
Unaudited
(in thousands except unit data and per unit data)

	Three Months Ended	
	March 31, 2008	March 31, 2007
REVENUES		
Gas sales	$ 236,692	$ 167,384
NGL sales	108,499	63,541
Gathering, transportation and other fees, including related party amounts of $53 and $353	61,986	19,878
Net realized and unrealized loss from risk management activities	(13,657)	(85)
Other	11,715	5,710
Total revenues	405,235	256,428
OPERATING COSTS AND EXPENSES		
Cost of sales, including related party amounts of $403 and $5,418	313,589	211,937
Operation and maintenance	28,845	10,925
General and administrative	10,923	6,851
Loss on asset sales, net	-	1,808
Management services termination fee	3,888	-
Transaction expenses	348	-
Depreciation and amortization	21,741	11,427
Total operating costs and expenses	379,334	242,948
OPERATING INCOME	25,901	13,480
Interest expense, net	(15,406)	(14,885)
Other income and deductions, net	176	110
Minority interest	(72)	-
INCOME (LOSS) BEFORE INCOME TAXES	10,599	(1,295)
Income tax expense	251	-
NET INCOME (LOSS)	$ 10,348	$ (1,295)
Less:		
General partner's make-whole allocation for prior year losses	$ 569	$ -
General partner's interest in current period net income (loss)	196	(26)
Beneficial conversion feature for Class C common units	-	1,385
Beneficial conversion feature for Class D common units	1,559	-
Limited partners' interest in net income (loss)	$ 8,024	$ (2,654)

Earnings per unit:				
Amount allocated to common and subordinated units	$	8,024	$	(2,654)
Weighted average number of common and subordinated units outstanding		59,229,507		42,356,956
Basic income (loss) per common and subordinated unit	$	0.14	$	(0.06)
Diluted income (loss) per common and subordinated unit	$	0.13	$	(0.06)
Distributions per unit	$	0.40	$	0.38
Amount allocated to Class B common units	$	-	$	-
Weighted average number of Class B common units outstanding		-		2,644,074
Basic and diluted income per Class B common unit	$	-	$	-
Distributions per unit	$	-	$	-
Amount allocated to Class C common units	$	-	$	1,385
Total number of Class C common units outstanding		-		2,857,143
Basic and diluted income per Class C common unit due to beneficial conversion feature	$	-	$	0.48
Distributions per unit	$	-	$	-
Amount allocated to Class D common units	$	1,559	$	-
Total number of Class D common units outstanding		7,276,506		-
Basic and diluted income per Class D common unit due to beneficial conversion feature	$	0.21	$	-
Distributions per unit	$	-	$	-
Amount allocated to Class E common units	$	-	$	-
Weighted average number of Class E common units outstanding		4,701,034		-
Basic and diluted income per Class E common unit	$	-	$	-
Distributions per unit	$	-	$	-

See accompanying notes to condensed consolidated financial statements

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Regency Energy Partners LP
Condensed Consolidated Statements of Comprehensive Income (Loss)
Unaudited
(in thousands)

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
Net income (loss)	$ 10,348	$ (1,295)
Hedging amounts reclassified to earnings	10,435	(54)
Net change in fair value of cash flow hedges	(2,834)	(12,445)
Comprehensive income (loss)	$ 17,949	$ (13,794)

See accompanying notes to condensed consolidated financial statements

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Regency Energy Partners LP
Condensed Consolidated Statements of Cash Flows
Unaudited
(in thousands)

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
OPERATING ACTIVITIES		
Net income (loss)	$ 10,348	$ (1,295)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:		
Depreciation and amortization, including debt issuance cost amortization	22,398	11,986
Equity income	-	(43)
Risk management portfolio valuation changes	3,098	(124)
Loss on asset sales	-	1,808
Unit based compensation expenses	794	1,103
Cash flow changes in current assets and liabilities:		
Accounts receivable and accrued revenues	(19,264)	(1,959)
Other current assets	2,800	598
Accounts payable, accrued cost of gas and liquids and accrued liabilities	25,950	5,220
Other current liabilities	18,249	10,617
Other assets and liabilities	(6,835)	(441)
Net cash flows provided by operating activities	57,538	27,470
INVESTING ACTIVITIES		
Capital expenditures	(97,896)	(47,501)
Acquisitions	(574,059)	-
Acquisition of investment in unconsolidated subsidiary, net of $100 cash	-	(5,000)
Proceeds from asset sales	-	5,610
Net cash flows used in investing activities	(671,955)	(46,891)
FINANCING ACTIVITIES		
Net borrowings under revolving credit facilities	609,000	33,400
Partner contributions	7,663	6
Partner distributions	(24,341)	(14,620)
Net cash flows provided by financing activities	592,322	18,786
Net decrease in cash and cash equivalents	(22,095)	(635)
Cash and cash equivalents at beginning of period	32,971	9,139
Cash and cash equivalents at end of period	$ 10,876	$ 8,504
Supplemental cash flow information:		
Interest paid, net of amounts capitalized	$ 5,047	$ 2,540
Non-cash capital expenditures in accounts payable	18,517	10,509
Non-cash capital expenditures for consolidation of investment in previously unconsolidated subsidiary	-	5,650
Issuance of Class D common units for an acquisition	219,590	-

See accompanying notes to condensed consolidated financial statements

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Regency Energy Partners LP
Condensed Consolidated Statements of Partners' Capital
Unaudited
(in thousands except unit data)

	Units									Ac
	Common	Class D	Class E	Subordinated	Common Unitholders	Class D Unitholders	Class E Unitholders	Subordinated Unitholders	General Partner Interest	Con
Balance - December 31, 2007 *	40,514,895	-	4,701,034	19,103,896	$ 490,351	$ -	$ 92,962	$ 7,019	$ 11,286	$
Issuance of Class D common units	-	7,276,506	-	-	-	219,590	-	-	-	
Issuance of restricted common units and option exercises, net of forfeitures	186,003	-	-	-	-	-	-	-	-	
Unit based compensation expenses	-	-	-	-	794	-	-	-	-	
General partner contributions	-	-	-	-	-	-	-	-	7,663	
Partner distributions	-	-	-	-	(16,212)	-	-	(7,642)	(487)	
Net income	-	-	-	-	6,522	-	-	3,061	765	
Net hedging amounts reclassified to earnings	-	-	-	-	-	-	-	-	-	
Net change in fair value of cash flow hedges	-	-	-	-	-	-	-	-	-	
Balance - March 31, 2008	40,700,898	7,276,506	4,701,034	19,103,896	$ 481,455	$ 219,590	$ 92,962	$ 2,438	$ 19,227	$

See accompanying notes to condensed consolidated financial statements

*Recast to reflect an acquisition accounted for in a manner similar to a pooling of interests.

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Regency Energy Partners LP
Notes to Unaudited Condensed Consolidated Financial Statements

1. Organization and Summary of Significant Accounting Policies

Organization and Basis of Presentation. The unaudited condensed consolidated financial statements presented herein contain the results of Regency Energy Partners LP, a Delaware limited partnership, and its wholly owned subsidiaries. The Partnership and its subsidiaries are engaged in the business of gathering, processing, contract compression, marketing, and transportation of natural gas and/or NGLs. The Partnership operates and manages its business as three reportable segments: a) gathering and processing, b) transportation, and c) contract compression.

On January 7, 2008, the Partnership acquired all the outstanding equity of FrontStreet (the "FrontStreet Acquisition") from ASC and EnergyOne for the issuance of 4,701,034 Class E common units of the Partnership to ASC and the cash payment of $11,752,000 to EnergyOne, inclusive of a payment to terminate a management services agreement in the amount of $3,880,000. FrontStreet owns a gas gathering system located in Kansas and Oklahoma, which is operated by a third party.

The Partnership financed the cash portion of the purchase price with borrowings under its revolving credit facility. In connection with the FrontStreet Acquisition, the General Partner entered into Amendment No. 3 to the Amended and Restated Agreement of Limited Partnership of the Partnership, which created the Partnership's Class E common units. The Class E common units have the same terms and conditions as the Partnership's common units, except that the Class E common units are not entitled to participate in earnings or distributions of operating surplus by the Partnership. The Class E common units were issued in a private offering conducted in accordance with the exemption from the registration requirements of the Securities Act of 1933 afforded by Section 4(2) thereof. The Class E common units converted into common units on a one-for-one basis on May 5, 2008.

Because the FrontStreet Acquisition is a transaction between commonly controlled entities (i.e., the buyer and the sellers were each affiliates of GECC), the Partnership accounted for the acquisition in a manner similar to the pooling of interests method. Under this method of accounting, the Partnership reflected the historical balance sheet data for both the Partnership and FrontStreet instead of reflecting the fair market value of FrontStreet's assets and liabilities. Further, certain transaction costs that would normally be capitalized were expensed. Common control between the Partnership and FrontStreet began on June 18, 2007. The Partnership recast the December 31, 2007 financial statements to reflect the as-if pooling accounting treatment of this acquisition. The three months ended March 31, 2008 statement of operations includes FrontStreet's results for the entire quarter.

The unaudited financial information as of, and for the three months ended, March 31, 2008 has been prepared on the same basis as the audited consolidated financial statements included in the Partnership's Annual Report on Form 10-K and in the Form 8-K filed on May 9, 2008 for the year ended December 31, 2007. In the opinion of the Partnership's management, such financial information reflects all adjustments necessary for a fair presentation of the financial position and the results of operations for such interim periods in accordance with GAAP. All intercompany items and transactions have been eliminated in consolidation. Certain information and footnote disclosures normally included in annual consolidated financial statements prepared in accordance with GAAP have been omitted pursuant to the rules and regulations of the SEC.

