# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION
**Washington, DC 20549**

# FORM 8-K/A

## CURRENT REPORT
**Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

Date of Report (Date of earliest event reported):
**August 3, 2018**

# KOSMOS ENERGY LTD.
(Exact Name of Registrant as Specified in its Charter)

| | | |
|---|---|---|
| **Bermuda** | **001-35167** | **98-0686001** |
| (State or other jurisdiction of incorporation) | (Commission File Number) | (I.R.S. Employer Identification No.) |

| | |
|---|---|
| **Clarendon House**<br>**2 Church Street**<br>**Hamilton, Bermuda** | **HM 11** |
| (Address of Principal Executive Offices) | (Zip Code) |

Registrant's telephone number, including area code: **+1 441 295 5950**

**Not Applicable**
(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 (see General Instruction A.2. below):

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (17 CFR §230.405) or Rule 12b-2 of the Securities Exchange Act of 1934 (17 CFR §240.12b-2).

Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

## Explanatory Note

As previously reported in a Current Report on Form 8-K filed on August 9, 2018 (the "Initial Form 8-K"), pursuant to the Securities Purchase Agreement (the "Purchase Agreement") dated August 3, 2018 by and among Kosmos Energy Gulf of Mexico, LLC ("Purchaser"), a wholly owned subsidiary of Kosmos Energy Ltd. ("Kosmos" or the "Company"), and certain affiliates of First Reserve Corporation (the sellers under the Purchase Agreement, the "Seller"), Kosmos indirectly acquired 100% of the outstanding equity interests in Deep Gulf Energy companies ("Deep Gulf Energy") from the Seller (the "Acquisition"). This Form 8-K/A amends the Initial Form 8-K to include the financial statements and pro forma financial information required by Items 9.01(a) and 9.01(b) of Form 8-K and should be read in conjunction with the Initial Form 8-K.

**Item 8.01 Other Events**

In connection with the Acquisition, the Company is filing the December 31, 2017 reports of Ryder Scott Company, L.P. ("Ryder Scott") and Netherland, Sewell & Associates, Inc. ("Netherland Sewell"), each with respect to estimated oil and gas reserves of certain Deep Gulf Energy entities. Additionally, Kosmos commissioned Ryder Scott to produce an independent engineer reserve report covering Deep Gulf Energy's reserves as of July 1, 2018, to provide investors a current aggregated view of the Deep Gulf Energy assets based on Kosmos management's plan for developing and producing them.

Attached as Exhibits 23.4 and 23.5 hereto are the consents of Ryder Scott and Netherland Sewell to the inclusion of such reports in the registration statements of the Company.

Attached as Exhibit 99.8 hereto is the report of Ryder Scott dated September 12, 2018 relating to Deep Gulf Energy LP as of December 31, 2017.

Attached as Exhibit 99.9 hereto is the report of Ryder Scott dated September 12, 2018 relating to Deep Gulf Energy II, LLC as of December 31, 2017.

Attached as Exhibit 99.10 hereto is the report of Ryder Scott dated September 12, 2018 relating to Deep Gulf Energy III, LLC as of December 31, 2017.

Attached as Exhibit 99.11 hereto is the report of Ryder Scott dated September 12, 2018 relating to Deep Gulf Energy III's Share of Houston Energy Deepwater Ventures V, LLC, as of December 31, 2017.

Attached as Exhibit 99.12 hereto is the report of Netherland Sewell dated September 14, 2018 relating to Deep Gulf Energy II, LLC as of December 31, 2017.

Attached as Exhibit 99.13 hereto is the report of Netherland Sewell dated September 14, 2018 relating to Deep Gulf Energy III, LLC as of December 31, 2017.

Attached as Exhibit 99.14 hereto is the report of Ryder Scott dated September 17, 2018 relating to Deep Gulf Energy LP, Deep Gulf Energy II, LLC, Deep Gulf Energy III, LLC and Deep Gulf Energy III, LLC's share of Houston Energy Deepwater Ventures V LLC, as of July 1, 2018.

Together, these reports are estimated to cover 100% of proved reserves of Deep Gulf Energy as of December 31, 2017.

**Item 9.01 Financial Statements and Exhibits**

**(a) Financial Statements of Businesses Acquired.**

Attached as Exhibit 99.1 hereto is the audited financial statements as of and for the year ended December 31, 2017 of Deep Gulf Energy LP.

Attached as Exhibit 99.2 hereto are the audited consolidated financial statements as of and for the year ended December 31, 2017 of DGE II Management, LLC and subsidiary.

Attached as Exhibit 99.3 hereto are the audited consolidated financial statements as of and for the year ended December 31, 2017 of DGE III Management, LLC and subsidiaries.

Attached as Exhibit 99.4 hereto are the unaudited interim financial statements as of June 30, 2018 and December 31, 2017 and for the six months ended June 30, 2018 and 2017 of Deep Gulf Energy LP.

Attached as Exhibit 99.5 hereto are the unaudited condensed consolidated interim financial statements as of June 30, 2018 and December 31, 2017 and for the six months ended June 30, 2018 and 2017 of DGE II Management, LLC and subsidiary.

Attached as Exhibit 99.6 hereto are the unaudited condensed consolidated interim financial statements as of June 30, 2018 and December 31, 2017 and for the six months ended June 30, 2018 and 2017 of DGE III Management, LLC and subsidiaries.

**(b) Pro Forma Financial Information.**

Attached hereto as Exhibit 99.7 is the unaudited pro forma condensed combined financial statements reflecting the Acquisition as required by this Item 9.01(b). Such financial statements are incorporated by reference into this Item 9.01(b).

**Item 9.01 Financial Statements and Other Exhibits**

| Exhibit Number | Description of Exhibit |
|---|---|
| 23.1 | Consent of Deloitte & Touche LLP (Deep Gulf Energy LP) |
| 23.2 | Consent of Deloitte & Touche LLP (DGE II Management, LLC) |
| 23.3 | Consent of Deloitte & Touche LLP (DGE III Management, LLC) |
| 23.4 | Consent of Ryder Scott Company, L.P. |
| 23.5 | Consent of Netherland, Sewell & Associates, Inc. |
| 99.1 | Audited financial statements of Deep Gulf Energy LP as of and for the year ended December 31, 2017. |
| 99.2 | Audited consolidated financial statements of DGE II Management, LLC and subsidiary as of and for the year ended December 31, 2017. |
| 99.3 | Audited consolidated financial statements of DGE III Management, LLC and subsidiaries as of and for the year ended December 31, 2017. |
| 99.4 | Unaudited interim financial statements as of June 30, 2018 and December 31, 2017 and for the six months ended June 30, 2018 and 2017 of Deep Gulf Energy LP. |
| 99.5 | Unaudited condensed consolidated interim financial statements as of June 30, 2018 and December 31, 2017 and for the six months ended June 30, 2018 and 2017 of DGE II Management, LLC and subsidiary. |
| 99.6 | Unaudited condensed consolidated interim financial statements as of June 30, 2018 and December 31, 2017 and for the six months ended June 30, 2018 and 2017 of DGE III Management, LLC and subsidiaries. |
| 99.7 | Unaudited pro forma condensed combined financial statements reflecting the Acquisition. |
| 99.8 | Report of Ryder Scott Company, L.P. dated September 12, 2018 relating to Deep Gulf Energy LP. |
| 99.9 | Report of Ryder Scott Company, L.P. dated September 12, 2018 relating to Deep Gulf Energy II, LLC. |
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## SIGNATURES

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

Date: October 5, 2018

KOSMOS ENERGY LTD.

By: /s/ Thomas P. Chambers
Thomas P. Chambers
Chief Financial Officer

## INDEX TO EXHIBITS

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**Exhibit 23.1**

## CONSENT OF INDEPENDENT AUDITORS

We consent to the incorporation by reference in Registration Statement No. 333-227084 on Form S-3 and Registration Statements No. 333-174234 and No. 333-207259 on Form S-8 of Kosmos Energy Ltd. of our report dated March 29, 2018 relating to the financial statements of Deep Gulf Energy LP as of and for the year ended December 31, 2017 (which report expresses an unmodified opinion and includes an emphasis of matter paragraph related to allocation of services with related parties, and an other matter paragraph related to supplemental information on oil and natural gas operations), appearing in this Current Report on Form 8-K/A of Kosmos Energy Ltd.

/s/ Deloitte & Touche LLP

Houston, Texas
October 5, 2018

**Exhibit 23.2**

# CONSENT OF INDEPENDENT AUDITORS

We consent to the incorporation by reference in Registration Statement No. 333-227084 on Form S-3 and Registration Statements No. 333-174234 and No. 333-207259 on Form S-8 of Kosmos Energy Ltd. of our report dated March 29, 2018 relating to the consolidated financial statements of DGE II Management, LLC as of and for the year ended December 31, 2017 (which report expresses an unmodified opinion and includes an emphasis of matter paragraph related to allocation of services with related parties, and an other matter paragraph related to supplemental information on oil and natural gas operations), appearing in this Current Report on Form 8-K/A of Kosmos Energy Ltd.

/s/ Deloitte & Touche LLP

Houston, Texas
October 5, 2018

**Exhibit 23.3**

**CONSENT OF INDEPENDENT AUDITORS**

We consent to the incorporation by reference in Registration Statement No. 333-227084 on Form S-3 and Registration Statements No. 333-174234 and No. 333-207259 on Form S-8 of Kosmos Energy Ltd. of our report dated March 29, 2018 relating to the consolidated financial statements of DGE III Management, LLC as of and for the year ended December 31, 2017 (which report expresses an unmodified opinion and includes an emphasis of matter paragraph related to allocation of services with related parties, and an other matter paragraph related to supplemental information on oil and natural gas operations), appearing in this Current Report on Form 8-K/A of Kosmos Energy Ltd.

/s/ Deloitte & Touche LLP

Houston, Texas
October 5, 2018

**Exhibit 23.4**

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE REGISTERED ENGINEERING FIRM F-1580
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 FAX (713) 651-0849
TELEPHONE (713) 651-9191

October 5, 2018

Mr. Eric Haas
Kosmos Energy, LLC
8176 Park Lane, Suite 500
Dallas, Texas 75231

We hereby consent to the reference of our firm and to the use of (1) our report relating to Deep Gulf Energy LP (DGE) effective December 31, 2017 and dated September 12, 2018, (2) our report relating to Deep Gulf Energy II, LLC (DGE II) effective December 31, 2017 and dated September 12, 2018, (3) our report relating to Deep Gulf Energy III, LLC (DGE III) effective December 31, 2017 and dated September 12, 2018, (4) our report relating to Deep Gulf Energy III LLC's share of Houston Energy Deepwater Ventures V, LLC effective December 31, 2017 and dated September 12, 2018 and (5) our report relating to Deep Gulf Energy LP, Deep Gulf Energy II, LLC, Deep Gulf Energy III, LLC and Deep Gulf Energy III, LLC's share of Houston Energy Deepwater Ventures V LLC effective July 1, 2018 and dated September 17, 2018, each appearing in this Current Report on Form 8-K/A of Kosmos Energy Ltd., in the Registration Statements No. 333-174234 and No. 333-207259 on Form S-8 and the Registration Statement No. 333-227084 on Form S-3 of Kosmos Energy Ltd.

/s/ Ryder Scott Company, L.P.

**RYDER SCOTT COMPANY, L.P.**
TBPE Firm Registration No. F-1580

Houston, Texas

**Exhibit 23.5**

**CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS**

We hereby consent to the reference of our firm and to the use of (1) our report effective December 31, 2017, dated September 14, 2018, related to the Deep Gulf Energy II, LLC (DGE II) interest in certain oil and gas properties located in federal waters in the Gulf of Mexico and (2) our report effective December 31, 2017, dated September 14, 2018, related to the Deep Gulf Energy III, LLC (DGE III) interest in certain oil and gas properties located in federal waters in the Gulf of Mexico, each appearing in this Current Report on Form 8-K/A of Kosmos Energy Ltd., in the Registration Statements No. 333-174234 and No. 333-207259 on Form S-8 and the Registration Statement No. 333-227084 on Form S-3 of Kosmos Energy Ltd.

**NETHERLAND, SEWELL & ASSOCIATES, INC.**

By: /s/ Danny D. Simmons
Danny D. Simmons
President and Chief Operating Officer

Houston, Texas
October 5, 2018

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.

# Deep Gulf Energy LP

Financial Statements as of and for the Year Ended December 31, 2017, and Independent Auditors’ Report

# DEEP GULF ENERGY LP

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Deloitte & Touche LLP
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Houston, TX 77002-2591
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www.deloitte.com

**INDEPENDENT AUDITORS' REPORT**

The Partners
Deep Gulf Energy LP

We have audited the accompanying financial statements of Deep Gulf Energy LP (the "Partnership"), which comprise the balance sheet as of December 31, 2017, and the related statements of operations, partners' capital, and cash flows for the year then ended, and the related notes to the financial statements ("financial statements").

**Management's Responsibility for the Financial Statements**

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

**Auditors' Responsibility**

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Partnership's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

**Opinion**

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Deep Gulf Energy LP as of December 31, 2017, and the results of its operations and its cash flows for the year then ended in accordance with accounting principles generally accepted in the United States of America.

**Emphasis of Matter**

The Partnership entered into Master Services and License Agreements with related parties, in which operating services, engineering services, and other cost-sharing services are provided and allocated to each other. The accompanying financial statements have been prepared from the separate records maintained by DGE III Management, LLC and may not necessarily be indicative of the conditions that would have existed or the results of operations if the Partnership had been operated as an unrelated company (see Note 3).

**Other Matter**

Accounting principles generally accepted in the United States of America require that the Supplemental Information on Oil and Natural Gas Operations be presented to supplement the financial statements. Such information, although not a part of the financial statements, is required by the Financial Accounting Standards Board who considers it to be an essential part of financial reporting for placing the financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management’s responses to our inquiries, the financial statements, and other knowledge we obtained during our audit of the financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

/s/ Deloitte & Touche LLP

March 29, 2018

## DEEP GULF ENERGY LP

**BALANCE SHEET**
**AS OF DECEMBER 31, 2017**
**(In thousands)**

| | | |
|---|---|---|
| **ASSETS** | | |
| CURRENT ASSETS: | | |
| Cash and cash equivalents | $ | 9,606 |
| Accounts receivable, net | | 1,339 |
| Prepaid expenditures | | 281 |
| Total current assets | | 11,226 |
| PROPERTY, PLANT, AND EQUIPMENT— | | |
| Oil and gas properties, successful efforts method—net of accumulated depreciation, depletion and amortization of $388,398 at December 31, 2017 | | 10,638 |
| OTHER ASSETS | | 725 |
| TOTAL ASSETS | $ | 22,589 |
| **LIABILITIES AND PARTNERS' CAPITAL** | | |
| CURRENT LIABILITIES: | | |
| Accounts payable | $ | 445 |
| Accounts payable—related-party | | 102 |
| Accrued liabilities | | 4,015 |
| Current portion of asset retirement obligations | | 5,150 |
| Total current liabilities | | 9,712 |
| LONG-TERM LIABILITIES—Asset retirement obligations | | 11,883 |
| COMMITMENTS AND CONTINGENCIES (Note 4) | | |
| PARTNERS' CAPITAL—Limited partners' interest | | 994 |
| TOTAL LIABILITIES AND PARTNERS' CAPITAL | $ | 22,589 |

See accompanying notes to the financial statements.

## DEEP GULF ENERGY LP

**STATEMENT OF OPERATIONS**
**FOR THE YEAR ENDED DECEMBER 31, 2017**
**(In thousands)**

| | |
|---|---|
| REVENUE: | |
| Oil revenue | $ 6,975 |
| Gas revenue | 1,105 |
| NGL revenue | 262 |
| Total revenue | 8,342 |
| OPERATING COSTS AND EXPENSES: | |
| Lease operating expenses | 4,463 |
| Workover expenses | 1,471 |
| Transportation expenses | 248 |
| Exploration expenses | 18 |
| Depreciation, depletion, and amortization | 1,906 |
| Impairment | 4,537 |
| Accretion expense | 786 |
| General and administrative expenses | 326 |
| Gain on sale of inventory | (1,171) |
| Other operating income | (16) |
| Total operating costs and expenses | 12,568 |
| OPERATING LOSS | (4,226) |
| INTEREST EXPENSE | (1) |
| NET LOSS | $ (4,227) |

See accompanying notes to the financial statements.

## DEEP GULF ENERGY LP

**STATEMENT OF PARTNERS' CAPITAL**
**FOR THE YEAR ENDED DECEMBER 31, 2017**
**(In thousands)**

| | Limited Partners' Units | Contributions | Distributions | Retained Earnings | Total Partners' Capital |
|---|---|---|---|---|---|
| BALANCE—January 1, 2017 | 100 | $ 148,601 | $ (283,875) | $ 140,495 | $ 5,221 |
| Net loss | — | — | — | (4,227) | (4,227) |
| BALANCE—December 31, 2017 | 100 | $ 148,601 | $ (283,875) | $ 136,268 | $ 994 |

See accompanying notes to the financial statements.

## DEEP GULF ENERGY LP

**STATEMENT OF CASH FLOWS**
**FOR THE YEAR ENDED DECEMBER 31, 2017**
**(In thousands)**

| | | |
|---|---|---|
| CASH FLOWS FROM OPERATING ACTIVITIES: | | |
| Net loss | $ | (4,227) |
| Adjustments to reconcile net cash provided by operating activities: | | |
| Depreciation, depletion, and amortization | | 1,906 |
| Impairment | | 4,537 |
| Bad debt expense | | 142 |
| Accretion expense | | 786 |
| Settlement of asset retirement obligations | | (3,183) |
| Net changes in assets and liabilities: | | |
| Accounts receivable | | 6,473 |
| Prepaid expenditures | | 787 |
| Other assets | | (325) |
| Accounts payable | | (5,336) |
| Accounts payable—related-party | | (1,082) |
| Accrued liabilities | | 1,772 |
| Net cash provided by operating activities | | 2,250 |
| CASH FLOWS FROM INVESTING ACTIVITIES— | | |
| Capital expenditures for oil and gas properties—net of reimbursements | | 16 |
| Net cash provided by investing activities | | 16 |
| NET INCREASE IN CASH AND CASH EQUIVALENTS | | 2,266 |
| CASH AND CASH EQUIVALENTS—Beginning of year | | 7,340 |
| CASH AND CASH EQUIVALENTS—End of year | $ | 9,606 |

See accompanying notes to the financial statements.

## 1. NATURE OF BUSINESS AND BASIS OF PRESENTATION

**Nature of Business**—Deep Gulf Energy LP, a Texas limited partnership (the "Partnership"), was formed to acquire, develop, operate, and manage deepwater exploitation and low-risk exploration projects located in the Gulf of Mexico and to produce and market oil, gas and natural gas liquids (NGL) from such properties. The Partnership has a perpetual existence unless and until dissolved and terminated.

**Basis of Presentation**—The financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America (GAAP). The financial statements include all the accounts of the Partnership. Undivided interests in oil, gas and NGL exploration and production joint ventures are consolidated on a proportionate basis. All adjustments that are of a normal, recurring nature and are necessary to fairly present the Partnership's financial position, results of operations and cash flows for the period are reflected.

## 2. ACCOUNTING POLICIES

**Use of Estimates**—The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities and disclosures of contingent liabilities at the date of the consolidated financial statements and the related reported amounts of revenue and expenses. Estimates of reserves are used to determine depletion and to conduct impairment analysis. Estimating reserves has inherent uncertainty, including the projection of future rates of production and the timing of expenditures. Actual results could differ from those estimates. Management believes that its estimates are reasonable.

**Revenue Recognition and Imbalances**—Oil, gas and NGL revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and when collectability of the revenue is probable.

The Partnership uses the sales method of accounting for gas production imbalances. The volumes of gas sold may differ from the volumes to which the Partnership is entitled, based on its interests in the properties. These differences create imbalances that are recognized as a liability only when the properties' estimated remaining reserves, net to the Partnership, will not be sufficient to enable the under produced owner to recoup its entitled share through production. No receivables are recorded for those wells where the Partnership has taken less than its share of production. There were no imbalances recorded at December 31, 2017.

**Service Charges**—The Partnership's service charges are generated through standardized industry overhead charges the Partnership receives as operator of oil, gas and NGL properties. The service costs associated with third-party reimbursements are recorded within other operating income in the accompanying statements of operations.

**Concentration of Credit Risk**—The Partnership extends credit in the form of uncollateralized oil, gas and NGL sales and joint interest owner receivables to various companies in the oil, gas and NGL industry. The following table lists companies that account for at least 10% of oil, gas and NGL sales for the year ended December 31, 2017:

| | |
|---|---|
| Shell Trading (US) Company | 82 % |
| Chevron Natural Gas | 11 % |

**Cash and Cash Equivalents**—Cash and cash equivalents consist of all cash balances and highly liquid investments that have an original maturity of three months or less. Cash equivalents are stated at cost, which approximates fair value.

**Fair Value Measurements**—Current fair value accounting standards define fair value, establish a consistent framework for measuring fair value, and stipulate the related disclosure requirements for each major asset and liability category measured at fair value on either a recurring or nonrecurring basis. These standards also clarify that fair value is an exit price representing the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. The Partnership follows a three-level hierarchy, prioritizing and defining the types of inputs used to measure fair value depending on the degree to which they are observable as follows:

***Level 1***—Inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.

***Level 2***—Inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial statement or quoted prices (unadjusted) for identical assets or liabilities in inactive markets.

***Level 3***—Inputs to the valuation methodology are unobservable (little or no market data), which require the reporting entity to develop its own assumptions, and are significant to the fair value measurement.

Assets and liabilities measured at fair value are based on one or more of three valuation techniques. The valuation techniques are as follows:

***Market Approach***—Prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities.

***Cost Approach***—Amount that would be required to replace the service capacity of an asset (replacement cost).

***Income Approach***—Techniques to convert expected future cash flows to a single present value amount based on market expectations (including present value techniques, option-pricing and excess earnings models).

Authoritative guidance on financial instruments requires certain fair value disclosures to be presented. The estimated fair value amounts have been determined using available market information and valuation methodologies. Considerable judgment may be required in interpreting market data to develop the estimates of fair value for Level 3 inputs to the valuation methodology. The use of different assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

Financial instruments consisting of cash and cash equivalents, accounts receivable, and accounts payable are reported at their carrying amounts, which approximate fair value due to the short-term nature of these instruments.

**Accounts Receivable**—Accounts receivable consist of oil and gas receivables and joint interest billing receivables on wells that the Partnership operates. Accounts receivable are carried at cost, net of allowance for losses. The Partnership recognizes an allowance or losses on accounts receivable in an amount equal to the estimated probable losses. The allowance is based on an analysis of historical bad debt experience, current receivables aging and expected future write-offs, as well as an assessment of specific identifiable customer accounts considered at risk or uncollectable. The expense associated with the allowance for doubtful accounts is recorded in our statements of operations as general and administrative expense. As of December 31, 2017 the Partnership has an allowance for doubtful accounts in the amount of $142 thousand.

**Prepaid Expenditures**—Prepaid expenditures consist of deposits and insurance. Prepaid expenditures are classified as current and are expected to be realized within twelve months.

**Property, Plant, and Equipment**—The Partnership uses the successful efforts method of accounting for its oil, gas and NGL properties. Under the successful efforts method of accounting, the Partnership depletes proved oil and natural gas properties on a units-of-production basis based on production and estimates of proved reserves quantities. The Partnership assesses depletion on each field. The Partnership depletes capitalized costs of proved mineral interests over total estimated proved reserves and capitalized costs of wells and related equipment and facilities over estimated proved developed reserves.

Unproved leasehold costs are capitalized and are not amortized, pending an evaluation of their exploration potential. Unproved leasehold costs are assessed periodically to determine whether an impairment of the cost of significant individual properties has occurred. The cost of impairment is charged to exploration expense in the period in which it occurs. Costs incurred for exploratory dry holes, geological and geophysical work, and delay rentals are charged to exploration expense as incurred.

The following table lists the total proved and unproved oil, gas and NGL properties as of December 31, 2017 (in thousands):

| | | |
|---|---|---|
| Proved properties—net of accumulated depreciation, depletion and amortization | $ | 10,370 |
| Unproved properties | | 268 |
| Total oil and gas properties—net of accumulated depreciation, depletion and amortization | $ | 10,638 |

The Partnership reviews long-lived assets for impairment at least annually and whenever events or changes in circumstances indicate that the carrying amounts may not be recovered. If the carrying amounts are not expected to be recovered by undiscounted future cash flows, an impairment loss is recorded through a charge to expense. The amount of impairment is based on the estimated fair value of the assets, which is determined by discounting anticipated future net cash flows. The net present value of future cash flows is based on management’s best estimate of future prices, which is determined using published forward prices, applied to projected production volumes, and discounted at a risk-adjusted rate. The projected production volumes represent reserves, including probable and possible reserves, expected to be produced based on a stipulated amount of capital expenditures.

