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Patrick T. Mulva
Vice President and Controller

ExxonMobil

**FOIA CONFIDENTIAL TREATMENT REQUESTED BY
EXXON MOBIL CORPORATION**

August 25, 2011

Mr. H. Roger Schwall
Assistant Director
U.S. Securities and Exchange Commission
Division of Corporation Finance
100 F Street, N.E.
Washington, DC 20549

Re: Exxon Mobil Corporation
Form 10-K for Fiscal Year Ended December 31, 2010
Filed February 25, 2011; amended February 28, 2011
File No. 1-02256

Dear Mr. Schwall:

On behalf of Exxon Mobil Corporation, please find enclosed our response to your comments regarding the above filing set forth in your letter of July 5, 2011.

We also acknowledge 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 desire clarification of our responses, please direct any questions to Mr. Stephen Littleton at 972-444-1290.

Sincerely,
By: /s/ Patrick T. Mulva

Name: Patrick T. Mulva
Title: Vice President and Controller

Enclosure

c: Mark Wojciechowski

ExxonMobil's Response to the
Comments Included in the SEC Letter of July 5, 2011

Form 10-K for Fiscal Year Ended December 31, 2010

General

1. *We note that unconventional oil and gas plays appear an increasing part of your business, and that an increasing industry practice in such unconventional plays is the use of hydraulic fracturing. Please tell us, with a view to disclosure:*
   - *The location of your hydraulic fracturing activities;*
   - *Your acreage subject to hydraulic fracturing;*
   - *The percentage of your reserves subject to hydraulic fracturing;*
   - *The anticipated costs and funding associated with hydraulic fracturing activities; and*
   - *Whether there have been any incidents, citations, or suits related to your hydraulic fracturing operations for environmental concerns, and if so, what your response has been.*

   Although the hydraulic fracturing process has recently received increased public attention due to its use in the growing production of certain "unconventional" oil and gas resources (namely shale gas and oil, "tight" gas and oil, and coal bed methane (CBM)), hydraulic fracturing has been used by industry since the 1940s in more than one million wells in the United States. ExxonMobil and industry at large have long experience in managing the associated risks, and along with state regulatory authorities have an excellent track record of responsible operations and oversight with no documented harm to groundwater supplies as a direct result of hydraulic fracturing operations. We do not consider the specific operational risks relating to hydraulic fracturing to be materially different in nature or magnitude than the many other operational risks we manage every day in our oil and gas operations around the world. Given the modest nature of these risks and the relatively modest contribution of unconventional resources to our total reserves, we also do not believe that additional specific disclosure concerning hydraulic fracturing in our Form 10-K is necessary or appropriate.

   In response to your specific questions:

   We currently have acreage positions subject to hydraulic fracturing throughout the U.S. and across the globe, as we have discussed publicly in our annual analyst meetings, congressional hearings, and elsewhere. Domestically, we have acreage positions in the Barnett, Marcellus, Woodford, Haynesville, Fayetteville, Eagle Ford, and Bakken shale plays; tight gas holdings across east Texas and the Rocky Mountains; and CBM acreage in the San Juan Basin and southern Rockies. Internationally, we currently have leased shale acreage in Canada, Poland, Germany, and Argentina; tight oil holdings in Canada; tight gas holdings in Germany and China; and CBM holdings in Germany and Indonesia. These unconventional resource holdings account for approximately 10.2 million acres or about 13 percent of our total acreage holdings, and approximately 3.5 billion barrels equivalent or about 14 percent of our proved reserves. However, approximately 2.2 billion barrels equivalent is classified as proved developed and has already undergone hydraulic fracturing. The remaining 1.3 billion barrels equivalent or approximately 5 percent of proved reserves is classified as proved undeveloped and is subject to hydraulic fracturing in the future.

The cost of hydraulically fracturing a well is dependent on the characteristics of the specific reservoir targeted and the complexity of the fracture treatment program. The cost is generally between $150 thousand and $2 million per well, however, more complex or multi-lateral treatments can cost more. Anticipated annual hydraulic fracturing costs are expected to be a relatively small portion of our overall annual capital investment program. As noted in MD&A under "Liquidity and Capital Resources -- Sources and Uses of Cash," the Corporation has access to significant long-term and short-term liquidity capacity, but internally generated funds cover the majority of our financial requirements. This includes costs of hydraulic fracturing.

The Corporation to date has not experienced any incidents, citations or suits related to hydraulic fracturing operations that would be material to investors.

