October 27, 2009

BY EDGAR AND OVERNIGHT COURIER

Securities and Exchange Commission
Division of Corporation Finance
100 F Street, N.E.
Mail Stop 7010
Washington, D.C. 20549-4628
Attention: Craig H. Arakawa

Re: Helix Energy Solutions Group, Inc.
Annual Report on Form 10-K for the fiscal year ended December 31, 2008
Filed March 2, 2009
Quarterly Report on Form 10-Q for the fiscal quarter ended June 30, 2009
Filed August 5, 2009
Quarterly Report on Form 10-Q for the fiscal quarter ended March 31, 2009
Filed May 11, 2009
Schedule 14A
Filed April 2, 2009
Definitive Proxy Statement
Filed April 2, 2009
File No. 001-32936

Dear Mr. Arakawa:

In its letter dated September 28, 2009, the staff ("Staff") of the Securities and Exchange Commission ("Commission") provided to Helix Energy Solutions Group, Inc. (the "Company") comments (the "Comments") with respect to the above-referenced filings.

Set forth below are the responses of the Company to such Comments after discussions with the Company's independent registered public accountants and our independent petroleum engineers. The following numbered paragraphs repeat the comments for your convenience, followed by our responses to those comments.

Form 10-K for the Fiscal Year Ended December 31, 2008

General

1. *You state on pages 5, 11, and elsewhere in your Form 10-K that you offer contracting services in the Middle East, and on page 72 that your subsidiaries operate in the Middle East and Latin America, regions generally understood to include Iran, Syria, Sudan, and Cuba. In*

addition, we are aware of a December 2008 report that your subsidiary, Canyon Offshore, Inc., was helping Reliance Industries Limited to build a facility to export gasoline to Iran. Iran, Syria, Sudan, and Cuba are identified by the State Department as state sponsors of terrorism, and are subject to U.S. economic sanctions and export controls. We note that your Form 10-K does not include disclosure regarding contacts with Iran, Syria, Sudan, and Cuba.

Please describe to us the nature and extent of your past, current, and anticipated operations in, or other contacts with, Iran, Syria, Sudan, and Cuba, whether through subsidiaries, joint ventures, or other direct or indirect arrangements. In this regard, tell us whether you or any of your customers use your marine vessels or employees in direct or indirect operations in Iran, Syria, Sudan, or Cuba. Your response should describe any products, equipment, components, technology, or services you have provided to Iran, Syria, Sudan, and Cuba, directly or indirectly, and any agreements, commercial arrangements, or other contacts you have had with the governments of Iran, Syria, Sudan, or Cuba, or entities controlled by those governments. Finally, tell us whether any marine vessels that you own, operate, or charter provide any U.S.-origin goods to Iran, Syria, Sudan, or Cuba, or involve employees who are U.S. nationals in operations associated with those countries.

Response: The Company does not have any past, current or anticipated operations in, or, to our knowledge, other contacts with, Iran, Syria, Sudan, or Cuba, whether through subsidiaries, joint ventures or other direct or indirect arrangements. The Company does not use, and to our knowledge, our customers do not use, our marine vessels or employees in direct or indirect operations in Iran, Syria, Sudan or Cuba. The Company does not now provide, and has not in the past provided, any products, equipment, components, technology or services to Iran, Syria, Sudan or Cuba, and we have no agreements, commercial arrangements or any other contacts with the governments of Iran, Syria, Sudan or Cuba or entities controlled by those governments. None of the marine vessels that we own, operate or charter provide any U.S.-origin goods to Iran, Syria, Sudan or Cuba or involve employees who are U.S. nationals in operations associated with those countries.

With respect to services provided by the Company to Reliance Industries, Ltd. (“Reliance”), the Company has provided services directly to Reliance (and will do so until at least March 2011) as well as to one of its prime contractors, Allseas Marine Contractors S.A., a Swiss based offshore construction company (“Allseas”), all related to the development of Reliance’s Dhirubhai offshore oil and gas field development project in the Godavari Basin in the Bay of Bengal in Indian waters off the east coast of India, primarily on the KGD6 block (the “Dhirubhai project”). The services contracted directly to Reliance involve the provision of inspection, repair and maintenance services by our robotics subsidiary, Canyon Offshore, Inc. (“Canyon”), for the Dhirubhai project field development and operation, and the services the Company provided indirectly to Reliance through the Company’s contract with Allseas involved the installation of umbilicals, manifolds and jumpers, all in connection with Reliance’s Dhirubhai project.

Reliance is part of the Reliance Group, the largest private sector enterprise in India. The business activities of the Reliance Group include exploration and production of oil and gas, petroleum refining and marketing, petrochemicals and textiles. The work performed by the Company for the Dhirubhai project involved only the development of an offshore oil and gas field. The work performed by Canyon for Reliance included the provision of the vessel *Olympic Canyon* for offshore work in connection with the development and operation of the Dhirubhai project and did not relate to the construction or operation of any type of facility that refines product or a facility that transports product to Iran. The Company affirms that neither it nor Canyon was assisting Reliance with building a facility that would export gasoline to Iran.

Financial Statements

Note 2 – Summary of Significant Accounting Principles, page 83

2. *You state that your calculation of depletion of your oil and gas properties is performed on a unit-of-production method and based on ". . . estimated remaining oil and gas proved and proved developed reserves." Please clarify whether your depletion of development costs is based on production in relation to reserves associated only with the developed properties from which production originates, or if you are also factoring in reserves that are associated with undeveloped or non-producing properties. In addition, please identify the types of any costs that are being amortized based on total estimated proved reserves, without distinction between developed and undeveloped properties; and any costs that are being amortized based only on estimated proved developed reserves. Please discuss your rationale for any aggregation of reserves if you are not amortizing costs on a property-by-property basis; including details sufficient to understand how your methodology compares to the guidance in paragraphs 30 and 35 of SFAS 19.*

Response: The Company advises the Staff that we deplete our oil and gas properties on a field-by-field basis using the units-of-production accounting method. Undeveloped or non-producing fields are not included in our depletion calculations as they do not have any production. For our producing properties, leasehold costs are amortized based on an individual field's total estimated remaining proved reserves. Well and related equipment costs are depleted based on the total remaining estimated proved developed reserves. When aggregating certain wells and/or fields into a unit for depletion, the Company determines the lowest level of identifiable cash flows for such units. This is accomplished through the use of certain shared facilities to generate production from wells and/or fields. If the Company has a field that has incurred significant development costs for a planned set of development wells before all of the planned wells have been drilled, the Company does not include a pro rata portion of these development costs in determining its units-of-production depletion rate until the additional development wells are drilled. Similarly, if the Company would need to incur a significant future development cost in order to produce any portion of the field's proved developed reserves, the affected proved developed reserves are also excluded from the Company's units-of-production depletion rate. The Company never includes future anticipated development costs in determining any field's units-of-production depletion rate.