Use of Estimates. The unaudited condensed consolidated financial statements have been prepared in conformity with GAAP and, of necessity, include the use of estimates and assumptions by management. Actual results could differ from these estimates.

Intangible Assets. The total gross carrying amount of intangible assets that were subject to amortization was $167,213,000 and $86,733,000 at March 31, 2008 and December 31, 2007, respectively. Aggregate amortization expense for the three months ended March 31, 2008 and 2007 was $2,583,000 and $993,000, respectively.

Recently Issued Accounting Standards. In January 2007, the FASB issued SFAS No. 159, “The Fair Value Option for Financial Assets and Financial Liabilities, Including an Amendment of FASB Statement No. 115” (“SFAS No. 159”), which permits entities to measure many financial instruments and certain other assets and liabilities at fair value on an instrument-by-instrument basis. The adoption of SFAS No. 159 in the three months ended March 31, 2008 had no impact on the Partnership’s financial position, results of operations or cash flows, as the Partnership has elected to continue valuing its outstanding senior notes at historical cost.

In December 2007, the FASB issued SFAS No. 141(R) “Business Combinations” (“SFAS No. 141(R)”), which significantly changes the accounting for business acquisitions both during the period of the acquisition and in subsequent periods. SFAS No. 141(R) is effective for fiscal years beginning after December 15, 2008. Generally, the effects of SFAS No. 141(R) will depend on future acquisitions.

In December 2007, the FASB issued SFAS No. 160, “Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51” (“SFAS No. 160”), which will significantly change the accounting and reporting related to noncontrolling interests in a consolidated subsidiary. SFAS No. 160 is effective for fiscal years beginning after December 15, 2008. The Partnership is currently evaluating the potential impacts on its financial position, results of operations or cash flows of the adoption of this standard.

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In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133" ("SFAS No. 161"). SFAS No. 161 requires enhanced disclosures about derivative and hedging activities. These enhanced disclosures will address (a) how and why a company uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under FASB Statement No. 133 and its related interpretations and (c) how derivative instruments and related hedged items affect a company's financial position, results of operations and cash flows. SFAS No. 161 is effective for fiscal years beginning on or after November 15, 2008, with earlier adoption allowed. The Partnership is currently evaluating the potential impacts on its financial position, results of operations or cash flows of the adoption of this standard.

2. Income (Loss) per Limited Partner Unit

In connection with the CDM acquisition, the Partnership issued 7,276,506 Class D common units. At the commitment date, the sales price of $30.18 per unit represented a $1.10 discount from the fair value of the Partnership's common units. Under EITF No. 98-5, "Accounting for Convertible Securities with Beneficial Conversion Features or Contingently Adjustable Conversion Ratios," the discount represented a beneficial conversion feature ("BCF") that is treated as a non-cash distribution for purposes of calculating earnings per unit. The BCF is reflected in income per unit using the effective yield method over the period the Class D common units are outstanding, as indicated on the statements of operations in the line item entitled "beneficial conversion feature for Class D common units."

The following table provides a reconciliation of the numerator and denominator of the basic and diluted earnings per unit computations for the three months ended March 31, 2008.

	For the Three Months Ended March 31, 2008		
	Income (Numerator) (in thousands)	Units (Denominator)	Per-Unit Amount
Basic Earnings per Unit			
Limited partners' interest in net income	$ 8,024	59,229,507	$ 0.14
Effect of Dilutive Securities			
Class D common units	1,559	7,276,506	
Class E common units	-	4,701,034	
Common unit options	-	207,817	
Restricted (nonvested) common units	-	-	
Diluted Earnings per Unit	$ 9,583	71,414,864	$ 0.13

The following data show securities that could potentially dilute earnings per unit in the future that were not included in the computation of diluted EPS because to do so would have been antidilutive for the period(s) presented.

	March 31, 2008	March 31, 2007
Restricted common units	555,000	687,500
Common unit options	-	884,866
Class B common units	-	5,173,189
Class C common units	-	2,857,143

3. Acquisitions

CDM Resource Management, Ltd. On January 15, 2008, the Partnership and an indirect wholly owned subsidiary of the Partnership ("Merger Sub") consummated an agreement and plan of merger (the "Merger Agreement") with CDM Resource Management, Ltd., CDM GP, and CDM LP (each a "CDM Partner" and together the "CDM Partners"). Upon closing, CDM merged with and into Merger Sub, with Merger Sub continuing as the surviving entity after the merger (the "CDM Merger"). Following the merger, Merger Sub changed its name to CDM Resource Management LLC. CDM provides its customers with turn-key natural gas contract compression services to maximize their natural gas and crude oil production, throughput, and cash flow in Texas, Louisiana, and Arkansas. The Partnership operates and manages CDM as a separate reportable segment.

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The total purchase price, subject to customary post-closing adjustments, paid by the Partnership for the partnership interests of CDM consisted of (1) the issuance of an aggregate of 7,276,506 Class D common units of the Partnership, which were valued at $219,590,000, (2) the payment of an aggregate of $161,945,000 in cash to the CDM Partners, and (3) the payment of $316,500,000 to retire CDM's debt obligations. Of the Class D common units issued, 4,197,303 Class D common units were deposited with an escrow agent pursuant to an escrow agreement. Such common units constitute security to the Partnership for a period of one year after the closing of the CDM Merger with respect to any obligations of the CDM Partners under the Merger Agreement, including obligations for breaches of representation, warranties and covenants. In connection with the CDM Merger, the General Partner entered into Amendment No. 4 to the Amended and Restated Agreement of Limited Partnership of the Partnership, which created the Partnership's Class D common units. The Class D common units have the same terms and conditions as the Partnership's common units, except that the Class D common units are not entitled to participate in distributions of operating surplus by the Partnership. The Class D common units automatically convert into common units on a one-for-one basis on the close of business on the first business day after the record date for the quarterly distribution on the common units for the quarter ending December 31, 2008. The Class D common units were issued in a private offering conducted in accordance with the exemption from the registration requirements of the Securities Act of 1933 afforded by Section 4(2) thereof.

The total purchase price of $698,035,000 was allocated preliminarily as follows based on estimates of the fair values of the assets acquired and the liabilities paid.

	At January 15, 2008 (in thousands)	
Working capital	$	19,276
Other assets		4,548
Gas plants and buildings		501
Gathering and transmission systems		410,075
Other property, plant and equipment		3,649
Construction-in-progress		40,737
Identifiable intangible assets		80,480
Goodwill		138,769
Net assets acquired	$	698,035

The final purchase price allocation, which management expects to be completed before year end, may differ from the above estimates.

Nexus Gas Holdings, LLC. On March 25, 2008, the Partnership acquired Nexus Gas Holdings, LLC, a Delaware limited liability company ("Nexus") ("Nexus Acquisition") by merger for $87,749,000 in cash, including customary closing adjustments. Nexus Gas Partners LLC, the sole member of Nexus prior to the merger ("Nexus Member"), deposited $8,500,000 in an escrow account as security to the Partnership for a period of one year against indemnification obligations and any purchase price adjustment. The Partnership funded the Nexus Acquisition through borrowings under the existing revolving credit facility.

Upon consummation of the Nexus Acquisition, the Partnership acquired Nexus' rights under a Purchase and Sale Agreement (the "Sonat Agreement") between Nexus and Southern Natural Gas Company ("Sonat"). Pursuant to the Sonat Agreement, Nexus will purchase 136 miles of pipeline from Sonat (the "Sonat Asset Acquisition") that would enable the Nexus gathering system to be integrated into the Partnership's north Louisiana asset base. The Sonat Asset Acquisition is subject to abandonment approval and jurisdictional redetermination by the FERC, as well as customary closing conditions. Upon closing of the Sonat Asset Acquisition, the Partnership will pay Sonat $27,500,000, and, if the closing occurs on or prior to March 1, 2010, on certain terms and conditions as provided in the Merger Agreement, the Partnership will make an additional payment of $25,000,000 to the Nexus Member.

The total purchase price of $87,749,000 was allocated preliminarily as follows based on estimates of the fair values of the assets acquired.

		At March 25, 2008 (in thousands)
Working capital	$	2,748
Buildings		12
Gathering and transmission systems		8,403
Other property, plant and equipment		11,096
Goodwill		65,490
Net assets acquired	$	87,749

The final purchase price allocation, which management expects to be completed before year end, may differ from the above estimates.

The following unaudited pro forma financial information has been prepared as if the acquisitions of FrontStreet, CDM and Nexus had occurred as of the beginning of the periods presented. In the three months ended March 31, 2007, the Partnership's acquisition of Pueblo is included since that acquisition occurred in April 2007. Such unaudited pro forma information does not purport to be indicative of the results of operations that would have been achieved if the transactions to which the Partnership is giving pro forma effect actually occurred on the date referred to above or the results of operations that may be expected in the future.

