

# ENERGY XXI GULF COAST, INC.

## **FORM 8-K** (Current report filing)

Filed 05/15/17 for the Period Ending 05/09/17

Address	1021 MAIN STREET SUITE 2626 HOUSTON, TX 77002
Telephone	713-351-3000
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Fiscal Year	12/31

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**UNITED STATES  
SECURITIES AND EXCHANGE COMMISSION**  
Washington, D.C. 20549

**FORM 8-K**

**CURRENT REPORT**  
**Pursuant to Section 13 OR 15(d)**  
**of The Securities Exchange Act of 1934**

**May 9, 2017**  
Date of Report (Date of earliest event reported)

**Energy XXI Gulf Coast, Inc.**  
(Exact name of registrant as specified in charter)

**Delaware**  
(State or other jurisdiction of incorporation or  
organization)

**001-38019**  
(Commission File Number)

**20-4278595**  
(IRS Employer Identification No.)

**1021 Main, Suite 2626**  
**Houston, Texas 77002**  
(Address of principal executive office) (Zip Code)

**(713) 351-3000**  
(Registrant's telephone number, including area code)

(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

- Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
  - Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
  - Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
  - Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))
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## **Introductory Note**

Energy XXI Gulf Coast, Inc. (the “Company”) today provided final results of its independently engineered reserves report prepared by Netherland Sewell & Associates, Inc. (“NSAI”) as of March 31, 2017, which included estimated proved and probable reserves based on SEC 12-month average NYMEX pricing on March 31, 2017 (the “NSAI Reserve Report”). In addition, NSAI also prepared an alternate case of the NSAI Reserve Report based on forward strip commodity pricing as of March 31, 2017 (the “NSAI Strip Pricing Reserve Case” and, together with the NSAI Reserve Report, the “NSAI Reports”).

### **Item 7.01 Regulation FD Disclosure**

A copy of the press issued by the Company regarding the results of the NSAI Reports is attached hereto as Exhibit 99.1 and is incorporated herein by reference.

The information responsive to this Item 7.01, including the press release attached as Exhibit 99.1, is being furnished and shall not be deemed to be filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the “Exchange Act”), or otherwise be subject to the liabilities of that section, nor shall it be deemed to be incorporated by reference in any filing under the Securities Act of 1933, as amended, or the Exchange Act.

### **Item 8.01 Other Events**

According to the NSAI Reserve Report, total SEC proved reserves as of March 31, 2017 were 109.4 million barrels of oil equivalent (“MMBOE”), of which 80% were oil, 2% were natural gas liquids, and 18% were natural gas. All of the Company’s proved reserves are on the Gulf of Mexico Shelf or U.S. Gulf Coast, and 71% are classified as proved developed reserves. SEC 12-month average NYMEX pricing on March 31, 2017 was \$47.62 per barrel of oil (“BBL”) and \$2.73 per thousand cubic feet of natural gas (“MCF”), before differentials. The present value of the SEC proved reserves discounted at 10% (“PV-10 Value”) was \$108.4 million.

By comparison, in the Company’s year-end 2016 internally-prepared report, total SEC proved reserves were 121.9 MMBOE and the PV-10 Value was \$135.4 million, using a crude oil price of \$42.74 per BBL and \$2.48 per MCF, before differentials. The primary non-commodity price factors contributing to the difference between the NSAI Reserve Report and the internally-prepared year-end 2016 report are: (i) technical reassessments, (ii) higher capital costs and (iii) production during the first quarter of 2017. The impact of those factors was partially offset by higher SEC average commodity prices for both crude oil and natural gas.

Proved reserves as of March 31, 2017 in the NSAI Strip Pricing Reserve Case are estimated to be 113.7 MMBOE based on forward strip commodity pricing for oil, which averages \$51.58 per BBL for the remainder of 2017, and for natural gas, which averages \$3.33 per MCF for the remainder of 2017, before differentials. The PV-10 Value of those proved reserves is estimated to be \$399.1 million.

