ANDREWS KURTH LLP
ATTORNEYS

600 Travis, Suite 4200
Houston, Texas 77002
713.220.4200 Phone
713.220.4285 Fax
andrewskurth.com

June 3, 2016

Via EDGAR

United States Securities and Exchange Commission
Division of Corporation Finance
100 F. Street
Washington, D.C. 20549
Attn: Mara L. Ransom, Assistant Director, Office of Consumer Products

Re: Enterprise Products Partners L.P.
Registration Statement on Form S-3
Filed April 22, 2016
File No. 333-210869
Form 10-K for the Year Ended December 31, 2015
Filed February 26, 2016
File No. 001-14323

Dear Ms. Ransom:

Set forth below are the responses of Enterprise Products Partners L.P., a Delaware limited partnership ("***Enterprise***," "***EPD***," "***we***," "***us***," "***our***" or "***partnership***"), to the comments received from the staff of the Division of Corporation Finance (the "***Staff***") of the U.S. Securities and Exchange Commission (the "***Commission***") by letter dated May 18, 2016, with respect to Enterprise's Registration Statement on Form S-3 filed on April 22, 2016 (the "***Form S-3***") and Form 10-K for the year ended December 31, 2015 filed on February 26, 2016 (the "***Form 10-K***"). Each response below has been prepared and is being provided by Enterprise, which has authorized Andrews Kurth LLP to respond to the Staff's comments on its behalf.

Registration Statement on Form S-3
General

1. At this time, a review is open for your annual report on Form 10-K for the fiscal year ended December 31, 2015. We will coordinate any request for acceleration of effectiveness for this registration statement with resolution of all comments regarding the Form 10-K review. Please confirm your understanding in this regard.

Response:

We hereby confirm our understanding that (i) at this time a review is open for our annual report on Form 10-K for the fiscal year ended December 31, 2015, and (ii) you will coordinate any request for acceleration of effectiveness for the registration statement on Form S-3 with resolution of all comments regarding the Form 10-K review.

Where you can find more information, page 36

2. Since the filing date of this registration statement, we note that you have filed certain Exchange Act reports. Please update this section to include the appropriate reports. Further, should you wish to incorporate by reference other Exchange Act reports filed during the period prior to the effectiveness of this registration statement, please also revise your disclosure in this section to state that any applicable filings made after the date of the initial registration statement and prior to effectiveness of this registration statement will be deemed incorporated by reference. See Compliance and Disclosure Interpretations – Securities Act Forms Question 123.05, which is available on our website.

Response:

We acknowledge the Staff's comments and confirm that we will (i) update the "Where You Can Find More Information" section of the registration statement to include the appropriate Exchange Act reports filed with the Commission since the filing date of the initial registration statement and (ii) revise the disclosure in such section to state that any applicable filings made after the date of the initial registration statement and prior to effectiveness of the registration statement will be deemed incorporated by reference.

Form 10-K for Fiscal Year Ended December 31, 2015
Management's Discussion and Analysis of Financial Condition and Results of Operations.
Results of Operations, page 72

3. Based on the table on page F-44, it appears that there was a significant increase from 2014 to 2015 in the gross margin on your product sales. Please explain to us in detail, and disclose in summary, the reason(s) for fluctuations in gross margin on product sales. To the extent material to an understanding of your segment results, please also provide such disclosures, including quantification of gross margins on product sales, on a segmental basis.

Response:

We provide midstream energy services across our integrated asset network. As stated on page 3 of our Form 10-K, our marketing activities (or groups) perform a supporting role to increase the utilization and expansion of our assets by increasing the volumes handled by such assets. In performing these support roles, our marketing groups also seek to participate in supply and demand opportunities provided by the marketplace.

In general, our marketing groups purchase energy commodities (e.g., natural gas liquids or "NGLs", crude oil and natural gas) based on index prices less a discount for location, quality, etc. The discount is a negotiated fixed dollar amount per unit of volume that is based on the costs our marketing activities incur to transport such energy commodities from the purchase location to a market hub (e.g., Mont Belvieu, Texas for NGLs and Houston, Texas for crude oil) for further processing or storage. In turn, our marketing groups sell the energy commodities based on index prices plus, if applicable, a premium. Sales prices typically include a premium when we sell energy commodities at locations other than market hubs. The premium is a negotiated fixed dollar amount per unit of volume that is generally determined based on the costs our marketing groups incur to deliver such energy commodities to the point of sale (e.g., the fees paid to our marine terminals or similar marine facilities owned by third parties).

