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

FORM 8-K

CURRENT REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

Date of Report (Date of earliest event reported)
November 30, 2009

TARGA RESOURCES PARTNERS LP

(Exact name of registrant as specified in its charter)

Delaware	**001-33303**	**65-1295427**
(State or other jurisdiction of incorporation or organization)	(Commission File Number)	(IRS Employer Identification No.)

1000 Louisiana, Suite 4300
Houston, TX 77002
(Address of principal executive office and Zip Code)

(713) 584-1000
(Registrants' telephone number, including area code)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01 Other Information.

On September 24, 2009, Targa Resources Partners LP (the "Partnership") closed on its previously announced acquisition of (i) 100% of the limited liability company interests in Targa Downstream GP LLC ("Targa Downstream GP"), a Delaware limited liability company, (ii) 100% of the limited liability company interests in Targa LSNG GP LLC ("Targa LSNG GP"), a Delaware limited liability company, (iii) 100% of the limited partner interests in Targa Downstream LP ("Targa Downstream LP"), a Delaware limited partnership, and (iv) 100% of the limited partner interests in Targa LSNG LP ("Targa LSNG LP"), a Delaware limited partnership (such limited liability company interests in Targa Downstream GP and Targa LSNG GP and limited partner interests in Targa Downstream LP and Targa LSNG LP being collectively referred to as the "Purchased Interests"), for aggregate consideration of $530 million, subject to certain adjustments.

Targa Downstream LP and Targa LSNG LP, collectively, owned at closing Targa Resources, Inc.'s ("Targa") natural gas liquids business (the "Downstream Business") consisting of (i) the Logistics Assets Segment, which consists of fractionation facilities, storage and terminalling facilities, low sulfur natural gasoline treating facilities, pipeline transportation and distribution assets, propane storage, truck terminals and NGL transport assets, as well as Targa's approximately 39% equity method investment in Gulf Coast Fractionators (the "Logistics Assets Segment"), (ii) the NGL Distribution and Marketing Segment, which markets NGL production and purchases mixed or component NGL products from third parties for resale (the "NGL Distribution and Marketing Segment") and (iii) the Wholesale Marketing Segment, which provides services for refineries, including NGL balancing, purchasing or marketing propane and providing butane supply, and sells propane to retailers and end users (the "Wholesale Marketing Segment").

The Partnership and the Downstream Business are considered entities under common control. As a result, the Partnership is providing supplemental consolidated financial statements to include the financial results of the Downstream Business for all periods presented. We are providing the following to reflect the supplemental results: Selected Financial Data, Management's Discussion and Analysis of Supplemental Financial Condition and Results of Operations, and Supplemental Consolidated Financial Statements of Targa Resources Partners LP for the periods indicated.

Item 9.01 Financial Statements and Exhibits.

(a) Not applicable

(b) Not applicable

(c) Not applicable

(d) Exhibits

Exhibit Number	Description
23.1	Consent of PricewaterhouseCoopers on Supplemental Consolidated Financial Statements of Targa Resources Partners LP
99.1	Selected Financial Data
99.2	Management's Discussion and Analysis of Supplemental Financial Condition and Results of Operations
99.3	Supplemental Consolidated Financial Statements of Targa Resources Partners LP

99.3

SIGNATURES

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

TARGA RESOURCES PARTNERS LP

By: Targa Resources GP LLC,
its general partner

Dated: November 30, 2009

By: /s/ John Robert Sparger
John Robert Sparger
Senior Vice President and Chief Accounting Officer

EXHIBIT INDEX

Exhibit Number	Description
23.1	Consent of PricewaterhouseCoopers on Supplemental Consolidated Financial Statements of Targa Resources Partners LP
99.1	Selected Financial Data
99.2	Management’s Discussion and Analysis of Supplemental Financial Condition and Results of Operations
99.3	Supplemental Consolidated Financial Statements of Targa Resources Partners LP

99.3

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form Form S-8 (No. 333-149200) and Form S-3 (No. 333-159678) of Targa Resources Partners LP of our report dated February 25, 2009, except with respect to our opinions on the consolidated financial statements and internal control over financial reporting insofar as they relate to the effects of the acquisition of the Downstream Business discussed in Note 2, as to which the date is November 30, 2009, relating to the financial statements of Targa Resources Partners LP, and the effectiveness of internal control over financial reporting, which appears in this Current Report on Form 8-K.

/s/PricewaterhouseCoopers LLP
Houston, Texas
November 30, 2009

SELECTED FINANCIAL DATA

The following table presents selected historical consolidated financial and operating data of Targa Resources Partners LP. See “Basis of Financial Statement Presentation” included under Note 2 to our “Supplemental Consolidated Financial Statements” contained in this Form 8-K for information regarding the retrospective adjustment of our financial information for the years 2005 through 2008 as entities under common control in connection with our acquisition of the Downstream Assets of Targa Resources, Inc. (the “Downstream Business”). The information contained herein should be read in conjunction with our “Management’s Discussion and Analysis of Supplemental Financial Condition and Results of Operations” and “Supplemental Consolidated Financial Statements” contained in this Form 8-K.

	Targa Resources Partners LP (1)					Predecessor
	Year Ended December 31,				March 12 (Inception) through December 31, 2004 (2)	106-Day Period Ended April 15, 2004
	2008	2007	2006	2005		
	(In millions, except per unit data)					
Statement of operations data:						
Revenues (3)	$ 7,473.4	$ 6,816.1	$ 5,907.5	$ 1,767.6	$ 602.6	$ 232.8
Costs and expenses:						
Product purchases	6,922.1	6,274.4	5,478.9	1,620.3	544.9	212.3
Operating expenses	254.0	219.6	193.1	44.3	15.3	7.9
Depreciation and amortization expense	97.8	93.5	90.7	26.3	10.4	3.8
General and administrative expense	68.6	64.0	57.3	23.0	11.1	0.8
Other	(0.9)	(0.3)	-	-	-	1.4
	7,341.6	6,651.2	5,820.0	1,713.9	581.7	226.2
Income from operations	131.8	164.9	87.5	53.7	20.9	6.6
Other income (expense):						
Interest expense, net	(97.1)	(99.4)	(127.1)	(27.9)	(6.1)	-
Equity in earnings of unconsolidated investment	3.9	3.5	2.8	0.4	-	-
Gain (loss) on early extinguishment of debt	13.1	-	-	(3.7)	-	-
Gain (loss) on mark-to-market derivative instruments	(1.0)	(30.2)	16.8	(12.0)	1.3	-
Other	1.4	(1.1)	(0.2)	(0.1)	-	-
Income (loss) before income taxes	52.1	37.7	(20.2)	10.4	16.1	6.6
Income tax expense	(2.4)	(2.5)	(3.4)	-	-	(2.6)
Net income (loss)	49.7	35.2	(23.6)	10.4	16.1	$ 4.0
Less: Net income (loss) attributable to noncontrolling interest	0.3	0.1	(0.6)	0.2	-	
Net income (loss) attributable to Targa Resources Partners LP	$ 49.4	$ 35.1	$ (23.0)	$ 10.2	$ 16.1	
Net income (loss) attributable to predecessor operations	$ (42.1)	$ 7.0				
Net income attributable to general partner	7.0	0.6				
Net income attributable to limited partners	84.5	27.5				
Net income per limited partner unit--basic and diluted	$ 1.83	$ 0.81				
Weighted average limited partner units						
outstanding--basic and diluted	46.2	34.0				
Operating data:						
Operating margin	297.3	322.1	235.5	103.0	42.4	12.6
Adjusted EBITDA	269.4	260.5	179.2	76.2	31.3	11.8
Distributable cash flow	120.7	132.2	36.3	45.8	N/A	N/A
Operating data:						
Gathering throughput, MMcf/d (4)	445.8	452.0	433.8	302.4	285.6	316.5
Plant natural gas inlet, MMcf/d (5) (6)	421.2	429.2	419.6	253.6	262.6	313.5
Gross NGL production, MBbl/d	42.0	42.6	42.4	23.5	22.8	24.8
Natural gas sales, Bbtu/d (6)	415.6	410.2	489.4	259.3	252.7	297.4
NGL sales, MBbl/d	278.1	310.1	290.1	57.6	22.8	24.8
Condensate sales, MBbl/d	3.6	3.6	3.3	1.3		
Average realized prices: (7)						
Natural gas, $/MMBtu	8.45	6.60	6.62	9.36	6.45	5.42
NGL, $/gal	1.39	1.19	1.02	0.95	0.70	0.55
Condensate, $/Bbl	82.52	65.63	59.87	58.96		

	Targa Resources Partners LP (1)					Predecessor
	Year Ended December 31,				March 12 (Inception) through December 31,	106-Day Period Ended April 15,
	2008	2007	2006	2005	2004 (2)	2004
	(In millions, except per unit data)					
Balance sheet data (at year end):						
Property, plant and equipment, net	$ 1,719.1	$ 1,716.4	$ 1,732.6	$ 1,843.4	$ 237.6	$ 266.0
Total assets	2,314.8	2,702.9	2,401.0	2,524.4	323.4	288.8
Long-term allocated debt, less current maturities	773.9	711.3	1,029.0	1,532.0	103.0	-
Long-term debt, less current maturities	696.8	626.3	-	-	-	-
Total equity	553.1	614.4	433.6	581.1	139.2	170.9
Cash flow data:						
Net cash provided by (used in):						
Operating activities	$ 293.0	$ 268.3	$ 169.9	21.7	28.2	$ 11.5
Investing activities	(86.1)	(76.8)	(54.6)	(8.0)	(2.9)	(1.2)
Financing activities	(175.9)	(139.7)	(110.7)	(12.0)	(25.4)	(10.3)
Cash dividends declared per unit	$ 1.97	$ 1.24	N/A	N/A	N/A	N/A

____

(1) The supplemental consolidated selected financial data includes our accounts and: (i) prior to September 24, 2009 the assets, liabilities and operations of the Downstream Business; (ii) prior to October 24, 2007 the assets, liabilities and operations of the SAOU and LOU Systems as the predecessor entities; and (iii) prior to October 24, 2007 the assets, liabilities and operations of the North Texas System. The supplemental consolidated selected financial data has been retrospectively adjusted to assume that the acquisition of the Downstream Business from Targa by us had occurred at the date when both the Downstream Business and the North Texas System met the accounting requirements for entities under common control (October 31, 2005) following the acquisition of the SAOU and LOU Systems.

(2) Targa commenced operations on April 16, 2004 with the closing of the acquisition of certain assets in Texas and Louisiana from ConocoPhillips. Prior to April 16, 2004, certain investors in Targa had previous investments in Pipeco, f.k.a. Targa Resources, Inc., f.k.a. Warburg Pincus VII Development Company, Inc. Pipeco was the entity that performed due diligence and other acquisition-specific activities associated with the asset acquisitions from ConocoPhillips.

(3) Includes business interruption insurance revenues of $18.6 million, $4.6 million and $7.0 million for the years ended 2008, 2007 and 2006.

(4) Gathering throughput represents the volume of natural gas gathered and passed through natural gas gathering pipelines from connections to producing wells and central delivery points.

(5) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.

(6) Plant inlet volumes include producer take-in-kind, while natural gas sales exclude producer take-in-kind volumes.

(7) Average realized prices include the impact of hedging activities.

Non-GAAP Financial Measures

Adjusted EBITDA. We define Adjusted EBITDA as net income before interest, income taxes, depreciation and amortization and non-cash income or loss related to derivative instruments. Adjusted EBITDA is used as a supplemental financial measure by our management and by external users of our financial statements such as investors, commercial banks and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- our operating performance and return on capital as compared to 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.

The economic substance behind management's use of Adjusted EBITDA is to measure the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make distributions to our investors.

The generally accepted accounting principles ("GAAP") measures most directly comparable to Adjusted EBITDA are net cash provided by operating activities and net income. Our non-GAAP financial measure of Adjusted EBITDA should not be considered as an alternative to GAAP net cash provided by operating activities and GAAP net income. Adjusted EBITDA is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. You should not consider Adjusted EBITDA in isolation or as a substitute for analysis of our results as reported under GAAP. Because Adjusted EBITDA excludes some, but not all, items that affect net income and net cash provided by operating activities and is defined differently by different companies in our industry, our definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies. Management compensates for the limitations of Adjusted EBITDA as an analytical tool by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these insights into management's decision-making processes.

	Targa Resources Partners LP (1)					Predecessor
	Year Ended December 31,				March 12 (Inception) through December 31,	106-Day Period Ended April 15,
	2008	2007	2006	2005	2004 (2)	2004
	(In millions)					
Reconciliation of net cash provided by operating activities to Adjusted EBITDA:						
Net cash provided by operating activities	$ 293.0	$ 268.3	$ 169.9	$ 22.2	$ 28.2	$ 11.5
Net income attributable to noncontrolling interest	(0.3)	(0.1)	0.6	(0.2)	-	-
Interest expense, net (3)	35.8	39.1	118.0	22.7	5.2	-
Gain on debt repurchases	13.1	-	-	(3.7)	-	-
Termination of commodity derivatives	87.4	-	-	-	-	-
Current income tax expense	0.6	0.6	-	-	-	-
Other	3.7	(1.5)	(0.6)	(4.8)	0.8	2.6
Changes in operating assets and liabilities which used (provided) cash:						
Accounts receivable and other assets	(658.2)	145.7	(71.1)	19.4	76.7	(23.7)
Accounts payable and other liabilities	494.3	(191.6)	(37.6)	(20.6)	(79.6)	21.4
Adjusted EBITDA	$ 269.4	$ 260.5	$ 179.2	$ 76.2	$ 31.3	$ 11.8
Reconciliation of net income (loss) attributable to Targa Resources Partners LP to Adjusted EBITDA:						
Net income (loss) attributable to Targa Resources Partners LP	$ 49.4	$ 35.1	$ (23.0)	$ 10.2	$ 16.1	$ 4.0
Add:						
Interest expense, net	97.1	99.4	127.1	27.9	6.1	-
Income tax expense	2.4	2.5	3.4	-	-	2.6
Taxes other than income taxes	-	-	-	-	-	1.4
Depreciation and amortization expense	97.8	93.5	90.7	26.3	10.4	3.8
Non-cash (gain) loss related to derivatives	23.4	30.8	(18.3)	12.0	(1.3)	-
Noncontrolling interest adjustment	(0.7)	(0.8)	(0.7)	(0.2)	-	-
Adjusted EBITDA	$ 269.4	$ 260.5	$ 179.2	$ 76.2	$ 31.3	$ 11.8

---

(1) The supplemental consolidated selected financial data includes our accounts and: (i) prior to September 24, 2009 the assets, liabilities and operations of the Downstream Business; (ii) prior to October 24, 2007 the assets, liabilities and operations of the SAOU and LOU Systems as the predecessor entities; and (iii) prior to October 24, 2007 the assets, liabilities and operations of the North Texas System. The supplemental consolidated selected financial data has been retrospectively adjusted to assume that the acquisition of the Downstream Business from Targa by us had occurred at the date when both the Downstream Business and the North Texas System met the accounting requirements for entities under common control (October 31, 2005) following the acquisition of the SAOU and LOU Systems.

(2) Targa commenced operations on April 16, 2004 with the closing of the acquisition of certain assets in Texas and Louisiana from ConocoPhillips. Prior to April 16, 2004, certain investors in Targa had previous investments in Pipeco, f.k.a. Targa Resources, Inc., f.k.a. Warburg Pincus VII Development Company, Inc. Pipeco was the entity that performed due diligence and other acquisition-specific activities associated with the asset acquisitions from ConocoPhillips.

(3) Net of amortization of debt issuance costs of $2.1 million, $1.8 million, $9.1 million and $5.2 million for 2008, 2007, 2006 and 2005.

Operating Margin. We define operating margin as total operating revenues, which consist of natural gas and NGL sales plus service fee revenues, less product purchases, which consist primarily of producer payments and other natural gas purchases and operating expense. Management reviews operating margin monthly for consistency and trend analysis. Based on this monthly analysis, management takes appropriate action to maintain positive trends or to reverse negative trends. Management uses operating margin as an important performance measure of the core profitability of our operations.

The GAAP measure most directly comparable to operating margin is net income. Our non-GAAP financial measure of operating margin should not be considered as an alternative to GAAP net income. Operating margin is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. You should not consider operating margin in isolation or as a substitute for analysis of our results as reported under GAAP. Because operating margin excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of operating margin may not be comparable to similarly titled measures of other companies, thereby diminishing its utility. Management compensates for the limitations of operating margin as an analytical tool by reviewing the comparable GAAP measure, understanding the differences between the measures and incorporating these insights into management’s decision-making processes.

We believe that investors benefit from having access to the same financial measures that our management uses in evaluating our operating results. Operating margin provides useful information to investors because it is used as a supplemental financial measure by our management and by external users of our financial statements, including such investors, commercial banks and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- our operating performance and return on capital as compared to 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.

	Targa Resources Partners LP (1)					Predecessor
	Year Ended December 31,				March 12 (Inception) through December 31,	106-Day Period Ended April 15,
	2008	2007	2006	2005	2004 (2)	2004
	(In millions)					
Reconciliation of net income (loss) attributable to Targa Resources Partners LP to operating margin:						
Net income (loss) attributable to Targa Resources Partners LP	$ 49.4	$ 35.1	$ (23.0)	$ 10.2	$ 16.1	$ 4.0
Add:						
Depreciation and amortization expense	97.8	93.5	90.7	26.3	10.4	3.8
General and administrative and other expense	67.7	63.7	57.3	23.0	11.1	0.8
Interest expense, net	97.1	99.4	127.1	27.9	6.1	-
Income tax expense	2.4	2.5	3.4	-	-	2.6
Taxes other than income taxes	-	-	-	-	-	1.4
(Gain) loss on debt repurchases	(13.1)	-	-	3.7	-	-
(Gain) loss related to derivatives	1.0	30.2	(16.8)	12.0	(1.3)	-
Other, net	(5.0)	(2.3)	(3.2)	(0.1)	-	-
Operating margin (3)	$ 297.3	$ 322.1	$ 235.5	$ 103.0	$ 42.4	$ 12.6

(1) The supplemental consolidated selected financial data includes our accounts and: (i) prior to September 24, 2009 the assets, liabilities and operations of the Downstream Business; (ii) prior to October 24, 2007 the assets, liabilities and operations of the SAOU and LOU Systems as the predecessor entities; and (iii) prior to October 24, 2007 the assets, liabilities and operations of the North Texas System. The supplemental consolidated selected financial data has been retrospectively adjusted to assume that the acquisition of the Downstream Business from Targa by us had occurred at the date when both the Downstream Business and the North Texas System met the accounting requirements for entities under common control (October 31, 2005) following the acquisition of the SAOU and LOU Systems.

(2) Targa commenced operations on April 16, 2004 with the closing of the acquisition of certain assets in Texas and Louisiana from ConocoPhillips. Prior to April 16, 2004, certain investors in Targa had previous investments in Pipeco, f.k.a. Targa Resources, Inc., f.k.a. Warburg Pincus VII Development Company, Inc. Pipeco was the entity that performed due diligence and other acquisition-specific activities associated with the asset acquisitions from ConocoPhillips.

(3) Includes non-cash charges related to commodity hedges of $1.0 million, $30.2 million, $(16.8) million and $12.0 million for 2008, 2007, 2006 and 2005 and affiliated interest expense of $59.2 million and $58.5 million for 2008 and 2007.

Distributable Cash Flow. Distributable cash flow is a significant performance metric used by us and by external users of our financial statements, such as investors, commercial banks, research analysts and others to compare basic cash flows generated by us (prior to the establishment of any retained cash reserves by the board of directors of our general partner) to the cash distributions we expect to pay our unitholders. Using this metric, management can quickly compute the coverage ratio of estimated cash flows to planned cash distributions. Distributable cash flow is also an important non-GAAP financial measure for our unitholders since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our quarterly distribution rates. Distributable cash flow is also a quantitative standard used throughout the investment community with respect to publicly-traded partnerships and limited liability companies because the value of a unit of such an entity is generally determined by the unit's yield (which in turn is based on the amount of cash distributions the entity pays to a unitholder).

The economic substance behind our use of distributable cash flow is to measure the ability of our assets to generate cash flow sufficient to make distributions to our investors.

The GAAP measure most directly comparable to distributable cash flow is net income. Our non-GAAP measure of distributable cash flow should not be considered as an alternative to GAAP net income. Distributable cash flow is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. You should not consider distributable cash flow in isolation or as a substitute for analysis of our results as reported under GAAP. Because distributable cash flow excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of distributable cash flow may not be compatible to similarly titled measures of other companies, thereby diminishing its utility.

We compensate for the limitations of distributable cash flow as an analytical tool by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these insights into our decision making processes.

	Targa Resources Partners LP			
	Year Ended December 31,			
	2008	**2007**	**2006**	**2005**
	(In millions)			
Reconciliation of net income to distributable cash flow:				
Net income (loss) attributable to Targa Resources Partners LP	$ 49.4	$ 35.1	$ (23.0)	$ 10.2
Depreciation and amortization expense	97.8	93.5	90.7	26.3
Deferred income tax expense	1.8	1.9	3.4	-
Amortization in interest expense	2.1	1.8	9.1	0.5
(Gain) loss on debt extinguishment	(13.1)	-	-	3.7
Non-cash (gain) loss related to derivatives	23.4	30.8	(18.3)	12.0
Maintenance capital expenditures	(40.3)	(30.4)	(25.1)	(6.9)
Other	(0.4)	(0.5)	(0.5)	-
Distributable cash flow (1)	$ 120.7	$ 132.2	$ 36.3	$ 45.8

(1) Distributable cash flow for 2007, 2006, and 2005 reflect allocated interest from parent of $19.4 million, $127.3 million and $27.9 million.

Exhibit 99.2

Management's Discussion and Analysis of Supplemental 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 historical financial statements and notes included in Exhibit 99.3.

Overview

We are a Delaware limited partnership formed by Targa to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. We are engaged in the business of gathering, compressing, treating, processing and selling natural gas and fractionating and selling NGLs and NGL products.

We are owned 98% by our limited partners and 2% by our general partner, Targa Resources GP LLC, an indirect, wholly owned subsidiary of Targa. Our limited partner common units are publicly traded on the NASDAQ Stock Market LLC under the symbol "NGLS."

We conduct our business operations through two divisions and report our results of operations under four segments: Our Natural Gas Gathering and Processing division, is a single segment consisting of our natural gas gathering and processing facilities, as well as certain fractionation capability integrated within those facilities; and the NGL Logistics and Marketing division, which consists of three segments: Logistics Assets, NGL Distribution and Marketing, and Wholesale Marketing.

Our natural gas gathering and processing assets are located primarily in the Fort Worth Basin in North Texas, the Permian Basin in West Texas and the onshore region of the Louisiana Gulf Coast. Our NGL logistics and marketing assets are located primarily at Mont Belvieu and Galena Park near Houston, Texas and in Lake Charles, Louisiana, with terminals and transportation assets across the U.S.

Recent Events

Under the terms of our amended and restated partnership agreement, all 11,528,231 subordinated units converted to common units on a one-for-one basis on May 19, 2009. The conversion will have no impact upon our calculation of earnings per unit since the subordinated units were included in the basic and diluted earnings per unit calculation.

On July 6, 2009, we completed the private placement under Rule 144A and Regulation S of the Securities Act of 1933 of $250 million in aggregate principal amount of 11¼% senior notes due 2017 (the "11¼% Notes"). The 11¼% Notes were issued at 94.973% of the face amount, resulting in gross proceeds of $237.4 million. Proceeds from the 11¼% Notes were used to repay borrowings under our credit facility. During the third quarter of 2009, we repurchased $18.7 million face value of the 11¼% Notes for $18.9 million plus accrued interest of $0.3 million.

On July 29, 2009, we executed a Commitment Increase Supplement to our existing senior secured credit facility, which increased the commitments under our credit facility by $127.5 million, bringing the total commitments to $977.5 million. We may request additional commitments under our credit facility of up to $22.5 million, which would increase the total commitments under our credit facility to $1 billion.

On August 12, 2009, we completed a unit offering under our shelf registration statement of 6.9 million common units representing limited partner interests in us at a price of $15.70 per common unit. Net proceeds generated by the offering were $105.3 million, after deducting underwriting discounts, commissions and estimated offering expenses, and including the general partner's proportionate capital contribution of $2.2 million. The proceeds were used to reduce borrowings under our credit facility by $103.5 million.

On September 24, 2009, we completed the acquisition of the Downstream Assets of Targa Resources, Inc. (the "Downstream Business") for $530 million. See "Basis of Financial Statement Presentation" included under Note 2 of the Notes to "Supplemental Consolidated Financial Statements" in Exhibit 99.3 for information regarding the retrospective adjustment of our financial information for the years 2006 through 2008 as entities under common control in connection with our acquisition of the Downstream Business.

Factors That Significantly Affect Our Results

Our results of operations are substantially impacted by changes in commodity prices as well as increases and decreases in the volume of natural gas that we gather through our pipeline systems, which we refer to as throughput volume. Throughput volumes generally are driven by wellhead production, our competitive position on a regional basis and more broadly by prices and demand for natural gas and NGLs (which maybe impacted by economic, political and regulatory development factors beyond our control).

Contract Mix. Our natural gas gathering and processing contract arrangements can have a significant impact on our profitability. Because of the significant volatility of natural gas and NGL prices, the contract mix of our natural gas gathering and processing segment can have a significant impact on our profitability. Negotiated contract terms are based upon a variety of factors, including natural gas quality, geographic location, the competitive environment at the time the contract is executed and customer preferences. Contract mix and, accordingly, exposure to natural gas and NGL prices may change over time as a result of changes in these underlying factors.