Prospectively, to clarify its significant accounting policy related to depletion expense, the Company proposes to include disclosure related to depletion expense substantially similar to the following in our future periodic report filings with the Commission:

> Depletion expense is determined on a field-by-field basis using the units-of-production method, with depletion rates for leasehold acquisition costs based on estimated total remaining proved reserves. Depletion rates for well and related facility costs are based on estimated total remaining proved developed reserves associated with each individual field. The depletion rates are changed whenever there is an indication of the need for a revision but, at a minimum, are evaluated annually. Any such revisions are accounted for prospectively as a change in accounting estimate.

Note 13 – Convertible Preferred Stock, page 111

3. *We understand that in the first quarter 2009, you recorded a $29.3 million non-cash dividend associated with the redemption of all of the Series A-2 Cumulative Convertible Preferred Stock, reflecting the value of an additional 3,974,718 shares delivered over the original 1,964,058 shares that were contractually required to be issued upon conversion, and a $24.1 million charge associated with an adjustment to the conversion price on the Series A-1 Cumulative Convertible Preferred Stock, reflecting the value of an additional 7,368,388 shares that will be delivered on future conversion over the 1,666,668 shares called for under the original conversion rate.*

Please expand your disclosure to describe the conversion adjustment provisions that are associated with each of these subsequent re-computations to convey the number and value of incremental shares potentially issuable based on the relationship between market prices, and the conversion and minimum prices as of year-end, including a description of the circumstances upon which recognition in your financial statements is dependent.

Response: The Company issued $55 million of Cumulative Convertible Preferred Stock ("Preferred Stock") in two separate tranches to the private investment firm, Fletcher International, Ltd. (Fletcher). The first tranche, Series A-1, in the amount of $25 million was issued in January 2003 and the second tranche, Series A-2, in the amount of $30 million was issued in June 2004. Through December 31, 2008 the shares of Preferred Stock under each Series were convertible into the Company's common stock at conversion prices of $15.00 and

$15.27 per share, respectively. Under the terms of the agreements with Fletcher (the "Fletcher Agreements"), the Company is required to make an election if the price of its stock fell below certain thresholds, including a possible election to adjust the conversion price for the Preferred Stock. Furthermore, the holder of the Preferred Stock could convert its shares at any time or redeem its shares anytime after December 31, 2004. The Preferred Stock was redeemable/convertible into shares of the Company's common stock unless the Company elected to settle any redemption/conversion with cash by providing advance notice to Fletcher.

In January 2009, Fletcher elected to redeem 30,000 shares of its Preferred Stock, representing its entire $30 million of Series A-2 Preferred Stock. The Company satisfied the redemption by issuing 5,938,776 shares of the Company's common stock. As a result of the calculation of the redemption price as required by the Fletcher Agreements, the redemption price was $5.0667 per share, reduced from the $15.27 conversion price set forth in the Fletcher Agreements. The reduction in the price was based on the average market price of the Company's common stock for the three days ended on the third day prior to the redemption notice. Upon the redemption of the Series A-2 Preferred Stock, the minimum price threshold for the remaining shares of Preferred Stock was reduced to $2.767. On February 25, 2009, the volume weighted average price of our common stock was below the minimum threshold price. On February 27, 2009, the Company provided notice to Fletcher that with respect to the Series A-1 Preferred Stock the conversion price was reset to $2.767 as of that date. As a result of the Company's election to reset the conversion price, Fletcher no longer has any right to redeem the Preferred Stock but may convert its shares of Preferred Stock at the fixed conversion price of $2.767 per share. The Company retained the right to settle any future conversions by issuing a maximum 9,035,056 shares of its common stock ($25,000,000/$2.767) or in the cash equivalent (subject to senior credit agreement restrictions) based upon the prevailing market value of the shares (9,035,056) on the day preceding the applicable conversion notice.

Under terms of the agreement with Fletcher, Fletcher solely controls the timing of any conversion or redemption of the Preferred Stock. Accordingly, for accounting purposes, the contingent conversion feature embedded within the A-2 Cumulative Convertible Preferred shares was not triggered until Fletcher provided its redemption notice in January 2009 and until February 2009 for the Series A-1 Cumulative Convertible Preferred shares, when the Company's common stock price dropped below the minimum threshold and the Company elected to reset the conversion price for those shares of Preferred Stock to $2.767 per share.

For this conclusion, the Company directs the Staff to Issues No. 2 and No. 7 of EITF 00-27 "*Application of Issue 98-5 to Certain Convertible Instruments*" replicated here in its entirety:

> Issue 2—For a contingent conversion option, Issue 98-5 requires the intrinsic value to be measured using the commitment date fair value of the underlying stock but does not require it to be recognized unless the triggering event occurs and the contingency is resolved. In some cases, it may not be clear which conversion option should be considered the "initial" conversion option and which option should be considered the "contingent" conversion option.

8. The Task Force reached a consensus that the most favorable conversion price that would be in effect at the conversion date, assuming there are no changes to the current circumstances except for the passage of time, should be used to measure the intrinsic value of an embedded conversion option. Changes to the conversion terms that would be triggered by future events not controlled by the issuer should be accounted for as contingent conversion options, and the intrinsic value of such conversion options would not be recognized until and unless the triggering event occurs.

Issue 7—How an issuer should apply Issue 98-5 if the terms of a contingent conversion option do not permit the number of shares that would be received upon conversion if the contingent event occurs to be calculated at the commitment date.

23. The Task Force reached a consensus that if the terms of a contingent conversion option do not permit an issuer to compute the number of shares that the holder would receive if the contingent event occurs and the conversion price is adjusted, an issuer should wait until the contingent event occurs and then compute the resulting number of shares that would be received pursuant to the new conversion price. The number of shares that would be received upon conversion based on the adjusted conversion price would then be compared with the number that would have been received prior to the occurrence of the contingent event. The excess number of shares multiplied by the commitment date stock price equals the incremental intrinsic value that results from the resolution of the contingency and the corresponding adjustment to the conversion price. That incremental amount would be recognized when the triggering event occurs.