Copies of the letters addressed from NSAI to the Company regarding the NSAI Reserve Report and the NSAI Strip Pricing Reserve Case are attached hereto as Exhibits 99.2 and 99.3, respectively, and are incorporated herein by reference.

The Company has filed a Notification of Late Filing on Form 12b-25 with respect to its Quarterly Report on Form 10-Q for the period ended March 31, 2017 (the “March Form 10-Q”). As disclosed in the Form 12b-25, the Company is unable to file its March Form 10-Q by the prescribed due date because the timing of the receipt of the NSAI Reserve Report resulted in unexpected delays in the completion of its financial statements and related portions of its March Form 10-Q. The Company is working diligently to process this information through its financial statements and anticipates that the March Form 10-Q will be filed on or before the fifth calendar day following its prescribed due date.

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**Item 9.01 Financial Statements and Exhibits**

<b>Exhibit Number</b>	<b>Description</b>
99.1	Press release dated May 15, 2017
99.2	Letter from Netherland Sewell & Associates, Inc., dated May 9, 2017 (NSAI Reserve Report)
99.3	Letter from Netherland Sewell & Associates, Inc., dated May 10, 2017 (NSAI Strip Pricing Reserve Case)

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**SIGNATURES**

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

**ENERGY XXI GULF COAST, INC.**

By: /s/ Douglas E. Brooks  
Douglas E. Brooks  
Chief Executive Officer and President

Dated: May 15, 2017

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## Exhibit Index

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**ENERGY XXI GULF COAST PROVIDES FINAL MARCH 31, 2017 INDEPENDENT RESERVE  
REPORT RESULTS AND  
ANNOUNCES FIRST QUARTER 2017 EARNINGS RELEASE  
AND CONFERENCE CALL DATE**

HOUSTON – May 15, 2017 - Energy XXI Gulf Coast, Inc. (“EGC” or the “Company”) (NASDAQ: EXXI) today provided final results of its independently engineered reserves report prepared by Netherland Sewell & Associates, Inc. (“NSAI”) as of March 31, 2017. In recent years, the Company had utilized third-party engineers to audit its internal calculations of reserves, but has not had a fully-engineered third-party report prepared since 2012. The Company’s most recent internally-prepared report was prepared as of December 31, 2016.

NSAI’s report estimates total SEC proved reserves as of March 31, 2017 to be 109.4 million barrels of oil equivalent, (“MMBOE”), of which 80% were oil, 2% were natural gas liquids, and 18% were natural gas. All of the Company’s proved reserves are on the Gulf of Mexico Shelf or U.S. Gulf Coast, and 71% are classified as proved developed reserves. SEC 12-month average NYMEX pricing on March 31, 2017 was \$47.62 per barrel of oil (“BBL”) and \$2.73 per thousand cubic feet of natural gas (“MCF”), before differentials. The present value of the SEC proved reserves discounted at 10% (“PV-10 Value”) was \$108.4 million.

By comparison, in the Company’s year-end 2016 internally-prepared report, total SEC proved reserves were 121.9 MMBOE and the PV-10 was \$135.4 million, using a crude oil price of \$42.74 per BBL and \$2.48 per MCF, before differentials. The primary non-commodity price factors contributing to the difference between the NSAI March 31, 2017 SEC report and the internally-prepared year-end 2016 report are: (i) technical reassessments, (ii) higher capital costs and (iii) production during the first quarter of 2017. The impact of those factors was partially offset by higher SEC average commodity prices for both crude oil and natural gas.

Proved reserves as of March 31, 2017 based on forward strip commodity pricing for oil, which averages \$51.58 per BBL for the remainder of 2017, and for natural gas, which averages \$3.33 per MCF for the remainder of 2017, before differentials, are estimated to be 113.7 MMBOE. The PV-10 value of those proved reserves is estimated to be \$399.1 million.