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	Pro Forma Results for the Three Months Ended March 31, 2008	March 31, 2007
	(in thousands except unit and per unit data)	
Revenue	$ 412,443	$ 297,198
Net income	$ 12,162	$ 3,487
Less:		
General partner's make-whole allocation for prior year losses	-	176
General partner's interest in current period net income	243	66
Beneficial conversion feature for Class C common units	-	1,385
Beneficial conversion feature for Class D common units	1,559	-
Limited partners' interest in net income	$ 10,360	$ 1,860
Earnings per unit:		
Amount allocated to common and subordinated units	$ 10,360	$ 1,860
Weighted average number of common and subordinated units outstanding	59,229,507	42,356,956
Basic income per common and subordinated unit	$ 0.17	$ 0.04
Diluted income per common and subordinated unit	$ 0.16	$ 0.04
Distributions per unit	$ 0.40	$ 0.38
Amount allocated to Class B common units	$ -	$ -
Weighted average number of Class B common units outstanding	-	2,644,074
Basic and diluted income per Class B common unit	$ -	$ -
Distributions per unit	$ -	$ -
Amount allocated to Class C common units	$ -	$ 1,385
Total number of Class C common units outstanding	-	2,857,143
Basic and diluted income per Class C common unit due to beneficial conversion feature	$ -	$ 0.48
Distributions per unit	$ -	$ -
Amount allocated to Class D common units	$ 1,559	$ -
Total number of Class D common units outstanding	7,276,506	7,276,506
Basic and diluted income per Class D common unit due to beneficial conversion feature	$ 0.21	$ -
Distributions per unit	$ -	$ -
Amount allocated to Class E common units	$ -	$ -
Weighted average number of Class E common units outstanding	4,701,034	4,701,034
Basic and diluted income per Class E common unit	$ -	$ -
Distributions per unit	$ -	$ -

4. Risk Management Activities

Effective June 19, 2007, the Partnership elected to account for its entire outstanding commodity hedging instruments on a mark-to-market basis except for the portion pursuant to which all NGL products for a particular year were hedged and the hedging relationship was, for accounting purposes, effective. On March 7, 2008, the Partnership entered offsetting trades against its existing 2009 portfolio of mark-to-market hedges, which it believes will substantially reduce the volatility of its net income. This group of trades, along with the pre-existing 2009 portfolio, will continue to be accounted for on a mark-to-market basis. Simultaneously, the Partnership executed additional 2009 NGL swaps which were designated under SFAS No. 133 as cash flow hedges. Currently, the Partnership accounts for a portion of its 2008 West Texas Intermediate crude oil swap and its 2009 West Texas Intermediate crude oil swap using mark-to-market accounting.

On February 29, 2008, the Partnership entered into two year interest rate swaps related to $300,000,000 of borrowings under its revolving credit facility, effectively locking the rate for these borrowings at 2.4 percent, plus the applicable margin (1.5 percent as of March 31, 2008). These interest rate swaps were designated as cash flow hedges on March 7, 2008 and the Partnership incurred an immaterial charge for the period in which mark-to-market accounting applied.

The Partnership's hedging positions help reduce exposure to variability of future commodity prices through 2009 and future interest rates on $300,000,000 of debt under its revolving credit facility through March 5, 2010.

The net fair value of the Partnership's risk management activities constituted a net liability of $48,422,000 at March 31, 2008. The Partnership expects to reclassify $29,334,000 of hedging losses as an offset to revenues or interest expense from accumulated other comprehensive income (loss) in the next twelve months. During the three months ended March 31, 2008 and 2007, the Partnership recorded $3,090,000 and $8,000 of mark-to-market losses for certain commodity hedges that do not qualify for hedge accounting and recognized a $223,000 ineffectiveness gain during the three months ended March 31, 2008, which is included in the March 31, 2008 mark-to-market loss.

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5. Long-Term Debt

Long-term debt obligations of the Partnership are as follows:

		March 31, 2008		December 31, 2007
		(in thousands)		
Senior notes	$	357,500	$	357,500
Revolving loans		733,000		124,000
Total		1,090,500		481,500
Less: current portion		-		-
Long-term debt	$	1,090,500	$	481,500
Availability under term and revolving credit facility				
Total credit facility limit	$	900,000	$	500,000
Revolver loans		(733,000)		(124,000)
Letters of credit		(27,263)		(27,263)
Total available	$	139,737	$	348,737

RGS entered into Amendment No. 4 to its Fourth Amended and Restated Credit Facility on January 15, 2008, thereby expanding its revolving credit facility thereunder to $750,000,000. RGS also entered into Amendment No. 5 to its Fourth Amended and Restated Credit Facility on February 13, 2008, expanding its revolving credit facility thereunder to $900,000,000 and availability for letters of credit to $100,000,000. The Partnership has the option to request an additional $250,000,000 in revolving commitments with 10 business days written notice provided that no event of default has occurred or would result due to such increase, and all other additional conditions for the increase of the commitments set forth in the credit facility have been met. These amendments did not materially change other terms of the RGS revolving credit facility.

The outstanding balance of revolving debt under the credit facility bears interest at LIBOR plus a margin or Alternative Base Rate (equivalent to the U.S. prime lending rate) plus a margin, or a combination of both. The weighted average interest rates for the revolving loans and senior notes, including interest rate swap settlements, commitment fees, and amortization of debt issuance costs were 6.90 percent and 8.78 percent for the three months ended March 31, 2008 and 2007, respectively. The senior notes bear interest at a fixed rate of 8.375 percent. The estimated fair market value of the senior notes was $372,694,000 as of March 31, 2008.

The senior notes are guaranteed by each of the Partnership's current subsidiaries (the "Guarantors") as of March 31, 2008, except for the FrontStreet assets. These note guarantees are the joint and several obligations of the Guarantors. A Guarantor may not sell or otherwise dispose of all or substantially all of its properties or assets if such sale would cause a default under the terms of the senior notes. Events of default include nonpayment of principal or interest when due; failure to comply with certain limits on the payment of distributions; failure to make a change of control offer; failure to comply with reporting requirements according to SEC rules and regulations; and defaults on the payment of obligations under other mortgages or indentures. Since certain wholly owned subsidiaries do not guarantee the senior notes, the consolidating financial statements of the guarantors and non-guarantors as of and for the three months March 31, 2008 are disclosed below.

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Balance Sheet
March 31, 2008
(in thousands)

	Guarantors	Non Guarantors	Consolidated
ASSETS			
Total current assets	$ 195,732	$ 12,975	$ 208,707
Property, plant and equipment, net	1,355,631	93,137	1,448,768
Total other assets	496,458	-	496,458
TOTAL ASSETS	$ 2,047,821	$ 106,112	$ 2,153,933
LIABILITIES & PARTNERS' CAPITAL			
Total current liabilities	$ 241,963	$ 5,529	$ 247,492
Long-term liabilities from risk management activities	14,033	-	14,033
Other long-term liabilities	16,075	-	16,075
Long-term debt	1,090,500	-	1,090,500
Minority interest	885	-	885
Partners' capital	684,365	100,583	784,948
TOTAL LIABILITIES & PARTNERS' CAPITAL	$ 2,047,821	$ 106,112	$ 2,153,933

Statement of Operations
For the Three Months Ended March 31, 2008
(in thousands)

	Guarantors	Non Guarantors	Consolidated
Total revenues	$ 393,048	$ 12,187	$ 405,235
Total operating costs and expenses	369,882	9,452	379,334
OPERATING INCOME	23,166	2,735	25,901
Interest expense, net	(15,406)	-	(15,406)
Other income and deductions, net	176	-	176
Minority interest	(66)	(6)	(72)
INCOME BEFORE INCOME TAXES	7,870	2,729	10,599
Income tax expense	251	-	251
NET INCOME	$ 7,619	$ 2,729	$ 10,348

Statement of Cash Flow
For the Three Months Ended March 31, 2008
(in thousands)

	Guarantors	Non Guarantors	Consolidated
Net cash flows provided by (used in) operating activities	$ 61,220	$ (3,682)	$ 57,538
Net cash flows used in investing activities	(671,488)	(467)	(671,955)
Net cash flows provided by financing activities	592,322	-	592,322

6. Commitments and Contingencies

Legal. The Partnership is involved in various other claims and lawsuits incidental to its business. In the opinion of management, these claims and lawsuits in the aggregate will not have a material adverse effect on the Partnership's business, financial condition, results of operations or cash flows.

Contingent Purchase of Sonat Assets. In March of 2008, the Partnership, through its Nexus acquisition, obtained the rights to a contingent commitment to purchase 136 miles of pipeline that would enable the integration of the recently acquired Nexus gathering system into the Partnership's north Louisiana asset base. The purchase commitment is contingent upon the FERC declaring that the pipeline is no longer subject to its jurisdiction, together with approval of the current owner's abandonment and other customary closing conditions. In the event that all contingencies are satisfactorily resolved, the Partnership will pay Sonat $27,500,000. Furthermore, if the closing occurs on or prior to March 1, 2010, the Partnership will pay an additional $25,000,000 to the sellers, subject to certain terms and conditions.

Escrow Payable. At March 31, 2008, $6,064,000 remained in escrow pending the completion by El Paso Field Services, LP ("El Paso") of environmental remediation projects pursuant to the purchase and sale agreement ("El Paso PSA") related to the assets in north Louisiana and in the mid-continent area. In the El Paso PSA, El Paso indemnified the predecessor of our operating partnership RGS against losses arising from pre-closing and known environmental liabilities subject to a limit of $84,000,000 and subject to certain deductible limits. Upon completion of a Phase II environmental study, the Partnership notified El Paso of remediation obligations amounting to $1,800,000 with respect to known environmental matters and $3,600,000 with respect to pre-closing environmental liabilities.

In January 2008, pursuant to authorization by the Board of Directors of the General Partner, the Partnership signed a settlement of the El Paso environmental remediation. Under the settlement, El Paso will clean up and obtain "no further action" letters from the relevant state agencies for three owned Partnership facilities. El Paso is not obligated to clean up properties leased by the Partnership, but it indemnified the Partnership for pre-closing environmental liabilities. All sites for which the Partnership made environmental claims against El Paso are either addressed in the settlement or have already been resolved. In May 2008, the Partnership released all but $1,500,000 from the escrow fund maintained to secure El Paso's obligations. This amount will be further reduced under a specified schedule as El Paso completes its clean-up obligations and the remainder will be released upon completion.