Set forth below is a table summarizing the contract mix of our natural gas gathering and processing division for 2008 and the potential impacts of commodity prices on operating margins:

Contract Type	Percent of Throughput	Impact of Commodity Prices
Percent-of-Proceeds	77%	Decreases in natural gas and/or NGL prices generate decreases in operating margin.
Wellhead Purchases/Keep Whole	20%	Increases in natural gas prices relative to NGL prices generate decreases in operating margin. Decreases in NLG prices relative to natural gas prices generate decreases in operating margin.
Hybrid	1%	In periods of favorable processing economics, similar to percent-of-liquids (or wellhead purchases/keep-whole in some circumstances, if economically advantageous to the processor). In periods of unfavorable processing economics, similar to fee-based.
Fee-Based	2%	No direct impact from commodity price movements.

Actual contract terms are based upon a variety of factors, including natural gas quality, geographic location, the competitive commodity and pricing environment at the time the contract is executed, and customer requirements. Our gathering and processing contract mix and, accordingly, our exposure to natural gas and NGL prices, may change as a result of producer preferences, competition, and changes in production as wells decline at different rates or are added, our expansion into regions where different types of contracts are more common as well as other market factors. We prefer to enter into contracts with less commodity price sensitivity including fee-based and percent-of-proceeds arrangements.

We attempt to mitigate the impact of commodity prices on our results of operations through hedging activities which can materially impact our results of operations. See "Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk."

Impact of Our Hedging Activities. In an effort to reduce the variability of our cash flows, we have hedged the commodity price associated with a portion of our expected natural gas, NGLs and condensate equity volumes for the years 2009 through 2012 by entering into derivative financial instruments including swaps and purchased puts (or floors). With these arrangements, we have attempted to mitigate our exposure to commodity price movements with respect to our forecasted volumes for this period. For additional information regarding our hedging activities, see “Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk.”

General and Administrative Expenses. Prior to the contribution of the assets of the North Texas System to us and the acquisition of the assets from the SAOU and LOU Systems and Downstream Business by us from Targa, general and administrative expenses were allocated from Targa to the North Texas, SAOU and LOU Systems and Downstream Business in accordance with the general and administrative expenses allocation policies of Targa. On February 14, 2007, we entered into an omnibus agreement with Targa, pursuant to which our allocated general and administrative expenses related to the North Texas System were capped at $5.0 million per year for three years, subject to adjustment.

On October 24, 2007, we amended and restated our omnibus agreement with Targa (the “Omnibus Agreement”). The Omnibus Agreement governs certain relationships between Targa and us, including:

- Targa’s obligation to provide certain general and administrative services to us;
- our obligation to reimburse Targa and its affiliates for the provision of general and administrative services (a) subject to a cap of $5 million (relating solely to the North Texas System) in the first year, with increases in the subsequent two years based on a formula specified in the Omnibus Agreement and (b) fully allocated as to the SAOU and LOU Systems according to Targa’s previously established allocation practices;
- our obligation to reimburse Targa and its affiliates for direct expenses incurred on our behalf; and
- Targa’s obligation to indemnify us for certain liabilities and our obligation to indemnify Targa for certain liabilities.

On September 24, 2009 we completed the acquisition of Targa’s Downstream Business. As part of the transaction, Targa will provide distribution support to us in the form of a reduction in the reimbursement for general and administrative expense allocated to us if necessary for a 1.0 times distribution coverage ratio, at the current $0.5175 per limited partner unit, subject to maximum support of $8 million in any quarter. The distribution support is in effect for the nine-quarter period beginning with the fourth quarter of 2009 and continuing through the fourth quarter of 2011.

Allocated general and administrative expenses were $61.7 million, $60.4 million and $56.5 million for 2008, 2007 and 2006.

In addition to these allocated general and administrative expenses, we incur incremental general and administrative expenses as a result of operating as a separate publicly held limited partnership. These direct, incremental general and administrative expenses, which were approximately $4.2 million and $3.3 million during 2008 and 2007, including one-time expenses associated with our equity offerings, financing arrangements and acquisitions were not subject to the cap contained in the Omnibus Agreement. These costs include costs associated with annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, independent auditor fees, registrar and transfer agent fees and independent director compensation. These incremental general and administrative expenditures are not reflected in the historical financial statements of the North Texas, SAOU and LOU Systems, and Downstream Business.

The historical supplemental financial statements of the SAOU and LOU Systems, the North Texas System and the Downstream Business include certain items that will not impact our future results of operations and liquidity including the items described below:

Affiliate Indebtedness and Borrowings. Affiliate indebtedness prior to our acquisition of the SAOU and LOU Systems, the contribution of the North Texas System and the acquisition of the Downstream Business, consisted of borrowings incurred by Targa and allocated to us for financial reporting purposes.

Prior to Targa’s acquisition of Dynegy’s interest in Dynegy Midstream Services, Limited Partnership (the

“DMS Acquisition”), which included the North Texas System, the Predecessor Business was financed through borrowings by Targa and reflected allocated indebtedness on its balance sheet and allocated interest expense on its income statement. A substantial portion of the DMS Acquisition was also financed through borrowings by Targa. Following the October 31, 2005 DMS Acquisition, a significant portion of Targa’s acquisition borrowings were allocated to the North Texas System, resulting in approximately $870.1 million of allocated indebtedness and corresponding levels of interest expense. This indebtedness was incurred by Targa in connection with the DMS Acquisition, and the entity holding the North Texas System provided a guarantee of this indebtedness. This indebtedness was also secured by a collateral interest in both the equity of the entity holding the North Texas System as well as its assets. In connection with our IPO, this guarantee was terminated, the collateral interest was released and the allocated indebtedness was retired.

On February 14, 2007, we borrowed approximately $294.5 million under our credit facility. The proceeds from this borrowing, together with approximately $371.2 million of net proceeds from our IPO (including 2,520,000 common units sold pursuant to the full exercise by the underwriters of their option to purchase additional common units), were used to repay approximately $665.7 million of affiliate indebtedness and the remaining balance of this indebtedness was retired and treated as a capital contribution to us.

On October 24, 2007, we completed our acquisition of the SAOU and LOU Systems concurrently with the sale of 13,500,000 common units representing limited partnership interests in us for gross proceeds of $362.7 million (approximately $349.2 million after underwriting discount and structuring fees). The net proceeds from the sale of the 13,500,000 units were used to pay approximately $2.5 million in expenses associated with the sale of the common units and $24.2 million to Targa for certain hedge transactions associated with the SAOU and LOU Systems. We used the net proceeds after offering expenses and the hedge transactions of $322.5 million along with net borrowings of $375.5 million to pay approximately $698.0 million of the acquisition costs of the SAOU and LOU Systems. The allocated indebtedness from Targa related to the SAOU and LOU Systems was $124.0 million. Targa debt was guaranteed by the entities that own the SAOU and LOU Systems and was secured by a collateral interest in both the equity interests of those entities as well as their underlying assets. In conjunction with our acquisition of the SAOU and LOU Systems, this guarantee was terminated, the collateral interest was released and the allocated indebtedness was retired.

On January 1, 2007, Targa contributed to us affiliated indebtedness related to the assets of Targa Downstream LP and Targa LSNG LP of approximately $639.7 million (including accrued interest of $61.8 million). During the years ended December 31, 2008 and 2007, additional affiliated indebtedness of $3.4 million and $13.0 million was incurred by Targa LSNG LP to fund the construction of its Mont Belvieu, Texas isomerization unit. During 2008 and 2007, we recorded $59.3 million and $58.5 million in interest expense associated with this affiliated debt.

Working Capital Adjustments. Prior to the contribution of the North Texas System in February 2007, the acquisition of the SAOU and LOU Systems in October 2007 and the acquisition of the Downstream Business in September 2009, all intercompany transactions, including commodity sales and expense reimbursements, were not cash settled with the Predecessor Business’ respective parent, but were recorded as an adjustment to parent equity on the balance sheet. The primary intercompany transactions between the respective parent and the Predecessor Business are natural gas and NGL sales, the provision of operations and maintenance activities and the provision of general and administrative services. Accordingly, the working capital of the Predecessor Business does not reflect any affiliate accounts receivable for intercompany commodity sales or affiliate accounts payable for the personnel and services provided or paid for by the applicable parent on behalf of the Predecessor Business.

Distributions to our Unitholders

We intend to make cash distributions to our unitholders and our general partner at least at the minimum quarterly distribution rate of $0.3375 per common unit per quarter ($1.35 per common unit on an annualized basis). Due to our cash distribution policy, we expect that we will distribute to our unitholders most of the cash generated by our operations. As a result, we expect that we will rely upon external financing sources, including other debt and common unit issuances, to fund our acquisition and expansion capital expenditures, as well as our working capital needs. Historically, we have relied on internally generated cash flows for these purposes. Due to the timing of our IPO, a pro-rated distribution for the first quarter of 2007 of $0.16875 per common and subordinated unit was paid.

The following table shows the distributions we paid for the period February 14, 2007 through February 13, 2009.

Date Paid	For the Three Months Ended	Distributions Paid Common Units	Subordinated Units	General Partner Incentive	General Partner 2%	Total	Distributions per limited partner unit
		(In thousands, except per unit amounts)					
February 13, 2009	December 31, 2008	$ 17,949	$ 5,966	$ 1,933	$ 528	$ 26,376	$ 0.51750
November 14, 2008	September 30, 2008	17,934	5,966	1,931	527	26,358	0.51750
August 14, 2008	June 30, 2008	17,759	5,908	1,711	518	25,896	0.51250
May 15, 2008	March 31, 2008	14,467	4,813	208	398	19,886	0.41750
February 14, 2008	December 31, 2007	13,768	4,582	66	376	18,792	0.39750
November 14, 2007	September 30, 2007	11,082	3,891	-	305	15,278	0.33750
August 14, 2007	June 30, 2007	6,526	3,890	-	212	10,628	0.33750
May 15, 2007	March 31, 2007	3,263	1,945	-	107	5,315	0.16875

General Trends and Outlook

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

Natural Gas Supply and Outlook. Fluctuations in energy prices can affect production rates and investments by third parties in the development of new natural gas reserves. Generally, drilling and production activity will increase as natural gas prices increase and decrease as natural gas prices decrease.

Significant Relationships. Our largest suppliers of natural gas are Crosstex Energy, a gas gatherer that sells to us on a spot basis, and ConocoPhillips Company, representing 12% and 11% of the natural gas supplied to our system for 2008; and 11% and 12% of the natural gas supplied to our system for 2007.

During 2008 and 2007, approximately 22% and 24% of our consolidated revenues, and approximately 8% and 11% of our consolidated product purchases, were derived from transactions with Chevron and CPC. No other third party customer accounted for more than 10% of our consolidated revenues during these periods.

Commodity Prices. Our operating income generally improves in an environment of higher natural gas, NGL and condensate prices, primarily as a result of our percent-of-proceeds contracts. Our processing profitability is largely dependent upon pricing and market demand for natural gas, NGLs and condensate, which are beyond our control and have been volatile. The current weak economic conditions have negatively affected the pricing and market demand for natural gas, NGLs and condensate, which has caused a reduction in profitability of our processing operations. In a declining commodity price environment, without taking into account our hedges, we will realize a reduction in cash flows under our percent-of-proceeds contracts proportionate to average price declines. We have attempted to mitigate our exposure to commodity price movements by entering into hedging arrangements. For additional information regarding our hedging activities, See “Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk.”

Volatile Capital Markets. We are dependent on our ability to access the equity and debt capital markets in order to fund acquisitions and expansion expenditures. Global financial markets have been, and are expected to continue to be, extremely volatile and disrupted and the current weak economic conditions have recently caused a significant decline in commodity prices. As a result, we may be unable to raise equity or debt capital on satisfactory terms, or at all, which may negatively impact the timing and extent to which we execute growth plans. Prolonged periods of low commodity prices or volatile capital markets may impact our ability or willingness to enter into new hedges, fund organic growth, connect to new supplies of natural gas, execute acquisitions or implement expansion capital expenditures.

How We Evaluate Our Operations

Our profitability is a function of the difference between the revenues we receive from our operations, including revenues from the natural gas, NGLs and condensate we sell, and the costs associated with conducting our operations, including the costs of wellhead natural gas that we purchase as well as operating and general and administrative costs. Because commodity price movements tend to impact both revenues and costs, increases or decreases in our revenues alone are not necessarily indicative of increases or decreases in our profitability. Our contract portfolio, the prevailing pricing environment for natural gas and NGLs, and the natural gas and NGL throughput on our system are important factors in determining our profitability. Our profitability is also affected by the NGL content in gathered wellhead natural gas, demand for our products and changes in our customer mix.

Our management uses a variety of financial and operational measurements to analyze our performance. These measurements include the following: (1) throughput volumes, (2) facility efficiencies and fuel consumption, (3) operating margin, (4) operating expenses, (5) Adjusted EBITDA and (6) distributable cash flow.

Throughput Volumes, *Facility Efficiencies and Fuel Consumption.* Our profitability is impacted by our ability to add new sources of natural gas supply to offset the natural decline of existing volumes from natural gas wells that are connected to our systems. This is achieved by connecting new wells, adding new volumes in existing areas of production as well as by capturing supplies currently gathered by third parties.

In addition, we seek to increase operating margins by limiting volume losses and reducing fuel consumption by increasing compression efficiency. With our gathering systems' extensive use of remote monitoring capabilities, we monitor the volumes of natural gas received at the wellhead or central delivery points along our gathering systems, the volume of natural gas received at our processing plant inlets and the volumes of NGLs and residue natural gas recovered by our processing plants. This information is tracked through our processing plants to determine customer settlements and helps us increase efficiency and reduce fuel consumption.

As part of monitoring the efficiency of our operations, we measure the difference between the volume of natural gas received at the wellhead or central delivery points on our gathering systems and the volume received at the inlet of our processing plants as an indicator of fuel consumption and line loss. We also track the difference between the volume of natural gas received at the inlet of the processing plant and the NGLs and residue gas produced at the outlet of such plants to monitor the fuel consumption and recoveries of the facilities. These volume, recovery and fuel consumption measurements are an important part of our operational efficiency analysis.

Operating Margin. We review performance based on the non-generally accepted accounting principle ("non-GAAP") financial measure of operating margin. We define operating margin as total operating revenues, which consist of natural gas and NGL sales plus service fee revenues, less product purchases, which consist primarily of producer payments and other natural gas purchases, and operating expense. Natural gas and NGL sales revenue includes settlement gains and losses on commodity hedges. Our operating margin is impacted by volumes and commodity prices as well as by our contract mix and hedging program, which are described in more detail below. We view our operating margin as an important performance measure of the core profitability of our operations. We review our operating margin monthly for consistency and trend analysis.

The GAAP measure most directly comparable to operating margin is net income. Our non-GAAP financial measure of operating margin should not be considered as an alternative to GAAP net income. Operating margin is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. You should not consider operating margin in isolation or as a substitute for analysis of our results as reported under GAAP. Because operating margin excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of operating margin may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

We compensate for the limitations of operating margin as an analytical tool by reviewing the comparable GAAP measure, understanding the differences between the measures and incorporating these insights into our decision-making processes.

Reconciliation of net income (loss) attributable to Targa Resources Partners LP to operating margin:	Year Ended December 31, 2008	2007 (In millions)	2006
Net income (loss) attributable to Targa Resources Partners LP	$ 49.4	$ 35.1	$ (23.0)
Add:			
Depreciation and amortization expense	97.8	93.5	90.7
General and administrative and other expense	67.7	63.7	57.3
Interest expense, net	97.1	99.4	127.1
Income tax expense	2.4	2.5	3.4
Gain on debt repurchases	(13.1)	-	-
(Gain) loss related to derivatives	1.0	30.2	(16.8)
Other, net	(5.0)	(2.3)	(3.2)
Operating margin (1)	$ 297.3	$ 322.1	$ 235.5

(1) Includes non-cash charges related to commodity hedges of $1.0 million, $30.2 million and ($16.8) million for 2008, 2007 and 2006 and affiliated interest expense of $59.2 million and $58.5 million for 2008 and 2007.

Our operating margin by segment and in total is as follows for the periods indicated:

	Year Ended December 31, 2008	2007 (In millions)	2006
Natural Gas Gathering and Processing	$ 215.8	$ 203.8	$ 171.7
Logistics Assets	49.9	40.0	42.6
NGL Distribution and Marketing Services	18.5	55.5	10.6
Wholesale Marketing	13.1	22.8	10.6
	$ 297.3	$ 322.1	$ 235.5

We believe that investors benefit from having access to the same financial measures that our management uses in evaluating our operating results. Operating margin provides useful information to investors because it is used as a supplemental financial measure by us and by external users of our financial statements, including such investors, commercial banks and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;

- our operating performance and return on capital as compared to 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.

Operating Expenses. Operating expenses are costs associated with the operation of a specific asset. Direct labor, ad valorem taxes, repair and maintenance, utilities and contract services compose the most significant portion of our operating expenses. These expenses generally remain relatively stable independent of the volumes through our systems but fluctuate depending on the scope of the activities performed during a specific period.

Adjusted EBITDA. Adjusted EBITDA is another non-GAAP financial measure that is used by us. We define Adjusted EBITDA as net income before interest, income taxes, depreciation and amortization and non-cash income or loss related to derivative instruments. Adjusted EBITDA is used as a supplemental financial measure by us and by external users of our financial statements such as investors, commercial banks and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- our operating performance and return on capital as compared to 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.

The economic substance behind our use of Adjusted EBITDA is to measure the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make distributions to our investors.

The GAAP measures most directly comparable to Adjusted EBITDA are net cash provided by operating activities and net income. Our non-GAAP financial measure of Adjusted EBITDA should not be considered as an alternative to GAAP net cash provided by operating activities and GAAP net income. Adjusted EBITDA is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. You should not consider Adjusted EBITDA in isolation or as a substitute for analysis of our results as reported under GAAP. Because Adjusted EBITDA excludes some, but not all, items that affect net income and net cash provided by operating activities and is defined differently by different companies in our industry, our definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies.

We compensate for the limitations of Adjusted EBITDA as an analytical tool by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these insights into our decision-making processes.

	Year Ended December 31,		
	2008	**2007**	**2006**
Reconciliation of net cash provided by operating activities to Adjusted EBITDA:		**(In millions)**	
Net cash provided by operating activities	$ 293.0	$ 268.3	$ 169.9
Net income attributable to noncontrolling interest	(0.3)	(0.1)	0.6
Interest expense, net (1)	35.8	39.1	118.0
Gain on debt repurchases	13.1	-	-
Termination of commodity derivatives	87.4	-	-
Current income tax expense	0.6	0.6	-
Other	3.7	(1.5)	(0.6)
Changes in operating assets and liabilities which used (provided) cash:			
Accounts receivable and other assets	(658.2)	145.7	(71.1)
Accounts payable and other liabilities	494.3	(191.6)	(37.6)
Adjusted EBITDA	$ 269.4	$ 260.5	$ 179.2

(1) Net of amortization of debt issuance costs of $2.1 million, $1.8 million and $9.1 million for 2008, 2007 and 2006.

Reconciliation of net income (loss) attributable to Targa Resources Partners LP to Adjusted EBITDA:	Year Ended December 31, 2008	2007 (In millions)	2006
Net income (loss) attributable to Targa Resources Partners LP	$ 49.4	$ 35.1	$ (23.0)
Add:			
Interest expense, net	97.1	99.4	127.1
Income tax expense	2.4	2.5	3.4
Depreciation and amortization expense	97.8	93.5	90.7
Non-cash (gain) loss related to derivatives	23.4	30.8	(18.3)
Noncontrolling interest adjustment	(0.7)	(0.8)	(0.7)
Adjusted EBITDA	$ 269.4	$ 260.5	$ 179.2

Distributable Cash Flow. Distributable cash flow is a significant performance metric used by us and by external users of our financial statements, such as investors, commercial banks, research analysts and others to compare basic cash flows generated by us (prior to the establishment of any retained cash reserves by the board of directors of our general partner) to the cash distributions we expect to pay our unitholders. Using this metric, management can quickly compute the coverage ratio of estimated cash flows to planned cash distributions. Distributable cash flow is also an important non-GAAP financial measure for our unitholders since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our quarterly distribution rates. Distributable cash flow is also a quantitative standard used throughout the investment community with respect to publicly-traded partnerships and limited liability companies because the value of a unit of such an entity is generally determined by the unit's yield (which in turn is based on the amount of cash distributions the entity pays to a unitholder).

The economic substance behind our use of distributable cash flow is to measure the ability of our assets to generate cash flow sufficient to make distributions to our investors.

The GAAP measure most directly comparable to distributable cash flow is net income. Our non-GAAP measure of distributable cash flow should not be considered as an alternative to GAAP net income. Distributable cash flow is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. You should not consider distributable cash flow in isolation or as a substitute for analysis of our results as reported under GAAP. Because distributable cash flow excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of distributable cash flow may not be compatible to similarly titled measures of other companies, thereby diminishing its utility.

We compensate for the limitations of distributable cash flow as an analytical tool by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these insights into our decision making processes.

	Year Ended December 31,		
	2008	2007	2006
Reconciliation of net income (loss) attributable to Targa Resources Partners LP distributable cash flow:		(In millions)	
Net income (loss) attributable to Targa Resources Partners LP	$ 49.4	$ 35.1	$ (23.0)
Depreciation and amortization expense	97.8	93.5	90.7
Deferred income tax expense	1.8	1.9	3.4
Amortization in interest expense	2.1	1.8	9.1
Gain on debt repurchases	(13.1)	-	-
Non-cash (gain) loss related to derivatives	23.4	30.8	(18.3)
Maintenance capital expenditures	(40.3)	(30.4)	(25.1)
Other	(0.4)	(0.5)	(0.5)
Distributable cash flow	$ 120.7	$ 132.2	$ 36.3

Results of Operations

The following table summarizes the key components of our results of operations for the periods indicated:

	Year Ended December 31,		
	2008	2007	2006
		(In millions)	
Revenues (1)	$ 7,473.4	$ 6,816.1	$ 5,907.5
Product purchases	6,922.1	6,274.4	5,478.9
Operating expenses	254.0	219.6	193.1
Depreciation and amortization expense	97.8	93.5	90.7
General and administrative expense	68.6	64.0	57.3
Other	(0.9)	(0.3)	-
Income from operations	131.8	164.9	87.5
Interest expense, net	(97.1)	(99.4)	(127.1)
Equity in earnings of unconsolidated investment	3.9	3.5	2.8
Gain on debt repurchases	13.1	-	-
Gain (loss) on mark-to-market derivative instruments	(1.0)	(30.2)	16.8
Other	1.4	(1.1)	(0.2)
Income tax expense	(2.4)	(2.5)	(3.4)
Net income (loss)	49.7	35.2	(23.6)
Less: Net income (loss) attributable to noncontrolling interest	0.3	0.1	(0.6)
Net income (loss) attributable to Targa Resources Partners LP	$ 49.4	$ 35.1	$ (23.0)
Financial and operating data:			
Financial data:			
Operating margin (2)	$ 297.3	$ 322.1	$ 235.5
Adjusted EBITDA (3)	269.4	260.5	179.2
Distributable cash flow (4)	120.7	132.2	36.3
Operating data:			
Gathering throughput, MMcf/d (5)	445.8	452.0	433.8
Plant natural gas inlet, MMcf/d (6) (7)	421.2	429.2	419.6
Gross NGL production, MBbl/d	42.0	42.6	42.4
Natural gas sales, BBtu/d (7)	415.6	410.2	489.4
NGL sales, MBbl/d	278.1	310.1	290.1
Condensate sales, MBbl/d	3.6	3.6	3.3
Average realized prices:			
Natural gas, $/MMBtu	8.45	6.60	6.62
NGL, $/gal	1.39	1.19	1.02
Condensate, $/Bbl	82.52	65.63	59.87

(1) Includes business interruption insurance revenues of $18.6 million, $4.6 million and $7.0 million for the years ended 2008, 2007 and 2006.

(2) Operating margin is revenues less product purchases and operating expense. See “How We Evaluate Our Operations.”

(3) Adjusted EBITDA is net income before interest, income taxes, depreciation and amortization and non-cash gain or loss related to derivative instruments. See “How We Evaluate Our Operations.”

(4) Distributable Cash Flow is net income plus depreciation and amortization and deferred taxes, adjusted for losses on mark-to-market derivative contracts, less maintenance capital expenditures. See “How We Evaluate Our Operations.”

(5) Gathering throughput represents the volume of natural gas gathered and passed through natural gas gathering pipelines from connections to producing wells and central delivery points.
(6) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(7) Plant inlet volumes include producer take-in-kind, while natural gas sales exclude producer take-in-kind volumes.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Revenues increased by $657.3 million, or 10%, to $7,473.4 million for 2008 compared to $6,816.1 million for 2007. Revenues from the sale of natural gas increased by $291.7 million, consisting of increases of $275.9 million due to higher realized prices and $15.8 million due to higher sales volumes. Revenues from the sale of NGL increased by $306.5 million, consisting of an increase of $875.6 million due to higher realized prices, partially offset by a decrease of $569.1 million due to lower sales volumes. Revenues from the sale of condensate increased by $23.2 million, consisting of increases of $22.2 million due to higher realized prices and $1.0 million due to higher sales volumes. Non-commodity revenues, which principally include revenues derived from fee-based services and business interruption insurance, increased by $35.9 million.

Our average realized prices for natural gas increased by $1.85 per MMBtu, or 28%, to $8.45 per MMBtu for 2008 compared to $6.60 per MMBtu for 2007. Our average realized prices for NGL increased by $0.20 per gallon, or 17%, to $1.39 per gallon for 2008 compared to $1.19 per gallon for 2007. Our average realized price for condensate increased by $16.89, or 26%, to $82.52 per barrel for 2008 compared to $65.63 per barrel for 2007.

Natural gas sales volumes increased by 5.4 BBtu per day, or 1%, to 415.6 BBtu per day for 2008 compared to 410.2 BBtu per day for 2007. NGL sales volumes decreased by 32.0 MBbl per day, or 10%, to 278.1 MBbl per day for 2008 compared to 310.1 MBbl per day for 2007. Condensate sales volumes remained unchanged for 2008 compared to 2007. For information regarding the period to period changes in our commodity sales volumes, see “Results of Operations—By Segment.”

