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

FORM 10-Q

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

For the quarterly period ended September 30, 2019
or

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

For the transition period from _____ to _____

Commission File Number: 001-33303

TARGA RESOURCES PARTNERS LP
(Exact name of registrant as specified in its charter)

Delaware	**65-1295427**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
811 Louisiana St, Suite 2100, Houston, Texas	**77002**
(Address of principal executive offices)	**(Zip Code)**

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

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of exchange on which registered
9.0% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units	NGLS/PA	New York Stock Exchange

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes☑ No ☐

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

Large accelerated filer	☐	Accelerated filer	☐
Non-accelerated filer	☑	Smaller reporting company	☐
		Emerging growth company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

As of November 1, 2019, there were 5,000,000 9.0% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units outstanding.

TABLE OF CONTENTS

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Targa Resources Partners LP's (together with its subsidiaries, "we," "us," "our," "TRP" or the "Partnership") reports, filings and other public announcements may from time to time contain statements that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements." You can typically identify forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, by the use of forward-looking statements, such as "may," "could," "project," "believe," "anticipate," "expect," "estimate," "potential," "plan," "forecast" and other similar words.

All statements that are not statements of historical facts, including statements regarding our future financial position, business strategy, budgets, projected costs and plans and objectives of management for future operations, are forward-looking statements.

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. Known risks and uncertainties include, but are not limited to, the following risks and uncertainties:

- the timing and extent of changes in natural gas, natural gas liquids, crude oil and other commodity prices, interest rates and demand for our services;
- the level and success of crude oil and natural gas drilling around our assets, our success in connecting natural gas supplies to our gathering and processing systems, oil supplies to our gathering systems and natural gas liquid supplies to our transportation and logistics and marketing facilities and our success in connecting our facilities to transportation services and markets;
- our ability to access the capital markets, which will depend on general market conditions and the credit ratings for our debt obligations;
- the amount of collateral required to be posted from time to time in our transactions;
- our success in risk management activities, including the use of derivative instruments to hedge commodity price risks;
- the level of creditworthiness of counterparties to various transactions with us;
- changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment;
- weather and other natural phenomena;
- industry changes, including the impact of consolidations and changes in competition;
- our ability to obtain necessary licenses, permits and other approvals;
- our ability to grow through acquisitions or internal growth projects and the successful integration and future performance of such assets;
- general economic, market and business conditions; and
- the risks described in our Annual Report on Form 10-K for the year ended December 31, 2018 ("Annual Report") and our reports and registration statements filed from time to time with the United States Securities and Exchange Commission ("SEC").

Although we believe that the assumptions underlying our forward-looking statements are reasonable, any of the assumptions could be inaccurate, and, therefore, we cannot assure you that the forward-looking statements included in this Quarterly Report on Form 10-Q for the quarter ended September 30, 2019 ("Quarterly Report") will prove to be accurate. Some of these and other risks and uncertainties that could cause actual results to differ materially from such forward-looking statements are more fully described in our Annual Report. Except as may be required by applicable law, we undertake no obligation to publicly update or advise of any change in any forward-looking statement, whether as a result of new information, future events or otherwise.

As generally used in the energy industry and in this Quarterly Report, the identified terms have the following meanings:

Bbl	Barrels (equal to 42 U.S. gallons)
BBtu	Billion British thermal units
Bcf	Billion cubic feet
Btu	British thermal units, a measure of heating value
/d	Per day
GAAP	Accounting principles generally accepted in the United States of America
gal	U.S. gallons
LIBOR	London Interbank Offered Rate
LPG	Liquefied petroleum gas
MBbl	Thousand barrels
MMBbl	Million barrels
MMBtu	Million British thermal units
MMcf	Million cubic feet
MMgal	Million U.S. gallons
NGL(s)	Natural gas liquid(s)
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
SCOOP	South Central Oklahoma Oil Province
STACK	Sooner Trend, Anadarko, Canadian and Kingfisher

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED BALANCE SHEETS

			September 30, 2019	December 31, 2018
			(Unaudited)	
			(In millions)	
ASSETS				
Current assets:				
Cash and cash equivalents			$ 294.9	$ 203.3
Trade receivables, net of allowances of $0.0 and $0.1 million at September 30, 2019 and December 31, 2018			742.9	864.4
Inventories			210.9	164.7
Assets from risk management activities			140.1	115.3
Other current assets			43.4	32.2
Total current assets			1,432.2	1,379.9
Property, plant and equipment			19,589.1	17,213.8
Accumulated depreciation and amortization			(4,892.4)	(4,285.5)
Property, plant and equipment, net			14,696.7	12,928.3
Intangible assets, net			1,854.4	1,983.2
Goodwill, net			46.6	46.6
Long-term assets from risk management activities			60.0	34.1
Investments in unconsolidated affiliates			718.5	490.5
Other long-term assets			49.9	27.5
Total assets			$ 18,858.3	$ 16,890.1
LIABILITIES AND OWNERS' EQUITY				
Current liabilities:				
Accounts payable and accrued liabilities			$ 1,234.8	$ 1,636.9
Accounts payable to Targa Resources Corp.			194.0	187.4
Liabilities from risk management activities			83.5	33.6
Current debt obligations			258.0	1,027.9
Total current liabilities			1,770.3	2,885.8
Long-term debt			6,844.7	5,197.4
Long-term liabilities from risk management activities			46.1	3.1
Deferred income taxes, net			23.9	23.9
Other long-term liabilities			261.7	233.8
Contingencies (see Note 16)				
Owners' equity:				
Series A preferred limited partners	Issued	Outstanding	120.6	120.6
September 30, 2019	5,000,000	5,000,000		
December 31, 2018	5,000,000	5,000,000		
Common limited partners	Issued	Outstanding	5,437.1	6,227.2
September 30, 2019	275,168,410	275,168,410		
December 31, 2018	275,168,410	275,168,410		
General partner	Issued	Outstanding	786.4	802.6
September 30, 2019	5,629,136	5,629,136		
December 31, 2018	5,629,136	5,629,136		
Accumulated other comprehensive income (loss)			186.6	124.9
			6,530.7	7,275.3
Noncontrolling interests			3,380.9	1,270.8
Total owners' equity			9,911.6	8,546.1
Total liabilities and owners' equity			$ 18,858.3	$ 16,890.1

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(Unaudited) (In millions)			
Revenues:				
Sales of commodities	$ 1,594.2	$ 2,654.1	$ 5,254.8	$ 6,981.4
Fees from midstream services	308.3	332.3	942.4	904.9
Total revenues	1,902.5	2,986.4	6,197.2	7,886.3
Costs and expenses:				
Product purchases	1,328.1	2,383.5	4,415.7	6,229.7
Operating expenses	200.2	194.9	600.7	538.7
Depreciation and amortization expense	244.3	206.3	718.9	607.1
General and administrative expense	65.6	59.3	212.3	165.0
Other operating (income) expense	18.4	61.8	21.7	15.7
Income (loss) from operations	45.9	80.6	227.9	330.1
Other income (expense):				
Interest expense, net	(84.2)	(75.7)	(229.2)	(113.3)
Equity earnings (loss)	10.0	3.0	15.9	6.4
Gain (loss) from financing activities	—	—	(1.4)	(1.3)
Gain (loss) from sale of equity-method investment	65.8	—	65.8	—
Change in contingent considerations	—	(16.6)	(8.8)	(12.1)
Income (loss) before income taxes	37.5	(8.7)	70.2	209.8
Income tax (expense) benefit	—	—	—	—
Net income (loss)	37.5	(8.7)	70.2	209.8
Less: Net income (loss) attributable to noncontrolling interests	76.6	9.7	144.3	32.0
Net income (loss) attributable to Targa Resources Partners LP	$ (39.1)	$ (18.4)	$ (74.1)	$ 177.8
Net income attributable to preferred limited partners	$ 2.8	$ 2.8	$ 8.4	$ 8.4
Net income (loss) attributable to general partner	(0.9)	(0.4)	(1.7)	3.4
Net income (loss) attributable to common limited partners	(41.0)	(20.8)	(80.8)	166.0
Net income (loss) attributable to Targa Resources Partners LP	$ (39.1)	$ (18.4)	$ (74.1)	$ 177.8

See notes to consolidated financial statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(Unaudited) (In millions)			
Net income (loss)	$ 37.5	$ (8.7)	$ 70.2	$ 209.8
Other comprehensive income (loss):				
Commodity hedging contracts:				
Change in fair value	118.2	(139.6)	167.8	(178.0)
Settlements reclassified to revenues	(41.5)	23.9	(106.1)	58.3
Other comprehensive income (loss)	76.7	(115.7)	61.7	(119.7)
Comprehensive income (loss)	114.2	(124.4)	131.9	90.1
Less: Comprehensive income (loss) attributable to noncontrolling interests	76.6	9.7	144.3	32.0
Comprehensive income (loss) attributable to Targa Resources Partners LP	$ 37.6	$ (134.1)	$ (12.4)	$ 58.1

See notes to consolidated financial statements.

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

	Limited Partner		Limited Partner		General Partner		Accumulated Other Comprehensive	Non-controlling	
	Preferred	Amount	Common	Amount	Units	Amount	Income (Loss)	Interests	Total
	(Unaudited) (In millions, except units in thousands)								
Balance, June 30, 2019	5,000	$ 120.6	275,168	$ 5,703.1	5,629	$ 791.9	$ 109.9	$ 3,276.2	$ 10,001.7
Contributions from Targa Resources Corp.	—	—	—	9.8	—	0.2	—	—	10.0
Sale of ownership interests in subsidiaries	—	—	—	—	—	—	—	—	—
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(87.2)	(87.2)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	115.3	115.3
Other comprehensive income (loss)	—	—	—	—	—	—	76.7	—	76.7
Net income (loss)	—	2.8	—	(41.0)	—	(0.9)	—	76.6	37.5
Distributions	—	(2.8)	—	(234.8)	—	(4.8)	—	—	(242.4)
Balance, September 30, 2019	5,000	$ 120.6	275,168	$ 5,437.1	5,629	$ 786.4	$ 186.6	$ 3,380.9	$ 9,911.6

	Limited Partner		Limited Partner		General Partner		Accumulated Other Comprehensive	Non-controlling	
	Preferred	Amount	Common	Amount	Units	Amount	Income (Loss)	Interests	Total
	(Unaudited) (In millions, except units in thousands)								
Balance, June 30, 2018	5,000	$ 120.6	275,168	$ 6,322.2	5,629	$ 804.5	$ (49.9)	$ 911.8	$ 8,109.2
Contributions from Targa Resources Corp.	—	—	—	450.6	—	9.2	—	—	459.8
Acquisition of related party	—	—	—	—	—	—	—	—	—
Purchase of noncontrolling interests in subsidiaries, net	—	—	—	—	—	—	—	—	—
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(17.7)	(17.7)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	164.4	164.4
Other comprehensive income (loss)	—	—	—	—	—	—	(115.8)	—	(115.8)
Net income (loss)	—	2.8	—	(20.8)	—	(0.4)	—	9.7	(8.7)
Distributions	—	(2.8)	—	(226.5)	—	(4.6)	—	—	(233.9)
Balance, September 30, 2018	5,000	$ 120.6	275,168	$ 6,525.5	5,629	$ 808.7	$ (165.7)	$ 1,068.2	$ 8,357.3

See notes to consolidated financial statements.

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

	Limited Partner Preferred	Limited Partner Amount	Limited Partner Common	Limited Partner Amount	General Partner Units	General Partner Amount	Accumulated Other Comprehensive Income (Loss)	Non-controlling Interests	Total
	(Unaudited) (In millions, except units in thousands)								
Balance, December 31, 2018	5,000	$ 120.6	275,168	$ 6,227.2	5,629	$ 802.6	$ 124.9	$ 1,270.8	$ 8,546.1
Contributions from Targa Resources Corp.	—	—	—	196.0	—	4.0	—	—	200.0
Sale of ownership interests in subsidiaries	—	—	—	(10.5)	—	(0.2)	—	1,619.7	1,609.0
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(172.6)	(172.6)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	518.7	518.7
Other comprehensive income (loss)	—	—	—	—	—	—	61.7	—	61.7
Net income (loss)	—	8.4	—	(80.8)	—	(1.7)	—	144.3	70.2
Distributions	—	(8.4)	—	(894.8)	—	(18.3)	—	—	(921.5)
Balance, September 30, 2019	5,000	$ 120.6	275,168	$ 5,437.1	5,629	$ 786.4	$ 186.6	$ 3,380.9	$ 9,911.6

	Limited Partner Preferred	Limited Partner Amount	Limited Partner Common	Limited Partner Amount	General Partner Units	General Partner Amount	Accumulated Other Comprehensive Income (Loss)	Non-controlling Interests	Total
	(Unaudited) (In millions, except units in thousands)								
Balance, December 31, 2017	5,000	$ 120.6	275,168	$ 6,500.3	5,629	$ 808.2	$ (46.0)	$ 475.1	$ 7,858.2
Contributions from Targa Resources Corp.	—	—	—	529.2	—	10.8	—	—	540.0
Acquisition of related party	—	—	—	—	—	—	—	1.1	1.1
Purchase of noncontrolling interests in subsidiaries, net	—	—	—	—	—	—	—	(0.1)	(0.1)
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(51.5)	(51.5)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	611.6	611.6
Other comprehensive income (loss)	—	—	—	—	—	—	(119.7)	—	(119.7)
Net income (loss)	—	8.4	—	166.0	—	3.4	—	32.0	209.8
Distributions	—	(8.4)	—	(670.0)	—	(13.7)	—	—	(692.1)
Balance, September 30, 2018	5,000	$ 120.6	275,168	$ 6,525.5	5,629	$ 808.7	$ (165.7)	$ 1,068.2	$ 8,357.3

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
	(Unaudited) (In millions)	
Cash flows from operating activities		
Net income (loss)	$ 70.2	$ 209.8
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Amortization in interest expense	6.8	6.8
Depreciation and amortization expense	718.9	607.1
Accretion of asset retirement obligations	3.7	2.8
Increase (decrease) in redemption value of mandatorily redeemable preferred interests	—	(66.3)
Equity (earnings) loss of unconsolidated affiliates	(15.9)	(6.4)
Distributions of earnings received from unconsolidated affiliates	26.0	16.0
Risk management activities	100.8	9.6
(Gain) loss on sale or disposition of assets	3.6	14.3
Write-down of assets	17.9	—
(Gain) loss from financing activities	1.4	1.3
(Gain) loss from sale of equity-method investment	(65.8)	—
Change in contingent considerations	8.8	12.1
Changes in operating assets and liabilities, net of business acquisitions:		
Receivables and other assets	108.0	(221.7)
Inventories	(89.7)	(16.6)
Accounts payable and other liabilities	2.7	374.7
Net cash provided by operating activities	897.4	943.5
Cash flows from investing activities		
Outlays for property, plant and equipment	(2,433.8)	(2,033.6)
Proceeds from sale of assets	2.7	71.5
Investments in unconsolidated affiliates	(243.7)	(223.7)
Proceeds from sale of equity-method investment	70.3	—
Return of capital from unconsolidated affiliates	1.1	2.2
Other, net	(16.3)	(9.2)
Net cash used in investing activities	(2,619.7)	(2,192.8)
Cash flows from financing activities		
Debt obligations:		
Proceeds from borrowings under credit facility	2,180.0	950.0
Repayments of credit facility	(2,050.0)	(970.0)
Proceeds from borrowings under accounts receivable securitization facility	770.0	440.0
Repayments of accounts receivable securitization facility	(804.0)	(500.0)
Proceeds from issuance of senior notes	1,500.0	1,000.0
Redemption of senior notes	(749.4)	—
Principal payments of finance leases	(8.5)	—
Costs incurred in connection with financing arrangements	(25.1)	(15.8)
Payment of contingent consideration	(317.1)	—
Sale of ownership interests in subsidiaries	1,619.7	(0.1)
Contributions from general partner	4.0	10.8
Contributions from TRC	196.0	529.2
Contributions from noncontrolling interests	518.7	611.6
Distributions to noncontrolling interests	(98.9)	(51.5)
Distributions to unitholders	(921.5)	(692.1)
Net cash provided by financing activities	1,813.9	1,312.1
Net change in cash and cash equivalents	91.6	62.8
Cash and cash equivalents, beginning of period	203.3	124.7
Cash and cash equivalents, end of period	$ 294.9	$ 187.5

See notes to 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 millions of dollars.

Note 1 — Organization and Operations

Our Organization

Targa Resources Partners LP is a Delaware limited partnership formed in October 2006 by our parent, Targa Resources Corp. ("Targa" or "TRC" or the "Company" or "Parent"). In this Quarterly Report, unless the context requires otherwise, references to "we," "us," "our," "TRP," or the "Partnership" are intended to mean the business and operations of Targa Resources Partners LP and its consolidated subsidiaries.

Our common units are wholly owned by TRC and no longer publicly traded as a result of TRC's acquisition of our outstanding common units that it and its subsidiaries did not already own in 2016.

The 5,000,000 9.00% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Preferred Units") that were issued in October 2015 remain outstanding as limited partner interests in us and continue to trade on the NYSE under the symbol "NGLS/PA."

Our Operations

We are primarily engaged in the business of:

- gathering, compressing, treating, processing, transporting and selling natural gas;
- transporting, storing, fractionating, treating and selling NGLs and NGL products, including services to LPG exporters; and
- gathering, storing, terminaling and selling crude oil.

