March 4, 2009

Via Facsimile and EDGAR

Mr. H. Roger Schwall
Assistant Director
U.S. Securities and Exchange Commission
Division of Corporation Finance
100 F Street, NE — Mail Stop 7010
Washington, D.C. 20549-7010

Re: Evolution Petroleum Corporation
Form 10-K for Fiscal Year Ended June 30, 2008
Filed September 24, 2008
Form 10-Q for Fiscal Quarter Ended September 30, 2008
Filed November 14, 2008
Amended Schedule 14A
Filed November 4, 2008
File No. 001-32942

Dear Mr. Schwall:

On behalf of Evolution Petroleum Corporation (the "Company", "we", "our" or "us"), I am responding to comments received in a letter dated January 30, 2009 from you with respect to the filings listed above. For your convenience, I have repeated in bold type the comments and requests for additional information as set forth in your letter. My response follows each applicable comment or request.

Form 10-K for the Fiscal Year Ended June 30, 2008

General

1. **We direct your attention to Item 601(b)(10) of Regulation S-K. Please confirm that all material contracts have been filed. We note, in particular, that it does not appear that the agreements with your customers from whom you derive 10 percent or more of your net oil and natural gas revenues referenced on pages 7 and 53, have been filed. If you do not believe that such contracts fall within the purview of Item 601(b)(10), please explain why.**

Response:

Item 601(b)(10) of Regulation S-K requires that contracts made in the ordinary course of business should be filed as an exhibit for those contracts for which the company is:

> *substantially dependent as in the case of continuing contracts to sell the major part of registrant's products or services or to purchase the major part of registrant's requirements of goods, services or raw materials . . .*

Our crude oil contracts are in the ordinary course of business, are of short duration and we believe we are not overly dependent on the performance of the contract or on the purchaser. Although our contracts are with purchasers who buy 10 percent or more of our production of crude oil, the contracts themselves are not substantial as we believe there would be numerous other purchasers of our oil production if we lost or were unable to renew any of our current contracts.

Although our natural gas contracts are in the ordinary course of business, our relationships with our purchasers could be considered significant, in that there are not as many alternatives to market our natural gas. Based on this, we believe our sales contracts with DCP Midstream, LP, and ETC Texas Pipeline, LTD may be considered material contracts as defined by Item 601(b) (10), and as such we will file the contracts as exhibits to a Form 8-K to be filed based on your concurrence.

Item 2. Properties, page 16

2. **Please provide support for the statement that the companies that submitted offers to participate with you in the Delhi Bryant Unit, "believe that the Delhi Bryant Unit is an excellent candidate for a CO_2 EOR project….."**

Response:

Prior to our June 2006 sale of the Delhi Holt Bryant Unit through a farmout to Denbury Resources, we conducted a competitive offering process soliciting major participants with CO2-EOR expertise, funding and operating abilities. During the process, we offered analyses of three CO2 pilot tests successfully completed in our field by a prior operator, along with comparisons to analogous full scale projects in the same geological formation. The solicitation was made primarily on the basis of the EOR potential of a CO2 flood and not on the relatively immaterial associated proved reserves existing at that time. After considerable analyses by three parties and extensive negotiations with two of them, two confidential competitive offers were made to us in writing that focused on the CO2-EOR potential. Of these, we accepted Denbury's offer, wherein they paid us $50 million in cash and committed to develop, at their sole cost and expense, an EOR flood with dedicated proved CO2 reserves from Denbury's Jackson Dome property, including the construction of the necessary pipeline to transport the CO2 approximately 100 miles to the Delhi Field. Based on the two competitive offers,

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we believe that both offering parties considered the field to be an excellent candidate for such, due to their willingness to pay us substantial funds, up front for an immaterial amount of proved reserves, combined with their commitment to fund hundreds of millions of dollars in capital expenditures.

In total, Denbury has expended over $190 million on the Delhi CO2-EOR project through November 2008, in addition to the $50 million they paid us at closing. We understand through public presentations by Denbury that the CO2 delivery pipeline from the Jackson Dome to the Delhi Field is complete, except for the crossing at the Mississippi River. Well preparations in the field have begun, with CO2 injection expected to begin by mid-year 2009.

Controls and Procedures, page 57

3. **We note your statement that you "… carried out an evaluation… of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the *quarter* covered by this report." (emphasis added). Please revise to state whether your evaluation of the effectiveness of the design and operations of your disclosure controls and procedures as of the end of the *fiscal year* covered by your Form 10-K.**

Response:

We carried out an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures as of June 30, 2008, the last day of our fiscal year. In our Form 10-K filed with the Securities and Exchange Commission ("SEC") on September 24, 2009, which covered our fiscal period July 1, 2007 through June 30, 2008, we stated in our statement on *Disclosure Controls and Procedures* under *Item 9A. Controls and Procedures* that the report covered the fiscal quarter ended June 30, 2008 instead of the fiscal year ended June 30, 2008. Although this did not correctly state the period covered by our report, it correctly identified the date of our evaluation of the effectiveness of the design and operation of our disclosure controls and procedures in effect as of June 30, 2008. We respectfully suggest prospectively correcting the statement in our Annual Report on Form 10-K for the year ended June 30, 2009.