Nexus Escrow. Nexus Gas Partners LLC deposited $8,500,000 in an escrow account as security to the Partnership for a period of one year against indemnification obligations and any purchase price adjustment related to the March 25, 2008 acquisition of Nexus Gas Partners LLC.

Environmental. A Phase I environmental study was performed on the Waha assets in connection with the pre-acquisition due diligence process in 2004. Most of the identified environmental contamination had either been remediated or was being remediated by the previous owners or operators of the properties. The aggregate potential environmental remediation costs at specific locations were estimated to range from $1,900,000 to $3,100,000. No governmental agency has required the Partnership to undertake these remediation efforts. Management believes that the likelihood that it will be liable for any significant potential remediation liabilities identified in the study is remote. Separately, the Partnership acquired an environmental pollution liability insurance policy in connection with the acquisition to cover any undetected or unknown pollution discovered in the future. The policy covers clean-up costs and damages to third parties, and has a 10-year term (expiring 2014) with a $10,000,000 limit subject to certain deductibles. No claims have been made.

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TCEQ Notice of Enforcement. On February 15, 2008, the Texas Commission on Environmental Quality ("TCEQ") issued to RFS a Notice of Enforcement concerning its Tilden Gas Plant ("the Plant"), located in McMullen County, Texas. The Notice of Enforcement alleges that, between March 9, 2006, and May 8, 2007, the Plant experienced 15 emission events of various durations from 4 hours to 41 days, which the Plant failed to report to TCEQ and other agencies within 24 hours of occurrence. These events occurred during times of failure of the Tilden plant sulphur recovery unit or ancillary equipment and resulted in the flaring of acid gas. Of these events, one relates to an alleged release of nearly 6 million pounds of sulphur dioxide and 64,000 pounds of hydrogen sulphide, 11 related to less than 2,500 pounds of sulphur dioxide and three related to more than 2,500 and less than 40,000 pounds of sulphur dioxide (including two releases of 126 and 393 pounds of hydrogen sulphide). In 2007, the subsidiary completed construction of an acid gas reinjection unit at the Tilden plant and permanently shut down the Sulphur Recovery Unit.

All these emission incidents were reported by means of fax or telephone to the TCEQ pursuant to an informal procedure established with the TCEQ by the prior owner of the Tilden plant and emission fines were paid in connection with all the incidents. Using that procedure, all except one were timely. Prior to the acquisition of the Plant by our subsidiary, the TCEQ had established its electronic data base for emission events, but our subsidiary did not report using that facility. On April 3, 2008, the TCEQ presented RFS with a written offer to settle the allegations made in the Notice of Enforcement for an administrative penalty in the amount of $480,000. RFS will meet with TCEQ to present its view that the emissions were neither excessive nor improperly reported. Management of the General Partner does not expect the NOE to have a material adverse effect on its results of operations or financial condition.

RIGS FERC Petition. On April 29, 2008, we filed a petition with the FERC seeking approval to maintain RIGS' maximum Section 311 transportation rates. The rate filing was required by a FERC Letter Order issued on September 26, 2005, which approved a settlement in which RIGS agreed to justify its existing rates or establish new rates for Section 311 service by May 1, 2008. The triennial rate review requirement is a standard settlement provision in most intrastate pipeline rate proceedings.

In the petition, RIGS requests to maintain its current maximum rates for both firm and interruptible services as follows: firm service: reservation fee of $4.5625 per MMBtu monthly ($0.15 per MMBtu daily) and commodity fee of $0.05 per MMBtu; interruptible service: $0.20 per MMBtu. RIGS also requested a continuation of its existing fuel retention percentage of up to two percent. The proposed rates are subject to refund beginning May 1, 2008.

7. Related Party Transactions

The employees operating the assets of the Partnership and its subsidiaries and substantially all those providing staff or support services are employees of the General Partner and other affiliates of the Partnership. Pursuant to the Partnership Agreement, our General Partner receives a monthly reimbursement for all direct and indirect expenses that it incurs on behalf of the Partnership. Reimbursements of $6,888,000 and $6,049,000 were recorded in the Partnership's financial statements during three months ended March 31, 2008 and 2007, respectively, as operating expenses or general and administrative expenses, as appropriate.

In conjunction with distributions by the Partnership on common, subordinated units, and general partner interest, GE EFS and affiliates, HM Capital Partners and affiliates, and certain members of management received cash distributions of $7,570,545, $3,259,469 and $289,755, respectively, in the three months ended March 31, 2008 as a result of their ownership interest in the Partnership.

8. Segment Information

The Partnership has three reportable segments: i) gathering and processing, ii) transportation, and iii) contract compression. Gathering and processing involves collecting raw natural gas from producer wells and transporting it to treating plants where water and other impurities such as hydrogen sulfide and carbon dioxide are removed. Treated gas is then processed to remove the natural gas liquids. The treated and processed natural gas is then transported to market separately from the natural gas liquids. Revenues and the associated cost of sales directly expose the Partnership to commodity price risk, which is managed through derivative contracts and other measures. The Partnership aggregates the results of its gathering and processing activities across five geographic regions into a single reporting segment.

The transportation segment uses pipelines to transport natural gas from receipt points on its system to interconnections with larger pipelines or trading hubs and other markets. The Partnership performs transportation services for shipping customers under firm or interruptible arrangements. In either case, revenues are primarily fee based and involve minimal direct exposure to commodity price fluctuations. The Partnership also purchases natural gas at the inlets to the pipeline and sells this gas at its outlets. The north Louisiana intrastate pipeline operated by this segment serves the Partnership's gathering and processing facilities in the same area and those transactions create the intersegment revenues shown in the table below.

The contract compression segment services include designing, sourcing, owning, insuring, installing, operating, servicing, repairing, and maintaining compressors and related equipment, with a focus on meeting the complex requirements of field-wide compression applications, as opposed to targeting the compression needs of individual wells within a field. These field-wide applications include compression for natural gas gathering, natural gas lift for crude oil production and natural gas processing. Revenues in this segment are fee-based, with minimal direct exposure to commodity price risk. The contract compression operations are primarily located in Texas, Louisiana, and Arkansas.

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Management evaluates the performance of each segment and makes capital allocation decisions through the separate consideration of segment margin and operation and maintenance expenses. Segment margin, for the gathering and processing and for the transportation segments, is defined as total revenues, including service fees, less cost of sales. In the contract compression segment, segment margin is defined as revenues minus direct costs, which primarily consists of compressor repairs. Management believes segment margin is an important measure because it is directly related to volumes and commodity price changes. Operation and maintenance expenses are a separate measure used by management to evaluate performance of field operations. Direct labor, insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of operation and maintenance expenses. These expenses fluctuate depending on the activities performed during a specific period. The Partnership does not deduct operation and maintenance expenses from total revenues in calculating segment margin because management separately evaluates commodity volume and price changes in segment margin.

Results for each statement of operations period, together with amounts related to balance sheets for each segment, are shown below.

	Gathering and Processing	Transportation	Contract Compression	Corporate	Eliminations	Total
			(in thousands)			
External Revenue						
For the three months ending March 31, 2008	$ 261,585	$ 118,383	$ 25,267	$ -	$ -	$ 405,235
For the three months ending March 31, 2007	177,119	79,309	-	-	-	256,428
Intersegment Revenue						
For the three months ending March 31, 2008	-	30,684	118	-	(30,802)	-
For the three months ending March 31, 2007	-	14,818	-	-	(14,818)	-
Cost of Sales						
For the three months ending March 31, 2008	207,578	134,374	2,364	-	(30,727)	313,589
For the three months ending March 31, 2007	146,941	79,814	-	-	(14,818)	211,937
Segment Margin						
For the three months ending March 31, 2008	54,007	14,693	23,021	-	(75)	91,646
For the three months ending March 31, 2007	30,178	14,313	-	-	-	44,491
Operation and Maintenance						
For the three months ending March 31, 2008	18,627	1,396	8,844	-	(22)	28,845
For the three months ending March 31, 2007	9,115	1,810	-	-	-	10,925
Depreciation and Amortization						
For the three months ending March 31, 2008	12,670	3,491	5,354	226	-	21,741
	7,885	3,250	-	292	-	11,427

For the three months ending March 31, 2007						
Assets						
March 31, 2008	1,033,486	330,000	751,031	39,416	-	2,153,933
December 31, 2007	886,477	329,862	-	62,071	-	1,278,410
Goodwill						
March 31, 2008	125,568	34,243	138,769	-	-	298,580
December 31, 2007	59,832	34,243	-	-	-	94,075
Expenditures for Long-Lived Assets						
For the three months ending March 31, 2008	35,219	1,015	61,299	363	-	97,896
For the three months ending March 31, 2007	35,547	4,385	-	87	-	40,019

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The table below provides a reconciliation of total segment margin to net income (loss).

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
	(in thousands)	
Net income (loss)	$ 10,348	$ (1,295)
Add (deduct):		
Operation and maintenance	28,845	10,925
General and administrative	10,923	6,851
Loss on assets sales, net	-	1,808
Management services termination fee	3,888	-
Transaction expenses	348	-
Depreciation and amortization	21,741	11,427
Interest expense, net	15,406	14,885
Other income and deductions, net	(176)	(110)
Minority interest	72	-
Income tax expense	251	-
Total segment margin	$ 91,646	$ 44,491

9. Equity Based Compensation

In December 2005, the compensation committee of the board of directors of the Partnership's General Partner approved a long-term incentive plan ("LTIP") for the Partnership's employees, directors and consultants covering an aggregate of 2,865,584 common units. Outstanding, unvested LTIP restricted unit awards generally vest on the basis of one-fourth of the award each year. The Partnership expects to recognize an aggregate of $16,367,000 of compensation expense related to the non-vested grants under LTIP. All outstanding options are vested and expire ten years after the grant date.