By comparison, in the Company's year-end 2016 internally-prepared report, total strip pricing proved reserves were 132.6 MMBOE and the PV-10 was \$988.2 million, using a crude oil price which averages \$54.77 per BBL and \$3.34 per MCF for 2017, before differentials. The non-price factors described above also contributed the difference between the NSAI March 31, 2017 strip-pricing report and the internally-prepared year-end 2016 report. In addition, instead of serving as a positive partial offset to those factors, strip prices (particularly the strip price for crude oil) declined from year-end 2016 to March 31, 2017.

The Company has significant resource potential in addition to its proved reserves. NSAI's strip-price report as of March 31, 2017 estimates proved and probable reserves ("2P Reserves") to be 183.6 MMBOE with a PV-10 of \$1.15 billion at these forward prices. 2P Reserves do not include possible reserves or exploratory resource potential.

The following table includes the amounts referenced above as well as March 31, 2017 estimated probable reserves and related PV-10 attributable to the Company's net interests in oil and gas properties at varying price assumptions which were independently engineered and compiled by NSAI.

<b>SEC Pricing Oil \$47.62 Gas \$2.73</b>	<b>Oil MMBO</b>	<b>NGL MMBO</b>	<b>Gas BCF</b>	<b>Oil Eq. MMBOE</b>	<b>PV10 MMS</b>
PDP	51.8	0.9	53.7	61.6	\$304.9
PDN	9.3	0.9	33.2	15.7	\$100.8
PUD	26.5	0.5	30.3	32.0	\$203.7
P&A	0.0	0.0	0.0	0.0	(\$501.0)
<b>1P</b>	<b>87.6</b>	<b>2.2</b>	<b>117.2</b>	<b>109.4</b>	<b>\$108.4</b>
PRB	45.8	1.4	122.1	67.5	\$574.8
P&A	0.0	0.0	0.0	0.0	\$62.6
<b>2P</b>	<b>133.4</b>	<b>3.6</b>	<b>239.3</b>	<b>176.9</b>	<b>\$745.9</b>



	SEC Pricing Oil \$47.62 Gas \$2.73	Strip 3/31/17 Oil \$51.58 Gas \$3.33
<b>MMBOE</b>		
Proved	109.4	113.7
Probable	67.5	70.0
<b>Total 2P</b>	<b>176.9</b>	<b>183.6</b>
<b>PV10 \$MM</b>		
Proved	\$108.4	\$399.1
Probable	\$637.4	\$749.8
<b>Total 2P</b>	<b>\$745.9</b>	<b>\$1,148.8</b>

(PDP: Proved Developed Producing; PDN: Proved Developed Non-Producing; PUD: Proved Undeveloped; P&A: Plug and Abandon; PRB: Probable; 1P: Total Proved Reserves; 2P: Total Proved and Probable Reserves)

Douglas E. Brooks, Chief Executive Officer and President remarked, “We have completed the transition to utilizing a third party to fully engineer our reserves with the March 31, 2017 NSAI report. Our next third party reserve report will be prepared as of December 31, 2017 and issued in early 2018.”

Brooks continued, “As detailed in this release, we have meaningful upside potential in our proved reserves and their valuation from substantial optionality in our probable and possible reserves and exploratory resource potential. In addition, if the commodity price environment were to improve, any such improvement would further enhance both our volumes and PV-10. In the remainder of 2017, we will work diligently to reduce all costs to remain competitive in today’s market.”

**First Quarter 2017 Earnings Release and Conference Call Date**

On Monday, May 22, 2017, the Company will issue its first quarter 2017 earnings release before the market opens and will host a conference call at 10:00 a.m. Central Time (11:00 a.m. Eastern Time) to discuss its first quarter 2017 financial and operating results.

To actively participate on the conference call, please dial the number below before the scheduled start time. A webcast of the call can be accessed through the Company's web site at [www.EnergyXXI.com](http://www.EnergyXXI.com). A replay of the call will be archived and available on the web site shortly after the live call.