In order to fulfill their obligations under purchase and sales contracts, our marketing groups enter into both intersegment and intrasegment transactions with our assets. These transactions result in additional fee-based earnings for the assets in each of our business segments. For example, our NGL marketing group takes title to mixed NGLs at our natural gas processing plants in the Permian Basin. NGL marketing then transports the mixed NGLs on our Seminole Pipeline to our Mont Belvieu complex for NGL fractionation and storage before selling the purity NGL products to third parties. In this example, our NGL marketing group purchases mixed NGLs from our natural gas plants and pays intercompany fees to our pipeline transportation, NGL fractionation and storage assets. When reviewing business segment results, our marketing activities generate incremental earnings for us to the extent that sales prices exceed the sum of the costs, which include intercompany fees paid by the marketing groups to our assets.

Due to the interrelated nature of our assets and marketing activities, management assesses segment performance before the elimination of intercompany transactions using the non-GAAP financial measure of gross operating margin. Assessing marketing results before intercompany eliminations allows us to quantify the incremental earnings generated by the underlying marketing activities on the sales of product to customers. For these reasons, management believes that gross operating margin is the most appropriate performance measure (as opposed to consolidated gross margin) for our operations.

In our Management's Discussion and Analysis, we discuss year-to-year changes in gross operating margin from our marketing activities to the extent such changes are material to an understanding of our segment results. This detailed discussion is included in the "Business Segment Highlights" section beginning on page 79 of our Form 10-K. In order to provide additional information regarding the results of our marketing activities, we propose to add the following types of disclosures to our discussion of gross operating margin in future filings (where such information is considered material). The following is an excerpt from our Form 10-K with the type of disclosure we propose to add (added disclosure is underlined):

"*Comparison of 2015 with 2014*

Gross operating margin from natural gas processing and related NGL marketing activities for 2015 decreased $267.0 million when compared to 2014. Gross operating margin from our natural gas processing plants decreased $243.0 million year-to-year primarily due to lower processing margins. In addition, gross operating margin from our NGL marketing activities for 2015 decreased a net $24.0 million when compared to 2014 primarily due to lower sales margins, which accounted for a $167.4 million decrease, partially offset by a $152.0 million increase due to higher sales volumes. <u>Gross operating margin from our sale of LPGs into export markets decreased $25.1 million year-to-year.</u> During 2015, a higher percentage of volume in the LPG export business was associated with long-term, fee-based marketing contracts rather than spot business, which is typically contracted at higher margins and was prevalent in 2014. <u>Gross operating margin from the remainder of our NGL marketing spot and term contract transactions decreased $50.9 million year-to-year primarily due to lower sales margins. Lastly, gross operating margin from NGL marketing increased a net $52.0 million year-to-year attributable to margins on forward contracts and associated commodity derivative contracts."</u>

We acknowledge the Staff's comment that our consolidated gross margin on product sales increased from 2014 to 2015. However, for the reasons noted above, gross margin is not a measure we use to manage our business, analyze consolidated financial results or assess segment performance. Since gross margin is calculated based on our consolidated revenues and cost of sales (i.e., after the elimination of intercompany transactions), we do not believe gross margin is an appropriate measure of asset performance or incremental earnings from our marketing activities.

<u>Gross operating margin, page 102</u>

4. Please explain how "make-up rights" operate and whether inclusion of such amounts in your non-GAAP measure is limited to only new pipeline projects. If such revenue required by GAAP to be deferred but included in your non-GAAP measure contains other types of non-refundable fees on existing pipelines, please explain. To the extent helpful to an understanding of such rights, please provide an example of the

provisions of a standard “make-up right” included in your transportation contracts. Please also consider using plain English in describing the difference between the two “make-up rights” line items included in your reconciliation.

<u>Response:</u>

The deferred revenue amounts attributable to “make-up rights” included in our non-GAAP gross operating margin are limited to those recent major liquids pipeline projects described in the table on page 103 of our Form 10-K.

