July 20, 2012

Via EDGAR and e-mail

Ms. Jennifer Thompson
Accounting Branch Chief
United States Securities and Exchange Commission
Division of Corporate Finance
Washington, D.C. 20549-7010

Re: Targa Resources Corp.
Form 10-K for Fiscal Year Ended December 31, 2011
Filed February 27, 2012
File No. 1-34991

Targa Resources Partners LP
Form 10-K for Fiscal Year Ended December 31, 2011
Filed February 27, 2012
File No. 1-33303

Dear Ms. Thompson:

Set forth below are the responses of Targa Resources Corp., a Delaware corporation (the "Company," "we," "us" or "our") and Targa Resources Partners LP., a Delaware limited partnership (the "Partnership") to the comments and requests for additional information contained in the letter received from the staff of the Division of Corporation Finance (the "Staff") of the Securities and Exchange Commission (the "Commission") dated July 6, 2012, with respect to the Company's Form 10-K for Fiscal Year Ended December 31, 2011 filed with the Commission on February 27, 2012, File No. 1-34991, and the Partnership's Form 10-K for Fiscal Year Ended December 31, 2011 filed with the Commission on February 27, 2012, File No. 1-33303. Each response below has been prepared and is being provided by the Company and Partnership, as applicable, each of which has authorized us to respond to the Staff's comments on their behalf.

For your convenience, each response is prefaced by the exact text of the Staff's corresponding comment in bold, italicized text. In addition, the Staff should note that common control accounting impacts the questions relating to Investment in Unconsolidated Affiliate (Comment 1) and Income Taxes (Comment 5). As background for the numerous transactions which have been accounted for on a common control basis, you should be aware that over time such transactions have included the Partnership's acquisition of the Company's Downstream Business, which included the interest in Gulf Coast Fractionators, LP ("GCF") in September 2009, the acquisition of the Company's interests in the Permian Business and Straddle Assets in April 2010, the acquisition of the Company's equity interest in Versado in August 2010 and the acquisition of the Company's Venice Operations in September 2010. The Partnership, the Company's

Downstream Business, the Company's interests in the Permian Business and Straddle Assets, the Company's equity interest in Versado and the Company's Venice Operations were controlled by a common parent entity, the Company, at the time of acquisition. The Company continues to control the Partnership through its ownership and control of the Partnership's general partner.

<u>Targa Resources Corp. Form 10-K for Fiscal Year Ended December 31, 2011</u>

<u>Notes to Consolidated Financial Statements, page F-9</u>

<u>Note 7 – Investment in Unconsolidated Affiliate, page F-15</u>

1. ***We note that the Partnership's allocated cost basis on the date of its investment in Gulf Coast Fractionators, LP ("GCF") was less than its partnership equity balance by approximately $5.2 million and that you are amortizing this basis difference over the estimated useful life of the underlying fractionating assets on a straight-line basis. Please tell us the authoritative GAAP guidance that supports your accounting treatment. Please also tell us the date the Partnership acquired its interest in GCF.***

   <u>Response:</u>

   The Company acknowledges the Staff's comment. The Company's subsidiary, Targa Resources, Inc. ("TRI"), acquired its interest in GCF on October 31, 2005. Authoritative accounting guidance at the time of this business combination was Statements of Financial Accounting Standards No. 141 ("SFAS 141") and No. 142 ("SFAS 142"), as well as Accounting Principles Board Opinion No. 18 ("APB 18"), paragraph 19(n) (subsequently codified as ASC 323-10-35-13). This transaction resulted in a $5.2 million difference between the carrying amount and the amount of the underlying equity in the net assets under the application of SFAS 141. Under APB 18, paragraph 19(n), as the $5.2 million difference specifically related to the underlying fractionation assets, no goodwill was recognized. Therefore, the difference between the carrying amount and the amount of the underlying equity in the net assets is being amortized over the useful lives of the fractionating assets.

   The Partnership acquired its interest in GCF by purchasing it from the Company, in a "dropdown" transaction of the Downstream Business on September 24, 2009. The transaction was not a business combination, but rather a transfer between entities under common control, as recognized by ASC 805-50 (formerly SFAS 141(R), paragraphs D8 through D14).