The Partnership makes distributions to non-vested restricted common units at the same rate as the common units. Restricted common units are subject to contractual restrictions against transfer which lapse over time and are subject to forfeiture upon termination of employment. Upon the exercise of the common unit options, the Partnership anticipates settling these obligations with common units.

The common unit options and restricted (non-vested) unit activity for the three months ended March 31, 2008 are as follows.

Common Unit Options	Units	Weighted Average Exercise Price	Weighted Average Contractual Term (Years)	Aggregate Intrinsic Value * (in thousands)
Outstanding at beginning of period	738,668	$ 21.05		
Granted	-	-		
Exercised	(54,000)	21.01		$ 310
Forfeited or expired	(7,700)	20.00		
Outstanding at end of period	676,968	21.06	7.98	3,846
Exercisable at end of period	676,968	21.06		3,846

* Intrinsic value equals the closing market price of a unit less the option strike price, multiplied by the number of unit options outstanding as of the end of each period presented. Unit options with a strike price greater than the end of the

period closing market price are excluded.

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Restricted (Non-Vested) Units	Units	Weighted Average Grant Date Fair Value
Outstanding at beginning of period	397,500	$ 31.62
Granted	192,000	30.99
Vested	-	-
Forfeited or expired	(34,500)	31.58
Outstanding at end of period	555,000	31.41

10. Fair Value Measures

On January 1, 2008, the Partnership adopted the provisions of SFAS No. 157, “Fair Value Measurements” (“SFAS No. 157”), for financial assets and liabilities. SFAS No. 157 became effective for financial assets and liabilities on January 1, 2008. On January 1, 2009, the Partnership will apply the provisions of SFAS No. 157 for non-recurring fair value measurements of non-financial assets and liabilities, such as goodwill, indefinite-lived intangible assets, property, plant and equipment and asset retirement obligations. SFAS No. 157 defines fair value, thereby eliminating inconsistencies in guidance found in various prior accounting pronouncements, and increases disclosures surrounding fair value calculations.

SFAS No. 157 establishes a three-tiered fair value hierarchy that prioritizes inputs to valuation techniques used in fair value calculations. The three levels of inputs are defined as follows:

- Level 1 – unadjusted quoted prices for identical assets or liabilities in active markets accessible by the Partnership;
- Level 2 – inputs that are observable in the marketplace other than those inputs classified as Level 1; and
- Level 3 – inputs that are unobservable in the marketplace and significant to the valuation.

SFAS No. 157 encourages entities to maximize the use of observable inputs and minimize the use of unobservable inputs. If a financial instrument uses inputs that fall in different levels of the hierarchy, the instrument will be categorized based upon the lowest level of input that is significant to the fair value calculation.

The Partnership’s financial assets and liabilities measured at fair value on a recurring basis are risk management assets and liabilities. Risk management assets and liabilities include interest rate swaps and commodity swaps. Risk management assets and liabilities are valued in the market using discounted cash flow techniques. These techniques incorporate Level 1 and Level 2 inputs such as future interest rates and commodity rates. These market inputs are utilized in the discounted cash flow calculation considering the instrument’s term, notional amount, discount rate and credit risk. Significant inputs to the discounted cash flow valuations are observable in the active markets and are classified as Level 2 in the hierarchy. The Partnership has no non-financial assets and liabilities as of March 31, 2008 classified as Level 3 in the hierarchy.

11. Subsequent Events

Partner Distributions. On April 25, 2008, the Partnership declared a distribution of $0.42 per common and subordinated unit including units equivalent to the General Partner’s two percent interest in the Partnership, and an aggregate distribution of $177,000 with respect to the General Partner’s incentive distribution rights, payable on May 14, 2008 to unitholders of record at the close of business on May 7, 2008.

Class E Common Units. The Class E common units converted into common units on a one-for-one basis on May 5, 2008.

Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations
The following discussion analyzes our financial condition and results of operations. You should read the following discussion of our financial condition and results of operations in conjunction with our unaudited condensed consolidated financial statements and notes included elsewhere in this document.

OVERVIEW. We are a growth-oriented publicly-traded Delaware limited partnership engaged in the gathering, processing, contract compression, marketing, and transportation of natural gas and NGLs. We provide these services through systems located in Louisiana, Texas, Arkansas, and the mid-continent region of the United States, which includes Kansas and Oklahoma.

RECENT DEVELOPMENTS.

We completed three acquisitions in the three months ended March 31, 2008.

FrontStreet Hugoton, LLC. On January 7, 2008, the Partnership, through RGS, acquired all of the outstanding equity (the “FrontStreet Acquisition”) of FrontStreet Hugoton, LLC from ASC and EnergyOne. FrontStreet owns a gas gathering system located in Kansas and Oklahoma, which is operated by a third party.

The total purchase price, subject to customary post-closing adjustments, paid by the Partnership for FrontStreet consisted of (1) the issuance of 4,701,034 Class E common units of the Partnership to ASC and (2) the cash payment of $11,752,000 to EnergyOne, inclusive of a payment to terminate a management services agreement in the amount of $3,888,000. RGS financed the cash portion of the purchase price out of its revolving credit facility. In connection with the FrontStreet Acquisition, the General Partner entered into Amendment No. 3 to the Amended and Restated Agreement of Limited Partnership of the Partnership, which created the Partnership’s Class E common units. The Class E common units have the same terms and conditions as the Partnership’s common units, except that the Class E common units were not entitled to participate in earnings or distributions of operating surplus by the Partnership. The Class E common units were issued in a private offering conducted in accordance with the exemption from the registration requirements of the Securities Act of 1933 afforded by Section 4(2) thereof. The Class E common units converted into common units on a one-for-one basis on May 5, 2008.

Because the FrontStreet Acquisition is a transaction between commonly controlled entities (i.e., the buyer and the sellers were each affiliates of GECC), the Partnership accounted for the acquisition in a manner similar to the pooling of interest method. Under this method of accounting, the Partnership will reflect historical balance sheet data for both the Partnership and FrontStreet instead of reflecting the fair market value of FrontStreet’s assets and liabilities. Further, certain transaction costs that would normally be capitalized were expensed. Common control between the Partnership and FrontStreet began on June 18, 2007. The three months ended March 31, 2008 statement of operations includes FrontStreet’s results for the entire quarter.

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CDM Resource Management, Ltd. On January 15, 2008, the Partnership and an indirect wholly owned subsidiary of the Partnership ("Merger Sub") consummated an agreement and plan of merger (the "Merger Agreement") with CDM Resource Management, Ltd., CDM GP, and CDM LP (each a "CDM Partner" and together the "CDM Partners"). Upon closing, CDM merged with and into Merger Sub, with Merger Sub continuing as the surviving entity after the merger (the "CDM Merger"). Following the merger, Merger Sub changed its name to CDM Resource Management LLC. CDM provides its customers with turn-key natural gas contract compression services to maximize their natural gas and crude oil production, throughput, and cash flow in Texas, Louisiana, and Arkansas. The Partnership operates and manages CDM as a separate reportable segment.

The total purchase price, subject to customary post-closing adjustments, paid by the Partnership for the partnership interests of CDM consisted of (1) the issuance of an aggregate of 7,276,506 Class D common units of the Partnership, which were valued at $219,590,000, (2) the payment of an aggregate of $161,945,000 in cash to the CDM Partners, and (3) the payment of $316,500,000 to retire CDM's debt obligations. Of the Class D common units issued, 4,197,303 Class D common units were deposited with an escrow agent pursuant to an escrow agreement. Such common units constitute security to the Partnership for a period of one year after the closing of the CDM Merger with respect to any obligations of the CDM Partners under the Merger Agreement, including obligations for breaches of representation, warranties and covenants. In connection with the CDM Merger, the General Partner entered into Amendment No. 4 to the Amended and Restated Agreement of Limited Partnership of the Partnership, which created the Partnership's Class D common units. The Class D common units have the same terms and conditions as the Partnership's common units, except that the Class D common units are not entitled to participate in distributions of operating surplus by the Partnership. The Class D common units automatically convert into common units on a one-for-one basis on the close of business on the first business day after the record date for the quarterly distribution on the common units for the quarter ending December 31, 2008. The Class D common units were issued in a private offering conducted in accordance with the exemption from the registration requirements of the Securities Act of 1933 afforded by Section 4(2) thereof.

Nexus Gas Holdings, LLC. On March 25, 2008, the Partnership acquired Nexus Gas Holdings, LLC, a Delaware limited liability company ("Nexus") ("Nexus Acquisition") by merger for $87,749,000 in cash, including customary closing adjustments. Nexus Gas Partners LLC, the sole member of Nexus prior to the merger ("Nexus Member"), deposited $8,500,000 in an escrow account as security to the Partnership for a period of one year against indemnification obligations and any purchase price adjustment. The Partnership funded the Nexus Acquisition through borrowings under our existing revolving credit facility.

Upon consummation of the Nexus Acquisition, the Partnership acquired Nexus' rights under a Purchase and Sale Agreement (the "Sonat Agreement") between Nexus and Southern Natural Gas Company ("Sonat"). Pursuant to the Sonat Agreement, Nexus will purchase 136 miles of pipeline from Sonat (the "Sonat Asset Acquisition") that would enable the Nexus gathering system to be integrated into the Partnership's north Louisiana asset base. The Sonat Asset Acquisition is subject to abandonment approval and jurisdictional redetermination by the FERC, as well as customary closing conditions. Upon closing of the Sonat Asset Acquisition, the Partnership will pay Sonat $27,500,000, and, if the closing occurs on or prior to March 1, 2010, on certain terms and conditions as provided in the Merger Agreement, the Partnership will make an additional payment of $25,000,000 to the Nexus Member.