Product purchases increased by $647.7 million, or 10%, to $6,922.1 million for 2008 compared to $6,274.4 million for 2007. See “Results of Operations—By Segment” for a detailed explanation of the components of the increase.

Operating expenses increased by $34.4 million, or 16%, to $254.0 million for 2008 compared to $219.6 million for 2007. See “Results of Operations—By Segment” for a detailed explanation of the components of the increase.

Depreciation and amortization expense increased by $4.3 million, or 5%, to $97.8 million for 2008 compared to $93.5 million for 2007. The increase is primarily attributable to a 22% increase in purchases of property, plant and equipment for 2008 compared to 2007.

General and administrative expense increased by $4.6 million, or 7%, to $68.6 million for 2008 compared to $64.0 million for 2007. The increase included increases in compensation related expenses, professional services, allocated corporate level expenses and insurance expenses.

Interest expense decreased by $2.3 million, or 2%, to $97.1 million for 2008 compared to $99.4 million for 2007. The decrease is primarily from lower average outstanding debt during 2008. See “Liquidity and Capital Resources” for information regarding our outstanding debt obligations.

Gain on debt repurchases of $13.1 million for 2008 relates to open market repurchases of our 8¼% Senior Notes due 2016.

Our loss on mark-to-market derivative instruments was $1.0 million for 2008 compared to $30.2 million for 2007. During 2008 we adjusted the fair value of certain contracts with Lehman Brothers Commodity Services Inc. to zero as a result of the Lehman Brothers bankruptcy filing. The 2007 loss resulted from derivative financial instruments that did not qualify for hedge accounting.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

Revenues increased by $908.6 million, or 15%, to $6,816.1 million for 2007 compared to $5,907.5 million for 2006. Revenues from the sale of natural gas decreased by $189.7 million, consisting of a decrease of $191.4 million due to lower sales volume partially offset by an increase of $1.7 million due to higher realized prices. Revenues from the sale of NGLs increased by $1,081.3 million, consisting of increases of $766.1 million due to higher realized prices and $315.2 million due to higher sales volumes. Revenues from the sale of condensate increased by $12.2 million, consisting of an increase of $4.8 million due to higher sales volumes and $7.4 million due to higher realized prices. Non-commodity revenues, which principally include revenues derived from fee-based services and business interruption insurance, increased by $4.8 million.

Our average realized prices for natural gas decreased by $0.02 per MMBtu, or less than 1%, to $6.60 per MMBtu for 2007 compared to $6.62 per MMBtu for 2006. Our average realized prices for NGL increased by $0.17 per gallon, or 17%, to $1.19 per gallon for 2007 compared to $1.02 per gallon for 2006. Our average realized price for condensate increased by $5.76 per barrel, or 10%, to $65.63 per barrel for 2007 compared to $59.87 per barrel for 2006.

Natural gas sales volumes decreased by 79.2 BBtu per day, or 16%, to 410.2 BBtu per day for 2007 compared to 489.4 BBtu per day for 2006. NGL sales volumes increased by 20.0 MBbl per day, or 7%, to 310.1 MBbl per day for 2007 compared to 290.1 MBbl per day for 2006. Condensate sales volumes increased by 0.3 MBbl per day, or 9%, to 3.6 MBbl per day for 2007 compared to 3.3 MBbl per day for 2006. For information regarding the period to period changes in our commodity sales volumes, see “Results of Operations—By Segment.”

Product purchases increased by $795.5 million, or 15%, to $6,274.4 million for 2007 compared to $5,478.9 million for 2006. See “Results of Operations—By Segment” for a detailed explanation of the components of the increase.

Operating expenses increased by $26.5 million, or 14%, to $219.6 million for 2007 compared to $193.1 million for 2006. See “Results of Operations—By Segment” for a detailed explanation of the components of the increase.

Depreciation and amortization expense for 2007 was $93.5 million compared to $90.7 million for 2006, an increase of $2.8 million or 3%. The increase is due to the higher carrying value of property, plant and equipment as a result of plant and gathering system expansions.

General and administrative expense increased by $6.7 million, or 12%, to $64.0 million for 2007 compared to $57.3 million for 2006. The increased included increases in insurance expenses, professional services, compensation related expenses and other general and administrative expenses, partially offset by a decrease in allocated corporate level expenses.

Interest expense decreased by $27.7 million, or 22%, to $99.4 million for 2007 compared to $127.1 million for 2006. The decrease is primarily the result of lower average debt during 2007, partially offset by the effect of higher interest rates during 2007. See “Liquidity and Capital Resources” in this Item 7 for information regarding our outstanding debt obligations.

Results of Operations—By Segment

Natural Gas Gathering and Processing Segment

The following table provides summary financial data regarding results of operations in our Natural Gas Gathering and Processing segment for the periods indicated:

	Year Ended December 31, 2008	Year Ended December 31, 2007	Year Ended December 31, 2006
		(In millions)	
Revenues	$ 2,074.1	$ 1,661.5	$ 1,738.5
Product purchases	(1,803.0)	(1,406.8)	(1,517.7)
Operating expenses	(55.3)	(50.9)	(49.1)
Operating margin (1)	$ 215.8	$ 203.8	$ 171.7
Operating statistics: (2)			
Gathering throughput, MMcf/d	445.8	452.0	433.8
Plant natural gas inlet, MMcf/d	421.2	429.2	419.6
Gross NGL production, MBbl/d	42.0	42.6	42.4
Natural gas sales, BBtu/d	415.6	410.2	489.4
NGL sales, MBbl/d	37.3	36.4	36.0
Condensate sales, MBbl/d	3.6	3.6	3.3
Average realized prices:			
Natural gas, $/MMBtu	8.45	6.60	6.62
NGL, $/gal	1.17	1.03	0.85
Condensate, $/Bbl	82.52	65.63	59.87

(1) See “How We Evaluate Our Operations.”
(2) Segment operating statistics include the effect of intersegment sales, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the year and the denominator is the number of calendar days during the year.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Revenues. Revenues increased $412.6 million, or 25%, to $2,074.1 million for 2008 compared to $1,661.5 million for 2007. The increase was primarily due to the following factors:

- an increase attributable to prices of $383.5 million, consisting of increases in natural gas, NGL, and condensate revenues of $280.5million, $80.8 million, and $22.2 million;
- an increase attributable to volumes of $32.2 million, consisting of increases in natural gas, NGL and condensate revenues of $15.7 million, $15.5 million, and $1.0 million; and
- an increase in fee and other revenues of $3.1 million.

Average realized prices for our sales of:

- natural gas increased by $1.85 per MMBtu, or 28%, to $8.45 per MMBtu during 2008 compared to $6.60 per MMBtu for 2007.
- NGLs increase by $0.14 per gallon, or 14%, to $1.17 per gallon for 2008 compared to $1.03 per gallon for 2007.
- condensate increased by $16.89 per Bbl, or 26%, to $82.52 per Bbl for 2008 compared to $65.63 per Bbl for 2007.

Natural gas sales volume increased by 5.4 BBtu/d or 1%, to 415.6 BBtu/d during 2008 compared to 410.2 BBtu/d for 2007 due to a lower proportion of take-in-kind volumes, increased marketing activity and the effects of unfavorable processing economics. Net NGL sales increased by 0.9 MBbl/d or 2%, to 37.3 MBbl/d for 2008 compared to 36.4 MBbl/d for 2007. Condensate sales remained flat at 3.6 MBbl/d.

Product Purchases. Product purchases during 2008 were $1,803.0 million, which increased by $396.2 million or 28%, compared to $1,406.8 million during 2007. The increase in product purchases corresponds with the increase in commodity revenue for 2008.

Operating Expenses. Operating expenses during 2008 were $55.3 million, which increased by $4.4 million or 9%, compared to $50.9 million during 2007. The increase in operating expenses was primarily the result of increases in general maintenance and supplies, lube oil, environmental and automotive expenses, compensation related expenses and ad valorem taxes.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

Revenues. Revenues decreased by $77.0 million or 4%, to $1,661.5 million for 2007 compared to $1,738.5 million for 2006. This decrease was primarily due to the following:

- a net increase attributable to prices of $102.5 million, consisting of a decrease in natural gas revenues of $3.9 million and increases in NGL and condensate revenues of $99.0 million and $7.4 million;
- a net decrease attributable to volumes of $181.2 million, consisting of a decrease in natural gas revenues of $191.6 million and increases of NGL and condensate revenues of $5.7 million and $4.8 million; and
- a decrease in fee and other revenues of $1.6 million.

Average realized prices for our sales of:

- natural gas decreased by $0.02 per MMBtu or less than 1%, to $6.60 per MMBtu during 2007 compared to $6.62 per MMBtu for 2006.
- NGLs increased by $0.18 per gallon or 21%, to $1.03 per gallon for 2007 compared to $0.85 per gallon for 2006.
- condensate increased by $5.76 per Bbl or 10%, to $65.63 per Bbl for 2007 compared to $59.87 per Bbl for 2006.

Natural gas sales volume decreased by 79.2 BBtu/d or 16%, to 410.2 BBtu/d during 2007 compared to 489.4 BBtu/d for 2006. The decrease in sales of natural gas volumes was attributable to a net decrease in natural gas purchased from affiliates and increased take-in-kind volumes by producers for whom we process natural gas, offset by net increases in other non-wellhead supply sources and wellhead supplies attributable to additional well connections which were partially offset by the natural decline of field production. Net NGL sales increased by 0.4 MBbl/d or 1%, to 36.4 MBbl/d for 2007 compared to 36.0 MBbl/d for 2006. The volume increase was primarily attributable to additional well connections partially offset by the natural decline in field production. Condensate production increased by 0.3 MBbl/d or 9%, to 3.6 MBbl/d for 2007 compared to 3.3 MBbl/d for 2006.

Product Purchases. Product purchases during 2007 were $1,406.8 million, a decrease of $110.9 million or 7%, compared to $1,517.7 million during 2006.

Operating Expenses. Operating expenses during 2007 were $50.9 million, an increase of $1.8 million or 4%, compared to $49.1 million during 2006. The increase was partially attributable to increased operating costs due to our processing plant and gathering system expansions, as well as increased prices for labor, supplies and equipment.

Logistics Assets Segment

The following table provides summary financial data regarding results of operations of our Logistics Assets segment for the periods indicated:

	Year Ended December 31,		
	2008	2007	2006
		(In millions)	
Revenues from services	$ 235.5	$ 195.1	$ 177.7
Other revenues (1)	2.5	-	0.4
	238.0	195.1	178.1
Operating expenses	(188.1)	(155.1)	(135.5)
Operating margin (2)	$ 49.9	$ 40.0	$ 42.6
Equity in earnings of GCF	$ 3.9	$ 3.5	$ 2.8
Operating statistics:			
Fractionation volumes, MBbl/d	212.2	209.2	181.9
Treating volumes, MBbl/d (3)	20.7	9.1	-

(1) Includes business interruption insurance revenues of $2.5 million and $0.4 million for 2008 and 2006.
(2) See “How We Evaluate Our Operations.”
(3) Consists of the volumes treated in our low sulfur natural gasoline (“LSNG”) unit, which began commercial operations in June 2007.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Revenues from fractionation, terminalling and storage, transport, and treating increased $40.4 million, or 21%, to $235.5 million for 2008 compared to $195.1 million for 2007. The increase was due to higher service rates, a full year of commercial operations at our LSNG unit in 2008 compared to six months of operations in 2007, increased treating and related service revenues, additional transport fees from spot barge activity and additional terminalling revenue from a new common carrier connection.

Operating expenses increased $33.0 million, or 21%, to $188.1 million for 2008 compared to $155.1 million for 2007. The increase was primarily the result of higher fuel and utilities expense, increased LSNG unit and other facility maintenance costs, plant turnaround costs and third-party fractionation expense, additional barge activity, inventory adjustments and pipeline integrity costs.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

Revenues from fractionation, terminalling and storage, transport, and treating increased $17.4 million, or 10%, to $195.1 million for 2007 compared to $177.7 million for 2006. The increase was primarily the result of higher service rates for 2007 compared to 2006, the commencement of commercial operations at our LSNG unit in June 2007 and higher fractionation volumes. These increases were partially offset by the effect of lower terminalling and storage and transport volumes.

Higher service rates for 2007 compared to 2006 were derived primarily from commercial transportation activities. These include new barge transportation contracts for mixed butanes and propane/propylene mix, new railcar lease revenue earned from the NGL Distribution and Marketing and Wholesale Marketing segment and increased truck transportation fees as a result of an increased fuel surcharge.

The overall volume increase was due to higher fractionation and LSNG related service volumes in 2007 compared to 2006, partially offset by lower terminalling and storage volumes primarily due to lower imports. Our fractionation facilities operated at 75% and 66% of design capacity for 2007 and 2006.

Operating expenses increased $19.6 million, or 14%, to $155.1 million for 2007 compared to $135.5 million for 2006. This increase is primarily due to:

- increased railcar lease expense as a result of new railcar leases following the termination of a railcar sharing agreement. Under the railcar sharing agreement, rail transportation costs were included in product purchases in our NGL Distribution and Marketing and Wholesale Marketing segments;
- the June 2007 commencement of commercial operations at our new LSNG unit, which added to operating expenses;
- increased fractionation-related expenses due to higher fractionation volumes and increased fuel costs;
- higher barge transportation costs, caused by an increase in tug rates; and
- increased terminalling and storage costs due to the timing of well workovers at Mont Belvieu.

NGL Distribution and Marketing Services Segment

The following table provides summary financial data regarding results of operations of our NGL Distribution and Marketing Services segment for the periods indicated:

	Year Ended December 31,		
	2008	2007	2006
		(In millions)	
NGL sales revenues	$ 5,172.2	$ 4,889.3	$ 3,728.4
Other revenues (1)	12.5	6.5	10.4
	5,184.7	4,895.8	3,738.8
Product purchases	(5,164.5)	(4,838.8)	(3,726.2)
Operating expenses	(1.7)	(1.5)	(2.0)
Operating margin (2)	$ 18.5	$ 55.5	$ 10.6
Operating statistics:			
NGL sales, MBbl/d	244.6	275.6	246.3
NGL realized price, $/gal	1.38	1.16	0.99

(1) Includes business interruption insurance revenues of $9.6 million, $3.8 million and $5.5 million for 2008, 2007 and 2006.
(2) See “How We Evaluate Our Operations.”

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Revenues increased $288.9 million, or 6%, to $5,184.7 million for 2008 compared to $4,895.8 million for 2007. Higher market prices increased revenue $820.6 million partially offset by lower sales volume, which decreased revenue by $537.8 million. The increase in other revenues was primarily from increased business interruption insurance revenues during 2008.

NGL sales decreased 31.0 MBbl/d, or 11%, to 244.6 MBbl/d for 2008 compared to 275.6 MBbl/d for 2007. The decrease was primarily the result of disruptions due to hurricanes Gustav and Ike as well as reduced petrochemical operating rates for 2008 as compared to 2007.

Product purchases increased $325.7 million, or 7%, to $5,164.5 million for 2008 compared to $4,838.8 million for 2007. Higher market prices increased product purchases by $857.9 million partially offset by lower volumes, which decreased product purchases by $532.2 million.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

Revenues increased $1,157.0 million, or 31%, to $4,895.8 million for 2007 compared to $3,738.8 million for 2006. The net increase comprised a $443.6 million increase as a result of higher sales volumes, a $717.3 million increase due to higher commodity prices, a $2.2 million decrease in non-commodity revenues, which are principally derived from fee-based services, and a $1.7 million decrease in business interruption insurance revenues.

NGL sales increased 29.3 MBbl/d, or 12%, to 275.6 MBbl/d for 2007 compared to 246.3 MBbl/d for 2006. The increase was primarily the result of a new source of raw product supply; sales of production from Gillis, Mertzon, and Sterling plants which prior to April 2006 were marketed by our Natural Gas Gathering and Processing segment; increased sales of production from our Yscloskey facility which was not in operation during a portion of 2006 as a result of damage from hurricanes Katrina and Rita during 2005.

Our average realized price for NGLs increased $0.17 per gallon, or 17%, to $1.16 per gallon for 2007 compared to $0.99 per gallon for 2006.

Product purchases increased $1,112.6 million, or 30%, to $4,838.8 million for 2007 compared to $3,726.2 million for 2006. Higher average market prices increased product purchases by $669.3 million and higher volumes increased product purchases by $443.1 million.

Wholesale Marketing Segment

The following table provides summary financial data regarding results of operations of our Wholesale Marketing segment for the periods indicated:

	Year Ended December 31,		
	2008	2007	2006
		(In millions)	
NGL sales revenues	$ 1,453.3	$ 1,294.7	$ 1,302.5
Other revenues (1)	6.8	1.2	7.9
	1,460.1	1,295.9	1,310.4
Product purchases	(1,446.9)	(1,273.1)	(1,299.8)
Operating expenses	(0.1)	-	-
Operating margin (2)	$ 13.1	$ 22.8	$ 10.6
Operating statistics:			
NGL sales, MBbl/d	62.5	63.6	73.2
NGL realized price, $/gal	1.51	1.33	1.16

(1) Includes business interruption insurance revenues of $6.5 million, $0.8 million and $1.1 million for 2008, 2007 and 2006.
(2) See “How We Evaluate Our Operations.”

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Revenues increased $164.2 million, or 13%, to $1,460.1 million for 2008 compared to $1,295.9 million for 2007. Higher NGL market prices increased revenue $177.4 million partially offset by lower sales volume, which decreased revenue by $18.9 million. The increase in other revenues consists of a $5.7 million increase in business interruption insurance revenues.

Our average realized price for NGL increased $0.18 per gallon, or 14%, to $1.51 per gallon for 2008 compared to $1.33 per gallon for 2007. The increase was primarily due to higher overall market prices for all components. However, market prices dropped significantly in the fourth quarter of 2008 quarter due to overall market conditions. NGL sales decreased 1.1 MBbl/d, or 2%, to 62.5 MBbl/d for 2008 compared to 63.6 MBbl/d for 2007. The decrease in volumes is due primarily to the expiration of refinery supply agreements and an operating disruption at a customer facility.

Product purchases increased $173.8 million, or 14%, to $1,446.9 million for 2008 compared to $1,273.1 million for 2007. Higher NGL market prices and lower of cost or market adjustments increased product purchases by

$186.4 million and $6.0 million partially offset by lower volumes, which decreased product purchases by $18.6 million.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

Revenues decreased $14.5 million, or 1%, to $1,295.9 million for 2007 compared to $1,310.4 million for 2006. Lower NGL sales volumes decreased revenues by $170.2 million and higher commodity prices increased revenues by $162.4 million. The decrease in other revenues consists primarily of a $6.7 million decrease in fee-based service revenue due to the termination of certain refinery service contracts.

NGL sales decreased 9.6 MBbl/d, or 13%, to 63.6 MBbl/d for 2007 compared to 73.2 MBbl/d for 2006. The decrease is primarily due to direct and indirect impacts of terminated feedstock contracts with Chevron that ended in September 2006.

Product purchases decreased $26.7 million, or 2%, to $1,273.1 million for 2007 compared to $1,299.8 million for 2006. Lower NGL volumes decreased product purchases by $169.9 million partially offset by higher market prices, which increased product purchases by $140.2 million. We incurred a smaller lower of cost or market adjustment in 2007 versus 2006 by $3.0 million.

Insurance Claims

We recognize income from business interruption insurance in our combined statements of operations as a component of revenues from third parties in the period that a proof of loss is executed and submitted to the insurers for payment. For 2008, income from business interruption insurance resulting from the effects of Hurricanes Katrina and Rita was $18.1 million. In addition, we received $0.6 million during 2008 as a result of fire damage claims at certain plants in our Wholesale Marketing segment.

Hurricanes Gustav and Ike

In September 2008, certain of our facilities in Louisiana and Texas sustained damage and had disruption to their operations from Hurricanes Gustav and Ike.

We currently estimate the cost associated with our interest for repairs to the impacted facilities to be approximately $17.4 million. We believe that we have adequate insurance coverage (subject to customary deductibles, limits and sub-limits) to cover the respective facility repair costs and to offset the majority of the associated lost profits as a result of the hurricanes. The property damage deductibles under our insurance coverage will reduce our ultimate property damage insurance recoveries by approximately $3.3 million. We will have additional out of pocket costs associated with improvements (e.g., elevating critical equipment) that may not be covered by insurance.

During 2008 we recorded a loss provision of $4.8 million for our estimated out-of-pocket cleanup and repair costs related to these two hurricanes, after estimated insurance proceeds. As of December 31, 2008, expenditures related to the hurricanes totaled $5.5 million.

Liquidity and Capital Resources

Our ability to finance our operations, including funding capital expenditures and acquisitions, to meet our indebtedness obligations, to refinance our indebtedness, to meet our collateral requirements, or to pay our distributions will depend on our ability to generate cash in the future. Our ability to generate cash is subject to a number of factors, some of which are beyond our control, including weather, commodity prices, particularly for natural gas and NGLs, and our ongoing efforts to manage operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory and other factors.

Our main sources of liquidity and capital resources are internally generated cash flow from operations, borrowings under our credit facility, the issuance of additional units by the Partnership and access to debt markets. The credit markets are undergoing significant volatility. Many financial institutions have liquidity concerns, prompting government intervention to mitigate pressure on the credit markets. Our exposure to the current credit crisis includes our credit facility, cash investments and counterparty performance risks. Continued volatility in the debt markets may increase costs associated with issuing debt instruments due to increased spreads over relevant interest rate benchmarks and affect our ability to access those markets. In order to increase our cash position in the face of the credit and capital market disruptions, on October 16, 2008, we requested a $100 million funding under our credit facility. Lehman Bank, a lender under our credit facility, defaulted on its portion of this borrowing request, resulting in actual funding of $97.8 million. As a result, we believe the availability under our credit facility has been effectively reduced by $10.0 million.

Current market conditions also elevate the concern over counterparty risks related to our commodity derivative contracts and trade credit. We have all of our commodity derivatives with major financial institutions. Should any of these financial counterparties not perform, we may not realize the benefit of some of our hedges under lower commodity prices. We sell a significant portion of our natural gas, NGLs and condensate to a variety of purchasers. Non-performance by a trade creditor could result in losses.

Crude oil and natural gas prices are also volatile and have recently declined significantly. In a continuing effort to reduce the volatility of our cash flows, we have periodically entered into commodity derivative contracts for a portion of our estimated equity volumes through 2012. See “Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk.” The current market conditions may also impact our ability to enter into future commodity derivative contracts. In the event of a global recession, commodity prices may stay depressed or fall further thereby causing a prolonged downturn, which could reduce our operating margins and cash flow from operations.

As of December 31, 2008, we had liquidity of $433.8 million, including $91.3 million of available cash and $342.5 million of available borrowings under our credit facility. We will continue to monitor our liquidity and the credit markets. Additionally, we will continue to monitor events and circumstances surrounding each of the other twenty three lenders in our credit facility. To date, other than the Lehman Bank default, we have experienced no disruptions in our ability to access funds committed under our credit facility. However, we cannot predict with any certainty the impact to us of any further disruptions in the credit environment.

Historically, our cash generated from operations has been sufficient to finance our operating expenditures and non-acquisition related capital expenditures, with remaining amounts being distributed to Targa during its period of ownership and to our unitholders since our IPO. Based on our anticipated levels of operations and absent any disruptive events, we believe that internally generated cash flow and borrowings available under our senior secured credit facilities should provide sufficient resources to finance our operations, non-acquisition related capital expenditures, hurricane-related repair expenditures, long-term indebtedness obligations, collateral requirements and minimum quarterly cash distributions for at least the next twelve months.

We intend to make cash distributions to our unitholders and our general partner in an amount at least equal to the minimum quarterly distribution rate of $0.3375 per common unit per quarter ($1.35 per common unit on an annualized basis). Due to our cash distribution policy, we expect that we will distribute to our unitholders most of the cash generated by our operations. As a result, we expect that we will rely upon external financing sources, including other debt and common unit issuances, to fund our acquisition and expansion capital expenditures. Historically, we have relied on internally generated cash flows for these purposes. See “—Factors That Significantly

Affect Our Results—Distributions to our Unitholders" for a table that shows the distributions we declared subsequent to the fourth quarter of 2008 and distributions declared and paid in 2008 and 2007.

Working Capital. Working capital is the amount by which current assets exceed current liabilities. Our working capital requirements are primarily driven by changes in accounts receivable and accounts payable. These changes are impacted by changes in the prices of commodities that we buy and sell. In general, our working capital requirements increase in periods of rising commodity prices and decrease in periods of declining commodity prices. However, our working capital needs do not necessarily change at the same rate as commodity prices because both accounts receivable and accounts payable are impacted by the same commodity prices. In addition, the timing of payments received by our customers or paid to our suppliers can also cause fluctuations in working capital because we settle with most of our larger suppliers and customers on a monthly basis and often near the end of the month. We expect that our future working capital requirements will be impacted by these same factors.

Prior to the contribution of the North Texas System in February 2007, the acquisition of the SAOU and LOU Systems in October 2007 and the acquisition of the Downstream Business in September 2009, all intercompany transactions, including commodity sales and expense reimbursements, were not cash settled with Targa, but were recorded as an adjustment to parent equity on the balance sheet. The primary transactions between Targa and us are natural gas and NGL sales, the provision of operations and maintenance activities and the provision of general and administrative services. As a result of this accounting treatment, our working capital did not reflect any affiliate accounts receivable for intercompany commodity sales or any affiliate accounts payable for the personnel and services provided by or paid for by our parent prior to the acquisition of the North Texas System and the subsequent acquisition of the SAOU and LOU Systems.

As of December 31, 2008, we had a positive working capital balance of $224.5 million.