   ASC 805-10-15-4(c) (formerly SFAS 141(R), paragraph 2(c)) excludes transactions between entities under common control. The guidance regarding common control has remained unchanged since APB 16. Under the transactions between entities under common control guidance, the historical basis of accounting for the transferred assets and liabilities was carried forward. The guidance regarding accounting for equity method investments contained in ASC 323 has also remained consistent.

Note 8 – Debt Obligations, page F-15

2. ***We note that you recognized pre-tax debt extinguishment gains of $36.8 million and $25.2 million during fiscal years 2010 and 2009, respectively, related to repurchases of approximately $341.5 million of debt under your TRC Holdco Loan Facility. Please tell us the reasons why you were able to repurchase your debt at such a significant discount to your carrying value given the variable interest rate of such debt. In doing so, please tell us if any of the debt issuers were related parties.***

Response:

The Company acknowledges the Staff's comment. We were able to purchase the TRC Holdco Loan Facility at a discount to carrying value in 2009 due to significant volatility in the debt markets following the financial crisis of 2008 and 2009 and the precipitous drop in crude oil and natural gas prices in 2008. The discount to par value for debt in other companies and the Company specifically we believe was related to market illiquidity (particularly following the Lehman Brothers' bankruptcy) and to investors' perceptions of default risk, and was reflected to differing degrees in the market prices of both floating-rate and fixed-rate instruments. As markets began to recover in 2009 and 2010, the average price of TRC Holdco debt increased. The average price paid in 2009 was approximately 61% of par value, while in 2010 the average price paid was approximately 88% of par value.

None of the repurchased TRC Holdco debt was from a related party.

3. ***We note that you exchanged $158.6 million of your 6 7/8% senior unsecured notes for the same amount of your 11 1/4% senior unsecured notes and accounted for the exchange as a non-substantial debt modification. Please tell us in sufficient detail how this exchange qualifies for non-extinguishment accounting under FASB ASC 470-50-40. In doing so, please explain how you determined the debt instruments do not have substantially different terms.***

Response:

The Company acknowledges the Staff's comment. In January 2011, the Partnership and its subsidiary, Targa Resources Partners Finance Corporation, announced a private exchange offer to certain Eligible Holders of any and all outstanding 11.25% Senior Notes due 2017 (the "Old Notes") which could be exchanged for consideration consisting of 6.875% Senior Notes due 2021 (the "New Notes") plus a lump sum cash payment. The New Notes bear interest at a rate of 6.875% per year from February 2, 2011 to, but excluding, February 1, 2021, when they will mature. Both the Old Notes and New Notes contain terms within the respective indentures that allow for early prepayments in part and in whole at various prices during the term of the debt. The total exchange price for each $1,000 of principal of the Old Notes was $1,000 principal of New Notes and a cash amount of $175.

The economic substance of the transaction, which was an exchange of debt instruments with the same creditors, is indicative of debt modification rather than extinguishment. The terms of the debt exchange were offered to 100% of the creditors holding the Old Notes, and accepted by 69% ($158.6 million of $231.3 million of outstanding principal). The remaining $72.7 million of 11.25% Senior Notes remained outstanding and was excluded from the present value analysis. In general, the upfront lump sum cash payment, taken together with the reduced interest rate and extended term of the New Notes, resulted in present values of the New Notes and the Old Notes that were not substantially different. "Substantial" is defined in ASC 470-50-40-10 as a change or changes in which the present value of the cash flows under the amended or new debt represents a change equal to or greater than 10 percent when compared to the present value of the remaining cash flows under the original terms ("10 percent cash flow test").

ASC 470-50-40-12(c) specifies that if either the new debt instrument or the original debt instrument is callable (by the issuer) or puttable (by the holder), then separate cash flow analyses should be performed assuming both exercise and non-exercise of the call or put. The cash flow test that generates the smaller change should be used as the basis for determining whether the 10 percent threshold has been met. Therefore, our analysis reviewed all relevant scenarios and cash flow models for both the old and new debt based on terms within the respective indentures that allow for early prepayments in part and in whole at various prices during the term of the debt. Neither the old nor new debt was puttable by the holder. The six scenarios were:

- "Held-to-maturity" (PV Old Notes: $148.6 mm; PV New Notes: $135.6 mm; a difference of 8.8%);
- Callable by the Company: "Redemption at stated premium at first available date" (PV Old Notes: $160.3 mm; PV New Notes: $156.6 mm; a difference of 2.3%);
- Callable by the Company: "Full redemption at Par at first available date" (PV Old Notes: $150.9 mm; PV New Notes: $141.5 mm; a difference of 6.2%);
- Callable by the Company: "At first available clawback date with remainder to maturity" (PV Old Notes: $157.6 mm; PV New Notes: $155.6 mm; a difference of 1.2%);
- Callable by the Company: "At first available clawback date and then first available redemption date at stated premium" (PV Old Notes: $165.2 mm; PV New Notes: $169.3 mm; a difference of -2.5%); and

- Callable by the Company: “At first available clawback date and then first available redemption date for redemption at Par” (PV Old Notes: $159.1 mm; PV New Notes: $159.5 mm; a difference of -0.3%).

Based on the results of the 10 percent cash flow tests, the exchange of the Old Notes for New Notes was accounted for as a modification under ASC 470-50 as the present value of the cash flows of the New Notes represented less than a 10% difference from the present value of the cash flows of the Old Notes.

Note 14 – Fair Value Measurements, page F-26

4. We note that you transferred $7.9 million in derivative liabilities during fiscal 2011 and $69.8 million of derivative assets during fiscal 2009 from Level 3 to Level 2 due to the “increased transparency and liquidity in NGL markets.” Please explain to us in detail the developments that occurred in the functioning of the NGL markets and disclose in greater detail the reasons for these reclassifications. Please ensure your disclosures include a discussion of any changes in valuation techniques and related inputs and why unobservable inputs for these items became observable inputs. Please confirm for these transfers that none of the inputs significant to the fair value measurements in their entirety are Level 3 inputs. See ASC 820-10-50.

Response:

The Company acknowledges the Staff’s comment. During the years 2009 and 2011, we are unaware of any developments that caused the NGL markets to function materially differently, at least as far as such changes would affect our assessment of inputs within the fair value hierarchy. Furthermore, we did not change our valuation technique. We referred to “increased transparency and liquidity in the NGL markets” within our disclosure as the rationale for the transfers from Level 3 to Level 2. It was not our intention to suggest that NGL markets had changed, but rather to suggest that forward pricing on our NGL derivative contracts had become more transparent and liquid as a result of (a) their shorter tenor (i.e.; time from the value date until the expiry date) due to the passage of time, and (b) the level of trading activity in the NGL markets and time periods in which we had positions.

The transparency and liquidity of the NGL derivative contracts we enter into is primarily driven by the tenor of the particular financial instrument. In the past, the Company entered into NGL derivative contracts which had a tenor into future periods where there was little or no open interest and/or active trading of contracts with limited availability of ask/bid price information (i.e.; deemed unobservable Level 3 data). As the tenor of these transactions has shortened with the passage of time, open interests increased along with more active trading of contracts and the availability of bid/ask pricing (i.e., observable Level 2 data).

Each quarter, we retrieve publicly available information from the Chicago Mercantile Exchange ("CME") that includes close prices, open interest, and bid and ask data. This data is used to fair value our transactions and determine market place transparency and liquidity based on changes to open interests, bids and asks. Increasing levels of market activity are indicators of transparency and liquidity. Our process identifies valuation inputs and assesses the liquidity of the market underlying those inputs to ensure that we could offset our transactions in the market. When the marketplace has the transparency and liquidity to absorb our transactions, we view these as Level 2 observable inputs. The inputs are evaluated at the end of the quarter and if we elect to make transfers between levels, those transfers occur on that date

As a result of this quarterly analysis and pursuant to the requirements of ASC 820, the Company determined that certain NGL derivatives should be classified as Level 2 instruments because all significant valuation model inputs were now based on observable market data.

Specifically, the 2009 transfer of derivative assets from Level 3 to Level 2 related to long term OTC swaps executed in 2007 and 2008 for NGL products, all available on the CME, which we sell as part of our normal business operations. Certain of these swaps were based on calendar year 2012 deliveries. The significant inputs included Natural Gasoline for which pricing was extrapolated (Level 3) for some periods. During subsequent reporting periods, we valued the swaps using a combination of available prices (Level 2) for some settlement periods, and extrapolating prices for settlement periods that did not have market pricing available (Level 3). As of September 30, 2009, Natural Gasoline had actively traded contracts through December 2012 with open interest and settlement prices. Accordingly, we were no longer required to extrapolate to value our contracts and reclassified these instruments as Level 2.