RIGS FERC Petition. On April 29, 2008, we filed a petition with the FERC seeking approval to maintain RIGS' maximum Section 311 transportation rates. The rate filing was required by a FERC Letter Order issued on September 26, 2005, which approved a settlement in which RIGS agreed to justify its existing rates or establish new rates for Section 311 service by May 1, 2008. The triennial rate review requirement is a standard settlement provision in most intrastate pipeline rate proceedings.

In the petition, RIGS requests to maintain its current maximum rates for both firm and interruptible services as follows: firm service: reservation fee of $4.5625 per MMBtu monthly ($0.15 per MMBtu daily) and commodity fee of $0.05 per MMBtu; interruptible service: $0.20 per MMBtu. RIGS also requested a continuation of its existing fuel retention percentage of up to 2 percent. The proposed rates are subject to refund beginning May 1, 2008.

TCEQ Notice of Enforcement. On April 3, 2008, TCEQ presented RFS with a written offer to settle the allegations made in the Notice of Enforcement for an administrative penalty in the amount of $480,000. RFS will meet with TCEQ to present its view that the emissions were neither excessive nor improperly reported.

TRENDS IN INDUSTRY. Recently, a number of key producers have announced the discovery of a significant gas reserves, the Haynesville Shale, in north Louisiana that encompasses more than 3,000 square miles. We believe our Louisiana assets, including our recently acquired Nexus system, are well positioned to capitalize on this new development.

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OUR OPERATIONS. We manage our business and analyze and report our results of operations through three business segments.

- Gathering and Processing: We provide "wellhead-to-market" services to producers of natural gas, which include transporting raw natural gas from the wellhead through gathering systems, processing raw natural gas to separate NGLs from the raw natural gas and selling or delivering the pipeline-quality natural gas and NGLs to various markets and pipeline systems;
- Transportation: We deliver natural gas from northwest Louisiana to more favorable markets in northeast Louisiana through our 320-mile Regency Intrastate Pipeline system; and
- Contract Compression: We provide customers with turn-key natural gas compression services to maximize their natural gas and crude oil production, throughput, and cash flow. Our integrated solutions include a comprehensive assessment of a customer's natural gas contract compression needs and the design and installation of a compression system that addresses those particular needs. We are responsible for the installation and ongoing operation, service, and repair of our compression units, which we modify as necessary to adapt to our customers' changing operating conditions.

HOW WE EVALUATE OUR OPERATIONS. Our management uses a variety of financial and operational measurements to analyze our performance. We view these key performance indicators as important tools for evaluating the success of our operations and review these key performance indicators on a monthly basis for consistency and trend analysis. For our gathering and processing and transportation segments, the key performance indicators include volumes, segment margin, and operating and maintenance expenses. For our contract compression segment, the key performance indicators include revenue generating horsepower, average horsepower per revenue generating compression unit, segment margin, and operation and maintenance expenses. Management also reviews EBITDA for each reportable segment and in total to analyze our performance.

Volumes. We must continually obtain new supplies of natural gas to maintain or increase throughput volumes on our gathering and processing systems. Our ability to maintain existing supplies of natural gas and obtain new supplies is affected by (1) the level of workovers or recompletions of existing connected wells and successful drilling activity in areas currently dedicated to our pipelines, (2) our ability to compete for volumes from successful new wells in other areas and (3) our ability to obtain natural gas that has been released from other commitments. We routinely monitor producer activities in the areas served by our gathering and processing systems to pursue new supply opportunities.

To increase throughput volumes on our intrastate pipeline we must contract with shippers, including producers and marketers, for supplies of natural gas. We routinely monitor producer and marketing activities in the areas served by our transportation system in search of new supply opportunities.

Revenue Generating Horsepower. Revenue generating horsepower growth is the primary driver for revenue growth in the contract compression segment, and it is also the base measure for evaluating our operational efficiency. Revenue generating horsepower is our total available horsepower less horsepower under contract that is not yet generating revenue and idle horsepower.

Average Horsepower per Revenue Generating Compression Unit. We calculate average horsepower per revenue generating compression unit as our revenue generating horsepower divided by the number of revenue generating compression units.

Segment Margin. We calculate our gathering and processing segment margin as our revenue generated from our gathering and processing operations minus the cost of natural gas and NGLs purchased and other cost of sales, including third-party transportation and processing fees. Revenue includes revenue from the sale of natural gas and

NGLs resulting from these activities and fixed fees associated with the gathering and processing of natural gas.

We calculate our transportation segment margin as revenue generated by fee income as well as, in those instances in which we purchase and sell gas for our account, gas sales revenue minus the cost of natural gas that we purchase and transport. Revenue primarily includes fees for the transportation of pipeline-quality natural gas and the margin generated by sales of natural gas transported for our account. Most of our segment margin is fee-based with little or no commodity price risk. We generally purchase pipeline-quality natural gas at a pipeline inlet price adjusted to reflect our transportation fee and we sell that gas at the pipeline outlet. We regard the difference between the purchase price and the sale price as the economic equivalent of our transportation fee.

We calculate our contract compression segment margin as our revenues generated from our contract compression operations minus the direct costs, primarily compressor unit repairs, associated with those revenues.

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Total Segment Margin. Segment margin from gathering and processing, transportation and contract compression comprise total segment margin. We use total segment margin as a measure of performance. The reconciliation of the non-GAAP financial measure, total segment margin, to its most directly comparable GAAP measure, net income (loss) is included in Note 8, Segment Information, within the condensed consolidated financial statements included in Item 1 of this report.

Operation and Maintenance. Operation and maintenance expenses are a separate measure that we use to evaluate operating performance of field operations. Direct labor, insurance, property taxes, repair and maintenance, consumables, utilities and contract services comprise the most significant portion of our operating and maintenance expenses. These expenses fluctuate depending on the activities performed during a specific period. We do not deduct operation and maintenance from total revenues in calculating segment margin because we separately evaluate commodity volume, revenue generating horsepower and price changes in segment margin.

EBITDA. We define EBITDA as net income plus interest expense, provision for income taxes and depreciation and amortization expense. EBITDA is used as a supplemental measure by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others, to assess:

- financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make cash distributions to our unitholders and general partners;
- our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

EBITDA should not be considered as an alternative to net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP. EBITDA is the starting point in determining cash available for distribution, which is an important non-GAAP financial measure for a publicly traded partnership. The following table reconciles the non-GAAP financial measure, EBITDA, to its most directly comparable GAAP measures, net income (loss) and net cash flows provided by operating activities.

	Three Months Ended	
	March 31, 2008	March 31, 2007
	(in thousands)	
Net cash flows provided by operating activities	$ 57,538	$ 27,470
Add (deduct):		
Depreciation and amortization, including debt issuance cost amortization	(22,398)	(11,986)
Equity income	-	43
Risk management portfolio value changes	(3,098)	124
Loss on asset sales	-	(1,808)
Unit based compensation expenses	(794)	(1,103)
Changes in current assets and liabilities:		
Accounts receivable and accrued revenues	19,264	1,959
Other current assets	(2,800)	(598)
Accounts payable, accrued cost of gas and liquids and accrued liabilities	(25,950)	(5,220)
Other current liabilities	(18,249)	(10,617)
Other assets and liabilities	6,835	441

Net income (loss)	$	10,348	$	(1,295)
Add:				
Interest expense, net		15,406		14,885
Depreciation and amortization		21,741		11,427
Income tax expense		251		-
EBITDA	$	47,746	$	25,017

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CASH DISTRIBUTIONS. On April 25, 2008, the Partnership declared a distribution of $0.42 per common and subordinated unit including units equivalent to the General Partner's two percent interest in the Partnership, and an aggregate distribution of $177,000 with respect to the General Partner's incentive distribution rights, payable on May 14, 2008 to unitholders of record at the close of business on May 7, 2008.

RESULTS OF OPERATIONS
Three Months Ended March 31, 2008 vs. Three Months Ended March 31, 2007
The following table contains key company-wide performance indicators related to our discussion of the results of operations.

	Three Months Ended			
	March 31, 2008	March 31, 2007	Change	Percent
	(in thousands except percentages and volume data)			
Revenues	$ 405,235	$ 256,428	$ 148,807	58%
Cost of sales	313,589	211,937	101,652	48
Total segment margin (1)	91,646	44,491	47,155	106
Operation and maintenance	28,845	10,925	17,920	164
General and administrative	10,923	6,851	4,072	59
Loss on asset sales, net	-	1,808	(1,808)	(100)
Management services termination fee	3,888	-	3,888	N/M
Transaction expenses	348	-	348	N/M
Depreciation and amortization	21,741	11,427	10,314	90
Operating income	25,901	13,480	12,421	92
Interest expense, net	(15,406)	(14,885)	(521)	4
Other income and deductions, net	176	110	66	60
Minority interest	(72)	-	(72)	N/M
Income tax expense	(251)	-	(251)	N/M
Net income (loss)	$ 10,348	$ (1,295)	$ 11,643	899%
System inlet volumes (MMbtu/d) (2)	1,378,932	1,133,844	245,088	22
Revenue generating horsepower (3)	615,852	-	615,852	N/M

(1) For reconciliation of total segment margin to its most directly comparable financial measure calculated and presented in accordance with GAAP, please read "– Item 1. Financial Statements - Note 8, Segment Information."
(2) System inlet volumes include total volumes taken into both our gathering and processing system and our transportation systems.
(3) Revenue generating horsepower is the primary volumetric measure for our contract compression segment.
N/M – Not Meaningful

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The table below contains key segment performance indicators related to our discussion of the results of operations.