2. *With regard to your hydraulic fracturing operations, please also tell us what steps you have taken to minimize any potential environmental impact. In this regard, we note Mr. Tillerson's comments at the Analyst Meeting on March 9, 2011 in which he cited "obligations on well operators to monitor …casing strength" and the "challenge…in handling the large volumes of fluids on the surface." For example, and without limitation, please explain if you:*

- *Have steps in place to ensure that your drilling, casing, and cementing adhere to known best practices;*
- *Monitor the rate and pressure of the hydraulic fracturing treatment in real time for any abrupt change in rate or pressure and/or detection of fluid leak-off;*
- *Evaluate the environmental impact of additives to the hydraulic fracturing fluid, including disclosure of all chemicals involved, in the volume/concentration and total amounts utilized;*
- *Perform a baseline assessment of nearby water sources, and have the capability to monitor for, and potentially detect, these chemicals in local water supplies; and*
- *Minimize the use of water and/or dispose of the flowback water in a way that minimizes the impact to nearby surface water.*

As noted above in our response to Question 1, ExxonMobil has extensive experience of safely managing hydraulic fracturing operations and we do not believe these operations pose any exceptional risks or challenges for which additional specific disclosure in our Form 10-K would be necessary or appropriate.

During hydraulic fracturing operations, a mixture of water and proppants (usually fine grain sand) and trace levels of several chemicals (0.5% – 2% of total solution) are pumped deep underground under pressure to create small fissures in the target rock formation. The proppants hold open the fissures so the previously entrapped gas (or oil) can flow to the wellbore. Due to the depth at which the target formation lies, and layers of rock between groundwater resources and the target formations, the chances of the fracturing process itself contaminating groundwater reservoirs is extremely low. (Note: the FracFocus website sponsored by the state-level Groundwater Protection Council and Interstate Oil and Gas Compact Commission, discussed below in Question 3, provides background information on the fracturing process, the purpose of the chemicals used, how groundwater is protected, and other associated topics.)

Every oil and gas well, conventional or unconventional, and whether or not ultimately "fracked," is drilled through the groundwater zone whether or not groundwater is present. After doing so, and before any fracturing operations occur, the water resource is protected by multiple layers of steel casing and cement near the surface and the aquifer. Properly installed, casing protects the water aquifer from migration from other formations. As noted, this groundwater zone penetration occurs with oil and gas wells, and ExxonMobil has longstanding experience in managing well integrity. The "best" practice for installing the layers of casing varies and depends on local factors – geology, hydrology, depth of water reservoirs, depth of target formation, etc. The American Petroleum Institute has a long history of developing and maintaining recommended practices and standards with respect to drilling, casing, and cementing. ExxonMobil actively participates in this industry effort. Sound operational principles are applied to ensure compliance with governing state regulatory standards, and in some cases, based on our own operational experience, exceed regulatory standards.

To ensure safe and effective operations, flow rates and pressure are continuously monitored real time as the hydraulic fracturing process occurs, and site operations are overseen by ExxonMobil personnel.

The environmental impacts of frac fluid additives are evaluated by the service companies that provide them, and to the best of our knowledge, the service companies comply with OSHA's Material Safety Data Sheet (MSDS) requirements. These MSDS sheets are kept on site during well drilling and fracturing operations. See the response to Question 3 below for additional information on disclosure of frac fluid additives. Baseline assessments of nearby water supplies are generally not required by states, but are performed in certain instances.

States regulate water withdrawals and the siting of wells near surface water sources. We seek to minimize environmental impacts and burdens on local water infrastructure, and are using increasing amounts of recycled water. Local water availability, disposal options, and other factors govern when treatment and recycling is undertaken.

Multiple options exist for complying with wastewater disposal regulations, with the selection depending upon the surrounding geology, available infrastructure, and applicable requirements. The flowback water can be treated and re-used on-site or treated through the same facilities that manage similar types of wastewater from other industrial systems. If the wastewater is not reused, it is injected into deep saline formations using wells specifically permitted for this purpose. Solids from treatment are also disposed in permitted facilities.

3. *Please supplementally provide us with a report detailing all chemicals used in your hydraulic fracturing fluid formulation/mixture, in the volume/concentration and total amounts utilized, for representative wells in each basin where hydraulic fracturing is a method you use*.

ExxonMobil was the first major oil and gas operator to publicly state its support for the disclosure of fracturing fluid ingredients on a well by well basis. Several states currently have regulatory requirements addressing disclosure of the chemicals used in hydraulic fracturing fluids. For states that do not have regulatory requirements regarding disclosure, we utilize the FracFocus online registry sponsored by the Groundwater Protection Council and Interstate Oil and Gas Compact Commission. See www.fracfocus.org.

This website includes all the specific data requested (which varies by region, play, and even by location within a play) for representative wells across the various plays. See also https://www.hydraulicfracturingdisclosure.org/fracfocusfind/, and choose XTO/ExxonMobil under the Well Operator tab. Attached for your reference are several reports from various plays as entered into and available at the FracFocus registry.

We are currently in the process of entering additional ExxonMobil data on the FracFocus website and expect that process to be complete before year end.