Pipeline transportation revenue is typically recognized when volumes have been transported and delivered; however, under certain of our transportation agreements (e.g., those associated with committed shippers on our Texas Express Pipeline, Front Range Pipeline, ATEX, Aegis Ethane Pipeline and Seaway Pipeline), customers are required to ship a minimum volume over an agreed-upon period, with make-up rights. Under agreements with make-up rights, the customer typically pays for transportation services using a tiered arrangement as follows:

- For volumes shipped up to their minimum volume commitment to the pipeline, a contractually fixed, non-refundable dollar amount. This amount is paid to the pipeline regardless of whether the customer ships the minimum volume or not. To the extent that a customer is not able to ship its full minimum volume commitment, the customer is allowed to “make up” the deficient volume (i.e., the excess of minimum volume commitment for that period over the actual volume shipped) over an agreed-upon period (typically a one-year contractual period).
- For volumes shipped in excess of a minimum volume commitment, and not associated with the make-up of deficient volumes for prior periods, a contractual excess volume transportation fee.

We also reference the summaries of shipper “make-up” rights for NGL pipelines set forth on page 7 of our Form 10-K and for crude oil pipelines set forth on page 15 of our Form 10-K, as well as on pages 102-103 of our Form 10-K.

With respect to agreements with make-up rights, we initially recognize as revenue only that portion of the fees collected that are attributable to actual volumes transported and delivered. The remaining portion of the fees paid by the shipper (i.e., attributable to the deficient volume that can be “made up” in future periods) is initially deferred and subsequently recognized at the earlier of when (i) the deficiency volume, or make-up volume, is shipped, (ii) the shipper’s ability to meet the minimum volume commitment has expired (typically a one-year contractual period), or (iii) the pipeline is otherwise released from its transportation service performance obligation.

We believe adjusting our non-GAAP gross operating margin measure for the receipt of these deferred revenues and subsequently adjusting the measure upon recognizing the related revenues is appropriate since under the terms of these contracts, we receive non-refundable payments from these customers. Once any make-up rights are extinguished regarding these payments, the amounts are recognized in revenue and we adjust our gross operating margin to reduce those recognized amounts.

We note your comment regarding the descriptions used in the reconciliation table for the make-up rights adjustments. In order to clarify our intention, we propose changing these adjustments in future filings to read “Subtract non-refundable payments attributable to shipper make-up rights on new pipeline projects reflected in gross operating margin” and “Add subsequent revenue recognition of deferred revenues attributable to make-up rights not reflected in gross operating margin.” We believe these subtle edits will allow readers to interpret our intentions in making these adjustments in reconciling our gross operating margin to operating income.

Notes to Consolidated Financial Statements
Note 2. Summary of Significant Accounting Policies
Allowance for Doubtful Accounts, page F-9

5. We note your disclosures on pages 44 and 91 that “adverse economic conditions in [your] industry, such as those experienced throughout 2015 and that [you] continue to experience at the beginning of 2016, increase the risk of nonpayment and nonperformance by customers, particularly customers that have sub-investment grade credit ratings or small-scale companies.” You also indicate that approximately 4.5% of your consolidated revenues were associated with 22 independent oil and gas producers with sub-investment grade credit ratings. Given these circumstances, please tell us why your allowance for doubtful accounts and amounts charged to bad debt expense for 2015 declined from the prior year. Tell us if you have any material accounts receivable balances from customers with sub-investment grade credit ratings, customers currently in bankruptcy, and/or, as noted on page 68, any of the 120 energy companies Moody’s placed on review for a possible downgrade in January 2016. If so, please tell us how any of the factors cited impacted your determination of the allowance for doubtful accounts.

Response:

The table of activity for our allowance for doubtful accounts on page F-9 of our Form 10-K shows that we charged $0.8 million to expense in 2015 compared to $8.4 million in 2014. Our allowance for doubtful accounts was $12.1 million at December 31, 2015 and $13.9 million at December 31, 2014.

Our allowance for doubtful accounts is determined based on two components: (i) specific identification of accounts that we have reason to believe will not be collected (i.e., by reviewing accounts receivable aging or upon learning of significant customer credit risks); and (ii) a calculation based on the rolling average receivable balance and a risk factor based on the credit ratings of our top 30 customers, which represents approximately 70% of our total revenues. The risk factor increased 11.6% from 2014 to 2015. However, the overall allowance for doubtful accounts balance declined year-to-year due to a significant decrease in the overall receivable balance driven by lower commodity prices in 2015 as compared to 2014.