See Note 20 – Segment Information for certain financial information regarding our business segments.

The employees supporting our operations are employed by Targa. Our consolidated financial statements include the direct costs of Targa employees deployed to our operating segments, as well as an allocation of costs associated with our usage of Targa's centralized general and administrative services.

Note 2 — Basis of Presentation

The accompanying unaudited consolidated financial statements have been prepared in accordance with the instructions to Form 10-Q and do not include all information and disclosures required by GAAP. Therefore, this information should be read in conjunction with our consolidated financial statements and notes contained in our Annual Report. The information furnished herein reflects all adjustments that are, in the opinion of management, necessary for a fair statement of the results of the interim periods reported. All significant intercompany balances and transactions have been eliminated in consolidation. Certain amounts in prior periods may have been reclassified to conform to the current year presentation. Operating results for the three and nine months ended September 30, 2019, are not necessarily indicative of the results that may be expected for the year ending December 31, 2019.

Note 3 — Significant Accounting Policies

The accounting policies that we follow are set forth in Note 3 – Significant Accounting Policies of the Notes to Consolidated Financial Statements in our Annual Report. Other than the updates noted below, there were no significant updates or revisions to our accounting policies during the nine months ended September 30, 2019.

Recent Accounting Pronouncements

Recently adopted accounting pronouncements

Leases

In February 2016, the Financial Accounting Standards Board issued Accounting Standards Update ("ASU") 2016-02, *Leases* (Topic 842). The amendments in this update supersede the leases guidance in Topic 840. We adopted Topic 842 on January 1, 2019 by applying the optional transition method in ASU 2018-11, which permits an entity to initially apply the new leases standard at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. The adoption of Topic 842 did not result in a cumulative effect adjustment to retained earnings on January 1, 2019. As part of the adoption of Topic 842, we recognized a net right-of-use asset of $64.2 million (net of $0.4 million of lease incentives/deferred rent) and lease liability of $64.6 million. Other practical expedients we elected include:

- The package for transition relief, which among other things, allows us to carry forward our historical lease classification;
- The land easements transition, which allows us to carry forward our historical accounting treatment for land easements prior to the effective date of the new leases standard, and evaluate only new or modified land easements on or after January 1, 2019 under Topic 842;
- The short-term lease election, which allows us to elect not to record leases with an initial term of twelve months or less, for all asset classes;
- The election to not separate non-lease components from lease components for all the asset classes in our current lease portfolio, where Targa is the lessee; and
- The election to not separate non-lease components from lease components for gathering, processing and storage assets, where Targa is the lessor. Based on our election, we determined the non-lease component in certain of these arrangements is the predominant component and therefore account for the arrangements under ASC 606.

We recognize the following for all leases (with the exception of short-term leases) at the commencement date:

- A lease liability, which is a lessee's obligation to make lease payments arising from a lease.
- A right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term.

We determine if an arrangement is or contains a lease at inception. Leases with an initial term of twelve months or less are considered short-term leases, which are excluded from the balance sheet. Right-of-use assets and lease liabilities are recognized at the commencement date based on the present value of future lease payments over the lease term. The right-of-use asset also includes any lease prepayments and excludes lease incentives. As most of the Company's leases do not provide an implicit interest rate, we use our incremental borrowing rate as the discount rate to compute the present value of our lease liability. The discount rate applied is determined based on information available on the date of adoption for all leases existing as of that date, and on the date of lease commencement for all subsequent leases.

Our lease arrangements may include variable lease payments based on an index or market rate, or may be based on performance. For variable lease payments based on an index or market rate, we estimate and apply a rate based on information available at the commencement date. Variable lease payments based on performance are excluded from the calculation of the right-of-use asset and lease liability, and are recognized in our Consolidated Statements of Operations when the contingency underlying such variable lease payments is resolved. Our lease terms may include options to extend or terminate the lease. Such options are included in the measurement of our right-of-use asset and liability, provided we determine that we are reasonably certain to exercise the option.

See Note 11 – Leases for additional details.

Note 4 — Divestitures

Train 7 Joint Venture

In February 2019, we announced an extension of the Grand Prix NGL Pipeline ("Grand Prix") from Southern Oklahoma to the STACK region of Central Oklahoma where it will connect with the Williams Companies, Inc. ("Williams") Bluestem Pipeline and link the Conway, Kansas, and Mont Belvieu, Texas, NGL markets. In connection with this project, Williams has committed significant volumes to us that we will transport on Grand Prix and fractionate at our Mont Belvieu facilities. Williams also had an initial option to purchase a 20% equity interest in one of our recently announced 110 MBbl/d fractionation trains (Train 7 or Train 8) in Mont Belvieu. Williams exercised its option to acquire a 20% equity interest in Train 7 and subsequently executed a joint venture agreement with us in the second quarter of 2019. Certain fractionation-related infrastructure for Train 7, including storage caverns and brine handling, will be funded and owned 100% by Targa. We present Train 7 on a consolidated basis in our consolidated financial statements.

Sale of Interest in Targa Badlands LLC

On April 3, 2019, we closed on the sale of a 45% interest in Targa Badlands LLC ("Targa Badlands"), the entity that holds substantially all of our assets in North Dakota, to funds managed by GSO Capital Partners and Blackstone Tactical Opportunities (collectively, "Blackstone") for $1.6 billion in cash. We used the net cash proceeds to repay debt and for general corporate purposes, including funding our growth capital program. Future growth capital of Targa Badlands is expected to be funded on a pro rata ownership basis. Targa Badlands pays a minimum quarterly distribution ("MQD") to Blackstone and Targa, with Blackstone having a priority right on such MQDs. Once Blackstone receives funds sufficient to meet a predetermined fixed return on their invested capital, their interest will convert to a 7.5% equity interest in Targa Badlands, and it will no longer have a priority right on MQDs. Additionally, upon a sale of Targa Badlands, Blackstone's capital contributions would have a liquidation preference equal to a predetermined fixed return on their invested capital.

After the seventh anniversary of the closing date or upon the occurrence of certain triggering events, we have the option to acquire all of Blackstone's interest in Targa Badlands for a purchase price payable to Blackstone based on their liquidation preference after taking into account all prior distributions to Blackstone, plus a set percentage on a multiple of the trailing twelve-month EBITDA of Targa Badlands. Targa will continue to control the management of Targa Badlands pending the occurrence of certain triggering events, including if Blackstone has not received funds sufficient to meet its liquidation preference and Targa has not exercised its purchase right to acquire Blackstone's interest by April 3, 2029.

We continue to be the operator of Targa Badlands and hold majority governance rights. As a result, we continue to present Targa Badlands on a consolidated basis in our consolidated financial statements and Blackstone's contributions are reflected as noncontrolling interests.

Subsequent Event

In November 2019, we executed agreements to sell our crude gathering and storage business in the Permian Delaware for approximately $135 million. Subject to customary regulatory approvals and closing conditions, the sale is expected to close in the fourth quarter of 2019.

We have also engaged Jefferies LLC to evaluate the potential divestiture of our crude gathering business in the Permian Midland, which includes crude gathering and storage assets. The potential divestiture is predicated on third party valuations adequately capturing our forward growth expectations for the assets, and no assurance can be made that a sale will be consummated.

Note 5 — Inventories

	September 30, 2019	December 31, 2018
Commodities	$ 202.6	$ 151.1
Materials and supplies	8.3	13.6
	$ 210.9	$ 164.7

Note 6 — Property, Plant and Equipment and Intangible Assets

	September 30, 2019	December 31, 2018	Estimated Useful Lives (In Years)
Gathering systems	$ 8,767.6	$ 7,547.9	5 to 20
Processing and fractionation facilities	4,961.3	4,001.0	5 to 25
Terminaling and storage facilities	1,459.1	1,138.7	5 to 25
Transportation assets	2,221.9	445.1	10 to 50
Other property, plant and equipment	302.0	334.3	3 to 25
Land	154.4	144.3	—
Construction in progress	1,675.9	3,602.5	—
Finance lease right-of-use assets	46.9	—	
Property, plant and equipment	19,589.1	17,213.8	
Accumulated depreciation and amortization	(4,892.4)	(4,285.5)	
Property, plant and equipment, net	$ 14,696.7	$ 12,928.3	
Intangible assets	$ 2,736.6	$ 2,736.6	10 to 20
Accumulated amortization	(882.2)	(753.4)	
Intangible assets, net	$ 1,854.4	$ 1,983.2	

During the preparation of the Company's first quarter 2019 consolidated financial statements, the Company identified an error related to depreciation expense on certain assets that should have been placed in-service during 2018. The Company does not believe this error is material to its previously issued historical consolidated financial statements for any of the periods impacted and accordingly, has not adjusted the historical financial statements. The Company recorded the cumulative impact of the adjustment in the period of identification, resulting in a one-time $12.5 million overstatement of depreciation expense.

During the three and nine months ended September 30, 2019, depreciation expense was $201.4 million and $590.1 million. During the three and nine months ended September 30, 2018, depreciation expense was $161.7 million and $470.9 million.

Intangible Assets

Intangible assets consist of customer contracts and customer relationships acquired in prior business combinations. The fair value of these acquired intangible assets were determined at the date of acquisition based on the present values of estimated future cash flows. Amortization expense attributable to these assets is recorded over the periods in which we benefit from services provided to customers.

The estimated annual amortization expense for intangible assets is approximately $171.6 million, $159.4 million, $149.5 million, $141.2 million and $136.0 million for each of the years 2019 through 2023.

The changes in our intangible assets are as follows:

Balance at December 31, 2018	$ 1,983.2
Amortization	(128.8)
Balance at September 30, 2019	$ 1,854.4

Note 7 – Investments in Unconsolidated Affiliates

Our investments in unconsolidated affiliates consist of the following:

Gathering and Processing Segment

- two operated joint ventures in South Texas: a 75% interest in T2 LaSalle Gathering Company L.L.C. (“T2 LaSalle”) and a 50% interest in T2 Eagle Ford Gathering Company L.L.C. (“T2 Eagle Ford”), (together the “T2 Joint Ventures”); and
- a 50% operated ownership interest in Little Missouri 4 LLC (“Little Missouri 4”).

Logistics and Marketing Segment

- a 25% non-operated ownership interest in Gulf Coast Express Pipeline LLC ("GCX");
- a 38.8% non-operated ownership interest in Gulf Coast Fractionators LP ("GCF"); and
- a 50% operated ownership interest in Cayenne Pipeline, LLC ("Cayenne").

The terms of these joint venture agreements do not afford us the degree of control required for consolidating them in our consolidated financial statements, but do afford us the significant influence required to employ the equity method of accounting.

The T2 Joint Ventures were formed to provide services for the benefit of their joint venture owners and have capacity lease agreements with their joint venture owners, which cover costs of operations (excluding depreciation and amortization). On April 1, 2019, we assumed the operatorship of the T2 Joint Ventures.

During the third quarter of 2019, we closed on the sale of an equity-method investment for $70.3 million that resulted in the recognition of a gain of $65.8 million during the three months ended September 30, 2019, which is reported as part of Other (income) expense.

The following table shows the activity related to our investments in unconsolidated affiliates:

	Balance at December 31, 2018	Equity Earnings (Loss)	Cash Distributions	Disposition	Contributions	Balance at September 30, 2019
GCX (1)	$ 211.6	$ 8.9	$ (5.3)	$ —	$ 210.4	$ 425.6
T2 Eagle Ford (2)	99.0	(7.5)	—	—	—	91.5
Little Missouri 4	67.3	0.1	—	—	33.0	100.4
T2 LaSalle (2)	49.3	(3.5)	—	—	—	45.8
GCF	40.3	14.0	(14.7)	—	—	39.6
Cayenne	16.6	5.4	(6.7)	—	0.3	15.6
Agua Blanca	6.4	(1.5)	(0.4)	(4.5)	—	—
Total	$ 490.5	$ 15.9	$ (27.1)	$ (4.5)	$ 243.7	$ 718.5

(1) Our 25% interest in GCX is owned by Targa GCX Pipeline LLC ("GCX DevCo JV"), of which we own a 20% interest. GCX DevCo JV is accounted for on a consolidated basis in our consolidated financial statements.

(2) As of September 30, 2019, $23.5 million of unamortized excess fair value over the T2 LaSalle and T2 Eagle Ford capital accounts remained. These basis differences, which are attributable to the underlying depreciable tangible gathering assets, are being amortized on a straight-line basis as components of equity earnings over the estimated 20-year useful lives of the underlying assets.

Note 8 — Accounts Payable and Accrued Liabilities

	September 30, 2019	December 31, 2018
Commodities	$ 612.0	$ 721.9
Other goods and services	359.6	474.5
Interest	91.6	79.4
Permian Acquisition contingent consideration	—	308.2
Income and other taxes	79.5	45.4
Accrued distributions to noncontrolling interests	73.8	—
Other	18.3	7.5
	$ 1,234.8	$ 1,636.9

Accounts payable and accrued liabilities includes $15.3 million and $52.2 million of liabilities to creditors to whom we have issued checks that remained outstanding as of September 30, 2019 and December 31, 2018.

Permian Acquisition Contingent Consideration

As a result of a 2017 acquisition of certain gas gathering and processing and crude gathering assets in the Permian Basin (the "Permian Acquisition"), we included the fair value of the contingent consideration in accounts payable and accrued liabilities as of December 31, 2018. The contingent consideration earn-out period ended on February 28, 2019 and resulted in a $317.1 million payment in May 2019.

Note 9 — Debt Obligations

	September 30, 2019	December 31, 2018
Current:		
Accounts receivable securitization facility, due December 2019 (1)	$ 246.0	$ 280.0
Senior unsecured notes, 4⅛% fixed rate, due November 2019	—	749.4
	246.0	1,029.4
Debt issuance costs, net of amortization	—	(1.5)
Finance lease liabilities	12.0	—
Current debt obligations	258.0	1,027.9
Long-term:		
Senior secured revolving credit facility, variable rate, due June 2023 (2)	830.0	700.0
Senior unsecured notes:		
5¼% fixed rate, due May 2023	559.6	559.6
4¼% fixed rate, due November 2023	583.9	583.9
6¾% fixed rate, due March 2024	580.1	580.1
5⅛% fixed rate, due February 2025	500.0	500.0
5⅞% fixed rate, due April 2026	1,000.0	1,000.0
5⅜% fixed rate, due February 2027	500.0	500.0
6½% fixed rate, due July 2027	750.0	—
5% fixed rate, due January 2028	750.0	750.0
6⅞% fixed rate, due January 2029	750.0	—
TPL notes, 4¾% fixed rate, due November 2021 (3)	6.5	6.5
TPL notes, 5⅞% fixed rate, due August 2023 (3)	48.1	48.1
Unamortized premium	0.3	0.3
	6,858.5	5,228.5
Debt issuance costs, net of amortization	(40.7)	(31.1)
Finance lease liabilities	26.9	—
Long-term debt	6,844.7	5,197.4
Total debt obligations	$ 7,102.7	$ 6,225.3
Irrevocable standby letters of credit outstanding (2)	$ 73.8	$ 79.5

(1) As of September 30, 2019, we had $246.0 million of qualifying receivables under our $400.0 million accounts receivable securitization facility, resulting in zero availability.
(2) As of September 30, 2019, availability under our $2.2 billion senior secured revolving credit facility ("TRP Revolver") was $1,296.2 million.
(3) "TPL" refers to Targa Pipeline Partners LP.

The following table shows the range of interest rates and weighted average interest rate incurred on our variable-rate debt obligations during the nine months ended September 30, 2019:

	Range of Interest Rates Incurred	Weighted Average Interest Rate Incurred
TRP Revolver	3.8% - 4.7%	4.2%
Accounts receivable securitization facility	2.9% - 3.4%	3.3%

Compliance with Debt Covenants

As of September 30, 2019, we were in compliance with the covenants contained in our various debt agreements.

Senior Unsecured Notes Issuance

In January 2019, we issued $750.0 million of 6½% Senior Notes due July 2027 and $750.0 million of 6⅞% Senior Notes due January 2029, resulting in total net proceeds of $1,486.6 million. The net proceeds from the issuance were used to redeem in full our 4⅛% Senior Notes due 2019, at par value plus accrued interest through the redemption date, with the remainder used for general partnership purposes, which included repayment of borrowings under our credit facilities.

Debt Extinguishment

In February 2019, we redeemed in full our outstanding 4⅛% Senior Notes due 2019 at par value plus accrued interest through the redemption date. The redemption resulted in a non-cash loss to write-off $1.4 million of unamortized debt issuance costs, which is included in Gain (loss) from financing activities in the Consolidated Statements of Operations.

Note 10 — Other Long-term Liabilities

Other long-term liabilities is comprised of deferred revenue, asset retirement obligations and operating lease liabilities.

Deferred Revenue

We have certain long-term contractual arrangements for which we have received consideration that we are not yet able to recognize as revenue. The resulting deferred revenue will be recognized once all conditions for revenue recognition have been met.

Deferred revenue as of September 30, 2019 and December 31, 2018, was $173.0 million and $175.5 million, respectively, which includes $129.0 million of payments received from Vitol Americas Corp. (“Vitol”) (formerly known as Noble Americas Corp.), a subsidiary of Vitol US Holding Co., in 2016, 2017, and 2018 as part of an agreement (the “Splitter Agreement”) related to the construction and operation of a crude oil and condensate splitter. In December 2018, Vitol elected to terminate the Splitter Agreement. The Splitter Agreement provides that the first three annual payments are ours if Vitol elects to terminate, which Vitol disputes. The timing of revenue recognition related to the Splitter Agreement deferred revenue is dependent upon resolution of the dispute with Vitol. Deferred revenue also includes nonmonetary consideration received in a 2015 amendment to a gas gathering and processing agreement and consideration received for other construction activities of facilities connected to our systems.