4. *At an appropriate place in the MD&A discussion or elsewhere, please disclose the scope and limits of your insurance coverage with respect to pollution liability.*

As noted under the heading "Safety, business controls, and environmental risk management" under Item 1A in our Form 10-K, the ability to insure against the environmental risks inherent in our business is limited by the capacity of the applicable insurance markets, which may not be sufficient. Given the size and scope of our business, the Corporation is effectively self-insured with respect to any potential pollution liability that would be of such a magnitude as to be material to our investors. Accordingly, we do not believe further discussion of insurance in the MD&A would be appropriate.

5. *We note press reports dated February 23, 2011 indicating that ExxonMobil may have been “hacked” resulting in the loss of project-financing information regarding certain oil and gas field bids and operations. We are unable to locate any disclosure from you addressing such incident(s). Please advise us to what consideration you have given to providing risk factor or other disclosure about this event(s) or possible similar future events and their actual potential effects upon your operations.*

To the best of our knowledge, the referenced media reports concerning a hacking incident against ExxonMobil were false. As in all aspects of risk management, ExxonMobil maintains rigorous systems to protect against cybersecurity breaches. To date, no cybersecurity issues have had any serious or residual consequences for the Corporation. However, in future filings, we will expand our discussion of risk factors under Item 1A in our Form 10-K to include language specifically highlighting cybersecurity risks substantially along the following lines:

> "Business risks include cybersecurity breaches. If management's systems for protecting against cybersecurity risks prove not to be sufficient, the Corporation could be adversely affected such as by having its data management systems compromised or its proprietary information lost or stolen."

Properties, page 6

Disclosure of Reserves, page 6

6. *For the Europe, Africa, Asia, and Australia/Oceania geographic areas, please tell us the specific countries included in the areas, and the corresponding amount of total proved developed and undeveloped reserves associated with each country as of December 31, 2010.*

   We are in compliance with the requirement to separately disclose reserves for each country with 15% or more of total proved reserves to the extent that we are not subject to restrictions that the government of a country has imposed on us, or where disclosure of the reserves associated with an individual field would occur. The following table lists the specific countries included in each of the Europe, Africa, Asia and Australia/Oceania geographic areas. The table also provides the portion of the year-end 2010 total reported proved reserves of 24,809 million oil equivalent barrels for each area and the amounts classified as proved developed and proved undeveloped. Consistent with restrictions imposed by The State of Qatar and Angola on separately disclosing reserves in their countries, and to avoid disclosing field level reserves for countries where the reserves are related to a single field (*), country specific information for the Africa and Asia areas has not been provided.

   [Confidential information omitted; XOM-001]

7. *We note that crude oil represents a decreasing portion of your proved reserves, and that, as of December 31, 2010, crude oil represented less than half or your total proved reserves on the BOE-basis used in your filing. With a view towards expanded disclosure, tell us whether you expect this trend to continue. Additionally, describe any risks associated with this trend, as well as the reasonably possible impact of this trend on your financial position, results of operations or liquidity in future periods.*

   ExxonMobil utilizes a well established and highly disciplined approach when evaluating projects and when considering potential acquisitions. Our approach focuses on the quality and attractiveness of each specific opportunity and not necessarily on the product mix it will provide. Due to the size and unique product mix in any given opportunity we consider, we would expect that the relative proportion of liquids and gas in our reported proved reserves will vary (up and down) over time depending on the timing of completion of specific large development projects, as well as the timing of acquisitions or divestments.

   During 2010, net additions to proved reserves through acquisitions and projects exceeded production for both liquids and gas. However, our acquisitions, which were dominated by XTO, added more gas on an oil equivalent basis than liquids and resulted in the shift in the relative proportion that the SEC Staff noted.

   Notwithstanding the relative increase in gas reserves in 2010 (from 49.3% at year-end 2009 to 52.9% gas at year-end 2010), our portfolio remains relatively evenly split between liquids and gas. Looking at proved reserve changes over a one year period is not representative of the long-term nature of project development in the oil and gas industry. We believe that a view of proved reserves over an extended period is a more meaningful indicator. In fact, ExxonMobil's proportion of proved liquids and gas reserves over the past five years has averaged 50%.

Qualifications of Reserves Technical Oversight Group and Internal Controls over Proved Reserves, page 7

8. *Your disclosure under this section makes reference to "ExxonMobil's proved reserves". Confirm to us that this reference is to reserves determined in accordance with SEC rules and regulations, including pricing assumptions. If this is not the case, revise your description of these quantities to refer to them as something other than "proved reserves".*

   We confirm that the reserves referenced in the noted text were prepared in accordance with SEC rules and regulations, including pricing assumptions. The following excerpt from the 2010 Exxon Mobil Corporation 10-K, page 107, Index to Financial Statements, Oil and Gas Reserves is provided for your reference. Please refer to the full text on this page for a more complete description of the approach we have used.