Accordingly, no dividend was recorded and no additional shares were added to our fully diluted share number until after the notice of redemption was received in January 2009 and then again after the reset of the conversion price in February 2009. After the adjustment in February 2009, the conversion price is no longer subject to further adjustment and Fletcher is no longer permitted to redeem the Preferred Stock, and as a result, the Company asserts that no further modifications can be made to the features of its convertible preferred stock that would affect either the number of shares necessary to satisfy any future conversion transactions or result in any additional earnings charge to the Company's consolidated statement of operations.

The Company also notes that the disclosure included in the Annual Report on Form 10-K for the year ended December 31, 2008 was updated in the subsequent quarterly reports on Form 10-Q for the periods ended March 31, 2009 and June 30, 2009, and we will continue to update the existing disclosure as additional conversions occur.

Note 18 – Commitment and contingencies, page 117

4. *We note your disclosure indicating that you accrued $69.7 million in other long term liabilities as of December 31, 2008 associated with orders received from the U.S. Department of the Interior Minerals Management Services ("MMS") which claim that you owe royalties on prior year oil and gas production. We understand that you have reversed this accrual in the first quarter 2009, based on a favorable decision received by Kerr-McGee, an operator that contested similar orders it received from MMS. As the decision in favor of Kerr McGee was affirmed on January 19, 2009, a date prior to the issuance of your financial statements, please explain why you believe that this event would not require recognition in your annual financial statements to comply with the guidance in paragraphs 1 through 8 of AU §560.*

Response: The Company's leases on Garden Banks blocks 667, 668 and 669 contain provisions that state that a royalty is triggered in the event certain commodity price thresholds are exceeded, even on volumes for which a royalty would be suspended under certain provisions of the DeepWater Royalty Relief Act ("DWRRA"). As such, the Company was party to a contract pursuant to which it had a contractual obligation to the MMS whenever the price thresholds were exceeded. Absent that contractual obligation, these amounts would have been recognized as additional revenue from the applicable leases. The litigation filed by Kerr McGee asserted that the commodity price thresholds in the leases on Garden Banks blocks 667, 668 and 669 were invalid under the DWRRA; therefore, there was no obligation to pay the MMS royalties. Under the SAB Topic 13, revenue is generally not recognized until realized or realizable. That same guidance states that revenue is not considered to be realized or realizable until several criteria are met including that persuasive evidence of an arrangement exists and collectability is reasonably assured (probable). On January 12, 2009, the United States Court of Appeals for the Fifth Circuit rendered its decision affirming the district court's decision in favor of Kerr McGee. The Company believes that this event provided sufficient persuasive evidence to conclude that it was entitled to the revenue related to the disputed royalties and it was probable that the Company would not be required to pay to the MMS the disputed amounts. As a result, the Company concluded that all criteria for revenue recognition were met in the first quarter of 2009. The Company recognized revenue of $73.5 million and included disclosure of such in Note 6 of the March 31, 2009 Quarterly Report on Form 10-Q.

The Company advises the Staff that in early October 2009, the U.S. Supreme Court announced that it denied the MMS' petition for certiorari to hear the case.

5. We note your disclosure indicating that you are disputing the $23 million tax assessment that you received from the Mexican tax authority related to fiscal year 2001; and we understand that you may have taken a similar tax position during subsequent years. Tell us the extent of any loss that you have accrued for this matter in your financial statements, the periods in which those amounts were recognized, and your estimate of the range of reasonably possible additional loss, following the guidance in FIN 14 and paragraphs 8 to 10 of SFAS 5. Please quantify your exposure separately for all subsequent years that remain subject to audit by the tax authority, assuming they prevail in their position on your 2001 tax. Please explain why you have not disclosed this information.

Response: The disputed $23 million tax assessment was received from Mexican tax authorities by our former majority owned subsidiary, Cal Dive International, Inc. Prior to June 10, 2009, we consolidated Cal Dive's operations and, as a result, Cal Dive's treatment of the disputed tax assessment was reflected in our consolidated financial statements. As of June 10, 2009 our interest in Cal Dive was reduced to approximately 26% and such interest was further reduced to less than 1% in September. As a result, we no longer consolidate or have an equity investment in Cal Dive and thus have no future exposure related to this issue. The Company understands that Cal Dive received a similar comment to its periodic reports and provided the following explanation of the accrual and disclosure of the disputed tax assessment to the Staff via a separate response letter dated October 13, 2009. All references to "us" or "we" in the response below is a reference to Cal Dive International, Inc. Our response is consistent with that of Cal Dive.

Background

On December 11, 2007, we completed the acquisition of Horizon Offshore, Inc. ("Horizon"), which became our wholly-owned subsidiary. During the fourth quarter of 2006, prior to the completion of this acquisition, Horizon received a notice of tax assessment for fiscal year 2001 from the Servicio de Administracion Tributaria (the "SAT"), the Mexican taxing authority, for approximately $23 million, including penalties, interest and monetary correction (the "2001 Assessment"). The 2001 Assessment claims unpaid taxes related to services performed by Horizon's subsidiaries. On February 14, 2008, we received notice from the SAT that it had upheld the 2001 Assessment, and on April 21, 2008, we filed a petition in the Mexico tax court seeking judicial overturn of the SAT's determination.

Your comment is framed, and asks us to respond, within the context of SFAS 5, *Accounting for Contingencies* (FAS 5) and FASB Interpretation No. 14, *Reasonable Estimation of the Amount of a Loss, an interpretation of FASB Statement No. 5* (FIN 14), which relates to FAS 5. However, the 2001

Assessment from the Mexican tax authority relates to income taxes, and on January 1, 2007, Cal Dive adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109,* (FIN 48). FAS 5 was amended by FIN 48, paragraph C2(a) effective for fiscal years beginning after December 15, 2006. FAS 5, paragraph 2[1a], as amended, states, "Because FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes*, provides guidance on accounting for uncertainty in income taxes, this Statement no longer applies to income taxes". Accordingly, in our financial statements, we have followed the guidance set forth in FIN 48, and the following responses to your comment are also prepared within the framework of FIN 48.