Note 11 – Leases

We have non-cancellable operating leases primarily associated with our office facilities, rail assets, land, and storage and terminal assets. We have finance leases primarily associated with our tractors and vehicles. Our leases have remaining lease terms of 1 to 6 years, some of which include options to extend the lease term for up to 10 years.

The balances of right-of-use assets and liabilities of finance leases and operating leases, and their locations on our Consolidated Balance Sheets are as follows:

	Balance Sheet Location	September 30, 2019	
Right-of-use assets			
Operating leases, gross	Other long-term assets	$	31.5
Finance leases, gross	Property, plant and equipment		46.9
Lease liabilities			
Current:			
Operating leases	Accounts payable and accrued liabilities	$	6.9
Finance leases	Current debt obligations		12.0
Non-current:			
Operating leases	Other long-term liabilities	$	19.6
Finance leases	Long-term debt		26.9

Operating lease costs and short-term lease costs are included in Operating expenses or General and administrative expense in our Consolidated Statements of Operations, depending on the nature of the leases. Finance lease costs are included in Depreciation and amortization expense and Interest expense, net in our Consolidated Statements of Operations. The components of lease expense were as follows:

	Three Months Ended September 30, 2019		Nine Months Ended September 30, 2019	
Lease cost				
Operating lease cost	$	2.2	$	6.0
Short-term lease cost		6.7		22.4
Variable lease cost		0.8		3.6
Finance lease cost				
Amortization of right-of-use assets		3.4		9.7
Interest expense		0.4		1.2
Total lease cost	$	13.5	$	42.9

Other supplemental information related to our leases are as follows:

		Nine Months Ended September 30, 2019
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows for operating leases	$	6.1
Operating cash flows for finance leases		1.2
Financing cash flows for finance leases		8.5

The weighted-average remaining lease terms for operating leases and finance leases are 4 years and 3 years, respectively. The weighted-average discount rates for operating leases and finance leases are 3.9% and 3.9%, respectively.

The following table presents the maturities of our lease liabilities under non-cancellable leases as of September 30, 2019:

		Operating Leases		Finance Leases
Future Minimum Lease Payments Beginning After September 30,				
2019	$	7.8	$	13.3
2020		6.9		11.4
2021		6.1		10.3
2022		4.6		6.1
2023		2.6		0.6
Thereafter		0.7		—
Total undiscounted cash flows		28.7		41.7
Less imputed interest		(2.2)		(2.8)
Total lease liabilities	$	26.5	$	38.9

The following table presents future minimum payments under non-cancellable leases as of December 31, 2018:

		Leases
2019	$	20.5
2020		17.7
2021		14.9
2022		12.6
2023		6.0
Thereafter		1.7
Total payments	$	73.4

Note 12 — Partnership Units and Related Matters

Distributions

TRC is entitled to receive all Partnership distributions after payment of preferred unit distributions each quarter.

The following table details the distributions declared and paid by us for the nine months ended September 30, 2019:

Three Months Ended	Date Paid or To Be Paid		Total Distributions		Distributions to Targa Resources Corp.
September 30, 2019	November 13, 2019	$	242.1	$	239.3
June 30, 2019	August 13, 2019		242.4		239.6
March 31, 2019	April 5, 2019		437.8		435.0
December 31, 2018	February 13, 2019		241.3		238.5

Contributions

All capital contributions to us continue to be allocated 98% to the limited partner and 2% to our general partner; however, no units will be issued for those contributions. During the three and nine months ended September 30, 2019, TRC made total contributions of $10.0 million and $200.0 million to us.

Preferred Units

Our Preferred Units rank senior to our common units with respect to the distribution rights. Distributions on our 5,000,000 Preferred Units are cumulative from the date of original issue in October 2015 and are payable monthly in arrears on the 15th day of each month of each year, when, as and if declared by the board of directors of our general partner. Distributions on our Preferred Units are payable out of amounts legally available at a rate equal to 9.0% per annum. On and after November 1, 2020, distributions on our Preferred Units will accumulate at an annual floating rate equal to the one-month LIBOR plus a spread of 7.71%.

We paid $2.8 million and $8.4 million of distributions to the holders of Preferred Units (“Preferred Unitholders”) for the three and nine months ended September 30, 2019.

Subsequent Event

In October 2019, the board of directors of our general partner declared a cash distribution of $0.1875 per Preferred Unit, resulting in approximately $0.9 million in distributions that will be paid on November 15, 2019.

Note 13 — Derivative Instruments and Hedging Activities

The primary purpose of our commodity risk management activities is to manage our exposure to commodity price risk and reduce volatility in our operating cash flow due to fluctuations in commodity prices. We have entered into derivative instruments to hedge the commodity price risks associated with a portion of our expected (i) natural gas, NGL, and condensate equity volumes in our Gathering and Processing operations that result from percent-of-proceeds processing arrangements, (ii) future commodity purchases and sales in our Logistics and Marketing segment and (iii) natural gas transportation basis risk in our Logistics and Marketing segment. The hedge positions associated with (i) and (ii) above will move favorably in periods of falling commodity prices and unfavorably in periods of rising commodity prices and are designated as cash flow hedges for accounting purposes.

The hedges generally match the NGL product composition and the NGL delivery points of our physical equity volumes. Our natural gas hedges are a mixture of specific gas delivery points and Henry Hub. The NGL hedges may be transacted as specific NGL hedges or as baskets of ethane, propane, normal butane, isobutane and natural gasoline based upon our expected equity NGL composition. We believe this approach avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as "proxy" hedges of NGL prices. Our natural gas and NGL hedges are settled using published index prices for delivery at various locations.

We hedge a portion of our condensate equity volumes using crude oil hedges that are based on the NYMEX futures contracts for West Texas Intermediate light, sweet crude, which approximates the prices received for condensate. This exposes us to a market differential risk if the NYMEX futures do not move in exact parity with the sales price of our underlying condensate equity volumes.

We also enter into derivative instruments to help manage other short-term commodity-related business risks. We have not designated these derivatives as hedges and record changes in fair value and cash settlements to revenues.

At September 30, 2019, the notional volumes of our commodity derivative contracts were:

Commodity	Instrument	Unit	2019	2020	2021	2022	2023	2024
Natural Gas	Swaps	MMBtu/d	172,254	96,130	85,151	7,500	-	-
Natural Gas	Basis Swaps	MMBtu/d	398,098	352,260	339,360	200,000	200,000	40,000
NGL	Swaps	Bbl/d	30,468	20,305	8,396	3,236	-	-
NGL	Futures	Bbl/d	29,620	15,495	-	-	-	-
NGL	Options	Bbl/d	410	-	-	-	-	-
Condensate	Swaps	Bbl/d	4,170	4,140	3,154	1,110	-	-
Condensate	Options	Bbl/d	590	-	-	-	-	-

Our derivative contracts are subject to netting arrangements that permit our contracting subsidiaries to net cash settle offsetting asset and liability positions with the same counterparty within the same Targa entity. We record derivative assets and liabilities on our Consolidated Balance Sheets on a gross basis, without considering the effect of master netting arrangements. The following schedules reflect the fair value of our derivative instruments and their location on our Consolidated Balance Sheets as well as pro forma reporting assuming that we reported derivatives subject to master netting agreements on a net basis:

		Fair Value as of September 30, 2019		Fair Value as of December 31, 2018	
	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Derivatives designated as hedging instruments					
Commodity contracts	Current	$ 138.2	$ (11.4)	$ 112.5	$ (18.9)
	Long-term	56.6	(1.1)	31.6	(1.5)
Total derivatives designated as hedging instruments		$ 194.8	$ (12.5)	$ 144.1	$ (20.4)
Derivatives not designated as hedging instruments					
Commodity contracts	Current	$ 1.9	$ (72.1)	$ 2.8	$ (14.7)
	Long-term	3.4	(45.0)	2.5	(1.6)
Total derivatives not designated as hedging instruments		$ 5.3	$ (117.1)	$ 5.3	$ (16.3)
Total current position		$ 140.1	$ (83.5)	$ 115.3	$ (33.6)
Total long-term position		60.0	(46.1)	34.1	(3.1)
Total derivatives		$ 200.1	$ (129.6)	$ 149.4	$ (36.7)

The pro forma impact of reporting derivatives on our Consolidated Balance Sheets on a net basis is as follows:

September 30, 2019	Gross Presentation Asset	Gross Presentation Liability	Gross Presentation Collateral	Pro Forma Net Presentation Asset	Pro Forma Net Presentation Liability
Current Position					
Counterparties with offsetting positions or collateral	$ 103.9	$ (69.5)	$ (25.2)	$ 62.5	$ (53.3)
Counterparties without offsetting positions - assets	36.2	-	-	36.2	-
Counterparties without offsetting positions - liabilities	-	(14.0)	-	-	(14.0)
	140.1	(83.5)	(25.2)	98.7	(67.3)
Long Term Position					
Counterparties with offsetting positions or collateral	47.1	(46.1)	-	32.1	(31.1)
Counterparties without offsetting positions - assets	12.9	-	-	12.9	-
Counterparties without offsetting positions - liabilities	-	-	-	-	-
	60.0	(46.1)	-	45.0	(31.1)
Total Derivatives					
Counterparties with offsetting positions or collateral	151.0	(115.6)	(25.2)	94.6	(84.4)
Counterparties without offsetting positions - assets	49.1	-	-	49.1	-
Counterparties without offsetting positions - liabilities	-	(14.0)	-	-	(14.0)
	$ 200.1	$ (129.6)	$ (25.2)	$ 143.7	$ (98.4)

December 31, 2018	Gross Presentation Asset	Gross Presentation Liability	Gross Presentation Collateral	Pro Forma Net Presentation Asset	Pro Forma Net Presentation Liability
Current Position					
Counterparties with offsetting positions or collateral	$ 100.0	$ (33.6)	$ (14.2)	$ 70.0	$ (17.8)
Counterparties without offsetting positions - assets	15.3	-	-	15.3	-
Counterparties without offsetting positions - liabilities	-	-	-	-	-
	115.3	(33.6)	(14.2)	85.3	(17.8)
Long Term Position					
Counterparties with offsetting positions or collateral	8.9	(3.1)	-	5.9	(0.1)
Counterparties without offsetting positions - assets	25.2	-	-	25.2	-
Counterparties without offsetting positions - liabilities	-	-	-	-	-
	34.1	(3.1)	-	31.1	(0.1)
Total Derivatives					
Counterparties with offsetting positions or collateral	108.9	(36.7)	(14.2)	75.9	(17.9)
Counterparties without offsetting positions - assets	40.5	-	-	40.5	-
Counterparties without offsetting positions - liabilities	-	-	-	-	-
	$ 149.4	$ (36.7)	$ (14.2)	$ 116.4	$ (17.9)

Our payment obligations in connection with a majority of these hedging transactions are secured by a first priority lien in the collateral securing the TRP Revolver that ranks equal in right of payment with liens granted in favor of our senior secured lenders. Some of our hedges are futures contracts executed through brokers that clear the hedges through an exchange. We maintain a margin deposit with the brokers in an amount sufficient enough to cover the fair value of our open futures positions. The margin deposit is considered collateral, which is located within other current assets on our Consolidated Balance Sheets and is not offset against the fair value of our derivative instruments.

The fair value of our 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 based on those observed in underlying markets. The estimated fair value of our derivative instruments was a net asset of $70.5 million as of September 30, 2019. The estimated fair value is net of an adjustment for credit risk based on the default probabilities as indicated by market quotes for the counterparties' credit default swap rates. The credit risk adjustment was immaterial for all periods presented. Our futures contracts that are cleared through an exchange are margined daily and do not require any credit adjustment.

The following tables reflect amounts recorded in Other comprehensive income ("OCI") and amounts reclassified from OCI to revenue for the periods indicated:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion) — Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
Commodity contracts	$ 118.2	$ (139.6)	$ 167.8	$ (178.0)

Location of Gain (Loss)	Gain (Loss) Reclassified from OCI into Income (Effective Portion) Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
Revenues	$ 41.5	$ (23.9)	$ 106.1	$ (58.3)

Based on valuations as of September 30, 2019, we expect to reclassify commodity hedge-related deferred gains of $182.2 million included in accumulated other comprehensive income into earnings before income taxes through the end of 2022, with $126.7 million of gains to be reclassified over the next twelve months.

Our consolidated earnings are also affected by the use of the mark-to-market method of accounting for derivative 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 rather than being deferred until the anticipated transaction settles. 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. For the three and nine months ended September 30, 2019, the unrealized mark-to-market losses are primarily attributable to unfavorable movements in natural gas forward basis prices.

Derivatives Not Designated as Hedging Instruments	Location of Gain Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
Commodity contracts	Revenue	$ (103.3)	$ (1.1)	$ (113.8)	$ (14.1)

See Note 14 – Fair Value Measurements and Note 20 – Segment Information for additional disclosures related to derivative instruments and hedging activities.

Note 14 — Fair Value Measurements

Under GAAP, our Consolidated Balance Sheets reflect a mixture of measurement methods for financial assets and liabilities ("financial instruments"). Derivative financial instruments and contingent consideration related to business acquisitions are reported at fair value on our Consolidated Balance Sheets. Other financial instruments are reported at historical cost or amortized cost on our Consolidated Balance Sheets. The following are additional qualitative and quantitative disclosures regarding fair value measurements of financial instruments.

Fair Value of Derivative Financial Instruments

Our derivative instruments consist of financially settled commodity swaps, futures, option contracts and fixed-price forward commodity contracts with certain counterparties. We determine the fair value of our derivative contracts using present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets. We have consistently applied these valuation techniques in all periods presented and we believe we have obtained the most accurate information available for the types of derivative contracts we hold.

The fair values of our derivative instruments are sensitive to changes in forward pricing on natural gas, NGLs and crude oil. The financial position of these derivatives at September 30, 2019, a net asset position of $70.5 million, reflects the present value, adjusted for counterparty credit risk, of the amount we expect to receive or pay in the future on our derivative contracts. If forward pricing on natural gas, NGLs and crude oil were to increase by 10%, the result would be a fair value reflecting a net liability of $34.0 million, ignoring an adjustment for counterparty credit risk. If forward pricing on natural gas, NGLs and crude oil were to decrease by 10%, the result would be a fair value reflecting a net asset of $175.4 million, ignoring an adjustment for counterparty credit risk.

Fair Value of Other Financial Instruments

Due to their cash or near-cash nature, the carrying value of other financial instruments included in working capital (i.e., cash and cash equivalents, accounts receivable, accounts payable) approximates their fair value. Long-term debt is primarily the other financial instrument for which carrying value could vary significantly from fair value. We determined the supplemental fair value disclosures for our long-term debt as follows:

- The TRP Revolver and the accounts receivable securitization facility are based on carrying value, which approximates fair value as their interest rates are based on prevailing market rates; and
- Senior unsecured notes are based on quoted market prices derived from trades of the debt.

Contingent consideration liabilities related to business acquisitions are carried at fair value until the end of the related earn-out period.

Fair Value Hierarchy

We categorize the inputs to the fair value measurements of financial assets and liabilities at each balance sheet reporting date using a three-tier fair value hierarchy that prioritizes the significant inputs used in measuring fair value:

- Level 1 – observable inputs such as quoted prices in active markets;
- Level 2 – inputs other than quoted prices in active markets that we can directly or indirectly observe to the extent that the markets are liquid for the relevant settlement periods; and
- Level 3 – unobservable inputs in which little or no market data exists, therefore we must develop our own assumptions.

The following table shows a breakdown by fair value hierarchy category for (1) financial instruments measurements included on our Consolidated Balance Sheets at fair value and (2) supplemental fair value disclosures for other financial instruments:

	September 30, 2019				
		Fair Value			
	Carrying Value	Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheets at Fair Value:					
Assets from commodity derivative contracts (1)	$ 197.5	$ 197.5	$ —	$ 196.4	$ 1.1
Liabilities from commodity derivative contracts (1)	127.0	127.0	—	127.0	—
TPL contingent consideration (2)	2.4	2.4	—	—	2.4
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	294.9	294.9	—	—	—
TRP Revolver	830.0	830.0	—	830.0	—
Senior unsecured notes	6,028.5	6,310.6	—	6,310.6	—
Accounts receivable securitization facility	246.0	246.0	—	246.0	—

	December 31, 2018				
		Fair Value			
	Carrying Value	Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheets at Fair Value:					
Assets from commodity derivative contracts (1)	$ 144.4	$ 144.4	$ —	$ 137.5	$ 6.9
Liabilities from commodity derivative contracts (1)	31.7	31.7	—	31.3	0.4
Permian Acquisition contingent consideration	308.2	308.2	—	—	308.2
TPL contingent consideration (2)	2.4	2.4	—	—	2.4
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	203.3	203.3	—	—	—
TRP Revolver	700.0	700.0	—	700.0	—
Senior unsecured notes	5,277.9	5,088.9	—	5,088.9	—
Accounts receivable securitization facility	280.0	280.0	—	280.0	—

(1) The fair value of derivative contracts in this table is presented on a different basis than the Consolidated Balance Sheets presentation as disclosed in Note 13– Derivative Instruments and Hedging Activities. The above fair values reflect the total value of each derivative contract taken as a whole, whereas the Consolidated Balance Sheets presentation is based on the individual maturity dates of estimated future settlements. As such, an individual contract could have both an asset and liability position when segregated into its current and long-term portions for Consolidated Balance Sheets classification purposes.

