14313 North May Avenue, Suite 100
Oklahoma City, OK 73134

November 7, 2014

United States Securities and Exchange Commission
The Division of Corporate Finance
100 F Street, N.E.
Washington, D.C. 20549-3561
Attn: H. Roger Schwall, Assistant Director
Mark Wojciechowski

Re: Gulfport Energy Corporation
Form 10-K for the Fiscal Year Ended December 31, 2013
Filed February 28, 2014
Form 10-Q for the Quarterly Period Ended March 31, 2014
Filed May 9, 2014
Response letter dated September 11, 2014
File No. 0-19514

Dear Messrs. Schwall and Wojciechowski:

Set forth below are the responses of Gulfport Energy Corporation, a Delaware corporation (the "***Company***"), to the comment letter of the staff (the "***Staff***") of the Securities and Exchange Commission (the "***Commission***") dated September 30, 2014 with respect to Form 10-K for the fiscal year ended December 31, 2013 filed February 28, 2014 (the "***Form 10-K***"), and with respect to Form 10-Q for the quarterly period ended March 31, 2014 filed May 9, 2014 (the "***Form 10-Q***").

For your convenience, we have set forth below each Staff comment followed by the Company's response. Caption references and page numbers refer to the captions and pages contained in the Form 10-K, unless otherwise indicated.

Form 10-K for the Fiscal Year Ended December 31, 2013

Properties, page 42

Proved Undeveloped Reserves, page 45

1. **We note your response to prior comment one from our letter dated August 13, 2014, in which you explain that your conversion rate was greater than indicated by the quantity of proved reserves transferred from undeveloped to developed status, considering that you drilled eight of 57 proved undeveloped (PUD) reserve locations**

during 2013, reflecting a conversion rate of 14%. However, you do not address your progress in 2012 nor for either period as indicated by the incremental reserves. You also explain in your response that you increased your 2014 capital expenditure budget for exploration and production to a range of $715.0 million to $767.0 million, from $513.5 million in 2013. However, you do not address the amount of development costs that have been budgeted and which you expect to incur, as would be pertinent to an assessment of your PUD reserves. Please address these points for us.

Response: At December 31, 2011, the Company had 295 booked PUD locations of which 13 were drilled during 2012. Of the remaining 282 undrilled PUDs, 245 were attributable to its non-operated Permian Basin acreage and were dropped from the Company's reserve report at December 31, 2012 because of the Company's sale of this non-operated acreage during 2012. Incremental reserves attributable to PUD locations drilled in 2012 and 2013 are set forth in the table in response to Comment 2(a) below.

As noted in the Company's response to Comment 1 in its prior letter, total capital expenditures budgeted for 2014 range from $715 million to $767 million. On page 45 of the Form 10-K, the Company has previously disclosed that $135.4 million of this budgeted range is attributable to the development of PUDs in 2014.

2. **The disclosures that you have provided in your annual reports for 2010 through 2013 indicate an average annual percentage conversion rate that is substantially less than the conversion rate implied by the five-year limitation specified in Rule 4-10(a)(31)(ii) of Regulation S-X. To help us understand your historical PUD conversion rate, please provide the following:**

   - **Submit an analysis of changes in your PUD reserves, covering the 2010 through 2013 fiscal years, including a schedule stratifying, for each year-end estimate, the quantity of such reserves initially claimed in that year and each preceding year. For each strata, show the conversions for each year, and the percentage that such conversions are of the beginning reserve strata balance. Additionally, indicate and describe the reasons for all other adjustments for each strata between years.**

Response 2(a):

Changes in PUD Reserves

Year	Reserves Attributable to PUDs at Prior Year End	PUD Reserves Converted during Year	Percent of Prior Year End Reserves Converted
2010	12,991 MBOE	718 MBOE	6%
2011	14,156 MBOE	2,502 MBOE	18%
2012	10,856 MBOE	468 MBOE	4%
2013	5,580 MBOE	2,731 MBOE	49%

For descriptions of the changes in PUDs that occurred during each of the years in the table above, including quantification by additions, conversions, revisions and exclusions, please see “Item 2 Properties—Proved Oil and Gas Reserves—Proved Undeveloped Reserves (PUDs)” in the Company’s Annual Reports on Form 10-K for the applicable year. In addition, please see the additional information contained in the text of the response to Comment 2(b) below.