Similarly, the 2011 transfer of derivative assets from Level 3 to Level 2 related to long term OTC swaps executed in 2010 for NGL products with calendar year 2013 deliveries for which pricing was extrapolated (Level 3) for some periods. As of December 31, 2011, all products had actively traded contracts through December 2013 with open interest and settlement prices. Accordingly, we were no longer required to extrapolate to value our contracts and reclassified these instruments as Level 2.

None of the inputs related to the transfers in fair value hierarchy noted in our disclosures in their entirety are Level 3 inputs. In future filings, as applicable, the Company will provide additional clarity to its disclosures regarding the basis for reclassification between levels.

Note 20 – Income Taxes, page F-33

5. ***You disclose on page F-34 that the tax consequences of transactions with common control entities are not reflected in pre-tax income under applicable accounting principles. We further note that the tax effect of your Permian and Straddle Systems and your Venice Operations sales to the Partnership were recorded as an increase in other long term assets of $64.7 to be amortized over the remaining life of the underlying assets, an increase in your current tax liability of $94.9 million, a decrease in your deferred tax liability of $27.5 million and an increase in current tax expense of $2.7 million. Citing authoritative GAAP guidance, please tell us how you determined the appropriate accounting treatment and calculated these amounts. Please also tell us the tax treatment that you were trying to achieve with intercompany transactions.***

Response:

The Company acknowledges the Staff's comment. The sales of the Permian Business and Straddle Assets and Venice Operations from the Company to the Partnership (the "Transactions") are not business combination transactions to which the standard asset and liability approach of ASC 740 (formerly FAS 109) is applied when accounting for and reporting income taxes, but rather transfers between entities under common control, as recognized by ASC 805-50 (formerly SFAS 141(R), paragraphs D8 through D14). The Partnership and the transferred entities continue to be consolidated in the Company's financial statements.

The guidance for transfers between entities under common control requires transferred assets and liabilities, including tax assets and liabilities, in the Transactions to be carried forward at their historical basis of accounting. While the Transactions did not generate intra-entity GAAP profit or loss for the Company, the Transactions did result in cash taxes payable that impact the consolidated income statement in current and future periods. Since the two entities executing the Transactions are consolidated by the Company for financial reporting purposes, we applied the guidance in 740-10-25-3(e) by analogy to our circumstances. The treatment of intra-entity profit in the Transactions is an exception under ASC 740-10-25-3(e) which prohibits the recognition of a deferred tax asset for basis differences relating to intra-entity (i.e.; intercompany) profits on assets remaining within the consolidated group and continues the ARB 51 requirement to eliminate the income statement effects of such intercompany transactions. In consolidation, there would normally be a deductible temporary difference for the excess of the buyer's tax basis over the cost to the seller, which normally would require recording a deferred tax asset for the gross deductible difference. However, ASC 810-10-45-8 requires deferral of income taxes on intra-entity profits on assets remaining within the consolidated group or for the intra-entity profits to be eliminated in consolidation to be appropriately reduced.

As a result of the Transactions, the Company deferred recognition of income tax expense and the Partnership did not recognize a deferred tax asset for the temporary difference. Typically when ASC 740-10-25-3(e) is applied, a deferred charge (an asset on the balance sheet) is recorded for the income tax expense on the sale. The deferred charge is amortized as income tax expense over the remaining life of the underlying assets. This treatment for book purposes matches the recognition of the income tax expense on the transaction with the pre-tax book consequences associated with the transferred assets. The impact of this application is set forth below:

- The "other long term asset" of $64.7 million represents the deferred charge recorded for the tax impact of the change to the book investment in the Partnership as a result of the Transactions. The deferred charge was recorded to "other long term assets" as ASC 740-10-25-3(e) does not allow deferred tax assets to be established. This deferred charge is amortized to income tax expense over the remaining life of the underlying assets.
- The current liability of $94.9 million represents the amount of cash taxes payable on the sales, after utilization of net operating loss carried over from 2009.
- The decrease in deferred tax liability of $27.5 million results from the elimination of pre-existing book/tax basis differences related to the sold assets.
- The increase in current tax expense of $2.7 million represents the 2010 amortization of the "other long term assets" recorded as a result of the Transactions.