(2) We have a contingent consideration liability for TPL's previous acquisition of a gas gathering system and related assets, which is carried at fair value.

Additional Information Regarding Level 3 Fair Value Measurements Included on Our Consolidated Balance Sheets

We reported certain of our swaps and option contracts at fair value using Level 3 inputs due to such derivatives not having observable market prices or implied volatilities for substantially the full term of the derivative asset or liability. For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract length extends into unobservable periods.

The fair value of these swaps is determined using a discounted cash flow valuation technique based on a forward commodity basis curve. For these derivatives, the primary input to the valuation model is the forward commodity basis curve, which is based on observable or public data sources and extrapolated when observable prices are not available.

As of September 30, 2019, we had 10 commodity swap and option contracts categorized as Level 3. The significant unobservable inputs used in the fair value measurements of our Level 3 derivatives are (i) the forward natural gas liquids pricing curves, for which a significant portion of the derivative's term is beyond available forward pricing and (ii) implied volatilities, which are unobservable as a result of inactive natural gas liquids options trading. The change in the fair value of Level 3 derivatives associated with a 10% change in the forward basis curve where prices are not observable is immaterial.

The fair value of the TPL contingent consideration was determined using a probability-based model measuring the likelihood of meeting certain volumetric measures. The inputs are not observable; therefore, the entire valuation of the contingent consideration is categorized in Level 3. The Permian Acquisition contingent consideration earn-out period ended on February 28, 2019 and resulted in a $317.1 million payment in May 2019. See Note 8 – Accounts Payable and Accrued Liabilities for additional discussion of the Permian Acquisition contingent consideration. Changes in the fair value of these liabilities are included in Other income (expense) in our Consolidated Statements of Operations.

The following table summarizes the changes in fair value of our financial instruments classified as Level 3 in the fair value hierarchy:

	Commodity Derivative Contracts Asset/(Liability)	Contingent Consideration
Balance, December 31, 2018	$ 6.5	$ (310.6)
Completion of Permian Acquisition contingent consideration earn-out period	—	308.2
New Level 3 derivative instruments	(0.4)	—
Transfers out of Level 3 (1)	(6.5)	—
Unrealized gain/(loss) included in OCI	1.5	—
Balance, September 30, 2019	$ 1.1	$ (2.4)

(1) Transfers relate to long-term over-the-counter swaps for NGL products for which observable market prices became available for substantially their full term.

Note 15 — Related Party Transactions – Targa

Relationship with Targa

We do not have any employees. Targa provides operational, general and administrative and other services to us associated with our existing assets and assets acquired from third parties. 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.

Our Partnership Agreement governs the reimbursement of costs incurred by Targa on behalf of us. Targa charges us for all the direct costs of the employees assigned to our operations, as well as all general and administrative support costs other than (1) costs attributable to Targa's status as a separate reporting company and (2) until March 2018, costs of Targa providing management and support services to certain unaffiliated spun-off entities. We generally reimburse Targa monthly for cost allocations to the extent that Targa has made a cash outlay.

The following table summarizes transactions with Targa:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Targa billings of payroll and related costs included in operating expenses	$ 61.6	$ 61.3	$ 177.3	$ 177.7
Targa allocation of general and administrative expense	59.5	54.6	188.4	149.3
Cash distributions to Targa based on general partner and limited partner ownership	239.6	231.2	913.1	683.7
Cash contributions from Targa related to limited partner ownership (1)	9.8	450.7	196.0	529.2
Cash contributions from Targa to maintain its 2% general partner ownership	0.2	9.2	4.0	10.8

(1) The cash contributions from Targa related to limited partner ownership were allocated 98% to the limited partner and 2% to general partner. See Note 12 – Partnership Units and Related Matters.

Note 16 – Contingencies

Legal Proceedings

We are a party to various legal, administrative and regulatory proceedings that have arisen in the ordinary course of our business. We are also a party to various proceedings with governmental environmental agencies, including but not limited to the Environmental Protection Agency, Texas Commission on Environmental Quality, Oklahoma Department of Environmental Quality, New Mexico Environment Department, Louisiana Department of Environmental Quality and North Dakota Department of Environmental Quality, which assert penalties for alleged violations of environmental regulations, including air emissions, discharges into the environment and reporting deficiencies, related to events that have arisen at certain of our facilities in the ordinary course of our business.

Note 17 – Revenue

Fixed consideration allocated to remaining performance obligations

The following table includes the estimated minimum revenue expected to be recognized in the future related to performance obligations that are unsatisfied (or partially unsatisfied) at the end of the reporting period and is comprised of fixed consideration primarily attributable to contracts with minimum volume commitments and for which a guaranteed amount of revenue can be calculated. These contracts are comprised primarily of gathering and processing, fractionation, export, terminaling and storage agreements.

	2019	2020	2021 and after
Fixed consideration to be recognized as of September 30, 2019	$ 130.8	$ 486.3	$ 3,474.4

In accordance with the optional exemptions that we elected to apply, the amounts presented in the table above exclude variable consideration for which the allocation exception is met and consideration associated with performance obligations of short-term contracts. In addition, consideration from contracts for which we recognize revenue at the amount that we have the right to invoice for services performed is also excluded from the table above, with the exception of any fixed consideration attributable to such contracts. The nature of the performance obligations for which the consideration has been excluded is consistent with the performance obligations described within our revenue recognition accounting policy; the estimated remaining duration of such contracts primarily ranges from 1 to 19 years. In addition, variability exists in the consideration excluded due to the unknown quantity and composition of volumes to be serviced or sold as well as fluctuations in the market price of commodities to be received as consideration or sold over the applicable remaining contract terms. Such variability is resolved at the end of each future month or quarter.

For disclosures related to disaggregated revenue, see Note 20 – Segment Information.

Note 18 – Other Operating (Income) Expense

Other operating (income) expense is comprised of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
(Gain) loss on sale or disposition of assets (1)	$ 0.5	$ 61.1	$ 3.6	$ 14.3
Write-down of assets	17.9	—	17.9	—
Miscellaneous business tax	—	0.4	0.2	1.0
Other	—	0.3	—	0.4
	$ 18.4	$ 61.8	$ 21.7	$ 15.7

(1) Our 2018 loss is comprised primarily of a $57.5 million loss on sale of our refined products and crude oil storage and terminaling facilities in Tacoma, WA, and Baltimore, MD during the third quarter of 2018, offset by a $48.1 million gain on sale of our inland marine barge business to a third party during the second quarter of 2018.

Note 19 — Supplemental Cash Flow Information

	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
Cash:		
Interest paid, net of capitalized interest (1)	$ 216.6	$ 140.5
Income taxes paid, net of refunds	(1.7)	0.2
Non-cash investing activities:		
Impact of capital expenditure accruals on property, plant and equipment	$ (150.6)	$ 283.9
Transfers from materials and supplies inventory to property, plant and equipment	21.7	8.9
Non-cash financing activities:		
Accrued distributions to noncontrolling interests	$ 73.8	$ —
Non-cash balance sheet movements related to assets held for sale:		
Working capital	$ —	$ 12.6
Property, plant and equipment, net	—	151.4
Lease liabilities arising from recognition of right-of-use assets:		
Operating lease	$ 6.7	$ —
Finance lease	8.0	—

(1) Interest capitalized on major projects was $50.5 million and $30.8 million for the nine months ended September 30, 2019 and 2018.

Note 20 — Segment Information

We operate in two primary segments: (i) Gathering and Processing, and (ii) Logistics and Marketing (also referred to as the Downstream Business). Our reportable segments include operating segments that have been aggregated based on the nature of the products and services provided.

Our 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 NGLs and removing impurities; and assets used for crude oil gathering and terminaling. The Gathering and Processing segment's assets are located in the Permian Basin of West Texas and Southeast New Mexico (including the Midland and Delaware Basins); the Eagle Ford Shale in South Texas; the Barnett Shale in North Texas; the Anadarko, Ardmore, and Arkoma Basins in Oklahoma (including the SCOOP and STACK) and South Central Kansas; the Williston Basin in North Dakota; and the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

Our Logistics and Marketing segment includes the activities and assets necessary to convert mixed NGLs into NGL products and also includes other assets and value-added services such as transporting, storing, fractionating, terminaling and marketing of NGLs and NGL products, including services to LPG exporters; storing and terminaling of refined petroleum products and crude oil and certain natural gas supply and marketing activities in support of our other businesses. The associated assets are generally connected to and supplied in part by our Gathering and Processing segment and, except for pipelines and smaller terminals, are located predominantly in Mont Belvieu and Galena Park, Texas, and in Lake Charles, Louisiana.

Other contains the results of commodity derivative activities related to Gathering and Processing hedges of equity volumes that are included in operating margin and mark-to-market gains/losses related to derivative contracts that were not designated as cash flow hedges. Elimination of inter-segment transactions are reflected in the corporate and eliminations column.

Reportable segment information is shown in the following tables:

	Three Months Ended September 30, 2019				
	Gathering and Processing	Logistics and Marketing	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$ 254.4	$ 1,403.1	$ (63.3)	$ —	$ 1,594.2
Fees from midstream services	173.0	135.3	—	—	308.3
	427.4	1,538.4	(63.3)	—	1,902.5
Intersegment revenues					
Sales of commodities	534.0	34.9	—	(568.9)	—
Fees from midstream services	1.9	7.4	—	(9.3)	—
	535.9	42.3	—	(578.2)	—
Revenues	$ 963.3	$ 1,580.7	$ (63.3)	$ (578.2)	$ 1,902.5
Operating margin	$ 208.6	$ 228.9	$ (63.3)	$ —	$ 374.2
Other financial information:					
Total assets (1)	$ 12,172.4	$ 6,475.0	$ 157.0	$ 53.9	$ 18,858.3
Goodwill	$ 46.6	$ —	$ —	$ —	$ 46.6
Capital expenditures	$ 230.3	$ 301.2	$ —	$ 10.8	$ 542.3

(1) Assets in the Corporate and Eliminations column primarily include cash, prepaids and debt issuance costs for our TRP Revolver.

	Three Months Ended September 30, 2018				
	Gathering and Processing	Logistics and Marketing	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$ 296.7	$ 2,378.2	$ (20.8)	$ —	$ 2,654.1
Fees from midstream services	199.3	133.0	—	—	332.3
	496.0	2,511.2	(20.8)	—	2,986.4
Intersegment revenues					
Sales of commodities	1,069.7	15.5	—	(1,085.2)	—
Fees from midstream services	1.5	8.5	—	(10.0)	—
	1,071.2	24.0	—	(1,095.2)	—
Revenues	$ 1,567.2	$ 2,535.2	$ (20.8)	$ (1,095.2)	$ 2,986.4
Operating margin	$ 255.3	$ 173.5	$ (20.8)	$ —	$ 408.0
Other financial information:					
Total assets (1)	$ 11,331.5	$ 5,019.0	$ 64.2	$ 111.8	$ 16,526.5
Goodwill	$ 256.6	$ —	$ —	$ —	$ 256.6
Capital expenditures	$ 453.0	$ 560.7	$ —	$ 4.0	$ 1,017.7

(1) Assets in the Corporate and Eliminations column primarily include cash, prepaids and debt issuance costs for our TRP Revolver.

	Nine Months Ended September 30, 2019				
	Gathering and Processing	Logistics and Marketing	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$ 761.5	$ 4,508.5	$ (15.2)	$ —	$ 5,254.8
Fees from midstream services	549.1	393.3	—	—	942.4
	1,310.6	4,901.8	(15.2)	—	6,197.2
Intersegment revenues					
Sales of commodities	1,896.5	117.0	—	(2,013.5)	—
Fees from midstream services	5.3	20.1	—	(25.4)	—
	1,901.8	137.1	—	(2,038.9)	—
Revenues	$ 3,212.4	$ 5,038.9	$ (15.2)	$ (2,038.9)	$ 6,197.2
Operating margin	$ 630.9	$ 565.0	$ (15.2)	$ —	$ 1,180.7
Other financial information:					
Total assets (1)	$ 12,172.4	$ 6,475.0	$ 157.0	$ 53.9	$ 18,858.3
Goodwill	$ 46.6	$ —	$ —	$ —	$ 46.6
Capital expenditures	$ 1,068.7	$ 1,197.5	$ —	$ 38.7	$ 2,304.9

(1) Assets in the Corporate and Eliminations column primarily include cash, prepaids and debt issuance costs for our TRP Revolver.

	Nine Months Ended September 30, 2018				
	Gathering and Processing	Logistics and Marketing	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$ 835.3	$ 6,188.3	$ (42.2)	$ —	$ 6,981.4
Fees from midstream services	536.8	368.1	—	—	904.9
	1,372.1	6,556.4	(42.2)	—	7,886.3
Intersegment revenues					
Sales of commodities	2,848.9	147.0	—	(2,995.9)	—
Fees from midstream services	5.4	24.3	—	(29.7)	—
	2,854.3	171.3	—	(3,025.6)	—
Revenues	$ 4,226.4	$ 6,727.7	$ (42.2)	$ (3,025.6)	$ 7,886.3
Operating margin	$ 718.4	$ 441.7	$ (42.2)	$ —	$ 1,117.9
Other financial information:					
Total assets (1)	$ 11,331.5	$ 5,019.0	$ 64.2	$ 111.8	$ 16,526.5
Goodwill	$ 256.6	$ —	$ —	$ —	$ 256.6
Capital expenditures	$ 1,008.2	$ 1,229.9	$ —	$ 72.3	$ 2,310.4

(1) Assets in the Corporate and Eliminations column primarily include cash, prepaids and debt issuance costs for our TRP Revolver.

The following table shows our consolidated revenues disaggregated by product and service for the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Sales of commodities:				
Revenue recognized from contracts with customers:				
Natural gas	$ 305.3	$ 451.9	$ 934.2	$ 1,338.5
NGL	1,160.5	2,063.2	3,752.4	5,254.4
Condensate and crude oil	178.7	95.7	488.4	286.1
Petroleum products	11.5	68.2	87.5	176.0
	1,656.0	2,679.0	5,262.5	7,055.0
Non-customer revenue:				
Derivative activities - Hedge	41.5	(23.8)	106.1	(59.6)
Derivative activities - Non-hedge (1)	(103.3)	(1.1)	(113.8)	(14.0)
	(61.8)	(24.9)	(7.7)	(73.6)
Total sales of commodities	1,594.2	2,654.1	5,254.8	6,981.4
Fees from midstream services:				
Revenue recognized from contracts with customers:				
NGL transportation and services	45.8	37.5	122.0	115.8
Storage, terminaling and export	84.6	79.6	254.7	233.1
Gathering and processing	171.6	196.5	543.7	522.3
Other	6.3	18.7	22.0	33.7
Total fees from midstream services	308.3	332.3	942.4	904.9
Total revenues	$ 1,902.5	$ 2,986.4	$ 6,197.2	$ 7,886.3

(1) Represents derivative activities that are not designated as hedging instruments under ASC 815.

The following table shows a reconciliation of reportable segment operating margin to income (loss) before income taxes for the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Reconciliation of reportable segment operating margin to income (loss) before income taxes:				
Gathering and Processing operating margin	$ 208.6	$ 255.3	$ 630.9	$ 718.4
Logistics and Marketing operating margin	228.9	173.5	565.0	441.7
Other operating margin	(63.3)	(20.8)	(15.2)	(42.2)
Depreciation and amortization expense	(244.3)	(206.3)	(718.9)	(607.1)
General and administrative expense	(65.6)	(59.3)	(212.3)	(165.0)
Interest expense, net	(84.2)	(75.7)	(229.2)	(113.3)
Gain (loss) from sale of equity-method investment	65.8	—	65.8	—
Change in contingent considerations	—	(16.6)	(8.8)	(12.1)
Other, net	(8.4)	(58.8)	(7.1)	(10.6)
Income (loss) before income taxes	$ 37.5	$ (8.7)	$ 70.2	$ 209.8

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations contained in our Annual Report on Form 10-K for the year ended December 31, 2018 ("Annual Report"), as well as the unaudited consolidated financial statements and notes hereto included in this Quarterly Report on Form 10-Q.

Overview

Targa Resources Partners LP ("we," "our," the "Partnership" or "TRP") is a Delaware limited partnership formed in October 2006 by Targa Resources Corp. ("TRC" or "Targa"). Our common units were listed on the NYSE under the symbol "NGLS" prior to TRC's acquisition on February 17, 2016 of all our outstanding common units that it and its subsidiaries did not already own. Our 9.00% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Preferred Units") remain outstanding as preferred limited partner interests in us and continue to trade on the NYSE under the symbol "NGLS/PA."

Targa Resources GP LLC, our general partner, is a Delaware limited liability company formed by Targa 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.

Our Operations

We are engaged primarily in the business of:

- gathering, compressing, treating, processing, transporting and selling natural gas;
- transporting, storing, fractionating, treating and selling NGLs and NGL products, including services to LPG exporters; and
- gathering, storing, terminaling and selling crude oil.

To provide these services, we operate in two primary segments: (i) Gathering and Processing, and (ii) Logistics and Marketing (also referred to as the Downstream Business).