The Partnership is obligated to make minimum quarterly cash distributions to unitholders from available cash, as defined in the partnership agreement. As of December 31, 2008, such minimum amounts payable to non-Targa unitholders total approximately $46.8 million annually.

Cash Flow

The following table summarizes cash flow provided by or used in operating activities, investing activities and financing activities for the periods indicated:

	Year Ended December 31,		
	2008	2007	2006
		(In millions)	
Net cash provided by (used in):			
Operating activities	$ 293.0	$ 268.3	$ 169.9
Investing activities	(86.1)	(76.8)	(54.6)
Financing activities	(175.9)	(139.7)	(110.7)

Operating Activities

Net cash provided by operating activities was $293.0 million for 2008 compared to $268.3 million for 2007. The $24.7 million increase was primarily due to changes in operating assets and liabilities, which provided $163.9 million in cash during 2008, compared to providing $45.9 million in cash during 2007, partially offset by an $87.4 million payment during 2008 to terminate certain out-of-the-money commodity derivatives.

Net cash provided by operating activities was $268.3 million for 2007 compared to $169.9 million for 2006. The $98.4 million increase is primarily due to a $58.8 million increase in net income, a $58.5 million increase in accrued interest expense, and a $49.0 million increase in noncash risk management charges, partially offset by a $62.8 million increase in working capital balances and a $7.3 million decrease in amortized debt issue costs.

Investing Activities

Net cash used in investing activities was $86.1 million for 2008 compared to $76.8 million for 2007. The $9.3 million increase is primarily due to increased capital expenditures during 2008. The increase is primarily from increased expenditures related to gathering system expansion projects begun in the third quarter of 2008.

Net cash used in investing activities was $76.8 million for 2007 compared to $54.6 million for 2006. The $22.2 million increase is primarily due to the completion of gathering system expansion projects; high major maintenance expenditures and the completion of construction of our low sulfur natural gasoline unit (see discussion below of "Capital Requirements").

Financing Activities

Net cash used in financing activities was $175.9 million for 2008 compared to net cash used in financing activities of $139.7 million for 2007. The $36.2 million increase is primarily due to $772.8 million of nonrecurring net proceeds from equity offerings in 2007, a $285.6 million decrease in proceeds from borrowings, a $59.7 million increase in distributions to unitholders, and a $26.8 million repurchase of senior notes in 2008, partially offset by a $671.7 million net decrease in distributions to Targa and a $436.9 million decrease in repayments of indebtedness.

Net cash used in financing activities was $139.7 million for 2007 compared to $110.7 million for 2006. The $29.0 million increase is primarily due to a $760.7 million increase in repayments of indebtedness, a $723.8 million increase in distributions to Targa and $31.2 million in distributions to unitholders, partially offset by $772.8 million of nonrecurring net proceeds from equity offerings in 2007 and a $713.8 million increase in net proceeds from borrowings.

Capital Requirements

The midstream energy business can be capital intensive, requiring significant investment to maintain and upgrade existing operations. A significant portion of the cost of constructing new gathering lines to connect to our gathering system is generally paid for by the natural gas producer. We expect to make significant expenditures during the next year for the construction of additional natural gas gathering and processing infrastructure and to enhance the value of our natural gas logistics and marketing assets.

We categorize our capital expenditures as either: (i) maintenance expenditures or (ii) expansion expenditures. Maintenance expenditures are those expenditures that are necessary to maintain the service capability of our existing assets including the replacement of system components and equipment which is worn, obsolete or completing its useful life, the addition of new sources of natural gas supply to our systems to replace natural gas production declines and expenditures to remain in compliance with environmental laws and regulations. Expansion expenditures improve the service capability of the existing assets, extend asset useful lives, increase capacities from existing levels, add capabilities, reduce costs or enhance revenues.

	Year Ended December 31,		
	2008	2007	2006
		(In millions)	
Capital expenditures:			
Expansion	$ 55.9	$ 48.7	$ 30.6
Maintenance	40.3	30.4	25.1
	$ 96.2	$ 79.1	$ 55.7

Our planned capital expenditures for 2009, excluding expenditures for the repair of previously discussed hurricane damage, are approximately $46.6 million, of which $21.8 million will be for maintenance. Given our objective of growth through acquisitions, expansions of existing assets and other internal growth projects, we anticipate that over time we will invest significant amounts of capital to grow and acquire assets. Expansion capital expenditures may vary significantly based on investment opportunities. We are currently funding the cost of hurricane damage related repairs for our facilities through operating cash flow.

Description of Senior Notes. On June 12, 2008, we entered into a purchase agreement to issue and sell $250,000,000 in aggregate principal amount of our 8¼% senior unsecured notes due 2016 (the "8¼% Notes"). On June 18, 2008, in connection with the issuance of the 8¼% Notes, we entered into an indenture (the "Indenture") governing the terms of the 8¼% Notes.

The 8¼% Notes will mature on July 1, 2016 and interest is payable on the 8¼% Notes semi-annually in arrears on each January 1 and July 1. The 8¼% Notes are guaranteed on a senior unsecured basis by certain of our subsidiaries.

The Indenture restricts our ability to make distributions to unitholders if we are in default or an event of default (as defined in the Indenture) exists. It also restricts our ability and the ability of certain of our subsidiaries to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay certain distributions on or repurchase, equity interests (only if such distributions do not meet specified conditions); (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of important exceptions and qualifications. If at any time when the 8¼% Notes are rated investment grade by both Moody's Investors Service, Inc. and Standard & Poor's Ratings Services and no Default (as defined in the Indenture) has occurred and is continuing, many of such covenants will terminate and we and our subsidiaries will cease to be subject to such covenants.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements.

Credit Facilities and Long-Term Debt

As of December 31, 2008, we had approximately $342.5 million of availability under our credit facility.

We also have senior unsecured debt and affiliated indebtedness to Targa outstanding of $209 million and $773.9 million. See Note 9 of the Notes to Supplemental Consolidated Financial Statements in Exhibit 99.3 for a discussion of our credit agreements.

On September 24, 2009, the entire balance of affiliated indebtedness was repaid to Targa.

Contractual Obligations

Following is a summary of our contractual cash obligations over the next several fiscal years, as of December 31, 2008:

	Payments Due By Period				
Contractual Obligations	**Total**	**Less Than 1 Year**	**1-3 Years**	**4-5 Years**	**More Than 5 Years**
			(In millions)		
Debt obligations (1)	$ 1,470.8	$ -	$ 773.9	$ 487.8	$ 209.1
Interest on debt obligations (2)	159.8	27.0	54.0	35.7	43.1
Operating leases (3)	53.9	10.3	15.5	11.6	16.5
Capacity payments (4)	8.2	5.4	2.8	-	-
Right-of-way	7.3	0.5	0.9	0.8	5.1
Asset retirement obligation	6.2	-	-	-	6.2
	$ 1,706.2	$ 43.2	$ 847.1	$ 535.9	$ 280.0

____

(1) Represents our scheduled future maturities of consolidated debt obligations for the periods indicated. See Note 9 of the Notes to Supplemental Consolidated Financial Statements in Exhibit 99.3 for information regarding our debt obligations.
(2) Represents interest expense on our debt obligations based on interest rates as of December 31, 2008 and the scheduled future maturities of those debt obligations.
(3) Operating lease obligations include minimum lease payment obligations associated with site leases, railcar leases, office space leases and pipeline right-of-way.
(4) Consist of capacity payments for firm transportation contracts.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with GAAP requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from these estimates. The policies and estimates discussed below are considered by management to be critical to an understanding of our financial statements because their application requires the most significant judgments from management in estimating matters for financial reporting that are inherently uncertain. Please see the description of our accounting policies in the notes to the financial statements for additional information about our critical accounting policies and estimates.

Property, Plant and Equipment. In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the period it benefits. Our property, plant and equipment is depreciated using the straight-line method over the estimated useful lives of the assets. Our estimate of depreciation incorporates assumptions regarding the useful economic lives and residual values of our assets. At the time we place our assets in-service, we believe such assumptions are reasonable; however, circumstances may develop that would cause us to change these assumptions, which would change our depreciation amounts prospectively. Examples of such circumstances include:

- changes in energy prices;
- changes in competition;
- changes in laws and regulations that limit the estimated economic life of an asset;
- changes in technology that render an asset obsolete;
- changes in expected salvage values; and

- changes in the forecast life of applicable resource basins, if any.

As of December 31, 2008, the net book value of our property, plant and equipments was $1.7 billion and we recorded $97.8 million in depreciation expense for the year ended December 31, 2008. The weighted average life of our long-lived assets is approximately 20 years. If the useful lives of these assets were found to be shorter than originally estimated, depreciation expense may increase, liabilities for future asset retirement obligations may be insufficient and impairments in carrying values of tangible and intangible assets may result. For example, if the depreciable lives of our assets were reduced by 10%, we estimate that depreciation expense would increase by $10.9 million, which would result in a corresponding reduction in our operating income. In addition, if an assessment of impairment resulted in a reduction of 1% of our long-lived assets, our operating income would decrease by $17.2 million. There have been no material changes impacting estimated useful lives of the assets.

Revenue Recognition. Revenues for a period reflect collections to the report date plus any uncollected revenues reported for the period which is reflected as accounts receivable in the balance sheet. As of December 31, 2008, the Partnership's balance sheet reflects total accounts receivable from third parties of $236.1 million. We have recorded an allowance for doubtful accounts as of December 31, 2008 of $2.2 million.

The Partnership's exposure to uncollectible accounts receivable relates to the financial health of its counterparties. The Partnership and its indirect parent, Targa, have an active credit management process which is focused on controlling loss exposure to bankruptcies or other liquidity issues of counterparties. If an assessment of uncollectibility resulted in a 1% reduction of our third-party accounts receivable, our operating income would decrease by $2.4 million. There have been no material changes impacting accounts receivable.

Price Risk Management (Hedging). Our net income and cash flows are subject to volatility stemming from changes in commodity prices and interest rates. To reduce the volatility of our cash flows, we have entered into (i) derivative financial instruments related to a portion of our equity volumes to manage the purchase and sales prices of commodities and (ii) interest rate financial instruments to fix the interest rate on our variable debt. We are exposed to the credit risk of our counterparties in these derivative financial instruments.

Our cash flow is affected by the derivative financial instruments we enter into to the extent these instruments are settled by (i) making or receiving a payment to/from the counterparty or (ii) making or receiving a payment for entering into a contract that exactly offsets the original derivative financial instrument. Typically a derivative financial instrument is settled when the physical transaction that underlies the derivative financial instrument occurs.

One of the primary factors that can affect our operating results each period is the price assumptions we use to value our derivative financial instruments, which are reflected at their fair values in the balance sheet. The relationship between the derivative financial instruments and the hedged item must be highly effective in achieving the offset of changes in cash flows attributable to the hedged risk both at the inception of the derivative financial instrument and on an ongoing basis. Hedge accounting is discontinued prospectively when a derivative financial instrument becomes ineffective. Gains and losses deferred in other comprehensive income related to cash flow hedges for which hedge accounting has been discontinued remain deferred until the forecasted transaction occurs. If it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the derivative financial instrument are reclassified to earnings immediately.

The estimated fair value of our derivative financial instruments was $138.7 million as of December 31, 2008, net of an adjustment for credit risk. The credit risk adjustment is based on the default probabilities by year for each counterparty's traded credit default swap transactions. These default probabilities have been applied to the unadjusted fair values of the derivative financial instruments to arrive at the credit risk adjustment, which aggregates to $6.5 million as of December 31, 2008. We and our indirect parent, Targa, have an active credit management process which is focused on controlling loss exposure to bankruptcies or other liquidity issues of counterparties. If financial instrument counterparty were to declare bankruptcy, we would be exposed to the loss of fair value of the financial instrument transaction with that counterparty. Ignoring our adjustment for credit risk, if a bankruptcy by financial instrument counterparty impacted 10% of the fair value of commodity-based financial instruments, we estimate that our operating income would decrease by $13.9 million.

Recent Accounting Pronouncements.

For a discussion of recent accounting pronouncements that will affect us, see Note 3 to our Supplemental Consolidated Financial Statements in Exhibit 99.3.

Quantitative and Qualitative Disclosures About Market Risk

Our principal market risks are our exposure to changes in commodity prices, particularly to the prices of natural gas and NGLs, changes in interest rates, as well as nonperformance by our customers. We do not use risk sensitive instruments for trading purposes.

Commodity Price Risk. A majority of our revenues are derived from percent-of-proceeds contracts under which we receive a portion of the natural gas and/or NGLs or equity volumes, as payment for services. The prices of natural gas and NGLs are subject to fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional factors beyond our control. We monitor these risks and enter into hedging transactions designed to mitigate the impact of commodity price fluctuations on our business. Cash flows from a derivative instrument designated as a hedge are classified in the same category as the cash flows from the item being hedged.

The primary purpose of our commodity risk management activities is to hedge our exposure to commodity price risk and reduce fluctuations in our operating cash flow despite fluctuations in commodity prices. In an effort to reduce the variability of our cash flows, as of December 31, 2008, we have hedged the commodity price associated with a significant portion of our expected natural gas, NGL and condensate equity volumes for the years 2009 through 2012 by entering into derivative financial instruments including swaps and purchased puts (or floors). The percentages of our expected equity volumes that are hedged decrease over time. With swaps, we typically receive an agreed fixed price for a specified notional quantity of natural gas or NGL and we pay the hedge counterparty a floating price for that same quantity based upon published index prices. Since we receive from our customers substantially the same floating index price from the sale of the underlying physical commodity, these transactions are designed to effectively lock-in the agreed fixed price in advance for the volumes hedged. In order to avoid having a greater volume hedged than our actual equity volumes, we typically limit our use of swaps to hedge the prices of less than our expected natural gas and NGL equity volumes. We utilize purchased puts (or floors) to hedge additional expected equity commodity volumes without creating volumetric risk. We intend to continue to manage our exposure to commodity prices in the future by entering into similar hedge transactions using swaps, collars, purchased puts (or floors) or other hedge instruments as market conditions permit.

We have tailored our hedges to generally match the NGL product composition and the NGL and natural gas delivery points to those of our physical equity volumes. Our NGL hedges cover baskets of ethane, propane, normal butane, iso-butane and natural gasoline based upon our expected equity NGL composition. We believe this strategy avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as “proxy” hedges of NGL prices. Additionally, our NGL hedges are based on published index prices for delivery at Mont Belvieu and our natural gas hedges are based on published index prices for delivery at Waha and Mid-Continent, which closely approximate our actual NGL and natural gas delivery points. We hedge a portion of our condensate sales using crude oil hedges that are based on the NYMEX futures contracts for West Texas Intermediate light, sweet crude.

Our commodity price hedging transactions are typically documented pursuant to a standard International Swap Dealers Association form with customized credit and legal terms. Our principal counterparties (or, if applicable, their guarantors) have investment grade credit ratings. Our payment obligations in connection with substantially all of these hedging transactions and any additional credit exposure due to a rise in natural gas and NGL prices relative to the fixed prices set forth in the hedges, are secured by a first priority lien in the collateral securing our senior secured indebtedness that ranks equal in right of payment with liens granted in favor of our senior secured lenders. As long as this first priority lien is in effect, we expect to have no obligation to post cash, letters of credit or other additional collateral to secure these hedges at any time, even if our counterparty’s exposure to our credit increases over the term of the hedge as a result of higher commodity prices or because there has been a change in our creditworthiness. A purchased put (or floor) transaction does not create credit exposure to us for our counterparties.

During 2008, 2007 and 2006, we entered into hedging arrangements for a portion of our forecasted equity volumes. Floor volumes and floor pricing are based solely on purchased puts (or floors). During 2008, 2007 and 2006, our operating revenues were adjusted by net hedge losses of $33.7 million, $1.0 million and $0.9 million.

As of December 31, 2008, our commodity hedges were as follows:

Natural Gas

Instrument Type	Index	Avg. Price $/MMBtu	MMBtu per day 2009	2010	2011	2012	Fair Value
							(In thousands)
Natural Gas Sales							
Swap	IF-HSC	7.39	1,966	-	-	-	$ 1,159
			1,966	-	-	-	
Swap	IF-NGPL MC	9.18	6,256	-	-	-	9,466
Swap	IF-NGPL MC	8.86	-	5,685	-	-	5,129
Swap	IF-NGPL MC	7.34	-	-	2,750	-	843
Swap	IF-NGPL MC	7.18	-	-	-	2,750	738
			6,256	5,685	2,750	2,750	
Swap	IF-Waha	8.73	6,936	-	-	-	8,627
Swap	IF-Waha	7.52	-	5,709	-	-	2,294
Swap	IF-Waha	7.36	-	-	3,250	-	886
Swap	IF-Waha	7.18	-	-	-	3,250	708
			6,936	5,709	3,250	3,250	
Total Swaps			15,158	11,394	6,000	6,000	
Floor	IF-NGPL MC	6.55	850	-	-	-	574
			850	-	-	-	
Floor	IF-Waha	6.55	565	-	-	-	326
			565	-	-	-	
Total Floors			1,415	-	-	-	
Total Sales			16,573	11,394	6,000	6,000	
							$ 30,750

NGL

Instrument Type	Index	Avg. Price $/gal	Barrels per day 2009	2010	2011	2012	Fair Value
							(In thousands)
NGL Sales							
Swap	OPIS-MB	1.32	6,248	-	-	-	$ 66,137
Swap	OPIS-MB	1.27	-	4,809	-	-	39,122
Swap	OPIS-MB	0.92	-	-	3,400	-	8,288
Swap	OPIS-MB	0.92	-	-	-	2,700	6,018
Total Swaps			6,248	4,809	3,400	2,700	
Floor	OPIS-MB	1.44	-	-	199	-	1,807
Floor	OPIS-MB	1.43	-	-	-	231	1,932
Total Floors			-	-	199	231	
Total Sales			6,248	4,809	3,599	2,931	
							$ 123,304

Condensate

Instrument Type	Index	Avg. Price $/Bbl	Barrels per day 2009	2010	2011	2012	Fair Value
							(In thousands)
Condensate Sales							
Swap	NY-WTI	69.00	322	-	-	-	$ 1,655
Swap	NY-WTI	68.10	-	301	-	-	431
Total Swaps			322	301	-	-	
Floor	NY-WTI	60.00	50	-	-	-	239
Total Floors			50	-	-	-	
Total Sales			372	301	-	-	
							$ 2,325

These contracts may expose us to the risk of financial loss in certain circumstances. Our hedging arrangements provide us protection on the hedged volumes if prices decline below the prices at which these hedges are set. If prices rise above the prices at which we have hedged, we will receive less revenue on the hedged volumes than we would receive in the absence of hedges.

Interest Rate Risk. We are exposed to changes in interest rates, primarily as a result of our variable rate debt under our credit facility. To the extent that interest rates increase, our interest expense for our revolving debt will also increase. As of December 31, 2008, there were borrowings of approximately $487.8 million outstanding under our $850 million credit facility.

As of December 31, 2008 we had the following open interest rate swaps:

Expiration Date	Fixed Rate	Notional Amount	Fair Value
			(In thousands)
January 24, 2011	4.00%	$100 million	$ (5,282)
January 24, 2012	3.75%	200 million	(12,294)
			$ (17,576)

We have designated all interest rate swaps as cash flow hedges. Accordingly, unrealized gains and losses relating to the interest rate swaps are recorded in OCI until the interest expense on the related debt is recognized in earnings. A hypothetical increase of 100 basis points in the underlying interest rate, after taking into account our interest rate swaps, would increase our annual interest expense by $1.9 million.

Credit Risk. We are subject to risk of losses resulting from nonpayment or nonperformance by our customers. We operate under the Targa credit policy and closely monitor the creditworthiness of customers to whom we grant credit and establish credit limits in accordance with this credit policy. In addition to third party contracts, we have entered into several agreements with Targa. For example, we are party to natural gas, NGL and condensate purchase agreements pursuant to which Targa purchases the majority of our natural gas, NGLs and high-pressure condensate. In addition, we are also a party to an omnibus agreement with Targa which addresses, among other things, the provision of general and administrative and operating services to us. Any material nonperformance under the omnibus and purchase agreements by Targa could materially and adversely impact our ability to operate and make distributions to our unitholders.

As of December 31, 2008, affiliates of Goldman Sachs, BofA and Barclays Bank accounted for 67%, 21% and 11% of our counterparty credit exposure related to commodity derivative instruments. Goldman Sachs, BofA and Barclays Bank are major financial institutions, each possessing investment grade credit ratings, based upon minimum credit ratings assigned by Standard & Poor’s Ratings Services.

Supplemental Consolidated Financial Statements of Targa Resources Partners LP

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Targa Resources GP LLC, the general partner of the Partnership, is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

The management of Targa Resources GP LLC has used the framework set forth in the report entitled "Internal Control — Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") to evaluate the effectiveness of the Partnership's internal control over financial reporting. Based on that evaluation, management has concluded that the Partnership's internal control over financial reporting was effective as of December 31, 2008.

The effectiveness of the Partnerships' internal control over financial reporting as of December 31, 2008 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on Page 2.

/s/ Rene R. Joyce
Rene R. Joyce
Chief Executive Officer of Targa Resources GP LLC, the general partner of Targa Resources Partners LP (Principal Executive Officer)

/s/ Jeffrey J. McParland
Jeffrey J. McParland
Executive Vice President, Chief Financial Officer of Targa Resources GP LLC, the general partner of Targa Resources Partners LP (Principal Financial Officer)

Report of Independent Registered Public Accounting Firm

To the Partners of Targa Resources Partners LP:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of comprehensive income (loss), of changes in partners' capital/net parent investment and of cash flows present fairly, in all material respects, the financial position of Targa Resources Partners LP and its subsidiaries (the "Partnership") at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Partnership's internal control over financial reporting based on our audits (which was an integrated audit in 2008). We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 14 to the consolidated financial statements, the Partnership has engaged in significant transactions with other subsidiaries of its parent company, Targa Resources, Inc., a related party.

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Houston, Texas

February 25, 2009, except with respect to our opinions on the consolidated financial statements and internal control over financial reporting insofar as they relate to the effects of the acquisition of the Downstream Business discussed in Note 2, as to which the date is November 30, 2009

TARGA RESOURCES PARTNERS LP
SUPPLEMENTAL CONSOLIDATED BALANCE SHEETS

	December 31, 2008	December 31, 2007
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 95,308	$ 64,342
Trade receivables, net of allowances of $2,207 and $943	236,137	733,968
Inventory	72,183	147,591
Assets from risk management activities	91,816	8,695
Other current assets	782	683
Total current assets	496,226	955,279
Property, plant and equipment, at cost	2,036,378	1,936,158
Accumulated depreciation	(317,322)	(219,737)
Property, plant and equipment, net	1,719,056	1,716,421
Long-term assets from risk management activities	68,296	3,040
Investment in unconsolidated affiliate	18,465	19,238
Other long-term assets	12,776	8,876
Total assets	$ 2,314,819	$ 2,702,854
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable to third parties	$ 138,745	$ 435,118
Accounts payable to affiliates	17,227	65,598
Accrued liabilities	104,112	155,697
Liabilities from risk management activities	11,664	44,003
Total current liabilities	271,748	700,416
Long-term debt payable to third parties	696,845	626,300
Long-term debt payable to Targa Resources, Inc.	773,883	711,267
Long-term liabilities from risk management activities	9,679	43,109
Deferred income taxes	3,337	1,529
Other long-term liabilities	6,239	5,861
Commitments and contingencies (see Note 15)		
Owners' equity:		
Common unitholders (34,652,000 and 34,636,000 units issued and outstanding as of December 31, 2008 and 2007)	769,921	770,207
Subordinated unitholders (11,528,231 units issued and outstanding as of as of December 31, 2008 and 2007)	(85,185)	(84,999)
General partner (942,455 and 942,128 units issued and outstanding as of December 31, 2008 and 2007)	5,556	4,234
Net parent investment	(223,534)	(15,338)
Accumulated other comprehensive income (loss)	72,238	(73,250)
	538,996	600,854
Noncontrolling interest in subsidiary	14,092	13,518
Total owners' equity	553,088	614,372
Total liabilities and owners' equity	$ 2,314,819	$ 2,702,854

See notes to supplemental consolidated financial statements

TARGA RESOURCES PARTNERS LP
SUPPLEMENTAL CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2008	2007	2006
	(In thousands, except per unit data)		
Revenues from third parties	$ 6,983,624	$ 6,398,721	$ 5,578,236
Revenues from affiliates	489,773	417,425	329,253
Total operating revenues	7,473,397	6,816,146	5,907,489
Costs and expenses:			
Product purchases from third parties	5,824,433	5,321,627	4,550,470
Product purchases from affiliates	1,097,640	952,774	928,403
Operating expenses from third parties	195,190	175,129	154,492
Operating expenses from affiliates	58,846	44,530	38,603
Depreciation and amortization expenses	97,837	93,520	90,744
General and administrative expenses	68,641	63,986	57,259
Other	(966)	(296)	34
	7,341,621	6,651,270	5,820,005
Income from operations	131,776	164,876	87,484
Other income (expense):			
Interest expense from affiliate	(59,255)	(58,526)	-
Interest expense allocated from Parent	-	(19,436)	(127,288)
Other interest income (expense), net	(37,757)	(21,392)	227
Equity in earnings of unconsolidated investment	3,877	3,511	2,754
Gain on debt repurchases	13,061	-	-
Gain (loss) on mark-to-market derivative instruments	(991)	(30,221)	16,756
Other	1,378	(1,101)	(155)
Income (loss) before income taxes	52,089	37,711	(20,222)
Income tax expense:			
Current	(582)	(574)	-
Deferred	(1,808)	(1,945)	(3,430)
	(2,390)	(2,519)	(3,430)
Net income (loss)	49,699	35,192	(23,652)
Less: Net income attributable to noncontrolling interest	274	112	(630)
Net income attributable to Targa Resources Partners LP	$ 49,425	$ 35,080	$ (23,022)
Net income (loss) attributable to predecessor operations	$ (42,069)	$ 7,014	
Net income attributable to general partner	7,049	561	
Net income allocable to limited partners	84,445	27,505	
Basic and diluted net income per limited partner unit	$ 1.83	$ 0.81	
Basic and diluted weighted average limited partner units outstanding	46,177	34,002	