2001 Assessment

Question 1(A): "*Tell us the extent of any loss that you have accrued for this matter in your financial statements, the periods in which those amounts were recognized, and your estimate of the range of reasonably possible additional loss, following the guidance in FIN 14 and paragraphs 8 to 10 of SFAS 5.*

Response:

After consulting with our Mexican counsel, we believe that under the Mexican and United States double taxation treaty, the services performed by Horizon's subsidiaries to which the 2001 Assessment relates are not taxable and the 2001 Assessment is invalid. Our Mexican counsel has further advised that it is of the opinion that the Mexican tax courts will likely render a judgment absolving us of any liability associated with the 2001 Assessment. Based on the foregoing, our position has consistently been that the facts, circumstances and legal analysis with respect to the 2001 Assessment does not support a position that it is "more likely than not" a liability had been incurred as of the date of our financial statements as set forth in Paragraph 6 of FIN 48. Therefore, we have neither accrued a liability for, nor reserved against, the 2001 Assessment.

FIN 48, unlike FAS 5, does not require the estimate of tax contingencies within a possible range of loss; rather, the guidance requires measurement be based on the largest amount of tax benefit that is greater than 50 percent likely of being realized upon settlement with a taxing authority that has full knowledge of all relevant information. Given our conclusion stated above, for FIN 48 purposes we measure that exposure as zero. However, the following is provided to respond to your question of what we estimate the range of reasonable possible additional loss to be. Notwithstanding that at the time of the filing of our 2008 Form 10-K we believed the services forming the basis of the 2001 Assessment were not taxable, and that the 2001 Assessment was itself invalid, the ultimate outcome of this litigation and our potential liability from this assessment, if any, could not be determined. The range of possible loss associated with the 2001 Assessment was between $0.0 (assuming a favorable ruling by the Mexican tax court based on our interpretation of applicable law) and $23.0 million (assuming an unfavorable ruling by the Mexican tax court for the full amount of the 2001 Assessment). Our current position and the range of possible loss has not changed since the filing of our 2008 Form 10-K.

Years Subsequent to the 2001 Assessment

Question 1(B): "*Please quantify your exposure separately for all subsequent years that remain subject to audit by the tax authority, assuming they prevail in their position on your 2001 tax.*"

Response:

As disclosed in our 2008 Form 10-K, Horizon's 2002, 2003 and 2004 taxable years are currently under audit by the SAT, with all taxable years from 2002 through 2007 remaining open to examination. We have taken a similar tax position with respect to Horizon's open taxable years subsequent to the 2001 Assessment, and fully expected the SAT to review these open tax years and to assert a claim of unpaid taxes related to services performed. However, notwithstanding our belief that our position is valid and that we should prevail with respect to these taxable periods if a comparable assessment was made by the SAT, in early 2008 our management determined it was in our best interest to seek a negotiated resolution of this issue in an attempt to minimize the costs and time necessary to contest such matters with the SAT. Accordingly, management embarked on a proactive effort to develop a plan to settle the taxable years subsequent to 2001 with the SAT, none of which had yet entered the formal process of the Mexican tax court.

With the assistance of our Mexican counsel, in 2008 we approached the SAT with a non-binding offer of settlement using an approach and strategy that we believed was a reasonable and fair compromise. We subsequently received a written statement by the SAT that it viewed favorably our methodology and overall approach as an acceptable solution. This written acknowledgement represented a material change from our prior communications with the SAT on this issue, because the SAT had previously adopted an "all or nothing" approach. The SAT's communication of its favorable disposition towards our proposal during the fourth quarter of 2008 also constituted "new information" that allowed us to use this proposed methodology to estimate our potential liability for tax years 2002 through 2007 in accordance with FIN 48. Accordingly, based on the methodology submitted to the SAT, we established an accrual of $5.0 million for such years in the fourth quarter of 2008.

As the estimated tax liability of $5.0 million was a result of Horizon operations prior to our acquisition of Horizon in 2007, we recorded the estimated tax liability and increased goodwill by the same amount as part of the purchase business combination. EITF Issue No. 93-7, "*Uncertainties Related to Income Taxes in a Purchase Business Combination*" specifically requires liabilities for uncertainties about tax returns of the acquired company for periods prior to the acquisition date to increase goodwill attributable to that acquisition.

During 2009, we successfully completed our negotiations with the SAT with respect to Horizon's 2002 through 2004 taxable years, and paid an aggregate of approximately $2.1 million in settlement of these periods. This settlement for these tax years was consistent with our estimated uncertain tax benefit liability included in the $5 million described above. We have, however, been advised by our Mexican counsel that for procedural reasons particular to the Mexican tax court, we are unable to pursue settlement negotiations with respect to the 2001 Assessment similar to those completed in connection with Horizon's 2002 to 2004 taxable years because the 2001 Assessment, which entered the Mexican tax court in the second quarter of 2008, is now subject to the formal process of the tax court.

Horizon's 2002 and 2003 taxable years are now closed with the SAT as was disclosed in our second quarter 2009 Form 10-Q. We expect to close the 2004 taxable year with the SAT during the fourth quarter of 2009. Following the successful settlement of Horizon's 2004 taxable year, we intend to pursue a similar strategy to proactively settle the 2005 through 2007 taxable years. Given our success in settlement with respect to the prior periods, we are comfortable that the remaining unused portion of our estimated uncertain tax benefit liability we recorded is sufficient to provide for the settlements we expect to reach with the SAT for the tax years 2005 through 2007. Our 2008 taxable year is also currently subject to audit with the SAT, and while we intend to pursue a similar settlement strategy for this taxable period, given that we did not utilize any of our assets in Mexico during 2008, we believe our exposure for this year is negligible, if not zero. We have been in communication with the SAT in this regard on a verbal basis, and have received at least preliminary oral confirmation of our position with respect to the 2008 taxable year.

Question 1(C): "*Please explain why you have not disclosed this information.*"

Response:

As stated previously, we disclosed in our 2008 Form 10-K all information regarding this tax contingency for tax years 2001 through 2008, following the guidance of FIN 48. Specifically, we disclosed in Note 8 – Income Taxes: (i) our accrual of the $5.0 million tax liability as uncertain tax benefits, interest and penalty as of December 31, 2008, as part of the $5.4 million accrued globally for all international tax jurisdictions; (ii) a tabular reconciliation of the total amount of unrecognized tax benefits at the beginning and end of the period; (iii) the total amounts of interest and penalties recognized in our consolidated and combined statement of operations and the total amounts of interest and penalties recognized on our consolidated balance sheet; (v) a statement that we do not expect a significant change to the unrecognized tax benefits during the following 12 months; and (vi) a description of the tax years that remain subject to examination by the SAT. Finally, although not required by FIN 48, for transparency we also disclosed the assessed tax amount and the nature of the contingency associated with the 2001 Assessment in both Note 8 – Income Taxes and Note 10 – Commitments and Contingencies. We also disclosed our belief that the services forming the basis of the 2001 Assessment were not taxable, and that the 2001 Assessment was itself invalid. We appropriately qualified this statement by advising investors that the "ultimate outcome of this litigation and our potential liability from this assessment, if any, cannot be determined at this time."