Although our allowance for doubtful accounts decreased year-to-year on an absolute basis, our allowance for doubtful accounts actually increased when viewed as a percentage of total revenues and total accounts receivable. The total allowance for doubtful accounts as a percentage of our consolidated revenues was 0.045% in 2015 and 0.029% in 2014. The total allowance for doubtful accounts as a percentage of consolidated accounts receivable was 0.471% in 2015 and 0.364% in 2014. Revenues decreased by 43.6% from 2014 to 2015, while our accounts receivable and allowance accounts decreased 32.8% and 12.9%, respectively, year-to-year.

We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures, and for certain transactions may utilize letters of credit, prepayments, net out agreements and guarantees. See our credit risk disclosure on page F-71 of the Form 10-K. After considering our credit risks and information known at the time, we determined our allowance for doubtful accounts balance was appropriate.

At both December 31, 2015 and at the time of filing of the Form 10-K, we had no material accounts receivable balances from customers with sub-investment grade credit ratings or customers currently in bankruptcy. While Moody’s placed 120 energy companies on review for a possible downgrade in January

2016, the outstanding accounts receivable balance that was considered uncollectible by us from all customers at December 31, 2015 was immaterial. During the first quarter of 2016, we had no material write-offs of uncollected balances, and we collected substantially all of the December 31, 2015 balances due to us. A review of our accounts receivable balances as of March 31, 2016 indicated that amounts outstanding greater than 90 days were immaterial.

Note 3. Revenue Recognition, page F-16

6. We note your disclosures on pages F-17 and -18 that certain NGL and crude oil pipeline transportation agreements have minimum volume requirements. We further note from page 69 that you expect certain of your assets in the Eagle Ford, Rockies and Haynesville areas to be impacted by lower volumes in 2016. Please tell us whether you have renegotiated or are in the process of renegotiating the fees or minimum volume commitments for any material contracts as a result of recent production declines and projections and their resulting impact on your customers' liquidity. If so, please revise MD&A to discuss and quantify the related impact of such trend on your results of operations. Please also quantify the amount of minimum volume contracts that expire over the next 12 months, to the extent material, in future quarterly and annual reports.

Response:

We have renegotiated contracts with certain customers where the agreements include minimum volume commitments. These renegotiated contracts are not "material contracts," as that term is defined in Item 601(b)(10) of Regulation S-K. Furthermore, the renegotiated contracts are immaterial to our overall results of operations, financial position and liquidity, and as such, we do not believe a revision to MD&A is necessary as the impact of such a trend is immaterial.

We acknowledge your comment regarding quantifying the amount of minimum volume commitment contracts that expire over the next 12 months and have determined that there are no material minimum volume contracts that are set to expire within this time frame. We will continue to evaluate any future minimum volume contract expirations that are material to our financial statements and will add disclosures detailing any such expirations in our future quarterly and annual reports, as applicable.

7. We note your disclosures on pages F-17, -18, and -19 that reservation fees related to NGL, crude oil, and refined products storage agreements are "recognized ratably" over the respective storage periods. Please explain to us and clarify in future filings how ratable recognition of such reservation fees is accomplished. If similar, please compare ratable recognition to straight-line recognition or some other analogous method. An example of how storage fees contracts are structured and recognized in revenue may be helpful to an understanding of your method.

Response:

When using the phrase "recognized ratably," we mean a straight-line revenue recognition approach over the term of the applicable storage agreement. In future filings, we will use the term "straight-line" when describing our revenue recognition policy for such agreements.

Note 6. Investments in Unconsolidated Affiliates, page F-23

8. Please tell us how the decline in crude oil prices and related drilling activity has impacted your evaluation of impairment in investments in Crude Oil Pipelines and Services, specifically your Seaway and Eagle Ford crude oil pipeline investments.

Response:

As discussed in our response to Comment #10, we view the overall decline in energy commodity prices and drilling activity as temporary events. In fact, as stated on page 69 of the Form 10-K, we believe that crude oil supply and demand fundamentals will likely begin to balance by the end of 2016. The International Energy Agency ("IEA") currently forecasts the same trend. The expectation of global crude oil supply and demand balancing during 2016 is further supported by recent news from the industry and an approximately 75% increase in crude oil prices between the lows experienced in February 2016 and current market prices.

We believe that the future expected earnings of Seaway Crude Pipeline Company LLC ("Seaway") and Eagle Ford Pipeline LLC ("Eagle Ford") fully support the carrying amount of these investments. The assets owned by both Seaway and Eagle Ford are supported by long-term, fee-based contracts with minimum volume commitments, which help to insulate both investees from temporary periods of energy price fluctuations and declines in drilling activity. The remaining terms of these contracts range from one year to 18 years. Furthermore, the Seaway and Eagle Ford pipelines are connected to upstream crude oil pipelines that are owned by our joint venture partners in each investee. These upstream pipelines continue to provide significant throughput volumes for Seaway and Eagle Ford.