Our 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 NGLs and removing impurities; and assets used for crude oil gathering and terminaling. The Gathering and Processing segment's assets are located in the Permian Basin of West Texas and Southeast New Mexico (including the Midland and Delaware Basins); the Eagle Ford Shale in South Texas; the Barnett Shale in North Texas; the Anadarko, Ardmore, and Arkoma Basins in Oklahoma (including the SCOOP and STACK) and South Central Kansas; the Williston Basin in North Dakota and in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

Our Logistics and Marketing segment includes the activities and assets necessary to convert mixed NGLs into NGL products and also includes other assets and value-added services such as transporting, storing, fractionating, terminaling and marketing of NGLs and NGL products, including services to LPG exporters; storing and terminaling of refined petroleum products and crude oil and certain natural gas supply and marketing activities in support of our other businesses. The Logistics and Marketing segment also includes the Grand Prix NGL Pipeline ("Grand Prix"), which integrates our gathering and processing positions in the Permian Basin, Southern Oklahoma and North Texas with our downstream facilities in Mont Belvieu, Texas. The associated assets are generally connected to and supplied in part by our Gathering and Processing segment and, except for pipelines and smaller terminals, are located predominantly in Mont Belvieu and Galena Park, Texas, and in Lake Charles, Louisiana.

Other contains the results of commodity derivative activities related to Gathering and Processing hedges of equity volumes that are included in operating margin and mark-to-market gains/losses related to derivative contracts that were not designated as cash flow hedges.

Recent Developments

Gathering and Processing Segment Expansion

Permian Midland Processing Expansions

In response to increasing production and to meet the infrastructure needs of producers, we have completed construction of or have begun constructing three new 250 MMcf/d cryogenic natural gas processing plants in the Midland Basin. The first plant, the Hopson Plant, began operations in the second quarter of 2019. The second plant, the Pembrook Plant, began operations in the third quarter of 2019. In August 2019, we announced commencement of a third plant, the Gateway Plant, which is expected to begin operations in the fourth quarter of 2020.

Permian Delaware Processing Expansions

In March 2018, we announced that we entered into long-term fee-based agreements with an investment grade energy company for natural gas gathering and processing services in the Delaware Basin and for downstream transportation, fractionation and other related services. The agreements are underpinned by the customer's dedication of significant acreage within a large, well-defined area in the Delaware Basin. The approximately 220 miles of 12- to 24-inch high-pressure rich gas gathering pipelines that we constructed across the Delaware Basin are operational. We have recently completed construction of or are currently constructing two new 250 MMcf/d cryogenic natural gas processing plants in the Delaware Basin. The first plant, the Falcon Plant, began operations late in the third quarter of 2019. The second plant, the Peregrine Plant, is expected to begin operations in the second quarter of 2020. Total growth capital expenditures related to the plants and high-pressure gas pipeline system are expected to be approximately $600 million.

We will provide NGL transportation services on Grand Prix and fractionation services at our Mont Belvieu complex for a majority of the NGLs from the Falcon and Peregrine Plants.

Badlands

In January 2018, we announced the formation of a 50/50 joint venture with Hess Midstream Partners LP under which Targa would construct and operate a new 200 MMcf/d natural gas processing plant (“Little Missouri 4”) at Targa’s existing Little Missouri facility. Little Missouri 4 began operations in the third quarter of 2019.

Downstream Segment Expansion

Grand Prix NGL Pipeline

In the third quarter of 2019, we began full service into Mont Belvieu on Grand Prix, our new common carrier NGL pipeline. Grand Prix transports NGLs from the Permian Basin, North Texas, and Southern Oklahoma to our fractionation and storage complex in the NGL market hub at Mont Belvieu, Texas. The pipeline is comprised of three primary segments:

- Permian Basin Segment – Connects our Gathering and Processing positions throughout the Delaware and Midland Basins to North Texas. The capacity of the 24-inch diameter pipeline segment from the Permian Basin is approximately 300 MBbl/d, expandable to 550 MBbl/d.

- Southern Oklahoma Extension – Connects our SouthOK and North Texas Gathering and Processing positions with the North Texas to Mont Belvieu Segment. The extension varies in capacity based on telescoping pipe size.

- North Texas to Mont Belvieu Segment – The Permian Basin Segment and Southern Oklahoma Extension connect to a 30-inch diameter pipeline segment in North Texas, which connects Permian, North Texas and Oklahoma volumes to Mont Belvieu. The North Texas to Mont Belvieu Segment has a capacity of approximately 450 MBbl/d, expandable to 950 MBbl/d.

In February 2019, we announced an additional extension:

- Central Oklahoma Extension – Extends from Southern Oklahoma to the STACK region of Central Oklahoma where it will connect with The Williams Companies, Inc. (“Williams”) Bluestem Pipeline, linking the Conway, Kansas, and Mont Belvieu, Texas, NGL markets. In connection with this project, Williams has committed significant volumes to us that we will transport on Grand Prix and fractionate at our Mont Belvieu facilities. The Central Oklahoma Extension is expected to be completed in the first quarter of 2021.

Grand Prix volumes flowing on the pipeline from the Permian Basin to Mont Belvieu are included in Grand Prix Pipeline LLC ("Grand Prix Joint Venture"), a consolidated subsidiary of which Targa owns a 56% interest, while the volumes flowing from North Texas and Oklahoma to Mont Belvieu accrue solely to Targa's benefit. Total growth capital spending on Grand Prix, including the extensions into Oklahoma, is estimated to be approximately $2.0 billion, with our portion of growth capital spending estimated to be approximately $1.4 billion.

Fractionation Expansion

In February 2018, we announced plans to construct a new 100 MBbl/d fractionation train in Mont Belvieu, Texas ("Train 6"), which began operations in the second quarter of 2019. The total cost of the fractionation train and related infrastructure was approximately $350 million. Targa Train 6 LLC, a joint venture between Targa and Stonepeak Infrastructure Partners ("Stonepeak"), owns 100% interest in certain assets associated with Train 6. Certain fractionation-related infrastructure for Train 6, such as storage caverns and brine handling, were funded and are owned 100% by Targa.

In November 2018, we announced plans to construct two new 110 MBbl/d fractionation trains in Mont Belvieu, Texas ("Train 7 and Train 8"), which are expected to begin operations by the end of the first quarter of 2020 and the end of the third quarter of 2020, respectively. The total cost of these fractionation trains and related infrastructure is expected to be approximately $825 million. In connection with the Central Oklahoma Extension, Williams exercised its initial option to acquire a 20% equity interest in Train 7 and executed a joint venture agreement with us in the second quarter of 2019. Certain fractionation-related infrastructure for Train 7, including storage caverns and brine handling, will be funded and owned 100% by Targa.

LPG Export Expansion

In February 2019, we announced plans to further expand our LPG export capabilities of propane and butanes at our Galena Park Marine Terminal by increasing refrigeration capacity and associated load rates. Our current effective export capacity will increase to approximately 11 to 15 MMBbl per month, depending upon the mix of propane and butane demand, vessel size and availability of supply, among other factors. The total cost of the expansion and related infrastructure is expected to be approximately $120 million and is expected to be completed in the third quarter of 2020.

Gulf Coast Express Pipeline

In December 2017, we entered into definitive joint venture agreements to form Gulf Coast Express Pipeline LLC ("GCX") with Kinder Morgan Texas Pipeline LLC ("KMTP") and DCP Midstream Partners, LP ("DCP") for the purpose of developing the Gulf Coast Express Pipeline ("GCX Pipeline"), a natural gas pipeline from the Waha hub, including direct connections to the tailgate of many of our Midland Basin processing facilities, to Agua Dulce in South Texas. The pipeline provides an outlet for increased natural gas production from the Permian Basin to growing markets along the Texas Gulf Coast. Targa GCX Pipeline LLC, a joint venture between us and Stonepeak, and DCP each own a 25% interest, KMTP owns a 34% interest, and Altus Midstream Company owns the remaining 16% interest in GCX. KMTP serves as the operator of GCX Pipeline. We have committed significant volumes to GCX Pipeline. In addition, Pioneer Natural Resources Company, a joint owner in our WestTX Permian Basin assets, has committed volumes to GCX Pipeline. GCX Pipeline is designed to transport up to 1.98 Bcf/d of natural gas and the total cost of the project is estimated to be approximately $1.75 billion. GCX Pipeline was placed in service late in the third quarter of 2019.

Badlands Interest Sale

In April 2019, we closed on the sale of a 45% interest in Targa Badlands LLC ("Targa Badlands"), the entity that holds substantially all of our assets in North Dakota, to funds managed by GSO Capital Partners and Blackstone Tactical Opportunities (collectively, "Blackstone") for $1.6 billion in cash. We used the net cash proceeds to repay debt and for general corporate purposes, including funding our growth capital program. We continue to be the operator of Targa Badlands and hold majority governance rights. Future growth capital of Targa Badlands is expected to be funded on a pro rata ownership basis. Targa Badlands pays a minimum quarterly distribution ("MQD") to Blackstone and Targa, with Blackstone having a priority right on such MQDs. Additionally, Blackstone's capital contributions would have a liquidation preference upon a sale of Targa Badlands.

Asset Sales

We continue to evaluate and execute asset sales to reduce leverage and focus on our core operations. During the third quarter of 2019, we closed on the sale of an equity-method investment for $70.3 million. In November 2019, we executed agreements to sell our crude gathering and storage business in the Permian Delaware for approximately $135 million. Subject to customary regulatory approvals and closing conditions, the sale is expected to close in the fourth quarter of 2019.

We have also engaged Jefferies LLC to evaluate the potential divestiture of our crude gathering business in the Permian Midland, which includes crude gathering and storage assets. The potential divestiture is predicated on third party valuations adequately capturing our forward growth expectations for the assets, and no assurance can be made that a sale will be consummated.

Financing Activities

In January 2019, we issued $750.0 million of 6½% Senior Notes due July 2027 and $750.0 million of 6⅞% Senior Notes due January 2029, resulting in total net proceeds of $1,486.6 million. The net proceeds from the issuance were used to redeem in full our 4⅛% Senior Notes due 2019, at par value plus accrued interest through the redemption date, with the remainder used for general partnership purposes, which included repayment of borrowings under our credit facilities.

Recent Accounting Pronouncements

For a discussion of recent accounting pronouncements that will affect us, see “Recent Accounting Pronouncements” included within Note 3 – Significant Accounting Policies in our Consolidated Financial Statements.

How We Evaluate Our Operations

The profitability of our business is a function of the difference between: (i) the revenues we receive from our operations, including fee-based revenues from services and revenues from the natural gas, NGLs, crude oil and condensate we sell, and (ii) the costs associated with conducting our operations, including the costs of wellhead natural gas, crude oil and mixed NGLs that we purchase as well as operating, general and administrative costs and the impact of our commodity hedging activities. 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 crude oil, natural gas and NGLs, and the volumes of crude oil, natural gas and NGL throughput on our systems are important factors in determining our profitability. Our profitability is also affected by the NGL content in gathered wellhead natural gas, supply and demand for our products and services, utilization of our assets and changes in our customer mix.

Our profitability is also impacted by fee-based contracts. Our growing fee-related capital expenditures for pipelines and gathering and processing assets underpinned by fee-based margin, expansion of our downstream facilities, continued focus on adding fee-based margin to our existing and future gathering and processing contracts, as well as third-party acquisitions of businesses and assets, will continue to increase the number of our contracts that are fee-based. Fixed fees for services such as fractionation, storage, terminaling and crude oil gathering are not directly tied to changes in market prices for commodities. Nevertheless, a change in unit fees due to market dynamics such as available commodity throughput does affect profitability.

Management uses a variety of financial measures and operational measurements to analyze our performance. These include: (1) throughput volumes, facility efficiencies and fuel consumption, (2) operating expenses, (3) capital expenditures and (4) the following non-GAAP measures: gross margin, operating margin, and Adjusted EBITDA.

Throughput Volumes, Facility Efficiencies and Fuel Consumption

Our profitability is impacted by our ability to add new sources of natural gas supply and crude oil supply to offset the natural decline of existing volumes from oil and natural gas wells that are connected to our gathering and processing systems. This is achieved by connecting new wells and adding new volumes in existing areas of production, as well as by capturing crude oil and natural gas supplies currently gathered by third parties. Similarly, our profitability is impacted by our ability to add new sources of mixed NGL supply, connected by third-party transportation and Grand Prix, to our Downstream Business fractionation facilities and at times to our export facilities. We fractionate NGLs generated by our gathering and processing plants, as well as by contracting for mixed NGL supply from third-party facilities.

In addition, we seek to increase operating margin by limiting volume losses, reducing fuel consumption and by increasing efficiency. With our gathering systems' extensive use of remote monitoring capabilities, we monitor the volumes 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. We also monitor the volumes of NGLs received, stored, fractionated and delivered across our logistics assets. This information is tracked through our processing plants and Downstream Business facilities to determine customer settlements for sales and volume related fees for service 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 plant to monitor the fuel consumption and recoveries of our facilities. Similar tracking is performed for our crude oil gathering and logistics assets. These volume, recovery and fuel consumption measurements are an important part of our operational efficiency analysis and safety programs.

Operating Expenses

Operating expenses are costs associated with the operation of specific assets. Labor, contract services, repair and maintenance, utilities and ad valorem taxes comprise the most significant portion of our operating expenses. These expenses, other than fuel and power, remain relatively stable and independent of the volumes through our systems, but may increase with system expansions and will fluctuate depending on the scope of the activities performed during a specific period.

Capital Expenditures

Capital projects associated with growth and maintenance projects are closely monitored. Return on investment is analyzed before a capital project is approved, spending is closely monitored throughout the development of the project, and the subsequent operational performance is compared to the assumptions used in the economic analysis performed for the capital investment approval.

Gross Margin

We define gross margin as revenues less product purchases. It is impacted by volumes and commodity prices as well as by our contract mix and commodity hedging program.

Gathering and Processing segment gross margin consists primarily of:

- revenues from the sale of natural gas, condensate, crude oil and NGLs less producer payments and other natural gas and crude oil purchases; and
- service fees related to natural gas and crude oil gathering, treating and processing.

Logistics and Marketing segment gross margin consists primarily of:

- service fees (including the pass-through of energy costs included in fee rates);
- system product gains and losses; and
- NGL and natural gas sales, less NGL and natural gas purchases, transportation costs and the net inventory change.

The gross margin impacts of our equity volumes hedge settlements are reported in Other.

Operating Margin

We define operating margin as gross margin less operating expenses. Operating margin is an important performance measure of the core profitability of our operations.

Management reviews business segment gross margin and operating margin monthly as a core internal management process. We believe that investors benefit from having access to the same financial measures that management uses in evaluating our operating results. Gross margin and operating margin provide useful information to investors because they are used as supplemental financial measures by management and by external users of our financial statements, including investors and commercial banks, 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.

Gross margin and operating margin are non-GAAP measures. The GAAP measure most directly comparable to gross margin and operating margin is net income (loss). Gross margin and operating margin are not alternatives to GAAP net income and have important limitations as analytical tools. Investors should not consider gross margin and operating margin in isolation or as a substitute for analysis of our results as reported under GAAP. Because gross margin and operating margin exclude some, but not all, items that affect net income and are defined differently by different companies in our industry, our definitions of gross margin and operating margin may not be comparable with similarly titled measures of other companies, thereby diminishing their utility. Management compensates for the limitations of gross margin and operating margin as analytical tools by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these insights into its decision-making processes.

Adjusted EBITDA

We define Adjusted EBITDA as net income (loss) attributable to TRP before interest, income taxes, depreciation and amortization, and other items that we believe should be adjusted consistent with our core operating performance. The adjusting items are detailed in the Adjusted EBITDA reconciliation table and its footnotes. 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. 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 holders of our equity interests.

Adjusted EBITDA is a non-GAAP financial measure. The GAAP measure most directly comparable to Adjusted EBITDA is net income (loss) attributable to TRP. Adjusted EBITDA should not be considered as an alternative to GAAP net income. Adjusted EBITDA has important limitations as an analytical tool. Investors 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 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, thereby diminishing its utility.

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 its decision-making processes.