Controls and Procedures, page 136

6. *We note your use of the criterion set forth in "Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission" in your principal executive officer and principal financial officer's evaluation of your disclosure controls and procedures. The COSO Framework is generally used as a criterion for an evaluation of the effectiveness of a company's internal control over financial reporting. Please clarify the use of the criterion in your disclosure controls and procedures evaluation or remove the reference to the criterion from your discussion of the evaluation of your disclosure controls and procedures.*

Response: The Company agrees with the Commission that the reference to the COSO Framework is used as a criterion for an evaluation of the effectiveness of the Company's internal controls over financial reporting but not the evaluation of such controls and procedures. Accordingly, the Company will remove all references to the COSO Framework from future disclosure within Item 9A. Controls and Procedures.

7. *We note your statement that "[b]ased on [your disclosure controls and procedures] evaluation, the principal executive officer and the principal financial officer believe that our disclosure controls and procedures were effective....." Rather than state a belief, please revise to state whether your principal executive officer and principal financial officer came to a definitive conclusion regarding the effectiveness of your disclosure controls and procedures.*

Response: In future filings, the Company will modify the following sentence within subpart (a) of Item 9A, Controls and Procedures, to replace the word "believe" with "conclude" as follows:

Based on this evaluation, the principal executive officer and principal financial officer conclude that our disclosure controls and procedures were effective as of the end of the fiscal year ended December 31, 2008 to ensure that information that is required to be disclosed by us in the reports we file or submit under the Exchange Act is (i) indentified, recorded, processed, summarized and reported, on a timely basis and (ii) accumulated and communicated to our management, as appropriate, to allow timely decisions regarding required disclosure.

8. *Please consolidate your disclosure in paragraphs (b) and (c). Further, if you choose to separate your Item 308 of Regulation S-K disclosure from your Item 307 disclosure, include the changes in internal control over financial reporting disclosure with your Item 308 disclosure.*

Response: The Company will consolidate the disclosure in paragraphs (b) and (c) in our future filings. In the event we separate our Item 308 disclosure from our Item 307 disclosure, we will include changes in internal control over financial reporting with our Item 308 disclosures in future periodic report filings.

Form 10-K for the Fiscal Year Ended December 31, 2008; Form 10-Q for the Fiscal Quarter Ended June 30, 2009; Form 10-Q for the Fiscal Quarter Ended March 31, 2009

Controls and Procedures

9. *We note your disclosure regarding the implementation of your enterprise resource planning system and the statement that the "[r]esulting impacts on internal controls over financial reporting were evaluated and determined not to be significant for [the reporting period]." Please revise to state, if true, that the resulting impacts on internal control over financial reporting were determined not to be material for the reporting period. If you are unable to make this assertion, please revise your disclosure to state that there have been changes in your internal control over financial reporting and discuss the changes.*

Response: The Company's internal control changes related to the implementation of its enterprise resource planning system did not have a material impact on its internal controls over financial reporting for the fiscal year ended December 31, 2008 and the fiscal quarters ended March 31, 2009 and June 30, 2009. The Company does not believe that we will need to continue to make reference to these changes in its future filings as management has now concluded that the enterprise resource planning system has not had and will not have any material effect on internal controls over financial reporting.

In further response to Staff's Comments 6 through 9, the Company proposes that we expand the existing disclosure and include disclosure substantially similar to the following in our future periodic report filings with the Commission (based on Form 10-K in this example):

Item 9A. Controls and Procedures.

(a) Evaluation of disclosure controls and procedures. Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the fiscal year ended December 31, ____. Based on this evaluation, the principal executive officer and the principal financial officer conclude that our disclosure controls and procedures were effective as of the end of the fiscal year ended December 31, ____ to ensure that information that is required to be disclosed by us in the reports we file or submit under the Exchange Act is (i) identified, recorded, processed, summarized and reported, on a timely basis and (ii) accumulated and communicated to our management, as appropriate, to allow timely decisions regarding required disclosure.

(b) Changes in internal control over financial reporting. There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Securities Exchange

Act, in the fourth quarter of fiscal _____ that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting and the Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting thereon are set forth in Part II, Item 8 of this report on Form 10-K on page ___ and page ___, respectively.

Schedule 14A filed April 2, 2009

General

10. *Regarding the comments that follow for the Schedule 14A filed April 2, 2009, please confirm in writing that you will comply with comments in all future filings, and provide us with an example of the disclosure you intend to use in each case. After our review of your responses, we may raise additional comments.*

Response: The Company confirms that all of our future Schedule 14A filings will be consistent with the responses provided below to each of the Staff's comments, including incorporating any language provided below as applicable.

Compensation Discussion and Analysis, page 23
CEO Recommendation, page 26

11. *We note that your compensation committee is guided by recommendations from your president and CEO. In addition, "[s]enior members of [y]our management team including the chief executive officer provide recommendations regarding many aspects of [y]our compensation program, including executive compensation." Please clarify the compensation committee's role and authority with respect to final compensation determinations for the CEO and to what extent the CEO is permitted to make recommendations regarding his own salary. See Item 407(e)(3) of Regulation S-K.*

Response: We propose that, in the event such disclosure remains true and correct, we expand the existing disclosure and include disclosure substantially similar to the following in our future Schedule 14A filings:

While the Compensation Committee considered the recommendations of the Chief Executive Officer with respect to the various elements of compensation for each executive officer, the Compensation Committee had complete discretion over all decisions regarding compensation for our executive officers, including for the Chief Executive Officer. As the highest ranking officer involved in the management of the Company, the Chief Executive Officer is in the best position to assess the individual performance of each executive officer and, as a result, the Chief Executive Officer may make recommendations regarding the compensation of all executive officers, including himself, based on any factors he deemed relevant; however, the Compensation Committee makes its determinations of all executive officer compensation in its absolute discretion. The Compensation Committee independently evaluated the recommendations of the Chief Executive Officer and made all final compensation decisions. The Compensation Committee decided the base salary, bonus targets, and long-term incentive award for each of the executive officers, including the Chief Executive Officer, in executive session.