   > *In accordance with the Securities and Exchange Commission's rules, the year-end reserves volumes for 2009 and 2010 as well as the reserves change categories for 2009 and 2010 shown in the following tables were calculated using average prices during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period. The year-end reserves volumes for 2008 as well as the reserves change categories for 2008 shown in the following tables were calculated using December 31 prices and costs. These reserves quantities are also used in calculating unit-of-production depreciation rates and in calculating the standardized measure of discounted net cash flow.*

Drilling and Other Exploratory and Development Activities, page 13

9. *We note the significant increase in the number of development wells drilled in the United States during 2010 as compared to the two prior years. With a view towards expanded disclosure, tell us the reasons for this increase. Additionally, tell us the extent to which you expect this to continue in future years. Finally, describe the reasonably possible impact of this increased drilling on your financial position, results of operations and liquidity in future periods.*

   The increase in the number of development wells drilled in the U.S. during 2010, as compared to the prior two years, is attributable to the XTO acquisition, completed in June 2010. We expect a further increase in the number of development wells drilled in the U.S. in 2011, reflecting the full year impact of XTO's activities. The number of development wells to be drilled in 2012 and future years will depend on a number of factors, including the risk factors described in Item 1A in the company's Form 10-K.

   The noted higher level of development drilling is expected to be covered by internally generated funds and is not expected to have an adverse impact on our financial position or liquidity.

<u>Review of Principal Ongoing Activities, page 16</u>

<u>Iraq, page 18</u>

10. *We note that you entered a contract with South Oil Company of the Iraqi Ministry of Oil to redevelop and expand the West Qurna (Phase 1) oil field. Please provide us a summary of the significant terms of this contract. Please also tell us if you have booked proved reserves related to this project. If so, please furnish to us a detailed explanation of the contractual arrangements that support your claim to proved reserves. Address the capital you will have at risk, the contractual oil price(s) and the cost recovery and profit apportionment of derived revenue.*

    The West Qurna (Phase 1) contract ("Contract") for rehabilitation of production and enhanced recovery of petroleum from the West Qurna (Phase 1) oil field ("Petroleum Operations") has a 20 year term with a right for the Contractor Group to extend for an additional five year period. The entities comprising the Contractor Group are ExxonMobil Iraq Limited (60% interest), Shell West Qurna B.V. (15% interest) and the Oil Exploration Company of the Iraqi Ministry of Oil (25% interest, but carried by the other participants for some portion of its costs).

    As directed by the Contract, Petroleum Operations are conducted by an unincorporated joint operating entity, the West Qurna (Phase 1) Field Operating Division ("FOD"), formed by the Contractor Group and the South Oil Company ("SOC"). Per the Contract, the Contractor Group has appointed ExxonMobil Iraq Limited to serve as Lead Contractor and, in such capacity, to take a substantial role in the supervision, direction and management of planning, decisions, and surveillance as well as the day-to-day conduct of operations by the FOD. The FOD also receives general direction from a Joint Management Committee composed of four SOC representatives and four representatives from the Contractor Group.

    The Contract provides for an initial rehabilitation period of up to 36 months to arrest production decline and achieve a production increase to raise rates to at least 110% of the initial production. This is followed by a full field redevelopment period to achieve an agreed production plateau. The Contract also requires commitment to a minimum work program and related investments and expenditures. Discovered but currently undeveloped reservoirs may also be developed and produced. The Contract also provides exclusive rights to negotiate terms for exploration of other potential reservoirs in the contract area.

    Contractor's entitlement is based on: a) recovery of "Petroleum Costs" (i.e. expenditures incurred and payments made in connection with Petroleum Operations), b) recovery of "Supplementary Costs" (i.e. recoverable costs other than Petroleum Costs including, but not limited to, certain field preparations, environmental work, crude transportation facilities and other required work), and c) receipt of a "Remuneration Fee" (for discovered developed reservoirs) and an "Additional Remuneration Fee" (for discovered undeveloped reservoirs), which are amounts per barrel of incremental production. The Remuneration Fee and Additional Remuneration Fee are subject to R-Factors (ratios of cash receipts to aggregate expenditures) and performance factors (ratios of actual production during the plateau period to the Plateau Production Target agreed in the Contract), which may act to reduce these entitlement components. The recovery of Petroleum Costs and receipt of Remuneration Fees commences upon the earlier of achieving 110% of initial production or 36 months after the field Rehabilitation Plan is approved.

Contractor's entitlement may be received in crude or in cash. SOC has the option to make a one-time election on whether to pay Supplementary Costs in crude or cash; Contractor has the right to make an annual election to receive Petroleum Costs, Remuneration Fees and Additional Remuneration Fees in crude or cash. In the event SOC is unable to make any payment in crude, then payment shall be made in cash. An oil price, based on the prevailing Iraq export market price, is utilized for determination of contractor entitlement.