Our Non-GAAP Financial Measures

The following tables reconcile the non-GAAP financial measures used by management to the most directly comparable GAAP measures for the periods indicated.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(In millions)			
Reconciliation of Net Income (Loss) to Operating Margin and Gross Margin				
Net income (loss)	$ 37.5	$ (8.7)	$ 70.2	$ 209.8
Depreciation and amortization expense	244.3	206.3	718.9	607.1
General and administrative expense	65.6	59.3	212.3	165.0
Interest (income) expense, net	84.2	75.7	229.2	113.3
(Gain) loss on sale or disposition of assets	0.5	61.1	3.6	14.3
Write-down of assets	17.9	—	17.9	—
(Gain) loss from sale of equity-method investment	(65.8)	—	(65.8)	—
(Gain) loss from financing activities	—	—	1.4	1.3
Change in contingent considerations	—	16.6	8.8	12.1
Other, net	(10.0)	(2.3)	(15.7)	(5.0)
Operating margin	**374.2**	**408.0**	**1,180.8**	**1,117.9**
Operating expenses	200.2	194.9	600.7	538.7
Gross margin	**$ 574.4**	**$ 602.9**	**$ 1,781.5**	**$ 1,656.6**

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
	(In millions)			
Reconciliation of Net Income (Loss) attributable to TRP to Adjusted EBITDA				
Net income (loss) attributable to TRP	$ (39.1)	$ (18.4)	$ (74.1)	$ 177.8
Interest (income) expense, net (1)	84.2	75.7	229.2	113.3
Depreciation and amortization expense	244.3	206.3	718.9	607.1
(Gain) loss on sale or disposition of assets	0.5	61.1	3.6	14.3
Write-down of assets	17.9	—	17.9	—
(Gain) loss from sale of equity-method investment	(65.8)	—	(65.8)	—
(Gain) loss from financing activities (2)	—	—	1.4	1.3
Equity (earnings) loss	(10.0)	(3.0)	(15.9)	(6.4)
Distributions from unconsolidated affiliates and preferred partner interests, net	14.0	7.5	33.4	21.4
Change in contingent considerations	—	16.6	8.8	12.1
Risk management activities	100.7	(0.8)	100.8	8.3
Noncontrolling interests adjustments (3)	(8.9)	(7.7)	(25.6)	(19.7)
TRP Adjusted EBITDA (4)	**$ 337.8**	**$ 337.3**	**$ 932.6**	**$ 929.5**

(1) Includes the change in estimated redemption value of the mandatorily redeemable preferred interests.
(2) Gains or losses on debt repurchases, amendments, exchanges or early debt extinguishments.
(3) Noncontrolling interest portion of depreciation and amortization expense.
(4) Beginning in the second quarter of 2019, we revised our reconciliation of Net Income (Loss) attributable to TRP to Adjusted EBITDA to exclude the Splitter Agreement adjustment previously included in the comparative periods presented herein. For all comparative periods presented, our Adjusted EBITDA measure previously included the Splitter Agreement adjustment, which represented the recognition of the annual cash payment received under the condensate splitter agreement ratably over four quarters. The effect of these revisions reduced TRP's Adjusted EBITDA by $10.8 million and $32.3 million for the three and nine months ended September 30, 2018.

Consolidated Results of Operations

The following table and discussion is a summary of our consolidated results of operations:

	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	2019 vs. 2018		Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018	2019 vs. 2018	
	(In millions)							
Revenues:								
Sales of commodities	$ 1,594.2	$ 2,654.1	$ (1,059.9)	(40%)	$ 5,254.8	$ 6,981.4	$ (1,726.6)	(25%)
Fees from midstream services	308.3	332.3	(24.0)	(7%)	942.4	904.9	37.5	4%
Total revenues	1,902.5	2,986.4	(1,083.9)	(36%)	6,197.2	7,886.3	(1,689.1)	(21%)
Product purchases	1,328.1	2,383.5	(1,055.4)	(44%)	4,415.7	6,229.7	(1,814.0)	(29%)
Gross margin (1)	574.4	602.9	(28.5)	(5%)	1,781.5	1,656.6	124.9	8%
Operating expenses	200.2	194.9	5.3	3%	600.7	538.7	62.0	12%
Operating margin (1)	374.2	408.0	(33.8)	(8%)	1,180.8	1,117.9	62.9	6%
Depreciation and amortization expense	244.3	206.3	38.0	18%	718.9	607.1	111.8	18%
General and administrative expense	65.6	59.3	6.3	11%	212.3	165.0	47.3	29%
Other operating (income) expense	18.4	61.8	(43.4)	(70%)	21.7	15.7	6.0	38%
Income (loss) from operations	45.9	80.6	(34.7)	(43%)	227.9	330.1	(102.2)	(31%)
Interest expense, net	(84.2)	(75.7)	(8.5)	(11%)	(229.2)	(113.3)	(115.9)	(102%)
Equity earnings (loss)	10.0	3.0	7.0	233%	15.9	6.4	9.5	148%
Gain (loss) from financing activities	—	—	—	—	(1.4)	(1.3)	(0.1)	(8%)
Gain (loss) from sale of equity-method investment	65.8	—	65.8	—	65.8	—	65.8	—
Change in contingent considerations	—	(16.6)	16.6	100%	(8.8)	(12.1)	3.3	27%
Net income (loss)	37.5	(8.7)	46.2	NM	70.2	209.8	(139.6)	(67%)
Less: Net income (loss) attributable to noncontrolling interests	76.6	9.7	66.9	NM	144.3	32.0	112.3	NM
Net income (loss) attributable to Targa Resources Partners LP	$ (39.1)	$ (18.4)	$ (20.7)	113%	$ (74.1)	$ 177.8	$ (251.9)	(142%)
Financial data:								
Adjusted EBITDA (1)	$ 337.8	$ 337.3	$ 0.5	—	$ 932.6	$ 929.5	$ 3.1	—
Growth capital expenditures (2)	511.3	984.4	(473.1)	(48%)	2,203.4	2,230.0	(26.6)	(1%)
Maintenance capital expenditures (3)	31.0	33.3	(2.3)	(7%)	101.5	80.4	21.1	26%

(1) Gross margin, operating margin, and Adjusted EBITDA are non-GAAP financial measures and are discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations."

(2) Growth capital expenditures, net of contributions from noncontrolling interest, were $1,870.8 million and $1,824.0 million for the nine months ended September 30, 2019 and 2018. Net contributions to investments in unconsolidated affiliates were $75.4 million and $99.9 million for the nine months ended September 30, 2019 and 2018.

(3) Maintenance capital expenditures, net of contributions from noncontrolling interests, were $95.5 million and $78.8 million for the nine months ended September 30, 2019 and 2018.

NM Due to a low denominator, the noted percentage change is disproportionately high and as a result, considered not meaningful.

Three Months Ended September 30, 2019 Compared to Three Months Ended September 30, 2018

The decrease in commodity sales reflects lower NGL, natural gas, and condensate prices ($1,352.5 million), the unfavorable impact of mark-to-market hedges ($102.0 million) and lower petroleum products and condensate volumes ($62.2 million), partially offset by higher NGL, crude marketing and natural gas volumes ($373.3 million), the favorable impact of equity volume hedges ($59.5 million) and higher crude marketing prices ($20.1 million).

The decrease in fees from midstream services is largely due to lower gas gathering fees attributable to our non-cash take in-kind equity volumes, partially offset by an overall increase in gas gathered volumes. Subsequent to our January 2018 adoption of ASC 606, Revenue from Contracts with Customers, non-cash take in-kind volumes, which have exposure to commodity prices, received from a customer are presented as a component of fees from midstream services with a corresponding offset to product purchases and have no impact to our operating margin or gross margin.

The decrease in product purchases reflects decreased NGL, natural gas and condensate prices, partially offset by increases in volumes.

Lower 2019 operating margin and gross margin reflect decreased segment results for Gathering and Processing, offset by increased segment results for Logistics and Marketing. See "—Results of Operations—By Reportable Segment" for additional information regarding changes in operating margin and gross margin on a segment basis. Operating margin and gross margin also include the effect of hedges as discussed in "—Other."

Depreciation and amortization expense increased primarily due to higher depreciation related to major growth projects placed in service, including additional processing plants and associated infrastructure in the Permian Basin and Grand Prix.

General and administrative expense increased primarily due to higher compensation and benefits costs as a result of increased staffing levels, partially offset by lower professional services and lower contract labor.

During the third quarter of 2019, we wrote down certain assets to their recoverable amounts. In the prior year, a loss on sale was recognized associated with our refined products and crude oil storage and terminaling facilities in Tacoma, WA, and Baltimore, MD.

Interest expense, net, increased due to higher average borrowings, partially offset by higher capitalized interest related to our major growth investments.

The increase in equity earnings is primarily due to higher earnings from GCX.

During the third quarter of 2019, we closed on the sale of an equity-method investment for $70.3 million that resulted in the recognition of a gain of $65.8 million.

During 2019, the Permian Acquisition contingent consideration earn-out period ended and resulted in a final payment in May. During 2018, we recorded an expense resulting primarily from an increase in fair value of the contingent consideration liability. The fair value change was primarily attributable to a shorter discount period.

Net income attributable to noncontrolling interests was higher in 2019 due to earnings allocated to noncontrolling interest holders in Targa Badlands, Grand Prix and Train 6.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

The decrease in commodity sales reflects lower commodity prices ($2,640.8 million) and lower petroleum products volumes due to the sale of certain petroleum logistics storage and terminaling facilities in the fourth quarter of 2018 ($85.3 million), partially offset by higher NGL, crude marketing and natural gas volumes ($936.4 million) and the favorable impact of hedges ($65.8 million). Higher exports and crude gathering fees resulted in increased fees from midstream services.

The decrease in product purchases reflects decreased NGL, natural gas and condensate prices, partially offset by increases in volumes.

Higher 2019 operating margin and gross margin reflect increased segment results for Logistics and Marketing, offset by decreased segment results for Gathering and Processing. See "—Results of Operations—By Reportable Segment" for additional information regarding changes in operating margin and gross margin on a segment basis. Operating margin and gross margin also include the effect of hedges as discussed in "—Other."

Depreciation and amortization expense increased primarily due to higher depreciation related to major growth projects placed in service, including additional processing plants and associated infrastructure in the Permian Basin and Grand Prix.

General and administrative expense increased primarily due to higher compensation and benefits costs as a result of increased staffing levels and higher system costs.

Interest expense, net, increased due to higher average borrowings, partially offset by higher capitalized interest related to our major growth investments. During 2018, we recognized non-cash interest income resulting from a decrease in the estimated redemption value of the mandatorily redeemable interests, primarily attributable to the February 2018 amendments to such arrangements.

The increase in equity earnings is primarily due to higher earnings from GCX.

During 2019, we closed on the sale of an equity-method investment for $70.3 million that resulted in the recognition of a gain of $65.8 million.

Net income attributable to noncontrolling interests was higher in 2019 due to earnings allocated to noncontrolling interest holders in Targa Badlands, Grand Prix and Train 6.

Results of Operations—By Reportable Segment

Our operating margins by reportable segment are:

	Gathering and Processing	Logistics and Marketing	Other	Consolidated Operating Margin
		(In millions)		
Three Months Ended:				
September 30, 2019	$ 208.6	$ 228.9	$ (63.3)	$ 374.2
September 30, 2018	255.3	173.5	(20.8)	408.0
Nine Months Ended:				
September 30, 2019	$ 630.9	$ 565.0	$ (15.2)	$ 1,180.7
September 30, 2018	718.4	441.7	(42.2)	1,117.9

Gathering and Processing Segment

	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	2019 vs. 2018		Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018	2019 vs. 2018	
Gross margin	$ 328.8	$ 373.7	$ (44.9)	(12%)	$ 1,006.1	$ 1,046.3	$ (40.2)	(4%)
Operating expenses	120.2	118.4	1.8	2%	375.2	327.9	47.3	14%
Operating margin	$ 208.6	$ 255.3	$ (46.7)	(18%)	$ 630.9	$ 718.4	$ (87.5)	(12%)
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
Permian Midland (4)	1,546.7	1,161.7	385.0	33%	1,438.7	1,100.8	337.9	31%
Permian Delaware	629.4	470.5	158.9	34%	552.2	432.5	119.7	28%
Total Permian	2,176.1	1,632.2	543.9		1,990.9	1,533.3	457.6	
SouthTX (5)	328.6	364.1	(35.5)	(10%)	335.3	397.8	(62.5)	(16%)
North Texas	228.2	247.6	(19.4)	(8%)	227.6	243.0	(15.4)	(6%)
SouthOK (6)	590.8	568.2	22.6	4%	606.1	549.4	56.7	10%
WestOK	329.2	353.9	(24.7)	(7%)	335.2	350.8	(15.6)	(4%)
Total Central	1,476.8	1,533.8	(57.0)		1,504.2	1,541.0	(36.8)	
Badlands (7), (8)	120.8	90.5	30.3	33%	103.4	83.3	20.1	24%
Total Field	3,773.7	3,256.5	517.2		3,598.5	3,157.6	440.9	
Coastal	721.0	783.3	(62.3)	(8%)	765.1	724.5	40.6	6%
Total	4,494.7	4,039.8	454.9	11%	4,363.6	3,882.1	481.5	12%
NGL production, MBbl/d (3)								
Permian Midland (4)	216.5	152.2	64.3	42%	199.8	148.0	51.8	35%
Permian Delaware	82.3	58.9	23.4	40%	71.4	51.6	19.8	38%
Total Permian	298.8	211.1	87.7		271.2	199.6	71.6	
SouthTX (5)	41.5	49.0	(7.5)	(15%)	44.0	52.5	(8.5)	(16%)
North Texas	27.3	29.6	(2.3)	(8%)	26.9	28.1	(1.2)	(4%)
SouthOK (6)	69.5	61.2	8.3	14%	65.4	53.8	11.6	22%
WestOK	19.2	20.7	(1.5)	(7%)	22.4	19.9	2.5	13%
Total Central	157.5	160.5	(3.0)		158.7	154.3	4.4	
Badlands (8)	14.0	10.5	3.5	33%	12.2	10.5	1.7	16%
Total Field	470.3	382.1	88.2		442.1	364.4	77.7	
Coastal	45.4	47.3	(1.9)	(4%)	47.0	42.8	4.2	10%
Total	515.7	429.4	86.3	20%	489.1	407.2	81.9	20%
Crude oil gathered, Badlands, MBbl/d	164.3	161.7	2.6	2%	167.0	139.9	27.1	19%
Crude oil gathered, Permian, MBbl/d	95.2	75.1	20.1	27%	86.1	63.8	22.3	35%
Natural gas sales, BBtu/d (3)	2,056.6	1,817.6	239.0	13%	2,011.2	1,821.1	190.1	10%
NGL sales, MBbl/d	398.0	329.6	68.4	21%	382.4	311.3	71.1	23%
Condensate sales, MBbl/d	11.0	12.6	(1.6)	(13%)	12.2	12.8	(0.6)	(5%)
Average realized prices (9):								
Natural gas, $/MMBtu	1.02	1.93	(0.91)	(47%)	1.19	2.03	(0.84)	(41%)
NGL, $/gal	0.27	0.75	(0.48)	(64%)	0.35	0.67	(0.32)	(48%)
Condensate, $/Bbl	50.94	58.31	(7.37)	(13%)	49.79	58.49	(8.70)	(15%)

(1) Segment operating statistics include the effect of intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.
(2) Plant natural gas inlet represents our undivided interest in the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant, other than Badlands.
(3) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes, while natural gas sales and NGL sales exclude producer take-in-kind volumes.
(4) Permian Midland includes operations in WestTX, of which we own 72.8%, and other plants that are owned 100% by us. Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in our reported financials.
(5) SouthTX includes the Raptor Plant, of which we own a 50% interest through the Carnero Joint Venture. SouthTX also includes the Silver Oak II Plant, of which we owned a 100% interest until it was contributed to the Carnero Joint Venture in May 2018. The Carnero Joint Venture is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.
(6) SouthOK includes the Centrahoma Joint Venture, of which we own 60%, and other plants that are owned 100% by us. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.
(7) Badlands natural gas inlet represents the total wellhead gathered volume.
(8) As of April 3, 2019, Targa owns 55% of Targa Badlands through a joint venture (the “Badlands Joint Venture”), prior to which we owned a 100% interest. The Badlands Joint Venture is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.
(9) Average realized prices exclude the impact of hedging activities presented in Other.

Three Months Ended September 30, 2019 Compared to Three Months Ended September 30, 2018

The decrease in gross margin was primarily due to lower commodity prices, partially offset by higher Permian and Badlands volumes. The impact of lower commodity prices in 2019 excludes the third quarter realized gain from our hedging activities presented in Other. NGL production, NGL sales and natural gas sales increased primarily due to higher inlet volumes and increased NGL recoveries. In the Permian, natural gas gathered volumes and NGL production increased due to incremental processing capacity available with the commencement of operations at the Johnson Plant in the fourth quarter of 2018, the Hopson Plant in the second quarter of 2019 and the Pembrook Plant in the third quarter of 2019, while total crude oil gathered volumes increased due to production from new wells. In the Badlands, natural gas gathered volumes and NGL production increased due to incremental processing capacity available with the commencement of operations at the Little Missouri 4 Plant in the third quarter of 2019, while total crude oil gathered volumes increased due to production from new wells.

Operating expenses were relatively flat with increased operating expenses in the Permian, due to gas plant and system expansions, partially offset by reductions in other regions.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

The decrease in gross margin was primarily due to lower commodity prices, partially offset by higher Permian and Badlands volumes. The impact of lower commodity prices in 2019 excludes the realized gain from our hedging activities presented in Other. NGL production, NGL sales and natural gas sales increased primarily due to higher inlet volumes and increased NGL recoveries. In the Permian, natural gas gathered volumes and NGL production increased due to incremental processing capacity available with the commencement of operations at the Johnson Plant in the fourth quarter of 2018, the Hopson Plant in the second quarter of 2019 and the Pembrook Plant in the third quarter of 2019. In the Badlands, natural gas gathered volumes and NGL production increased due to production from new wells and the incremental processing capacity available with the commencement of operations at the Little Missouri 4 Plant in the third quarter of 2019. Total crude oil gathered volumes increased in both the Permian region and the Badlands due to production from new wells.

The increase in operating expenses was primarily driven by gas plant and system expansions in the Permian region and the Badlands. Operating expenses in other areas were relatively flat.