Dial-In Numbers: (877) 794-3620 (Toll Free)  
(631) 813-4724 (International)

Confirmation Code: 22507001



### **Cautionary Note Regarding Forward-Looking Statements**

*This press release contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. These statements, including those relating to the intent, beliefs, plans, or expectations of EGC are based upon current expectations and are subject to a number of risks, uncertainties, and assumptions. It is not possible to predict or identify all such factors and the following list should not be considered a complete statement of all potential risks and uncertainties relating to emergence from Chapter 11, the recent change in EGC's senior management team, or EGC's oil and gas reserves, including, but not limited to: (i) the PV-10 and reserve volumes reported in the final NSAI reserve report, (ii) the level of potential upside actually realized by EGC from its non-proved resource base, (iii) the effects of the departure of EGC's senior leaders on the Company's employees, suppliers, regulators and business counterparties, (iv) the impact of restrictions in the exit financing on EGC's ability to make capital investments and pursue strategic growth opportunities and (v) other risks and uncertainties. These risks and uncertainties could cause actual results, including project plans and related expenditures and resource recoveries, to differ materially from those described in the forward-looking statements. For a more detailed discussion of risk factors, please see Part I, Item 1A, "Risk Factors" of the Transition Report on Form 10-K for the transition period ended December 31, 2016 filed by EGC for more information. EGC assumes no obligation and expressly disclaims any duty to update the information contained herein except as required by law.*

### **Cautionary Note Regarding Hydrocarbon Quantities**

*This press release includes NSAI-prepared estimates for proved and probable reserves and aggregated proved and probable reserves as of March 31, 2017, with each category of reserves estimated in accordance with SEC guidelines and definitions. The SEC permits the optional disclosure of probable reserves. The SEC defines "probable" reserves as "those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." EGC has included the NSAI estimate of proved, probable and aggregated proved and probable reserves in this release because management believes it is useful information that is widely used by the investment community in the valuation, comparison and analysis of companies. However, the Company notes that the SEC prohibits companies from aggregating proved and probable reserves in filings with the SEC due to the different levels of certainty associated with each reserve category.*

*Actual quantities that may be ultimately recovered from EGC's interests may differ substantially from the NSAI estimates included in this press release. Factors affecting ultimate recovery include the scope of EGC's ongoing drilling program, which will be directly affected by commodity prices, the availability of capital, regulatory approvals, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints and other factors; actual drilling results, including geological and mechanical factors affecting recovery rates; and budgets based upon our future evaluation of risk, returns and the availability of capital. With respect to commodity prices, there can be no assurance that actual oil and gas prices will be consistent with the forward strip pricing case or any of the other pricing assumptions described in this press release.*

### **About the Company**

Energy XXI Gulf Coast, Inc. is an independent oil and natural gas development and production company whose assets are primarily located in the U.S. Gulf of Mexico waters offshore Louisiana and Texas. The Company's near-term strategy emphasizes exploitation of key assets, enhanced by its focus on financial discipline and operational excellence. To learn more, visit EGC's website at [www.EnergyXXI.com](http://www.EnergyXXI.com).

### **Investor Relations Contact**

Al Petrie  
Investor Relations Coordinator  
713-351-3171  
[apetrie@energyxxi.com](mailto:apetrie@energyxxi.com)



<b>EXECUTIVE COMMITTEE</b>			<b>CHAIRMAN &amp; CEO</b>	
ROBERT C. BARG	MIKE K. NORTON		C.H. (SCOTT) REES III	
P. SCOTT FROST	DAN PAUL SMITH		<b>PRESIDENT &amp; COO</b>	
JOHN G. HATTNER	JOSEPH J. SPELLMAN		DANNY D. SIMMONS	
J. CARTER HENSON, JR.	DANIEL T. WALKER		<b>EXECUTIVE VP</b>	
			G. LANCE BINDER	

May 9, 2017

Mr. Hugh Menown  
Energy XXI Gulf Coast, Inc.  
1021 Main Street, Suite 2626  
Houston, Texas 77002

Dear Mr. Menown:

In accordance with your request, we have estimated the proved and probable reserves and future revenue, as of March 31, 2017, to the Energy XXI Gulf Coast, Inc. (Energy XXI) interest in certain oil and gas properties located in Louisiana, Texas, and federal waters in the Gulf of Mexico. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by Energy XXI. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and conform to the FASB Accounting Standards Codification Topic 932, *Extractive Activities — Oil and Gas, except that future income taxes are excluded for all properties and, as requested, corporate-level overhead expenses are excluded for the operated properties*. Definitions are presented immediately following this letter. This report has been prepared for Energy XXI's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Energy XXI interest in these properties, as of March 31, 2017, to be:

Category	Net Reserves			Future Net Revenue <sup>(1)</sup> (M\$)	
	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	51,810.4	872.3	53,685.4	-869,754.2	-196,066.5
Proved Developed Non-Producing	9,295.8	879.2	33,240.3	190,860.0	100,773.1
Proved Undeveloped	26,509.5	464.9	30,282.8	603,872.8	203,728.5
Total Proved	87,615.7	2,216.4	117,208.4	-75,021.4	108,435.1
Probable Developed	11,816.1	1,080.8	50,816.2	208,449.1	212,400.2
Probable Undeveloped	33,989.1	288.7	71,277.3	1,133,707.1	425,040.1
Total Probable	45,805.2	1,369.5	122,093.6	1,342,156.3	637,440.3

*Totals may not add because of rounding.*

(1) Future net revenue is after deducting estimated abandonment costs.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

The estimates shown in this report are for proved and probable reserves. As requested, possible reserves that exist for these properties have not been included. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Gross revenue is Energy XXI's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Energy XXI's share of production taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period April 2016 through March 2017. For oil and NGL volumes, the average West Texas Intermediate posted price of \$44.10 per barrel is adjusted by field for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of \$2.730 per MMBTU is adjusted by field for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. For the proved reserves, the average adjusted product prices weighted by production over the remaining lives of the properties are \$46.32 per barrel of oil, \$23.58 per barrel of NGL, and \$2.574 per MCF of gas.

Operating costs used in this report are based on operating expense records of Energy XXI. For the nonoperated properties, these costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. As requested, operating costs for the operated properties include only direct lease- and field-level costs. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs. For all properties, headquarters general and administrative overhead expenses of Energy XXI are not included. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Energy XXI and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Energy XXI's estimates of the costs to abandon the wells, platforms, and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Energy XXI interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Energy XXI receiving its net revenue interest share of estimated future gross production. Additionally, we have made no investigation of any firm transportation contracts that may be in place for these properties; no adjustments have been made to our estimates of future revenue to account for such contracts.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Energy XXI, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

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For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Energy XXI, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Connor B. Riseden, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2006 and has over 4 years of prior industry experience. Shane M. Howell, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2005 and has over 7 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

**NETHERLAND, SEWELL & ASSOCIATES, INC.**  
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III  
C.H. (Scott) Rees III, P.E.  
Chairman and Chief Executive Officer

By: /s/ Connor B. Riseden  
Connor B. Riseden, P.E. 100566  
Vice President

By: /s/ Shane M. Howell  
Shane M. Howell, P.G. 11276  
Vice President

Date Signed: May 9, 2017

Date Signed: May 9, 2017

CBR:SAO

Please be advised that the digital document you are viewing is provided by Netherland, Sewell & Associates, Inc. (NSAI) as a convenience to our clients. The digital document is intended to be substantively the same as the original signed document maintained by NSAI. The digital document is subject to the parameters, limitations, and conditions stated in the original document. In the event of any differences between the digital document and the original document, the original document shall control and supersede the digital document.

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties*. Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

- (i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
- (ii) Same environment of deposition;
- (iii) Similar geological structure; and
- (iv) Same drive mechanism.

*Instruction to paragraph (a)(2)*: Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

- (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
- (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

*Supplemental definitions from the 2007 Petroleum Resources Management System:*

*Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.*

*Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.*

(7) *Development costs*. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

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- (i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
- (ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
- (iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
- (iv) Provide improved recovery systems.