	Three Months Ended March 31, 2008	March 31, 2007	Change	Percent
	(in thousands except percentages and volume data)			
Segment Financial and Operating Data:				
Gathering and Processing Segment				
Financial data:				
Segment margin (1)	$ 54,007	$ 30,178	$ 23,829	79%
Operation and maintenance	18,627	9,115	9,512	104
Operating data:				
Throughput (MMbtu/d) (2)	918,950	729,218	189,732	26
NGL gross production (Bbls/d)	23,068	20,047	3,021	15
Transportation Segment				
Financial data:				
Segment margin (1)	$ 14,693	$ 14,313	$ 380	3
Operation and maintenance	1,396	1,810	(414)	(23)
Operating data:				
Throughput (MMbtu/d) (2)	732,006	704,458	27,548	4
Contract Compression Segment				
Financial data:				
Segment margin (1)	$ 23,021	$ -	$ 23,021	N/M
Operation and maintenance	8,844	-	8,844	N/M
Operating data:				
Revenue generating horsepower	615,852	-	615,852	N/M
Average horsepower per revenue generating compression unit	849	-	849	N/M

(1) Combined segment margin varies from consolidated total segment margin due to inter-segment eliminations between the contract compression, transportation and gathering and processing segments.
(2) Combined throughput volumes for the gathering and processing segment and the transportation segment vary from consolidated system inlet volumes due to inter-segment eliminations between the two segments.
N/M – Not Meaningful

Net income. Net income for the three months ended March 31, 2008 increased $11,643,000 compared to the three months ended March 31, 2007. An increase in total segment margin of $47,155,000 primarily attributable to our acquisitions of CDM and FrontStreet as well as organic growth in the gathering and processing segment and the absence in March 2008 of a $1,808,000 loss in March 2007 on the sale of non-core assets, was offset in part by:

- increased operation and maintenance expense of $17,920,000 primarily due to our CDM and FrontStreet acquisitions, employee related expenses and contractor expenses primarily in the gathering and processing segment;
- increased depreciation and amortization expense of $10,314,000 primarily due to our CDM, FrontStreet and Pueblo acquisitions and organic growth projects completed since March 31, 2007;
- increased general and administrative expense of $4,072,000 primarily due to our CDM acquisition and increased employee-related expenses; and
- payment, in the three months ended March 31, 2008, of a management services termination fee of $3,888,000 related to the acquisition of FrontStreet.

Segment Margin. Segment margin for the three months ended March 31, 2008 increased $47,155,000 compared with the three months ended March 31, 2007, consisting of an increase of $23,829,000 in gathering and processing segment, an increase of $380,000 in transportation segment and $23,021,000 in the contract compression segment recorded in the three months ended March 31, 2008, discussed below.

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Gathering and processing segment margin increased to $54,007,000 in the three months ended March 31, 2008 from $30,178,000, an increase of $23,829,000, or 79 percent. The major components of this increase were as follows:

- $12,187,000 attributed to our FrontStreet assets;
- $9,749,000 attributed to organic growth projects, primarily in Texas;
- $3,524,000 attributed to higher throughput volumes, primarily in north Louisiana;
- $1,450,000 attributed to better pricing on commodity derivative contract settlements; and partially offset by a
- $3,082,000 decrease in non-cash valuation changes in certain commodity derivative contracts.

Transportation segment margin increased to $14,693,000 for the three months ended March 31, 2008 from $14,313,000 for the three months ended March 31, 2007, an increase of $380,000, or three percent. The major components of this increase were as follows:

- $276,000 increase due to our merchant function; and
- $104,000 increase from additional throughput volumes partially offset by slightly lower margins per unit of throughput.

Contract compression segment margin was $23,021,000 in the three months ended March 31, 2008, which consisted of $25,267,000, exclusive of $118,000 of intersegment revenue, of operating revenue and $2,364,000 of direct operating costs. The following table sets forth certain information regarding revenue generating horsepower as of March 31, 2008.

Horsepower Range	Total Revenue Generating Horsepower	Percentage of Revenue Generating Horsepower	Number of Units
0-499	47,673	8%	285
500-999	65,699	11%	106
1,000+	502,480	81%	334
	615,852	100%	725

Operation and Maintenance. Operation and maintenance expense increased to $28,845,000 in the three months ended March 31, 2008 from $10,925,000 for the corresponding period in 2007, a 164 percent increase. This increase is attributable to the following factors:

- $8,844,000 related to contract compression assets acquired on January 15, 2008;
- $6,846,000 related to our FrontStreet assets;
- $977,000 increase primarily in the gathering and processing segment for the hiring of additional employees;
- $868,000 increase in contractor expense primarily in the gathering and processing segment related to assets acquired, which are operated by a third party, subsequent to March 31, 2007;
- $848,000 in various operation and maintenance expenses primarily in the gathering and processing segment associated with organic growth; and partially offset by a
- $463,000 charge to unplanned outage expense in the three months ended March 31, 2007 in the transportation segment related to the Eastside compressor fire, which represents an estimated 30-day deductible under our insurance coverage.

General and Administrative. General and administrative expense increased to $10,923,000 in the three months ended March 31, 2008 from $6,851,000 for the same period in 2007, a 59 percent increase. The increase is primarily attributable the following factors:

- $3,440,000 related to contract compression assets acquired on January 15, 2008; and
- $919,000 increase for hiring additional employees.

Other. In the three months ended March 31, 2008, we recorded a charge of $3,888,000 for the termination of long-term management services contract and transaction expenses of $348,000 in connection with our FrontStreet Acquisition. In the three months ended March 31, 2007, we sold certain non-core assets and recorded a net charge of $1,808,000.

Depreciation and Amortization. Depreciation and amortization expense increased to $21,741,000 in the three months ended March 31, 2008 from $11,427,000 for the three months ended March 31, 2007, a 90 percent increase. This increase consists of the following:

- $5,353,000 related to contract compression assets acquired on January 15, 2008;
- $2,576,000 related primarily to organic growth projects completed since March 31, 2007; and
- $2,385,000 attributed to our FrontStreet assets.

Interest Expense, Net. Interest expense, net increased $521,000, or four percent, in the three months ended March 31, 2008 compared to the same period in 2007. Of this increase, $3,895,000 was attributable to increased levels of borrowings, offset by a decrease of $3,374,000 attributable to lower interest rates.

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CRITICAL ACCOUNTING POLICIES AND ESTIMATES. In addition to the information set forth in this report, further information regarding the Partnership's critical accounting policies and estimates is included in Item 7 of the Partnership's Annual Report on Form 10-K for the year ended December 31, 2007.

As-if Pooling of Interests Method of Accounting. We account for acquisitions where common control exists by following the as-if pooling method of accounting as described in SFAS No. 141, "Business Combinations". Under this method of accounting, we reflect the historical balance sheet data for both the acquirer and acquiree instead of reflecting the fair market value of acquiree's assets and liabilities. In common control acquisitions where a minority interest is also acquired, we use the purchase method of accounting for the minority interest. Further, certain transaction costs that would normally be capitalized are expensed.

Fair Value Measurements. On January 1, 2008, we adopted the provisions of SFAS No. 157, "Fair Value Measurements" ("SFAS No. 157"), for financial assets and liabilities. SFAS No. 157 defines fair value, thereby eliminating inconsistencies in guidance found in various prior accounting pronouncements, and increases disclosures surrounding fair value calculations. The adoption of SFAS No. 157 for financial assets and liabilities did not have a material impact on our statement of operations, financial position or cash flows for the three months ended March 31, 2008.

SFAS No. 157 establishes a three-tiered fair value hierarchy that prioritizes inputs to valuation techniques used in fair value calculations. The three levels of inputs are defined as follows:

- Level 1 — unadjusted quoted prices for identical assets or liabilities in active markets accessible by us;
- Level 2 — inputs that are observable in the marketplace other than those inputs classified as Level 1; and
- Level 3 — inputs that are unobservable in the marketplace and significant to the valuation.

SFAS No. 157 requires us to maximize the use of observable inputs and minimize the use of unobservable inputs. If a financial instrument valuation uses inputs that fall in different levels of the hierarchy, the instrument will be categorized based upon the lowest level of input that is significant to the fair value calculation. Our financial assets and liabilities measured at fair value on a recurring basis are derivative financial instruments consisting of interest rate swaps and commodity swaps.

OTHER MATTERS. Information regarding the Partnership's commitments and contingencies are included in Note 6-Commitments and Contingencies to the condensed consolidated financial statements included in Item 1 of this report.

LIQUIDITY AND CAPITAL RESOURCES
We expect our sources of liquidity to include:

- cash generated from operations;
- borrowings under our credit facility;
- debt offerings; and
- issuance of additional partnership units.

We believe that the cash generated from these sources, including $139,737,000 available under our revolving credit facility, will be sufficient to meet our minimum quarterly cash distributions and our requirements for short-term working capital and growth capital expenditures for the next twelve months.

Working Capital Surplus (Deficit). Working capital is the amount by which current assets exceed current liabilities and is a measure of our ability to pay our liabilities as they become due. During periods of growth capital expenditures, we experience working capital deficits when we fund construction expenditures out of working capital until they are permanently financed. Our working capital is also influenced by current risk management assets and liabilities due to fair market value changes in our derivative positions being reflected on our balance sheet. These represent our expectations for the settlement of risk management rights and obligations over the next twelve months, and so must be viewed differently from trade accounts receivable and accounts payable which settle over a much shorter span of time. When our derivative positions are settled, we expect an offsetting physical transaction, and, as a result, we do not expect risk management assets and liabilities to affect our ability to pay bills as they come due.