In 2017, the Partnership determined that it would be unable to recover the net book value of its investment in certain of its proved properties due to current reserves profile of the wells. Accordingly, the Partnership recorded impairment charges on the Sargent Property located at Garden Banks block 339 of $0.7 for the year ended December 31, 2017. The Partnership used an income-based approach to determine impairment that considered cash flows and other significant unobservable Level 3 inputs, including the Partnership’s estimated future oil, gas and NGL production, costs and capital expenditures, forward prices, and a discount rate believed to be consistent with those applied by market participants. Additionally, in 2017 the Partnership recorded impairment charges of $3.8 million related to properties that are no longer producing.

Commodity prices have remained volatile subsequent to December 31, 2017. Further price declines from these levels and/or changes to the Partnership’s future capital, production rates, levels of proved reserves and development plans as a consequence of the lower price environment may result in an additional impairment of the carrying value of the Partnership’s proved and/or unproved properties in the future.

In 2017 the Partnership received proceeds of $1.2 million on the sale inventory on a well that was previously plugged and abandoned. The partnership recognized a gain of $1.2 million on the sale of inventory.

**Other Assets**—The Partnership has $0.4 million in credit with another operator to offset future asset retirement obligations associated with one of the Partnership’s offshore platforms. Additionally, the Partnership has a deposit of $0.3 million as collateral related to a bond for the Nancy well, which the Partnership exited in early 2017. See Note 4 for more information about the collateralized bond. The Partnership has recorded the liability associated with the platform and the Nancy well, gross of these assets, in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification Topic (ASC) 410, *Asset Retirement and Environmental Obligations.*

**Asset Retirement Obligations**—The Partnership is required to record a liability for its asset retirement obligations at fair value in the period such obligations are incurred with the associated asset retirement costs being capitalized as part of the carrying cost of the asset. The Partnership’s asset retirement obligations relate to the plugging, abandonment, dismantlement, removal, site reclamation and similar activities associated with its oil, gas and NGL properties. Accretion of the liability is recognized for changes in the value of the liability as a result of the passage of time over the estimated productive life of the related assets as the discounted liabilities are accreted to their expected settlement values. Revisions in the estimates of property lives and cost estimates are capitalized as part of the property balance. Any gain or loss upon settlement of obligations is recognized in income.

The obligation to plug wells is settled when the Partnership abandons wells in accordance with governmental regulations. The Partnership accrues a liability with respect to these obligations based on its estimate of the timing and amount to replace, remove or retire the associated assets. The estimate of the asset retirement cost is determined, inflated to an estimated future value using a seven year average of the Consumer Price Index, and discounted to present value using the Partnership’s credit-adjusted risk-free rate.

In estimating the liability associated with its asset retirement obligations, the Partnership utilizes several assumptions, including a credit-adjusted risk-free interest rate, estimated costs of decommissioning services, estimated timing of when the work will be performed and a projected inflation rate. Revisions in the estimate presented in the table below represent changes to the expected amount and timing of payments to settle the asset retirement obligations. Typically, these changes primarily result from obtaining new information about the timing of the obligations to plug and abandon oil, gas and NGL wells and the costs to do so. If the Partnership incurs an amount different from the amount accrued for decommissioning obligations, it recognizes the difference as a gain or loss on settlement of asset retirement obligations on the statements of operations.

The discounted asset retirement liability included on the balance sheets in current and noncurrent liabilities, and the changes in that liability for the year ended December 31, 2017, were as follows (in thousands):

| | | |
|---|---|---|
| Asset retirement obligations at beginning of year | $ | 13,937 |
| Settlement of asset retirement obligations | | (3,183) |
| Revisions in estimated liabilities | | 5,493 |
| Accretion expense | | 786 |
| Asset retirement obligations at end of year | | 17,033 |
| Less current portion | | (5,150) |
| Asset retirement obligations, long term | $ | 11,883 |

The Partnership partially settled asset retirement obligations related to four different properties during 2017. The total cost to partially settle those obligations was $3.2 million, and has a remaining asset retirement obligation of $5.1 million.

In 2017, the Partnership had upward revisions in estimated costs to abandon wells primarily due to an increase in assumed rig days on location for blowout preventer certification.

**Federal Income Taxes**—In accordance with the provisions of the Internal Revenue Code, the Partnership is not subject to federal income tax. Each partner includes its share of the Partnership's income or loss in its own federal and state income tax returns.

The Partnership may be subject to state income taxes in certain jurisdictions and applicable state laws; however, currently the Partnership incurs no state income taxes.

**Employee Share Ownership Program**—The Amended and Restated Limited Partnership Agreement of the Partnership (the "Operating Agreement") established Common Units and Incentive Units. Incentive Units are generally intended to be used as incentives for Partnership employees. The Partnership was initially authorized to issue 50,000 Incentive Units and may be authorized to issue more under the Operating Agreement. As of December 31, 2017, the Partnership was authorized to issue 50,000 Incentive Units.

With the exception of annual distributions to cover the assumed tax liability of the Incentive Unit holders, Incentive Units do not participate in cash distributions prior to vesting and until non-employee holders of Common Units have received a 2.00X return on investment multiple. After issuance, the Incentive Units fully vest (a) annually over a three year period from grant date, (b) upon occurrence of a Liquidity Event, or (c) upon occurrence of a Tag Along Sale.

**Recently Issued Accounting Standards**—In May 2014, the FASB issued Accounting Standards Update (ASU) 2014-09, *Revenue from Contracts with Customers*, which supersedes the revenue recognition requirements in ASC 605, *Revenue Recognition*, and requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which entity expects to be entitled in exchange for those goods or services. The Partnership is required to adopt the new standard in 2019 using one of two allowable methods: (1) a full retrospective method, which applies the standard to each period presented in the financial statements, or (2) the modified retrospective method, which applies the standard to only the most current period presented, with a cumulative effect adjustment recorded to retained earnings. The Partnership is continuing to evaluate the provisions of this ASU, and has not determined the impact this standard may have on its financial statements and related disclosures or decided upon the method of adoption.

In August 2014, the FASB issued ASU 2014-15, *Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern*. The guidance requires management to evaluate whether there are conditions and events that raise substantial doubt about the Partnership's ability to continue as a going concern within one year after the financial statements are issued on both an interim and annual basis. Additionally, management is required to provide certain footnote disclosures if it concludes that substantial doubt exists or when it plans to alleviate substantial doubt about the Partnership's ability to continue as a going concern. ASU 2014-15 is effective for annual periods ending after December 15, 2016. The Partnership adopted the guidance in ASU 2014-15 in 2016. The adoption of ASU 2014-15 did not have a material impact on our financial statements.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*, which significantly changes accounting for leases by requiring that lessees recognize a right-of-use asset and a related lease liability representing the obligation to make lease payments, for virtually all lease transactions. Additional disclosures about an entity's lease transactions will also be required. ASU 2016-02 defines a lease as "a contract, or part of a contract, that conveys the right to control the use of identified property, plant or equipment (an identified asset) for a period of time in exchange for consideration." ASU 2016-02 is effective for annual periods beginning after December 31, 2018 and early application is permitted. Lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented in the financial statements using a modified retrospective approach. The Partnership is continuing to evaluate the provisions of this ASU and has not yet decided upon the method of adoption or determined the impact this standard may have on its consolidated financial statements and related disclosures.

In August 2016, the FASB issued ASU 2016-15*, Statements of Cash Flows (Topic 230)—Classification of Certain Cash Receipts and Cash Payments*. ASU 2016-15 reduces existing diversity in practice by providing guidance on the classification of eight specific cash receipts and cash payments transactions in the statements of cash flows. For nonpublic entities, the new standard is effective for fiscal years beginning after December 15, 2018. Early adoption is permitted. The Partnership does not expect the adoption of the new standard to have a material impact on its financial statements and related disclosures.

In January 2017, the FASB issued ASU 2017-1, *Business Combinations (Topic 805): Clarifying the definition of a Business*. ASU 2017-1 reduces existing diversity in practice by providing guidance on the definition of a business. The definition of a business affects many areas of accounting including acquisitions, disposals, goodwill impairment, and consolidation. The new standard is effective for fiscal years beginning after December 15, 2018. Early adoption is permitted. The Partnership does not expect the adoption of the new standard to have a material impact on its consolidated financial statements and related disclosures.

## 3. RELATED-PARTY TRANSACTIONS

The Partnership's controlling interest is owned by the same persons who own DGE II Management, LLC; Deep Gulf Energy II, LLC; DGE III Management, LLC; and Deep Gulf Energy III, LLC. DGE II Management, LLC; DGE III Management, LLC; and the Partnership have entered into Master Services and License Agreements in which operating services, engineering services, and other cost-sharing services are provided to each other. As of December 31, 2017, the Partnership had related party payables to other entities under this Master Services and License Agreement of $0.1 million.

These financial statements have been prepared from the separate records maintained by DGE III Management, LLC and may not necessarily be indicative of the conditions that would have existed or the results of operations if the Partnership had been operated as an unrelated company.

## 4. COMMITMENTS AND CONTINGENCIES

**Insurance**—The Partnership has insurance policies to mitigate its risk of loss associated with its operations, and it maintains the coverages and amounts of insurance believed to be prudent based on reasonably estimated loss potential. However, not all of the Partnership's business activities can be insured at the levels it desires because of either limited market availability or unfavorable economics (limited coverage for the underlying cost).

The Partnership's general property damage insurance provides varying ranges of coverage based upon several factors, including well counts and cost of replacement facilities. Its general liability insurance program provides a limit of $150 million (for the Partnership's interest) for each occurrence and in the aggregate and includes varying deductibles, and the Partnership's Offshore Pollution Act insurance is also subject to a maximum of $35 million for each occurrence and in the aggregate and includes a $100,000 (100%) retention. The Partnership separately maintains an operator's extra expense policy for wells being drilled and producing wells with additional coverage for an amount up to $100 million that would cover costs involved in making a well safe after a blowout or getting the well under control, re-drilling a well to the depth reached prior to the well being out of control or blown out, costs for plugging and abandoning the well, costs for cleanup and containment and for damages caused by contamination and pollution.

The Partnership customarily has reciprocal agreements with its customers and vendors in which each contracting party is responsible for its respective personnel. Under these agreements, the Partnership is indemnified against third party claims related to the injury or death of its customers' or vendors' personnel.

Although there can be no assurance the amount of insurance the Partnership carries is sufficient to protect it fully in all events, it believes that its insurance protection is adequate for its business operations.

**Performance Obligations**—Regulations with respect to offshore operations govern, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells, and removal of facilities. As of December 31, 2017, the Partnership had secured performance bonds totaling approximately $4.1 million for its supplemental bonding requirements stipulated by the Bureau of Ocean Energy Management related to costs anticipated for the plugging and abandonment of certain wells and removal of certain facilities in its Gulf of Mexico fields, respectively. These performance bonds are uncollateralized. If the Partnership were to have to obtain additional performance bonds for other reasons, it cannot ensure that it would be able to secure any such additional performance bonds on acceptable commercial terms or at all.

Additionally, the Partnership has a $1.2 million collateralized bond to a third party for the plugging and abandonment of Nancy property located at Garden Banks block 463 that the Partnership exited in 2017. On January 4, 2017 the Partnership executed an agreement withdrawing from the Nancy property located at Garden Banks block 463. The agreement has an effective date of August 19, 2016. As part of the agreement, the Partnership was required to post a performance bond with the purchaser as obligee for the Partnership's estimated share of certain future abandonment expenses as the Partnership retained financial responsibility and liability for its proportionate share of certain of the abandonment liabilities. The Partnership posted such performance bond on January 4, 2017 in the amount of $1.2 million. As part of the performance bond, the Partnership entered into a collateral agreement with the bonding surety and was required to fund a collateral account with an initial contribution of $50 thousand by January 10, 2017 and in monthly deposits of $25 thousand on the 1st day of each month beginning on February 1, 2017 through November 1, 2018 in until such time that the deposit totals $0.6 million. As of December 31, 2017 the Partnership has recorded a $0.3 million deposit related to this bond.

**Legal Proceedings and Other Contingencies**—The Partnership is a party to a Deferred Amount Payment Agreement (DAPA) with Energy Resource Technology GOM, Inc. (ERT) related to the Danny Noonan project (Project). Through this DAPA, the Partnership is required to reimburse ERT $7.3 million from the Project's net cash flow in monthly installments if the gross production from the Project equals or exceeds 265 BCFE. As of December 31, 2017, the Partnership does not expect gross production from the Project to equal or exceed 265 BCFE. As of December 31, 2017, the Partnership had no liability recorded for this DAPA.

From time to time, the Partnership could be a party to certain legal actions and claims arising in the ordinary course of business. Management is not aware of any legal actions or claims against the Partnership.

**5. SUBSEQUENT EVENTS**

Subsequent events were evaluated through March 29, 2018, which is the date these financial statements were available to be issued.

## 6. SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS OPERATIONS (UNAUDITED)

**Capitalized Costs Relating to Oil and Natural Gas Producing Activities**—The total amount of capitalized costs relating to oil and natural gas producing activities and the total amount of related accumulated depreciation, depletion and amortization indicated are presented below as of December 31, 2017 (in thousands):

| | |
|---|---|
| Proved properties—net of accumulated depreciation, depletion and amortization | $ 10,370 |
| Unproved properties | 268 |
| | |
| Total oil and gas properties—net of accumulated depletion | $ 10,638 |

Included in the depletable basis of the Partnership's proved properties is the estimate of the Partnership's proportionate share of asset retirement obligations relating to these properties which are also reflected as asset retirement obligations in the accompanying consolidated balance sheets. At December 31, 2017 oil and gas asset retirement obligations totaled $17.0 million.

**Estimated Quantities of Proved Oil and Gas Reserves**—Users of this information should be aware that the process of estimating quantities of "proved" and "proved developed" oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

A variety of deterministic methods are used to determine the Partnership's proved reserve estimates. Standard engineering and geoscience methods or a combination of methods are used, including performance analysis, volumetric analysis, analogy, and reservoir modeling. 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.

Proved reserves are those quantities of oil and natural gas that 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. 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.

The Partnership engaged Ryder Scott Company, L.P. Petroleum Consultants to prepare reserves estimates for all of the Partnership's estimated proved reserves (by volume) at December 31, 2017. All proved reserves are located in the Gulf of Mexico and all prices are held constant in accordance with SEC rules.

The following tables set forth estimates of the net proved reserves as of December 31, 2017:

| | Oil (MBbls) | Gas (MMcf) | NGL (MBbls) | Total (Mboe)[2] |
|---|---|---|---|---|
| Proved reserves at December 31, 2016 | 1,048 | 965 | 62 | 1,271 |
| Revision of previous estimate[1] | 102 | 579 | 7 | 205 |
| Production | (142) | (352) | (11) | (211) |
| Purchase of reserves in place | — | — | — | — |
| Sales of reserves in place | — | — | — | — |
| Extensions and discoveries | — | — | — | — |
| Proved reserves at December 31, 2017 | 1,008 | 1,192 | 58 | 1,265 |
| Proved developed reserves at December 31, 2017 | 1,008 | 1,192 | 58 | 1,265 |

(1) Revisions in quantity estimates resulted from positive performance in the following fields:

- Danny Noonan +0.2 MMBOE for performance-based increase in recovery efficiency
- Sargent +0.1 MMBOE based on continued performance above what was expected year end 2016
- Gladden -0.1 MMBOE for a performance-based decrease in expected ultimate gas-oil-ratio

(2) Natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent.

**Standardized Measure of Discounted Future Net Cash Flows from Proved Reserves**—The standardized measure of discounted future net cash flows presented below is computed by applying first-day-of-the-month average prices, year-end costs and legislated tax rates and a discount factor of 10 percent to proved reserves. The Partnership does not believe the standardized measure provides a reliable estimate of the Partnership's expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its proved oil and gas reserves. The standardized measure is prepared on the basis of certain prescribed assumptions including first-day-of-the-month average prices, which represent discrete points in time and therefore may cause significant variability in cash flows from year to year as prices change.

Future net cash flows are discounted at the prescribed rate of 10%. Actual future net cash flows may vary considerably from these estimates. Although the Partnership's estimates of total proved reserves, development costs and production rates were based on the best information available, the development and production of oil and gas reserves may not occur in the periods assumed. Actual prices realized, costs incurred and production quantities may vary significantly from those used. Therefore, such estimated future net cash flow computations should not be considered to represent our estimate of the expected revenues or the current value of existing proved reserves.

The standardized measure of discounted future net cash flows at December 31, 2017 is as follows (in thousands):

| | |
|---|---|
| Future cash inflows | $ 51,486 |
| Future production costs | (29,149) |
| Future completion & abandonment costs | (23,681) |
| Future income tax expense | — |
| Future net cash flows[1] | (1,344) |
| Discount at 10% annual rate | 153 |
| Standardized measure of discounted future net cash flows | $ (1,191) |

(1) Negative future net cash flows attributable to certain plug and abadndonment liability costs.

Future cash inflows are computed by applying the appropriate average of the first-day-of-the-month price for each month within the period January through December of each year presented, adjusted for location and quality differentials on a property-by-property basis, to year-end quantities of proved reserves. For oil and NGL volumes the average Texas intermediate spot price of $51.34 per barrel is adjusted by field for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.98 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. The discounted future cash flow estimates do not include the effects of the Partnership's derivative financial instruments.

**Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves**—The following is a summary of the changes in the standardized measure of discounted future net cash flows for the proved oil and natural gas reserves during the year ended December 31, 2017 (in thousands):

| | | |
|---|---|---|
| Standardized measure, beginning of year(2) | $ | (3,919) |
| Changes during the year: | | |
| Sales, net of production | | (2,161) |
| Net change in prices and production costs | | 4,367 |
| Changes in future completion and abandonment costs | | (5,421) |
| Development costs incurred | | 3,183 |
| Accretion of discount | | (392) |
| Net change in income taxes(1) | | — |
| Purchase of reserves in place | | — |
| Extensions and discoveries | | — |
| Sales of reserves in place | | — |
| Net change due to revision in quantity estimates | | 2,417 |
| Changes in production rates (timing) and other | | 735 |
| Standardized measure, end of year(2) | | (1,191) |

(1) The Partnership's calculation of the standardized measure of discounted future net cash flows and the related changes therein do not include the effect of the estimated future income tax expenses because the Partnership is not subject to federal or state income taxes on income from proved oil and gas reserves.

(2) Negative future net income attributable to certain plug and abadndonment liability costs.

******

# DGE II
# Management, LLC
# and Subsidiary

Consolidated Financial Statements as of and for the
Year Ended December 31, 2017, and
Report of Independent Auditors

# DGE II MANAGEMENT, LLC AND SUBSIDIARY

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**REPORT OF INDEPENDENT AUDITORS**

The Members
DGE II Management, LLC:

We have audited the accompanying consolidated financial statements of DGE II Management, LLC and subsidiary (the "Company"), which comprise the consolidated balance sheet as of December 31, 2017, and the related consolidated statements of operations, members' capital, and cash flows for the year then ended, and the related notes to the consolidated financial statements ("consolidated financial statements").

**Management's Responsibility for the Consolidated Financial Statements**

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

**Auditors' Responsibility**

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

**Opinion**

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of DGE II Management, LLC and subsidiary as of December 31, 2017, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

**Emphasis of Matter**

The Company entered into Master Services and License Agreements with related parties, in which operating services, engineering services, and other cost-sharing services are provided and allocated to each other. The accompanying consolidated financial statements have been prepared from the separate records maintained by DGE III Management, LLC and may not necessarily be indicative of the conditions that would have existed or the results of operations if the Company had been operated as an unrelated company (see Note 5).

**Other Matter**

Accounting principles generally accepted in the United States of America require that the Supplemental Information on Oil and Natural Gas Operations be presented to supplement the consolidated financial statements. Such information, although not a part of the consolidated financial statements, is required by the Financial Accounting Standards Board who considers it to be an essential part of financial reporting for placing the consolidated financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the consolidated financial statements, and other knowledge we obtained during our audit of the consolidated financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

/s/ Deloitte & Touche LLP

March 29, 2018

## DGE II MANAGEMENT, LLC AND SUBSIDIARY

**CONSOLIDATED BALANCE SHEET**
**FOR THE YEAR ENDED DECEMBER 31, 2017**
**(In thousands)**

| | | |
|---|---|---|
| **ASSETS** | | |
| CURRENT ASSETS: | | |
| Cash and cash equivalents | $ | 51,524 |
| Accounts receivable | | 15,351 |
| Accounts receivable—related party | | 43 |
| Current asset from price risk management activities | | 735 |
| Prepaid expenditures | | 4,766 |
| Inventory | | 2,684 |
| Total current assets | | 75,103 |
| PROPERTY, PLANT, AND EQUIPMENT: | | |
| Oil and gas properties, successful efforts method—net of accumulated depletion of $284,352 at December 31, 2017 | | 232,047 |
| Other property, plant, and equipment—net of accumulated depreciation of $2,084 at December 31, 2017 | | 315 |
| Total property, plant, and equipment | | 232,362 |
| INVESTMENTS | | 3,819 |
| OTHER ASSETS | | 800 |
| INTEREST RECEIVABLE—related party | | 1,591 |
| TOTAL ASSETS | $ | 313,675 |
| **LIABILITIES AND MEMBERS' CAPITAL** | | |
| CURRENT LIABILITIES: | | |
| Accounts payable | $ | 269 |
| Accounts payable—related party | | 4,258 |
| Accrued liabilities | | 20,769 |
| Liability from price risk management activities | | 4,200 |
| Current portion of asset retirement obligations | | 330 |
| Interest payable | | 856 |
| Total current liabilities | | 30,682 |
| LONG-TERM LIABILITIES: | | |
| Asset retirement obligations | | 15,227 |
| Long-term accounts payable—related party | | 4,721 |
| Long-term notes payable—related party | | 4,564 |
| Liability from price risk management activities | | 1,477 |
| Long term interest payable | | 6,201 |
| Other non-current liabilities | | - |
| Long-term debt—net of original issuance discount and issuance costs of $12,676 at December 31, 2017 | | 287,324 |
| Total long-term liabilities | | 319,514 |
| COMMITMENTS AND CONTINGENCIES (NOTE 7) | | |
| MEMBERS' DEFICIT | | (36,521) |
| TOTAL LIABILITIES AND MEMBERS' DEFICIT | $ | 313,675 |

See accompanying notes to the consolidated financial statements.

## DGE II MANAGEMENT, LLC AND SUBSIDIARY

**CONSOLIDATED STATEMENT OF OPERATIONS**
**FOR THE YEAR ENDED DECEMBER 31, 2017**
**(In thousands)**

| | | |
|---|---|---|
| REVENUE: | | |
| Oil revenue | $ | 122,492 |
| Gas revenue | | 9,013 |
| NGL revenue | | 6,451 |
| Total revenue | | 137,956 |
| OPERATING COSTS AND EXPENSES: | | |
| Lease operating expenses | | 30,895 |
| Workover expenses | | 11,792 |
| Transportation expenses | | 7,703 |
| Exploration expenses | | 52 |
| Depreciation, depletion, and amortization | | 55,874 |
| Impairment | | 1,778 |
| Inventory write-down | | 1,316 |
| Accretion expense | | 1,559 |
| Loss on settlement of asset retirement obligations | | 138 |
| General and administrative expenses | | 3,632 |
| Other operating income | | (2,799) |
| Total operating costs and expenses | | 111,940 |
| OPERATING INCOME | | 26,016 |
| OTHER EXPENSE | | (1,766) |
| INTEREST EXPENSE—Net | | (58,074) |
| LOSS FROM PRICE RISK MANAGEMENT ACTIVITIES | | (2,320) |
| NET LOSS | $ | (36,144) |

See accompanying notes to the consolidated financial statements.

## DGE II MANAGEMENT, LLC AND SUBSIDIARY

**CONSOLIDATED STATEMENT OF MEMBERS' DEFICIT**
**FOR THE YEAR ENDED DECEMBER 31, 2017**
**(In thousands, except units)**

| | Units | Capital Contributions | Additional Paid-In Capital | Retained Deficit | Total |
|---|---|---|---|---|---|
| BALANCE—January 1, 2017 | 382,695 | $ 382,695 | $ 5,935 | $ (393,772) | $ (5,142) |
| Issuance of warrants | - | - | 4,765 | - | 4,765 |
| Net loss | - | - | - | (36,144) | (36,144) |
| BALANCE—December 31, 2017 | 382,695 | $ 382,695 | $ 10,700 | $ (429,916) | $ (36,521) |

See accompanying notes to the consolidated financial statements.