We have the intent and ability to hold our investments in Seaway and Eagle Ford during periods of temporary market fluctuations, and our long-term outlook for these investments remains very positive. The assets owned by Seaway connect the Cushing, Oklahoma crude oil market hub with refineries and marine terminals along the Texas Gulf Coast, including two marine terminals owned by Seaway. The assets owned by Eagle Ford transport crude oil produced from the Eagle Ford Shale and Permian Basin to refineries and marine terminals along the Texas Gulf Coast, including a marine terminal owned by Eagle Ford. As crude oil supply and demand fundamentals begin to balance resulting in increased drilling activity, we believe Seaway and Eagle Ford are poised to take advantage of expected increases in domestically produced crude oil. Also, we believe that the U.S. government's action in December 2015 to completely lift its ban on exporting domestically produced crude oil should have a beneficial impact on the crude oil pipelines and marine terminals owned by Seaway and Eagle Ford.

Note 7. Intangible Assets and Goodwill, page F-27

9. We note your disclosure on page F-29 that you used a 15% discount rate to value the discounted cash flows related to EFS Midstream customer relationships and used a 6.5% discount rate related to acquired Oiltanking customer relationships. Please tell us in sufficient detail how you determined these discount rates and clarify why the EFS Midstream rate is more than double that of Oiltanking. In this regard, please provide a detailed description of how you develop the input assumptions for each fair value model and the reason(s) for differences in the discount rates.

Response:

The discount rates selected were determined in relation to the overall weighted-average cost of capital ("WACC") analysis we performed for EFS Midstream LLC ("EFS Midstream") and Oiltanking Partners, L.P. ("Oiltanking").

The WACC we estimated for each of EFS Midstream and Oiltanking is representative of a market participant's required return for investing in the overall business of each entity. Inputs used in our estimates were based on data obtained from market research and an analysis of peer group companies as of the respective acquisition dates. The input assumptions for our WACC estimates, and adjustments to reconcile to the discount rates we selected for acquired customer relationships, are summarized in the following table:

	EFS Midstream As of July 2015		Oiltanking As of October 2014	
Cost of equity:				
Risk-free rate of return	2.9%		2.9%	
Product of beta multiplied by equity market risk premium	4.8%		4.0%	
Company specific risk premium	7.0%		—	
Company size risk premium	3.7%		—	
Cost of equity	18.4%		6.9%	
Weight applied to cost of equity	65.0%	12.0%	75.0%	5.2%
Cost of debt	5.3%		4.7%	
Weight applied to cost of debt	35.0%	1.9%	25.0%	1.2%
Weighted average cost of capital, rounded		14.0%		6.5%
Adjustments		1.0%		—
Selected discount rate for customer relationships		15.0%		6.5%

The primary difference in our WACC estimates for EFS Midstream and Oiltanking is the risk premium that market participants would apply to EFS Midstream's cost of equity, which is based on the higher perceived risk of its operations.

EFS Midstream provides condensate gathering and processing services as well as gathering, treating and compression services for associated natural gas. The operations of EFS Midstream are confined to a single geographic region, and volumes handled by EFS Midstream are produced from a single supply basin (i.e., a specific region of the Eagle Ford Shale). Further, a majority of EFS Midstream's revenues are earned from two customers, both of which have a focus on crude oil and natural gas exploration and production activities. These factors represent company specific risks that market participants would consider before investing in EFS Midstream.

In contrast, the operations of and services provided by Oiltanking are much more diverse and established. In October 2014, Oiltanking owned marine terminals located on the Houston Ship Channel and at the Port of Beaumont that have been in continuous operation for several decades. Unlike EFS Midstream's focus on serving upstream producers, Oiltanking's services are geared to downstream customers and include the loading and unloading of marine vessels and product storage and distribution. Oiltanking's marine terminals handle a wide variety of commodities including crude oil, crude oil derivatives such as naphtha, refined petroleum products, natural gas liquids, octane additives and certain petrochemicals. Oiltanking serves a diverse customer base including major integrated oil companies, petrochemical companies, midstream energy companies and refiners. When compared to EFS Midstream, all of these factors translate into a lower risk profile for a potential investor in Oiltanking. In consideration of these factors, a company specific risk premium was deemed unnecessary.