While certain capital investments and costs are recoverable under the terms of the Contract, in the event of early termination by either party, Contractor is obliged to pay SOC any unspent portions of a "Minimum Expenditure Obligation" specified in the Contract. Such payment is not recoverable and therefore at risk (though the amount of any payment would not be material to ExxonMobil's investors). The ability to report reserves is based on the revenue interest in production established by the Contract, the commitment of significant capital to the project over its 20 year life, and further supported by our role as Lead Contractor in the management and supervision of Petroleum Operations undertaken by and through the FOD. At year-end 2010, we carried a very small quantity of proved reserves (< 5 million oil-equivalent barrels) for West Qurna (Phase 1) related to Supplementary Cost Recovery entitlement. ExxonMobil provided additional information regarding the Contract in response to a question by the SEC contained in its letter to the Company of April 1, 2010.

11. With regard to your activities in Iraq, we note you filed a press release on March 28, 2011 explaining that you reached a "major production milestone in the redevelopment of the West Qurna I oil field in Southern Iraq. Initial field production of 244,000 barrels per day has now increased to 285,000 barrels per day, which exceeds the 10 percent improved production target established under the technical services contract." With a view towards expanded disclosure, please tell us what impact reaching the improved production target and the related production milestones has on your operations and activities in Iraq. Please also tell us what future milestones are included in the contract, and what impact reaching such milestones will have on your operations.

As described in our response to Question 10, the West Qurna (Phase 1) Contract provides an economic incentive by allowing recovery of Petroleum Costs and receipt of Remuneration Fees to begin when the 110% of initial production rate milestone is reached. Otherwise, recovery of Petroleum Costs and receipt of Remuneration Fees begins 36 months after the field Rehabilitation Plan is approved. A second key future milestone is reaching the agreed field Plateau Production Target rate and sustaining this production rate for a period of seven years. Any unexcused failure to meet or sustain this Plateau Production Target rate triggers the application of performance factors discussed in the response to Question 10, which would reduce the Remuneration Fee element of entitlement.

Financial Statements, page 62

Notes to Consolidated Financial Statements, page 69

Note 1. Summary of Significant Accounting Policies, page 69

Property, Plant and Equipment, page 70

12. *Your discussion under this section indicates, in part, that cash flow estimates used for purposes of impairment testing are based on your internal pricing assumptions. Separately, your discussion also indicates that impairment analyses are generally prepared based on "proved reserves". Confirm to us that "proved reserves" refers to quantities determined in accordance with SEC rules and regulations, including pricing assumptions. If this is not the case, revise your description of these quantities to refer to them as something other than "proved reserves".*

    We confirm that the reserves referenced in the noted text were prepared in accordance with SEC rules and regulations, including pricing assumptions. Please also refer to our response to Question 8.

Note 15. Litigation and Other Contingencies, page 87

Litigation, page 87

13. *We note the disclosure under this section indicating that "For contingencies where an unfavorable outcome is reasonably possible and which are significant, the Corporation discloses the nature of the contingency and, where feasible, an estimate of the possible loss." Explain to us what the word "significant" is intended to mean in the context of this disclosure.*

    The word "significant" in this instance includes all litigation contingencies for which a probable or reasonably possible unfavorable outcome would be material, as well as other matters that may not be material but for which management believes specific disclosure may be appropriate.

14. *Separately, we note the disclosure indicating that "Based on a consideration of all relevant facts and circumstances, the Corporation does not believe the ultimate outcome of any currently pending lawsuit against ExxonMobil will have a materially adverse effect upon the Corporation's operations, financial condition, or financial statements taken as a whole".*

    Please note that this disclosure does not satisfy the requirements of FASB ASC Topic 450 if there is at least a reasonable possibility that a loss exceeding amounts already recognized may have been incurred and the amount of that additional loss would be material to a decision to buy or sell your securities. In that case, you *must either disclose the estimated additional loss, or range of loss, that is reasonably possible, or state that such an estimate cannot be made.*

We confirm our compliance with the requirements of FASB ASC Topic 450. Specifically, we confirm the absence at the time of the Form 10-K of any litigation contingencies with respect to which a probable or reasonably possible loss in excess of amounts already recognized would have been material to a reasonable investor's decision to buy or sell the Corporation's securities. We also confirm our understanding that, should such an additional loss become reasonably possible in the future, the Corporation is required to disclose an estimate of the additional loss, or range of loss, that is reasonably possible, or state that such an estimate cannot be made.

Supplemental Information on Oil and Gas Exploration and Production Activities, page 103

Oil and Gas Reserves, page 107

15. *We note that you have combined crude oil and natural gas liquids for purposes of disclosing information related to your reserve quantities. Explain to us how you considered the requirements of FASB ASC paragraph 932-235-50-4 in preparing this combined presentation. As part of your response, provide us with the information disclosed in the table on page 110 for crude oil and natural gas liquids separately.*

FASB ASC paragraph 932-235-50-4 states: “Net quantities of an entity’s interests in proved reserves and proved developed reserves of both of the following shall be disclosed as of the beginning and the end of the year:

a. Crude oil, including condensate and natural gas liquids (if significant, the reserve quantity information shall be disclosed separately for natural gas liquids)

b. Natural gas.”