## DGE II MANAGEMENT, LLC AND SUBSIDIARY

**CONSOLIDATED STATEMENT OF CASH FLOWS**
**FOR THE YEAR ENDED DECEMBER 31, 2017**
**(In thousands)**

| | | |
|---|---|---|
| OPERATING ACTIVITIES: | | |
| Net loss | $ | (36,144) |
| Adjustments to reconcile net loss to net cash provided by operating activities: | | |
| Depreciation, depletion, and amortization | | 55,874 |
| Impairment | | 1,778 |
| Amortization of deferred financing costs | | 6,983 |
| Non-cash fees on long-term debt | | 3,000 |
| Non-cash loss on price risk management activities | | 1,640 |
| Oil inventory write-down | | 182 |
| Accretion expense | | 1,559 |
| Inventory write-down | | 1,316 |
| Settlement of asset retirement obligations | | (2,599) |
| Net changes in assets and liabilities: | | |
| Accounts receivable | | 11,057 |
| Accounts receivable—related party | | 644 |
| Prepaid expenditures | | 354 |
| Inventory | | 2,183 |
| Interest receivable—related party | | (195) |
| Accounts payable | | (12,378) |
| Accounts payable—related party | | 2,538 |
| Accrued liabilities | | (8,923) |
| Interest payable | | 4,908 |
| Interest payable—related party | | 193 |
| Long term accounts payable—related party | | 4,721 |
| Net cash provided by operating activities | | 38,691 |
| INVESTING ACTIVITIES: | | |
| Capital expenditures for oil and gas properties | | (21,790) |
| Proceeds from sale of property to related party | | 2,702 |
| Net cash used in investing activities | | (19,088) |
| NET INCREASE IN CASH AND CASH EQUIVALENTS | | 19,603 |
| CASH AND CASH EQUIVALENTS—Beginning of year | | 31,921 |
| CASH AND CASH EQUIVALENTS—End of year | $ | 51,524 |

See accompanying notes to the consolidated financial statements.

## 1. NATURE OF BUSINESS AND BASIS OF PRESENTATION

**Nature of Business**—DGE II Management, LLC, a Delaware limited liability company, and its wholly owned subsidiary, Deep Gulf Energy II, LLC (collectively, the “Company”), were formed in 2007 to acquire, develop, operate, and manage deepwater exploitation and low-risk exploration projects located in the Gulf of Mexico and to produce and market oil, gas and natural gas liquids (NGL) from such properties. The Company has a perpetual existence unless and until dissolved and terminated.

**Basis of Presentation**—The consolidated financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America (GAAP). The consolidated financial statements include all the accounts of the Company. Undivided interests in oil, gas and NGL exploration and production joint ventures are consolidated on a proportionate basis. All adjustments that are of a normal, recurring nature and are necessary to fairly present the Company’s consolidated financial position, results of operations and cash flows for the period are reflected.

**Principles of Consolidation**—The consolidated financial statements include the accounts of DGE II Management, LLC and its wholly owned subsidiary, Deep Gulf Energy II, LLC. All intercompany account balances and transactions have been eliminated.

## 2. ACCOUNTING POLICIES

**Use of Estimates**—The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities and disclosures of contingent liabilities at the date of the consolidated financial statements and the related reported amounts of revenue and expenses. Estimates of reserves are used to determine depletion and to conduct impairment analysis. Estimating reserves has inherent uncertainty, including the projection of future rates of production and the timing of expenditures. Actual results could differ from those estimates. Management believes that its estimates are reasonable.

**Revenue Recognition and Imbalances**—Oil, gas and NGL revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and when collectability of the revenue is probable. The Company uses the sales method of accounting for gas production imbalances. The volumes of gas sold may differ from the volumes to which the Company is entitled, based on its interests in the properties. These differences create imbalances that are recognized as a liability only when the properties’ estimated remaining reserves, net to the Company, will not be sufficient to enable the under-produced owner to recoup its entitled share through production. No receivables are recorded for those wells where the Company has taken less than its share of production. There were no imbalances recorded at December 31, 2017.

**Service Charges**—The Company’s service charges are generated through standardized industry overhead charges the Company receives as operator of oil, gas and NGL properties. The service costs associated with third-party reimbursements are recorded within other operating income in the accompanying statement of operations.

**Concentration of Credit Risk**—The Company extends credit in the form of uncollateralized oil, gas and NGL sales and joint interest owner receivables to various companies in the oil, gas and NGL industry. The following table lists companies that account for at least 10% of oil, gas and NGL sales for the year ended December 31, 2017:

| | |
|---|---|
| Phillips 66 Company | 84 % |

**Cash and Cash Equivalents**—Cash and cash equivalents consist of all cash balances and highly liquid investments that have an original maturity of three months or less. Cash equivalents are stated at cost, which approximates fair value.

**Fair Value Measurements**—Current fair value accounting standards define fair value, establish a consistent framework for measuring fair value, and stipulate the related disclosure requirements for each major asset and liability category measured at fair value on either a recurring or nonrecurring basis. These standards also clarify that fair value is an exit price representing the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. The Company follows a three-level hierarchy, prioritizing and defining the types of inputs used to measure fair value depending on the degree to which they are observable as follows:

***Level 1***—Inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.

***Level 2***—Inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial statement or quoted prices (unadjusted) for identical assets or liabilities in inactive markets.

***Level 3***—Inputs to the valuation methodology are unobservable (little or no market data), which require the reporting entity to develop its own assumptions, and are significant to the fair value measurement.

Assets and liabilities measured at fair value are based on one or more of three valuation techniques. The valuation techniques are as follows:

***Market Approach***—Prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities.

***Cost Approach***—Amount that would be required to replace the service capacity of an asset (replacement cost).

***Income Approach***—Techniques to convert expected future cash flows to a single present value amount based on market expectations (including present value techniques, option-pricing and excess earnings models).

Authoritative guidance on financial instruments requires certain fair value disclosures to be presented. The estimated fair value amounts have been determined using available market information and valuation methodologies. Considerable judgment may be required in interpreting market data to develop the estimates of fair value for Level 3 inputs to the valuation methodology. The use of different assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

Financial instruments consisting of cash and cash equivalents, accounts receivable, and accounts payable are reported at their carrying amounts, which approximate fair value due to the short term nature of these instruments. The fair values of the Company's commodity derivatives are discussed in Note 8. Nonrecurring fair value measurements associated with oil, gas and NGL properties are discussed below.

**Accounts Receivable**—Accounts receivable consist of oil and gas receivables and joint interest billing receivables on wells that the Company operates. Accounts receivable are carried at cost, net of allowance for losses. The Company recognizes an allowance or losses on accounts receivable in an amount equal to the estimated probable losses. The allowance is based on an analysis of historical bad debt experience, current receivables aging and expected future write-offs, as well as an assessment of specific identifiable customer accounts considered at risk or uncollectable. The expense associated with the allowance for doubtful accounts is recorded in our statements of operations as general and administrative expense. As of December 31, 2017 the Company does not have an allowance for doubtful accounts as all of the Company's receivable's have been deemed collectable.

**Prepaid Expenditures**—Prepaid expenditures consist of deposits, insurance and prepayments of capital expenditures on the Company's non-operated properties. Prepaid expenditures are classified as current and are expected to be realized within twelve months.

**Inventory**—Inventory consists of tubular and other goods used in the exploration for, and development and production of, offshore oil, gas and NGL wells and oil used for line fill.

Tubular and other goods inventory is stated at cost with adjustments made, as appropriate, to recognize reduction in value. The cost of tubular and other goods inventory is determined by specific identification. During 2017 the Company recorded a $1.3 million noncash charge to write down inventory to the lower of cost or market value.

Oil inventory used for line fill is carried at lower of cost or market with adjustments to oil inventory being recorded in lease operating expenses. The cost of oil inventory used for linefill is determined using weighted average cost, or net realized value. During 2017 the Company recorded a $0.2 million noncash charge to write down oil inventory to the lower of cost or market value.

**Property, Plant, and Equipment**—The Company uses the successful efforts method of accounting for its oil, gas and NGL properties. Under the successful efforts method of accounting, the Company depletes proved oil and natural gas properties on a units-of-production basis based on production and estimates of proved reserves quantities. The Company assesses depletion on each field. The Company depletes capitalized costs of proved mineral interests over total estimated proved reserves and capitalized costs of wells and related equipment and facilities over estimated proved developed reserves.

Unproved leasehold costs are capitalized and are not amortized, pending an evaluation of their exploration potential. Unproved leasehold costs are assessed periodically to determine whether an impairment of the cost of significant individual properties has occurred. The cost of impairment is charged to exploration expense in the period in which it occurs.

Costs incurred for exploratory dry holes, geological and geophysical work, and delay rentals are charged to exploration expense as incurred. In 2017 the Company recognized geological and geophysical expense in the amount of $0.1 million.

The following table lists the total proved and unproved oil, gas and NGL properties at December 31, 2017 (in thousands):

| | |
|---|---|
| Proved properties | $ 509,197 |
| Proved properties under development | 6,639 |
| Accumulated depletion | (284,352) |
| Total proved | 231,484 |
| Unproved properties | 563 |
| Total oil and gas properties—net of accumulated depletion | $ 232,047 |

The Company reviews long-lived assets for impairment at least annually and whenever events or changes in circumstances indicate that the carrying amounts may not be recovered. If the carrying amounts are not expected to be recovered by undiscounted future cash flows, an impairment loss is recorded through a charge to expense. The amount of impairment is based on the estimated fair value of the assets, which is determined by discounting anticipated future net cash flows. The net present value of future cash flows is based on management's best estimate of future prices, which is determined using published forward prices, applied to projected production volumes, and discounted at a risk-adjusted rate. The projected production volumes represent reserves, including probable and possible reserves, expected to be produced based on a stipulated amount of capital expenditures.

In 2017, the Company determined that it would be unable to recover the net book value of its investment in certain of its proved properties as a result of decreases to the reserves on certain legacy properties. Accordingly, the Company recorded impairment charges on proved properties of $1.8 million for the year ended December 31, 2017. The Company used an income-based approach to determine impairment that considered probability-weighted cash flows and other significant unobservable Level 3 inputs, including the Company's estimated future oil, gas and NGL production, costs and capital expenditures, forward prices, and a discount rate believed to be consistent with those applied by market participants. Commodity prices have remained volatile subsequent to December 31, 2017. Commodity price declines and/or changes to the Company's future capital, production rates, levels of proved reserves and development plans as a consequence of the lower price environment may result in an additional impairment of the carrying value of the Company's proved and/or unproved properties in the future.

Costs of office furniture and equipment are depreciated on a straight-line basis over seven years. Costs of computer equipment and software are depreciated on a straight-line basis over three years. Costs of leasehold improvements are depreciated on a straight-line basis over the term of the associated lease.

**Investments**—The Company owns class B shares in Delta House Oil and Gas FPS, LLC. Delta House Oil and Gas FPS, LLC owns the Delta House floating production facility to which certain of the Company's oil, gas and NGL production flows. The Company accounts for its investments in Delta House Oil and Gas FPS, LLC using the cost method since the interests provide little influence over the investees' operating and financial policies. The investment in Delta House Oil and Gas FPS, LLC is recorded on the consolidated balance sheet at cost minus impairment plus or minus changes resulting from observable price changes in orderly transactions for the identical or a similar investment of Delta House Oil and Gas FPS, LLC. The Company recorded no upward or downward adjustments to the investment in Delta House Oil and Gas FPS, LLC in 2017. The Company reviews this investment for impairment at least annually and whenever events or changes in circumstances indicate that the carrying amounts may not be recovered. The Company recorded no impairment on the investment in Delta House Oil and Gas FPS, LLC in 2017.

**Other Assets**—At December 31, 2017, the Company has $0.8 million in credit with the operator of one of its non-operated properties to offset future asset retirement obligations associated with one of its offshore platforms. The Company recorded the liability associated with that platform gross of this asset, in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification Topic (ASC) 410, *Asset Retirement and Environmental Obligations*.

**Asset Retirement Obligations**—The Company is required to record a liability for its asset retirement obligations at fair value in the period such obligations are incurred with the associated asset retirement costs being capitalized as part of the carrying cost of the asset. The Company's asset retirement obligations relate to the plugging, abandonment, dismantlement, removal, site reclamation and similar activities associated with its oil, gas and NGL properties. Accretion of the liability is recognized for changes in the value of the liability as a result of the passage of time over the estimated productive life of the related assets as the discounted liabilities are accreted to their expected settlement values. Revisions in the estimates of property lives and cost estimates are capitalized as part of the property balance. Any gain or loss upon settlement of obligations is recognized in income.

The obligation to plug wells is settled when the Company abandons wells in accordance with governmental regulations. The Company accrues a liability with respect to these obligations based on its estimate of the timing and amount to replace, remove or retire the associated assets. The estimate of the asset retirement cost is determined, inflated to an estimated future value using a seven-year average of the Consumer Price Index and discounted to present value using the Company's credit-adjusted risk-free rate.

In estimating the liability associated with its asset retirement obligations, the Company utilizes several assumptions, including a credit-adjusted risk-free interest rate, estimated costs of decommissioning services, estimated timing of when the work will be performed and a projected inflation rate. Revisions in the estimate presented in the table below represent changes to the expected amount and timing of payments to settle the asset retirement obligations. Typically, these changes primarily result from obtaining new information about the timing of the obligations to plug and abandon oil, gas and NGL wells and the costs to do so. If the Company incurs an amount different from the amount accrued for decommissioning obligations, it recognizes the difference as a gain or loss on settlement of asset retirement obligations on the consolidated statement of operations.

The discounted asset retirement liability is included on the consolidated balance sheet in current and long-term liabilities, and the changes in that liability for the year ended December 31, 2017, were as follows (in thousands):

| | | |
|---|---|---|
| Asset retirement obligations at January 1, 2017 | $ | 10,869 |
| Settlement of asset retirement obligations | | (2,599) |
| Revisions in estimated liabilities | | 5,728 |
| Accretion expense | | 1,559 |
| Asset retirement obligations at December 31, 2017 | | 15,557 |
| Less current portion | | (330) |
| Asset retirement obligations, long term | $ | 15,227 |

The Company partially settled asset retirement obligations related to two properties during 2017. The total cash paid to partially settle those obligations was $2.7 million, of which the Company had an asset retirement obligation recorded of $2.6 million. As the result of the settlement the Company recorded a $0.1 million loss on settlement.

In 2017 the Company had upward revisions in our estimated costs to abandon wells primarily due to an increase in assumed rig days on location for blowout preventer certification.

**Capitalized Interest**—The Company capitalizes interest expense related to significant investments in unproved properties and costs related to wells in the exploration and development phases that are not being depleted. During 2017 the Company recognized interest expense of $58.3 million. In 2017 the Company did not incur any capital costs related to wells in the exploration and development phases, and as a result did not capitalize any interest. Interest is capitalized using the effective interest rate based on the Company's outstanding borrowings.

Cash paid for interest amounted to $39.4 million in 2017.

**Federal Income Taxes**—In accordance with the provisions of the Internal Revenue Code, the Company is not subject to federal income tax. Each member includes its share of the Company's income or loss in its own federal and state income tax returns.

The Company may be subject to state income taxes in certain jurisdictions and applicable state laws; however, currently the Company incurs no state income taxes.

**Warrants**—As an additional fee for amending the credit agreement, on December 30, 2015 and December 4, 2017, the Company granted certain of the lenders with warrants to purchase shares of Deep Gulf Energy II, LLC with a strike price of $0.01. These warrants are not puttable by the lenders and do not require Deep Gulf Energy II, LLC to settle the warrant with assets. The Company measures all such warrants at fair value as calculated using an option pricing method for valuing such securities on the date awards are granted and recognizes this expense on a straight-line basis in the financial statements over the vesting period. The Company recorded a $2.2 million expense related to the warrants in 2017.

**Commodity Derivatives and Price Risk Management Activities**—The Company periodically enters into derivative contracts to manage its exposure to commodity price risk. These derivative contracts, which are placed with major financial institutions that the Company believes have minimal credit risks, may take the form of swaps, options, or collars. The reference prices upon which the commodity derivative contracts are based reflect various market indexes that have a high degree of historical correlation with actual prices received by the Company for its production.

The Company accounts for its commodity derivative instruments in accordance with ASC 815, *Derivatives and Hedging*, which requires that all derivative instruments, other than those that meet the normal purchases and sales exception, be recorded on the consolidated balance sheet as either an asset or liability measured at fair value. The Company has historically not designated its derivative instruments as cash flow hedges and has recorded all changes in fair value directly on the consolidated statement of operations. See Note 8.

**Employee Share Ownership Program**—The Amended and Restated Operating Agreement of the Company (the "Operating Agreement") established Common Units and Incentive Units. Incentive Units are generally intended to be used as incentives for Company employees. The Company was initially authorized to issue 50,000 Incentive Units and may be authorized to issue more under the Operating Agreement. As of December 31, 2017, the Company was authorized to issue 50,000 Incentive Units.

With the exception of annual distributions to cover the assumed tax liability of the Incentive Unit holders, Incentive Units do not participate in cash distributions prior to vesting and until the occurrence of a Liquidity Event in which Common Units have received a multiple on invested capital of at least 1.5X. After issuance, the Incentive Units fully vest (a) annually over a three year period from grant date, (a) upon occurrence of a Liquidity Event or (b) upon occurrence of a Termination Event on Accepted Terms (other than as a result of the voluntary resignation by the Incentive Unit holder without cause).

**Recently Issued Accounting Standards**—In May 2014, the FASB issued Accounting Standards Update (ASU) 2014-09, *Revenue from Contracts with Customers*, which supersedes the revenue recognition requirements in ASC 605, *Revenue Recognition*, and industry-specific guidance in ASC 605 Subtopic 932, *Extractive Activities—Oil and Gas*, and requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. The Company is required to adopt the new standard in 2019 using one of two allowable methods: (1) a full retrospective method, which applies the standard to each period presented in the financial statements, or (2) the modified retrospective method, which applies the standard to only the most current period presented, with a cumulative effect adjustment recorded to retained earnings. The Company is continuing to evaluate the provisions of this ASU and has not yet decided upon the method of adoption or determined the impact this standard may have on its consolidated financial statements and related disclosures.

In August 2014, the FASB issued ASU 2014-15, *Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern (Subtopic 205-40)*. The guidance requires management to evaluate whether there are conditions and events that raise substantial doubt about the Company's ability to continue as a going concern within one year after the consolidated financial statements are issued. Additionally, management is required to provide certain footnote disclosures if it concludes that substantial doubt exists or when it plans to alleviate substantial doubt about the Company's ability to continue as a going concern. ASU 2014-15 is effective for annual periods ending after December 15, 2016. The adoption of ASU 2014-15 did not have a material impact on the consolidated financial statements and related disclosures.

In April 2015, the FASB issued Accounting Standards Update (ASU) 2015-03, *Simplifying the Presentation of Debt Issuance Costs*. ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented on the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The Company has early-adopted the guidance in ASU 2015-03 retrospectively. As a result of adoption, the Company reclassified unamortized deferred financing costs on the consolidated balance sheet in the amount of $12.7 million as of December 31, 2017, and reduced the carrying value of debt by the same amounts.

In July 2015, the FASB issued ASU 2015-11, *Accounting for Inventory*, which requires entities to measure most inventory at lower of cost or net realizable value. ASU 2015-11 defines net realizable value as “the estimated selling prices in the ordinary course of business, less reasonably predictable cost of completion, disposal and transportation.” ASU 2015-11 is effective prospectively for annual periods beginning after December 15, 2016, and early application is permitted. The guidance in ASU 2015-11 did not have a material impact on the consolidated financial statements and related disclosures.

In January 2016, the FASB issued ASU 2016-01, *Financial Instruments—Overall: Recognition and Measurement of Financial Assets and Financial Liabilities* (Topic 825), which changes accounting for equity investments and liabilities under the fair value option and the presentation and disclosure requirements for financial instruments. In addition, the FASB clarified guidance related to the valuation allowance assessment when recognizing deferred tax assets resulting from unrealized losses on the available for sale debt securities. Entities that are not public business will no longer be required to disclose the fair value of financial instruments carried at amortized costs. ASU 2016-01 is effective fiscal periods beginning after December 15, 2017 and early application is permitted. The Company has early adopted guidance in 2016. The guidance in ASU 2016-01 did not have a material impact on the consolidated financial statements and related disclosures.

In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows (Topic 230)—Classification of Certain Cash Receipts and Cash Payments*. ASU 2016-15 reduces existing diversity in practice by providing guidance on the classification of eight specific cash receipts and cash payments transactions in the statement of cash flows. The new standard is effective for fiscal years beginning after December 15, 2018. Early adoption is permitted. The Company does not expect the adoption of the new standard to have a material impact on its consolidated financial statements and related disclosures.

In January 2017, the FASB issued ASU 2017-1, *Business Combinations (Topic 805): Clarifying the definition of a Business*. ASU 2017-1 reduces existing diversity in practice by providing guidance on the definition of a business. The definition of a business affects many areas of accounting including acquisitions, disposals, goodwill impairment, and consolidation. The new standard is effective for fiscal years beginning after December 15, 2018. Early adoption is permitted. The Company does not expect the adoption of the new standard to have a material impact on its consolidated financial statements and related disclosures.

## 3. DEBT

In December 2015, the Company amended its credit agreement (“December 2015 Credit Agreement”) to increase the term loan amount to $300 million, and drew the entire available commitment amount at closing. Amounts outstanding bear interest at the Eurodollar rate or the base prime rate plus a margin, but in no case less than 14.5% per annum. In addition, the borrower must pay an existing lender fee of 1% on the $225 million that was outstanding prior to the amendment on the earlier of September 30, 2018 or the date the Company pays off all of the outstanding debt. In addition, the Company must pay a termination fee to the lenders ranging from $3 million to $9 million on the earlier of September 30, 2018 or the date the Company pays off all of the outstanding debt. The termination fee is recorded in accrued liabilities as of December 31, 2017. The termination fee becomes due and payable according to the following schedule:

| Date | Fee (In thousands) |
|---|---|
| January 1, 2017 through June 30, 2017 | $ 4,500 |
| July 1, 2017 through December 31, 2017 | 6,000 |
| January 1, 2018 through June 30, 2018 | 7,500 |
| July 1, 2018 through September 30, 2018 | 9,000 |

Under the December 2015 Credit Agreement, mandatory prepayments on the debt of $33.8 million were due quarterly beginning September 2017 through June 2018 with the remainder of the debt principal to be paid on or before September 30, 2018.

In December 2017, the Company further amended its credit agreement (“December 2017 Credit Agreement”) to delay repayment of the $300 million in principal payments until September 30, 2019 from September 30, 2018. Amounts outstanding under the December 2017 Credit Agreement bear interest at the Eurodollar rate or the base prime rate plus a margin, but in no case less than 15.5% per annum. The December 2017 Credit Agreement allows the Company to pay in kind (“PIK”) 9% per annum of the specified interest; any PIK interest will be added to the principal amount of the outstanding loans. PIK interest recorded in 2017 totals $6.2 million and is classified as long term interest payable. PIK interest, along with the principal amounts, is due on September 30, 2019.

Additionally, in accordance with the December 2017 Credit Agreement, the Company must pay an amendment and extension fee of $3 million due on the earlier of September 30, 2018 or the date the Company pays off all of the outstanding debt, and the Company issued certain of the lenders with warrants to purchase 103,257.19 shares of Deep Gulf Energy II, LLC with a strike price of $0.01, amounting to 20% of the total equity shares outstanding at December 31, 2017. As long as the obligations under the December 2017 Credit Agreement remain outstanding, the Company must issue additional warrants to purchase shares of Deep Gulf Energy II, LLC with the strike price of $0.01 according to the following schedule:

| **Date** | **Additional Warrants** | **Percentage Ownership** |
|---|---|---|
| September 30, 2018 | 34,784.33 | 5% |
| December 31, 2018 | 39,976.02 | 5 |
| March 31, 2019 | 46,423.77 | 5 |
| June 30, 2019 | 119,630.49 | 10 |
| | 240,814.61 | 25% |

The Company incurred $10.7 million in costs associated with the December 2017 Credit Agreement, of which $7.8 million in lender fees were recognized as a reduction to debt, and the remaining $2.9 million in third party costs were expensed in accordance with ASC 470-50 *Debt Modification*. Prior to amending its credit agreement with the December 2017 Credit Agreement, the Company had $5.7 million of unamortized debt issuance costs associated with the December 2015 Credit Agreement recognized as a reduction of debt in the accompanying consolidated balance sheet. As a result of ASC 470-50 *Debt Modification*, at December 31, 2017, $5.5 million of the unamortized debt issuance costs remained capitalized as reduction of debt in the accompanying consolidated balance sheet, and $0.2 million was expensed in the consolidated statement of operations.