In July 2015, EFS Midstream was a privately-held entity that we purchased for approximately $2.1 billion. In October 2014, Oiltanking was a well-known, publicly traded partnership with a fair value of approximately $6.0 billion. Accordingly, a company size risk premium was applied to estimate EFS Midstream's cost of capital; whereas, a similar risk premium was not applied for Oiltanking.

Several tests were performed as part of our overall valuation analyses for EFS Midstream and Oiltanking to ensure that the assumptions used were reasonable (both individually and in the aggregate) and that the resulting fair value estimates were reasonable. The most common test to ensure the reasonableness of discount rates selected to estimate fair value of individual assets is a comparison of the estimated WACC and the estimated weighted-average return on assets ("WARA"). The WACC is a computation based on rates of return for debt and equity. In contrast, the WARA computation is based on estimated required rates of return for individual assets (e.g., working capital, property, plant and equipment, intangible assets and goodwill), which are weighted by the assets' respective fair values. Based on the fundamental accounting equation that assets must equal liabilities plus equity, it follows that the estimated WARA should approximate the WACC. Based on our analyses for EFS Midstream and Oiltanking, we confirmed that the WARA calculated for each entity was equivalent to the WACC we estimated for each entity.

It is also common practice to calculate the implied internal rate of return ("IRR") for a transaction, which is compared to the WACC as a test for reasonableness. The IRR is a discount rate that equates (i) the present value of forecasted cash flows that an acquiring entity expects to receive as a result of the transaction with (ii) the purchase price paid by the acquiring entity to gain access to and control of the forecasted cash flows. We calculated the implied IRR in our analyses for EFS Midstream and Oiltanking and compared these IRRs to our WACC estimates for both EFS Midstream and Oiltanking. In both cases, we concluded that our WACC estimates were reasonable in light of the IRR computations.

Note 14. Derivative Instruments, Hedging Activities and Fair Value Measurements, page F-53

10. We note your disclosure on page F-60 that you recorded asset impairments during fiscal 2015 primarily in connection with the sale of your Offshore Business and the abandonment of certain natural gas and crude oil pipeline assets in Texas. Please address the following comments related to your long-lived asset impairments:

- We note your disclosure on page 98 that circumstances indicating the carrying amount of long-lived assets may not be recoverable could include production declines or long-term decreases in the demand or price of commodities. Considering the declines in commodity prices and drilling activity discussed on pages 68-69, tell us why your fiscal 2015 impairments appear to be primarily limited to assets sold and abandoned as opposed to assets held and used. If you tested other long-lived assets for impairment but the estimated cash flows from such assets exceeded the carrying amount, please summarize the results.
- We note your disclosure on page 69 regarding certain operating regions where you may see 2016 crude oil and condensate production declines of 10-20% and natural gas production declines of 5-15%. To the extent not covered in the preceding bullet point, please tell us how such forecasts were factored into whether an impairment assessment was necessary for such assets.

Response to bullets 1 and 2:

Based on our reviews and analysis during 2015 of material assets to be held and used, none were deemed impaired. Long-lived assets, which include property, plant and equipment and intangible assets with finite useful lives generally ranging from 20 to 40 years, are reviewed for impairment whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of undiscounted estimated cash flows expected to result from the use and eventual disposition of the asset. As discussed in more detail below, three of our asset groups to be held and used were tested for impairment during 2015, and we concluded that their undiscounted estimated cash flows exceeded their respective carrying amounts.

Based on our analysis, we determined that impairment tests for the remainder of our long-lived assets to be held and used were not required. On a quarterly basis, we review our long-lived assets to identify events or changes in circumstances that could potentially impact recoverability of the underlying carrying values. When such events or changes are identified, we review all relevant information before concluding that the asset's carrying amount may not be recoverable. The factors we consider may include, but are not limited to, the following:

- The estimated duration of an adverse event or change in circumstances (i.e., short-term versus long-term) relative to the asset's remaining useful life;
- Changes in hydrocarbon reserve estimates that impact long-term throughput volumes on the affected assets and production forecasts (i.e. the timing of crude oil and natural gas production volumes) that are influenced by energy commodity prices;
- The expiration of any material contractual terms (particularly those associated with minimum volume commitments or minimum cash payments), contract renegotiations that have a material adverse effect on future cash flows, and a change in our expectations regarding contract renewals;
- An analysis of payback periods relative to an asset's remaining useful life. Payback period represents a quotient where an asset's carrying amount (i.e., the numerator) is divided by an annual cash flow amount (i.e., the denominator). We may consider both actual and budgeted cash flows in our analysis. As a sensitivity analysis, we may reduce the annual cash flow amount to consider customer-specific credit risk (i.e., customers that have sub-investment grade credit ratings), the renegotiation or non-renewal of contracts, or other known events;
- A comparison of year-over-year cash flows and throughput volumes (both actual and budgeted amounts) to assess the impact of changing economic conditions; and
- Material changes in the use or physical condition of our long-lived assets (e.g., obsolescence).

On page 98 of our Form 10-K, we provide two examples of events or changes in circumstances that may impact our long-term cash flows: (i) production declines that are not replaced by new discoveries; and (ii) long-term decreases in the demand or price of natural gas, NGLs, crude oil, petrochemicals or refined products. A production decline that is not replaced by new discoveries represents the depletion of a crude oil or natural gas resource base. We believe that each of the major supply basins connected to our long-lived assets have sufficient crude oil and/or natural gas reserves to support long-term throughput volumes on our material assets for at least their remaining useful lives.

Our expectations regarding short-term and long-term changes in the demand or price of energy commodities are discussed on pages 68-71 of our Form 10-K. As noted, the global supply of hydrocarbons began to exceed demand in 2014, which resulted in a dramatic decline in energy commodity prices from 2014 to 2015. In response to the lower energy commodity prices, domestic producers began to reduce their drilling activity in 2015. Many producers have announced that additional reductions in drilling activity will occur in 2016, and most forecasters predict that production of crude oil and natural gas in the U.S. could decline in the range of 5% to 10% during 2016. However, certain supply basins may experience production declines that exceed the forecasted range.

In contrast to the negative impacts on upstream energy producers, we also discuss how lower energy commodity prices are contributing to an increase in energy demand by individual consumers and energy intensive industries (e.g., steel manufacturing and petrochemicals). We believe that an increase in demand for crude oil, natural gas and NGLs from these types of industries, along with other positive consumer-driven demand responses to lower prices, will balance crude oil supply and demand fundamentals by the end of 2016. Furthermore, we believe that as U.S. supply and demand for natural gas and certain NGLs becomes more balanced over the next few years through exports and incremental demand from new or expanded ethylene facilities that the prices of these energy commodities will stabilize and increase.

Given our expectations for the next few years, we view the current decline in energy commodity prices and drilling activity as temporary events that do not impact the recoverability of our material assets. In relation to the useful lives of our assets (i.e., which generally range from 20 to 40 years), we believe that these temporary events do not impact our assets' ability to generate sufficient undiscounted cash flows that will recover the underlying carrying values. Further, we do not believe that these temporary events will have a material impact on the long-term development of the underlying crude oil and natural gas resource bases that will support our assets' ability to generate cash flows for the remainder of their useful lives. Lastly, we believe that our long-term contracts serve to insulate our material assets from this period of temporary declines in energy commodity prices and drilling activity.

The majority of our long-lived assets generate fee-based revenues that are not directly impacted by fluctuations in energy commodity prices. These assets are supported by long-term contracts that may provide for minimum cash payments (e.g., demand and reservation fees paid regardless of whether or not the customer uses our services, or deficiency fees paid if a customer does not meet a contractual specified volume commitment) or the dedication of volumes produced within certain geographical boundaries (i.e., acreage dedications). For example, substantially all of the midstream energy assets we constructed in recent years were done so after our customers committed to long-term contracts with minimum cash payments.

- Please quantify for us the long-lived assets associated with each of your supply basins and/or regions as well as the long-lived assets within each region that you tested for impairment during fiscal 2015. Explain to us in sufficient detail how you determined such tested assets were not impaired. For material asset groups tested for impairment, tell us the significant estimates and assumptions used in your tests and how such estimates and assumptions were determined. Quantify for us the long-lived assets considered at risk of impairment at the end of fiscal 2015.