See notes to supplemental consolidated financial statements

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31, 2008	2007	2006
		(In thousands)	
Net income (loss)	$ 49,699	$ 35,192	$ (23,652)
Other comprehensive income (loss):			
Commodity hedges:			
Change in fair value	130,002	(105,584)	36,937
Reclassification adjustment for settled periods	33,650	993	(822)
Related income taxes	-	312	(312)
Interest rate hedges:			
Change in fair value	(19,037)	(1,689)	1,838
Reclassification adjustment for settled periods	2,693	(232)	(708)
Foreign currency translation adjustment	(1,820)	1,925	59
Other comprehensive income (loss)	145,488	(104,275)	36,992
Comprehensive income (loss)	195,187	(69,083)	13,340
Less: Comprehensive income attributable to noncontrolling interest	274	112	(630)
Comprehensive income (loss) attributable to Targa Resources Partners LP	$ 194,913	$ (69,195)	$ 13,970

See notes to supplemental consolidated financial statements

TARGA RESOURCES PARTNERS LP
SUPPLEMENTAL CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2008	2007	2006
		(In thousands)	
Cash flows from operating activities			
Net income (loss)	$ 49,699	$ 35,192	$ (23,652)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Amortization in interest expense	2,116	1,805	9,095
Amortization in general and administrative expense	280	180	-
Interest expense on affiliate indebtedness	59,255	58,526	-
Depreciation and other amortization expense	97,837	93,520	90,744
Accretion of asset retirement obligations	312	413	311
Deferred income tax expense	1,808	1,945	3,430
Equity in earnings of unconsolidated investments, net of distributions	773	364	(448)
Risk management activities	(63,973)	30,751	(18,297)
Gain on debt repurchases	(13,061)	-	-
Gain on sale of assets	(5,917)	(296)	34
Changes in operating assets and liabilities:			
Receivables and other assets	582,753	(117,096)	35,073
Inventory	75,408	(28,630)	35,977
Accounts payable and other liabilities	(494,300)	191,578	37,594
Net cash provided by operating activities	292,990	268,252	169,861
Cash flows from investing activities			
Additions to property, plant and equipment	(86,279)	(77,545)	(54,405)
Other, net	180	787	(156)
Net cash used in investing activities	(86,099)	(76,758)	(54,561)
Cash flows from financing activities			
Proceeds from borrowings under credit facility	185,265	721,300	-
Repayments of credit facility	(323,800)	(95,000)	-
Proceeds from issuance of senior notes	250,000	-	-
Repurchases of senior notes	(26,832)	-	-
Repayment of affiliated indebtedness	-	(665,692)	-
Proceeds from equity offerings	-	777,471	-
Distributions to unitholders	(90,932)	(31,221)	-
General partner contributions	8	-	-
Costs incurred in connection with public offerings	(89)	(4,640)	-
Costs incurred in connection with financing arrangements	(7,079)	(7,491)	-
Parent distributions	(166,127)	(847,468)	(110,690)
Loan from Parent	3,361	13,024	-
Contribution from noncontrolling interest	300	-	-
Net cash used in financing activities	(175,925)	(139,717)	(110,690)
Net change in cash and cash equivalents	30,966	51,777	4,610
Cash and cash equivalents, beginning of year	64,342	12,565	7,955
Cash and cash equivalents, end of year	$ 95,308	$ 64,342	$ 12,565

See notes to supplemental consolidated financial statements

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENT OF CHANGES IN OWNERS' EQUITY

	Limited Partners		General	Accumulated Other Comprehensive	Net Parent	Noncontrolling	
	Common	Subordinated	Partner	Income (Loss)	Investment	Interest	Total
				(In thousands)			
Balance, December 31, 2005	$ -	$ -	$ -	$ (5,654)	$ 586,823	$ 14,036	$ 595,205
Distributions to Parent	-	-	-	-	(214,596)	-	(214,596)
Net loss	-	-	-	-	(23,022)	(630)	(23,652)
Other comprehensive income	-	-	-	36,992	-	-	36,992
Balance, December 31, 2006	-	-	-	31,338	349,205	13,406	393,949
Contribution from Parent, net	-	-	-	(313)	270,529	-	270,216
Book value of net assets transferred under common control	-	(83,715)	(4,101)	-	(642,086)	-	(729,902)
Issuance of units to public (including underwriter over-allotment), net of offering and other costs	771,835	-	8,398	-	-	-	780,233
Amortization of equity awards	180	-	-	-	-	-	180
Distributions to unitholders	(20,871)	(9,726)	(624)	-	-	-	(31,221)
Net income	19,063	8,442	561	-	7,014	112	35,192
Other comprehensive loss	-	-	-	(104,275)	-	-	(104,275)
Balance, December 31, 2007	770,207	(84,999)	4,234	(73,250)	(15,338)	13,518	614,372
Contributions	-	-	8	-	-	-	8
Amortization of equity awards	280	-	-	-	-	-	280
Distributions to unitholders	(63,928)	(21,269)	(5,735)	-	-	-	(90,932)
Distribution to Parent	-	-	-	-	(166,127)	-	(166,127)
Contribution from noncontrolling interest	-	-	-	-	-	300	300
Net income (loss)	63,362	21,083	7,049	-	(42,069)	274	49,699
Other comprehensive income	-	-	-	145,488	-	-	145,488
Balance, December 31, 2008	$ 769,921	$ (85,185)	$ 5,556	$ 72,238	$ (223,534)	$ 14,092	$ 553,088

See notes to supplemental consolidated financial statements

Except as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars.

Note 1—Organization and Operations

Targa Resources Partners LP, together with its subsidiaries, is a publicly traded Delaware limited partnership formed on October 26, 2006 by Targa Resources, Inc. ("Targa" or "Parent"). In this report, unless the context requires otherwise, references to "we," "us," "our" or the "Partnership" are intended to mean the business and operations of Targa Resources Partners LP and its consolidated subsidiaries. References to "TRP LP" are intended to mean and include Targa Resources Partners LP, individually, and not on a consolidated basis. Our common units are listed on The NASDAQ Stock Market LLC under the symbol "NGLS." Our business operations consist of natural gas gathering and processing, and the fractionating, storing, terminalling, transporting, distributing and marketing of natural gas liquids ("NGLs"). See Note 18.

Targa Resources GP LLC is a Delaware single-member limited liability company, formed in October 2006 to own a 2% general partner interest in us. Its primary business purpose is to manage our affairs and operations. Targa Resources GP LLC is an indirect wholly-owned subsidiary of Targa.

On February 14, 2007, we completed an initial public offering ("IPO") of common units representing limited partner interests in the Partnership. Concurrent with the IPO, Targa conveyed its ownership interests in Targa North Texas GP LLC and Targa North Texas LP (collectively, the "North Texas System") to us.

On October 24, 2007, Targa conveyed its ownership interests in Targa Texas Field Services LP (the "SAOU System") and Targa Louisiana Field Services LLC (the "LOU System") to us. This conveyance consisted of the SAOU System's natural gas gathering and processing businesses and the LOU System's natural gas gathering and processing businesses.

On September 24, 2009, we acquired Targa's interests in Targa Downstream LP, Targa LSNG LP, Targa Downstream GP LLC and Targa LSNG GP LLC (collectively, the "Downstream Business") in a transaction among entities under common control. See Note 4.

Note 2—Basis of Presentation

The supplemental consolidated financial statements include our accounts and: (i) prior to September 24, 2009 the assets, liabilities and operations of the Downstream Business; (ii) prior to October 24, 2007 the assets, liabilities and operations of the SAOU and LOU Systems as the predecessor entities; and (iii) prior to February 14, 2007 the assets, liabilities and operations of the North Texas System.

Targa's conveyances to us of the North Texas System, the SAOU and LOU Systems and the Downstream Business have been accounted for as transfers of net assets between entities under common control. We recognize transfers of net assets between entities under common control at Targa's historical basis in the net assets conveyed. In addition, transfers of net assets between entities under common control are accounted for as if the transfer occurred at the beginning of the period, and prior years are retroactively adjusted to furnish comparative information similar to the pooling of interests method. The amount of the purchase price in excess of Targa's basis in the net assets, if any, is recognized as a reduction to net parent investment.

Our supplemental consolidated financial statements and all other financial information included in this report have been retrospectively adjusted to assume that the acquisition of the Downstream Business from Targa by us had occurred at the date when both the Downstream Business and the North Texas System met the accounting requirements for entities under common control (October 31, 2005) following the acquisition of the SAOU and LOU Systems. As a result, supplemental financial statements and financial information presented for prior periods in this report have been retrospectively adjusted.

The retrospective adjustment resulted in all the footnotes and other financial information being updated to reflect the acquisition, including: significant accounting policies (Note 3), conveyance of Downstream Business (Note 4), investment in unconsolidated affiliate (Note 7), debt obligations (Note 9), insurance claims (Note 11), segment information (Note 18), other operating income (Note 19) and supplemental cash flow information (Note 20).

The supplemental consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). We refer to the operations, assets and liabilities of the North Texas System, the SAOU and LOU Systems, and the Downstream Business, prior to our acquisition from Targa, collectively as our "predecessors." The consolidated financial statements of our predecessors have been prepared from the separate records maintained by Targa and may not necessarily be indicative of the conditions that would have existed or the results of operations if our predecessors had been operated as unaffiliated entities. All significant intercompany balances and transactions have been eliminated. Transactions between us and other Targa operations have been identified in the consolidated financial statements as transactions between affiliates.

We have been allocated general and administrative expenses incurred by our Parent in order to present financial statements on a stand-alone basis. See Note 14. All of the allocations are not necessarily indicative of the costs and expenses that would have resulted had we been operated as stand-alone entities.

Note 3—Significant Accounting Policies

Asset retirement obligations ("AROs"). AROs are legal obligations associated with the retirement of tangible long-lived assets that result from the asset's acquisition, construction, development and/or normal operation. An ARO is initially measured at its estimated fair value. Upon initial recognition of an ARO, we record an increase to the carrying amount of the related long-lived asset and an offsetting ARO liability. The consolidated cost of the asset and the capitalized asset retirement obligation is depreciated using a systematic and rational allocation method over the period during which the long-lived asset is expected to provide benefits. After the initial period of ARO recognition, the ARO will change as a result of either the passage of time or revisions to the original estimates of either the amounts of estimated cash flows or their timing. Changes due to the passage of time increase the carrying amount of the liability because there are fewer periods remaining from the initial measurement date until the settlement date; therefore, the present values of the discounted future settlement amount increases. These changes are recorded as a period cost called accretion expense. Upon settlement, AROs will be extinguished by us at either the recorded amount or we will recognize a gain or loss on the difference between the recorded amount and the actual settlement cost. See Note 8.

Cash and Cash Equivalents. Cash and cash equivalents include all cash on hand, demand deposits, and investments with original maturities of three months or less. We consider cash equivalents to include short-term, highly liquid investments that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value. See discussion of centralized cash management in Note 14.

Comprehensive Income. Comprehensive income includes net income and other comprehensive income, which includes unrealized gains and losses on derivative instruments that are designated as hedges and currency translation adjustments.

Concentration of Credit Risk. Financial instruments which potentially subject us to concentrations of credit risk consist primarily of trade accounts receivable and commodity derivative instruments.

Trade Accounts Receivable. We extend credit to customers and other parties in the normal course of business. We have established various procedures to manage our credit exposure, including initial credit approvals, credit limits and terms, letters of credit, and rights of offset. We also use prepayments and guarantees to limit credit risk to ensure that our established credit criteria are met.

Estimated losses on accounts receivable are provided through an allowance for doubtful accounts. In evaluating the level of established reserves, we make judgments regarding each party's ability to make required payments, economic events and other factors. As the financial condition of any party changes, circumstances develop or additional information becomes available, adjustments to an allowance for doubtful accounts may be required.

The following table presents the activity of our allowance for doubtful accounts for the periods indicated:

	Year Ended December 31,		
	2008	2007	2006
Balance at beginning of year	$ 943	$ 781	$ 775
Additions	1,264	242	746
Deductions	-	(80)	(740)
Balance at end of year	$ 2,207	$ 943	$ 781

Significant Commercial Relationships. The following table lists the percentage of our combined sales and purchases with Chevron (including the Chevron Phillips Chemical Company LLC joint venture), which accounted for more than 10% of our combined revenues and combined product purchases for the years indicated:

	Year Ended December 31,		
	2008	2007	2006
% of revenues	22%	24%	29%
% of product purchases	8%	11%	18%

Commodity Derivative Instruments. As of December 31, 2008, affiliates of Goldman Sachs, Bank of America (“BofA”) and Barclays Bank accounted for 67%, 21% and 11% of our counterparty credit exposure related to commodity derivative instruments. Goldman Sachs, BofA and Barclays Bank are major financial institutions, each possessing investment grade credit ratings, based upon minimum credit ratings assigned by Standard & Poor’s Ratings Services. See Note 13.

Consolidation Policy. We evaluate our financial interests in business enterprises to determine if they represent variable interest entities where we are the primary beneficiary. If such criteria are met, we consolidate the financial statements of such businesses with those of our own. Our consolidated financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling interest, and our proportionate share of assets, liabilities, revenues and expenses of undivided interests in certain gas processing facilities after the elimination of all material intercompany accounts and transactions. We also consolidate other entities and ventures in which we possess a controlling interest.

We follow the equity method of accounting if our ownership interest is between 20% and 50% and we exercise significant influence over the operating and financial policies of the investee. Our proportionate share of profits and losses from transactions with equity method unconsolidated affiliates are eliminated in consolidation to the extent such amounts are material and remain on our equity method investees’ balance sheet in inventory or similar accounts.

If our ownership interest in an investee does not provide us with either control or significant influence over the investee, we account for the investment using the cost method.

Debt Issue Costs. Costs incurred in connection with the issuance of long-term debt are capitalized and charged to interest expense over the term of the related debt.

Environmental Liabilities. Liabilities for loss contingencies, including environmental remediation costs arising from claims, assessments, litigation, fines, and penalties and other sources are charged to expense when it is probable that a liability has been incurred and the amount of the assessment and/or remediation can be reasonably estimated. See Note 15.

Exchanges. Exchanges are movements of NGL products between parties to satisfy timing and logistical needs of the parties. Volumes received and delivered under exchange agreements are recorded as inventory. If the locations of receipt and delivery are in different markets, a price differential may be billed or owed. The price differential is recorded as either accounts receivable or accrued liabilities.

Impairment Testing for Unconsolidated Investments. We evaluate equity method investments (which include excess cost amounts attributable to tangible or intangible assets) for impairment when events or changes in circumstances indicate that there is a loss in value of the investment which is an other than temporary decline. Examples of such events or changes in circumstances include continuing operating losses of the investee or long-term negative changes in the investee's industry. In the event we determine that the decline in value of an investment is other than temporary, we record a charge to earnings to adjust the carrying value to fair value.

Income Taxes. We are not subject to federal income taxes. As a result, our earnings or losses for federal income tax purposes are included in the tax returns of our individual partners. In May 2006, Texas adopted a margin tax, consisting generally of a 1% tax on the amount by which total revenues exceed cost of goods sold, as apportioned to Texas. Accordingly, we have estimated our liability for this tax and it is presently recorded as a deferred tax liability.

We have determined that there are no significant uncertain tax positions requiring recognition in our financial statements as of December 31, 2008. There are no unrecognized tax benefits that, if recognized, would affect the effective rate, and there are no unrecognized tax benefits that are reasonably expected to increase or decrease in the next twelve months. We file tax returns in the United States Federal and several state jurisdictions, and are open to federal and state income tax examinations for years 2007 forward. Presently, no income tax examinations are underway, and none have been announced. No potential interest or penalties were recognized as of December 31, 2008.

Inventory Imbalance. Quantities of natural gas and/or NGLs over-delivered or under-delivered related to operational balancing agreements are recorded monthly as inventory or as a payable using weighted average prices as of the time the imbalance was created. Monthly, inventory imbalances receivable are valued at the lower of cost or market; inventory imbalances payable are valued at replacement cost. These imbalances are typically settled in the following month with deliveries of natural gas or NGLs. Certain contracts require cash settlement of imbalances on a current basis. Under these contracts, imbalance cash-outs are recorded as a sale or purchase of natural gas, as appropriate.

Net Income per Limited Partner Unit. Our net income is allocated to the general partner and the limited partners in accordance with their respective ownership percentages, after giving effect to incentive distributions paid to the general partner. Basic and diluted net income per limited partner unit is calculated by dividing limited partners' interest in net income by the weighted average number of outstanding limited partner units during the period.

Unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are classified as participating securities and are included in our computation of basic and diluted net income per limited partner unit.

We compute earnings per unit using the Two-Class Method. The Two-Class Method requires that securities that meet the definition of a participating security be considered for inclusion in the computation of basic earnings per unit using the Two-Class Method. Under the Two-Class Method, earnings per unit is calculated as if all of the earnings for the period were distributed under the terms of the partnership agreement, regardless of whether the general partner has discretion over the amount of distributions to be made in any particular period, whether those earnings would actually be distributed during a particular period from an economic or practical perspective, or whether the general partner has other legal or contractual limitations on its ability to pay distributions that would prevent it from distributing all of the earnings for a particular period.

The Two-Class Method does not impact our overall net income or other financial results; however, in periods in which aggregate net income exceeds our aggregate distributions for such period, it will have the impact of reducing net income per limited partner unit. This result occurs as a larger portion of our aggregate earnings, as if distributed, is allocated to the incentive distribution rights of the general partner, even though we make distributions on the basis of available cash and not earnings. In periods in which our aggregate net income does not exceed our aggregate distributions for such period, the Two-Class Method does not have any impact on our calculation of earnings per limited partner unit.

The calculation of net income per limited unit for 2006 is not presented as we did not have any outstanding units until we completed our IPO on February 14, 2007. The calculation of basic and diluted net income per common and subordinated unit are the same for all periods presented as distributable cash flow was greater than net income for those periods and distributions to the subordinated unitholders have been equivalent to the distribution to the common unitholders for all quarters.

Noncontrolling Interest. Noncontrolling interest represents third party ownership in the net assets of our consolidated subsidiaries. For financial reporting purposes, the assets and liabilities of our majority owned subsidiaries are consolidated with those of our own, with any third party investor's interest shown as noncontrolling interest. In the statements of operations, noncontrolling interest reflects the allocation of joint venture earnings to a third party investor. Distributions to and contributions from noncontrolling interest represent cash payments and cash contributions from such third party investor.

Price Risk Management (Hedging). All derivative instruments not qualifying for the normal purchases and normal sales exception are recorded on the balance sheet at fair value. If a derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss on the derivative is recognized currently in earnings. If a derivative qualifies for hedge accounting and is designated as a cash flow hedge, the effective portion of the unrealized gain or loss on the derivative is deferred in accumulated other comprehensive income ("OCI"), a component of net parent investment, and reclassified to earnings when the forecasted transaction occurs. Cash flows from a derivative instrument designated as a hedge are classified in the same category as the cash flows from the item being hedged.

Our policy is to formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategy for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedged item, the nature of the risk being hedged and the manner in which the hedging instrument's effectiveness will be assessed. At the inception of the hedge and on an ongoing basis, we assess whether the derivatives used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items. Hedge ineffectiveness is measured on a quarterly basis. Any ineffective portion of the unrealized gain or loss is reclassified to earnings in the current period.

The relationship between the hedging instrument and the hedged item must be highly effective in achieving the offset of changes in cash flows attributable to the hedged risk both at the inception of the contract and on an ongoing basis. Hedge accounting is discontinued prospectively when a hedge instrument is terminated or ceases to be highly effective. Gains and losses deferred in OCI related to cash flow hedges for which hedge accounting has been discontinued remain deferred until the forecasted transaction occurs. If it is no longer probable that a hedged forecasted transaction will occur, deferred gains or losses on the hedging instrument are reclassified to earnings immediately. See Notes 13, 14 and 17.

Property, Plant and Equipment. Property, plant and equipment are stated at cost less accumulated depreciation. Depreciation is computed using the straight-line method over the estimated useful lives of the assets. The estimated service lives of our functional asset groups are as follows:

Asset Group	**Range of Years**
Gas gathering systems and processing systems	15 to 25
Fractionation, terminalling and natural gas liquids storage facilities	5 to 25
Transportation assets	10 to 25
Other property and equipment	3 to 25

Expenditures for maintenance and repairs are expensed as incurred. Expenditures to refurbish assets that extend the useful lives or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the asset.

Our determination of the useful lives of property, plant and equipment requires us to make various assumptions, including the supply of and demand for hydrocarbons in the markets served by our assets, normal wear and tear of the facilities, and the extent and frequency of maintenance programs. From time to time, we utilize consultants and other experts to assist us in assessing the remaining lives of the crude oil or natural gas production in the basins we serve.

We may capitalize certain costs directly related to the construction of assets, including internal labor costs, interest and engineering costs. Upon disposition or retirement of property, plant and equipment, any gain or loss is charged to operations.

We evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, the business climate, legal and other factors indicate we may not recover the carrying amount of the assets. We continually monitor our businesses and the market and business environments to identify indicators that may suggest an asset may not be recoverable.

We evaluate an asset for recoverability by comparing the carrying value of the asset with the asset's expected future undiscounted cash flows. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost and other factors. If the carrying amount exceeds the expected future undiscounted cash flows we recognize an impairment loss to write down the carrying amount of the asset to its fair value as determined by quoted market prices in active markets or present value techniques if quotes are unavailable. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding the probability of a range of outcomes and the rates of interest used in the present value calculations. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of recoverability of our property, plant and equipment and the recognition of an impairment loss in our supplemental consolidated statements of operations.

Revenue Recognition. Our primary types of sales and service activities reported as operating revenues include:

- sales of natural gas, NGLs and condensate; and

- natural gas processing, from which we generate revenues through the compression, gathering, treating, and processing of natural gas.

We recognize revenues when all of the following criteria are met: (1) persuasive evidence of an exchange arrangement exists, if applicable, (2) delivery has occurred or services have been rendered, (3) the price is fixed or determinable and (4) collectibility is reasonably assured.

For processing services, we receive either fees or a percentage of commodities as payment for these services, depending on the type of contract. Under percent-of-proceeds contracts, we receive either an agreed upon percentage of the actual proceeds that we receive from our sales of the residue natural gas and NGLs or an agreed upon percentage based on index related prices for the natural gas and NGLs. Percent-of-value and percent-of-liquids contracts are variations on this arrangement. Under keep-whole contracts, we keep the NGLs extracted and return the processed natural gas or value of the natural gas to the producer. Natural gas or NGLs that we receive for services or purchase for resale are in turn sold and recognized in accordance with the criteria outlined above. Under fee-based contracts, we receive a fee based on throughput volumes.

We generally report revenues gross in our supplemental consolidated statements of operations. Except for fee-based contracts, we act as the principal in the transactions where we receive commodities, take title to the natural gas and NGLs, and incur the risks and rewards of ownership.

Unit-Based Employee Compensation. We award share-based compensation to directors in the form of restricted common units. Compensation expense on restricted common units is measured by the fair value of the award at the date of grant. Compensation expense is recognized in general and administrative expense over the requisite service period of each award. See Note 12.

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities as of the date of the supplemental financial statements and the reported amounts of revenues and expenses during the period. Estimates and judgments are based on information available at the time such estimates and judgments are made. Adjustments made with respect to the use of these estimates and judgments often relate to information not previously available. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things, (1) estimating unbilled revenues and operating and general and administrative costs (2) developing fair value assumptions, including estimates of future cash flows and discount rates, (3) analyzing long-lived assets for possible impairment, (4) estimating the useful lives of assets and (5) determining amounts to accrue for contingencies, guarantees and indemnifications. Actual results could differ materially from estimated amounts.

Accounting Pronouncements Recently Adopted

In September 2006, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") 157, *"Fair Value Measurements."* SFAS 157 establishes a framework for measuring fair value and expands disclosures about fair value measurements. In February 2008, the FASB issued FASB Staff Position FAS 157-2, "*Effective Date of FASB Statement No. 157,"* which delayed the effective date of SFAS 157 for all non-financial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis, until January 1, 2009.

We do not anticipate SFAS 157 to significantly impact our supplemental consolidated financial statements. We adopted SFAS 157 with respect to financial assets and liabilities that are recognized on a recurring basis on January 1, 2008. Although the adoption of SFAS 157 did not materially impact our supplemental financial condition, results of operations, or cash flows, we are now required to provide additional disclosures as part of our supplemental financial statements. See Note 17.

In December 2007, the FASB issued SFAS 160, "*Noncontrolling Interests in Consolidated Financial Statements—an amendment of ARB No. 51."* SFAS 160 establishes new accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS 160 is effective for fiscal periods and interim periods within those fiscal years, beginning on or after December 15, 2008 with retroactive presentation of all years presented. These supplemental financial statements incorporate the retrospective disclosure provisions of SFAS 160.

In March 2008, the FASB issued SFAS 161, *"Disclosures about Derivative Instruments and Hedging Activities —an amendment of FASB Statement No. 133."* SFAS 161 changes the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under SFAS 133, *"Accounting for Derivative Instruments and Hedging Activities*" and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. Early adoption is encouraged. Our adoption of SFAS 161 as of December 31, 2008 did not impact our supplemental consolidated financial position, results of operations or cash flows. See Note 13.