The Company's obligations under the credit agreement are secured by liens on all of Deep Gulf Energy II, LLC's working interests in its oil, gas and NGL properties. The credit agreement contains customary financial covenants requiring certain ratios to be met on a quarterly, semiannual and annual basis. Other covenants contained in the credit agreement restrict, among other things, capital expenditures, asset dispositions, mergers and acquisitions, dividends, additional debt, liens, investments, and affiliate transactions. The credit agreement also contains customary events of default. The Company was in compliance with these covenants at December 31, 2017.

## 4. NOTES PAYABLE

The Company has entered into long-term notes payable with related parties, FR DGE II Holdings, LLC and DG II Holdings, LLC. Each note accrues simple interest at a rate of 6.5%.

These notes have no maturity date. Following is a summary of the notes payable at December 31, 2017 (in thousands):

| | | |
|---|---|---|
| Notes issued in March 2012 | $ | 2,440 |
| Notes issued in July 2012 | | 232 |
| Notes issued in October 2013 | | 270 |
| Notes issued in February 2014 | | 37 |
| Total principal | | 2,979 |
| Accrued interest | | 1,585 |
| Total notes payable | $ | 4,564 |

Interest expense to these related parties amounted to $0.2 million in 2017 and was recorded in interest expense. No cash was paid for interest on these notes in 2017.

**5. RELATED-PARTY TRANSACTIONS**

The Company's controlling interest is owned by the same persons who own Deep Gulf Energy Management, LLC; Deep Gulf Energy LP; DGE III Management, LLC; and Deep Gulf Energy III, LLC. Deep Gulf Energy LP; DGE III Management, LLC; and the Company have entered into Master Services and License Agreements in which operating services, engineering services, and other cost-sharing services are provided to each other. General and administrative expenses are allocated between the parties based on time incurred. In 2015, DGE III Management, LLC, became the primary related party that allocated shared expense to the Company. Expenses allocated to the Company by related parties amounted to $9.0 million in 2017.

Included in the 2017 allocation was a one time $5.3 million charge from DGE III Management, LLC to the Company. Of the $5.3 million owed, $4.7 million is classified as a long term accounts payable and will be paid according to the following schedule:

| | | Long Term Payable |
|---|---|---|
| January 2019 | $ | 1,672 |
| January 2020 | | 1,630 |
| January 2021 | | 1,419 |
| Long term accounts payable—related party | $ | 4,721 |

No expenses were allocated by the Company to related parties in 2017.

These consolidated financial statements have been prepared from the separate records maintained by DGE III Management, LLC and may not necessarily be indicative of the conditions that would have existed or the results of operations if the Company had been operated as an unrelated company.

From time to time, the Company enters into notes receivable bearing simple interest at 6.5% with management members to fund capital contributions, as allowed by the members' equity agreements. These notes have no maturity date. Due to the nature of the notes, they are reflected in the accompanying consolidated financial statements as a reduction of equity. As of December 31, 2017, these notes totaled $3.0 million. Interest income related to these notes amounted to $0.2 million in 2017, and was recorded in interest income (expense).

## 6. SUPPLEMENTARY CASH FLOW INFORMATION

Supplementary non-cash investing and financing activities information for the years ended December 31, 2017 is as follows (in thousands):

| | | |
|---|---|---|
| Non-cash deferred financing costs | $ | 3,000 |

## 7. COMMITMENTS AND CONTINGENCIES

**Insurance**—The Company has insurance policies to mitigate its risk of loss associated with its operations, and it maintains the coverages and amounts of insurance believed to be prudent based on reasonably estimated loss potential. However, not all of the Company's business activities can be insured at the levels it desires because of either limited market availability or unfavorable economics (limited coverage for the underlying cost).

The Company's general property damage insurance provides varying ranges of coverage based upon several factors, including well counts and cost of replacement facilities. The Company's general liability insurance program provides a limit of $150 million (for its interest) for each occurrence and in the aggregate and includes varying deductibles, and its Offshore Pollution Act insurance is also subject to a maximum of $150 million for each occurrence and in the aggregate and includes a $100,000 (100%) retention. The Company separately maintains an operator's extra expense policy for wells being drilled with additional coverage for an amount up to $1 billion and for producing wells with additional coverage for an amount up to $500 million that would cover costs involved in making a well safe after a blowout or getting the well under control, re-drilling a well to the depth reached prior to the well being out of control or blown out, costs for plugging and abandoning the well, costs for cleanup and containment and for damages caused by contamination and pollution.

The Company customarily has reciprocal agreements with its customers and vendors in which each contracting party is responsible for its respective personnel. Under these agreements, the Company is indemnified against third party claims related to the injury or death of its customers' or vendors' personnel. Although there can be no assurance that the amount of insurance the Company carries is sufficient to protect it fully in all events, the Company believes that its insurance protection is adequate for its business operations.

**Performance Obligations**—Regulations with respect to offshore operations govern, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells, and removal of facilities. As of December 31, 2017, the Company had secured performance bonds totaling approximately $39.7 million for its supplemental bonding requirements stipulated by the Bureau of Ocean Energy Management related to costs anticipated for the plugging and abandonment of certain wells and the removal of certain facilities in its Gulf of Mexico fields. These performance bonds are uncollateralized. If the Company were to have to obtain additional performance bonds for other reasons, it cannot assure that it would be able to secure any such additional performance bonds on acceptable commercial terms or at all.

Additionally, the Company has an uncollateralized bond to a third party for the plugging and abandonment of Nancy property located at Garden Banks block 463 that the Company exited in 2017. On January 4, 2017 the Company executed an agreement withdrawing from the Nancy property located at Garden Banks block 463. The agreement has an effective date of August 19th, 2016. As part of the agreement, the Company was required to post a performance bond with the purchaser as oblige for the Company's estimated share of certain future abandonment expenses as the Company retained financial responsibility and liability for its proportionate share of certain of the abandonment liabilities. The Company posted such performance bond on January 4, 2017 in the amount of $2.4 million.

**Legal Proceedings and Other Contingencies**—The Company is a party to a Deferred Amount Payment Agreement (DAPA) with Energy Resource Technology GOM, Inc. (ERT) related to the Danny Noonan project (Project). Through this DAPA, the Company is required to reimburse ERT $14.5 million from the Project's net cash flow in monthly installments if the gross production from the Project equals or exceeds 265 BCFE. As of December 31, 2017, the Company does not expect gross production from the Project to equal or exceed 265 BCFE. As of December 31, 2017, the Company had no liability recorded for this DAPA.

The Company or its subsidiary may be named defendants in legal proceedings that arise in the ordinary course of business. There are also other regulatory rules and orders in various stages of adoption, review and/or implementation. For each of these matters, the Company evaluates the merits of the case or claim, its exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. The Company discloses matters that are reasonably possibly of negative outcome and are material to its consolidated financial statements. If the Company determines that an unfavorable outcome is probable and is reasonably estimable, the Company accrues for such reasonably estimable outcome. While the outcome of the current matters cannot be predicted with certainty and there are still uncertainties related to the costs the Company may incur, based upon its evaluation and experience, the Company will establish appropriate accruals as it believes are necessary. It is possible; however, that new information or future developments could require the Company to reassess its potential exposure related to these matters and record or adjust its accruals accordingly, and these adjustments could be material.

## 8. PRICE RISK MANAGEMENT ACTIVITIES

**Objectives and Strategies**—The Company is exposed to fluctuations in oil, gas and NGL prices on its production. The Company believes it is prudent to manage the variability in cash flows on a portion of its oil production. The Company utilizes various types of derivative financial instruments, including swaps, costless collars and options, to manage fluctuations in cash flows resulting from changes in commodity prices.

**Commodity Derivative Instruments**—As of December 31, 2017, the Company had entered into commodity contracts with the following terms:

| Commodity Contract Type | Period Covered | Contracted Volume Oil (MBbls) | Fixed Price |
|---|---|---|---|
| Swaps | January–June 2018 | 178.9 | $ 54.70 |
| Swaps | January–June 2018 | 79.2 | 47.50 |
| Swaps | January–June 2018 | 47.8 | 45.00 |
| Swaps | January–December 2018 | 555.0 | 56.08 |
| Swaps | January–September 2019 | 560.5 | 53.53 |
| Puts | February–December 2018 | 276.3 | 53.00 |

The following table sets forth the fair values and classification of the Company's outstanding derivatives (dollars in thousands):

| | Recognized Asset (Liability) in 000's December 31, 2017 |
|---|---|
| Current derivative asset | $ 735 |
| Current derivative liability | (4,200) |
| Net current derivative liability | (3,465) |
| Long term derivative asset | $ - |
| Long term derivative liability | (1,477) |
| Net long term derivative liability | $ (1,477) |

The Company has entered into master netting arrangements with its counterparties. The amounts above are presented on a net basis in its balance sheet when such amounts are with the same counterparty. The Company recognized $0.7 million in realized losses related to its derivative financial instruments in 2017. The Company recognized $1.6 million in unrealized losses related to its derivative financial instruments in 2017.

The Company is subject to the risk of loss on its derivative financial instruments that it would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. The Company enters into International Swaps and Derivative Association agreements with counterparties to mitigate this risk, when possible. The Company also maintains credit policies with regard to its counterparties to minimize its overall credit risk. These policies require (i) the evaluation of potential counterparties' financial condition to determine their credit worthiness; (ii) the regular monitoring of oil and natural gas counterparties' credit exposures; (iii) comprehensive credit reviews on significant counterparties from physical and financial transactions on an ongoing basis; (iv) the utilization of contractual language that affords the Company netting or set off opportunities to mitigate exposure risk; and (v) potentially requiring counterparties to post cash collateral, parent guarantees or letters of credit to minimize credit risk. The

Company's assets or liabilities from derivatives at December 31, 2017 represent derivative financial instruments from one counterparty; which is a financial institution that has an "investment grade" (minimum Standard & Poor's rating of BBB- or better) credit rating and is party under the Company's credit agreement. The Company enters into derivatives directly with this third party and, subject to the terms of the credit agreement, are not required to post collateral or other securities for credit risk in relation to the derivative financial interests.

**Fair Value Measurement**

The following table presents the fair value hierarchy table for the Company's assets and liabilities that are required to be measured at fair value on a recurring basis (dollars in thousands):

| | Fair Value | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|
| At December 31, 2017: | | | | |
| Assets—oil, natural gas and natural gas liquids derivatives | $ 735 | $ - | $ 735 | $ - |
| Liabilities—oil, natural gas and natural gas liquids derivatives | (5,677) | - | (5,677) | - |

The Company's derivatives consist of over–the–counter ("OTC") contracts which are not traded on a public exchange. As the fair value of these derivatives is based on inputs using market prices obtained from independent brokers or determined using quantitative models that use as their basis readily observable market parameters that are actively quoted and can be validated through external sources, including third party pricing services, brokers and market transactions, the Company has categorized these derivatives as Level 2. The Company values these derivatives using the income approach using inputs such as the forward curve for commodity prices based on quoted market prices and prospective volatility factors related to changes in the forward curves and yield curves based on money market rates and interest rate swap data, such as forward LIBOR curves. The Company's estimates of fair value have been determined at discrete points in time based on relevant market data. There were no changes in valuation techniques or related inputs in 2017.

## 9. WARRANTS

As additional fees for amending the credit agreement in December 2015 and December 2017 (see Note 3), the Company issued certain of the lenders with warrants to purchase 11,928.52 and 103,257.19 shares, respectively, of Deep Gulf Energy II, LLC with a strike price of $0.01. The warrants are not puttable by the lenders and do not require the Company to settle the warrant with assets. The holder of the warrants may exercise the warrant ten years from the issue date of the warrant, and the warrant is not canceled upon repayment of the debt. The Company determined the warrants issued in December 2015 to have an estimated fair value of $497.54 per unit on the issuance date. The Company determined the warrants issued in December 2017 to have an estimated fair value of $46.15 per unit on the issuance date.

On issuance in 2015 and 2017, the Company recorded a discount on the debt for the total value of the warrants, with a corresponding credit to additional paid-in capital. The expense related to these warrants is recognized on a straight-line basis over the remaining term of the debt in the Company's consolidated financial statements and is reflected as a corresponding credit to the original issuance discount on the debt. The Company has $6.3 million discount on debt (net of amortization) related to the warrants as of December 31, 2017. The Company recognized approximately $4.4 million in amortization expense for the year ended December 31, 2017, which was recorded as interest expense in the accompanying consolidated statement of operations. No amount was capitalized during the year ended December 31, 2017. See Note 2 Accounting policies for more information on Capitalized interest.

As the warrants have a $0.01 strike price, the warrants are essentially the same as actually holding the underlying shares and are therefore valued as if they are an underlying equity contract. As such, the warrants issued were valued using an income-based approach that considered probability-weighted cash flows and other significant unobservable Level 3 inputs, including Deep Gulf Energy II, LLC's estimated future oil, gas and NGL production, costs and capital expenditures, forward prices, and a discount rate believed to be consistent with those applied by market participants.

## 10. SUBSEQUENT EVENTS

Subsequent events were evaluated through March 29, 2018, which is the date these consolidated financial statements were available to be issued.

## 11. SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS OPERATIONS (UNAUDITED)

**Capitalized Costs Relating to Oil and Natural Gas Producing Activities**—The total amount of capitalized costs relating to oil and natural gas producing activities and the total amount of related accumulated depreciation, depletion and amortization indicated are presented below as of December 31, 2017 (in thousands):

| | | |
|---|---|---|
| Proved properties | $ | 509,197 |
| Proved properties under development | | 6,639 |
| Accumulated depletion | | (284,352) |
| Total proved | | 231,484 |
| Unproved properties | | 563 |
| Total oil and gas properties—net of accumulated depletion | $ | 232,047 |

Included in the depletable basis of the Company's proved properties is the estimate of the Company's proportionate share of asset retirement obligations relating to these properties, which are also reflected as asset retirement obligations in the accompanying consolidated balance sheet. At December 31, 2017 the Company's oil and gas asset retirement obligations totaled $15.2 million.

**Estimated Quantities of Proved Oil and Gas Reserves**—Users of this information should be aware that the process of estimating quantities of "proved" and "proved developed" oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

A variety of deterministic methods are used to determine the Company's proved reserve estimates. Standard engineering and geoscience methods or a combination of methods are used, including performance analysis, volumetric analysis, analogy, and reservoir modeling. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, the Company's conclusions necessarily represent only informed professional judgment.

Proved reserves are those quantities of oil and natural gas that 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. 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.

The Company engaged Ryder Scott Company, L.P. Petroleum Consultants and Netherland Sewell and Associates, Inc. to prepare reserves estimates for all of the Company's estimated proved reserves (by volume) at December 31, 2017. All proved reserves are located in the Gulf of Mexico and all prices are held constant in accordance with SEC rules.

The following table sets forth estimates of the net proved reserves as of December 31, 2017:

| | **Oil (MBbls)** | **Gas (MMcf)** | **NGL (MBbls)** | **Total (Mboe)[(2)]** |
|---|---|---|---|---|
| Proved reserves at December 31, 2016 | 14,965 | 27,339 | 1,977 | 21,498 |
| Revision of previous estimate [(1)] | 3,105 | 3,605 | 1,221 | 4,928 |
| Production | (2,334) | (2,843) | (294) | (3,102) |
| Purchase of reserves in place | - | - | - | - |
| Sales of reserves in place | - | - | - | - |
| Extensions and discoveries | - | - | - | - |
| Proved reserves at December 31, 2017 | 15,736 | 28,101 | 2,904 | 23,324 |
| Proved developed reserves at December 31, 2017 | 8,719 | 14,936 | 1,538 | 12,746 |
| Proved undeveloped reserves at December 31, 2017 | 7,017 | 13,165 | 1,366 | 10,578 |

(1) Revisions in quantity estimates resulted from performance in the following Fields:

- Kodiak + 1.6 MMBOE as reservoir performance supports an increase in recovery factor estimate
- Marmalard + 1.4 MMBOE for performance-based increase in estimated recovery factor and an increase in ultimate gas-oil ratio and the associated NGL's
- Odd Job + 1.2 MMBOE as evidence of a water drive supports an increased recovery factor estimate; additionally, NGL processing performance supports an updated NGL yield
- Danny Noonan + 0.4 MMBOE for performance-based increase in recovery efficiency

- SOB2 + 0.2 MMBOE for performance-based increase in reservoir area

- Sargent + 0.1 MMBOE based on continued performance above that expected year-end 2016

(2) Natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent.

**Standardized Measure of Discounted Future Net Cash Flows from Proved Reserves**—The standardized measure of discounted future net cash flows presented below is computed by applying first-day-of-the-month average prices, year-end costs and legislated tax rates and a discount factor of 10 percent to proved reserves. The Company does not believe the standardized measure provides a reliable estimate of the Company's expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its proved oil and gas reserves. The standardized measure is prepared on the basis of certain prescribed assumptions including first-day-of-the-month average prices, which represent discrete points in time and therefore may cause significant variability in cash flows from year to year as prices change.

Future net cash flows are discounted at the prescribed rate of 10%. Actual future net cash flows may vary considerably from these estimates. Although the Company's estimates of total proved reserves, development costs and production rates were based on the best information available, the development and production of oil and gas reserves may not occur in the periods assumed. Actual prices realized, costs incurred and production quantities may vary significantly from those used. Therefore, such estimated future net cash flow computations should not be considered to represent the Company's estimate of the expected revenues or the current value of existing proved reserves.

The standardized measure of discounted future net cash flows at December 31, 2017 is as follows (in thousands):

| | | |
|---|---|---|
| Future cash inflows | $ | 901,602 |
| Future production costs | | (239,011) |
| Future development and abandonment costs | | (183,784) |
| Future income tax expense | | - |
| Future net cash flows | | 478,808 |
| Discount at 10% annual rate | | (136,194) |
| Standardized measure of discounted future net cash flows | $ | 342,614 |

Future cash inflows are computed by applying the appropriate average of the first-day-of-the-month price for each month within the period January through December of each year presented, adjusted for location and quality differentials on a property-by-property basis, to year-end quantities of proved reserves. For oil and NGL volumes the average Texas intermediate spot price of $51.34 per barrel is adjusted by field for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.98 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. The discounted future cash flow estimates do not include the effects of the Company's derivative financial instruments.

**Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves**—The following is a summary of the changes in the standardized measure of discounted future net cash flows for the proved oil and natural gas reserves during the year ended December 31, 2017 (in thousands):

| | | |
|---|---|---|
| Standardized measure, beginning of year | $ | 222,594 |
| Changes during the year: | | |
| Sales, net of production | | (87,566) |
| Net change in prices and production costs | | 114,664 |
| Changes in future development costs | | (25,679) |
| Development costs incurred | | 2,734 |
| Accretion of discount | | 22,259 |
| Net change in income taxes (1) | | - |
| Purchase of reserves in place | | - |
| Extensions and discoveries | | - |
| Sales of reserves in place | | - |
| Net change due to revision in quantity estimates | | 100,093 |
| Changes in production rates (timing) and other | | (6,485) |
| Standardized measure, end of year | | 342,614 |

(1) The Company's calculation of the standardized measure of discounted future net cash flows and the related changes therein do not include the effect of the estimated future income tax expenses because the Company is not subject to federal or state income taxes on income from proved oil and gas reserves.

******

# DGE III
# Management, LLC and
# Subsidiaries

Consolidated Financial Statements as of and
for the Year Ended December 31, 2017,
and Independent Auditors' Report

## DGE III MANAGEMENT, LLC AND SUBSIDIARIES

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**INDEPENDENT AUDITORS' REPORT**

The Members
DGE III Management, LLC:

We have audited the accompanying consolidated financial statements of DGE III Management, LLC and subsidiaries (the "Company"), which comprise the consolidated balance sheet as of December 31, 2017, and the related consolidated statement of operations, members' capital, and cash flows for the year then ended, and the related notes to the consolidated financial statements ("consolidated financial statements").

**Management's Responsibility for the Consolidated Financial Statements**

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

**Auditors' Responsibility**

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

a basis for our audit opinion.

**Opinion**

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of DGE III Management, LLC and subsidiaries as of December 31, 2017, and the results of its operations and its cash flows for the year then ended in accordance with accounting principles generally accepted in the United States of America.

**Emphasis of Matter**

The Company entered into Master Services and License Agreements with related parties, in which operating services, engineering services, and other cost-sharing services are provided and allocated to each other. The accompanying consolidated financial statements have been prepared from the separate records maintained by the Company and may not necessarily be indicative of the conditions that would have existed or the results of operations if the Company had been operated as an unrelated company (see Note 6).

**Other Matter**

Accounting principles generally accepted in the United States of America require that the Supplemental Information on Oil and Natural Gas Operations be presented to supplement the consolidated financial statements. Such information, although not a part of the consolidated financial statements, is required by the Financial Accounting Standards Board who considers it to be an essential part of financial reporting for placing the consolidated financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management’s responses to our inquiries, the consolidated financial statements, and other knowledge we obtained during our audit of the consolidated financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

/s/ Deloitte & Touche LLP

March 29, 2018

## DGE III MANAGEMENT, LLC AND SUBSIDIARIES

**CONSOLIDATED BALANCE SHEET**
**AS OF DECEMBER 31, 2017**
**(In thousands)**

**ASSETS**

| | | |
|---|---|---|
| CURRENT ASSETS: | | |
| Cash and cash equivalents | $ | 24,904 |
| Accounts receivable | | 59,341 |
| Accounts receivable—related party | | 3,545 |
| Prepaid expenditures and other current assets | | 12,708 |
| Inventory | | 26,903 |
| Total current assets | | 127,401 |
| PROPERTY, PLANT, AND EQUIPMENT: | | |
| Oil and gas properties, successful efforts method—net of accumulated depletion of $71,659 at December 31, 2017 | | 339,831 |
| Other property, plant, and equipment—net of accumulated depreciation of $743 at December 31, 2017 | | 1,563 |
| Total property, plant, and equipment | | 341,394 |
| OTHER ASSETS | | 12,123 |
| DEFERRED FINANCING COSTS—Net amortization of $555 at December 31, 2017 | | 769 |
| LONG TERM RECEIVABLE—Related-party | | 4,721 |
| INTEREST RECEIVABLE—Related-party | | 331 |
| TOTAL ASSETS | $ | 486,739 |

**LIABILITIES AND MEMBERS' CAPITAL**

| | | |
|---|---|---|
| CURRENT LIABILITIES: | | |
| Accounts payable | $ | 8,695 |
| Accrued liabilities | | 82,884 |
| Liability from price risk management—current | | 9,775 |
| Total current liabilities | | 101,354 |
| LONG-TERM LIABILITIES: | | |
| Asset retirement obligations | | 17,742 |
| Long-term notes payable—related party | | 4,789 |
| Liability from price risk management | | 3,318 |
| Total long-term liabilities | | 25,849 |
| COMMITMENTS AND CONTINGENCIES (NOTE 8) | | |
| MEMBERS' CAPITAL | | 359,536 |
| TOTAL LIABILITIES AND MEMBERS' CAPITAL | $ | 486,739 |

See accompanying notes to the consolidated financial statements.

## DGE III MANAGEMENT, LLC AND SUBSIDIARIES

**CONSOLIDATED STATEMENT OF OPERATIONS**
**FOR THE YEAR ENDED DECEMBER 31, 2017**
**(In thousands)**

| | |
|---|---|
| REVENUE: | |
| Oil revenue | $ 140,802 |
| Gas revenue | 8,009 |
| NGL revenue | 6,647 |
| Total revenue | 155,458 |
| OPERATING COSTS AND EXPENSES: | |
| Lease operating expenses | 28,327 |
| Workover expenses | 4,482 |
| Transportation expenses | 6,945 |
| Exploration expenses | 36,346 |
| Depreciation, depletion, and amortization | 56,700 |
| Impairment | 2,870 |
| Accretion expense | 380 |
| Inventory write-down | 5,787 |
| Gain on sale of property | (44) |
| General and administrative expenses | 12,332 |
| Other operating income | (4,205) |
| Total operating costs and expenses | 149,920 |
| OPERATING INCOME | 5,538 |
| INTEREST AND OTHER EXPENSE—Net | (1,006) |
| LOSS FROM PRICE RISK MANAGEMENT ACTIVITIES | (12,503) |
| NET LOSS | $ (7,971) |

See accompanying notes to the consolidated financial statements.