Response:

The following table presents the carrying amounts of our long-lived assets at December 31, 2015 by region as well as the long-lived assets to be held and used within each region that we tested for impairment during fiscal 2015 (dollars in millions):

	Total	Tested for Impairment
Assets that derive economic benefit from a single supply basin summarized by region:		
Rocky Mountains	$ 3,659.4	$ —
South Eastern New Mexico / West Texas	1,004.9	—
Southern Oklahoma / North & South Texas	2,575.4	—
East Texas / North Louisiana	1,849.0	1,662.1
Southern Louisiana / Mississippi / Alabama	380.8	—
Assets that derive economic benefit from multiple supply basins	26,602.4	—
Total long-lived assets	$36,071.9	$ 1,662.1

We tested our Haynesville Gathering System and our Fairplay Gathering System for impairment during 2015. A third asset group to be held and used was also tested; however, it is immaterial to our consolidated financial position and results of operations. Undiscounted estimated cash flows were forecasted for each of these asset groups, which we then compared to the respective asset carrying amounts. The sum of the undiscounted estimated cash flows forecasted for our Haynesville and Fairplay Gathering Systems exceeded the asset carrying amounts by more than 100% and approximately 70%, respectively. Based on our analysis of undiscounted estimated cash flows and comparisons to asset carrying amounts, we concluded that the carrying values of these asset groups are recoverable.

The significant estimates and assumptions used to forecast undiscounted estimated cash flows in our impairment tests for the Haynesville and Fairplay Gathering Systems are primarily our natural gas gathering volume forecasts and the gathering fees applied to forecasted volumes. Management prepares long-term volume forecasts for multiple purposes including analyzing potential capital investments, acquisitions, divestitures and impairment testing. The Haynesville and Fairplay Gathering Systems are both supported by long-term, fee-based contracts, some of which include minimum cash payments. As such, the gathering fees applied to forecasted volumes for our impairment tests reflected the terms of existing contracts. Beyond the terms of existing contracts, we also consider current market-based fees and our expectations for contract renewals when estimating natural gas gathering fees.

We employ a team of geologists and engineers (i.e., our Supply Appraisal group) whose primary responsibilities are estimating the crude oil and natural gas resource bases of U.S. supply basins and forecasting the hydrocarbon production that will supply throughput volumes for our assets. These individuals have decades of experience forecasting hydrocarbon supplies in the U.S., hold industry certifications (e.g., Certified Petroleum Geologist) and contribute to industry organizations that publish hydrocarbon-related estimates. Our Supply Appraisal group routinely reviews publicly available information (e.g., data published by the Energy Information Association, information disclosed by crude oil and natural gas producers, etc.) and producer forecasts provided to us under confidentiality agreements. The experience and knowledge held by our Supply Appraisal group makes them uniquely qualified to prepare long-term volume forecasts for our impairment tests.

Based on our quarterly reviews to identify events or changes in circumstances that could potentially impact recoverability of our asset carrying values and the results of our impairment testing completed during 2015, we concluded that none of our material long-lived assets were considered at risk of impairment at December 31, 2015.

- Although your disclosures on page 69 indicate that the Barnett, Fayetteville, and Haynesville regions may experience natural gas production declines in 2016, your disclosures on page 71 indicate that such regions “could experience an increase in drilling activity to maintain, and potentially increase, their future production levels.” Please revise your disclosures to clarify any perceived inconsistencies between these statements.

Response:

We note the Staff’s comment; however, we believe that when both statements are read in context, there are no inconsistencies. The statement on page 69 of our Form 10-K discusses circumstances that are specific to fiscal 2016. Whereas, the statement on page 71 of our Form 10-K discusses events and circumstances that we believe will occur over the next few years.

In response to the foregoing Staff comments, Enterprise acknowledges that:

- the partnership is responsible for the adequacy and accuracy of the disclosure in the filing;
- Staff comments or changes to disclosure in response to Staff comments do not foreclose the Commission from taking any action with respect to the filing; and
- the partnership 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.

If you have questions regarding the foregoing responses, you may contact Michael J. Knesek at (713) 381-6545 (for accounting matters) or Christopher S. Wade, Esq. at (713) 381-4847, or the undersigned at (713) 220-4301.

Sincerely,

/s/ David C. Buck

David C. Buck

cc: A. James Teague, Enterprise Products Partners L.P.
W. Randall Fowler, Enterprise Products Partners L.P.
Bryan F. Bulawa, Enterprise Products Partners L.P.
Michael J. Knesek, Enterprise Products Partners L.P.
Harry Paul “Hap” Weitzel, Esq., Enterprise Products Partners L.P.
Christopher S. Wade, Esq., Enterprise Products Partners L.P.
Kevin Siblik, Deloitte & Touche LLP