Financial Statements

Note 2 — Summary of Significant Accounting Policies, page 41

Limitation on Capitalized Costs, page 41

4. **The ceiling test that you describe does not reflect differentiation between unproved property costs excluded from costs to be amortized, and unproved property costs that are subject to amortization. The test required by Rule 4-10(c)(4) of Regulation S-X stipulates that you must utilize the lower of cost or**

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estimated fair value for this latter group of costs. Please tell us the extent to which you have followed this guidance for each of the periods presented, and submit the disclosures that you propose to clarify your practice.

Response:

We have followed the guidance referenced for all accounting periods presented in our Form 10-K filed as of June 30, 2008. During those periods, no amounts exceeding the lower of cost or estimated fair value for unproved property costs subject to amortization have been included in the "ceiling amount".

We suggest prospectively clarifying our current policy on "Limitation on Capitalized Costs" with the following:

> ***Limitation on Capitalized Costs.*** Under the full-cost method of accounting, we are required on a quarterly basis to perform a "ceiling test" which determines a limit on the book value of our oil and natural gas properties. If the capitalized cost of our oil and natural gas properties, net of accumulated depreciation, depletion, and amortization, and net of related deferred income taxes, exceed the "ceiling amount", the excess is charged to expense and reflected as additional accumulated depreciation, depletion and amortization or as a credit to oil and natural gas properties. The "ceiling amount" is defined as the sum of: (a) the present value, discounted at 10 percent, of estimated future net revenues from proved reserves, which is computed using oil and natural gas prices in effect at the balance sheet date (with consideration of price changes only to the extent provided by contractual arrangements), less estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves; plus (b) the cost of unproved oil and gas properties not subject to amortization; plus (c) the lower of cost or estimated fair value of unproven properties included in the costs being amortized; net of (d) the related tax effects. We did not have a "ceiling test" impairment during the years ended June 30, 2008 and 2007.

Note 5 — Property and Equipment, page 45

5. **Please expand your note to add disclosures pertaining to unproved properties and major development projects as required by Rule 4-10(c)(7)(ii) of Regulation S-X. This guidance requires that you disclose the current status of properties and projects for which costs are excluded from amortization, the anticipated timing of the inclusion of such costs in amortization, and a table indicating the nature of costs by**

category and identifying the periods in which the costs were incurred. Please ensure that your totals per the table agree to the corresponding amounts presented in this note and Note 16.

Response:

We respectfully request that we prospectively provide additional disclosures pertaining to unproved properties in all future filings, including our quarterly reports on Form 10-Q. Below is our property and equipment footnote for the year ended June 30, 2008, as if the expanded disclosures were included in Note 5 of our financial statements included in our fiscal 2008 Annual Report on Form 10-K.

Note 5 — Property and Equipment

As of June 30, 2008 and 2007 our oil and natural gas properties and other property and equipment consisted of the following:

	June 30, 2008	June 30, 2007
Oil and natural gas properties		
Property costs subject to amortization	$ 15,105,766	$ 4,187,440
Less: Accumulated depreciation, depletion, and amortization	(632,040)	(652,439)
Unproved properties not subject to amortization	7,573,507	1,924,552
Oil and natural gas properties, net	$ 22,047,233	$ 5,459,553
Other property and equipment		
Furniture, fixtures and equipment, at cost	231,841	173,205
Less: Accumulated depreciation	(70,814)	(18,333)
Other property and equipment, net	$ 161,027	$ 154,872

Unproved properties not subject to amortization are excluded from our full-cost pool until it is determined that proved reserves can be assigned to such properties or until such time as we have made an evaluation that impairment has occurred. Unproved properties not subject to amortization include unevaluated acreage of $5.6 million as of June 30, 2008, consisting of properties in the Giddings Field and our projects in the Woodford Shale trend in Oklahoma. Unproved properties not subject to amortization also consist of approximately $2.0 million and $1.9 million as of June 30, 2008 and 2007, respectively, of participating interests through separately acquired royalty and overriding royalty interests aggregating 7.4% of the Delhi Holt Bryant Unit in the Delhi Field in Louisiana. Evaluation of these properties is currently expected to be completed within three years. Our evaluation of impairment of unproved properties occurs, at a minimum, on a quarterly basis.