Determining Executive Compensation for 2008, page 24

12. *Please describe and clarify what is meant by the "internal equity and analysis of [y]our executive compensation program."*

Response: In future filings the Company will clarify that when determining compensation for each of our executive officers, the Compensation Committee, in its discretion, may consider the level of compensation of each such officer relative to the others. The Compensation Committee may consider a comparison of each executive officer's relative compensation, performance, and special complexities or difficulties related to his or her position during the applicable period when making compensation determinations. In future filings, we propose to delete the existing bullet on page 24 of the Company's Schedule 14A filed April 2, 2009 addressing "internal equity analysis" and propose that, in the event such disclosure remains true and correct, include disclosure substantially similar to the following:

- Information regarding the compensation, performance, responsibilities, difficulties and complexities related to each executive officer's role in our company relative to the other executive officers; and

Market and Peer Group Review, page 24

13. *We note that the peer group for your shareholder return performance graph and the peer group used by your compensation committee differ. Please explain the reason for the difference.*

Response: The Company believes that the disclosure of the selection process for the peer group for collecting compensation data and the rationale for the selection of such peer group is set forth on pages 24-25 of the Company's Schedule 14A filed April 2, 2009. This disclosure accurately reflects both our process and the disclosure requirements set forth in Schedule 14A and Regulation S-K. We note that Item 2.01 of Regulation S-K requires a performance graph showing cumulative total returns of the Company compared to the total returns of a peer group determined on the basis of industry or line of business (or other criteria disclosed by the

Company). A peer group selected on the basis of industry or line of business will not in all cases completely coincide with the objectives of the independent compensation consultant and the Compensation Committee.

The Company's performance graph required by Item 2.01 of Regulation S-K includes a comparison to total returns to a peer group of twelve companies selected by the executive management team as examples of our closest competitors in our respective services business and our oil and gas exploration business. The Company believes that this complies with the disclosure requirements in Item 2.01 of Regulation S-K.

On the other hand, the peer group used by our Compensation Committee is determined by that committee based on a peer group suggested by the independent compensation consultant engaged by the Compensation Committee. The independent compensation consultant proposes companies to be included in the peer group and management annually reviews such proposal to ensure that the companies proposed by the compensation consultant are appropriate. The Compensation Committee then reviews and approves the members of the peer group as it deems appropriate. The peer group proposed by the independent compensation consultant is comprised of companies in similar businesses and of similar size (based on revenue, market capitalization and enterprise value) that would be likely competitors for hiring executive talent, as opposed to being solely business competitors. In addition, the members of the proposed peer group must have reliable compensation data, must generally conform to a traditional compensation structure and must generally have executive positions similar to ours. In addition, considering these factors, the proposed peer group taken as a whole must contain a sufficient number of companies with reliable compensation information available so as to yield good reliable data for purposes of comparing executive compensation.

<u>Cash Bonus Program, page 27</u>

14. *We note that your inability to achieve your company performance financial objectives, your cash bonus awards were significantly reduced or, in the case of Mr. Kratz, were not paid at all. Please provide factors used by the compensation committee used in making this determination, including the company performance financial objectives and group performance budgetary and other goals.*

<u>Response</u>: We point to the disclosure on page 27 of the Company's Schedule 14A filed April 2, 2009 which states that "the committee awards bonuses for the previous year at its first meeting of the year based upon the exercise of its discretion." The amount of each element of executive compensation, including the amount of any cash bonus, is determined completely at the discretion of the Compensation Committee. The Compensation Committee did not establish objectives for each individual executive officer for 2008. Rather, the Compensation Committee engaged in a detailed discussion with respect to the performance of each executive officer. Based on those discussions, the Compensation Committee made a determination as to whether the Company's performance and/or the executive officer's performance warranted the payment of a bonus, and if so, determined the amount of such bonus in its discretion considering many factors as it deemed appropriate. These factors included the individual's performance, the difficulty of the officer's role, and the challenges and difficulties the officer may have faced during a difficult period for the Company, financially, and operationally. In future filings we will disclose whether targets or goals were established with respect to a bonus for the executive officers and, if so, identify them if such disclosure would not result in substantial competitive harm to the Company.

2009 Bonus Plan, page 28

15. *Please disclose the material differences in compensation policies and performance with respect to individual named executive officers. Refer to Section II.B.1 of Commission Release No. 33-8732A. For example, there is a significant disparity in the amount of an increase in the 2009 bonus target for the CEO as compared to that of the other named executive officers. Please provide a more detailed discussion of how and why the increase in the bonus target for the CEO differs so significantly from the increase given the other named executive officers.*

Response: The Company advises the Staff that as stated in the Company's Schedule 14A filed April 2, 2009, an overall compensation goal for executive officers has been to set annual base salary at or near the 50^{th} percentile of the peer group or survey data, and overall compensation (base salary, cash bonus opportunity and long term incentive compensation) at or near the 75^{th} percentile of the peer group or survey data. As a result, a substantial portion of overall compensation consists of incentive compensation consistent with our compensation principles. With respect to fiscal 2009, base salary and long term incentive compensation were not increased from the 2008 compensation levels for each executive officer, other than Mr. Hajdik whose increase was due to an increase in his role and responsibilities at the Company. As a result, any increase in the overall compensation target of each executive officer was directly reflected in the cash bonus opportunity and cash bonus opportunity for 2009 generally reflects the amounts obtained by subtracting base salary and long term incentive awards from the total compensation at or near the 75^{th} percentile as determined by the peer group or survey data. The amount of any actual cash bonus will be awarded at its first meeting in 2010 based upon the exercise of the Compensation Committee's discretion after its review of the data provided by management and any other data deemed appropriate by such committee. In future filings, we will include any required disclosure related to the determination of executive compensation levels.

Engineering Comments

Risk Factors, page 18

Approximately 87% of our total estimated proved reserves are....., page 26

16. *You report that approximately one half of your proved reserves are in the Bushwood field in the Gulf of Mexico. On page 33, you indicate that the field is comprised of 90% gas, located in the deepwater, and that you expect first production in January 2009. As your report was filed in March of 2009 we expect that you commenced production in January as scheduled. Please explain why the disclosure was not updated to clarify prior to filing. Please also provide us with the following information about this field:*

- *The current status of the field and the date it first went on production;*
- *The basis for reporting 314 BCFe of proved reserves net to your interest;*
- *The number of wells on production, the date you ran open hole logs for each well, and whether you expect to add additional wells;*
- *The current production rate of the field and the expected maximum production rate the field is expected to achieve;*
- *The current status of the pipelines necessary to transport production to market;*
- *The location where you are currently marketing the oil and gas production.*

Response: The Company acknowledges the table on page 33 of the Annual Report on Form 10-K for the year ended December 31, 2008, could have been updated to show the exact date sustained production commenced in January 2009. The disclosure was meant to inform the reader that production from the Bushwood field was a recent event. To modify the disclosure to "producing" could have had the unintended consequence of making it appear the field had been producing for some substantial period of time, or at a minimum that it was producing on December 31, 2008. The Company would direct the Staff to the disclosure on page 46 of the Annual Report on Form 10-K for the year ended December 31, 2008, where we state that sustained production commenced in January 2009.