(8) *Development project* . A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well* . A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible* . The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)* . Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs* . Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

- (i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
- (ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
- (iii) Dry hole contributions and bottom hole contributions.
- (iv) Costs of drilling and equipping exploratory wells.
- (v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well* . An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well* . An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field* . An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

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(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

- (A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
- (B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
- (C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
  - (1) Lifting the oil and gas to the surface; and
  - (2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
- (D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

*Instruction 1 to paragraph (a)(16)(i)* : The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

- a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
- b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

*Instruction 2 to paragraph (a)(16)(i)*: For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

- (A) Transporting, refining, or marketing oil and gas;
- (B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
- (C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
- (D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

- (i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
  - (ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
-

- (iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
- (iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
- (v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
- (vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

- (i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
- (ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
- (iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
- (iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

- (i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:
    - (A) Costs of labor to operate the wells and related equipment and facilities.
    - (B) Repairs and maintenance.
    - (C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
    - (D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
    - (E) Severance taxes.
  - (ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.
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(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price 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, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

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(25) *Reliable technology*. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves*. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

*Note to paragraph (a)(26)* : Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

*Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:*

*932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:*

- a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*
- b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

*The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.*

*932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:*

- a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
- b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
- c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*
- d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*
- e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*
- f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

(27) *Reservoir*. A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources*. Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

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(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

- (i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
- (ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

*From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):*

*Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.*

*Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:*

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

- (iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.

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May 10, 2017

Mr. Hugh Menown  
 Energy XXI Gulf Coast, Inc.  
 1021 Main Street, Suite 2626  
 Houston, Texas 77002

Dear Mr. Menown:

In accordance with your request, we have prepared a price sensitivity to our report dated May 9, 2017, which sets forth our estimates of reserves and future revenue, as of March 31, 2017, to the Energy XXI Gulf Coast, Inc. (Energy XXI) interest in certain oil and gas properties located in Louisiana, Texas, and federal waters in the Gulf of Mexico. The estimates in the May 9 report were prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and conform to the FASB Accounting Standards Codification Topic 932, *Extractive Activities — Oil and Gas, except that future income taxes are excluded for all properties and, as requested, corporate-level overhead expenses are excluded for the operated properties*. The differences between the estimates of reserves and revenue in the May 9 and this report are due to changes in price parameters only. With the exception of these changes, we completed our evaluation on or about May 9, 2017. This report has been prepared using price and cost parameters specified by Energy XXI, referred to as the Strip Price Sensitivity Case, as discussed in the subsequent paragraphs of this letter. This report has been prepared for Energy XXI's use in filing with the SEC as a sensitivity; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose. For your reference, the SEC definitions are presented immediately following this letter.

We estimate the net reserves and future net revenue to the Energy XXI interest in these properties, as of March 31, 2017, to be:

Category	Net Reserves			Future Net Revenue <sup>(1)</sup> (M\$)	
	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	53,815.9	890.4	56,115.2	-645,004.2	-13,216.2
Proved Developed Non-Producing	9,730.3	914.9	34,791.5	260,606.0	133,907.8
Proved Undeveloped	27,501.8	468.5	31,086.7	772,632.6	278,364.9
Total Proved	91,048.0	2,273.8	121,993.4	388,234.3	399,056.6
Probable Developed	12,479.3	1,101.7	51,404.8	272,436.6	240,218.0
Probable Undeveloped	35,238.6	375.7	73,367.0	1,360,058.5	509,548.8
Total Probable	47,717.9	1,477.4	124,771.8	1,632,494.6	749,767.0

*Totals may not add because of rounding.*

(1) Future net revenue is after deducting estimated abandonment costs.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

The estimates shown in this report are for proved and probable reserves. As requested, possible reserves that exist for these properties have not been included. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Gross revenue is Energy XXI's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Energy XXI's share of production taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

As requested, this report has been prepared using oil, NGL, and gas price parameters specified by Energy XXI. Oil and NGL prices are based on NYMEX West Texas Intermediate prices and are adjusted by field for quality, transportation fees, and market differentials. Gas prices are based on NYMEX Henry Hub prices and are adjusted by field for energy content, transportation fees, and market differentials. For the proved reserves, the average initial prices, after adjustments, are \$49.95 per barrel of oil, \$24.14 per barrel of NGL, and \$3.122 per MCF of gas. For the proved reserves, the average adjusted product prices weighted by production over the remaining lives of the properties are \$51.04 per barrel of oil, \$25.92 per barrel of NGL, and \$2.756 per MCF of gas. All prices, before adjustments, are shown in the following table:

Period Ending	Oil/NGL Price (\$/Barrel)	Gas Price (\$/MMBTU)
12-31-2017	51.58	3.325
12-31-2018	51.90	3.034
12-31-2019	51.37	2.833
12-31-2020	51.39	2.821
12-31-2021	51.98	2.832
Thereafter	52.98	2.842

Operating costs used in this report are based on operating expense records of Energy XXI. For the nonoperated properties, these costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. As requested, operating costs for the operated properties include only direct lease- and field-level costs. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs. For all properties, headquarters general and administrative overhead expenses of Energy XXI are not included. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Energy XXI and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Energy XXI's estimates of the costs to abandon the wells, platforms, and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Energy XXI interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Energy XXI receiving its net revenue interest share of estimated future gross production. Additionally, we have made no investigation of any firm transportation contracts that may be in place for these properties; no adjustments have been made to our estimates of future revenue to account for such contracts.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Energy XXI, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Energy XXI, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Connor B. Riseden, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2006 and has over 4 years of prior industry experience. Shane M. Howell, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2005 and has over 7 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

**NETHERLAND, SEWELL & ASSOCIATES, INC.**  
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III  
C.H. (Scott) Rees III, P.E.  
Chairman and Chief Executive Officer

By: /s/ Connor B. Riseden  
Connor B. Riseden, P.E. 100566  
Vice President

By: /s/ Shane M. Howell  
Shane M. Howell, P.G. 11276  
Vice President

Date Signed: May 10, 2017

Date Signed: May 10, 2017

CBR:SAO

Please be advised that the digital document you are viewing is provided by Netherland, Sewell & Associates, Inc. (NSAI) as a convenience to our clients. The digital document is intended to be substantively the same as the original signed document maintained by NSAI. The digital document is subject to the parameters, limitations, and conditions stated in the original document. In the event of any differences between the digital document and the original document, the original document shall control and supersede the digital document.

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties*. Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

- (i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
- (ii) Same environment of deposition;
- (iii) Similar geological structure; and
- (iv) Same drive mechanism.

*Instruction to paragraph (a)(2)*: Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

- (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
- (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

*Supplemental definitions from the 2007 Petroleum Resources Management System:*

*Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.*

*Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.*

(7) *Development costs*. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

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- (i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
- (ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
- (iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
- (iv) Provide improved recovery systems.

(8) *Development project* . A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well* . A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible* . The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)* . Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs* . Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

- (i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
- (ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
- (iii) Dry hole contributions and bottom hole contributions.
- (iv) Costs of drilling and equipping exploratory wells.
- (v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well* . An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well* . An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field* . An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

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(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

- (A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
- (B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
- (C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
  - (1) Lifting the oil and gas to the surface; and
  - (2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
- (D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

*Instruction 1 to paragraph (a)(16)(i)* : The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

- a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
- b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

*Instruction 2 to paragraph (a)(16)(i)*: For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

- (A) Transporting, refining, or marketing oil and gas;
- (B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
- (C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
- (D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

- (i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
  - (ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
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- (iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
- (iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
- (v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
- (vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

- (i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
- (ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
- (iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
- (iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

- (i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:
    - (A) Costs of labor to operate the wells and related equipment and facilities.
    - (B) Repairs and maintenance.
    - (C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
    - (D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
    - (E) Severance taxes.
  - (ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.
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(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price 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, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

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(25) *Reliable technology*. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves*. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

*Note to paragraph (a)(26)* : Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

*Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:*

*932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:*

- a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*
- b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

*The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.*

*932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:*

- a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
- b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
- c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*
- d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*
- e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*
- f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

(27) *Reservoir*. A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources*. Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

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(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

- (i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
- (ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

*From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):*

*Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.*

*Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:*

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

- (iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.

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