- **Submit an analysis of the PUD reserve locations and related volumes that had been scheduled to be drilled in 2011 in your year-end 2010 reserve reports, and in 2012 in your year-end 2011 reserve reports, and in 2013 in your year-end 2012 reserve reports, compared to those PUD reserve locations that were actually drilled during each of these fiscal years. Indicate, and explain the reasons for, all differences between the scheduled and actual locations and volumes.**

Response 2(b):

PUD Reserve Locations and Related Volumes

	COLUMN A	COLUMN B	COLUMN C	COLUMN D
Year	No. of PUDs Scheduled for the Specified Year Based on Prior Year-End Report	Reserves Related to PUD Locations in Column A	No. of PUD Locations in Column A Actually Drilled	Reserves Related to PUD Locations in Column C
2011	73	3,809 MBOE	34	2,502 MBOE
2012	63	2,392 MBOE	13	468 MBOE
2013	42	4,591 MBOE	8	2,731 MBOE

The differences between the reserves identified in Column B and the reserves identified in Column D are attributable to the differences between the number of PUDs scheduled to be drilled in the specified year and those actually drilled in that year. There are two primary reasons why scheduled PUDs were not drilled in a given year. In the case of PUD locations scheduled to be drilled on the Company’s acreage in the Permian Basin (none of which acreage was operated by the Company), the Company booked these locations after consultation with the operator of this acreage. However, since the Company was not the operator of this acreage at any time, the Company did not, ultimately, have control over when these locations were actually drilled. As noted in its response to Comment 1 above, the Company sold all of its Permian Basin acreage in 2012. The remaining PUD locations were primarily located in the Company’s South Louisiana fields. These are extremely complex fields. At the West Cote Blanche Bay field, for example, the Company has been continually drilling and mapping the field for over 15 years. There have been over 1,000 wells drilled, over 100 stratigraphically productive intervals recognized, nearly 200 discrete intervals tested and over 3,000 faults identified. When the Company books PUD locations in these fields, it identifies the most attractive options available at that time. However, as the Company continually maps and interprets the fields in the course of its continuous drilling activities during the year, it generates many new locations based on the most current data. As the Company identifies new locations with a greater number of potential producing zones and better economics than those locations booked as PUDs, it drills the new locations instead of the booked PUD locations.

- **Submit an analysis of the development costs and PUD conversion capital reported for the 2010 through 2013 fiscal years, showing the incremental reserves arising from these expenditures, compared to your plans and expectations for future conversions.**

Response 2(c):

Development Costs and PUD Conversion Capital

Year	*Total Development Costs (in millions)*	Reserves from Extensions and Discoveries	PUD Conversion Capital (in millions)	Actual Reserves Attributable to Drilling PUDs	Anticipated Reserves Attributed to Drilled PUDs
2010	$ 64.7	6,458 MBOE	$ 12.2	654 MBOE	718 MBOE
2011	$ 123.5	4,289 MBOE	$ 41.2	701 MBOE	2,502 MBOE
2012	$ 121.8	10,091 MBOE	$ 18.0	128 MBOE	468 MBOE
2013	$ 408.1	29,215 MBOE	$ 43.5	3,150 MBOE	2,731 MBOE

3. **We note that additions to your PUD reserves in 2013 and 2012 represent 65% and 83% of the respective year-end volumes. Tell us the extent to which the additions for each year relate to locations for which reserves had been claimed in an earlier period but which were derecognized prior to reclaiming the reserves. For any such instances identify the year-end PUD reserve estimates that included these locations.**

   Response: The Company advises the Staff that none of the additions to its PUD reserves in 2012 and 2013 relate to locations that had been claimed in an earlier period but were derecognized.