## DGE III MANAGEMENT, LLC AND SUBSIDIARIES

**CONSOLIDATED STATEMENT OF MEMBERS' CAPITAL**
**FOR THE YEAR ENDED DECEMBER 31, 2017**
**(In thousands, except units)**

| | Units | Capital Contributions | Additional Paid In Capital | Retained Deficit | Total |
|---|---|---|---|---|---|
| BALANCE—January 1, 2017 | $ 473,415 | $ 468,575 | $ 9,290 | $ (114,861) | $ 363,004 |
| Equity-based compensation | — | — | 4,503 | — | 4,503 |
| Net loss | — | — | — | (7,971) | (7,971) |
| BALANCE—December 31, 2017 | 473,415 | $ 468,575 | $ 13,793 | $ (122,832) | $ 359,536 |

See accompanying notes to the consolidated financial statements.

## DGE III MANAGEMENT, LLC AND SUBSIDIARIES

**CONSOLIDATED STATEMENT OF CASH FLOWS**
**FOR THE YEAR ENDED DECEMBER 31, 2017**
**(In thousands)**

| | | |
|---|---|---|
| CASH FLOWS FROM OPERATING ACTIVITIES: | | |
| Net loss | $ | (7,971) |
| Adjustments to reconcile net loss to net cash provided by operating activities: | | |
| Depreciation, depletion and amortization | | 56,700 |
| Exploratory dry hole and impairment | | 8,036 |
| Amortization of deferred financing costs | | 518 |
| Oil inventory write-down | | 91 |
| Accretion expense | | 380 |
| Inventory write-down | | 5,787 |
| Gain on sale of property | | (44) |
| Unrealized loss from price risk management | | 13,093 |
| Equity-based compensation | | 4,503 |
| Net changes in assets and liabilities: | | |
| Accounts receivable | | 367 |
| Accounts receivable—related party | | (1,360) |
| Prepaid expenditures | | (2,429) |
| Inventory | | 4,322 |
| Interest receivable—related party | | (136) |
| Long term receivable | | (4,721) |
| Accounts payable | | (11,531) |
| Accrued liabilities | | 35,367 |
| Interest payable on long term notes payable—related party | | 137 |
| Net cash provided by operating activities | | 101,109 |
| CASH FLOWS FROM INVESTING ACTIVITIES: | | |
| Capital expenditures for oil and gas properties | | (87,289) |
| Proceeds from sale of property to related party | | 1,493 |
| Capital expenditures for other property, plant and equipment | | (1,355) |
| Net cash used in investing activities | | (87,151) |
| CASH FLOWS FROM FINANCING ACTIVITIES: | | |
| Payment of debt issuance costs | | (82) |
| Net cash used in financing activities | | (82) |
| NET INCREASE IN CASH AND CASH EQUIVALENTS | | 13,876 |
| CASH AND CASH EQUIVALENTS—Beginning of year | | 11,028 |
| CASH AND CASH EQUIVALENTS—End of year | $ | 24,904 |

See accompanying notes to the consolidated financial statements.

## 1. NATURE OF BUSINESS AND BASIS OF PRESENTATION

**Nature of Business**—DGE III Management, LLC, a Delaware limited liability company, and its wholly owned subsidiary, Deep Gulf Energy III, LLC were formed and commenced operations on June 30, 2014. Additionally, during 2016 the Company acquired Deep Gulf Operating, LLC from Deep Gulf Energy LP for no consideration. Deep Gulf Operating LLC has no assets or liabilities. Collectively, DGE III Management, LLC, Deep Gulf Energy III, LLC and Deep Gulf Operating, LLC are referred to as the “Company” throughout these notes to the consolidated financial statements. The purpose of the Company is to acquire, develop, operate, and manage deepwater exploitation and low-risk exploration projects located in the Gulf of Mexico and to produce and market oil, gas and natural gas liquids (NGL) produced from such properties. The Company has a perpetual existence unless and until dissolved and terminated.

**Basis of Presentation**—The consolidated financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America (GAAP). The consolidated financial statements include all the accounts of the Company. Undivided interests in oil, gas and NGL exploration and production joint ventures are consolidated on a proportionate basis. All adjustments that are of a normal, recurring nature and are necessary to fairly present the Company’s consolidated financial position, results of operations, and cash flows for the period are reflected.

**Principles of Consolidation**—The consolidated financial statements include the accounts of DGE III Management, LLC and its wholly owned subsidiaries. All intercompany account balances and transactions have been eliminated.

## 2. ACCOUNTING POLICIES

**Use of Estimates**—The preparation of consolidated financial statements in conformity with GAAP in the United States requires management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities and disclosures of contingent liabilities at the date of the consolidated financial statements and the related reported amounts of revenue and expenses. Estimates of reserves are used to determine depletion and to conduct impairment analysis. Estimating reserves has inherent uncertainty, including the projection of future rates of production and the timing of expenditures. Actual results could differ from those estimates. Management believes that its estimates are reasonable.

**Revenue Recognition and Imbalances**—Oil, gas and NGL revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and when collectability of the revenue is probable. The Company uses the sales method of accounting for gas production imbalances. The volumes of gas sold may differ from the volumes to which the Company is entitled, based on its interests in the properties. These differences create imbalances that are recognized as a liability only when the properties’ estimated remaining reserves, net to the Company, will not be sufficient to enable the under-produced owner to recoup its entitled share through production. No receivables are recorded for those wells where the Company has taken less than its share of production. There were no imbalances recorded at December 31, 2017.

**Service Charges**—The Company's service charges are generated through standardized industry overhead charges the Company receives as operator of oil, gas and NGL properties. The service costs associated with third-party reimbursements are recorded within other operating income in the accompanying consolidated statements of operations.

**Concentration of Credit Risk**—The Company extends credit in the form of uncollateralized oil, gas and NGL sales and joint interest owner receivables to various companies in the oil, gas and NGL industry. The following table lists companies that account for at least 10% of oil, gas and NGL sales for the year ended December 31, 2017:

| | |
|---|---|
| Shell Trading (US) Company | 42% |
| Phillips 66 Company | 37 |

**Cash and Cash Equivalents**—Cash and cash equivalents consist of all cash balances and highly liquid investments that have an original maturity of three months or less. Cash equivalents are stated at cost, which approximates fair value.

**Fair Value Measurements**—Current fair value accounting standards define fair value, establish a consistent framework for measuring fair value, and stipulate the related disclosure requirements for each major asset and liability category measured at fair value on either a recurring or nonrecurring basis. These standards also clarify that fair value is an exit price representing the amount that would be received to sell an asset, or paid to transfer a liability, in an orderly transaction between market participants. The Company follows a three-level hierarchy, prioritizing and defining the types of inputs used to measure fair value depending on the degree to which they are observable as follows:

***Level 1***—Inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.

***Level 2***—Inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial statement or quoted prices (unadjusted) for identical assets or liabilities in inactive markets.

***Level 3***—Inputs to the valuation methodology are unobservable (little or no market data), which require the reporting entity to develop its own assumptions, and are significant to the fair value measurement.

Assets and liabilities measured at fair value are based on one or more of three valuation techniques. The valuation techniques are as follows:

***Market Approach***—Prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities.

***Cost Approach***—Amount that would be required to replace the service capacity of an asset (replacement cost).

***Income Approach***—Techniques to convert expected future cash flows to a single present value amount based on market expectations (including present value techniques, option-pricing, and excess earnings models).

Authoritative guidance on financial instruments requires certain fair value disclosures to be presented. The estimated fair value amounts have been determined using available market information and valuation methodologies. Considerable judgment may be required in interpreting market data to develop the estimates of fair value for Level 3 inputs to the valuation methodology. The use of different assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

Financial instruments consisting of cash and cash equivalents, accounts receivable, and accounts payable are reported at their carrying amounts, which approximate fair value due to the short-term nature of these instruments. Nonrecurring fair value measurements associated with oil, gas and NGL properties are discussed below.

**Accounts Receivable**—Accounts receivable consist of oil and gas receivables and joint interest billing receivables on wells that the Company operates. Accounts receivable are carried at cost, net of allowance for losses. The Company recognizes an allowance or losses on accounts receivable in an amount equal to the estimated probable losses. The allowance is based on an analysis of historical bad debt experience, current receivables aging and expected future write-offs, as well as an assessment of specific identifiable customer accounts considered at risk or uncollectable. The expense associated with the allowance for doubtful accounts is recorded in our statements of operations as general and administrative expense. As of December 31, 2017 the Company does not have an allowance for doubtful accounts as all of the Company’s receivable’s have been deemed collectable.

**Prepaid Expenditures and Other Current Assets**—Prepaid expenditures and other current assets consist of deposits, insurance, conveyance of override and prepayments of capital expenditures. Prepaid expenditures and other current assets are classified as current and are expected to be realized within twelve months.

**Inventory**—Inventory consists of tubular and other goods used in the exploration for, and development and production of, offshore oil, gas and NGL wells and of oil used for line fill.

Tubular and other goods inventory is stated at cost with adjustments made, as appropriate, to recognize reduction in value. The cost of tubular and other goods inventory is determined by specific identification. During 2017 the Company recorded a $5.8 million noncash charge to write down inventory to the lower of cost or market value.

Oil inventory used for line fill is carried at lower of cost or market with adjustments to oil inventory being recorded in lease operating expenses. The cost of oil inventory used for linefill is determined using weighted average cost, or net realized value. During 2017 the Company recorded a $0.1 million noncash charge to write down oil inventory to the lower of cost or market value.

**Property, Plant, and Equipment**—The Company uses the successful efforts method of accounting for its oil, gas and NGL properties. Under the successful efforts method of accounting, the Company depletes proved oil and natural gas properties on a units-of-production basis based on production and estimates of proved reserves quantities. The Company assesses depletion on each field. The Company depletes capitalized costs of proved mineral interests over total estimated proved reserves and capitalized costs of wells and related equipment and facilities over estimated proved developed reserves.

Unproved leasehold costs are capitalized and are not amortized, pending an evaluation of their exploration potential. Unproved leasehold costs are assessed periodically to determine whether an impairment of the cost of significant individual properties has occurred. The cost of impairment is charged to impairment expense in the period in which it occurs. The Company recognized impairment expense on unproved leasehold costs in the amount of $2.9 million for the year ended December 31, 2017.

Costs incurred for exploratory dry holes, geological and geophysical work, and delay rentals are charged to exploration expense as incurred. In 2017, the Company recognized geological and geophysical expense in the amount of $6.9 million. In 2017 the Company recognized $29.4 million of dry hole costs related to two exploratory wells.

The following table lists the total proved and unproved oil, gas and NGL properties as of December 31, 2017 (in thousands):

| | |
|---|---|
| Proved properties | $ 354,424 |
| Proved properties under development | 31,097 |
| Accumulated depletion | (71,659) |
| Total proved | 313,862 |
| Unproved properties | 25,969 |
| Total oil and gas properties—net of accumulated depletion | $ 339,831 |

The Company reviews long-lived assets for impairment at least annually and whenever events or changes in circumstances indicate that the carrying amounts may not be recovered. If the carrying amounts are not expected to be recovered by undiscounted future cash flows, an impairment loss is recorded through a charge to expense. The amount of impairment is based on the estimated fair value of the assets, which is determined by discounting anticipated future net cash flows. The net present value of future cash flows is based on management's best estimate of future prices, which is determined using published forward prices, applied to projected production volumes, and discounted at a risk-adjusted rate. The projected production volumes represent reserves, including probable and possible reserves, expected to be produced based on a stipulated amount of capital expenditures. The Company did not record any impairment charges for proved properties as of December 31, 2017.

Costs of office furniture and equipment are depreciated on a straight-line basis over seven years. Costs of computer equipment and software are depreciated on a straight-line basis over three years. Costs of leasehold improvements are depreciated on a straight-line basis over the term of the associated lease.

**Conveyance of Override Interest**—In 2017, the Company conveyed an oil and gas override in proved properties in exchange for future production handling costs, including access to the host platform for a twelve-year period. As a result of the transaction, the Company reduced the cost basis of the properties by $14.4 million and recorded a deferred asset that will be amortized based on units-of-production from the proved oil and gas properties. During 2017, the Company recorded amortization of $0.9 million in depreciation, depletion, and amortization. As of December 31, 2017, the estimated short-term portion of the deferred asset of $1.5 million is included in prepaid expenditures and other current assets and the remaining $12.0 million is included in other noncurrent assets.

**Asset Retirement Obligations**—The Company is required to record a liability for its asset retirement obligations at fair value in the period such obligations are incurred with the associated asset retirement costs being capitalized as part of the carrying cost of the asset. The Company's asset retirement obligations relate to the plugging, abandonment, dismantlement, removal, site reclamation and similar activities associated with its oil, gas and NGL properties. Accretion of the liability is recognized for changes in the value of the liability as a result of the passage of time over the estimated productive life of the related assets as the discounted liabilities are accreted to their expected settlement values. Revisions in the estimates of property lives and cost estimates are capitalized as part of the property balance. Any gain or loss upon settlement of obligations is recognized in income.

The obligation to plug wells is settled when the Company abandons wells in accordance with governmental regulations. The Company accrues a liability with respect to these obligations based on its estimate of the timing and amount to replace, remove or retire the associated assets.

The estimate of the asset retirement cost is determined, inflated to an estimated future value using a seven-year average of the Consumer Price Index and discounted to present value using the Company's credit-adjusted risk-free rate.

In estimating the liability associated with its asset retirement obligations, the Company utilizes several assumptions, including a credit-adjusted risk-free interest rate, estimated costs of decommissioning services, estimated timing of when the work will be performed, and a projected inflation rate. Revisions in the estimate presented in the table below represent changes to the expected amount and timing of payments to settle the asset retirement obligations. Typically, these changes primarily result from obtaining new information about the timing of the obligations to plug and abandon oil, gas and NGL wells and the costs to do so. If the Company incurs an amount different from the amount accrued for decommissioning obligations, it recognizes the difference as a gain or loss on settlement of asset retirement obligations in the consolidated statements of operations.

The discounted asset retirement liability is included in the consolidated balance sheets in long-term liabilities, and the changes in that liability for the year ended December 31, 2017, were as follows (in thousands):

| | | |
|---|---|---|
| Asset retirement obligations at January 1, 2017 | $ | 2,934 |
| Liabilities incurred | | 9,277 |
| Revisions in estimated liabilities | | 5,151 |
| Accretion expense | | 380 |
| Asset retirement obligations at December 31, 2017 | | 17,742 |
| Less current portion | | — |
| Asset retirement obligations, long term | $ | 17,742 |

In 2017, the Company had upward revisions in estimated costs to abandon wells primarily due to an increase in assumed additional rig days on location for blowout preventer certification.

**Federal Income Taxes**—In accordance with the provisions of the Internal Revenue Code, the Company is not subject to federal income tax. Each member includes its share of the Company's income or loss in its own federal and state income tax returns.

The Company may be subject to state income taxes in certain jurisdictions and applicable state laws; however, currently the Company incurs no state income taxes.

**Commodity Derivatives and Price Risk Management Activities**—The Company periodically enters into derivative contracts to manage its exposure to commodity price risk. These derivative contracts, which are placed with major financial institutions that the Company believes have minimal credit risks, may take the form of swaps, options, or collars. The reference prices upon which the commodity derivative contracts are based reflect various market indexes that have a high degree of historical correlation with actual prices received by the Company for its production.

The Company accounts for its commodity derivative instruments in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 815, *Derivatives and Hedging*, which requires that all derivative instruments, other than those that meet the normal purchases and sales exception, be recorded on the consolidated balance sheets as either an asset or liability measured at fair value. The Company has historically not designated its derivative instruments as cash flow hedges and has recorded all changes in fair value directly on the consolidated statements of operations. See Note 9.

**Equity-Based Compensation**—Certain of the Company's employees participate in the equity-based compensation plan of the Company. The Company measures all employee equity-based compensation awards at fair value as calculated using an option pricing method for valuing such securities on the date awards are granted to its employees and recognizes compensation cost on a straight-line basis in the consolidated financial statements over the vesting period of each grant according to FASB ASC 718, *Compensation—Stock Compensation*.

**Recently Issued Accounting Standards**—In May 2014, the FASB issued Accounting Standards Update (ASU) 2014-09, *Revenue from Contracts with Customers*, which supersedes the revenue recognition requirements in ASC 605, *Revenue Recognition*, and industry-specific guidance in ASC 605 Subtopic 932, *Extractive Activities—Oil and Gas*, and requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. The Company is required to adopt the new standard in 2019 using one of two allowable methods: (1) a full retrospective method, which applies the standard to each period presented in the financial statements, or (2) the modified retrospective method, which applies the standard to only the most current period presented, with a cumulative effect adjustment recorded to retained earnings. The Company is continuing to evaluate the provisions of this ASU and has not yet decided upon the method of adoption or determined the impact this standard may have on its consolidated financial statements and related disclosures.

In August 2014, the FASB issued ASU 2014-15, *Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern (Subtopic 205-40)*. The guidance requires management to evaluate whether there are conditions and events that raise substantial doubt about the Company's ability to continue as a going concern within one year after the consolidated financial statements are issued. Additionally, management is required to provide certain footnote disclosures if it concludes that substantial doubt exists or when it plans to alleviate substantial doubt about the Company's ability to continue as a going concern. ASU 2014-15 is effective for annual periods ending after December 15, 2016. The adoption of ASU 2014-15 did not have a material impact on the consolidated financial statements and related disclosures.

In April 2015, the FASB issued ASU 2015-03, *Simplifying the Presentation of Debt Issuance Costs*. ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented on the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. In August 2015, the FASB issued ASU 2015-15 *Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line of Credit Arrangements*, which confirmed that fees related to line of credit arrangements are not addressed in ASU 2015-03. The Company early-adopted the guidance in ASU 2015-03 and ASU 2015-15 and has presented its debt issuance related to the Company's Bank Credit Facility as an asset as was required under prior guidance (ASC 835-30, *Interest—Imputation of Interest*).

In July 2015, the FASB issued ASU 2015-11, *Accounting for Inventory*, which requires entities to measure most inventory at lower of cost or net realizable value. ASU 2015-11 defines net realizable value as "the estimated selling prices in the ordinary course of business, less reasonably predictable cost of completion, disposal and transportation." ASU 2015-11 is effective prospectively for annual periods beginning after December 15, 2016, and early application is permitted. The adoption of ASU 2015-11 did not have a material impact on the consolidated financial statements and related disclosures.

In January 2016, the FASB issued ASU 2016-01, *Financial Instruments—Overall: Recognition and Measurement of Financial Assets and Financial Liabilities* (Topic 825), which changes accounting for equity investments and liabilities under the fair value option and the presentation and disclosure requirements for financial instruments. In addition, the FASB clarified guidance related to the valuation allowance assessment when recognizing deferred tax assets resulting from unrealized losses on the available for sale debt securities. Entities that are not public business will no longer be required to disclose the fair value of financial instruments carried at amortized costs. ASU 2016-01 is effective fiscal periods beginning after December 15, 2017 and early application is permitted. The Company has early adopted guidance in 2016. The guidance in ASU 2016-01 did not have a material impact on the consolidated financial statements and related disclosures.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*, which significantly changes accounting for leases by requiring that lessees recognize a right-of-use asset and a related lease liability representing the obligation to make lease payments, for virtually all lease transactions. Additional disclosures about an entity's lease transactions will also be required. ASU 2016-02 defines a lease as "a contract, or part of a contract, that conveys the right to control the use of identified property, plant or equipment (an identified asset) for a period of time in exchange for consideration." ASU 2016-02 is effective for annual periods beginning after December 31, 2018 and early application is permitted. Lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented in the financial statements using a modified retrospective approach. The Company is continuing to evaluate the provisions of this ASU and has not yet decided upon the method of adoption or determined the impact this standard may have on its consolidated financial statements and related disclosures.

In March 2016, the FASB issued ASU 2016-09, *Improvements to Employee Share-Based Payment Accounting (ASU 2016-09)*, which amends certain aspects of accounting for share-based payment arrangements. ASU 2016-09 revises or provides alternative accounting for the tax impacts of share-based payment arrangements, forfeitures and minimum statutory tax withholdings and prescribes certain disclosures to be made in the period the new standard is adopted. ASU 2016-09 is effective for annual periods beginning after December 15, 2017, and early application is permitted. The Company is continuing to evaluate the provisions of this ASU and has not yet decided upon the method of adoption or determined the impact this standard may have on its consolidated financial statements and related disclosures.

In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows (Topic 230)—Classification of Certain Cash Receipts and Cash Payments*. ASU 2016-15 reduces existing diversity in practice by providing guidance on the classification of eight specific cash receipts and cash payments transactions in the statement of cash flows. The new standard is effective for fiscal years beginning after December 15, 2018. Early adoption is permitted. The Company does not expect the adoption of the new standard to have a material impact on its consolidated financial statements and related disclosures.

In January 2017, the FASB issued ASU 2017-1, *Business Combinations (Topic 805): Clarifying the definition of a Business*. ASU 2017-1 reduces existing diversity in practice by providing guidance on the definition of a business. The definition of a business affects many areas of accounting including acquisitions, disposals, goodwill impairment, and consolidation. The new standard is effective for fiscal years beginning after December 15, 2018. Early adoption is permitted. The Company does not expect the adoption of the new standard to have a material impact on its consolidated financial statements and related disclosures.

## 3. EXPLORATORY WELL COSTS

The Company's net changes in capitalized exploratory well costs for the year ended December 31, 2017, are presented below (in thousands):

| | | |
|---|---|---|
| Balance at January 1, 2017 | $ | 48,433 |
| Additions pending the determination of proved reserves | | 28,552 |
| Reclassifications to proved properties | | (48,433) |
| Costs charged to expense | | — |
| Balance at December 31, 2017 | $ | 28,552 |

The following table provides information about exploratory well costs capitalized pending the determination of proved reserves as of December 31, 2017 (in thousands):

| | | |
|---|---|---|
| Exploratory well costs capitalized for less than one year | $ | 28,552 |
| Exploratory well costs capitalized for greater than one year | | — |
| Total capitalized exploratory well costs | $ | 28,552 |

One well, the Mississippi Canyon block 116 well (the "Rampart Deep Well") comprised $28.6 million of exploratory well costs capitalized at December 31, 2017. The Company drilled the Rampart Deep Well in 2017. The Rampart Deep Well had two primary target sands, the M57 sand and the M58 sand. Based on the successful discovery in the M57 sand, the Company decided to drill a second well Mississippi Canyon block 72 (the "Derbio Well") adjacent to Rampart Deep Well in 2018. In early 2018, the Company returned to location and began drilling the Derbio Well. The decision to complete the M57 and M58 sands in the Rampart Deep Well will be determined once the Derbio Well drilling is complete.

## 4. LONG-TERM NOTES PAYABLE

The Company has entered into a long-term note payable with a related party, FR DGE III Holdings, LLC. Each individual borrowing under the note accrues simple interest at a rate of 3.1%. The note has no maturity date. Following is a summary of amounts borrowed under the note at December 31, 2017 (in thousands):

| | | |
|---|---|---|
| Notes issued in July 2014 | $ | 206 |
| Notes issued in August 2014 | | 1,193 |
| Notes issued in January 2015 | | 525 |
| Notes issued in June 2015 | | 661 |
| Notes issued in October 2015 | | 623 |
| Notes issued in January 2016 | | 305 |
| Notes issued in March 2016 | | 305 |
| Notes issued in June 2016 | | 245 |
| Notes issued in October 2016 | | 183 |
| Notes issued in November 2016 | | 191 |
| Total principal | | 4,437 |
| Accrued interest | | 352 |
| Total notes payable | $ | 4,789 |

Interest expense to these related parties amounted to $137 thousand for the year ended December 31, 2017. No cash was paid for interest on these notes during the year ended December 31, 2017.

## 5. DEBT

The Company has a $150 million Bank Credit Facility with an initial borrowing base of $50 million. The borrowing base is redetermined semi-annually with a maximum borrowing base of $150 million. The Bank Credit Facility bears interest based on the borrowing base usage, at the applicable London InterBank Offered Rate, plus applicable margins ranging from 6.0% to 8.0% or an alternate base rate, based on the federal funds effective rate plus applicable margins ranging from 5.0% to 7.0%. In addition, the Company is obligated to pay a commitment fee rate based on the borrowing base usage of 1.0% to 2.0%. The Bank Credit Facility is secured by substantially all of the oil, gas and NGL assets of the Company. As of December 31, 2017, Company has not drawn on the Bank Credit Facility. The Bank Credit Facility is fully and unconditionally guaranteed by its wholly-owned subsidiary, Deep Gulf Energy III, LLC.