As reported in ExxonMobil’s 2010 Form 10-K filing, total crude oil proved reserves, including condensate and NGL proved reserves, were 11,673 million barrels (MB). Total NGL proved reserves were 1,341 MB, or 5.8% of total oil-equivalent proved reserves (22,985 million oil-equivalent barrels). Our current disclosure is in compliance with the FASB requirements, and no additional disclosure is required.

As requested, the table below shows the 2010 proved reserve data split between crude and NGL’s.

[Confidential information omitted; XOM-002]

Hydraulic Fracturing Fluid Product Component Information Disclosure

Fracture Date	6/6/2011
State:	Texas
County:	Tarrant
API Number:	42-439-34740
Operator Name:	XTO Energy
Well Name and Number:	MB A Unit 1H
Longitude:	-97.264581
Latitude:	32.758669
Long/Lat Projection:	NAD27
Production Type:	Gas
True Vertical Depth (TVD):	7,263
Total Water Volume (gal)*:	2,652,594

Hydraulic Fracturing Fluid Composition:

Trade Name	Supplier	Purpose	Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient Concentration in Additive (% by mass)**	Maximum Ingredient Concentration in HF Fluid (% by mass)**	Comments
Water				7732-18-5	100.00%	89.79759%	
Sand	Pumpco	Proppant	Crystaline Silica	14808-60-7	100.00%	9.98618%	
HCL	Pumpco	Hydrochloric Acid					
			Hyrogen Chloride	7647-01-0	40.00%	0.06443%	
			Water	7732-18-5	60.00%	0.09664%	
Plexslick 921	Pumpco	Friction Reducer					
			Petroleum Distillate	64742-47-8	35.00%	0.00929%	
			Ammonium Salts	9003-06-9	28.00%	0.00744%	
			Polyethoxylated alcohol surfactants		7.00%	0.00186%	
			Water	7732-18-5	30.00%	0.00797%	
Plexhib 256	Pumpco	Corrosion inhibitor					
			Methyl Alcohol	67-56-1	30.00%	0.00012%	
			Polyethoxylated alchol surfactants	68951-67-7	30.00%	0.00012%	
			Thiourea/formaldehyde copolymer	68527-49-1	30.00%	0.00012%	
			2-propen-1-ol	107-19-1	5.00%	0.00002%	
			C14_C_16 alpha olefins	64743-02-8	5.00%	0.00002%	
Ferriplex 66	Pumpco	Iron Control					
			Acetic Acid	64-19-7	50.00%	0.00008%	
			Citric Acid	77-92-9	30.00%	0.00005%	
			Water	7732-18-5	20.00%	0.00003%	
Greenhib 677	Pumpco	Scale Inhibitor					
			Glycerine	56-81-5	40.00%	0.00445%	
			Proprietary Phosphonate		15.00%	0.00167%	
			Water	7732-18-5	45.00%	0.00500%	
Plexcide 24L	Pumpco	Biocide					
			Dazomat	533-74-4	24.00%	0.00387%	
			Sodium Hydroxide	1310-73-2	4.00%	0.00065%	

			Water	7732-18-5	72.00%	0.01162%
Ferriplex 40	Pumpco	Iron Control				
			Trisodium Nitrilotriacetate	5064-31-3	40.00%	0.00023%
			Sodium Sulfate	7757-82-6	2.00%	0.00001%
			Water	7732-18-5	58.00%	0.00033%
Plexbrak 145	Pumpco	Non Emulsifier				
			Methyl Alcohol	67-56-1	50.00%	0.00012%
			Water	7732-18-5	50.00%	0.00012%

* Total Water Volume sources may include fresh water, produced water, and/or recycled water
** Information is based on the maximum potential for concentration and thus the total may be over 100%

All component information listed was obtained from the supplier's Material Safety Data Sheets (MSDS). As such, the Operator is not responsible for inaccurate and/or incomplete information. Any questions regarding the content of the MSDS should be directed to the supplier who provided it. The Occupational Safety and Health Administration's (OSHA) regulations govern the criteria for the disclosure of this information. Please note that Federal Law protects “proprietary”, “trade secret”, and “confidential business information” and the criteria for how this information is reported on an MSDS is subject to 29 CFR 1910.1200(i) and Appendix D.