The following table provides a summary of costs that are not being amortized as of June 30, 2008, by the fiscal year in which the costs were incurred:

		For the Year Ended June 30,		
	Total	2008	2007	2006 and Prior
Costs excluded from amortization				
Leasehold acquisition costs	$ 5,622,766	$ 4,893,690	$ 729,076	$ —
Royalty and overriding royalty interests	1,950,741	—	966,794	983,947
	$ 7,573,507	$ 4,893,690	$ 1,695,870	$ 983,947

Certifications, exhibits 31.1 and 31.2

6. **We note, in both certifications, you still referred to yourself as a "small business issuer." Please revise your certifications to match the *exact* form set forth in Item 601(b)(31) of Regulation S-K. We note that your current certifications also include other deviations from the exact language of the form.**

Response:

During our transition from the disclosure requirements of Regulation S-B to the scaled disclosure requirements for smaller reporting companies under Regulation S-K, we inadvertently failed to make the necessary changes to the verifications as set forth in Item 601(b)(31). However, these changes were implemented in our Form 10-Q for the fiscal quarter ended September 30, 2008. We will continue to follow the certification requirement set forth in Item 601(b)(31) of Regulation S-K.

Amended Schedule 14A filed November 4, 2008

Legal Proceedings, page 5

7. **Please provide a confirmation, if true, that none of your directors or executive officers have been involved in any legal proceeding listed in Section 401(f) of Regulation S-K within the last five years, instead of limiting your statement to only whether they are not currently involved in a legal proceeding.**

Response:

Our executive officers and directors have verified through their annual Directors' and Officers' questionnaires that they have not been involved in any legal proceeding listed in Section 401(f) of Regulation S-K within the last five years. In compliance with the rules of Section 401(f), we suggest prospectively limiting our disclosure to positively affirming if any director or executive officers have been involved in such legal proceedings in the last five years, failing which there will be no confirmation or disclosure.

Executive Compensation and Related Information, page 10

Short Term Incentive Bonuses, page 11

8. **Provide us with an explanation, in table format or otherwise, as to how the committee determines the quantitative amount of these short term incentive bonuses for *each* named executive officer. Explain what the payout factor is and how it was determined for each named executive officer. Further, explain the weighting of each of the performance goals. See Item 402(b)(1)(v) of Regulation S-K.**

Response:

We request to prospectively clarify how we determine the amount of short-term incentive bonus for each executive officer in our 2009 proxy statement. The paragraph on short-term incentive bonus in our Amended Schedule 14A filed on November 4, 2008, would be modified in our 2009 proxy statement as follows:

Short Term Incentive Bonus. Short term incentive bonuses, generally and historically paid in cash, are a major portion of total compensation paid and are intended to vary with individual and Company performance against pre-determined goals. The bonus targets are 100% of base pay for the chief executive officer and 75% of base salary for other named executive officers. The Committee determines awards of short term incentive bonuses to our executive officers based upon overall performance against those goals on a qualitative basis, wherein individual and corporate performances are equally weighted, then multiplied to reach a payout factor. Since the two factors are multiplied, a 0% factor on either results in no bonus being paid. A substantial list of goals is mutually agreed upon between the employee, the chief executive officer and the compensation committee through a series of meetings. Each goal is not individually weighted — the chief executive officer reviews progress against those goals as a whole and then proposes an individual factor to the compensation committee for consideration. The committee evaluates the corporate performance as a whole against the corporate goals to determine the corporate factor. Progress against goals is measured and reviewed quarterly by the Board of Directors. Short term incentive bonus targets are set to allow recipients to achieve base and short-term incentive compensation at the upper quartile of the Reno survey range, if all goals are accomplished. For fiscal 2008, the chief executive officer requested that his individual factor be lowered from that recommended by the Committee to the lowest factor awarded to his direct reports. Short term incentive awards for fiscal 2008 for executive officers averaged 17% below target awards. Most of the senior management and all of the named executive officers took a substantial portion of their short term incentive bonus in the form of restricted stock.

Engineering Comments

Estimated Proved Oil and Natural Gas Reserves and Future Net Revenues, page 19

9. **You indicate that future net revenues used in estimating your reserves were determined using average NYMEX prices. Please tell us whether the NYMEX prices utilized in your computations were spot or futures prices. We believe that you would need to use the year-end spot prices, adjusted for differentials, for reserve determinations to comply with the guidance in Rule 4-10(a)(2) of Regulation S-X. If you have not used the year-end spot prices, please quantify the effects on your reserve determination.**

Response:

The estimated reserves and projected net revenues attributable to our oil and natural gas properties as of June 30, 2008 were correctly based on the effective NYMEX spot prices on June 30, 2008. Pricing differentials were applied to all properties, on an individual property basis, in order to reflect prices actually received at the wellhead.