The credit agreement contains customary financial covenants requiring certain ratios to be met on a quarterly, semiannual and annual basis. Other covenants contained in the credit agreement restrict, among other things, asset dispositions, mergers and acquisitions, dividends, additional debt, liens, investments, and affiliate transactions. The credit agreement also contains customary events of default. The Company was in compliance with all covenants at December 31, 2017.

The deferred financing costs on the Bank Credit Facility are being amortized on a straight-line basis over the life of the Bank Credit Facility, which amortization is not materially different than if the Company had utilized the effective interest method. Cash paid for interest on credit facility was $504 thousand in 2017.

## 6. RELATED PARTY TRANSACTIONS

The Company's controlling interest is owned by the same persons who own Deep Gulf Energy Management, LLC; Deep Gulf Energy LP; DGE II Management, LLC; and Deep Gulf Energy II, LLC. Deep Gulf Energy LP; DGE II Management, LLC; and the Company have entered into Master Services and License Agreements in which operating services, engineering services, and other cost-sharing services are provided to each other. General and administrative expenses are allocated between the parties based on time incurred. In 2015, the Company became the primary related party that allocated shared expense to the related parties. Expenses allocated by the Company to related parties amounted to $9.0 million in 2017. Included in the 2017 allocation was a one-time $5.3 million charge to DGE II Management, LLC. Of the $5.3 million, $4.7 million is classified as long term receivable—related-party on the accompanying consolidated balance sheet and will be paid according the following schedule:

| | Receivable |
|---|---|
| January 2019 | $ 1,672 |
| January 2020 | 1,630 |
| January 2021 | 1,419 |
| Long term receivable—Related-party | $ 4,721 |

These consolidated financial statements have been prepared from the separate records maintained by the Company and may not necessarily be indicative of the conditions that would have existed or the results of operations if the Company had been operated as an unrelated company.

From time to time, the Company enters into notes receivable bearing simple interest at 3.1% with management members to fund capital contributions, as allowed by the members' equity agreements. These notes have no maturity date. Due to the nature of the notes, they are reflected in the accompanying consolidated financial statements as a reduction of equity. These notes totaled $4.4 million at December 31, 2017. Interest income related to these notes amounted to $135 thousand for the year ended December 31, 2017.

## 7. SUPPLEMENTARY CASH FLOW INFORMATION

Supplementary noncash investing activities information for the year ended December 31, 2017 consisted of the following (in thousands):

| | |
|---|---|
| Capital expenditures in accounts payable | $ 7,221 |
| Accrued capital expenditures | 3,280 |
| Prepaid capital expenditures | 6,184 |
| Noncash deferred production handling costs | 13,485 |

## 8. COMMITMENTS AND CONTINGENCIES

**Insurance**—The Company has insurance policies to mitigate its risk of loss associated with its operations, and it maintains the coverages and amounts of insurance believed to be prudent based on reasonably estimated loss potential. However, not all of the Company's business activities can be insured at the levels it desires because of either limited market availability or unfavorable economics (limited coverage for the underlying cost).

The Company's general property damage insurance provides varying ranges of coverage based upon several factors, including well counts, and cost of replacement facilities. The Company's general liability insurance program provides a limit of $150 million (for its interest) for each occurrence and in the aggregate and includes varying deductibles, and its Offshore Pollution Act insurance is also subject to a maximum of $150 million for each occurrence and in the aggregate and includes a $100,000 (100%) retention. The Company separately maintains an operator's extra expense policy for wells being drilled with additional coverage for an amount up to $1.0 billion and for producing wells with additional coverage for an amount up to $500 million that would cover costs involved in making a well safe after a blowout or getting the well under control, re-drilling a well to the depth reached prior to the well-being out of control or blown out, costs for plugging and abandoning the well, costs for cleanup and containment and for damages caused by contamination and pollution.

The Company customarily has reciprocal agreements with its customers and vendors in which each contracting party is responsible for its respective personnel. Under these agreements, the Company is indemnified against third party claims related to the injury or death of its customers' or vendors' personnel. Although there can be no assurance that the amount of insurance the Company carries is sufficient to protect it fully in all events, the Company believes that its insurance protection is adequate for its business operations.

**Performance Obligations**—Regulations with respect to offshore operations govern, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells, and removal of facilities. As of December 31, 2017, the Company had secured performance bonds totaling approximately $159 million for its supplemental bonding requirements stipulated by the Bureau of Ocean Energy Management (BOEM) related to costs anticipated for the plugging and abandonment of certain wells and the removal of certain facilities in its Gulf of Mexico fields. These performance bonds are uncollateralized. If the Company were to have to obtain additional performance bonds for other reasons, it cannot assure that it would be able to secure any such additional performance bonds on acceptable commercial terms or at all.

**Legal Proceedings and Other Contingencies**—The Company or its subsidiaries may be named defendants in legal proceedings that arise in the ordinary course of business. There are also other regulatory rules and orders in various stages of adoption, review and/or implementation. For each of these matters, the Company evaluates the merits of the case or claim, its exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. The Company discloses matters that are reasonably possibly of negative outcome and are material to the consolidated financial statements. If the Company determines that an unfavorable outcome is probable and is reasonably estimable, the Company accrues for such reasonably estimable outcome. While the outcome of the Company's current matters cannot be predicted with certainty and there are still uncertainties related to the costs it may incur, based upon an evaluation and experience, the Company will establish appropriate accruals as it believes are necessary. It is possible; however, that new information or future developments could require the Company to reassess its potential exposure related to these matters and record or adjust accruals accordingly, and these adjustments could be material.

Future minimum lease payments under operating leases having initial or non-cancelable terms in excess of one year are $0.5 million in 2018. Rent expense totaled $0.7 million in 2017.

## 9. PRICE RISK MANAGEMENT ACTIVITIES

**Objectives and Strategies**—The Company is exposed to fluctuations in oil, gas and NGL prices on its production. The Company believes it is prudent to manage the variability in cash flows on a portion of its oil production. The Company utilizes various types of derivative financial instruments, including swaps, costless collars and options, to manage fluctuations in cash flows resulting from changes in commodity prices.

**Commodity Derivative Instruments**—As of December 31, 2017, the Company had entered into commodity contracts with the following terms:

| Commodity Contract Type | Period Covered | Contracted Volume Oil (MBbls) | Fixed Price |
|---|---|---|---|
| Swaps | January 2018 | 16.8 | $ 55.00 |
| Swaps | January–March 2018 | 42.7 | 55.55 |
| Swaps | January–March 2018 | 42.7 | 55.03 |
| Swaps | January 2018–Dec 2019 | 64.2 | 50.05 |
| Swaps | January 2018–Dec 2019 | 610.1 | 50.00 |
| Swaps | January 2018–Dec 2019 | 305.1 | 50.10 |
| Swaps | January 2018–Dec 2019 | 305.0 | 50.10 |

The following table sets forth the fair values and classification of the Company's outstanding derivatives (in thousands):

| | Gross Amount of Recognized Asset (Liability) December 31, 2017 |
|---|---|
| Current derivative asset | $ — |
| Current derivative liability | (9,775) |
| Net current derivative liability | $ (9,775) |
| Long term derivative asset | $ — |
| Long term derivative liability | (3,318) |
| Long term derivative liability | $ (3,318) |

The Company has entered into master netting arrangements with its counterparties. The amounts above are presented on a net basis in its balance sheets when such amounts are with the same counterparty. The Company recognized $0.6 million in realized gain and $13.1 million in unrealized losses in 2017 related to its derivative financial instruments.

The Company is subject to the risk of loss on its derivative financial instruments that it would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. The Company enters into International Swaps and Derivative Association agreements with counterparties to mitigate this risk, when possible. The Company also maintains credit policies with regard to its counterparties to minimize its overall credit risk. These policies require (i) the evaluation of potential counterparties' financial condition to determine their credit worthiness; (ii) the regular monitoring of oil and natural gas counterparties' credit exposures; (iii) comprehensive credit reviews on significant counterparties from physical and financial transactions on an ongoing basis; (iv) the utilization of contractual language that affords the Company netting or set off opportunities to mitigate exposure risk; and (v) potentially requiring counterparties to post cash collateral, parent guarantees or letters of credit to minimize credit risk. The Company's assets or liabilities from derivatives at December 31, 2017 represent derivative financial instruments from two counterparties; both of which are financial institutions that have an "investment grade" (minimum Standard & Poor's rating of BBB- or better) credit rating and are party under the Company's credit agreement. The Company enters into derivatives directly with these third parties and, subject to the terms of the credit agreement, are not required to post collateral or other securities for credit risk in relation to the derivative financial interests.

**Fair Value Measurement**

The following table presents the fair value hierarchy table for the Company's assets and liabilities that are required to be measured at fair value on a recurring basis (in thousands):

| | Fair Value | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|
| At December 31, 2017: | | | | |
| Assets—oil, natural gas and natural gas liquids derivatives | $ — | $ — | $ — | $ — |
| Liabilities—oil, natural gas and natural gas liquids derivatives | 13,093 | — | 13,093 | — |

The Company's derivatives consist of over-the-counter ("OTC") contracts which are not traded on a public exchange. As the fair value of these derivatives is based on inputs using market prices obtained from independent brokers or determined using quantitative models that use as their basis readily observable market parameters that are actively quoted and can be validated through external sources, including third party pricing services, brokers and market transactions, the Company has categorized these derivatives as Level 2. The Company values these derivatives using the income approach using inputs such as the forward curve for commodity prices based on quoted market prices and prospective volatility factors related to changes in the forward curves and yield curves based on money market rates and interest rate swap data, such as forward LIBOR curves. The Company's estimates of fair value have been determined at discrete points in time based on relevant market data. There were no changes in valuation techniques or related inputs in 2017.

## 10. EMPLOYEE INCENTIVE PROGRAMS

**Defined Contribution Plan**—The Company has a defined contribution savings plan (the Savings Plan) that is established for the benefit of eligible employees of the Company and complies with Section 401(k) of the Internal Revenue Code. The Savings Plan allows employees to contribute up to the maximum allowable amount as dictated by the Internal Revenue Code. Under the Savings Plan, the Company makes net profit contributions in the amount up to 7.5% of each employee's base salary annually. Participants direct the investment of their accumulated contributions into various plan investment options. The Company contributed $0.6 million to the Savings Plan for the year ended December 31, 2017.

**Employee Share Ownership Program**—The Amended and Restated Operating Agreement of DGE III Management, LLC (the "Operating Agreement") established Common Units and Incentive Units. Incentive Units are generally intended to be used as incentives for Company employees. The Company was initially authorized to issue 50,000 Incentive Units and may be authorized to issue more under the Operating Agreement. As of December 31, 2017, the Company was authorized to issue 50,201 incentive units.

With the exception of annual distributions to cover the assumed tax liability of the Incentive Unit holders, Incentive Units do not participate in cash distributions prior to vesting and until Common Units have received cumulative cash distributions equal to (i) 150% of the original cash contributed to the Company and (ii) a 10% return on investment, compounded annually. After issuance, the Incentive Units fully vest upon (a) occurrence of a Liquidity Event or (b) occurrence of a Termination Event, other than for Discouraged Terms, which occurs after three years from the date of employment (in which case a portion of the Incentive Units shall vest, as calculated in the Restricted Unit Agreement).

The Company had 48,704 Incentive Units outstanding at December 31, 2017. A summary of the Incentive Units activity for the years ended December 31, 2017, is presented below.

| | Number of Incentive Units | Weighted Average Estimated Fair Value per Unit |
|---|---|---|
| Non-vested at January 1, 2017 | 32,219 | $ 559 |
| Granted | 133 | 973.40 |
| Vested | (8,687) | 525.89 |
| Forfeited or canceled | (914) | 642.65 |
| Non-vested at December 31, 2017 | 22,751 | 570.52 |

Compensation expense related to these awards is recorded on a straight-line basis over the six-year service period in the Company's consolidated financial statements and is reflected as a corresponding credit to equity. The Company has recognized approximately $4.5 million in compensation expense included in general and administrative expense for the year ended December 31, 2017. The Incentive Units issued were valued using the option pricing method for valuing securities. In this method, the rights and claims of each security are modeled as a portfolio of Black-Scholes-Merton call options written on the total equity of the Company.

The fair value of the 2017 grant was estimated at the date of grant using the following weighted average assumptions (dollars in thousands):

| | Jan-17 Grant |
|---|---|
| Total value of equity | $ 700,883 |
| Risk-free rate of interest | 1.44% |
| Expected time to a liquidity event (in years) | 5.17 |
| Expected volatility of equity | 76.31% |
| Discount for lack of marketability | 40% |

The total value of the equity is calculated in an iterative process that results in the Common Units being valued at par. The risk-free rate of interest is based on the U.S. Treasury yield curve on the grant date. The expected time to a liquidity event is based on a weighted average calculation of management's estimate considering market conditions and expectations. The expected volatility of equity is based on the volatility of the assets of similar publicly traded companies using a Black-Scholes-Merton model. The discount for lack of marketability is based on the restrictions on the Incentive Units and the volatility of the Incentive Units using a Black-Scholes-Merton model as well.

The Company's unrecognized compensation expense at December 31, 2017, is approximately $13.0 million, which will continue to be recognized on a straight-line basis over the remainder of the requisite service period. The weighted average period over which the unrecognized compensation expense will be recognized is 38 months. At December 31, 2017, the Company has 1,498 Incentive Units authorized but not yet issued.

## 11. SUBSEQUENT EVENTS

Subsequent events were evaluated through March 29, 2018, which is the date these consolidated financial statements were available to be issued.

The Company entered into five separate commodity contracts after year end. The objective of these commodity contracts is to manage the variability of cash flows resulting from changes in commodity prices for oil production. The commodity contracts are not being designated as hedging instruments and all changes in fair value will be recognized in earnings as they occur. The commodity contracts are summarized in the table below.

| Date Entered | Commodity Contract Type | Contracted Volume Oil (MbblS) | Fixed Price | Period Covered |
|---|---|---|---|---|
| February 9, 2018 | Swap | 614.1 | $ 58.63 | March–Dec 2018 |
| February 12, 2018 | Swap | 272.7 | 54.25 | Jan–June 2019 |
| February 13, 2018 | Swap | 234.9 | 53.21 | July–Dec 2019 |
| March 9, 2018 | Swap | 123.1 | 60.07 | April–Dec 2019 |
| March 15, 2018 | Swap | 53.1 | 57.22 | Jan–June 2019 |
| March 21, 2018 | Swap | 44.5 | 57.00 | July–Dec 2019 |

## 12. SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

**Capitalized Costs Relating to Oil and Natural Gas Producing Activities**—The total amount of capitalized costs relating to oil and natural gas producing activities and the total amount of related accumulated depreciation, depletion and amortization indicated are presented below as of December 31, 2017 (in thousands):

| | |
|---|---|
| Proved properties | $ 354,424 |
| Proved properties under development | 31,097 |
| Accumulated depletion | (71,659) |
| Total proved | 313,862 |
| Unproved properties | 25,969 |
| | $ 339,831 |

Included in the depletable basis of the Company's proved properties is the estimate of the Company's proportionate share of asset retirement obligations relating to these properties, which are also reflected as asset retirement obligations in the accompanying consolidated balance sheet. At December 31, 2017, oil and gas asset retirement obligations totaled $17.7 million.

**Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development Activities**—Costs incurred in property acquisition, exploration and development activities during the period are presented below (in thousands):

| | |
|---|---|
| Property acquisition costs, proved | $ — |
| Property acquisition costs, unproved | 8,392 |
| Exploration costs | 64,617 |
| Development costs | 39,457 |
| Total | $ 112,466 |

**Estimated Quantities of Proved Oil and Gas Reserves**—Users of this information should be aware that the process of estimating quantities of "proved" and "proved developed" oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

A variety of deterministic methods are used to determine the Company's proved reserve estimates. Standard engineering and geoscience methods or a combination of methods are used, including performance analysis, volumetric analysis, analogy, and reservoir modeling. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, the Company's conclusions necessarily represent only informed professional judgment.

Proved reserves are those quantities of oil and natural gas that 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. 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.

The Company engaged Ryder Scott Company, L.P. Petroleum Consultants and Netherland Sewell and Associates, Inc. to prepare the reserve estimates for all of the Company's estimated proved reserves (by volume) at December 31, 2017. All proved reserves are located in the Gulf of Mexico and all prices are held constant in accordance with SEC rules.

The following tables set forth estimates of the net proved reserves as of December 31, 2017:

| | Oil (MBbls) | Gas (MMcf) | NGL (MBbls) | Total (Mboe)[3] |
|---|---|---|---|---|
| Proved reserves at December 31, 2016 | 23,939 | 24,596 | 236 | 28,274 |
| Revision of previous estimate [1] | 1,374 | 2,303 | 2,219 | 3,976 |
| Production | (2,794) | (2,734) | (259) | (3,508) |
| Purchase of reserves in place | — | — | — | — |
| Sales of reserves in place | — | — | — | — |
| Extensions and discoveries [2] | 2,690 | 2,523 | 224 | 3,334 |
| Proved reserves at December 31, 2017 | 25,209 | 26,688 | 2,420 | 32,076 |
| Proved developed reserves at December 31, 2017 | 15,915 | 16,078 | 1,414 | 20,008 |
| Proved undeveloped reserves at December 31, 2017 | 9,294 | 10,610 | 1,006 | 12,068 |

(1) Revision of previous estimate resulted from positive performance in the following fields:

- Barataria +1.1 MMBOE for performance-based increase in reservoir area
- Odd Job +0.9 MMBOE as evidence of a water drive supports an increased recovery factor estimate; additionally, NGL processing performance supports an updated NGL yield
- Kodiak +0.8 MMBOE as reservoir performance supports an increase in recovery factor estimate
- Tornado +0.8 MMBOE as a performance-based increase in expected ultimate gas-oil-ratio and the associated NGL's more than offsets a performance-based decrease in oil recovery factor
- South Santa Cruz +0.2 MMBOE as reservoir performance supports an increase in recovery factor estimate
- Big Bend +0.2 MMBOE for performance-based increase in reservoir area

(2) Discoveries include an Exploration well at the Tornado Field, which discovered the B5 and B6 reservoirs in a new fault block and the deepening of a well at the Barataria Field, which discovered the H-9 reservoir

(3) Natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent.

**Standardized Measure of Discounted Future Net Cash Flows from Proved Reserves**—The standardized measure of discounted future net cash flows presented below is computed by applying first-day-of-the-month average prices, year-end costs and legislated tax rates and a discount factor of 10 percent to proved reserves. The Company does not believe the standardized measure provides a reliable estimate of the Company's expected future cash flows to be obtained from the development and production of its oil and gas properties or of the value of its proved oil and gas reserves. The standardized measure is prepared on the basis of certain prescribed assumptions including first-day-of-the-month average prices, which represent discrete points in time and therefore may cause significant variability in cash flows from year to year as prices change.

Future net cash flows are discounted at the prescribed rate of 10%. Actual future net cash flows may vary considerably from these estimates. Although estimates of total proved reserves, development costs and production rates were based on the best information available, the development and production of oil and gas reserves may not occur in the periods assumed. Actual prices realized, costs incurred and production quantities may vary significantly from those used. Therefore, such estimated future net cash flow computations should not be considered to represent the Company's estimate of the expected revenues or the current value of existing proved reserves.

The standardized measure of discounted future net cash flows at December 31, 2017 is as follows (in thousands):

| | |
|---|---|
| Future cash inflows | $ 1,319,487 |
| Future production costs | (318,865) |
| Future development and abandonment costs | (222,287) |
| Future income tax expense | — |
| Future net cash flows | 778,335 |
| Discount at 10% annual rate | (222,274) |
| Standardized measure of discounted future net cash flows | $ 556,061 |

Future cash inflows are computed by applying the appropriate average of the first-day-of-the-month price for each month within the period January through December of each year presented, adjusted for location and quality differentials on a property-by-property basis, to year-end quantities of proved reserves. For oil and NGL volumes the average Texas intermediate spot price of $51.34 per barrel is adjusted by field for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.98 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. The discounted future cash flow estimates do not include the effects of the Company's derivative financial instruments.

**Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves**—The following is a summary of the changes in the standardized measure of discounted future net cash flows for the proved oil and natural gas reserves during the year ended December 31, 2017 (in thousands):

| | |
|---|---|
| Standardized measure, beginning of year | $ 396,033 |
| Changes during the year: | |
| Sales, net of production | (115,704) |
| Net change in prices and production costs | 71,180 |
| Changes in future development costs | (28,059) |
| Development costs incurred | 52,009 |
| Accretion of discount | 39,603 |
| Net change in income taxes (1) | — |
| Purchase of reserves in place | — |
| Extensions and discoveries | 29,153 |
| Sales of reserves in place | — |
| Net change due to revision in quantity estimates | 89,028 |
| Changes in production rates (timing) and other | 22,818 |
| Total | 160,028 |
| Standardized measure, end of year | $ 556,061 |

(1) The Company's calculation of the standardized measure of discounted future net cash flows and the related changes therein do not include the effect of the estimated future income tax expenses because the Company is not subject to federal or state income taxes on income from proved oil and gas reserves.

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**Exhibit 99.4**

# Deep Gulf Energy LP

Unaudited Condensed Financial Statements as of June 30, 2018 and December 31, 2017, and for the Six Months Ended June 30, 2018 and 2017

## DEEP GULF ENERGY LP

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## DEEP GULF ENERGY LP

**CONDENSED BALANCE SHEETS**
**(In thousands)**
**(Unaudited)**

| | June 30, 2018 | December 31, 2017 |
|---|---|---|
| **ASSETS** | | |
| CURRENT ASSETS: | | |
| Cash and cash equivalents | $ 9,879 | $ 9,606 |
| Accounts receivable, net | 1,721 | 1,339 |
| Prepaid expenditures | 278 | 281 |
| Total current assets | 11,878 | 11,226 |
| PROPERTY, PLANT, AND EQUIPMENT: | | |
| Oil and gas properties, successful efforts method—net of accumulated depreciation, depletion and amortization of $388,943 and $388,398 at June 30, 2018 and December 31, 2017, respectively | 10,080 | 10,638 |
| OTHER ASSETS | 875 | 725 |
| TOTAL ASSETS | $ 22,833 | $ 22,589 |
| **LIABILITIES AND PARTNERS' CAPITAL** | | |
| CURRENT LIABILITIES: | | |
| Accounts payable | $ 267 | $ 445 |
| Accounts payable—related-party | 65 | 102 |
| Accrued liabilities | 6,031 | 4,015 |
| Current portion of asset retirement obligations | 3,003 | 5,150 |
| Total current liabilities | 9,366 | 9,712 |
| LONG-TERM LIABILITIES—Asset retirement obligations | 10,377 | 11,883 |
| COMMITMENTS AND CONTINGENCIES (Note 4) | | |
| PARTNERS' CAPITAL—Limited partners' interest | 3,090 | 994 |
| TOTAL LIABILITIES AND PARTNERS' CAPITAL | $ 22,833 | $ 22,589 |

See accompanying notes to the unaudited condensed financial statements.

**DEEP GULF ENERGY LP**

**CONDENSED STATEMENTS OF OPERATIONS**
**FOR THE SIX MONTHS ENDED JUNE 30, 2018 AND 2017**
**(In thousands)**
**(Unaudited)**

| | **2018** | **2017** |
|---|---|---|
| REVENUE: | | |
| Oil revenue | $ 5,390 | $ 3,264 |
| Gas revenue | 603 | 507 |
| NGL revenue | 177 | 141 |
| Total revenue | 6,170 | 3,912 |
| OPERATING COSTS AND EXPENSES: | | |
| Lease operating expenses | 2,461 | 2,119 |
| Work over expense | 70 | 1,295 |
| Transportation expenses | 149 | 122 |
| Depreciation, depletion, and amortization | 545 | 799 |
| Accretion expense | 876 | 420 |
| General and administrative expense | 10 | 84 |
| Loss (gain) on the sale of inventory | 1 | (1,171) |
| Other operating income | (59) | (18) |
| Total operating costs and expenses | 4,053 | 3,650 |
| OPERATING INCOME | 2,117 | 262 |
| OTHER EXPENSE | (21) | 0 |
| NET INCOME | $ 2,096 | $ 262 |

See accompanying notes to the unaudited condensed financial statements.

