CORRESP 1 filename1.htm

VIA EDGAR FILING

October 7, 2015

Ethan Horowitz
Branch Chief
Office of Natural Resources
Division of Corporation Finance
Securities and Exchange Commission

Re: Energen Corporation
Form 10-K for Fiscal Year Ended December 31, 2014
Filed March 2, 2015
Form 10-Q for Fiscal Quarter Ended June 30, 2015
Filed August 7, 2015
Form 8-K filed August 7, 2015
File No. 1-07810
Comment Letter Dated September 3, 2015

Dear Mr. Horowitz:

Energen Corporation has received your letter dated September 3, 2015, to our Chief Financial Officer and Treasurer, Charles W. Porter, Jr. We have reviewed your comments and submit the following responses for your consideration:

Form 10-K for Fiscal Year Ended December 31, 2014

Properties, page 19

1. You have identified changes in your development plans as the primary cause of revisions to your proved undeveloped reserves ("PUDs") during the fiscal year ended December 31, 2014. Please describe the circumstances that led to the change in your development plans. As part of your response, tell us the years in which these PUDs were initially booked.

Our net downward revisions of approximately 75.7 MMBoe to total proved reserves included downward revisions of approximately 53.4 MMBoe of proved undeveloped reserves expected to be drilled after the five year period. The 53.4 MMBoe of revisions relate to 382 vertical PUD locations. These vertical PUD locations were initially booked between 2009 and 2013. As a result of a number of factors associated with horizontal drilling that occurred primarily in 2014 including improved technical expertise, increased expectations on rates of return and lower capital costs, we changed our development plans to drilling horizontal wells as the primary method of developing our undeveloped leasehold. Accordingly, the timing of drilling the 382 vertical PUD locations shifted to beyond the five year period, and we reflected these changes in our proved undeveloped reserves.

2. Disclosure on page 22 of your Form 10-K states that approximately 43% of your proved undeveloped reserves ("PUDs") are located on leased acreage which is not held by production and will be developed after the primary term of the leases. Please describe the continuous development provisions related to these leases and tell us when these PUDs will be drilled. As part of your response, explain how you concluded that these PUDs should be classified as proved reserves pursuant to Rule 4-10(22) of Regulation S-X which requires that production occur prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain.

The continuous development provisions of the leases in question extend the primary terms upon the satisfaction of certain conditions. The provisions require at least one well be drilled on such leases prior to the expiration of the primary term and that subsequent wells be drilled within a time period that is specific to each lease but ranges from 60 days to 180 days. Once a lease is developed, it remains in effect as long as production is maintained from the lease. Our drilling plans provided for the development of these PUDs prior to the expiration of the initial primary term or under the extended primary term as provided for under the continuous development provisions of our lease agreements. Accordingly, we concluded that these PUDs should be classified as proved reserves.

Financial Statements

Notes to Financial Statements

Note 20 - Oil and Natural Gas Operations, page 83

Oil and Natural Gas Operations, page 83

3. During the fiscal year ended December 31, 2014, extensions and discoveries resulted in an increase of 130.0 MMBoe to your proved reserves. Please tell us how the factors that resulted in the negative revisions of 75.7 MMBoe to your proved reserve quantities during the year (e.g., product prices) were considered when these extensions and discoveries were recorded.

As discussed in question 1 related to Properties, the specific factors related to our increase in extensions and discoveries were unrelated to the negative revisions in our proved reserves. The 130.0 MMBoe increase in extensions and discoveries relates to new horizontal wells and locations that are separate and distinct from the previously disclosed vertical PUD locations. For these horizontal wells and locations, we estimated 37.9 MMBoe are proved developed reserves and 91.3 MMBoe are proved undeveloped reserves. Negative revisions of 75.7 MMBoe were largely driven by a 53.4 MMBoe negative revision associated with our decision to redeploy capital from a vertical development program to a horizontal development program during the five year period. Conditions that resulted in the remaining 22.3 MMBoe of net negative revisions included performance of certain Wolfberry wells (vertical) drilled in the early part of 2014 and higher lease operating expense in 2014. Product prices were not a significant factor related to the negative revisions.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves, page 86