In summary, the Transactions were treated as (i) legal and taxable sales of assets by the Company to the Partnership for tax purposes and (ii) contributions of assets and distributions of cash accounted for as transfers of entities under common control by the Partnership. We did not attempt to achieve any specific tax treatment through intercompany transactions and, in fact, the Transactions resulted in $94.9 million of cash tax after utilization of our net operating losses.

<u>Targa Resources Partners LP Form 10-K for Fiscal Year Ended December 31, 2011</u>

6. Where appropriate, please apply all comments above to the Partnership's Form 10-K.

<u>Response:</u>

The Company acknowledges the Staff's comment. While we do not believe these comments materially affect our existing disclosure in our current filings with the Commission, any changes we have undertaken to make above in response to your comments will be applied to the Partnership's future filings, where appropriate.

Note 3 – Significant Accounting Policies, page F-10

Earnings per unit, page F-13

7. Please provide all earnings per unit disclosures required by ASC 260-10-50.

Response:

The Company acknowledges the Staff's comment. For the year ended December 31, 2011, the Partnership does not have a material number of dilutive units issued and outstanding, nor does it have dividends on preferred shares or extraordinary items. For the years ended December 31, 2010 and 2009, the Partnership has no dilutive units issued and outstanding, nor does it have dividends on preferred shares or extraordinary items. Currently, the Partnership does have dilutive units issued and outstanding. As described below, those dilutive units have an immaterial impact on our reported earnings per unit.

Specifically:

- At December 31, 2011, the Partnership's average outstanding undiluted units totaled 84,142,216 units (presented as 84.1 million on a rounded basis) and the fully diluted total was 84,158,668 units (presented as 84.2 million on a rounded basis), or a difference of 16,452 units or 0.02% of undiluted units. Net income for limited partner units was $166,537,180 (presented as $166.5 million on a rounded basis). Accordingly, both basic and diluted net income per limited partner unit was $1.98 after giving effect to rounding. The actual unrounded difference between basic and diluted net income per limited partner unit was $0.0004 per unit. This difference is small enough that we believe its omission is immaterial
- At March 31, 2012, the Partnership's average outstanding undiluted units totaled 88,104,838 units (presented as 88.1 million on a rounded basis) and the fully diluted total was 88,166,342 units (presented as 88.2 million on a rounded basis), or a difference of 61,504 units or 0.07% of undiluted units. Net income for limited partner units was $55,957,839 (presented as $56.0 million on a rounded basis). Accordingly, basic and diluted net income per limited partner unit was $0.64 and $0.63 after giving effect to rounding. The actual unrounded difference between basic and diluted net income per limited partner unit was $0.0004 per unit, an amount we also considered immaterial.

Therefore, given that ASC 105-10-05-6 states that the provisions of the Codification need not be applied to immaterial items, we concluded that additional disclosures otherwise required under ASC 260-10-50 were not necessary.

In subsequent filings, we acknowledge that it would be appropriate to include disclosure in the earnings per unit discussion in the notes to our financial statements showing the impact of dilutive units on our earnings per unit to the extent material.

In connection with responding to the Staff's comments, each of the Partnership and the Company acknowledges that (i) it is responsible for the adequacy and accuracy of the disclosure in its filings, (ii) Staff comments or changes to disclosure in response to Staff comments do not foreclose the Commission from taking any action with respect to the filings, and (iii) it may not assert Staff comments as a defense in any proceeding initiated by the Commission or any person under the federal securities laws of the United States.

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While we do not believe these comments materially affect our existing disclosure in our current filings with the Commission, we respectfully request that the Staff allow us to address any comments, where appropriate, in future filings with the Commission. Please direct any questions that you have with respect to the foregoing to David P. Oelman at Vinson & Elkins L.L.P. at (713) 758-3708.

Very truly yours,

Targa Resources Partners LP

By: Targa Resources GP LLC,
its general partner

By: /s/ Matthew J. Meloy
Matthew J. Meloy
Senior Vice President,
Chief Financial Officer and Treasurer

Targa Resources Corp.

By: /s/ Matthew J. Meloy
Matthew J. Meloy
Senior Vice President,
Chief Financial Officer and Treasurer

Enclosures

cc: Andrew Blume, Securities and Exchange Commission
David P. Oelman, Vinson & Elkins L.L.P.
Christopher S. Collins, Vinson & Elkins L.L.P.