4. **Your response to prior comment two indicates that 13 PUD reserve locations were dropped from your December 31, 2013 reserve reporting "...because they had not been drilled within five years of initial booking." Given the 57 PUD reserve locations that you had at the end of the preceding fiscal year, as mentioned in your response to prior comment one, it appears that you reversed investment decisions for 23% of these locations. We also note that you reported a material reduction in PUD reserves due to the five year limitation during the year ended December 31, 2010.**

Please note that undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time. See Rule 4-10(a)(31)(ii) of Regulation S-X. In this regard, the mere intent to develop, without more, does not constitute "adoption" of a development plan and therefore would not, in and of itself, justify recognition of reserves. Rather, adoption requires a final investment decision. See C&DI 131.04, which can be found at:

http//www.sec.gov/divisions/corpfin/guidance/oi1andgas-interp.htm

To help us understand your reserve booking procedures and the reasons your PUD reserve estimates and the underlying development schedules have not matched your actual development activities, please address the following points:

- **Describe the procedures that are routinely undertaken in the course of preparing your reserve estimates that are intended to ensure PUD reserves are only claimed for locations where a final investment decision has been made, and where you are able to demonstrate compliance with Rule 4-10(a)(31) of Regulation S-X. Describe those aspects and qualities of the investment decisions that are necessary in order to establish compliance with the reserve definitions.**

Response 4(a): In the course of preparing the Company's reserve estimates, the Company evaluates its annual budget dedicated to the development of its reserves, AFE approval criteria, which include analysis of the nature of the wells and well economics, including internal rates of return, and estimated payout period, anticipated drilling schedule and current production pricing terms in that field. The Company's decision process also includes analysis of its acreage position, closeness to infrastructure and lease terms and the process involved in proving up reserves in new areas or on new acreage. The Company also considers whether the wells are operated or non-operated. Finally, the Company takes into consideration new data that impacts its reserve estimates.

- **Describe the financial return criteria, including internal rates of return, underlying your decisions to claim PUD reserves for each period. Explain how these criteria compare to those which governed your subsequent decisions to not proceed with drilling according to the original drilling schedule adopted at the time you initially claimed the reserves.**

Response 4(b): When booking PUD reserves in a period, the Company considers financial criteria such as achieving returns in excess of its cost of capital and payback period, both of which are based on the commodity price outlook. Additional factors in claiming PUD reserves include the upcoming year's capital expenditure budget and estimated drilling plans. In its Louisiana properties, the Company generates many new well locations during the year based on its ongoing interpretation of recent well results. As new drilling opportunities arise, including wells the Company believes have more potential producing zones and resulting higher reserves, the Company evaluates which drilling location offers the best return opportunity and whether to substitute such new location in place of a PUD location that had already been planned.

- **Tell us the extent to which the PUD reserves disclosed as of December 31, 2013 have positive undiscounted future net revenue but negative present values when discounted at 10 percent.**

Response 4(c): In the year-end 2013 report, the Company had three Utica wells that had positive undiscounted future net revenue but negative PV-10%. The three wells had total undiscounted future net revenue of $6.65 million and a PV-10% of negative $1.62 million. At the time of the reserve report, the Utica play was less developed and had less takeaway infrastructure in place than today. The Company decided to leave these three wells in its PUD reserves because of its expectations that it will receive better pricing and higher reserves estimates than reflected in the reserve report. This was based on the commodity outlook at that time and the additional offset well reserve history and improved takeaway infrastructure expected over time. Since the Company intends to drill these three wells it believed they should remain on the reserve report.

5. **Your disclosure regarding PUD reserves on page 45 states that "Costs incurred relating to the development of PUDs were approximately $43.5 million in 2013." You have similar disclosure on pages 45 and 37 of your 2012 and 2011 annual reports, indicating conversion costs of $18.0 million and $41.2 million. However, within the table of costs incurred in oil and gas activities on page F-43, you disclose development costs of proved undeveloped properties of $408.1 million, $121.8 million, and $123.5 million for 2013, 2012, and 2011. Please provide the following**:

- **A reconciliation of these amounts which shows the nature and amount of expenditures involved the properties to which they relate, and their reserve status at the point of electing to proceed with development.**

Response 5(a): Of the total $408,121,000 development costs incurred in 2013, $324,871,000, or 80%, of the costs were spent in the development of the Utica Shale. The Company spud its first well in the Utica Shale in 2012 and had limited production during 2012 due to infrastructure delays. As a result, the Company had limited Utica Shale proved undeveloped reserves as of December 31, 2012 (six wells with booked PUDs). However, the Company focused its 2013 capital budget on the development of the Utica Shale, resulting in the majority of its 2013 costs being spent on Utica Shale wells that were not booked PUDs as of December 31, 2012. The Company drilled four of the six 2012 Utica PUDs in 2013, comprising $33.6 million of the $43.5 million disclosed on page 45 as costs incurred in the development of PUDs.