Hydraulic Fracturing Fluid Product Component Information Disclosure

Fracture Date	4/18/2011
State:	WV
County:	Upshur
API Number:	47-097-03739
Operator Name:	XTO Energy
Well Name and Number:	Gould 2240H
Longitude:	-80.2801
Latitude:	39.0797
Long/Lat Projection:	NAD27
Production Type:	Gas
True Vertical Depth (TVD):	7,349
Total Water Volume (gal)*:	3,439,968

Hydraulic Fracturing Fluid Composition:

Trade Name	Supplier	Purpose	Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient Concentration in Additive (% by mass)**	Maximum Ingredient Concentration in HF Fluid (% by mass)**	Comments
Water				7732-18-5	100.00%	89.195	
Sand		Proppant	Crystaline Silica	14808-60-7	100.00%	10.320	
Biocide EC 6116A	Universal	Biocide					
			Dibromoacetonitrile	3252-43-5	5.00%	0.002	
			2,2-Dibromo-3-nitrilopropionamide	10222-01-2	30.00%	0.010	
			Polyethylene Glycol	25322-68-3	60.00%	0.021	
			Other - unspecified		5.00%	0.002	
Unislik ST 50	Universal	Friction Reducer					
			Hydrotreated light distillates	64742-47-8	30.00%	0.016	
			Polyacrylamide powder and other		70.00%	0.037	
EC 6486A	Universal	Scale Inhibitor					
			Ethylene glycol	107-21-1	30.00%	0.011	
			Other - unspecified		70.00%	0.025	
7.5% HCl Acid	Universal	Cleaning					
			Hydrogen Chloride	7647-01-0	7.50%	0.027	
			Water	7732-18-5	92.50%	0.335	

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Hydraulic Fracturing Fluid Product Component Information Disclosure

Fracture Date	2/26/2011
State:	New Mexico
County:	San Juan
API Number:	30-045-28836
Operator Name:	XTO Energy
Well Name and Number:	Federal 33-42
Longitude:	-108.00302
Latitude:	36.53416
Long/Lat Projection:	NAD27
Production Type:	Gas
True Vertical Depth (TVD):	1,970
Total Water Volume (gal)*:	42,743

Hydraulic Fracturing Fluid Composition:

Trade Name	Supplier	Purpose	Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient Concentration in Additive (% by mass)**	Maximum Ingredient Concentration in HF Fluid (% by mass)**	Comments
Water				7732-18-5	100.00%	60.82017%	
Sand	Halliburton	Proppant	Crystaline Silica	14808-60-7	100.00%	15.28717%	
Nitrogen Liquified	Halliburton	Foam Fluid	Nitrogen	7727-37-9	100.00%	20.36029%	
310B	H&M	Biocide	Dimethyldithiocarbamate		9.00%	0.00423%	
			cocodiamine	61788-93-0	91.00%	0.04273%	
SF-147	H&M	Clay stabilizer	Propanal	67-63-0	22.00%	0.00977%	
			quaternary ammonium	61789-18-2	78.00%	0.03465%	
Water	Halliburton	mix acid	Water	7732-18-5	100.00%	1.66481%	
Hydrochloric Acid 15%	Halliburton	Acid					
			Hydrochloric acid	7647-01-0	30.00%	0.35702%	
			Water	7732-18-5	70.00%	0.83304%	
FE-1A	Halliburton	FE control					
			Acetic anhydride	108-24-7	100.00%	0.03059%	
			Acetic acid	64-19-7	60.00%	0.01836%	
FE-2A	Halliburton	FE Control					
			Citric acid	77-92-9	60.00%	0.02117%	
			Water	7732-18-5	40.00%	0.01412%	
HAI-404	Halliburton	Corrosion Inhibitor					
			Chloromethylnaphthalene quinoline quaternary amine	15619-48-4	10.00%	0.00028%	
			Methanol	67-56-1	30.00%	0.00084%	
			Aldehyde		30.00%	0.00084%	
			Isopropanol	67-63-0	30.00%	0.00084%	
LGC-36 UC	Halliburton	Liquid Gel Concentrate					
			Naphtha, hydrotreated heavy	64742-48-9	60.00%	0.08159%	
			Polysaccharide		60.00%	0.08159%	

AQF-2	Halliburton	Foaming Agent				
			Diethylene glycol	111-46-6	10.00%	0.01418%
			Ethylene glycol monobutyl ether	111-76-2	30.00%	0.04254%
BC-140	Halliburton	Crosslinker				
			Monoethanolamine borate	26038-87-9	60.00%	0.02049%
			Ethylene glycol	107-21-1	30.00%	0.01024%
GasPerm 1100	Halliburton	Non-Ionic Surfactant				
			Terpenes and Terpenoids, sweet orange-oil	68647-72-3	5.00%	0.00533%
			Ethanol	64-17-5	60.00%	0.06398%
GBW-30 Breaker	Halliburton	Breaker				
			Carbohydrates		95.00%	0.00241%
			Hemicellulase enzyme	9012-54-8	15.00%	0.00038%
Optiflo-HTE	Halliburton	Breaker				
			Walnut hulls	Mixture	100.00%	0.00339%
			Crystalline silica, quartz	14808-60-7	30.00%	0.00102%
OptiKleen-WF	Halliburton					
		Concentrate	Sodium perborate tetrahydrate	10486-00-7	100.00%	0.00254%
Activator W	Halliburton	Accelerator				
			Alcohols, C12-14-secondary, ethoxylated	84133-50-6	60.00%	0.05105%
			Methanol	67-56-1	60.00%	0.05105%
SandWedge NT	Halliburton	Flow Enhancer				
			Dipropylene glycol monomethyl ehter	34590-94-8	60.00%	0.00329%
			Heavy aromatic petroeum naphtha	64742-94-5	10.00%	0.00055%
FR 66	Halliburton	Friction Reducer				
			Hydrotreated Light Petroleum Distillate	64742-47-8	30.00%	0.00679%