4. We note that proved undeveloped reserves ("PUDs") increased from 88.0 MMBoe as of December 31, 2013 to 108.2 MMBoe as of December 31, 2014. In light of this change, tell us why future development costs used to calculate the standardized measure of discounted future cash flows decreased from $1.9 billion as of December 31, 2013 to $1.8 billion as of December 31, 2014. As part of your response, explain the extent to which you considered recent trends in capital expended to convert PUDs in determining the amount of future development costs used to calculate the standardized measure of discounted future cash flows (i.e., address the conversion cost for 2014 of approximately $20.67 per Boe compared to the future development costs used to calculate the standardized measure of discounted future cash flows of approximately $16.49 per Boe). Refer to FASB ASC 932-235-50-31.

In the standardized measure of discounted cash flows disclosed at December 31, 2014, we reflected a decrease over the prior year in the estimate of future development costs of approximately $112 million to $1.8 billion. Such future development costs are approximately $16.49 per Boe. The decrease over the prior year estimate resulted from a change in the type of wells to be drilled along with declines in drilling and completion costs. In the Midland Basin, our transition from primarily a vertical Wolfberry development program to primarily a horizontal Wolfcamp development program contributed to lower future development costs as future well costs will develop more reserves per dollar invested than the vertical wells we previously expected to drill. Related to our drilling and completion costs, we revised our future development costs in future periods to incorporate the lower service costs experienced in late 2014.

The vertical Wolfberry program represents approximately 16% of proved undeveloped reserves at year-end 2014 and has an estimated future development cost of approximately $19.94 per Boe. Our horizontal development program represents approximately 84% of proved undeveloped reserves at year-end 2014 and has an estimated future development cost of approximately $14.46 per Boe. Such program is composed of approximately 93% of lower cost, Midland Basin Wolfcamp wells. In contrast, our horizontal development program at year-end 2013 represented only 16% of proved undeveloped reserves. Of this program, approximately 48% related to the higher cost 3rd Bone Spring wells which were substantially completed in 2014 and contributed to the higher $20.67 per Boe conversion cost noted in 2014.

Specific to the conversion costs during 2014 of $20.67 per Boe, we drilled a horizontal 3rd Bone Spring program representing 45% of undeveloped reserves transferred to developed reserves with a conversion cost of $23.98 per Boe. The 3rd Bone Spring wells had a higher well cost per Boe as compared to the expected horizontal Midland Basin Wolfcamp wells. The 3rd Bone Spring program was substantially completed in 2014. In addition, we drilled and completed vertical Wolfberry wells representing 44% of our undeveloped reserves transferred to developed reserves at a conversion cost of $17.15 per Boe.

In summary, with the completion of our higher cost 3rd Bone Spring wells and the strategic shift away from a vertical program to a lower cost horizontal Midland Basin development program, we reflected lower future development costs in our standardized measure of future discounted cash flows disclosure.

Form 10-Q for Fiscal Quarter Ended June 30, 2015

Management 's Discussion and Analysis of Financial Condition and Results of Operations page 27

Results of Operations, page 30

5. We note that certain properties in the Permian Basin, primarily in the Central Basin Platform, are at risk of impairment if oil price declines subsequent to June 30, 2015 are sustained. Please revise to provide expanded disclosure addressing the following:

- **State the percentage by which the undiscounted cash flows exceeded the carrying value of your oil and gas properties;**
- **Describe how the key assumptions used to determine the undiscounted cash flows changed from December 31, 2014 to June 30, 2015;**
- **Discuss the degree of uncertainty associated with these key assumptions; and**
- **Identify potential events and/or changes in circumstances that could reasonably be expected to negatively affect these key assumptions.**

Please provide similar disclosure with regard to other oil and gas properties deemed to be at risk of impairment.