In October 2008, FASB issued FASB Staff Position ("FSP") FAS 157-3, "*Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active*." FSP FAS 157-3 clarifies the application of SFAS 157 in a market that is not active and provides factors to take into consideration when determining the fair value of an asset in an inactive market. FSP FAS 157-3 was effective upon issuance, including prior periods for which financial statements have not been issued. FSP FAS 157-3 did not have a material impact on our supplemental financial statements.

Accounting Pronouncements Recently Issued

In December 2007, FASB issued SFAS 141R, "*Business Combinations.*" ("SFAS 141R"). SFAS 141R requires the acquiring entity in a business combination to recognize all assets acquired and liabilities assumed in the transaction, establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed, and requires the acquirer to disclose certain information related to the nature and financial effect of the business combination. SFAS 141R also establishes principles and requirements for how an acquirer recognizes any noncontrolling interest in the acquiree and the goodwill acquired in a business combination. SFAS 141R was effective on a prospective basis for business combinations for which the acquisition date is on or after January 1, 2009. For any business combination that takes place subsequent to January 1, 2009, SFAS 141R may have a material impact on our financial statements. The nature and extent of any such impact will depend upon the terms and conditions of the transaction.

In March 2008, the FASB's Emerging Issues Task Force ("EITF") reached a consensus on EITF 07-4, *"Application of the Two- Class Method under FASB Statement No. 128 to Master Limited Partnerships."* EITF 07-4 provides guidance as to how a master limited partnership ("MLP") should allocate and present earnings per unit using the two-class method set forth in SFAS 128, "Earnings Per Share" when the MLP's partnership agreement contains incentive distribution rights. Under the two-class method, current period earnings are allocated to the partners according to the distribution formula for available cash set forth in the MLP's partnership agreement. Our adoption of EITF 07-4 is not expected to impact our supplemental consolidated financial position, results of operations or cash flows. However, it could potentially reduce our computation of earnings per common and subordinated unit.

FASB Staff Position ("FSP") EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities* was issued on June 16, 2008. It requires us to retrospectively adjust our earnings per unit data that will result in us recognizing unvested unit-based payment awards as participating units in our basic earnings per unit calculation.

On April 9, 2009, FASB issued FSP FAS 107-1 and APB 28-1, "*Interim Disclosures about Fair Value of Financial Instruments*." This FSP requires disclosures of fair value for any financial instruments not currently reflected at fair value on the balance sheet for all interim periods. This FSP is effective for interim and annual periods ending after June 15, 2009 and should be applied prospectively. We do not expect any material supplemental financial statement implications relating to the adoption of FSP 107-1.

In May 2009, FASB issued SFAS 165, "*Subsequent Events.*" SFAS 165 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. SFAS 165 sets forth (1) the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements, (2) the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements, and (3) the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. SFAS 165 is effective for interim and annual periods ended after June 15, 2009 and should be applied prospectively. The adoption of SFAS 165 will not have a material impact on our supplemental financial statements.

In June 2009, FASB issued SFAS 168, "*The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles—a replacement of FASB Statement No. 162."* SFAS 168 establishes the FASB Accounting Standards Codification ("Codification") as the source of authoritative GAAP recognized by FASB to be applied by nongovernmental entities. Rules and interpretive releases of the Securities and Exchange Commission ("SEC") under authority of federal securities laws are also sources of authoritative GAAP for SEC registrants. SFAS 168 is effective for financial statements issued for interim and annual periods ending after September 15, 2009. As of the effective date, the Codification supersedes all then-existing non-SEC accounting and reporting standards. All other non-grandfathered non-SEC accounting literature not included in the Codification has become non-authoritative.

Following SFAS 168, FASB will no longer issue new standards in the form of Statements, FASB Staff Positions, or Emerging Issues Task Force Abstracts. Instead, it will issue Accounting Standards Updates ("ASU"). FASB will not consider ASUs as authoritative in their own right. They will serve only to update the Codification, provide background information about the guidance, and provide the basis for conclusions on the change(s) in the Codification.

In 2009, FASB has issued ASUs 2009-01 through 2009-11, which either are technical corrections of the Codification and/or do not apply to us.

Note 4—Acquisition of Downstream Business

On September 24, 2009, we acquired Targa's interests in the Downstream Business for $530 million. Consideration to Targa comprised $397.5 million in cash and the issuance to Targa of 174,033 general partner units and 8,527,615 common units. The form of the transaction reflected in our consolidated financial statements was:

- Targa contributed the Downstream Business to us. On the contribution date, the Downstream Business' affiliate indebtedness payable to Targa was $530 million. Prior to the contribution, $287.3 million of the Downstream Business' affiliated indebtedness was settled through a capital contribution from Targa.

- We repaid the affiliate indebtedness with: (i) $397.5 million in cash; (ii) 174,033 in general partner units with an agreed-upon value of $2.7 million; and (iii) 8,527,615 in common units with an agreed-upon value of $129.8 million.

Our acquisition of the Downstream Business has been accounted for as a transfer of net assets between entities under common control.

As part of the transaction, Targa has agreed to provide distribution support to us in the form of a reduction in the reimbursement for general and administrative expense allocated to us if necessary (or make a payment to us, if needed) for a 1.0 times distribution coverage ratio, at the current distribution level of $0.5175 per limited partner unit, subject to maximum support of $8 million in any quarter. The distribution support is in effect for the nine-quarter period beginning with the fourth quarter of 2009 and continuing through the fourth quarter of 2011.

The Partnership now operates in two divisions: (i) Natural Gas Gathering and Processing (also a segment) and (ii) NGL Logistics and Marketing. Our NGL Logistics and Marketing division consists of three segments: (a) Logistics Assets, (b) NGL Distribution and Marketing and (c) Wholesale Marketing. As a result of the acquisition of the Downstream Business, we are now reporting segment information.

The following table presents the impact on our supplemental consolidated financial position at December 31, 2008 and 2007, adjusted for the acquisition of the Downstream Business from Targa.

	December 31, 2008			
	Historical Targa Resources Partners LP	Downstream Business	Adjustments	Targa Resources Partners LP
Current assets	$ 255,510	$ 263,011	$ (22,295)	$ 496,226
Property, plant and equipment, net	1,244,337	474,719	-	1,719,056
Other assets	81,059	18,478	-	99,537
Total assets	$ 1,580,906	$ 756,208	$ (22,295)	$ 2,314,819
Current liabilities	$ 106,504	$ 187,539	$ (22,295)	$ 271,748
Long-term debt	696,845	773,883	-	1,470,728
Other long-term liabilities	15,193	4,062	-	19,255
Owners of Targa Resources Partners LP	762,364	166	-	762,530
Net parent investment	-	(223,534)		(223,534)
Noncontrolling interest in subsidiary	-	14,092	-	14,092
Total owners' equity	762,364	(209,276)	-	553,088
Total liabilities and owners' equity	$ 1,580,906	$ 756,208	$ (22,295)	$ 2,314,819

	December 31, 2007			
	Historical Targa Resources Partners LP	Downstream Business	Adjustments	Targa Resources Partners LP
Current assets	$ 208,475	$ 834,351	$ (87,547)	$ 955,279
Property, plant and equipment, net	1,259,594	456,827	-	1,716,421
Other assets	11,903	19,251	-	31,154
Total assets	$ 1,479,972	$ 1,310,429	$ (87,547)	$ 2,702,854
Current liabilities	$ 192,532	$ 595,431	$ (87,547)	$ 700,416
Long-term debt	626,300	711,267	-	1,337,567
Other long-term liabilities	46,934	3,565	-	50,499
Owners of Targa Resources Partners LP	614,206	1,986	-	616,192
Net parent investment	-	(15,338)	-	(15,338)
Noncontrolling interest in subsidiary	-	13,518	-	13,518
Total owners' equity	614,206	166	-	614,372
Total liabilities and owners' equity	$ 1,479,972	$ 1,310,429	$ (87,547)	$ 2,702,854

The following tables present the impact on the supplemental consolidated statements of operations, adjusted for the acquisition of the Downstream Business from Targa, for the periods indicated:

	Year Ended December 31, 2008			
	Historical Targa Resources Partners LP	Downstream Business	Adjustments	Targa Resources Partners LP
Revenues	$ 2,074,118	$ 6,172,679	$ (773,400)	$ 7,473,397
Costs and expenses:				
Product purchases	1,803,031	5,892,376	(773,334)	6,922,073
Operating expenses	55,325	198,777	(66)	254,036
Depreciation and amortization expense	74,274	23,563	-	97,837
General and administrative expense and other	22,454	45,221	-	67,675
	1,955,084	6,159,937	(773,400)	7,341,621
Income from operations	119,034	12,742	-	131,776
Other income (expense):				
Interest expense	(38,274)	(58,738)	-	(97,012)
Other income	12,134	5,191	-	17,325
Income tax expense	(1,400)	(990)	-	(2,390)
Net income (loss)	91,494	(41,795)	-	49,699
Less: Net income attributable to noncontrolling interest	-	274	-	274
Net income attributable to Targa Resources Partners LP	$ 91,494	$ (42,069)	$ -	$ 49,425
Net loss attributable to predecessor operations	$ -	$ (42,069)	$ -	$ (42,069)
Net income allocable to partners	91,494	-	-	91,494

	Year Ended December 31, 2007			
	Historical Targa Resources Partners LP	Downstream Business	Adjustments	Targa Resources Partners LP
Revenues	$ 1,661,469	$ 5,767,948	$ (613,271)	$ 6,816,146
Costs and expenses:				
Product purchases	1,406,797	5,480,841	(613,237)	6,274,401
Operating expenses	50,931	168,762	(34)	219,659
Depreciation and amortization expense	71,756	21,764	-	93,520
General and administrative expense and other	18,631	45,059	-	63,690
	1,548,115	5,716,426	(613,271)	6,651,270
Income from operations	113,354	51,522	-	164,876
Other income (expense):				
Interest expense	(41,434)	(57,920)	-	(99,354)
Other income (expense)	(30,191)	2,380	-	(27,811)
Income tax expense	(1,479)	(1,040)	-	(2,519)
Net income (loss)	40,250	(5,058)	-	35,192
Less: Net income attributable to noncontrolling interest	-	112	-	112
Net income attributable to Targa Resources Partners LP	$ 40,250	$ (5,170)	$ -	$ 35,080
Net income (loss) attributable to predecessor operations	$ 12,184	$ (5,170)	$ -	$ 7,014
Net income allocable to partners	28,066	-	-	28,066

	Year Ended December 31, 2006			
	Historical Targa Resources Partners LP	Downstream Business	Adjustments	Targa Resources Partners LP
Revenues	$ 1,738,525	$ 4,632,596	$ (463,632)	$ 5,907,489
Costs and expenses:				
Product purchases	1,517,668	4,424,795	(463,590)	5,478,873
Operating expenses	49,075	144,062	(42)	193,095
Depreciation and amortization expense	69,957	20,787	-	90,744
General and administrative expense and other	16,063	41,230	-	57,293
	1,652,763	4,630,874	(463,632)	5,820,005
Income from operations	85,762	1,722	-	87,484
Other income (expense):				
Interest expense	(88,025)	(39,036)	-	(127,061)
Other income	16,756	2,599	-	19,355
Income tax expense	(2,926)	(504)	-	(3,430)
Net income (loss)	11,567	(35,219)	-	(23,652)
Less: Net loss attributable to noncontrolling interest	-	(630)	-	(630)
Net income attributable to Targa Resources Partners LP	$ 11,567	$ (34,589)	$ -	$ (23,022)

Note 5—Inventory

Our product inventories consist primarily of NGLs. Most product inventories turn over monthly, but some inventory, primarily propane, is held during the year to meet anticipated heating season requirements of our customers. Product inventories are valued at the lower of cost or market using the average cost method.

Due to fluctuating commodity prices for natural gas liquids, we occasionally recognize lower of cost or market adjustments when the carrying values of our inventories exceeds their net realizable value. These non-cash adjustments are charged to product purchases within operating costs and expenses in the period they are recognized, with the related cash impact in the subsequent period. For 2008, 2007 and 2006 we recognized $6.0 million, $0.2 million and $13.1 million to reduce the carrying value of NGL inventory to its net realizable value.

As of December 31, 2008 and 2007, inventory consisted primarily of NGL products of $71.2 million and $147.6 million.

Note 6—Property, Plant and Equipment

Property, plant and equipment and accumulated depreciation were as follows as of the dates indicated:

	December 31,	
	2008	**2007**
Gathering systems	$ 1,187,139	$ 1,150,971
Processing and fractionation facilities	374,011	360,847
Terminalling and natural gas liquids storage facilities	221,883	213,261
Transportation assets	144,466	135,599
Other property, plant and equipment	14,910	12,100
Land	49,770	49,770
Construction in progress	44,199	13,610
	2,036,378	1,936,158
Accumulated depreciation	(317,322)	(219,737)
	$ 1,719,056	$ 1,716,421

Note 7—Investment in Unconsolidated Affiliate

As of December 31, 2008 and 2007, our unconsolidated investment consisted of a 38.75% ownership interest in Gulf Coast Fractionators LP (“GCF”), a venture that fractionates natural gas liquids on the Gulf Coast.

Our equity in the net assets of GCF exceeded our acquisition date investment account by approximately $5.2 million. This amount is being amortized over the estimated remaining life of the net assets on a straight-line basis, and is included as a component of our equity in earnings of unconsolidated investments.

The following table shows our equity earnings and cash distributions with respect to our unconsolidated investment in GCF for the periods indicated:

	Year Ended December 31,		
	2008	**2007**	**2006**
Equity in earnings	$ 3,877	$ 3,511	$ 2,754
Cash distributions	4,650	3,875	2,306

Note 8—Asset Retirement Obligations

The changes in our aggregate asset retirement obligations are as follows:

	Year Ended December 31,		
	2008	2007	2006
Beginning of period	$ 5,857	$ 5,412	$ 3,040
Liabilities settled	(229)	-	-
Allocated from Parent	-	-	2,062
Change in cash flow estimate	266	32	(1)
Accretion expense	312	413	311
End of period	$ 6,206	$ 5,857	$ 5,412

Our asset retirement obligations are included in our supplemental consolidated balance sheets as a component of other long-term liabilities.

Note 9—Debt Obligations

Consolidated debt obligations consisted of the following as of the dates indicated:

	December 31,	
	2008	2007
Targa Resources Partners LP:		
Senior unsecured notes, 8¼% fixed rate, due July 2016	$ 209,080	$ -
Senior secured revolving credit facility, variable rate, due February 2012	487,765	626,300
Targa Downstream LP:		
Note payable to Parent, 10% fixed rate, due December 2011 (including accrued interest of $175,343 and $118,475)	744,020	687,152
Targa LSNG LP:		
Note payable to Parent, 10% fixed rate, due December 2011 (including accrued interest of $4,281 and $1,894)	29,863	24,115
	$ 1,470,728	$ 1,337,567
Letters of credit issued	$ 9,651	$ 25,900

On October 16, 2008, we requested a $100 million funding under our credit facility. Lehman Brothers Commercial Bank, a lender under our credit facility, defaulted on its portion of the borrowing request resulting in an actual funding of $97.8 million. As a result of the default, we believe the availability under the credit facility has been effectively reduced by approximately $10.0 million.

Repurchases of Senior Unsecured Notes

During November and December 2008, we repurchased $40.9 million face amount of our outstanding Senior Unsecured Notes in open market transactions at an aggregate purchase price of $28.3 million, including $1.5 million of accrued interest. We recognized a gain of $13.1 million from these transactions. The repurchased Senior Unsecured Notes were retired and are not eligible for re-issue at a later date.

Information Regarding Variable Interest Rates Paid

The following table shows the range of interest rates paid and weighted average interest rate paid on our variable-rate debt obligations during 2008:

	Range of interest rates paid	Weighted average interest rate paid
Credit facility	1.5% to 6.4%	4.4%

Affiliated Indebtedness

On January 1, 2007, Targa contributed to us affiliated indebtedness related to the North Texas System of approximately $904.5 million (including accrued interest of $88.3 million computed at 10% per annum). We recorded approximately $9.8 million in interest expense associated with this affiliated debt for the period from January 1, 2007 through February 13, 2007. On February 14, 2007, Targa contributed its interest in Targa North Texas GP LLC and Targa North Texas LP to us.

On January 1, 2007, Targa contributed to us affiliated indebtedness related to the assets of the Downstream Business of approximately $639.7 million (including accrued interest of $61.8 million). During the years ended December 31, 2008 and 2007, additional affiliated indebtedness of $3.4 million and $13.0 million was incurred to fund the construction of its Mont Belvieu, Texas isomerization unit. During 2008 and 2007, we recorded $59.3 million and $58.5 million in interest expense associated with this affiliated debt.

The stated 10% interest rate in the formal debt arrangement was not indicative of prevailing external rates of interest including that incurred under our credit facility which is secured by substantially all of our assets. On a pro forma basis, at prevailing interest rates the affiliated interest expense for the period from January 1, 2007 to February 13, 2007 related to the North Texas System would have been reduced by $3.0 million. The pro forma interest expense adjustment has been calculated by applying the weighted average rate of 6.9% that we incurred under our credit facility to the affiliate debt balance for the period from January 1, 2007 to February 13, 2007. On a pro forma basis, at prevailing interest rates the affiliated interest expense for the years ended December 31, 2008 and 2007 related to the Downstream business would have been reduced by $15.9 million and $10.2 million. The pro forma interest expense adjustment has been calculated by applying the weighted average rates of 7.3% and 8.3% that Targa incurred under its credit facility to the affiliate debt balance for the periods indicated.

Allocated Indebtedness

On October 24, 2007, we completed the acquisition of the SAOU and LOU Systems from Targa. As part of the acquisition of the SAOU and LOU Systems, the allocated indebtedness was settled with Targa through an adjustment to parent equity and the collateralization of the assets was released.

Credit Agreement

On February 14, 2007, we entered into a credit agreement which provided for a five-year $500 million credit facility with a syndicate of financial institutions. The credit facility bears interest at our option, at the higher of the lender's prime rate or the federal funds rate plus 0.5%, plus an applicable margin ranging from 0% to 1.25% dependent on our total leverage ratio, or LIBOR plus an applicable margin ranging from 1.0% to 2.25% dependent on our total leverage ratio. We initially borrowed $342.5 million under our credit facility, and concurrently repaid $48.0 million under our credit facility with the proceeds from the 2,520,000 common units sold pursuant to the full exercise by the underwriters of their option to purchase additional common units. The net proceeds of $294.5 million from this borrowing, together with approximately $371.2 million of available cash from the IPO (after payment of offering and debt issue costs and necessary operating cash reserve balances), were used to repay approximately $665.7 million of affiliate indebtedness. In connection with our IPO, the guarantee of indebtedness from the entity holding the North Texas System was terminated, the related collateral interest was released and the remaining affiliate indebtedness was retired and treated as a capital contribution to us. Our credit facility is secured by substantially all of our assets.

Concurrent with the acquisition of the SAOU and LOU Systems, we entered into a Commitment Increase Supplement to our existing credit facility, which increased the aggregate commitments under the Credit Agreement by $250 million to an aggregate $750 million. We paid for our acquisition of the SAOU and LOU Systems with the proceeds from our offering of common units and approximately $378.9 million in incremental borrowings under the increased credit facility. Substantially all of our assets (North Texas, SAOU and LOU Systems) are currently pledged as collateral on our credit facility.

On October 24, 2007, we entered into the First Amendment to Credit Agreement (the "Amendment"). The Amendment increased by $250 million the maximum amount of increases to the aggregate commitments that may be requested by us. The Amendment allows us to request commitments under the credit agreement, as supplemented and amended, up to $1 billion.

On June 18, 2008, we increased the commitments under our credit facility by $100 million, bringing the total commitments under our credit facility to $850 million. We may request additional commitments under our credit facility of up to $150 million, which would increase the total commitments under our credit facility to $1 billion.

The credit agreement restricts our ability to make distributions of available cash to unitholders if we are in any default or an event of default (as defined in the credit agreement) exists. The credit agreement requires us to maintain a leverage ratio (the ratio of consolidated indebtedness to our consolidated EBITDA, as defined in the credit agreement) of no more than 5.50 to 1.00 on the last day of any fiscal quarter. The credit agreement also requires us to maintain an interest coverage ratio (the ratio of our consolidated EBITDA to our consolidated interest expense, as defined in the credit agreement) of no less than 2.25 to 1.00 determined as of the last day of each quarter for the four-fiscal quarter period ending on the date of determination. In addition, the credit agreement contains various covenants that may limit, among other things, our ability to:

- incur indebtedness;
- grant liens; and
- engage in transactions with affiliates.

The credit facility matures on February 14, 2012, at which time all unpaid principal and interest is due.

8¼% Senior Notes due 2016

On June 18, 2008, we completed the private placement under Rule 144A and Regulation S of the Securities Act of 1933 of $250 million in aggregate principal amount of 8¼% senior notes due 2016 (the "8¼% Notes"). Proceeds from the 8¼% Notes were used to repay borrowings under our credit facility.

The 8¼% Notes:

- are our unsecured senior obligations;
- rank *pari passu* in right of payment with our existing and future senior indebtedness, including indebtedness under our credit facility;
- are senior in right of payment to any of our future subordinated indebtedness; and
- are unconditionally guaranteed by us.

The 8¼% Notes are effectively subordinated to all secured indebtedness under our credit agreement, which is secured by substantially all of our assets, to the extent of the value of the collateral securing that indebtedness.

Interest on the 8¼% Notes accrues at the rate of 8¼% per annum and is payable semi-annually in arrears on January 1 and July 1, commencing on January 1, 2009. Interest is computed on the basis of a 360-day year comprising twelve 30-day months.

Prior to July 1, 2011, we may on any one or more occasions redeem up to 35% of the aggregate principal amount of the 8¼% Notes with the net cash proceeds of one or more equity offerings by us at a redemption price of 108.25% of the principal amount, plus accrued and unpaid interest and liquidated damages, if any, to the redemption date provided that:

(1) at least 65% of the aggregate principal amount of the 8¼% Notes (excluding 8¼% Notes held by us) remains outstanding immediately after the occurrence of such redemption; and

(2) the redemption occurs within 90 days of the date of the closing of such equity offering.

At any time prior to July 1, 2012, we may also redeem all or a part of the 8¼% Notes at a redemption price equal to 100% of the principal amount of the 8¼% Notes redeemed plus the applicable premium as defined in the indenture agreement as of, and accrued and unpaid interest and liquidated damages, if any, to the date of redemption.

On or after July 1, 2012, we may redeem all or a part of the 8¼% Notes at the redemption prices set forth below (expressed as percentages of principal amount) plus accrued and unpaid interest and liquidated damages, if any, on the 8¼% Notes redeemed, if redeemed during the twelve-month period beginning on July 1 of each year indicated below:

Year	Percentage
2012	104.125%
2013	102.063%
2014 and thereafter	100.000%

The 8¼% Notes are subject to a registration rights agreement dated as of June 18, 2008. Under the registration rights agreement, we are required to file by June 19, 2009 a registration statement with respect to any 8¼% Notes that are not freely transferable without volume restrictions by holders of the 8¼% Notes that are not our affiliates. If we fail to do so, additional interest will accrue on the principal amount of the 8¼% Notes. We have determined that the payment of additional interest is not probable. As a result, we have not recorded a liability for any contingent obligation. Any subsequent accrual of a liability under this registration rights agreement will be charged to earnings as interest expense.

Compliance with Debt Covenants

As of December 31, 2008, the Partnership was in full compliance with the covenants contained in its various debt agreements.

Note 10—Partnership Equity and Distributions

General. The partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our Available Cash (defined below) to unitholders of record on the applicable record date, as determined by the general partner.

Definition of Available Cash. Available Cash, for any quarter, consists of all cash and cash equivalents on hand on the date of determination of available cash for that quarter: less the amount of cash reserves established by the general partner to:

- provide for the proper conduct of our business;

- comply with applicable law, any of our debt instruments or other agreements; or

- provide funds for distributions to the unitholders and to the general partner for any one or more of the next four quarters.

General Partner Interest and Incentive Distribution Rights. The general partner is currently entitled to approximately 2% of all quarterly distributions that we make prior to our liquidation. The general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. The general partner's 2% interest in these distributions will be reduced if we issue additional units in the future and the general partner does not contribute a proportionate amount of capital to us to maintain its 2% general partner interest.

The incentive distribution rights held by the general partner entitle it to receive an increasing share of Available Cash when pre-defined distribution targets are achieved. The general partner's incentive distribution rights are not reduced if we issue additional units in the future and the general partner does not contribute a proportionate amount of capital to us to maintain its 2% general partner interest. Please read "Distributions of Available Cash during the Subordination Period" and "Distributions of Available Cash after the Subordination Period" below for more details about the distribution targets and their impact on the general partner's incentive distribution rights.

Subordinated Units. All of the subordinated units are indirectly held by Targa. Our partnership agreement provides that, during the subordination period, the common units have the right to receive distributions of Available Cash each quarter in an amount equal to $0.3375 per common unit, or the "Minimum Quarterly Distribution," plus any arrearages in the payment of the Minimum Quarterly Distribution on the common units from prior quarters, before any distributions of Available Cash may be made on the subordinated units. These units are deemed "subordinated" because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the Minimum Quarterly Distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that during the subordination period there will be Available Cash to be distributed on the common units. The subordination period ended, and all 11,528,231 subordinated units converted to common units, on a one for one basis, on May 19, 2009.