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Hydraulic Fracturing Fluid Product Component Information Disclosure

Fracture Date	3/19/2011
State:	Arkansas
County:	White
API Number:	03-145-11126
Operator Name:	XTO Energy
Well Name and Number:	Edwards 2-12H
Longitude:	-92.013306
Latitude:	35.331185
Long/Lat Projection:	NAD27
Production Type:	Gas
True Vertical Depth (TVD):	5,540
Total Water Volume (gal)*:	7,415,268

Hydraulic Fracturing Fluid Composition:

Trade Name	Supplier	Purpose	Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient Concentration in Additive (% by mass)**	Maximum Ingredient Concentration in HF Fluid (% by mass)**	Comments
Fresh Water	XTO				100.00%	91.90117%	
Recycled Water	XTO				0.00%	0.00000%	
Sand	Weatherford	Proppant	Crystaline Silica	14808-60-7	100.00%	7.43422%	
HCL 15%	Weatherford	Hydrochloric Acid					
			Hyrogen Chloride	7647-01-0	40.00%	0.16379%	
			Water	7732-18-5	60.00%	0.24569%	
WAI-251LC	Weatherford	Corrosion inhibitor					
			Ethylene Glycol	107-21-1	40.00%	0.00029%	
			N, N-Dimethyl Formamide	68-12-2	30.00%	0.00022%	
			Proprietary Component	Undisclosed	13.00%	0.00010%	
			Decanol	112-30-1	7.00%	0.00005%	
			Octanol	111-87-5	7.00%	0.00005%	
			Glycol ethers	111-76-2	5.00%	0.00004%	
			Isopropyl Alcohol	67-63-0	7.00%	0.00005%	
WIC-644L	Weatherford	Iron Control					
			Acetic Acid (Mixture)	64-19-7	90.00%	0.00166%	
			Methanol	67-56-1	20.00%	0.00037%	
WNE-353LN	Weatherford	Non Emulsifier					
			Isopropyl Alcohol	67-63-0	10.00%	0.00007%	
			Heavy Aromatic Naphtha	64741-67-9	70.00%	0.00048%	
			Formaldehyde Polymer	55845-06-02	40.00%	0.00027%	
			Aziridine Polymer	31974-35-3	10.00%	0.00007%	
WFR-55LA	Weatherford	Friction Reducer					
			Polyacrylamide Polymer	Undisclosed	29.00%	0.01392%	
			Parraffinic hydrocarbon Solvent	64742-47-8	25.00%	0.01200%	
			Water	7732-18-5	42.00%	0.02016%	

			Polyoxyalkyene surfactant	Undisclosed	2.00%	0.00096%
			Nonionic surfactant	Undisclosed	2.00%	0.00096%
WIC-641L	Weatherford	Iron Control Agent				
			2-hydroxy-1,2,3 propanetricarboxylic acid	77-92-9	50.00%	0.00108%
			Water	7732-18-5	50.00%	0.00108%
WCS-631LC	Weatherford	Clay Stabilizer				
			Water	7732-18-5	50.00%	0.04888%
			Proprietary Non-Hazardous Salt	Undisclosed	70.00%	0.06843%
WBK-143L	Weatherford	Friction Reducer Breaker				
			Water	7732-18-5	75.00%	0.04259%
			Sodium Chloride	7647-14-5	25.00%	0.01420%
			Potassium Chloride	7447-40-7	10.00%	0.00568%
			Sodium Chlorite	7758-19-2	5.00%	0.00284%
MultiChem 2-1401	Multi-Chem	Scale Inhibitor				
			Water	7732-18-5	5.00%	0.00047%
			Ethylene Glycol	107-21-1	60.00%	0.00568%
			Sodium Hydroxide	1310-73-2	5.00%	0.00047%
			Neutralized Traceable Polymer	Trade Secret	30.00%	0.00284%
MultiChem 8642	Multi-Chem	Biocide				
			Water	7732-18-5	48.00%	0.01810%
			Glutaraldehyde	111-30-8	42.50%	0.01603%
			n-Alkyl dimethyl benzyl ammonium chloride	68424-85-1	7.50%	0.00283%
			Ethanol	64-17-5	0.90%	0.00034%
			Methanol	67-56-1	0.42%	0.00016%

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