The Central Basin Platform properties at risk of impairment disclosed in our June 30, 2015 Form 10-Q had undiscounted cash flows that exceeded the carrying values by 6%. Key assumptions at 12/31/2014 and 6/30/2015 were generally consistent except as updated to reflect commodity price changes and the roll-off of production. Price assumptions for both periods used period end commodity price curves for the first 5 years and were subsequently escalated at 3% until they reached our assumed price caps. Our price assumptions are consistent with our long-term expectations and internally developed economic outlook. At 6/30/2015, gas prices had declined by 11.1% and oil prices had declined by 3.1% from year-end for comparable periods.

Our commodity price assumption is the most significant uncertainty related to the impairment calculation. Volatility associated with expected future commodity prices is significant. We included disclosures related to this assumption in our December 31, 2014 Form 10-K. Please reference the commodity price discussions in our Risk Factors (pages 12 & 16) and Quantitative and Qualitative Disclosures about Market Risk (page 36) and the asset impairment discussion in our Critical Accounting Policies (page 34). Other areas of uncertainty include expected operating costs and production performance as discussed in our Critical Accounting Policies (page 34). However, these areas are typically less volatile and generally relate to specific wells or fields. Accordingly, negative variances are more localized and less significant to the overall undiscounted cash flow assumption.

At June 30, 2015, these Central Basin Platform properties with a net book value of $171 million represented the only properties deemed at risk of impairment given current market conditions. These properties represented approximately 3% of Property, Plant and Equipment at June 30, 2015. In future filings, disclosures with respect to a property deemed at risk of impairment will also include disclosures of the percentage by which the undiscounted cash flows exceeded the carrying value.

Form 8-K filed August 7, 2015

Exhibit 99.3 - Non-GAAP Financial Measures Reconciliation

6. Your reconciliation of the non-GAAP measure "Energen Adjusted EBITDAX from Continuing Operations" indicates that certain reconciling items were adjusted to exclude the San Juan Basin divestment. However, it appears that many of these line items were not adjusted from the amounts presented as part of your financial statements. Please revise this disclosure to clearly indicate the items for which the amounts presented as part of your financial statements were adjusted.

Exhibit 99.3 is a copy of the Non-GAAP Financial Measures Reconciliation which accompanied our August 6, 2015 press release (Exhibits 99.1 and 99.2). In the second table of Exhibit 99.3 (a summary EBITDAX table), we inadvertently asterisked the “Interest expense” and “Adjustments for asset impairment” line items indicating that these two items had been adjusted to exclude the San Juan Basin divestment. In the more detailed third and fourth tables of Exhibit 99.3, however, it is clear that no San Juan Basin divestment adjustments were made to the “Interest expense” or “Adjustment for asset impairment” line items. If the second table is used in future filings, we will remove the asterisk notations on unadjusted amounts.

7. We note that you have presented an income statement showing your net loss excluding the divestment of assets held in the San Juan Basin. This appears to represent a full nonGAAP income statement. Please revise or tell us why you believe your current presentation is appropriate. Refer to Regulation G, and for additional guidance, Question 102.10 of the Compliance & Disclosure Interpretations regarding Non-GAAP Financial Measures.

As stated in our disclosure, we believe excluding information associated with the divestment of certain assets held in the San Juan Basin provides analysts and investors useful information to understand the financial performance of the Company from ongoing business operations. We acknowledge that a full Non-GAAP income statement is generally not preferable consistent with Question 102.10 of the Compliance & Disclosure Interpretations regarding Non-GAAP Financial Measures. However, this disclosure included a significant number of line items in the prior year comparable period on the income statement that were impacted by our Non-GAAP adjustments. Accordingly, in our judgement, we concluded that providing a more full disclosure in the prior year comparable would allow for increased transparency to analysts and investors.

For the current year period disclosed, we elected to provide a consistent format with the prior year.

In accordance with your instructions, the Company acknowledges that the Company is responsible for the adequacy and accuracy of the disclosure in the filing; staff comments or changes to disclosures in response to comments do not foreclose the Commission from taking any action with respect to the filing; and the Company 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.

Please call me if you need additional information or clarification.

Sincerely,

/s/ J. David Woodruff
J. David Woodruff
General Counsel and Secretary
Energen Corporation

JDW/as