- *The current status of the field and the date it first went on production;*

Initial sustained production from the Bushwood field commenced in January 2009. The field's limited test production began in August 2008; however, the field only produced a few days before being shut in as a result of Hurricanes Gustav and Ike.

- *The basis for reporting 314 BCFe of proved reserves net to your interest;*

The Company determines its proved reserves estimates using log and production data. The Company's log data and maps were reviewed by Huddleston & Co., Inc. which audited our internal estimates of proved reserves as described in “Summary of Natural Gas and Oil Reserve Data” and in Note 21 “Supplemental Oil and Gas Disclosures” on page 32 and pages 123 and 124, respectively, of the Company’s Annual Report on Form 10-K for the year ended December 31, 2008.

- *The number of wells on production, the date you ran open hole logs for each well, and whether you expect to add additional wells;*

The Bushwood field is currently producing from two wells out of the Lentic formation. One additional well has been completed and production will commence once certain flowlines are installed . The field was discovered in January 2007 and three separate accumulations have been proven through the wells and log dates listed below:

· Garden Banks Block 506 #1 OH	January 4, 2007
· Garden Banks Block 506 #1 ST1	January 30, 2007
· Garden Banks Block 506 #1 ST2	February 22, 2007
· Garden Banks Block 506 #2	July 10, 2007
· Garden Banks Block 506 #3	December 19, 2007
· Garden Banks Block 463 #1	December 28, 2008

` Two additional wells will have to be drilled as well as an updip sidetrack well to recover all currently estimated proved reserves.

- *The current production rate of the field and the expected maximum production rate the field is expected to achieve;*

Limited test production was established in August 2008; however, Hurricane Ike caused severe damage to a third party pipeline, which required the field to be shut in until January 2009. During this time the Company installed an alternative pipeline to allow natural gas sales while additional damage is being repaired to a third party pipeline. The alternative pipeline constructed by the Company allowed the Bushwood field to commence sustained production on January 17, 2009. Currently, the field flows at a constrained gross rate of 31 million cubic feet of natural gas per day (MMcfd). Once the third party pipeline is repaired, the expected peak gross rate for the Bushwood field will approximate 100 MMcfd. Following the completion of another pipeline being constructed by the Company, an approximate additional 7,500 barrels of oil and 17 MMcfd of gas per day will be produced from the field.

- *The current status of the pipelines necessary to transport production to market;*

As noted above, currently a third party pipeline owner is repairing the pipeline to service the natural gas production from the Bushwood field. The Company has been informed by the third party pipeline owner that these repairs are on schedule to be completed in the fourth quarter of

2009. The Company is currently constructing an 8” x 12” oil pipeline connected to the host facility at East Cameron Block 381, which will allow for production of an approximate 7,500 barrels of oil per day from the field. Completion of this line is expected during the first quarter of 2010.

· *The location where you are currently marketing the oil and gas production.*

The Company is marketing its gas production at the Sabine Hub. Following installation of its oil pipeline, its oil production will be marketed at the Stingray Separation Facility.

<u>Significant Oil and Gas Properties, page 33</u>

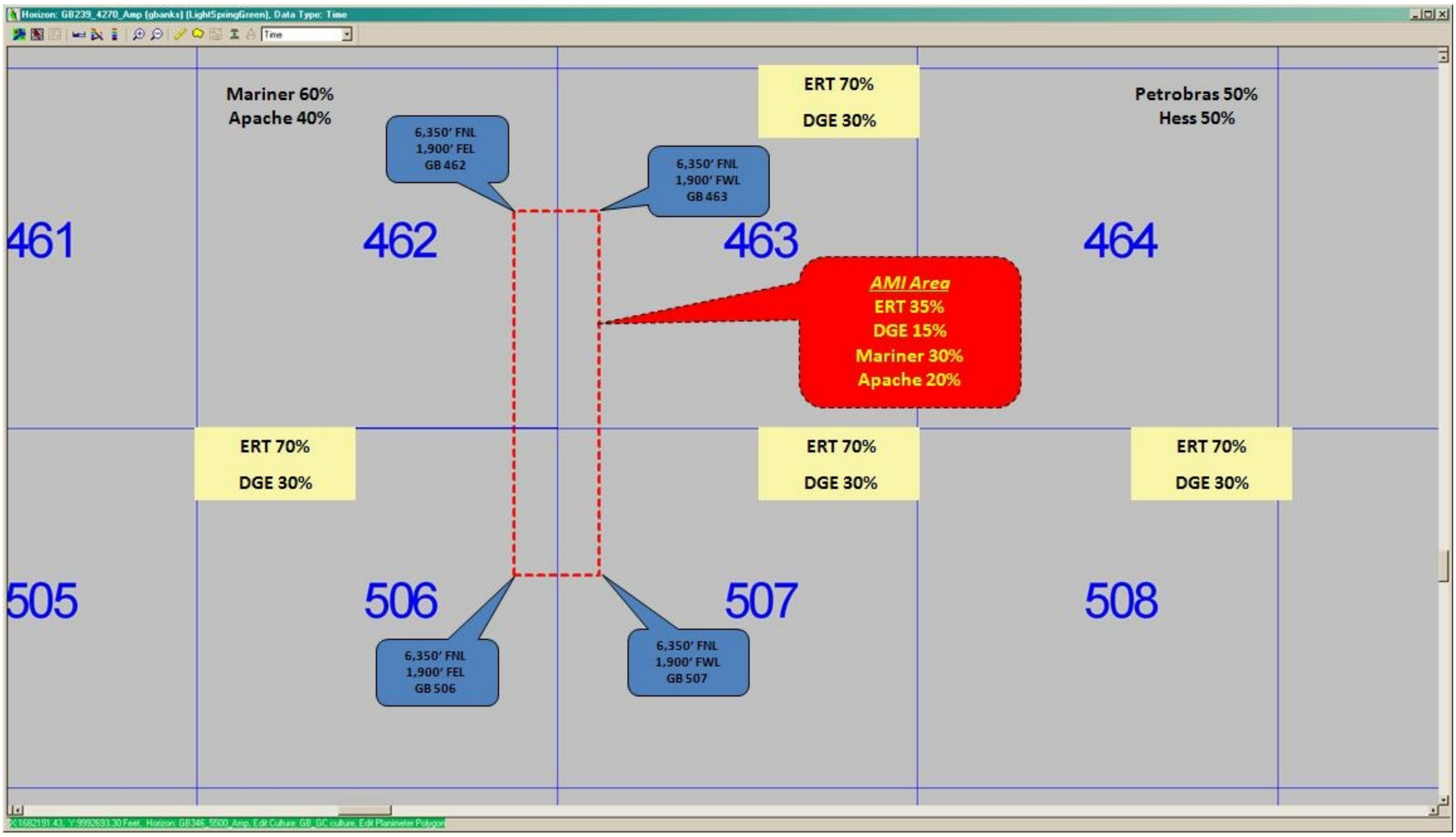
17. *Regarding the Bushwood field, we see that you report in the table that you have a 51% working interest, 314 BCFe of proved reserves net to your interest, and expect first production in January 2009. We note that in your 2007 10-K you reported that you had a 100% working interest in this field, 206 BCFe of proved reserves net to your interest, and expected first production in 2008. Please tell us the following:*