Distributions of Available Cash during the Subordination Period. Based on the general partner's initial 2% ownership percentage, the partnership agreement requires that we make distributions of Available Cash from operating surplus for any quarter during the subordination period in the following manner:

- *first*, 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to the Minimum Quarterly Distribution for that quarter;

- *second*, 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to any arrearages in payment of the Minimum Quarterly Distribution on the common units for any prior quarters during the subordination period;

- *third*, 98% to the subordinated unitholders, pro rata, and 2% to the general partner, until we distribute for each subordinated unit an amount equal to the Minimum Quarterly Distribution for that quarter;

- *fourth*, 98% to all unitholders, pro rata, and 2% to the general partner, until each unitholder receives a total of $0.3881 per unit for that quarter (the First Target Distribution);

- *fifth*, 85% to all unitholders, 2% to the general partner and 13% to the holders of the Incentive Distribution Rights, pro rata, until each unitholder receives a total of $0.4219 per unit for that quarter (the Second Target Distribution);

- *sixth*, 75% to all unitholders, 2% to the general partner and 23% to the holders of the Incentive Distribution Rights, pro rata, until each unitholder receives a total of $0.50625 per unit for that quarter (the Third Target Distribution); and

- *thereafter*, 50% to all unitholders, 2% to the general partner and 48% to the holders of the Incentive Distribution Rights, pro rata, (the Fourth Target Distribution).

Distributions of Available Cash after the Subordination Period. The partnership agreement requires that we make distributions of Available Cash from operating surplus for any quarter after the subordination period in the following manner:

- *first*, 98% to all unitholders, pro rata, and 2% to the general partner, until each unitholder receives a total of $0.3881 per unit for that quarter;

- *second*, 85% to all unitholders, pro rata, 2% to the general partner and 13% to the holders of the Incentive Distribution Rights, until each unitholder receives a total of $0.4219 per unit for that quarter;

- *third*, 75% to all unitholders, pro rata, 2% to the general partner and 23% to the holders of the Incentive Distribution Rights, until each unitholder receives a total of $0.50625 per unit for that quarter; and

- *thereafter*, 50% to all unitholders, pro rata, 2% to the general partner and 48% to the holders of the Incentive Distribution Rights.

The following table shows the amount of cash distributions we paid to date:

		Distributions Paid					Distributions
	For the Three	Common	Subordinated	General Partner			per limited
Date Paid	**Months Ended**	**Units**	**Units**	**Incentive**	**2%**	**Total**	**partner unit**
		(In thousands, except per unit amounts)					
February 13, 2009	December 31, 2008	$ 17,949	$ 5,966	$ 1,933	$ 528	$ 26,376	$ 0.51750
November 14, 2008	September 30, 2008	17,934	5,966	1,931	527	26,358	0.51750
August 14, 2008	June 30, 2008	17,759	5,908	1,711	518	25,896	0.51250
May 15, 2008	March 31, 2008	14,467	4,813	208	398	19,886	0.41750
February 14, 2008	December 31, 2007	13,768	4,582	66	376	18,792	0.39750
November 14, 2007	September 30, 2007	11,082	3,891	-	305	15,278	0.33750
August 14, 2007	June 30, 2007	6,526	3,890	-	212	10,628	0.33750
May 15, 2007	March 31, 2007	3,263	1,945	-	107	5,315	0.16875

Note 11—Insurance Claims

We recognize income from business interruption insurance in our combined statements of operations as a component of revenues from third parties in the period that a proof of loss is executed and submitted to the insurers for payment. For 2008, 2007 and 2006 income from business interruption insurance resulting from the effects of Hurricanes Katrina and Rita was $18.1 million, $4.6 million and $7.0 million. In addition, we received $0.6 million during 2008 as a result of fire damage claims at certain plants in our wholesale marketing segment.

Hurricanes Gustav and Ike

In September 2008, certain of our facilities in Louisiana and Texas sustained damage and had disruption to their operations from Hurricanes Gustav and Ike.

We estimate the cost associated with our interest for repairs to the impacted facilities to be approximately $17.4 million. We believe that we have adequate insurance coverage (subject to customary deductibles, limits and sub-limits) to cover the respective facility repair costs and to offset the majority of the associated lost profits as a result of the hurricanes. The property damage deductibles under our insurance coverage will reduce our ultimate property damage insurance recoveries by approximately $3.3 million. We will have additional out of pocket costs associated with improvements (e.g., elevating critical equipment) that may not be covered by insurance.

During 2008 we recorded a loss provision of $4.9 million for our estimated out-of-pocket cleanup and repair costs related to these two hurricanes, after estimated insurance proceeds. As of December 31, 2008, expenditures related to the hurricanes totaled $5.5 million.

Note 12—Accounting for Unit-Based Compensation

Our general partner has adopted a long-term incentive plan ("the Plan") for employees, consultants and directors of the general partner and its affiliates who perform services for us. The following table summarizes our unit-based awards for each of the periods indicated:

During 2008 and 2007, our general partner awarded 2,000 restricted common units in the Partnership to each of the general partner's and Targa Resources Investments Inc.'s ("Targa Investments") non-management directors under the Plan. The awards will settle with the delivery of common units and are subject to three-year vesting, without a performance condition, and will vest ratably on each anniversary of the grant date.

	Year Ended December 31,		
	2008	2007	2006
Outstanding at beginning of year	16,000	-	-
Granted	16,000	16,000	-
Vested	(5,336)	-	-
Forfeited	-	-	-
Outstanding at end of year	26,664	16,000	-
Weighted average grant date fair value per share	$ 22.12	$ 21.00	$ -

Compensation expense on the restricted common units is recognized on a straight-line basis over the vesting period. The fair value of an award of restricted common units is measured on the grant date using the market price of a common unit on such date. During 2008 and 2007, we recognized compensation expense of $0.3 million and $0.2 million related to these awards. We estimate that the remaining fair value of $0.2 million will be recognized in expense over approximately one year.

Note 13—Derivative Instruments and Hedging Activities

Our principal market risks are our exposure to changes in commodity prices, particularly to the prices of natural gas and NGLs, changes in interest rates, as well as nonperformance by our counterparties.

Commodity Price Risk. A majority of our revenues are derived from percent-of-proceeds contracts under which we receive a portion of the natural gas and/or NGLs or equity volumes, as payment for services. The prices of natural gas and NGLs are subject to market fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional factors beyond our control. We monitor these risks and enter into commodity derivative transactions designed to mitigate the impact of commodity price fluctuations on our business. Cash flows from a derivative instrument designated as a hedge are classified in the same category as the cash flows from the item being hedged.

The primary purpose of our commodity risk management activities is to hedge our exposure to commodity price risk and reduce fluctuations in our operating cash flow despite fluctuations in commodity prices. In an effort to reduce the variability of our cash flows, as of December 31, 2008, we have hedged the commodity price associated with a significant portion of our expected natural gas, NGL and condensate equity volumes for the years 2009 through 2013 by entering into derivative financial instruments including swaps and purchased puts (or floors). The percentages of our expected equity volumes that are hedged decrease over time. With swaps, we typically receive an agreed upon fixed price for a specified notional quantity of natural gas or NGL and we pay the hedge counterparty a floating price for that same quantity based upon published index prices. Since we receive from our customers substantially the same floating index price from the sale of the underlying physical commodity, these transactions are designed to effectively lock-in the agreed fixed price in advance for the volumes hedged. In order to avoid having a greater volume hedged than our actual equity volumes, we typically limit our use of swaps to hedge the prices of less than our expected natural gas and NGL equity volumes. We utilize purchased puts (or floors) to hedge additional expected equity commodity volumes without creating volumetric risk. Our commodity hedges may expose us to the risk of financial loss in certain circumstances. Our hedging arrangements provide us protection on the hedged volumes if market prices decline below the prices at which these hedges are set. If market prices rise above the prices at which we have hedged, we will receive less revenue on the hedged volumes than we would receive in the absence of hedges.

We have tailored our hedges to generally match the NGL product composition and the NGL and natural gas delivery points to those of our physical equity volumes. Our NGL hedges cover baskets of ethane, propane, normal butane, iso-butane and natural gasoline based upon our expected equity NGL composition. We believe this strategy avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as “proxy” hedges of NGL prices. Additionally, our NGL hedges are based on published index prices for delivery at Mont Belvieu and our natural gas hedges are based on published index prices for delivery at Columbia Gulf, Houston Ship Channel, Mid-Continent and Waha, which closely approximate our actual NGL and natural gas delivery points. We hedge a portion of our condensate sales using crude oil hedges that are based on the NYMEX futures contracts for West Texas Intermediate light, sweet crude.

Interest Rate Risk. We are exposed to changes in interest rates, primarily as a result of our variable rate debt under our credit facility. To the extent that interest rates increase, our interest expense for our revolving debt will also increase. As of December 31, 2008, we had borrowings of approximately $487.8 million outstanding under our revolving credit facility. In an effort to reduce the variability of our cash flows, we have entered into several interest rate swap and interest rate basis swap agreements. Under these agreements, which are accounted for as cash flow hedges, the base interest rate on the specified notional amount of our variable rate debt is effectively fixed for the term of each agreement and ineffectiveness is required to be measured each reporting period. The fair values of the interest rate swap agreements, which are adjusted regularly, have been aggregated by counterparty for classification in our consolidated balance sheets. Accordingly, unrealized gains and losses relating to the interest rate swaps are recorded in OCI until the interest expense on the related debt is recognized in earnings.

Credit Risk. Our credit exposure related to commodity derivative instruments is represented by the fair value of contracts with a net positive fair value to us at the reporting date. At such times, these outstanding instruments expose us to credit loss in the event of nonperformance by the counterparties to the agreements. Should the creditworthiness of one or more of our counterparties decline, our ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party. In the event of a counterparty default, we may sustain a loss and our cash receipts could be negatively impacted.

As of December 31, 2008, affiliates of Goldman Sachs, BofA and Barclays Bank accounted for 67%, 21% and 11% of our counterparty credit exposure related to commodity derivative instruments. Goldman Sachs, BofA and Barclays Bank are major financial institutions, each possessing investment grade credit ratings based upon minimum credit ratings assigned by Standard & Poor’s Ratings Services.

The following schedules reflect the fair values of derivative instruments in our supplemental financial statements:

	Asset Derivatives			Liability Derivatives		
	Balance Sheet Location	Fair Value as of December 31, 2008	2007	Balance Sheet Location	Fair Value as of December 31, 2008	2007
Derivatives designated as hedging instruments under SFAS 133						
Commodity contracts	Current assets	$ 88,206	$ 8,410	Current liabilities	$ -	$ 43,461
	Other assets	68,296	3,040	Other liabilities	123	42,134
Interest rate contracts	Current assets	-	-	Current liabilities	8,020	257
	Other assets	-	-	Other liabilities	9,556	975
Total derivatives designated as hedging instruments		156,502	11,450		17,699	86,827
Derivatives not designated as hedging instruments under SFAS 133						
Commodity contracts	Current assets	3,610	285	Current liabilities	3,644	285
	Other assets	-	-	Other liabilities	-	-
Total derivatives not designated as hedging instruments		3,610	285		3,644	285
Total derivatives		$ 160,112	$ 11,735		$ 21,343	$ 87,112

Derivatives in SFAS 133 Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion) Year Ended December 31, 2008	2007	2006	Location of Gain (Loss) Reclassified from OCI into Income	Amount of Gain (Loss) Reclassified from OCI into Income (Effective Portion) Year Ended December 31, 2008	2007	2006
Interest rate contracts	$ (19,037)	$ (1,689)	$ 1,267	Interest expense, net	$ (2,693)	$ 232	$ -
Commodity contracts	130,002	(105,583)	36,937	Revenues	(33,650)	(993)	822
	$ 110,965	$ (107,272)	$ 38,204		$ (36,343)	$ (761)	$ 822

Derivatives Not Designated as Hedging Instruments Under SFAS 133	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives Year Ended December 31, 2008	2007	2006
Commodity contracts	Other income (expense)	$ (991)	$ (30,221)	$ 16,756

As of December 31, 2008, OCI included $89.6 million of unrealized net gains on commodity hedges. As of December 31, 2007, OCI included $74.0 million of unrealized net losses on commodity hedges.

For 2008, 2007 and 2006 deferred net losses on commodity hedges of $33.7 million, $1.0 million and $0.9 million were reclassified from OCI to revenues. There were no adjustments for hedge ineffectiveness for 2008, 2007 or 2006.

As of December 31, 2008 and 2007, OCI also included $17.6 million and $1.2 million of unrealized losses on interest rate hedges.

For 2008, 2007 and 2006, deferred net gain (losses) on interest rate hedges of $2.7 million, ($0.2) million and ($0.5) million were reclassified from OCI to net interest expense. There were no adjustments for hedge ineffectiveness for 2008, 2007 or 2006.

As of December 31, 2008, deferred net gains (losses) of $50.0 million on commodity hedges and ($8.0) million on interest rate hedges recorded in OCI are expected to be reclassified to expense during the next twelve months.

In May 2008 we entered into certain NGL derivative contracts with Lehman Brothers Commodity Services Inc., a subsidiary of Lehman Brothers Holdings Inc. (“Lehman”). Due to Lehman’s bankruptcy filing, it is unlikely that we will receive full or partial payment of any amounts that may become owed to us under these contracts. Accordingly, we discontinued hedge accounting treatment for these contracts as of July 1, 2008. Deferred losses of $0.1 million and $0.3 million will be reclassified from OCI to revenues during 2011 and 2012 when the forecasted transactions related to these contracts are expected to occur. During 2008, we recognized a non-cash mark-to-market loss on derivatives of $1.0 million to adjust the fair value of the Lehman derivative contracts to zero. On October 22, 2008, we terminated the Lehman derivative contracts.

In July 2008, we paid $87.4 million to terminate certain out-of-the-money natural gas and NGL commodity swaps. Prior to the terminations, these swaps were designated as hedges in accordance with SFAS 133. Deferred losses will be reclassified from OCI as a non-cash reduction of revenue when the hedged forecasted sales transaction occurs. During 2008, deferred losses of $20.8 million related to the terminated swaps were reclassified from OCI as a non-cash reduction to revenue. We also entered into new natural gas and NGL commodity swaps at then current market prices that match the production volumes of the terminated swaps through 2010.

As of December 31, 2008, our commodity derivatives that have been designated as cash flow hedges were as follows:

Natural Gas

Instrument Type	Index	Avg. Price $/MMBtu	MMBtu per day 2009	2010	2011	2012	Fair Value
Natural Gas Sales							
Swap	IF-HSC	7.39	1,966	-	-	-	$ 1,159
			1,966	-	-	-	
Swap	IF-NGPL MC	9.18	6,256	-	-	-	9,466
Swap	IF-NGPL MC	8.86	-	5,685	-	-	5,129
Swap	IF-NGPL MC	7.34	-	-	2,750	-	843
Swap	IF-NGPL MC	7.18	-	-	-	2,750	738
			6,256	5,685	2,750	2,750	
Swap	IF-Waha	8.73	6,936	-	-	-	8,627
Swap	IF-Waha	7.52	-	5,709	-	-	2,294
Swap	IF-Waha	7.36	-	-	3,250	-	886
Swap	IF-Waha	7.18	-	-	-	3,250	708
			6,936	5,709	3,250	3,250	
Total Swaps			15,158	11,394	6,000	6,000	
Floor	IF-NGPL MC	6.55	850	-	-	-	574
			850	-	-	-	
Floor	IF-Waha	6.55	565	-	-	-	326
			565	-	-	-	
Total Floors			1,415	-	-	-	
Total Sales			16,573	11,394	6,000	6,000	
							$ 30,750

NGL

Instrument Type	Index	Avg. Price $/gal	Barrels per day 2009	2010	2011	2012	Fair Value
NGL Sales							
Swap	OPIS-MB	1.32	6,248	-	-	-	$ 66,137
Swap	OPIS-MB	1.27	-	4,809	-	-	39,122
Swap	OPIS-MB	0.92	-	-	3,400	-	8,288
Swap	OPIS-MB	0.92	-	-	-	2,700	6,018
Total Swaps			6,248	4,809	3,400	2,700	
Floor	OPIS-MB	1.44	-	-	199	-	1,807
Floor	OPIS-MB	1.43	-	-	-	231	1,932
Total Floors			-	-	199	231	
Total Sales			6,248	4,809	3,599	2,931	
							$ 123,304

Condensate

Instrument Type	Index	Avg. Price $/Bbl	Barrels per day 2009	2010	2011	2012	Fair Value
Condensate Sales							
Swap	NY-WTI	69.00	322	-	-	-	$ 1,655
Swap	NY-WTI	68.10	-	301	-	-	431
Total Swaps			322	301	-	-	
Floor	NY-WTI	60.00	50	-	-	-	239
Total Floors			50	-	-	-	
Total Sales			372	301	-	-	
							$ 2,325

As of December 31, 2008, we had the following commodity derivative contracts directly related to fixed price arrangements elected by certain customers in various natural gas purchase and sale agreements, which have been marked to market through earnings:

Period	Commodity	Instrument Type	Daily Volume		Average Price		Index	Fair Value
Purchases								
Jan 2009 - Dec 2009	Natural gas	Swap	6,005	MMBtu	$ 7.50	per MMBtu	NY-HH	$ (3,644)
Jan 2010 - Jun 2010	Natural gas	Swap	1,304	MMBtu	8.03	per MMBtu	NY-HH	(113)
Sales								
Jan 2009 - Dec 2009	Natural gas	Fixed price sale	6,005	MMBtu	7.50	per MMBtu	NY-HH	3,610
Jan 2010 - Jun 2010	Natural gas	Fixed price sale	1,304	MMBtu	8.03	per MMBtu	NY-HH	113
								$ (34)

Our earnings are also affected by use of the mark-to-market method of accounting for derivative financial instruments that do not qualify for hedge accounting or that have not been designated as hedges. The changes in fair value of these instruments are recorded on the balance sheet and through earnings (i.e., using the “mark-to-market” method) rather than being deferred until the anticipated transaction affects earnings. The use of mark-to-market accounting for financial instruments can cause non-cash earnings volatility due to changes in the underlying commodity price indices. During 2008, 2007 and 2006, we recorded mark-to-market gains (losses) of ($1.0) million, ($30.2) million and $16.8 million.

Interest Rate Swaps

As of December 31, 2008, we had $487.8 million outstanding under our credit facility, with interest accruing at a base rate plus an applicable margin. In order to mitigate the risk of changes in cash flows attributable to changes in market interest rates we have entered into interest rate swaps and interest rate basis swaps that effectively fix the base rate on $300 million in borrowings as shown below:

Expiration Date	Fixed Rate	Notional Amount	Fair Value
January 24, 2011	4.00%	$100 million	$ (5,282)
January 24, 2012	3.75%	200 million	(12,294)
			$ (17,576)

All interest rate swaps and interest rate basis swaps have been designated as cash flow hedges of variable rate interest payments on $50 million in borrowings under our credit facility.

The fair value of derivative instruments, depending on the type of instrument, was determined by the use of present value methods or standard option valuation models with assumptions about commodity prices and interest rates based on those observed in underlying markets. These contracts may expose us to the risk of financial loss in certain circumstances.

See also Notes 3, 14 and 17 for additional disclosures related to derivative instruments and hedging activities.

Note 14—Related-Party Transactions

Targa Resources, Inc.

On February 14, 2007, we entered into an Omnibus Agreement with Targa, our general partner and others that addressed the reimbursement of our general partner for costs incurred on our behalf and indemnification matters. Any or all of the provisions of this agreement, other than the indemnification provisions described in Note 15, are terminable by Targa at its option if our general partner is removed without cause and units held by our general partner and its affiliates are not voted in favor of that removal. The Omnibus Agreement will terminate in the event of a change of control of us or our general partner.

Concurrently with the closing of the acquisition of the SAOU and LOU Systems and the Downstream Business, we amended and restated our Omnibus Agreement (as amended and restated) with Targa, our general partner and others that addresses the reimbursement of our general partner for costs incurred on our behalf, competition and indemnification matters.

As part of the Downstream Business transaction, Targa will provide distribution support to us in the form of a reduction in the reimbursement for general and administrative expense allocated to us if necessary for a 1.0 times distribution coverage ratio, at the current $0.5175 per limited partner unit, subject to maximum support of $8 million in any quarter. The distribution support is in effect for the nine-quarter period beginning with the fourth quarter of 2009 and continuing through the fourth quarter of 2011.

Reimbursement of Operating and General and Administrative Expense

Under the Omnibus Agreement, we reimburse Targa for the payment of certain operating expenses, including compensation and benefits of operating personnel, and for the provision of various general and administrative services for our benefit. With respect to the North Texas System, we reimburse Targa for the following expenses:

- general and administrative expenses, which are capped at $5 million annually for three years, subject to increases based on increases in the Consumer Price Index and subject to further increases in connection with expansions of our operations through the acquisition or construction of new assets or businesses with the concurrence of our conflicts committee; thereafter, our general partner will determine the general and administrative expenses to be allocated to us in accordance with our partnership agreement; and

- operations and certain direct general and administrative expenses, which are not subject to the $5 million cap for general and administrative expenses.

With respect to the SAOU and LOU Systems and the Downstream Business, we will reimburse Targa for the following expenses:

- general and administrative expenses, which are not capped, allocated to the SAOU and LOU Systems and the Downstream Business according to Targa's allocation practice; and

- operating and certain direct expenses, which are not capped.

Pursuant to these arrangements, Targa performs centralized corporate functions for us, such as legal, accounting, treasury, insurance, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, engineering and marketing. We reimburse Targa for the direct expenses to provide these services as well as other direct expenses it incurs on our behalf, such as compensation of operational personnel performing services for our benefit and the cost of their employee benefits, including 401(k), pension and health insurance benefits.

Contracts with Affiliates

Sales to and purchases from affiliates. We routinely conduct business with other subsidiaries of Targa. The related party transactions result primarily from purchases and sales of natural gas. Prior to February 14, 2007, all of our expenditures were paid through Targa, resulting in intercompany transactions. Prior to February 14, 2007, settlement of these inter-company transactions was through adjustments to partners' capital accounts. After the conveyance of the assets of the North Texas System, the SAOU and LOU Systems, and the Downstream Business, all intercompany transactions were settled in cash.

Natural Gas Purchase Agreements. During 2007, the North Texas, SAOU and LOU Systems entered into natural gas purchase agreements at a price based on Targa Gas Marketing LLC's ("TGM") sale price for such natural gas, less TGM's costs and expenses associated therewith. These agreements have an initial term of 15 years and automatically extend for a term of five years, unless the agreements are otherwise terminated by either party. Furthermore, either party may elect to terminate the agreements if either party ceases to be an affiliate of Targa. In addition, Targa manages the SAOU and LOU Systems' natural gas sales to third parties under contracts that remain in the name of the Targa Texas Field Services and Targa Louisiana Field Services.

NGL Product Purchase Agreements. On September 24, 2009, Targa Liquids Marketing and Trade, a Delaware general partnership and indirectly, wholly-owned subsidiary of the Partnership ("Targa Liquids"), entered into product purchase agreements with Targa Midstream Services Limited Partnership, a Delaware limited partnership and indirectly wholly-owned subsidiary of Targa ("TMSLP"), and Targa Permian LP, a Delaware limited partnership and indirectly, wholly-owned subsidiary of Targa ("Targa Permian"), pursuant to which Targa Liquids will purchase all volumes of NGLs that are owned or controlled by TMSLP and Targa Permian and not otherwise committed for sale to a third party, at a price based on the prevailing market price less transportation, fractionation and certain other fees. The product purchase agreements will have an initial term of 15 years and will automatically extend for a term of five years. Furthermore, either party may elect to terminate the agreement if either party ceases to be an affiliate of Targa. Each product purchase agreement is effective as of September 1, 2009.

Allocations

Allocation of costs. The employees supporting our operations are employees of Targa. Our financial statements include costs allocated to us by Targa for centralized general and administrative services performed by Targa, as well as depreciation of assets utilized by Targa's centralized general and administrative functions. Costs allocated to us were based on identification of Targa's resources which directly benefit us and our proportionate share of costs based on our estimated usage of shared resources and functions. All of the allocations are based on assumptions that management believes are reasonable; however, these allocations are not necessarily indicative of the costs and expenses that would have resulted if we had been operated as a stand-alone entity. Prior to the initial IPO and the subsequent acquisition of the SAOU and LOU Systems these allocations were not settled in cash, but were settled through an adjustment to partners' capital accounts. Effective February 14, 2007, all of the North Texas System's allocations were settled monthly in cash. Effective October 23, 2007, all of the SAOU and LOU Systems' allocations were settled monthly in cash.

Allocations of long-term debt, debt issue costs, interest rate swaps and interest expense. Prior to January 1, 2007, our financial statements included long-term debt, debt issue costs, interest rate swaps and interest expense allocated from Targa. The allocations were calculated in a manner similar to Targa's purchase price allocation related to its acquisition of the SAOU and LOU Systems and the Downstream Business, and were based on the fair value of acquired tangible assets plus related net working capital and unconsolidated equity interests. These allocations were not settled in cash. Settlement of these allocations occurred through adjustments to partners' capital. The allocated debt, debt issue costs and interest rate swaps for the North Texas System and the Downstream Business, were settled through a deemed partner contributions of $846.3 million and $478.7 million on January 1, 2007. On October 23, 2007, The allocated debt, debt issue costs and interest rate swaps related to the SAOU and LOU Systems were settled through a deemed partner contribution of $179.6 million.

The following table summarizes the sales to and purchases from affiliates of Targa, payments made or received by Targa on behalf of us and allocations of costs from Targa which were settled through adjustments to partners' capital prior to the contribution of the North Texas System and the Downstream Business by Targa and the acquisition of the SAOU and LOU Systems from Targa. Management believes these transactions are executed on terms that are fair and reasonable.

	Year Ended December 31,		
	2008	2007	2006
Sales to affiliates	$ 489,773	$ 417,425	$ 329,253
Purchases from affiliates:			
Included in product purchases	1,097,640	952,774	928,403
Included in operating expenses	58,846	44,530	38,603
Payments made to our Parent	(1,658,240)	(911,581)	(997,068)
Parent allocation of interest expense	-	19,436	127,288
Parent allocation of general and administrative expense	61,723	60,393	56,516
Net change in affiliate payable	48,371	23,478	(26,192)

Centralized Cash Management

Prior to the conveyance of the assets of the North Texas, SAOU and LOU Systems and the Downstream Business to us, the excess cash from these subsidiaries was held in separate bank accounts and swept to a centralized account under Targa. Beginning with the contribution of these systems to us, their bank accounts have been maintained under a separate centralized cash management system.