Our statement on page 19 of our fiscal 2008 Annual Report on Form 10-K stated that the prices disclosed were average prices. In fact, the commodity prices disclosed of $138.73, $84.39, and $14.00 per barrel of crude oil, per barrel of natural gas liquid, and per MMBTU of natural gas, respectively, were actually the weighted average of the June 30, 2008 spot NYMEX price, adjusted for price differentials, which varied per proved location. Therefore, the June 30, 2008

NYMEX spot price was consistent throughout properties; however the differentials used were different to ensure an accurate price for each property.

We will prospectively clarify this in our Annual Report on Form 10-K for fiscal 2009.

Supplemental Disclosures About Oil and Natural Gas Producing Properties (unaudited), page 55.

10. **You report that you spent approximately $3 million on proved property acquisitions in 2008 and that you acquired approximately 3 million barrels equivalent of proved reserves. Please tell us the basis for the proved reserve classification of these 3 million barrels equivalent, which you purchased for $1 per barrel equivalent.**

Response:

The proved reserves claimed were based on an independent reserve report prepared by the outside petroleum engineering firm of W.D. Von Gonten & Associates.

As to the specific reserves to which you refer, we acquired proved undeveloped reserves through the leasing of open acreage targeted to the Austin Chalk, Buda and Georgetown formations in the Giddings Field in Texas. These proved locations are direct offsets to past and/or presently producing wells in a field with extensive well and production control data spanning over 10,000 wellbores and over many years of production. The acquisition costs we incurred relate to the leasehold bonus, acquisition and title costs and do not reflect the considerable drilling and completion costs associated with their future development. Of course, such development costs are included in our PV-10 calculations used in our ceiling test analysis, with the total cost per barrel of oil equivalent being in line with industry norms.

Subsequent to our acquisition, we have reentered, drilled and completed eight of our thirty-four identified proved undeveloped locations and placed another two existing wellbores back onto production through well workovers. With limited production history, these wells appear to be statistically producing as expected in the aggregate and validate the aggregate reserves assignments.

11. We note that you purchased property in the Giddings Field in 2007 and 2008. We also note that in each purchase you claimed approximately the same amount of oil reserves. However, in the 2008 purchase, it appears that you claimed over twice the gas reserves, compared to the 2007 purchase. Please explain to us the reasons for the disproportional relationship between the oil and gas reserves recorded in these acquisitions. Please identify the specific aspects of your computations leading to this difference.

<u>Response</u>:

The Giddings Field extends over six or more counties in central Texas, is more than 100 miles long by 30 miles wide and has had more than 10,000 wells drilled to date. Production is from several distinct formations at various depths, and each formation produces its own mix of oil, gas and gas liquids. The product mix also varies within a given formation, depending upon location and depth. Compared to our proved undeveloped reserves as of July 1, 2007, the proved undeveloped locations we leased in 2008 were concentrated in a different area with a different product mix, and particularly included numerous grassroots locations targeting deeper reservoirs that generally produce only gas,.

12. Please explain to us what you mean by stating that the revisions of previous estimates were in part due to "…the effect of the new SEC guideline on PUD locations within fractured reservoirs," and tell us the percentage of the revisions made for this reason.

<u>Response</u>:

During preparations for the proved reserves report as of July 1, 2008, we were informed by the outside reservoir engineer that prepares our reserve reports, W.D. Von Gonten, that the SEC had promulgated revised standards for proved undeveloped reserves in horizontal wells within naturally fractured reservoirs. The revised standards require that proved undeveloped locations be only one offset location removed from a producing well in the same formation and that *only the portion of the horizontal well location lying in the same fracture path of the offset well could be assigned proved reserves*. The effect was to remove one of our proved undeveloped locations and reduce the proved reserves previously assigned on three other proved undeveloped locations by the amounts associated with the portion of their horizontal sections extending outside of the offset well fracture path. The downward revisions in these four locations aggregated approximately 296 MBOE, compared to a total downward revision in all proved reserves of approximately 192 MBOE; the 296 MBOE downward revision therefore was offset by positive combined revisions of 104 MBOE in other wells. The 296 MBOE downward revision was equivalent to approximately 17% of our total proved reserves at July 1, 2007 of approximately 1,724 MBOE. The standards also resulted in our not being able to book additional proved undeveloped reserves on leases acquired in 2008 that we otherwise considered as proved reserves.

If you have any questions or comments concerning these comments, please contact me at (713) 935-0122 or Mr. Michael Larkin at (713) 308-0166.

Very truly yours,

Evolution Petroleum Corporation

<u>/s/ Sterling H. McDonald</u>

Sterling H. McDonald
VP and Chief Financial Officer

cc: Ms. Lily Dang

United States Securities and Exchange Commission

Michael T. Larkin

Adams and Reese LLP