· *How the reserves could have been increased by 52% in one year when there was no production and when your net interest decreased by 49%;*
· *The reason the field was not placed into production in 2008;*
· *Whether the engineer from Huddleston & Co. was informed of the decrease in working interest from 2007 when he performed his 2008 reserve audit.*

<u>Response</u>:

· *How the reserves could have been increased by 52% in one year when there was no production and when your net interest decreased by 49%;*

The increase in proved reserves related to the development of an Area of Mutual Interest (AMI) with the owners of Garden Banks Block 462 (see map below). As a result of the AMI agreement, we were able to obtain supporting data to map a contiguous reservoir from Garden Banks Block 506 through the AMI block and onto Garden Banks Block 463. Furthermore, the AMI concluded with the drilling of Garden Banks Block 463 #1 that extended proven limits for the proven Lentic reservoir and discovered a new accumulation deeper. The product of additional acreage ownership, wellbore interest, well data and new pool discovery yielded the additional reserves net to ERT despite the lower working interest.



· *The reason the field was not placed into production in 2008;*

As mentioned above in response to Comment 16, the Bushwood field commenced production in August 2008 but was shut in shortly thereafter because of Hurricane Ike. Following Hurricane Ike there was substantial damages to a third party pipeline. In January 2009, the Company was able to commence sustained production from the Bushwood field following the construction and installation of an alternative pipeline but at restricted rates due to smaller pipeline size in relation to the damaged third party pipeline.

· *Whether the engineer from Huddleston & Co. was informed of the decrease in working interest from 2007 when he performed his 2008 reserve audit.*

The 314 Bcfe of proved reserves for the Bushwood field were based on internal reservoir estimates. These estimates were reviewed by independent reservoir engineers, Huddleston & Co., Inc. which audited our internal estimates of proved reserves as described in "Summary of Natural Gas and Oil Reserve Data" and in Note 21 "Supplemental Oil and Gas Disclosures" on page 32 and pages 123 and 124, respectively, of the Company's Annual Report on Form 10-K for the year ended December 31, 2008. The audit included the review and discussion of all pertinent data including maps, log data and working/ net revenue interests.

Costs Incurred in Oil and Gas Producing Activities, page 122

18. *We note that you report $17.7 million in costs to acquire proved properties in 2008 on the first line of your table on page 122. Tell us why the reserve reconciliation tables on pages 124 and 125 do not show any purchase of oil and gas reserves in 2008.*

Response: The Company acknowledges that the $17.7 million reported as proved property acquisition costs within the Company's Cost Incurred in Oil and Gas Producing Activities disclosure represents the recorded capitalized interest associated with its development activities during 2008. The Company has historically reported such amounts on this line; however, it acknowledges that these amounts are better categorized as a component of development costs. Accordingly, we propose that in future periodic report filings, the Company will report its capitalized interest associated with development activities as development costs rather than proved property acquisition costs.

As the $17.7 million represented was recorded as capitalized interest rather than an actual acquisition of a producing property, the absence of any proved reserves is appropriate.

Estimated Quantities of Proved Oil and Gas Reserves, page 123

19. *We note that in 2008 there was a material decline in the percentage of reserves that were classified as proved undeveloped as compared to 2007. Please disclose the reasons for this change in the relative significance of the undeveloped reserves.*

Response: A majority of the category movement was associated with the Bushwood gas reservoir where a significant amount of proved undeveloped reserves were converted to proved developed during 2009. As previously noted in response to Comment 16, the Bushwood field was shut-in following Hurricane Ike and as such its proved developed reserves were reclassified to proved developed/shut in at December 31, 2008. In addition, the Company sold properties in 2008 that represented a total of approximately 96 Bcfe of proved undeveloped reserves at year end 2007.

20. *We note that you report significant reserve changes in several line items of the reserve reconciliation table but do not provide explanations for those changes. Please disclose the reasons for all significant changes as required by paragraph 11 of SFAS 69.*

Response: The Company utilizes the prescribed captions, as required under paragraph 11 of SFAS 69, that are significantly represented within its operations. The Company believes that the explanation of these changes is provided for within our Changes in Standardized Measure of Discounted Future Net Cash Flows disclosure on page 127 of our Annual Report on Form 10-K for the year ended December 31, 2008. In this disclosure, the Company provides the amount of the changes in its future discounted cash flows caused by specific types of events or circumstances. The Company believes that this information provides the data necessary to understand the effect of the changes to its estimated proved reserves. For 2008, the significant amount of changes in reserves is attributed to changes in prices and production costs as noted by the $1.7 billion reduction in estimated future discounted cash flows. This can be further illustrated by the inclusion of the average price per barrel of oil and per Mcf for natural gas as contained in the Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves.

In connection with responding to the Comments above, we acknowledge that:

- we are 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
- we 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 any member of the Staff has any questions concerning these matters or needs additional information or clarification, he or she should contact the undersigned at (281) 848-0431.

Very truly yours,

/s/ Anthony Tripodo

Anthony Tripodo, Executive Vice President and Chief Financial Officer

cc: Karl Hiller (Branch Chief-Securities and Exchange Commission)
Michael Overman (Helix)
Lloyd Hajdik (Helix)
Robert Murphy (Helix)
Alisa Johnson (Helix)
Marty Hall (Helix)