For the North Texas System, prior to February 14, 2007, cash distributions are deemed to have occurred through partners' capital and are reflected as an adjustment to partners' capital. For the period from January 1, 2007 through February 13, 2007, deemed net capital distributions from us were $0.5 million. For the SAOU and LOU Systems for the period from January 1, 2007 through October 23, 2007, deemed net capital distributions from us were $133.6 million.

For the Downstream Business, deemed net capital distributions of cash to (from) Targa were $166.1 million, $(26.0) million and $58.8 million for 2008, 2007 and 2006.

Transactions with GCF

For the years 2008, 2007 and 2006, transactions with GCF which were included in revenues totaled $0.5 million, $4.5 million and $1.4 million. For the same periods, transactions included in costs and expenses were $3.5 million, $3.3 million and $3.3 million.

Relationships with Warburg Pincus

Chansoo Joung and Peter Kagan, two of the directors of Targa, are Managing Directors of Warburg Pincus and are also directors of Broad Oak Energy, Inc. ("Broad Oak") from whom we buy natural gas and NGL products.

Affiliates of Warburg Pincus own a controlling interest in Broad Oak. We purchased $4.8 million of product from Broad Oak during 2008. We had no commercial transactions prior to 2008 with Broad Oak. These transactions were at market prices consistent with similar transactions with nonaffiliated entities.

Relationships with Noble Energy

Chris Tong, one of the directors of Targa, is a Senior Vice President and Chief Financial Officer of Noble Energy, Inc. ("Noble") from whom we buy certain commodity products. We had net purchases of less than $0.1 million, $0.1 million and $1.7 million of natural gas and NGL products from Noble during 2008, 2007 and 2006. These transactions were at market prices consistent with similar transactions with nonaffiliated entities.

Relationship with Bank of America

An affiliate of BofA is an equity investor in Targa Investments, which indirectly owns our general partner. We have executed NGL sales and purchase transactions on the spot market with BofA. For the years 2008, 2007 and 2006, sales to BofA which were included in revenues totaled $4.4 million, $18.1 million and $12.4 million. For the same periods, purchases from BofA were $0.8 million, $9.4 million and $11.2 million.

Financial Services. BofA is a lender and an administrative agent under our senior secured credit facility.

Commodity hedges. We have entered into various commodity derivative transactions with BofA. The following table shows our open commodity derivatives with BofA as of December 31, 2008:

Period	Commodity	Instrument Type	Daily Volumes		Average Price		Index
Jan 2009 - Dec 2009	Natural gas	Swap	3,556	MMBtu	$ 8.07	per MMBtu	IF-Waha
Jan 2009 - Dec 2009	Natural gas	Swap	575	MMBtu	7.83	per MMBtu	NY-HH
Jan 2010 - Dec 2010	Natural gas	Swap	3,289	MMBtu	7.39	per MMBtu	IF-Waha
Jan 2010 - Dec 2010	Natural gas	Swap	247	MMBtu	8.17	per MMBtu	NY-HH
Jan 2009 - Dec 2009	NGL	Swap	3,000	Bbl	1.18	per gallon	OPIS-MB
Jan 2009 - Dec 2009	Condensate	Swap	202	Bbl	70.60	per barrel	NY-WTI
Jan 2010 - Dec 2010	Condensate	Swap	181	Bbl	69.28	per barrel	NY-WTI

As of December 31, 2008, the fair value of these open positions was $32.0 million. During 2008, 2007 and 2006, we paid to (received from) BofA $9.1 million, $1.9 million and $(4.2) million in commodity derivative settlements.

Note 15—Commitments and Contingencies

Future non-cancelable commitments related to certain contractual obligations are presented below:

	Payments Due by Period						
	Total	2009	2010	2011	2012	2013	Thereafter
Operating leases (1)	$ 53,942	$ 10,258	$ 8,874	$ 6,655	$ 6,196	$ 5,436	$ 16,523
Capacity payments	8,215	5,419	2,050	746	-	-	-
Right of way	7,406	532	484	458	447	359	5,126
Asset retirement obligations	6,206	-	-	6	-	-	6,200
	$ 75,769	$ 16,209	$ 11,408	$ 7,865	$ 6,643	$ 5,795	$ 27,849

(1) Operating lease obligations include minimum lease payment obligations associated with site leases, railcar leases and office space leases.

The following table summarizes total expenses related to operating lease obligations, capacity payments and right-of-way payments for each of the years indicated:

	2008	2007	2006
Operating lease obligations	$ 11,273	$ 13,057	$ 6,762
Capacity payments	3,051	2,878	778
Right-of-way payments	2,183	1,355	1,029

Environmental

Under the Omnibus Agreement described in Note 14, Targa has indemnified us for three years from February 14, 2007 against certain potential environmental claims, losses and expenses associated with the operation of the North Texas System occurring before such date that were not reserved on the books of the North Texas System. Targa's maximum liability for this indemnification obligation will not exceed $10.0 million and Targa will not have any obligation under this indemnification until our aggregate losses exceed $250,000. We have indemnified Targa against environmental liabilities related to the North Texas System arising or occurring after February 14, 2007.

Our environmental liabilities not covered by the Omnibus Agreement are for ground water assessment and remediation and was less than $0.1 million as of December 31, 2008.

Litigation

On December 8, 2005, WTG Gas Processing ("WTG") filed suit in the 333rd District Court of Harris County, Texas against several defendants, including Targa Resources, Inc. and three other Targa entities and private equity funds affiliated with Warburg Pincus LLC, seeking damages from the defendants. The suit alleges that Targa and private equity funds affiliated with Warburg Pincus, along with ConocoPhillips Company ("ConocoPhillips") and Morgan Stanley, tortiously interfered with (i) a contract WTG claims to have had to purchase the SAOU System from ConocoPhillips and (ii) prospective business relations of WTG. WTG claims the alleged interference resulted from Targa's competition to purchase the ConocoPhillips' assets and its successful acquisition of those assets in 2004. On October 2, 2007, the District Court granted defendants' motions for summary judgment on all of WTG's claims. WTG's motion to reconsider and for a new trial was overruled. On January 2, 2008, WTG filed a notice of appeal. On February 3, 2009, the parties presented oral arguments and the appeal is pending before the 14th Court of Appeals in Houston, Texas. We are contesting WTG's appeal, but can give no assurances regarding the outcome of the proceeding. Targa has agreed to indemnify us for any claim or liability arising out of the WTG suit.

We are not a party to any other legal proceedings other than legal proceedings arising in the ordinary course of our business. We are a party to various administrative and regulatory proceedings that have arisen in the ordinary course of our business.

Note 16—Fair Value of Financial Instruments

The estimated fair values of our assets and liabilities classified as financial instruments have been determined using available market information and valuation methodologies described below. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

The carrying values of items comprising current assets and current liabilities approximate fair values due to the short term maturities of these instruments. Derivative financial instruments included in our financial statements are stated at fair value.

The carrying value of the senior secured revolving credit facility approximates its fair value, as its interest rate is based on prevailing market rates. The fair value of the senior unsecured notes is based on quoted market prices based on trades of such debt. The carrying value of the notes payable to Parent approximates their fair value as they were settled at their stated amount on September 24, 2009. The carrying amounts and fair values of our other financial instruments are as follows as of the dates indicated:

	As of December 31,			
	2008		2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Credit facility	$ 487,765	$ 487,765	$ 626,300	$ 626,300
Senior unsecured notes	209,080	128,333	-	-
Notes payable to Parent:				
Targa Downstream LP	744,020	744,020	687,152	687,152
Targa LSNG LP	29,863	29,863	24,115	24,115

Note 17—Fair Value Measurements

A three-tier fair value hierarchy, which prioritizes the significant inputs used in measuring fair value is used to record assets and liabilities. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

Our derivative instruments consist of financially settled commodity and interest rate swap and option contracts and fixed price commodity contracts with certain customers. We determine the value of our derivative contracts utilizing a discounted cash flow model for swaps and a standard option pricing model for options, based on inputs that are either readily available in public markets or are quoted by counterparties to these contracts. In situations where we obtain inputs via quotes from our counterparties, we verify the reasonableness of these quotes via similar quotes from another source for each date for which financial statements are presented. We have consistently applied these valuation techniques in all periods presented and believe we have obtained the most accurate information available for the types of derivative contracts we hold. We have categorized the inputs for these contracts as Level 2 or Level 3. The price quotes for the Level 3 inputs are provided by a counterparty with whom we regularly transact business.

The following table sets forth, by level within the fair value hierarchy, our financial assets and liabilities measured at fair value on a recurring basis as of December 31, 2008. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Total	Level 1	Level 2	Level 3
Assets from commodity derivative contracts	$ 160,112	$ -	$ 36,808	$ 123,304
Assets from interest rate derivatives	-	-	-	-
Total assets	$ 160,112	$ -	$ 36,808	$ 123,304
Liabilities from commodity derivative contracts	$ 3,767	$ -	$ 3,767	$ -
Liabilities from interest rate derivatives	17,576	-	17,576	-
Total liabilities	$ 21,343	$ -	$ 21,343	$ -

The following table sets forth a reconciliation of the changes in the fair value of our financial instruments classified as Level 3 in the fair value hierarchy:

	Commodity Derivative Contracts
Balance, December 31, 2007	$ (71,370)
Total gains (losses) realized/unrealized:	
Included in loss on mark-to-market derivatives (1)	(991)
Included in OCI	100,068
Purchases	2,866
Terminations	77,792
Settlements	14,939
Balance, December 31, 2008	$ 123,304

(1) No unrealized gains or losses were reported relating to assets and liabilities still held as of December 31, 2008.

Note 18—Segment Information

We categorize the midstream natural gas industry into, and describe our business in, two divisions: (i) Natural Gas Gathering and Processing (also a segment) and (ii) NGL Logistics and Marketing. Our NGL Logistics and Marketing division consists of three segments: (a) Logistics Assets, (b) NGL Distribution and Marketing and (c) Wholesale Marketing.

The Natural Gas Gathering and Processing segment includes assets used in the gathering of natural gas produced from oil and gas wells and processing this raw natural gas into merchantable natural gas by extracting natural gas liquids and removing impurities. These assets are located in North Texas, Louisiana and the Permian Basin of West Texas.

The Logistics Assets segment is involved with gathering and storing mixed NGLs and fractionating, storing, and transporting of finished NGLs. These assets are generally connected to and supplied, in part, by our Natural Gas Gathering and Processing segment and are predominantly located in Mont Belvieu, Texas and Western Louisiana.

The NGL Distribution and Marketing segment markets our own natural gas liquids production and purchased natural gas liquids products in selected United States markets. We also had the right to purchase or market substantially all of Chevron’s natural gas liquids pursuant to a Master Natural Gas Liquids Purchase Agreement.

The Wholesale Marketing segment includes our refinery services business and wholesale propane marketing operations. In our refinery services business, we provide liquefied petroleum gas balancing services, purchase natural gas liquids products from refinery customers and sell natural gas liquids products to various customers. Our wholesale propane marketing operations include the sale of propane and related logistics services to multi-state retailers, independent retailers and other end users. Wholesale Marketing operates principally in the United States, and has a small marketing presence in Canada.

Eliminations and Other includes amounts related to general and administrative expenses not allocated to segment operations, corporate development, interest expense, income tax expense, and the depreciation and cost of equipment used in our headquarters office. Eliminations and Other also includes the elimination of intersegment revenues and expenses.

Our reportable segment information is shown in the following tables:

	Year Ended December 31, 2008					
	Natural Gas Gathering and Processing	Logistics Assets	NGL Distribution and Marketing	Wholesale Marketing	Eliminations and Other	Total
Revenues from third parties	$ 848,725	$ 106,016	$ 4,613,423	$ 1,415,460	$ -	$ 6,983,624
Revenues from affiliates	489,113	-	(62)	722	-	489,773
Intersegment revenues	736,280	131,995	571,358	43,865	(1,483,498)	-
Revenues	2,074,118	238,011	5,184,719	1,460,047	(1,483,498)	7,473,397
Product purchases from third parties	1,479,061	(101)	3,445,263	900,210	-	5,824,433
Product purchases from affiliates	286,917	-	808,556	2,167	-	1,097,640
Intersegment product purchases	37,053	101	910,621	544,513	(1,492,288)	-
Product purchases	1,803,031	-	5,164,440	1,446,890	(1,492,288)	6,922,073
Operating expenses from third parties	55,259	138,125	1,746	60	-	195,190
Operating expenses from affiliates	66	49,990	-	-	8,790	58,846
Operating expenses	55,325	188,115	1,746	60	8,790	254,036
Operating margin	$ 215,762	$ 49,896	$ 18,533	$ 13,097	$ -	$ 297,288
Other financial information:						
Equity in earnings of unconsolidated investments	$ -	$ 3,877	$ -	$ -	$ -	$ 3,877
Identifiable assets	1,580,906	498,189	142,349	115,670	(22,295)	2,314,819
Unconsolidated investments	-	18,465	-	-	-	18,465
Capital expenditures	54,758	41,460	-	-	-	96,218
Revenues by type:						
Commodity sales	$ 2,063,724	$ 60	$ 5,172,168	$ 1,453,130	$ (1,349,199)	$ 7,339,883
Services	10,350	235,398	2,961	408	(134,299)	114,818
Business interruption/other	44	2,553	9,590	6,509	-	18,696
	$ 2,074,118	$ 238,011	$ 5,184,719	$ 1,460,047	$ (1,483,498)	$ 7,473,397

	Year Ended December 31, 2007					
	Natural Gas Gathering and Processing	Logistics Assets	NGL Distribution and Marketing	Wholesale Marketing	Eliminations and Other	Total
Revenues from third parties	$ 630,773	$ 83,129	$ 4,419,636	$ 1,265,183	$ -	$ 6,398,721
Revenues from affiliates	420,030	-	(3,320)	715	-	417,425
Intersegment revenues	610,666	111,968	479,498	30,107	(1,232,239)	-
Revenues	1,661,469	195,097	4,895,814	1,296,005	(1,232,239)	6,816,146
Product purchases from third parties	1,215,733	-	3,322,534	783,360	-	5,321,627
Product purchases from affiliates	188,494	-	764,105	175	-	952,774
Intersegment product purchases	2,570	-	752,183	489,532	(1,244,285)	-
Product purchases	1,406,797	-	4,838,822	1,273,067	(1,244,285)	6,274,401
Operating expenses from third parties	50,897	122,639	1,562	31	-	175,129
Operating expenses from affiliates	34	32,473	(23)	-	12,046	44,530
Operating expenses	50,931	155,112	1,539	31	12,046	219,659
Operating margin	$ 203,741	$ 39,985	$ 55,453	$ 22,907	$ -	$ 322,086
Other financial information:						
Equity in earnings of unconsolidated investments	$ -	$ 3,511	$ -	$ -	$ -	$ 3,511
Identifiable assets	1,479,972	482,190	588,505	239,734	(87,547)	2,702,854
Unconsolidated investments	-	19,238	-	-	-	19,238
Capital expenditures	43,947	35,179	-	-	-	79,126
Revenues by type:						
Commodity sales	$ 1,652,415	$ 45	$ 4,889,339	$ 1,294,599	$ (1,118,313)	$ 6,718,085
Services	7,223	195,081	2,643	580	(113,926)	91,601
Business interruption/other	1,831	(29)	3,832	826	-	6,460
	$ 1,661,469	$ 195,097	$ 4,895,814	$ 1,296,005	$ (1,232,239)	$ 6,816,146

	Year Ended December 31, 2006					
	Natural Gas Gathering and Processing	Logistics Assets	NGL Distribution and Marketing	Wholesale Marketing	Eliminations and Other	Total
Revenues from third parties	$ 951,936	$ 63,429	$ 3,315,535	$ 1,247,336	$ -	$ 5,578,236
Revenues from affiliates	324,945	-	3,442	866	-	329,253
Intersegment revenues	461,644	114,700	419,792	62,240	(1,058,376)	-
Revenues	1,738,525	178,129	3,738,769	1,310,442	(1,058,376)	5,907,489
Product purchases from third parties	1,194,751	3	2,496,448	859,268	-	4,550,470
Product purchases from affiliates	320,971	-	612,617	(5,185)	-	928,403
Intersegment product purchases	1,946	(3)	617,056	445,831	(1,064,830)	-
Product purchases	1,517,668	-	3,726,121	1,299,914	(1,064,830)	5,478,873
Operating expenses from third parties	49,033	103,405	2,044	10	-	154,492
Operating expenses from affiliates	42	32,107	-	-	6,454	38,603
Operating expenses	49,075	135,512	2,044	10	6,454	193,095
Operating margin	$ 171,782	$ 42,617	$ 10,604	$ 10,518	$ -	$ 235,521
Other financial information:						
Equity in earnings of unconsolidated investments	$ -	$ 2,754	$ -	$ -	$ -	$ 2,754
Identifiable assets	1,416,371	479,819	346,805	158,018	-	2,401,013
Unconsolidated investments	-	19,602	-	-	-	19,602
Capital expenditures	32,576	23,167	-	-	-	55,743
Revenues by type:						
Commodity sales	$ 1,725,161	$ -	$ 3,730,172	$ 1,302,287	$ (943,695)	$ 5,813,925
Services	13,031	177,744	3,092	7,059	(114,681)	86,245
Business interruption/other	333	385	5,505	1,096	-	7,319
	$ 1,738,525	$ 178,129	$ 3,738,769	$ 1,310,442	$ (1,058,376)	$ 5,907,489

The following table is a reconciliation of operating margin to net income for each period presented:

	Year Ended December 31,		
	2008	2007	2006
Reconciliation of operating margin to net income (loss):			
Operating margin	$ 297,288	$ 322,086	$ 235,521
Depreciation and amortization expense	(97,837)	(93,520)	(90,744)
General and administrative expense	(68,641)	(63,986)	(57,259)
Interest expense, net	(97,012)	(99,354)	(127,061)
Income tax expense	(2,390)	(2,519)	(3,430)
Other, net	18,291	(27,515)	19,321
Net income (loss)	$ 49,699	$ 35,192	$ (23,652)

Note 19—Other Operating Income

Our other operating (income) expense consists of the following items for the periods indicated:

	Year Ended December 31,		
	2008	2007	2006
Casualty loss adjustment (see Note 11)	$ 4,951	$ -	$ -
Loss (gain) on sale of assets	(5,917)	(296)	34
	$ (966)	$ (296)	$ 34

Note 20—Supplemental Cash Flow Information

The following table provides supplemental cash flow information for each period presented:

	Year Ended December 31,		
	2008	2007	2006
Net settlement of allocated indebtedness and debt issue costs	$ -	$ 941,518	$ 330
Net contribution of affiliated receivables	-	184,462	-
Noncash long-term debt allocation of payments from Parent	-	(419,277)	3,238
Interest paid	29,271	15,453	-
Debt issue costs allocated from Parent	-	(9,726)	6,054
Like-kind exchange of property, plant and equipment	5,813	-	-
Assets allocated to Parent, net	-	-	75,226

Note 21—Significant Risks and Uncertainties

Nature of Operations in Midstream Energy Industry

We operate in the midstream energy industry. Our business activities include gathering, transporting, processing and fractionating of natural gas, NGLs and crude oil. Our results of operations, cash flows and financial condition may be affected by (i) changes in the commodity prices of these hydrocarbon products and (ii) changes in the relative price levels among these hydrocarbon products. In general, the prices of natural gas, NGLs, crude oil and other hydrocarbon products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control.

Our profitability could be impacted by a decline in the volume of natural gas, NGLs and crude oil transported, gathered or processed at our facilities. A material decrease in natural gas or crude oil production or crude oil refining, as a result of depressed commodity prices, a decrease in exploration and development activities or otherwise, could result in a decline in the volume of natural gas, NGLs and crude oil handled by our facilities.

A reduction in demand for NGL products by the petrochemical, refining or heating industries, whether because of (i) general economic conditions, (ii) reduced demand by consumers for the end products made with NGL products, (iii) increased competition from petroleum-based products due to the pricing differences, (iv) adverse weather conditions, (v) government regulations affecting commodity prices and production levels of hydrocarbons or the content of motor gasoline or (vi) other reasons, could also adversely affect our results of operations, cash flows and financial position.

Counterparty Risk with Respect to Financial Instruments

Where we are exposed to credit risk in our financial instrument transactions, management analyzes the counterparty’s financial condition prior to entering into an agreement, establishes credit and/or margin limits and monitors the appropriateness of these limits on an ongoing basis. Generally, management does not require collateral and does not anticipate nonperformance by our counterparties.

Casualty or Other Risks

Targa maintains coverage in various insurance programs on our behalf, which provides us with property damage, business interruption and other coverages which are customary for the nature and scope of our operations.

Management believes that Targa has adequate insurance coverage, although insurance may not cover every type of interruption that might occur. As a result of insurance market conditions, premiums and deductibles for certain insurance policies have increased substantially, and in some instances, certain insurance may become unavailable, or available for only reduced amounts of coverage. As a result, Targa may not be able to renew existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all.

If we were to incur a significant liability for which we were not fully insured, it could have a material impact on our consolidated financial position and results of operations. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur. Any event that interrupts the revenues generated by us, or which causes us to make significant expenditures not covered by insurance, could reduce our ability to meet our financial obligations.

A portion of the insurance costs described above is allocated to us by Targa through the allocation methodology as prescribed in the Omnibus Agreement described in Note 14.

Under the Omnibus Agreement, Targa has also indemnified us for losses attributable to rights-of-way, certain consents or governmental permits, pre-closing litigation relating to the North Texas System and income taxes attributable to pre-closing operations that were not reserved on the books of the North Texas System as of February 14, 2007. Targa does not have any obligation under these indemnifications until our aggregate losses exceed $250,000. We have indemnified Targa for all losses attributable to the post-closing operations of the North Texas System. Targa’s obligations under this additional indemnification will survive for three years from February 14, 2007, except that the indemnification for income tax liabilities will terminate upon the expiration of the applicable statutes of limitations.

Note 22—Selected Quarterly Financial Data (Unaudited)

Our supplemental results of operations by quarter for the years ended December 31, 2008 and 2007, as adjusted to reflect the consideration of common control accounting as discussed in Note 2, were as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(In thousands, except per unit amounts)				
Year Ended December 31, 2008:					
Revenues	$ 2,079,458	$ 2,120,192	$ 2,214,851	$ 1,058,896	$ 7,473,397
Operating income	45,184	67,860	(7,530)	26,262	131,776
Net income attributable to partners	24,935	28,206	14,692	23,661	91,494
Net income per limited partner unit--basic and diluted	$ 0.50	$ 0.54	$ 0.31	$ 0.48	$ 1.83
Year Ended December 31, 2007:					
Revenues	$ 1,328,540	$ 1,505,084	$ 1,746,971	$ 2,235,551	$ 6,816,146
Operating income	37,216	23,976	38,092	65,592	164,876
Net income (loss) attributable to partners	2,153	4,040	3,869	18,004	28,066
Net income per limited partner unit--basic and diluted	$ 0.07	$ 0.13	$ 0.12	$ 0.42	$ 0.81

The following tables reconcile the previously reported amounts to those shown above:

	Historical Targa Resources Partners LP	Downstream Business	Adjustments	Targa Resources Partners LP	Historical Targa Resources Partners LP	Downstream Business	Adjustments	Targa Resources Partners LP
	(In thousands, except per unit amounts)				(In thousands, except per unit amounts)			
	First Quarter 2008				Second Quarter 2008			
Revenues	$ 512,069	$ 1,769,795	$ (202,406)	$ 2,079,458	$ 630,520	$ 1,729,321	$ (239,649)	$ 2,120,192
Operating income	33,974	11,186	24	45,184	36,525	31,335	-	67,860
Net income attributable to partners	24,935	-	-	24,935	28,206	-	-	28,206
Net income per limited partner unit--basic and diluted	$ 0.50	-	-	$ 0.50	$ 0.54	-	-	$ 0.54
	First Quarter 2007				Second Quarter 2007			
Revenues	$ 348,781	$ 1,086,667	$ (106,908)	$ 1,328,540	$ 433,615	$ 1,213,678	$ (142,209)	$ 1,505,084
Operating income	20,739	16,477	-	37,216	28,183	(4,207)	-	23,976
Net income (loss) attributable to partners	2,153	-	-	2,153	4,040	-	-	4,040
Net income per limited partner unit--basic and diluted	$ 0.07	-	-	$ 0.07	$ 0.13	-	-	$ 0.13

	Historical Targa Resources Partners LP	Downstream Business	Adjustments	Targa Resources Partners LP	Historical Targa Resources Partners LP	Downstream Business	Adjustments	Targa Resources Partners LP
	(In thousands, except per unit amounts)				(In thousands, except per unit amounts)			
	Third Quarter 2008				Fourth Quarter 2008			
Revenues	$ 578,747	$ 1,868,916	$ (232,812)	$ 2,214,851	$ 352,782	$ 804,647	$ (98,533)	$ 1,058,896
Operating income	26,815	(34,345)	-	(7,530)	21,720	4,542	-	26,262
Net income attributable to partners	14,692	-	-	14,692	23,661	-	-	23,661
Net income per limited partner unit--basic and diluted	$ 0.31	-	-	$ 0.31	$ 0.48	-	-	$ 0.48
	Third Quarter 2007				Fourth Quarter 2007			
Revenues	$ 405,038	$ 1,502,186	$ (160,253)	$ 1,746,971	$ 474,035	$ 1,965,445	$ (203,929)	$ 2,235,551
Operating income	29,965	8,127	-	38,092	34,467	31,125	-	65,592
Net income (loss) attributable to partners	3,869	-	-	3,869	18,004	-	-	18,004
Net income per limited partner unit--basic and diluted	$ 0.12	-	-	$ 0.12	$ 0.42	-	-	$ 0.42