Our working capital deficit increased by $20,420,000 from December 31, 2007 to March 31, 2008 primarily resulting from the following:

§ a $22,095,000 decrease in cash and cash equivalents primarily due to the timing of payment of accounts payable;

§ a $17,463,000 decrease from an increase in other current liabilities, excluding taxes payable, primarily due to the inclusion of deferred revenues from our contract compression segment, increased interest payable on our senior notes based on the timing of interest payments and increased interest payable on our revolving credit facility based on increased levels of borrowings related to our acquisitions and organic growth in the three months ended March 31, 2008;

§ a $15,421,000 increase resulting from an increase in net accounts receivable and payable due to the timing of cash receipts and payments; and

§ a $2,755,000 increase resulting from a decrease in net risk management liabilities primarily due to a decrease in commodity prices we expect to pay (index prices) on our outstanding swaps as compared to the commodity prices we expect to receive upon settlement.

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Cash Flows from Operations. Net cash flows provided by operating activities increased $30,068,000 for the three months ended March 31, 2008 as compared to the three months ended March 31, 2007. Our cash flows from operations increased primarily due to increased segment margin from our FrontStreet and CDM acquisitions in January 2008, our Pueblo acquisition in April 2007 and organic growth in our gathering and processing segment.

Cash Flows from Investing Activities. Net cash flows used in investing activities increased $625,064,000 in the three months ended March 31, 2008 compared to the three months ended March 31, 2007. The major portion of this increase is attributable to our FrontStreet, CDM and Nexus acquisitions and higher growth and maintenance capital expenditures discussed in "Capital Requirements."

Cash Flows from Financing Activities. Net cash flows provided by financing activities increased $573,536,000 in the three months ended March 31, 2008 compared to the three months ended March 31, 2007 primarily due to increased levels of borrowings on our revolving credit facility utilized to fund our FrontStreet, CDM and Nexus acquisitions.

Capital Requirements

We categorize our capital expenditures as either:

- Growth capital expenditures, which are made to acquire additional assets to increase our business, to expand and upgrade existing systems and facilities or to construct or acquire similar systems or facilities; or
- Maintenance capital expenditures, which are made to replace partially or fully depreciated assets, to maintain the existing operating capacity of our assets and to extend their useful lives or to maintain existing system volumes and related cash flows.

Growth Capital Expenditures. In the three months ended March 31, 2008, we incurred $61,427,000 of growth capital expenditures. Growth capital expenditures primarily relate to projects listed below.

- $25,300,000 for the fabrication of new compression packages for our contract compression segment;
- $12,600,000 for constructing 20 miles of 10 inch diameter pipeline, which will connect the Fashing Processing Plant to our Tilden Processing Plant in south Texas and reconfiguring our Tilden Processing Plant, which we anticipate will be completed in the first half of 2008;
- $4,600,000 for installation of gathering and compression facilities in south Texas; and
- $3,800,000 for construction of pipeline, compression, and treating facilities related to a joint venture in south Texas.

Our 2008 growth budget includes $208,000,000 of currently identified organic growth capital expenditures, including $117,000,000 for an additional 174,700 horsepower of compression for our contract compression segment. The most significant projects in our gathering and processing segment are the following:

- $12,000,000 for our portion of the construction of pipeline, compression, and treating facilities related to a joint venture in south Texas;
- $19,000,000 for constructing 40 miles, 10 inch diameter pipeline, which we anticipate will be completed in 2008;
- $17,100,000 for constructing 20 miles of 10 inch diameter pipeline, which will connect the Fashing Processing Plant to our Tilden Processing Plant in south Texas, and reconfiguring our Tilden Processing Plant, which we anticipate will be completed in the first half of 2008;
- $6,800,000 for installation of gathering and compression facilities in south Texas;
- $5,800,000 for additional processing, compression, and gathering facilities in north Louisiana.

Maintenance Capital Expenditures. In the three months ended March 31, 2008, we incurred $3,326,000 of maintenance capital expenditures. Maintenance capital expenditures primarily consist of compressor and equipment overhauls, as well as new well connects to our gathering systems, which help replace volumes from naturally occurring depletion of wells already connected.

Contractual Obligations. At March 31, 2008 our long-term debt increased to $1,090,500,000 from $481,500,000 at December 31, 2007 primarily due to three acquisitions completed in the three months ended March 31, 2008. Our long-term debt obligation, including interest at a one-month LIBOR of 2.70 percent as of March 31, 2008 plus our applicable margin, was $1,375,815,000 in the aggregate and by period as follows:

- § 2008: $53,423,000;
- § 2009 – 2010: $122,501,000;
- § 2011 – 2012: $812,450,000; and
- § Thereafter: $387,441,000

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk. We are a net seller of NGLs, and as such our financial results are exposed to fluctuations in NGLs pricing. We have executed swap contracts settled against crude oil, ethane, propane, normal butane, iso butane and natural gasoline market prices. We have hedged our expected exposure to declines in prices for NGLs and condensate volumes produced for our account in the approximate percentages set forth below:

	2008	2009
NGL	88%	78%
Condensate	69	69

We continually monitor our hedging and contract portfolio and expect to continue to adjust our hedge position as conditions warrant.

On February 29, 2008, the Partnership entered into two year interest rate swaps related to $300,000,000 of borrowings under our revolving credit facility, effectively locking the rate for these borrowings at 2.4 percent, plus the applicable margin (1.5 percent as of March 31, 2008).

On March 7, 2008, we entered offsetting trades against our existing 2009 portfolio of hedges, which we believe will substantially reduce the volatility of our net income. This group of trades, along with the pre-existing 2009 portfolio, will continue to be accounted for on a mark-to-market basis. Simultaneously, we executed additional 2009 NGL swaps which were designated under SFAS No. 133 as cash flow hedges.

The following table sets forth certain information regarding our NGL and interest rate swaps outstanding at March 31, 2008. The relevant payment index price is the monthly average of the daily closing price for deliveries of commodities into Mont Belvieu, Texas as reported by the Oil Price Information Service (OPIS).

Period	Underlying	Notional Volume/Amount	We Pay	We Receive	Fair Value Asset/(Liability) (in thousands)
April 2008-December 2009	Ethane	1,261 (MBbls)	Index	$0.58-$0.80 ($/gallon)	$ (7,223)
April 2008-December 2009	Propane	791 (MBbls)	Index	$0.93-$1.37 ($/gallon)	(12,423)
January 2009-December 2009	Iso Butane	422 (MBbls)	Index	$1.69 ($/gallon)	(9,519)
April 2008-December 2009	Normal Butane	95 (MBbls)	Index	$1.12-$1.68 ($/gallon)	(63)
April 2008-December 2009	Natural Gasoline	328 (MBbls)	Index	$1.41-$2.09 ($/gallon)	(6,653)
April 2008- December 2009	West Texas Intermediate Crude	416 (MBbls)	Index	$68.17-$68.38 ($/Bbls)	(11,924)
April 2008-March 2010	Interest Rate	$300,000,000	Fixed	LIBOR	(618)
				Total Fair Value	$ (48,423)

Item 4. Controls and Procedures
Disclosure controls. At the end of the period covered by this report, an evaluation was performed under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of our managing general partner, of the effectiveness of the design and operation of our disclosure controls and procedures (as such terms are defined in Rule 13a–15(e) and 15d–15(e) of the Exchange Act). Based on that evaluation, management, including the Chief Executive Officer and Chief Financial Officer of our managing general partner, concluded that our disclosure controls and procedures were effective as of March 31, 2008 to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is properly recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms.

Internal control over financial reporting. Other than described below, there have been no changes in the Partnership's internal controls over financial reporting that have materially affected, or are reasonably likely to affect, the Partnership's internal controls over financial reporting.

Subsequent to our CDM acquisition, we initiated a program of documentation, implementation and testing of internal controls over financial reporting for CDM. This program will continue through December 31, 2009, culminating with the inclusion of CDM in our Section 404 certification and attestation in early 2010.

PART II – OTHER INFORMATION
Item 1. Legal Proceedings
The information required for this item is provided in Note 6, Commitments and Contingencies, included in the notes to the unaudited condensed consolidated financial statements included under Part I, Item 1, which information is incorporated by reference into this item.

Item 1A. Risk Factors
In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2007, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing our Partnership.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds
The information required for this item is provided in Note 1, Organization and Summary of Significant Accounting Policies, and Note 3, Acquisitions, included in the notes to the unaudited condensed consolidated financial statements included under Part I, Item 1, which information is incorporated by reference into this item.

Item 6. Exhibits
The exhibits below are filed as a part of this report:
Exhibit 10.1. Employment Agreement with Byron R. Kelley
Exhibit 10.2. Severance Agreement with Dan A. Fleckman
Exhibit 10.3. Consulting Services Agreement with James W. Hunt
Exhibit 12.1. Computation of Ratio of Earnings to Fixed Charges
Exhibit 31.1. Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer
Exhibit 31.2. Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer
Exhibit 32.1. Section 1350 Certifications of Chief Executive Officer
Exhibit 32.2. Section 1350 Certifications of Chief Financial Officer

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SIGNATURE

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

REGENCY ENERGY PARTNERS LP

By: Regency GP LP, its general partner

By: Regency GP LLC, its general partner

May 9, 2008

/s/ Lawrence B. Connors

Lawrence B. Connors
Senior Vice President of Accounting and
Finance (Duly Authorized Officer and
Chief Accounting Officer)