The Company is providing the Staff supplementally with Schedule A reflecting the detailed well costs that make up the "Development of proved undeveloped properties" line items on page F-43, including which were booked PUDs, as well as the costs on page 45 (and pages 45 and 37 of the 2012 and 2011 annual report). Please note that such Schedule A is being furnished to the Staff under separate cover pursuant to Rule 12b-4 of the Securities Exchange Act of 1934, as amended, and under the Freedom of Information Act and is not being filed electronically as part of this letter. The Company has reported all costs associated with its capital budget as development costs in the table on page F-43, with the exception of costs associated with wells considered exploratory.

- **Describe for us the decision making process, including any internal rate of return criteria, employed in connection with the decision to spend current year development funds on conversion of beginning-of-year PUD reserves vs. other development activities.**

Response 5(b): A key part of the Company's drilling plan is returns-driven, with a focus on identifying the higher return wells in its portfolio based on the commodity price outlook and then determining how to schedule those wells in the drilling plan. Additional factors also impact which wells are drilled and whether they are PUD reserves or other development activities. These factors impacting the decision process include proximity to infrastructure such as midstream gathering systems, lease terms and goals to hold acreage by production, proving up reserves in a new area, efficiency savings realized by drilling contiguous leases, and well results experienced by other operators in proximity of the Company's acreage. In the Louisiana properties, the highly technical nature of those conventional reservoirs lends itself to new drilling opportunities arising following data interpretation from recent drilling results. As new drilling opportunities arise, including wells the Company believes have more potential producing zones and resulting higher reserves, the Company evaluates which drilling location offers the best return opportunity and whether to substitute such new location in place of a PUD location that had already been planned.

- **If you proceeded with development without previously establishing reserves, explain why your reserve booking procedures did not reflect these decisions.**

Response 5(c): In the case of the Utica, it is a new developing play that has areas with no production history and no booked proved reserves. The Company does not book any PUDs attributable to its Utica acreage until offset wells have been drilled and tested or producing to prove up the area.

In the case of Louisiana, the Company generates many new well locations based on the most current interpretation and new data gathered since the original PUD wells were booked. The Company discovers new opportunities to drill with its ongoing study and evaluations. When it can drill a well with multiple zones (PDNPs) and better economics, it moves such locations ahead of PUDs on its drilling schedule with fewer zones.

Note 19—Supplemental Information on Oil and Gas Exploration and Production Activities (Unaudited), page F-43

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves, page F-46

6. **We have reviewed your response to prior comment seven and the ceiling test calculation provided in Appendix A of your response. Within the ceiling test calculation, you identify total net book value of oil and gas properties as of December 31, 2013 of $1,627,373,085. This amount differs from the balance reported within the table of capitalized costs on page F-43, which shows total net capitalized costs of $1,697,617,000. Please reconcile these amounts and explain any significant reconciling items, including whether you have an impairment that needs to be recorded.**

Response: The Company excluded well costs of $70,244,000 associated with the development and drilling of its new Utica Shale field for wells that did not have booked reserves as of the balance sheet date of December 31, 2013 in its December 31, 2013 ceiling test calculation. These work-in-progress costs were excluded from the ceiling test calculation in accordance with Regulation S-X, §210.4-10(c)(3)(ii)(B)and (C). There is often a delay in the completion and subsequent production of the wells in this field from the time they are drilled, resulting in significant costs with no corresponding reserves. At the time the previously excluded well is completed and proved reserves are recognized, the corresponding well costs are moved into the amortization base. The Company believes no impairment was required at December 31, 2013.

The Company acknowledges that:

- the Company 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 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.

If you have any questions with respect to the foregoing, please do not hesitate to call me at (405) 242-4408 or Seth Molay of Akin Gump Strauss Hauer & Feld LLP at (214) 969-4780.

Sincerely,

/s/ Aaron Gaydosik

Name: Aaron Gaydosik
Title: Chief Financial Officer

cc: Seth R. Molay, P.C.