## DEEP GULF ENERGY LP

**CONDENSED STATEMENT OF PARTNERS' CAPITAL**
**(In thousands)**
**(Unaudited)**

| | Limited Partners' Units | Contributions | Distributions | Retained Earnings | Total Partners' Capital |
|---|---|---|---|---|---|
| BALANCE—January 1, 2018 | 100 | $ 148,601 | $ (283,875) | $ 136,268 | $ 994 |
| Net income | - | - | - | 2,096 | 2,096 |
| BALANCE—June 30, 2018 | 100 | $ 148,601 | $ (283,875) | $ 138,364 | $ 3,090 |

See accompanying notes to the unaudited condensed financial statements.

## DEEP GULF ENERGY LP

**CONDENSED STATEMENTS OF CASH FLOWS**
**FOR THE SIX MONTHS ENDED JUNE 30, 2018 AND 2017**
**(In thousands)**
**(Unaudited)**

| | 2018 | 2017 |
|---|---|---|
| CASH FLOWS FROM OPERATING ACTIVITIES: | | |
| Net income | $ 2,096 | $ 262 |
| Adjustments to reconcile net cash provided by operating activities: | | |
| Depreciation, depletion, and amortization | 545 | 799 |
| Accretion expense | 876 | 420 |
| Settlement of asset retirement obligations | (4,529) | (735) |
| Net changes in assets and liabilities: | | |
| Accounts receivable | (382) | 6,619 |
| Prepaid expenditures | 3 | 624 |
| Other assets | (150) | (175) |
| Accounts payable | (178) | (6,195) |
| Accounts payable—related-party | (37) | (478) |
| Accrued liabilities | 2,016 | (406) |
| Net cash provided by operating activities | 260 | 735 |
| CASH FLOWS FROM INVESTING ACTIVITIES: | | |
| Capital expenditures for oil and gas properties—net of reimbursements | 13 | 0 |
| Net cash provided by (used in) investing activities | 13 | |
| NET INCREASE IN CASH AND CASH EQUIVALENTS | 273 | 735 |
| CASH AND CASH EQUIVALENTS—Beginning of year | 9,606 | 7,340 |
| CASH AND CASH EQUIVALENTS—End of year | $ 9,879 | $ 8,075 |

See accompanying notes to the unaudited condensed financial statements.

## 1. NATURE OF BUSINESS AND BASIS OF PRESENTATION

**Nature of Business**—Deep Gulf Energy LP, a Texas limited partnership (the "Partnership"), was formed to acquire, develop, operate, and manage deepwater exploitation and low-risk exploration projects located in the Gulf of Mexico and to produce and market oil, gas and natural gas liquids (NGL) from such properties. The Partnership has a perpetual existence unless and until dissolved and terminated.

**Basis of Presentation**— The interim financial information presented in the condensed financial statements included in this report is unaudited and, in the opinion of management, includes all adjustments of a normal recurring nature necessary to present fairly the condensed financial position as of June 30, 2018, the changes in the condensed statement of shareholders' equity for the six months ended June 30, 2018, the condensed results of operations for the six months ended June 30, 2018 and 2017, and the condensed cash flows for the six months ended June 30, 2018 and 2017. The December 31, 2017 condensed balance sheet was derived from the 2017 audited financial statements. The results of the interim periods shown in this report are not necessarily indicative of the final results to be expected for the full year. These condensed financial statements were prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). As permitted under those rules, certain notes or other financial information that are normally required by GAAP have been condensed or omitted from these interim condensed financial statements. These condensed financial statements and the accompanying notes should be read in conjunction with our audited financial statements as of and for the year ended December 31, 2017.

## 2. ACCOUNTING POLICIES

**Use of Estimates**—The preparation of condensed financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities and disclosures of contingent liabilities at the date of the condensed financial statements and the related reported amounts of revenue and expenses. Estimates of reserves are used to determine depletion and to conduct impairment analysis. Estimating reserves has inherent uncertainty, including the projection of future rates of production and the timing of expenditures. Actual results could differ from those estimates. Management believes that its estimates are reasonable.

**Revenue Recognition and Imbalances**—Oil, gas and NGL revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and when collectability of the revenue is probable.

The Partnership uses the sales method of accounting for gas production imbalances. The volumes of gas sold may differ from the volumes to which the Partnership is entitled, based on its interests in the properties. These differences create imbalances that are recognized as a liability only when the properties' estimated remaining reserves, net to the Partnership, will not be sufficient to enable the under produced owner to recoup its entitled share through production. No receivables are recorded for those wells where the

Partnership has taken less than its share of production. There were no imbalances recorded at June 30, 2018.

**Fair Value Measurements**—Current fair value accounting standards define fair value, establish a consistent framework for measuring fair value, and stipulate the related disclosure requirements for each major asset and liability category measured at fair value on either a recurring or nonrecurring basis. These standards also clarify that fair value is an exit price representing the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. The Partnership follows a three-level hierarchy, prioritizing and defining the types of inputs used to measure fair value depending on the degree to which they are observable as follows:

***Level 1***—Inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.

***Level 2***—Inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial statement or quoted prices (unadjusted) for identical assets or liabilities in inactive markets.

***Level 3***—Inputs to the valuation methodology are unobservable (little or no market data), which require the reporting entity to develop its own assumptions, and are significant to the fair value measurement.

Assets and liabilities measured at fair value are based on one or more of three valuation techniques. The valuation techniques are as follows:

***Market Approach***—Prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities.

***Cost Approach***—Amount that would be required to replace the service capacity of an asset (replacement cost).

***Income Approach***—Techniques to convert expected future cash flows to a single present value amount based on market expectations (including present value techniques, option-pricing and excess earnings models).

Authoritative guidance on financial instruments requires certain fair value disclosures to be presented. The estimated fair value amounts have been determined using available market information and valuation methodologies. Considerable judgment may be required in interpreting market data to develop the estimates of fair value for Level 3 inputs to the valuation methodology. The use of different assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

Financial instruments consisting of cash and cash equivalents, accounts receivable, and accounts payable are reported at their carrying amounts, which approximate fair value due to the short-term nature of these instruments.

**Property, Plant and Equipment -** The following table lists the total proved and unproved oil, gas and NGL properties as of June 30, 2018 and December 31, 2017 (in thousands):

| | June 30, 2018 | December 31, 2017 |
|---|---|---|
| Proved properties—net of accumulated depreciation, depletion and amortization | $ 9,812 | $ 10,370 |
| Unproved properties | 268 | 268 |
| Total oil and gas properties—net of accumulated depreciation, depletion and amortization | $ 10,080 | $ 10,638 |

**Recently Issued Accounting Standards**—In May 2014, the FASB issued Accounting Standards Update (ASU) 2014-09, *Revenue from Contracts with Customers*, which supersedes the revenue recognition requirements in ASC 605, *Revenue Recognition*, and requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which entity expects to be entitled in exchange for those goods or services. The Partnership is required to adopt the new standard in 2019 using one of two allowable methods: (1) a full retrospective method, which applies the standard to each period presented in the financial statements, or (2) the modified retrospective method, which applies the standard to only the most current period presented, with a cumulative effect adjustment recorded to retained earnings. The Partnership is continuing to evaluate the provisions of this ASU, and has not determined the impact this standard may have on its financial statements and related disclosures or decided upon the method of adoption.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*, which significantly changes accounting for leases by requiring that lessees recognize a right-of-use asset and a related lease liability representing the obligation to make lease payments, for virtually all lease transactions. Additional disclosures about an entity’s lease transactions will also be required. ASU 2016-02 defines a lease as “a contract, or part of a contract, that conveys the right to control the use of identified property, plant or equipment (an identified asset) for a period of time in exchange for consideration.” ASU 2016-02 is effective for annual periods beginning after December 31, 2019 and early application is permitted. Lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented in the financial statements using a modified retrospective approach. The Partnership is continuing to evaluate the provisions of this ASU and has not yet decided upon the method of adoption or determined the impact this standard may have on its financial statements and related disclosures.

In July 2018, the FASB issued ASU 2018-11, Leases *(Topic 842): Targeted Improvements*. ASU 2018-11 provide entities with an additional (and optional) transition method to adopt the new lease requirements by allowing entities to initially apply the requirements by recognizing a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. Consequently, an entity’s reporting for the comparative periods presented in the financial statements in which the entity adopts the new lease requirements would continue to be in accordance with current GAAP (Topic 840). An entity electing this additional (and optional) transition method must provide the required Topic 840 disclosures for all periods that continue to be in accordance with Topic 840. The amendments do not change the existing disclosure requirements in Topic 840 (for example, they do not create interim disclosure requirements that entities previously were not required to provide. The new standard is effective for fiscal years beginning after periods beginning after December 31, 2019. Early adoption is permitted. The Partnership is continuing to evaluate the provisions of this ASU and has not yet decided upon the method of adoption or determined the impact this standard may have on its financial statements and related disclosures.

## 3. RELATED-PARTY TRANSACTIONS

The Partnership's controlling interest is owned by the same persons who own DGE II Management, LLC; Deep Gulf Energy II, LLC; DGE III Management, LLC; and Deep Gulf Energy III, LLC. DGE II Management, LLC; DGE III Management, LLC; and the Partnership have entered into Master Services and License Agreements in which operating services, engineering services, and other cost-sharing services are provided to each other. The Partnership had related party payables to other entities under this Master Services and License Agreement of $0.1 million as of June 30, 2018 and December 31, 2017, respectively.

These condensed financial statements have been prepared from the separate records maintained by DGE III Management, LLC and may not necessarily be indicative of the conditions that would have existed or the results of operations if the Partnership had been operated as an unrelated company.

## 4. COMMITMENTS AND CONTINGENCIES

**Insurance**—The Partnership has insurance policies to mitigate its risk of loss associated with its operations, and it maintains the coverages and amounts of insurance believed to be prudent based on reasonably estimated loss potential. However, not all of the Partnership's business activities can be insured at the levels it desires because of either limited market availability or unfavorable economics (limited coverage for the underlying cost).

The Partnership's general property damage insurance provides varying ranges of coverage based upon several factors, including well counts and cost of replacement facilities. Its general liability insurance program provides a limit of $150 million (for the Partnership's interest) for each occurrence and in the aggregate and includes varying deductibles, and the Partnership's Offshore Pollution Act insurance is also subject to a maximum of $35 million for each occurrence and in the aggregate and includes a $100,000 (100%) retention. The Partnership separately maintains an operator's extra expense policy for wells being drilled and producing wells with additional coverage for an amount up to $100 million that would cover costs involved in making a well safe after a blowout or getting the well under control, re-drilling a well to the depth reached prior to the well being out of control or blown out, costs for plugging and abandoning the well, costs for cleanup and containment and for damages caused by contamination and pollution.

The Partnership customarily has reciprocal agreements with its customers and vendors in which each contracting party is responsible for its respective personnel. Under these agreements, the Partnership is indemnified against third party claims related to the injury or death of its customers' or vendors' personnel.

Although there can be no assurance the amount of insurance the Partnership carries is sufficient to protect it fully in all events, it believes that its insurance protection is adequate for its business operations.

**Performance Obligations**—Regulations with respect to offshore operations govern, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells, and removal of facilities. As of June 30, 2018, the Partnership had secured performance bonds totaling approximately $0.3 million for its supplemental bonding requirements stipulated by the Bureau of Ocean Energy Management related to costs anticipated for the plugging and abandonment of certain wells and removal of certain facilities in its Gulf of Mexico fields. These performance bonds are uncollateralized. If the Partnership were to have to obtain additional performance bonds for other reasons, it cannot ensure that it would be able to secure any such additional performance bonds on acceptable commercial terms or at all.

Additionally, the Partnership has a $1.2 million collateralized bond to a third party for the plugging and abandonment of Nancy property located at Garden Banks block 463 that the Partnership exited in 2017. On January 4, 2017 the Partnership executed an agreement withdrawing from the Nancy property located at Garden Banks block 463. The agreement has an effective date of August 19$^{th}$, 2016. As part of the agreement, the Partnership was required to post a performance bond with the purchaser as obligee for the Partnership's estimated share of certain future abandonment expenses as the Partnership retained financial responsibility and liability for its proportionate share of certain of the abandonment liabilities. The Partnership posted such performance bond on January 4, 2017 in the amount of $1.2 million. As part of the performance bond, the Partnership entered into a collateral agreement with the bonding surety and was required to fund a collateral account with an initial contribution of $50 thousand by January 10, 2017 and in monthly deposits of $25 thousand on the 1$^{st}$ day of each month beginning on February 1, 2017 through November 1, 2018 in until such time that the deposit totals $0.6 million. As of June 30, 2018 the Partnership has recorded a deposit related to this bond of $0.5 million.

**Legal Proceedings and Other Contingencies**—The Partnership is a party to a Deferred Amount Payment Agreement (DAPA) with Energy Resource Technology GOM, Inc. (ERT) related to the Danny Noonan project (Project). Through this DAPA, the Partnership is required to reimburse ERT $7.3 million from the Project's net cash flow in monthly installments if the gross production from the Project equals or exceeds 265 BCFE. As of June 30, 2018 , the Partnership does not expect gross production from the Project to equal or exceed 265 BCFE. As of June 30, 2018, the Partnership had no liability recorded for this DAPA.

From time to time, the Partnership could be a party to certain legal actions and claims arising in the ordinary course of business. Management is not aware of any legal actions or claims against the Partnership.

## 5. SUBSEQUENT EVENTS

Subsequent events were evaluated through September 14, 2018, which is the date these condensed financial statements were available to be issued.

On August 3$^{rd}$, 2018, the Partnershp along with Deep Gulf Energy Management, LLC; DGE II Management, LLC; Deep Gulf Energy II, LLC; DGE III Management, LLC; and Deep Gulf Energy III, LLC entered into a securities purchase agreement with Kosmos Energy Gulf of Mexico, LLC to sell all shareholder interests in the Company; Deep Gulf Energy Management, LLC;; DGE II Management, LLC; Deep Gulf Energy II, LLC; DGE III Management, LLC; and Deep Gulf Energy III, LLC for a total consideration of $1.225

billion, subject to certain adjustments. This transaction is expected to close during the third quarter of 2018.

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# DGE II Management, LLC and Subsidiary

Unaudited Condensed Consolidated Financial Statements as of June 30, 2018 and December 31, 2017 and for the Six Months Ended June 30, 2018 and 2017

# DGE II MANAGEMENT, LLC AND SUBSIDIARY

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## DGE II MANAGEMENT, LLC AND SUBSIDIARY

**CONDENSED CONSOLIDATED BALANCE SHEETS**
**(In thousands)**
**(Unaudited)**

| | June 30, 2018 | December 31, 2017 |
|---|---|---|
| **ASSETS** | | |
| CURRENT ASSETS: | | |
| Cash and cash equivalents | $ 85,989 | $ 51,524 |
| Accounts receivable | 18,855 | 15,351 |
| Accounts receivable—related party | 6 | 43 |
| Current asset from price risk management activities | 49 | 735 |
| Prepaid expenditures | 3,570 | 4,766 |
| Inventory | 1,816 | 2,684 |
| Total current assets | 110,285 | 75,103 |
| PROPERTY, PLANT, AND EQUIPMENT: | | |
| Oil and gas properties, successful efforts method—net of accumulated depletion of $314,275 and $284,352 at June 30, 2018 and December 31, 2017, respectively | 216,393 | 232,047 |
| Other property, plant, and equipment—net of accumulated depreciation of $2,183 and $2,084 at June 30, 2018 and December 31, 2017, respectively | 216 | 315 |
| Total property, plant, and equipment | 216,609 | 232,362 |
| INVESTMENTS | 3,819 | 3,819 |
| OTHER ASSETS | 800 | 800 |
| INTEREST RECEIVABLE—related party | 1,688 | 1,591 |
| TOTAL ASSETS | $ 333,201 | $ 313,675 |
| **LIABILITIES AND MEMBERS' CAPITAL** | | |
| CURRENT LIABILITIES: | | |
| Accounts payable | $ 987 | $ 269 |
| Accounts payable—related party | 6,069 | 4,258 |
| Accrued liabilities | 28,680 | 20,769 |
| Liability from price risk management activities | 12,890 | 4,200 |
| Current portion of asset retirement obligations | 777 | 330 |
| Interest payable | 357 | 856 |
| Total current liabilities | 49,760 | 30,682 |
| LONG-TERM LIABILITIES: | | |
| Asset retirement obligations | 13,015 | 15,227 |
| Long-term accounts payable—related party | 3,048 | 4,721 |
| Long-term notes payable—related party | 4,661 | 4,564 |
| Liability from price risk management activities | 1,918 | 1,477 |
| Long term interest payable | 20,310 | 6,201 |
| Long-term debt—net of original issuance discount and issuance costs of $9,126 and $12,676 at June 30, 2018 and December 31, 2017, respectively | 290,874 | 287,324 |
| Total long-term liabilities | 333,826 | 319,514 |
| COMMITMENTS AND CONTINGENCIES (NOTE 6) | | |
| MEMBERS' DEFICIT | (50,385) | (36,521) |
| TOTAL LIABILITIES AND MEMBERS' CAPITAL | $ 333,201 | $ 313,675 |

See accompanying notes to the unaudited condensed consolidated financial statements.

## DGE II MANAGEMENT, LLC AND SUBSIDIARY

**CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS**
**FOR THE SIX MONTHS ENDED JUNE 30, 2018 AND 2017**
**(In thousands)**
**(Unaudited)**

| | 2018 | 2017 |
|---|---|---|
| REVENUE: | | |
| Oil revenue | $ 81,893 | $ 67,543 |
| Gas revenue | 3,430 | 4,900 |
| NGL revenue | 3,429 | 3,283 |
| Total revenue | 88,752 | 75,726 |
| OPERATING COSTS AND EXPENSES: | | |
| Lease operating expenses | 15,433 | 15,779 |
| Workover expenses | 7,904 | 2,369 |
| Transportation expenses | 1,730 | 3,830 |
| Exploration expenses | 45 | 14 |
| Depreciation, depletion, and amortization | 30,022 | 38,488 |
| Inventory write-down | 511 | - |
| Accretion expense | 1,114 | 740 |
| General and administrative expenses | 665 | 110 |
| Other operating income | (71) | (1,537) |
| Total operating costs and expenses | 57,353 | 59,793 |
| OPERATING INCOME | 31,399 | 15,933 |
| OTHER EXPENSE | - | (1,794) |
| INTEREST EXPENSE, NET | (29,885) | (27,398) |
| INCOME (LOSS) FROM PRICE RISK MANAGEMENT ACTIVITIES | (15,378) | 6,829 |
| NET LOSS | $ (13,864) | $ (6,430) |

See accompanying notes to the unaudited condensed consolidated financial statements.

## DGE II MANAGEMENT, LLC AND SUBSIDIARY

**CONDENSED CONSOLIDATED STATEMENT OF MEMBERS' CAPITAL (DEFICIT)**
**(In thousands, except units)**
**(Unaudited)**

| | Units | Capital Contributions | Additional Paid-In Capital | Retained Deficit | Total |
|---|---|---|---|---|---|
| BALANCE—December 31, 2017 | 382,695 | $ 382,695 | $ 10,700 | $ (429,916) | $ (36,521) |
| Net loss | - | - | - | (13,864) | (13,864) |
| BALANCE—June 30, 2018 | 382,695 | $ 382,695 | $ 10,700 | $ (443,780) | $ (50,385) |

See accompanying notes to the unaudited condensed consolidated financial statements.

## DGE II MANAGEMENT, LLC AND SUBSIDIARY

**CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS**
**FOR THE SIX MONTHS ENDED JUNE 30, 2018 AND 2017**
**(In thousands)**
**(Unaudited)**

| | 2018 | 2017 |
|---|---|---|
| OPERATING ACTIVITIES: | | |
| Net loss | $ (13,864) | $ (6,430) |
| Adjustments to reconcile net loss to net cash provided by operating activities: | | |
| Depreciation, depletion, and amortization | 30,022 | 38,488 |
| Amortization of deferred financing costs | 3,576 | 3,398 |
| Non-cash fees on long-term debt | 1,500 | 1,500 |
| Non-cash loss on price risk management activities | 9,328 | (7,519) |
| Accretion expense | 1,114 | 740 |
| Inventory write-down | 511 | - |
| Settlement of asset retirement obligations | (2,879) | (369) |
| Long term interest payable | 14,109 | - |
| Net changes in assets and liabilities: | | |
| Accounts receivable | (3,504) | 7,367 |
| Accounts receivable—related party | 37 | (4,021) |
| Prepaid expenditures | (801) | 1 |
| Inventory | 357 | 944 |
| Interest receivable—related party | (97) | (97) |
| Accounts payable | 718 | (12,973) |
| Accounts payable—related party | (4,784) | (1,720) |
| Accrued liabilities | 6,900 | (1,128) |
| Interest payable | (499) | (148) |
| Interest payable—related party | 97 | 96 |
| Net cash provided by operating activities | 41,841 | 18,129 |
| INVESTING ACTIVITIES: | | |
| Capital expenditures for oil and gas properties | (7,350) | (9,921) |
| Proceeds from sale of property to related party | | 905 |
| Net cash used in investing activities | (7,350) | (9,016) |
| FINANCING ACTIVITIES: | | |
| Payment of debt issuance costs | (26) | (34) |
| Net cash used in financing activities | (26) | (34) |
| NET INCREASE IN CASH AND CASH EQUIVALENTS | 34,465 | 9,079 |
| CASH AND CASH EQUIVALENTS—Beginning of year | 51,524 | 31,921 |
| CASH AND CASH EQUIVALENTS—End of year | $ 85,989 | $ 41,000 |

See accompanying notes to the unaudited condensed consolidated financial statements.

## 1. NATURE OF BUSINESS AND BASIS OF PRESENTATION

**Nature of Business**—DGE II Management, LLC, a Delaware limited liability company, and its wholly owned subsidiary, Deep Gulf Energy II, LLC (collectively, the “Company”), were formed in 2007 to acquire, develop, operate, and manage deepwater exploitation and low-risk exploration projects located in the Gulf of Mexico and to produce and market oil, gas and natural gas liquids (NGL) from such properties. The Company has a perpetual existence unless and until dissolved and terminated.

**Basis of Presentation**— The interim financial information presented in the condensed consolidated financial statements included in this report is unaudited and, in the opinion of management, includes all adjustments of a normal recurring nature necessary to present fairly the condensed consolidated financial position as of June 30, 2018, the changes in the condensed consolidated statement of shareholders’ equity for the six months ended June 30, 2018, the condensed consolidated results of operations for the six months ended June 30, 2018 and 2017, and the condensed consolidated cash flows for the six months ended June 30, 2018 and 2017. The December 31, 2017 condensed consolidated balance sheet was derived from the 2017 audited financial statements. The results of the interim periods shown in this report are not necessarily indicative of the final results to be expected for the full year. These condensed consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States of America (“GAAP”). As permitted under those rules, certain notes or other financial information that are normally required by GAAP have been condensed or omitted from these interim condensed consolidated financial statements. These condensed consolidated financial statements and the accompanying notes should be read in conjunction with our audited consolidated financial statements as of and for the year ended December 31, 2017.

**Principles of Consolidation**—The condensed consolidated financial statements include the accounts of DGE II Management, LLC and its wholly owned subsidiary, Deep Gulf Energy II, LLC. All intercompany account balances and transactions have been eliminated.

## 2. ACCOUNTING POLICIES

**Use of Estimates**—The preparation of condensed consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities and disclosures of contingent liabilities at the date of the condensed consolidated financial statements and the related reported amounts of revenue and expenses. Estimates of reserves are used to determine depletion and to conduct impairment analysis. Estimating reserves has inherent uncertainty, including the projection of future rates of production and the timing of expenditures. Actual results could differ from those estimates. Management believes that its estimates are reasonable.

**Revenue Recognition and Imbalances**—Oil, gas and NGL revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and when collectability of the revenue is probable. The Company uses the sales method of accounting for gas production imbalances. The volumes of gas sold may differ from the volumes to which the Company is entitled, based on its interests in the properties. These differences create imbalances that are recognized as a liability only when the properties' estimated remaining reserves, net to the Company, will not be sufficient to enable the under-produced owner to recoup its entitled share through production. No receivables are recorded for those wells where the Company has taken less than its share of production. There were no imbalances recorded at June 30, 2018.