Logistics and Marketing Segment

	Three Months Ended September 30, 2019	Three Months Ended September 30, 2018	2019 vs. 2018		Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018	2019 vs. 2018	
	(In millions)							
Gross margin	$ 310.4	$ 249.4	$ 61.0	24%	$ 792.4	$ 653.1	$ 139.3	21%
Operating expenses	81.5	75.9	5.6	7%	227.4	211.4	16.0	8%
Operating margin	$ 228.9	$ 173.5	$ 55.4	32%	$ 565.0	$ 441.7	$ 123.3	28%
Operating statistics MBbl/d (1):								
Fractionation volumes (2)	508.8	454.5	54.3	12%	492.8	419.0	73.8	18%
Export volumes (3)	239.2	208.2	31.0	15%	228.1	200.2	27.9	14%
Pipeline throughput (4)	131.8	-	131.8	-	44.4	-	44.4	-
NGL sales	672.1	555.7	116.4	21%	620.9	526.7	94.2	18%
Average realized prices:								
NGL realized price, $/gal	$ 0.43	$ 0.88	$ (0.45)	(51%)	$ 0.50	$ 0.80	$ (0.30)	(38%)

(1) Segment operating statistics include intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the period and the denominator is the number of calendar days during the period.

(2) Fractionation contracts include pricing terms composed of base fees and fuel and power components that vary with the cost of energy. As such, the Logistics and Marketing segment results include effects of variable energy costs that impact both gross margin and operating expenses. Fractionation volumes for 2019 reflect volumes delivered and fractionated, whereas fractionation volumes for 2018 reflect volumes delivered and settled under fractionation contracts.

(3) Export volumes represent the quantity of NGL products delivered to third-party customers at our Galena Park Marine Terminal that are destined for international markets.

(4) Pipeline throughput represents the total quantity of mixed NGLs delivered by Grand Prix to Mont Belvieu.

Three Months Ended September 30, 2019 Compared to Three Months Ended September 30, 2018

Logistics and Marketing gross margin increased due to higher NGL transportation, fractionation and services margin, higher marketing margin, and higher LPG export margin, partially offset by lower terminaling and storage throughput. NGL transportation, fractionation and services margin increased due to volumes delivered on Grand Prix, which began full service into Mont Belvieu during the third quarter of 2019, and higher fractionation volumes as a result of the commencement of operations of Train 6 in the second quarter of 2019. Fractionation and services margin was unfavorably impacted by fewer short-term high fee fractionation contracts in the third quarter of 2019 compared to the same period last year, and by a planned maintenance turnaround of our Cedar Bayou fractionator. Marketing margin increased due to optimization of gas and liquids arrangements. LPG export margin increased due to higher volumes. Terminaling and storage throughput decreased due to the sale of certain petroleum logistics terminals in the fourth quarter of 2018.

Operating expenses increased due to higher maintenance, higher fuel and power costs that are largely passed through to customers, and higher compensation and benefits primarily attributable to Grand Prix and Train 6 operations, partially offset by the sale of certain petroleum logistics terminals in the fourth quarter of 2018.

Nine Months Ended September 30, 2019 Compared to Nine Months Ended September 30, 2018

Logistics and Marketing gross margin increased due to higher NGL transportation, fractionation and services margin, higher LPG export margin, and higher marketing margin, partially offset by lower terminaling and storage throughput. NGL transportation, fractionation and services margin increased due to volumes delivered on Grand Prix, which began full service into Mont Belvieu during the third quarter of 2019, and higher fractionation volumes as a result of the commencement of operations of Train 6 in the second quarter of 2019. Fractionation and services margin was unfavorably impacted by fewer short-term high fee fractionation contracts in the third quarter of 2019 compared to the same period last year, and by a planned maintenance turnaround of our Cedar Bayou fractionator. LPG export margin increased due to higher volumes. Marketing margin increased due to optimization of gas and liquids arrangements. Terminaling and storage throughput decreased due to the sale of certain petroleum logistics terminals in the fourth quarter of 2018.

Operating expenses increased due to higher fuel and power costs that are largely passed through to customers, higher maintenance, and higher compensation and benefits and higher taxes primarily attributable to Grand Prix and Train 6 operations, partially offset by the sale of certain petroleum logistics terminals in the fourth quarter of 2018.

Other

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2019	2018	2019 vs. 2018	2019	2018	2019 vs. 2018
			(In millions)			
Gross margin	$ (63.3)	$ (20.8)	$ (42.5)	$ (15.2)	$ (42.2)	$ 27.0
Operating margin	$ (63.3)	$ (20.8)	$ (42.5)	$ (15.2)	$ (42.2)	$ 27.0

Other contains the results of commodity derivative activities related to Gathering and Processing hedges of equity volumes that are included in operating margin. The primary purpose of our commodity risk management activities is to mitigate a portion of the impact of commodity prices on our operating cash flow. We have entered into derivative instruments to hedge the commodity price associated with a portion of our expected natural gas, NGL and condensate equity volumes in our Gathering and Processing operations that result from percent of proceeds/liquids processing arrangements. Because we are essentially forward-selling a portion of our future plant equity volumes, these hedge positions will move favorably in periods of falling commodity prices and unfavorably in periods of rising commodity prices.

We have also entered into swaps and basis swaps that are not designated or do not qualify for hedge accounting treatment. The mark-to-market gains/losses related to these derivative instruments represent unrealized, non-cash changes in the fair value of the instruments. For the three and nine months ended September 30, 2019, the unrealized mark-to-market losses are primarily attributable to unfavorable movements in natural gas forward basis prices and will be more than offset by locked-in gains to be realized in future periods from the underlying transportation arrangements.

The following table provides a breakdown of the change in Other operating margin:

	Three Months Ended September 30, 2019			Three Months Ended September 30, 2018		
	(In millions, except volumetric data and price amounts)					
	Volume Settled	Price Spread (1)	Gain (Loss)	Volume Settled	Price Spread (1)	Gain (Loss)
Natural gas (BBtu)	18.8	$ 1.07	$ 20.1	15.7	$ 0.82	$ 12.9
NGL (MMgal)	110.0	0.17	18.5	99.0	(0.27)	(26.4)
Crude oil (MBbl)	0.4	(1.76)	(0.7)	0.5	(15.81)	(8.1)
Non-hedge accounting (2)			(101.2)			0.8
			$ (63.3)			$ (20.8)

	Nine Months Ended September 30, 2019			Nine Months Ended September 30, 2018		
	(In millions, except volumetric data and price amounts)					
	Volume Settled	Price Spread (1)	Gain (Loss)	Volume Settled	Price Spread (1)	Gain (Loss)
Natural gas (BBtu)	47.0	$ 1.29	$ 60.6	48.6	$ 0.74	$ 35.8
NGL (MMgal)	252.1	0.11	27.9	286.3	(0.17)	(49.7)
Crude oil (MBbl)	1.1	(2.28)	(2.6)	1.5	(13.10)	(20.0)
Non-hedge accounting (2)			(101.1)			(8.3)
			$ (15.2)			$ (42.2)

(1) The price spread is the differential between the contracted derivative instrument pricing and the price of the corresponding settled commodity transaction.
(2) Mark-to-market income (loss) associated with derivative contracts that are not designated as hedges for accounting purposes.

Liquidity and Capital Resources

As of September 30, 2019, we had $294.9 million of “Cash and cash equivalents,” on our Consolidated Balance Sheets. We believe our cash position, remaining borrowing capacity on our credit facilities (discussed below in “Short-term Liquidity”), and our cash flows from operating activities are adequate to allow us to manage our day-to-day cash requirements and anticipated obligations as discussed further below.

Our ability to finance our operations, including funding capital expenditures and acquisitions, meeting our indebtedness obligations, refinancing our indebtedness and meeting our collateral requirements, 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. These include commodity prices, weather and 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 flows from operations, contributions from TRC that are funded through TRC’s access to debt and equity markets, borrowings under the TRP Revolver and the Securitization Facility, and access to debt markets. We supplement these sources of liquidity with joint venture arrangements and proceeds from asset sales. For companies involved in hydrocarbon production, transportation and other oil and gas related services, the capital markets have experienced and may continue to experience volatility. Our exposure to adverse credit conditions includes our credit facility, cash investments, hedging abilities, customer performance risks and counterparty performance risks.

Short-term Liquidity

Our short-term liquidity as of November 1, 2019 was:

		November 1, 2019
		(In millions)
Cash on hand		$ 287.0
Total availability under the TRP Revolver		2,200.0
Total availability under the Securitization Facility		349.0
		2,836.0
Less:	Outstanding borrowings under the TRP Revolver	(880.0)
	Outstanding borrowings under the Securitization Facility	(349.0)
	Outstanding letters of credit under the TRP Revolver	(73.8)
	Total liquidity	$ 1,533.2

Other potential capital resources associated with our existing arrangements include:

- Our right to request an additional $500 million in commitment increases under the TRP Revolver, subject to the terms therein. The TRP Revolver matures on June 29, 2023.

A portion of our capital resources are allocated to letters of credit to satisfy certain counterparty credit requirements. These letters of credit reflect our non-investment grade status, as assigned to us by Moody's and S&P. They also reflect certain counterparties' views of our financial condition and ability to satisfy our performance obligations, as well as commodity prices and other factors.

Working Capital

Working capital is the amount by which current assets exceed current liabilities. On a consolidated basis, at the end of any given month, accounts receivable and payable tied to commodity sales and purchases are relatively balanced, with receivables from customers being offset by plant settlements payable to producers. The factors that typically cause overall variability in our reported total working capital are: (i) our cash position; (ii) liquids inventory levels and valuation, which we closely manage; (iii) changes in payables and accruals related to major growth projects; (iv) changes in the fair value of the current portion of derivative contracts; (v) monthly swings in borrowings under the Securitization Facility; and (vi) major structural changes in our asset base or business operations, such as acquisitions or divestitures and certain organic growth projects.

Working capital as of September 30, 2019 increased $1,167.8 million compared to December 31, 2018. The increase was primarily attributable to the February redemption of our 4⅛% Senior Notes due 2019 and the May 2019 contingent consideration payment associated with the Permian Acquisition, with funding provided by the issuance of long-term senior notes.

Based on our anticipated levels of operations and absent any disruptive events, we believe that internally generated cash flow, contributions from TRC, borrowings available under the TRP Revolver and the Securitization Facility and proceeds from debt offerings, as well as joint ventures and/or asset sales, should provide sufficient resources to finance our operations, capital expenditures, long-term debt obligations, collateral requirements and cash distributions to Targa for at least the next twelve months.

Long-term Financing

In February 2018, we formed three development joint ventures ("DevCo JVs") with investment vehicles affiliated with Stonepeak, which committed a maximum of approximately $960 million of capital to the DevCo JVs.

As of September 30, 2019, total contributions from Stonepeak to the DevCo JVs were $880.1 million. As of September 30, 2019, total contributions from Blackstone to the Grand Prix Joint Venture were $329.6 million. These contributions from Stonepeak and Blackstone are included in noncontrolling interests.

From time to time, we issue long-term debt securities, which we refer to as senior notes. Our senior notes issued to date, generally have similar terms other than interest rates, maturity dates and redemption premiums. As of September 30, 2019, and December 31, 2018, the aggregate principal amount outstanding of our senior notes and other various long-term debt obligations, including unamortized premiums, debt issuance costs and non-current liabilities of finance leases, was $6,844.7 million and $5,197.4 million, respectively.

The majority of our debt is fixed rate borrowings; however, we have some exposure to the risk of changes in interest rates, primarily as a result of the variable rate borrowings under the TRP Revolver and the Securitization Facility. We may enter into interest rate hedges with the intent to mitigate the impact of changes in interest rates on cash flows. As of September 30, 2019, we did not have any interest rate hedges.

In January 2019, we issued $750.0 million of 6½% Senior Notes due July 2027 and $750.0 million of 6⅞% Senior Notes due January 2029, resulting in total net proceeds of $1,486.6 million. The net proceeds from the issuance were used to redeem in full our 4⅛% Senior Notes due 2019, at par value plus accrued interest through the redemption date, with the remainder used for general partnership purposes, which included repayment of borrowings under our credit facilities.

In April 2019, we closed on the sale of a 45% interest in Targa Badlands, the entity that holds substantially all of our assets in North Dakota, to funds managed by Blackstone for $1.6 billion in cash. We used the net cash proceeds to repay debt and for general corporate purposes, including funding our growth capital program. We continue to be the operator of Targa Badlands and hold majority governance rights. Future growth capital of Targa Badlands is expected to be funded on a pro rata ownership basis. Targa Badlands pays an MQD to Blackstone and Targa, with Blackstone having a priority right on such MQDs. Additionally, Blackstone's capital contributions would have a liquidation preference upon a sale of Targa Badlands. As of September 30, 2019, the contributions from Blackstone were $63.0 million.

To date, our debt balances have not adversely affected our operations, ability to grow or ability to repay or refinance indebtedness. For additional information about our debt-related transactions, see Note 9 - Debt Obligations to our consolidated financial statements. For information about our interest rate risk, see "Item 3. Quantitative and Qualitative Disclosures About Market Risk—Interest Rate Risk."

Distributions on our 5,000,000 Preferred Units are cumulative from the date of original issue in October 2015 and are payable monthly in arrears on the 15th day of each month of each year, when, as and if declared by the board of directors of our general partner. Distributions on our Preferred Units are payable out of amounts legally available at a rate equal to 9.0% per annum.

On and after November 1, 2020, distributions on our Preferred Units will accumulate at an annual floating rate equal to the one-month LIBOR plus a spread of 7.71%. At any time on or after November 1, 2020, we may redeem the Preferred Units, in whole or in part, from any source of funds legally available for such purpose, by paying $25.00 per unit plus an amount equal to all accumulated and unpaid distributions thereon to the date of redemption, whether or not declared. In addition, we (or a third party with our prior written consent) may redeem the Preferred Units following certain changes of control, as described in our Partnership Agreement. If we do not (or a third party with our prior written consent does not) exercise this option, then the Preferred Unitholders have the option to convert the Preferred Units into a number of common units per Preferred Unit as set forth in our Partnership Agreement.

Compliance with Debt Covenants

As of September 30, 2019, we were in compliance with the covenants contained in our various debt agreements.

Cash Flow

Cash Flows from Operating Activities

Nine Months Ended September 30,		
2019	**2018**	**2019 vs. 2018**
	(In millions)	
$ 897.4	$ 943.5	$ (46.1)

The primary drivers of cash flows from operating activities are (i) the collection of cash from customers from the sale of NGLs, natural gas and other petroleum commodities, as well as fees for gas processing, crude gathering, export, fractionation, terminaling, storage and transportation, (ii) the payment of amounts related to the purchase of NGLs and natural gas, (iii) changes in payables and accruals related to major growth projects; and (iv) the payment of other expenses, primarily field operating costs, general and administrative expense and interest expense. In addition, we use derivative instruments to manage our exposure to commodity price risk. Changes in the prices of the commodities we hedge impact our derivative settlements as well as our margin deposit requirements on unsettled futures contracts.

Net cash provided by operating activities decreased in 2019 compared to 2018 primarily due to an increase in interest payments as a result of higher average borrowings.

Cash Flows Used in Investing Activities

Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018	2019 vs. 2018
(In millions)		
$ (2,619.7)	$ (2,192.8)	$ (426.9)

Cash used in investing activities increased in 2019 compared to 2018, primarily due to higher outlays for property, plant and equipment of $400.5 million, primarily related to the construction of Train 7 and Train 8, and additional processing plants and associated infrastructure in the Permian Basin. The change is also attributable to a $20.0 million increase in our contributions to unconsolidated affiliates essentially due to higher construction activities of GCX Pipeline, partially offset by lower construction activities of Little Missouri 4.

Cash Flows from Financing Activities

	Nine Months Ended September 30, 2019	Nine Months Ended September 30, 2018
Source of Financing Activities, net	(In millions)	
Sale of ownership interests in subsidiaries	$ 1,619.7	$ —
Debt, including financing costs	823.7	904.2
Contributions from noncontrolling interests	518.7	611.6
Contributions from TRC and General Partner	200.0	540.0
Distributions	(921.5)	(692.1)
Payment of contingent consideration	(317.1)	—
Other	(109.6)	(51.6)
Net cash provided by (used in) financing activities	$ 1,813.9	$ 1,312.1

In 2019, we realized a net source of cash from financing activities primarily due to the sale of ownership interests in Targa Badlands and Train 7, net increase of debt outstanding and contributions from noncontrolling interests. The result was partially offset by payments of distributions, as well as the final contingent consideration payment associated with the Permian Acquisition. The issuance of 6½% Senior Notes due 2027 and 6⅞% Senior Notes due January 2029, partially offset by the redemption of 4⅛% Senior Notes due November 2019 contributed to the net increase of debt outstanding. The contributions from noncontrolling interests were primarily from Stonepeak and Blackstone to fund growth projects.

In 2018, we realized a net source of cash from financing activities primarily due to a net increase of debt outstanding and contributions from noncontrolling interests and TRC, partially offset by payments of distributions to TRC. The issuance of 5⅞% Senior Notes due 2026, partially offset by repayments of outstanding borrowings under TRP Revolver contributed to the net increase of debt outstanding. The contributions from noncontrolling interests were primarily from Stonepeak and Blackstone to fund growth projects.

Distributions

TRC is entitled to receive all available Partnership distributions after payments of preferred distributions each quarter.

The following table details the distributions declared and paid by us during the nine months ended September 30, 2019:

Three Months Ended	Date Paid or To Be Paid	Total Distributions	Distributions to Targa Resources Corp.
September 30, 2019	November 13, 2019	$ 242.1	$ 239.3
June 30, 2019	August 13, 2019	242.4	239.6
March 31, 2019	April 5, 2019	437.8	435.0
December 31, 2018	February 13, 2019	241.3	238.5

Preferred Units

Distributions on our Preferred Units are declared and paid monthly. As of September 30, 2019, we have 5,000,000 Preferred Units outstanding. For the three and nine months ended September 30, 2019, $2.8 million and $8.4 million of distributions were paid. We have accrued distributions to Series A Preferred Unitholders of $0.9 million for September, which were paid subsequently on October 15, 2019.

In October 2019, the board of directors of our general partner declared a cash distribution of $0.1875 per Preferred Unit. This distribution will be paid on November 15, 2019.

Capital Expenditures

Our capital expenditures are classified as growth capital expenditures, business acquisitions, and maintenance capital expenditures. Growth capital expenditures improve the service capability of the existing assets, extend asset useful lives, increase capacities from existing levels, add capabilities, and reduce costs or enhance revenues. Maintenance capital 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 are worn, obsolete or completing their useful life and expenditures to remain in compliance with environmental laws and regulations.

The following table details cash outlays for capital projects for the nine months ended September 30, 2019 and 2018:

	Nine Months Ended September 30,	
	2019	2018
Capital expenditures:	(In millions)	
Growth (1)	2,203.4	2,230.0
Maintenance (2)	101.5	80.4
Gross capital expenditures	2,304.9	2,310.4
Transfers of capital expenditures to investment in unconsolidated affiliates	—	16.0
Transfers from materials and supplies inventory to property, plant and equipment	(21.7)	(8.9)
Change in capital project payables and accruals	150.6	(283.9)
Cash outlays for capital projects	2,433.8	2,033.6

(1) Growth capital expenditures, net of contributions from noncontrolling interests, were $1,870.8 million and $1,824.0 million for the nine months ended September 30, 2019 and 2018. Net contributions to investments in unconsolidated affiliates were $75.4 million and $99.9 million for the nine months ended September 30, 2019 and 2018.

(2) Maintenance capital expenditures, net of contributions from noncontrolling interests, were $95.5 million and $78.8 million for the nine months ended September 30, 2019 and 2018.

We currently estimate that in 2019 we will invest approximately $2,400 million in growth capital expenditures, net of noncontrolling interests (exclusive of outlays for business acquisitions), and net contributions to investments in unconsolidated affiliates for announced projects. Future growth capital expenditures may vary significantly based on investment opportunities. We expect that 2019 maintenance capital expenditures, net of noncontrolling interests, will be approximately $130 million.

Total growth capital expenditures were flat for the nine months ended September 30, 2019 as compared to the nine months ended September 30, 2018, primarily due to lower spending on Grand Prix as it began full service in the third quarter, partially offset by spending related to construction of Train 7 and Train 8, and additional processing plants and associated infrastructure in the Permian Basin. Total maintenance capital expenditures increased for the nine months ended September 30, 2019 as compared to the nine months ended September 30, 2018, primarily due to our increased asset base and additional infrastructure.

Off-Balance Sheet Arrangements

As of September 30, 2019, there were $55.2 million in surety bonds outstanding related to various performance obligations. These are in place to support various performance obligations as required by (i) statutes within the regulatory jurisdictions where we operate and (ii) counterparty support. Obligations under these surety bonds are not normally called, as we typically comply with the underlying performance requirement.

Item 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, NGLs and crude oil, changes in interest rates, as well as nonperformance by our customers.

Risk Management

We evaluate counterparty risks related to our commodity derivative contracts and trade credit. We have all our commodity derivatives with major financial institutions or major energy companies. Should any of these financial counterparties not perform, we may not realize the benefit of some of our hedges under lower commodity prices, which could have a material adverse effect on our results of operations. We sell our natural gas, NGLs and condensate to a variety of purchasers. Non-performance by a trade creditor could result in losses.

Crude oil, NGL and natural gas prices are also volatile. In an effort to reduce the variability of our cash flows, we have entered into derivative instruments to hedge the commodity price associated with a portion of our expected natural gas, NGL and condensate equity volumes, future commodity purchases and sales, and transportation basis risk through 2024. Market conditions may also impact our ability to enter into future commodity derivative contracts.

Commodity Price Risk

A significant portion of our revenues are derived from percent-of-proceeds contracts under which we receive a portion of the proceeds from the sale of commodities as payment for services. The prices of natural gas, NGLs and crude oil 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 some of the exposure to commodity price risk and reduce fluctuations in our operating cash flow due to fluctuations in commodity prices. In an effort to reduce the variability of our cash flows, as of September 30, 2019, we have hedged the commodity price associated with a portion of our expected (i) natural gas, NGL, and condensate equity volumes in our Gathering and Processing operations that result from our percent-of-proceeds processing arrangements, (ii) future commodity purchases and sales in our Logistics and Marketing segment and (iii) natural gas transportation basis risk in our Logistics and Marketing segment by entering into derivative instruments. We hedge a higher percentage of our expected equity volumes in the current year compared to future years, for which we hedge incrementally lower percentages of expected equity volumes. With swaps, we typically receive an agreed fixed price for a specified notional quantity of natural gas or NGLs 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 equity volumes. We utilize purchased puts (or floors) and calls (or caps) to hedge additional expected equity commodity volumes without creating volumetric risk. We may buy calls in connection with swap positions to create a price floor with upside. We intend to continue to manage our exposure to commodity prices in the future by entering into derivative transactions using swaps, collars, purchased puts (or floors), futures or other derivative instruments as market conditions permit.

When entering into new hedges, we intend to generally match the NGL product composition and the NGL and natural gas delivery points to those of our physical equity volumes. The NGL hedges cover specific NGL products based upon the 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. The fair value of our natural gas and NGL hedges are based on published index prices for delivery at various locations, which closely approximate the actual natural gas and NGL delivery points. A portion of our condensate sales are hedged using crude oil hedges that are based on the NYMEX futures contracts for West Texas Intermediate light, sweet crude.

A majority of these commodity price hedges are documented pursuant to a standard International Swap Dealers Association form with customized credit and legal terms. The 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 commodity 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. Absent federal regulations resulting from the Dodd-Frank Act, and 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 a 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 expose our counterparties to credit risk, as we have no obligation to make future payments beyond the premium paid to enter into the transaction; however, we are exposed to the risk of default by the counterparty, which is the risk that the counterparty will not honor its obligation under the put transaction.

We also enter into commodity price hedging transactions using futures contracts on futures exchanges. Exchange traded futures are subject to exchange margin requirements, so we may have to increase our cash deposit due to a rise in natural gas and NGL prices. Unlike bilateral hedges, we are not subject to counterparty credit risks when using futures on futures exchanges.

These contracts may expose us to the risk of financial loss in certain circumstances. Generally, 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 they have been hedged, we will receive less revenue on the hedged volumes than we would receive in the absence of hedges (other than with respect to purchased calls).

To analyze the risk associated with our derivative instruments, we utilize a sensitivity analysis. The sensitivity analysis measures the change in fair value of our derivative instruments based on a hypothetical 10% change in the underlying commodity prices, but does not reflect the impact that the same hypothetical price movement would have on the related hedged items. The financial statement impact on the fair value of a derivative instrument resulting from a change in commodity price would normally be offset by a corresponding gain or loss on the hedged item under hedge accounting. The fair values of our derivative instruments are also influenced by changes in market volatility for option contracts and the discount rates used to determine the present values.

The following table shows the effect of hypothetical price movements on the estimated fair value of our derivative instruments as of September 30, 2019:

	Fair Value	Result of 10% Price Decrease	Result of 10% Price Increase
Natural gas	$ (72.9)	$ (27.1)	$ (118.5)
NGLs	124.5	166.2	83.1
Crude oil	18.9	36.3	1.4
Total	$ 70.5	$ 175.4	$ (34.0)

The table above contains all derivative instruments outstanding as of the stated date for the purpose of hedging commodity price risk, which we are exposed to due to our equity volumes and future commodity purchases and sales, as well as basis differentials related to our gas transportation arrangements.

Our operating revenues decreased by $61.8 million and $24.9 million during the three months ended September 30, 2019 and 2018, and $7.7 million and $73.6 million during the nine months ended September 30, 2019 and 2018, as a result of transactions accounted for as derivatives. We account for derivatives designated as hedges that mitigate commodity price risk as cash flow hedges. Changes in fair value are deferred in other comprehensive income until the underlying hedged transactions settle. We also enter into derivative instruments to help manage other short-term commodity-related business risks. We have not designated these derivatives as hedges and record changes in fair value and cash settlements to revenues.

Our risk management position has moved from a net asset position of $112.7 million at December 31, 2018 to a net asset position of $70.5 million at September 30, 2019. The fixed prices we currently expect to receive on derivative contracts are above the aggregate forward prices for commodities related to those contracts, creating this net asset position.

Interest Rate Risk

We are exposed to the risk of changes in interest rates, primarily as a result of variable rate borrowings under the TRP Revolver and the Securitization Facility. As of September 30, 2019, we do not have any interest rate hedges. However, we may enter into interest rate hedges in the future with the intent to mitigate the impact of changes in interest rates on cash flows. To the extent that interest rates increase, interest expense for the TRP Revolver and the Securitization Facility will also increase. As of September 30, 2019, we had $1,076.0 million in outstanding variable rate borrowings under the TRP Revolver and the Securitization Facility. A hypothetical change of 100 basis points in the interest rate of our variable rate debt would impact our annual interest expense by $10.8 million based on our September 30, 2019 debt balances.

Counterparty Credit Risk

We are subject to risk of losses resulting from nonpayment or nonperformance by our counterparties. The credit exposure related to commodity derivative instruments is represented by the fair value of the asset position (i.e. the fair value of expected future receipts) at the reporting date. Our futures contracts have limited credit risk since they are cleared through an exchange and are margined daily. Should the creditworthiness of one or more of the 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. We have master netting provisions in the International Swap Dealers Association agreements with our derivative counterparties. These netting provisions allow us to net settle asset and liability positions with the same counterparties within the same Targa entity, and would reduce our maximum loss due to counterparty credit risk by $129.6 million as of September 30, 2019. The range of losses attributable to our individual counterparties as of September 30, 2019 would be between $0.1 million and $36.7 million, depending on the counterparty in default.

Customer Credit Risk

We extend credit to customers and other parties in the normal course of business. We have an established policy and various procedures to manage our credit exposure risk, including performing initial and subsequent credit risk analyses, setting maximum credit limits and terms and requiring credit enhancements when necessary. We use credit enhancements including (but not limited to) letters of credit, prepayments, parental guarantees and rights of offset to limit credit risk to ensure that our established credit criteria are followed and financial loss is mitigated or minimized.

We 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 uncollectible accounts resulted in a 1% reduction of our third-party accounts receivable as of September 30, 2019, our operating income would decrease by $7.4 million in the year of the assessment.

During the three and nine months ended September 30, 2019, sales of commodities and fees from midstream services provided to Petredec (Europe) Limited comprised approximately 11% and 12% of our consolidated revenues. During the three and nine months ended September 30, 2018, sales of commodities and fees from midstream services provided to Petredec (Europe) Limited comprised approximately 17% and 16% of our consolidated revenues.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

Management, with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the design and effectiveness of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”) as of the end of the period covered in this Quarterly Report. Based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of September 30, 2019, the design and operation of our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and (ii) accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting that occurred during the quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting, during our most recent fiscal quarter.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings.

The information required for this item is provided in Note 16 – Contingencies, under the heading “Legal Proceedings” included in the Notes to Consolidated Financial Statements included under Part I, Item 1 of this Quarterly Report, which is incorporated by reference into this item.

Item 1A. Risk Factors.

For an in-depth discussion of our risk factors, see “Part I—Item 1A. Risk Factors” of our Annual Report in addition to the updates below. All of these risks and uncertainties, including the updates below, could adversely affect our business, financial condition and/or results of operations.

The tax treatment of publicly traded partnerships or an investment in our Preferred Units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly applied on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in us, may be modified by administrative, legislative or judicial changes or differing interpretations at any time. From time to time, members of Congress propose and consider such substantive changes to the existing U.S. federal income tax laws that would affect publicly traded partnerships, including elimination of partnership tax treatment for publicly traded partnerships. For example, the “Clean Energy for America Act”, which is similar to legislation that was commonly proposed during the Obama Administration, was introduced in the U.S. Senate on May 2, 2019. If enacted, this proposal would, among other things, repeal Section 7704(d)(1)(E) of the Internal Revenue Code upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. In addition, the Treasury Department has issued, and in the future may issue, regulations interpreting those laws that affect publicly traded partnerships. There can be no assurance that there will not be further changes to U.S. federal income tax laws or the Treasury Department’s interpretation of the qualifying income rules in a manner that could impact our ability to qualify as a partnership for U.S. federal income tax purposes in the future.

Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in us. You are urged to consult with your own tax advisor with respect to the status of legislative or administrative developments and proposals and their potential effect on your investment in our Preferred Units.

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

Recent Sales of Unregistered Securities.

Not applicable.

Repurchase of Equity by Targa Resources Partners LP or Affiliated Purchasers.

Not applicable.

Item 3. Defaults Upon Senior Securities.

Not applicable.

Item 4. Mine Safety Disclosures.

Not applicable.

Item 5. Other Information.

Not applicable.

Item 6. Exhibits.

Number	Description
3.1	Certificate of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.2 to Targa Resources Partners LP's Registration Statement on Form S-1 filed November 16, 2006 (File No. 333-138747)).
3.2	Certificate of Formation of Targa Resources GP LLC (incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
3.3	Third Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP, effective December 1, 2016 (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 21, 2016 (File No. 001-33303)).
3.4	Amendment No. 1 to the Third Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's Current Report on Form 8-K filed December 12, 2017 (File No. 001-33303)).
3.5	Limited Liability Company Agreement of Targa Resources GP LLC (incorporated by reference to Exhibit 3.4 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
4.1	Specimen Unit Certificate for the Series A Preferred Units (attached as Exhibit B to the Second Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP and incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 15, 2015 (File No. 001-33303)).
10.1	Supplemental Indenture dated July 19, 2019 to Indenture dated October 25, 2012, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed August 9, 2019 (File No. 001-33303)).
10.2	Supplemental Indenture dated July 19, 2019 to Indenture dated May 14, 2013, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.3 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed August 9, 2019 (File No. 001-33303)).
10.3	Supplemental Indenture dated July 19, 2019 to Indenture dated September 14, 2015, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.4 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed August 9, 2019 (File No. 001-33303)).
10.4	Supplemental Indenture dated July 19, 2019 to Indenture dated October 6, 2016, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.5 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed August 9, 2019 (File No. 001-33303)).
10.5	Supplemental Indenture dated July 19, 2019 to Indenture dated October 17, 2017, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.6 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed August 9, 2019 (File No. 001-33303)).
10.6	Supplemental Indenture dated July 19, 2019 to Indenture dated April 12, 2018, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.7 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed August 9, 2019 (File No. 001-33303)).
10.7	Supplemental Indenture dated July 19, 2019 to Indenture dated January 17, 2019, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.8 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed August 9, 2019 (File No. 001-33303)).
31.1*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Number	Description
31.2*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	Inline XBRL Instance Document – The instance document does not appear in the interactive data file because its XBRL tags are embedded within the Inline XBRL document
101.SCH*	Inline XBRL Taxonomy Extension Schema Document
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB*	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document
104*	The cover page from this Quarterly Report on Form 10-Q for the quarter ended September 30, 2019, formatted in Inline XBRL (included with Exhibit 101 attachments).

* Filed herewith

** Furnished herewith

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

Date: November 7, 2019

By: */s/ Jennifer R. Kneale*
Jennifer R. Kneale
Chief Financial Officer
(Principal Financial Officer)

Exhibit 31.1

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED**

I, Joe Bob Perkins, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Targa Resources Partners LP (the “registrant”);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: November 7, 2019

By:	/s/ Joe Bob Perkins
Name:	Joe Bob Perkins
Title:	Chief Executive Officer of Targa Resources GP LLC, the general partner of Targa Resources Partners LP (Principal Executive Officer)

Exhibit 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Jennifer R. Kneale, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Targa Resources Partners LP (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 7, 2019

By:	/s/ Jennifer R. Kneale
Name:	Jennifer R. Kneale
Title:	Chief Financial Officer of Targa Resources GP LLC, the general partner of Targa Resources Partners LP (Principal Financial Officer)

Exhibit 32.1

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report on Form 10-Q of Targa Resources Partners LP (the "Partnership") for the three months ended September 30, 2019 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Joe Bob Perkins, as Chief Executive Officer of Targa Resources GP LLC, the general partner of the Partnership, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

By: /s/ Joe Bob Perkins
Name: Joe Bob Perkins
Title: Chief Executive Officer
of Targa Resources GP LLC, the general partner of Targa Resources Partners LP

Date: November 7, 2019

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

**CERTIFICATION OF CHIEF FINANCIAL OFFICER PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report on Form 10-Q of Targa Resources Partners LP (the "Partnership") for the three months ended September 30, 2019 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Jennifer R. Kneale, as Chief Financial Officer of Targa Resources GP LLC, the general partner of the Partnership, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to her knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

By: /s/ Jennifer R. Kneale
Name: Jennifer R. Kneale
Title: Chief Financial Officer
of Targa Resources GP LLC, the general partner of Targa Resources Partners LP

Date: November 7, 2019

*A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or
its staff upon request.*