**Fair Value Measurements**—Current fair value accounting standards define fair value, establish a consistent framework for measuring fair value, and stipulate the related disclosure requirements for each major asset and liability category measured at fair value on either a recurring or nonrecurring basis. These standards also clarify that fair value is an exit price representing the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. The Company follows a three-level hierarchy, prioritizing and defining the types of inputs used to measure fair value depending on the degree to which they are observable as follows:

***Level 1***—Inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.

***Level 2***—Inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial statement or quoted prices (unadjusted) for identical assets or liabilities in inactive markets.

***Level 3***—Inputs to the valuation methodology are unobservable (little or no market data), which require the reporting entity to develop its own assumptions, and are significant to the fair value measurement.

Assets and liabilities measured at fair value are based on one or more of three valuation techniques. The valuation techniques are as follows:

***Market Approach***—Prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities.

***Cost Approach***—Amount that would be required to replace the service capacity of an asset (replacement cost).

***Income Approach***—Techniques to convert expected future cash flows to a single present value amount based on market expectations (including present value techniques, option-pricing and excess earnings models).

Authoritative guidance on financial instruments requires certain fair value disclosures to be presented. The estimated fair value amounts have been determined using available market information and valuation methodologies. Considerable judgment may be required in interpreting market data to develop the estimates of fair value for Level 3 inputs to the valuation methodology. The use of different assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

Financial instruments consisting of cash and cash equivalents, accounts receivable, and accounts payable are reported at their carrying amounts, which approximate fair value due to the short term nature of these instruments. The fair values of the Company's commodity derivatives are discussed in Note 7. Nonrecurring fair value measurements associated with oil, gas and NGL properties are discussed below.

**Property, Plant and Equipment -** The following table lists the total proved and unproved oil, gas and NGL properties as of June 30, 2018 and December 31, 2017 (in thousands):

| | June 30, 2018 | December 31, 2017 |
|---|---|---|
| Proved properties | $ 505,193 | $ 509,197 |
| Proved properties under development | 24,912 | -6,639 |
| Accumulated depletion | (314,275) | (284,352) |
| Total proved | 215,830 | 231,484 |
| | | |
| Unproved properties | 563 | 563 |
| | | |
| Total oil and gas properties - net of accumulated depletion | $ 216,393 | $ 232,047 |

**Recently Issued Accounting Standards**—In May 2014, the FASB issued Accounting Standards Update (ASU) 2014-09, *Revenue from Contracts with Customers*, which supersedes the revenue recognition requirements in ASC 605, *Revenue Recognition*, and industry-specific guidance in ASC 605 Subtopic 932, *Extractive Activities—Oil and Gas*, and requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. The Company is required to adopt the new standard in 2019 using one of two allowable methods: (1) a full retrospective method, which applies the standard to each period presented in the financial statements, or (2) the modified retrospective method, which applies the standard to only the most current period presented, with a cumulative effect adjustment recorded to retained earnings. The Company is continuing to evaluate the provisions of this ASU and has not yet decided upon the method of adoption or determined the impact this standard may have on its consolidated financial statements and related disclosures.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*, which significantly changes accounting for leases by requiring that lessees recognize a right-of-use asset and a related lease liability representing the obligation to make lease payments, for virtually all lease transactions. Additional disclosures about an entity's lease transactions will also be required. ASU 2016-02 defines a lease as "a contract, or part of a contract, that conveys the right to control the use of identified property, plant or equipment (an identified asset) for a period of time in exchange for consideration." ASU 2016-02 is effective for annual periods beginning after December 31, 2019 and early application is permitted. Lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented in the financial statements using a modified retrospective approach. The Company is continuing to evaluate the provisions of this ASU and has not yet determined the impact this standard may have on its consolidated financial statements and related disclosures.

In July 2018, the FASB issued ASU 2018-11, Leases *(Topic 842): Targeted Improvements*. ASU 2018-11 provide entities with an additional (and optional) transition method to adopt the new lease requirements by allowing entities to initially apply the requirements by recognizing a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. Consequently, an entity's reporting for the comparative periods presented in the financial statements in which the entity adopts the new lease requirements would continue to be in accordance with current GAAP (Topic 840). An entity electing this additional (and optional) transition method must provide the required Topic 840 disclosures for all periods that continue to be in accordance with Topic 840. The amendments do not change the existing disclosure requirements in Topic 840 (for example, they do not create interim disclosure requirements that entities previously were not required to provide. The new standard is effective for fiscal years beginning after periods beginning after December 31, 2019. Early adoption is permitted. The Company is continuing to evaluate the provisions of this ASU and has not yet decided upon the method of adoption or determined the impact this standard may have on its consolidated financial statements and related disclosures.

## 3. RELATED-PARTY TRANSACTIONS

The Company's controlling interest is owned by the same persons who own Deep Gulf Energy Management, LLC; Deep Gulf Energy LP; DGE III Management, LLC; and Deep Gulf Energy III, LLC. Deep Gulf Energy LP; DGE III Management, LLC; and the Company have entered into Master Services and License Agreements in which operating services, engineering services, and other cost-sharing services are provided to each other. General and administrative expenses are allocated between the parties based on time incurred. In 2015, DGE III Management, LLC, became the primary related party that allocated shared expense to the Company. Expenses allocated to the Company by related parties amounted to $0.7 million and $2.0 million for six the months ended June 30, 2018 and 2017, respectively.

As of June 30, 2018 the Company has a $4.7 million payable with a related-party associated with a one-time charge allocation by DGE III Management, LLC to the Company, of which $3.0 million is classified as long term accounts payable related party on the accompanying condensed consolidated balance sheet, and will be paid according the following schedule:

| | Long Term Payable |
|---|---|
| January 2020 | 1,630 |
| January 2021 | 1,418 |
| Long term accounts payable—related party | $ 3,048 |

No expenses were allocated by the Company to related parties for the six months ended June 30, 2018 and 2017.

These condensed consolidated financial statements have been prepared from the separate records maintained by DGE III Management, LLC and may not necessarily be indicative of the conditions that would have existed or the results of operations if the Company had been operated as an unrelated company.

From time to time, the Company enters into notes receivable bearing simple interest at 6.5% with management members to fund capital contributions, as allowed by the members' equity agreements. These notes have no maturity date. Due to the nature of the notes, they are reflected in the accompanying condensed consolidated financial statements as a reduction of equity. As of June 30, 2018, these notes totaled $3.0 million. Interest income related to these notes amounted to $97 thousand for both the six months ended June 30, 2018 and 2017.

## 4. DEBT

In December 2015, the Company amended its credit agreement ("December 2015 Credit Agreement") to increase the term loan amount to $300 million, and drew the entire available commitment amount at closing. Amounts outstanding bear interest at the Eurodollar rate or the base prime rate plus a margin, but in no case less than 14.5% per annum. In addition, the borrower must pay an existing lender fee of 1% on the $225 million that was outstanding prior to the refinance on the earlier of September 30, 2018 or the date the Company pays off all of the outstanding debt. In addition, the Company must pay a termination fee to the lenders ranging from $3 million to $9 million on the earlier of September 30, 2018 or the date the Company pays off all of the outstanding debt. The termination fee is recorded in accrued liabilities as of June 30, 2018 and December 31, 2017. The termination fee becomes due and payable according to the following schedule:

| **Date** | **Fee (in thousands)** |
|---|---|
| December 30, 2015 through December 31, 2016 | $ 3,000 |
| January 1, 2017 through June 30, 2017 | 4,500 |
| July 1, 2017 through December 31, 2017 | 6,000 |
| January 1, 2018 through June 30, 2018 | 7,500 |
| July 1, 2018 through September 30, 2018 | 9,000 |

In December 2017, the Company further amended its credit agreement ("December 2017 Credit Agreement") to delay repayment of the $300 million in principal payments until September 30, 2019 from September 30, 2018. Amounts outstanding under the December 2017 Credit Agreement bear interest at the Eurodollar rate or the base prime rate plus a margin, but in no case less than 15.5% per annum. The December 2017 Credit Agreement allows the Company to pay in kind ("PIK") 9% per annum of the specified interest; any PIK interest will be added to the principal amount of the outstanding loans. PIK interest recorded at June 30, 2018 and December 31, 2017 totaled $20.3 million and $6.2 million, respectively, and is classified as long term interest payable. PIK interest, along with the principal amounts, is due on September 30, 2019.

As part of the December 2017 Credit Agreement there have been no changes to the termination fees that were included in the December 2015 Credit agreement.

Additionally, in accordance with the December 2017 Credit Agreement, the Company must pay an amendment and extension fee of $3 million due on the earlier of September 30, 2018 or the date the Company pays off all of the outstanding debt, and the Company issued certain of the lenders with warrants to purchase 103,257.19 shares of Deep Gulf Energy II, LLC with a strike price of $0.01, amounting to 20% of the total equity shares outstanding at June 30, 2018. As long as the obligations under the December 2017 Credit Agreement remain outstanding, the Company must issue additional warrants to purchase shares of Deep Gulf Energy II, LLC with the strike price of $0.01 according to the following schedule:

| **Date** | **Additional Warrants** | **Percentage Ownership** |
|---|---|---|
| September 30, 2018 | 34,784.33 | 5% |
| December 31, 2018 | 39,976.02 | 5 |
| March 31, 2019 | 46,423.77 | 5 |
| June 30, 2019 | 119,630.49 | 10 |
| | 240,814.61 | 25% |

The Company incurred $10.7 million in costs associated with the December 2017 Credit Agreement, of which $7.8 million in lender fees were recognized as a reduction to debt, and the remaining $2.9 million in third party costs were expensed in December 2017 in accordance with ASC 470-50 *Debt Modification*. Prior to amending its credit agreement with the December 2017 Credit Agreement, the Company had $5.7 million of unamortized debt issuance costs associated with the December 2015 Credit Agreement recognized as a reduction of debt in the accompanying condensed consolidated balance sheet. As a result of ASC 470-50 *Debt Modification*, at December 31, 2017, $5.5 million of the unamortized debt issuance costs remained capitalized as reduction of debt in the accompanying condensed consolidated balance sheet, and $0.2 million was expensed.

The Company's obligations under the credit agreement are secured by liens on all of Deep Gulf Energy II, LLC's working interests in its oil, gas and NGL properties. The credit agreement contains customary financial covenants requiring certain ratios to be met on a quarterly, semiannual and annual basis. Other covenants contained in the credit agreement restrict, among other things, capital expenditures, asset dispositions, mergers and acquisitions, dividends, additional debt, liens, investments, and affiliate transactions.

The credit agreement also contains customary events of default. The Company was in compliance with these covenants at June 30, 2018.

## 5. SUPPLEMENTARY CASH FLOW INFORMATION

Supplementary non-cash investing and financing activities information for the six months ended June 30, 2018 and 2017 is as follows (in thousands):

| | 2018 | 2017 |
|---|---|---|
| Capital expenditures in accounts payable | $ - | $ 5,428 |
| Capital expenditures in accounts payable related party | (4,922) | - |
| Accrued capital expenditures | - | 743 |
| Non-cash deferred financing costs | 1,500 | 1,500 |

## 6. COMMITMENTS AND CONTINGENCIES

**Insurance**—The Company has insurance policies to mitigate its risk of loss associated with its operations, and it maintains the coverages and amounts of insurance believed to be prudent based on reasonably estimated loss potential. However, not all of the Company's business activities can be insured at the levels it desires because of either limited market availability or unfavorable economics (limited coverage for the underlying cost).The Company's general property damage insurance provides varying ranges of coverage based upon several factors, including well counts and cost of replacement facilities. The Company's general liability insurance program provides a limit of $150 million (for its interest) for each occurrence and in the aggregate and includes varying deductibles, and its Offshore Pollution Act insurance is also subject to a maximum of $150 million for each occurrence and in the aggregate and includes a $100,000 (100%) retention. The Company separately maintains an operator's extra expense policy for wells being drilled with additional coverage for an amount up to $1 billion and for producing wells with additional coverage for an amount up to $500 million that would cover costs involved in making a well safe after a blowout or getting the well under control, re-drilling a well to the depth reached prior to the well being out of control or blown out, costs for plugging and abandoning the well, costs for cleanup and containment and for damages caused by contamination and pollution.

The Company customarily has reciprocal agreements with its customers and vendors in which each contracting party is responsible for its respective personnel. Under these agreements, the Company is indemnified against third party claims related to the injury or death of its customers' or vendors' personnel. Although there can be no assurance that the amount of insurance the Company carries is sufficient to protect it fully in all events, the Company believes that its insurance protection is adequate for its business operations.

**Performance Obligations**—Regulations with respect to offshore operations govern, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells, and removal of facilities. As of June 30, 2018, the Company had secured performance bonds totaling approximately $28.9 million for its supplemental bonding requirements stipulated by the Bureau of Ocean Energy Management related to costs anticipated for the plugging and abandonment of certain wells and the removal of certain facilities in its Gulf of Mexico fields. These performance bonds are uncollateralized. If the Company were to have to obtain additional performance bonds for other reasons, it cannot assure that it would be able to secure any such additional performance bonds on acceptable commercial terms or at all.

Additionally, the Company has an uncollateralized bond to a third party for the plugging and abandonment of Nancy property located at Garden Banks block 463 that the Company exited in 2017. On January 4, 2017 the Company executed an agreement withdrawing from the Nancy property located at Garden Banks block 463. The agreement has an effective date of August 19th, 2016. As part of the agreement, the Company was required to post a performance bond with the purchaser as oblige for the Company's estimated share of certain future abandonment expenses as the Company retained financial responsibility and liability for its proportionate share of certain of the abandonment liabilities. The Company posted such performance bond on January 4, 2017 in the amount of $2.4 million.

**Legal Proceedings and Other Contingencies**—The Company is a party to a Deferred Amount Payment Agreement (DAPA) with Energy Resource Technology GOM, Inc. (ERT) related to the Danny Noonan project (Project). Through this DAPA, the Company is required to reimburse ERT $14.5 million from the Project's net cash flow in monthly installments if the gross production from the Project equals or exceeds 265 BCFE. As of June 30, 2018, the Company does not expect gross production from the Project to equal or exceed 265 BCFE. As of June 30, 2018, the Company had no liability recorded for this DAPA.

The Company or its subsidiary may be named defendants in legal proceedings that arise in the ordinary course of business. There are also other regulatory rules and orders in various stages of adoption, review and/or implementation. For each of these matters, the Company evaluates the merits of the case or claim, its exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. The Company discloses matters that are reasonably possibly of negative outcome and are material to its condensed consolidated financial statements. If the Company determines that an unfavorable outcome is probable and is reasonably estimable, the Company accrues for such reasonably estimable outcome. While the outcome of the current matters cannot be predicted with certainty and there are still uncertainties related to the costs the Company may incur, based upon its evaluation and experience, the Company will establish appropriate accruals as it believes are necessary. It is possible; however, that new information or future developments could require the Company to reassess its potential exposure related to these matters and record or adjust its accruals accordingly, and these adjustments could be material.

## 7. PRICE RISK MANAGEMENT ACTIVITIES

**Objectives and Strategies**—The Company is exposed to fluctuations in oil, gas and NGL prices on its production. The Company believes it is prudent to manage the variability in cash flows on a portion of its oil production. The Company utilizes various types of derivative financial instruments, including swaps, costless collars and options, to manage fluctuations in cash flows resulting from changes in commodity prices.

**Commodity Derivative Instruments**—As of June 30, 2018, the Company had entered into commodity contracts with the following terms:

| Commodity Contract Type | Period Covered | Contracted Volume Oil (MBbls) | Fixed Price | Floor Price | Ceiling Price |
|---|---|---|---|---|---|
| Puts | Jul–Dec 2018 | 284.1 | $ 53.00 | | |
| Swaps | Jul–Dec 2018 | 412.8 | 56.08 | | |
| Swaps | Jul 2018–Sep 2019 | 560.5 | 53.53 | | |
| Collars | Jul–Dec 2018 | 57.0 | | $ 62.29 | $ 66.35 |
| Collars | Jan–Jun 2019 | 338.8 | | 57.77 | 63.30 |
| Swaps | Jul 2018 | 4.0 | 68.00 | | |

The following table sets forth the fair values and classification of the Company's outstanding derivatives at June 30, 2018 and December 31, 2017 (in thousands):

| | Gross Amount of Recognized Asset (Liability) June 30, 2018 | Gross Amount of Recognized Asset (Liability) December 31, 2017 |
|---|---|---|
| Current derivative asset | $ 49 | $ 735 |
| Current derivative liability | (12,890) | (4,200) |
| Net current derivative liability | (12,841) | (3,465) |
| Long term derivative asset | $ - | $ - |
| Long term derivative liability | (1,918) | (1,477) |
| Net long term derivative liability | $ (1,918) | $ (1,477) |

The Company has entered into master netting arrangements with its counterparties. The amounts above are presented on a net basis in its balance sheets when such amounts are with the same counterparty. The Company recognized a ($6.1) million and a ($0.7) million in realized loss related to its derivative financial instruments in the six months ended June 30, 2018 and 2017, respectively. The Company recognized a ($9.3) million unrealized loss and a $7.5 million unrealized gain related to its derivative financial instruments in the six months ended June 30, 2018 and 2017, respectively.

The Company is subject to the risk of loss on its derivative financial instruments that it would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. The Company enters into International Swaps and Derivative Association agreements with counterparties to mitigate this risk, when possible. The Company also maintains credit policies with regard to its counterparties to minimize its overall credit risk. These policies require (i) the evaluation of potential counterparties' financial condition to determine their credit worthiness; (ii) the regular monitoring of oil and natural gas counterparties' credit exposures; (iii) comprehensive credit reviews on significant counterparties from physical and financial transactions on an ongoing basis;

(iv) the utilization of contractual language that affords the Company netting or set off opportunities to mitigate exposure risk; and (v) potentially requiring counterparties to post cash collateral, parent guarantees or letters of credit to minimize credit risk. The Company's assets or liabilities from derivatives at June 30, 2018 represent derivative financial instruments from one counterparty; which is a financial institution that has an "investment grade" (minimum Standard & Poor's rating of BBB- or better) credit rating and is party under the Company's credit agreement. The Company enters into derivatives directly with this third party and, subject to the terms of the credit agreement, are not required to post collateral or other securities for credit risk in relation to the derivative financial interests.

**Fair Value Measurement**

The following table presents the fair value hierarchy table for the Company's assets and liabilities that are required to be measured at fair value on a recurring basis (in thousands):

| | Fair Value | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|
| **At June 30, 2018:** | | | | |
| Assets—oil, natural gas and natural gas liquids derivatives | $ 49 | $ - | $ 49 | $ - |
| Liabilities—oil, natural gas and natural gas liquids derivatives | (14,808) | - | (14,808) | - |
| | | | | |
| **At December 31, 2017:** | | | | |
| Assets—oil, natural gas and natural gas liquids derivatives | $ 735 | $ - | $ 735 | $ - |
| Liabilities—oil, natural gas and natural gas liquids derivatives | (5,677) | - | (5,677) | - |

The Company's derivatives consist of over–the–counter ("OTC") contracts which are not traded on a public exchange. As the fair value of these derivatives is based on inputs using market prices obtained from independent brokers or determined using quantitative models that use as their basis readily observable market parameters that are actively quoted and can be validated through external sources, including third party pricing services, brokers and market transactions, the Company has categorized these derivatives as Level 2. The Company values these derivatives using the income approach using inputs such as the forward curve for commodity prices based on quoted market prices and prospective volatility factors related to changes in the forward curves and yield curves based on money market rates and interest rate swap data, such as forward LIBOR curves. The Company's estimates of fair value have been determined at discrete points in time based on relevant market data. There were no changes in valuation techniques or related inputs in 2018.

## 8. SUBSEQUENT EVENTS

Subsequent events were evaluated through Septemeber 14, 2018, which is the date these condensed consolidated financial statements were available to be issued.

On August 3rd, 2018, the Company along with Deep Gulf Energy Management, LLC; Deep Gulf Energy LP; DGE III Management, LLC; and Deep Gulf Energy III, LLC entered into a securities purchase agreement with Kosmos Energy Gulf of Mexico, LLC to sell all shareholder interests in the Company; Deep Gulf Energy Management, LLC; Deep Gulf Energy LP; DGE II Management, LLC; and Deep Gulf Energy II, LLC for a total consideration of $1.225 billion, subject to certain adjustments. This transaction is expected to close during the third quarter of 2018.

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**Exhibit 99.6**

# DGE III Management, LLC and Subsidiaries

Unaudited Condensed Consolidated Financial Statements as of June 30, 2018 and December 31, 2017, and for the Six Months Ended June 30, 2018 and 2017

## DGE III MANAGEMENT, LLC AND SUBSIDIARIES

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## DGE III MANAGEMENT, LLC AND SUBSIDIARIES

**CONDENSED CONSOLIDATED BALANCE SHEETS**
**(In thousands)**
**(Unaudited)**

| | June 30, 2018 | December 31, 2017 |
|---|---|---|
| **ASSETS** | | |
| CURRENT ASSETS: | | |
| Cash and cash equivalents | $ 84,067 | $ 24,904 |
| Accounts receivable | 50,823 | 59,341 |
| Accounts receivable—related party | 6,127 | 3,545 |
| Prepaid expenditures and other current assets | 7,732 | 12,708 |
| Inventory | 15,879 | 26,903 |
| Total current assets | 164,628 | 127,401 |
| PROPERTY, PLANT, AND EQUIPMENT: | | |
| Oil and gas properties, successful efforts method—net of accumulated depletion of $109,588 and $71,659 at June 30, 2018 and December 31, 2017, respectively | 286,103 | 339,831 |
| Other property, plant, and equipment, net of accumulated depreciation of $1,154 and $743 at June 30, 2018 and December 31, 2017, respectively | 1,686 | 1,563 |
| Total property, plant, and equipment | 287,789 | 341,394 |
| OTHER ASSETS | 12,123 | 12,123 |
| DEFERRED FINANCING COSTS—Net amortization of $811 and $555 at June 30, 2018 and December 31, 2017, respectively | 513 | 769 |
| LONG TERM RECEIVABLE—Related-party | 3,048 | 4,721 |
| INTEREST RECEIVABLE—Related-party | 398 | 331 |
| TOTAL ASSETS | $ 468,499 | $ 486,739 |
| **LIABILITIES AND MEMBERS' CAPITAL** | | |
| CURRENT LIABILITIES: | | |
| Accounts payable | $ 7,607 | $ 8,695 |
| Accounts payable - related party | 1,052 | - |
| Accrued liabilities | 59,981 | 82,884 |
| Liability from price risk management—current | 27,611 | 9,775 |
| Total current liabilities | 96,251 | 101,354 |
| LONG-TERM LIABILITIES: | | |
| Asset retirement obligations | 18,537 | 17,742 |
| Long-term notes payable—related party | 4,857 | 4,789 |
| Liability from price risk management | 4,014 | 3,318 |
| Total long-term liabilities | 27,408 | 25,849 |
| COMMITMENTS AND CONTINGENCIES (NOTE 7) | | |
| MEMBERS' CAPITAL | 344,840 | 359,536 |
| TOTAL LIABILITIES AND MEMBERS' CAPITAL | $ 468,499 | $ 486,739 |

See accompanying notes to the unaudited condensed consolidated financial statements.

## DGE III MANAGEMENT, LLC AND SUBSIDIARIES

**CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS**
**FOR THE SIX MONTHS ENDED JUNE 30, 2018 AND 2017**
**(In thousands)**
**(Unaudited)**

| | 2018 | 2017 |
|---|---|---|
| REVENUE: | | |
| Oil revenue | $ 129,447 | $ 62,556 |
| Gas revenue | 5,150 | 3,574 |
| NGL revenue | 4,688 | 2,828 |
| Total revenue | 139,285 | 68,958 |
| OPERATING COSTS AND EXPENSES: | | |
| Lease operating expenses | 22,783 | 12,191 |
| Workover expenses | 4,076 | - |
| Transportation expenses | 4,006 | 2,578 |
| Exploration expenses | 48,756 | 2,483 |
| Depreciation, depletion, and amortization | 39,028 | 25,395 |
| Impairment | 1,044 | - |
| Accretion expense | 794 | 187 |
| Inventory write-down | 2,490 | - |
| General and administrative expenses | 8,247 | 6,394 |
| Other operating income | (4,781) | (1,496) |
| Total operating costs and expenses | 126,443 | 47,732 |
| OPERATING INCOME | 12,842 | 21,226 |
| INTEREST AND OTHER EXPENSE—Net | (502) | (513) |
| GAIN (LOSS) FROM PRICE RISK MANAGEMENT ACTIVITIES | (29,389) | 3,630 |
| NET INCOME (LOSS) | $ (17,049) | $ 24,343 |

See accompanying notes to the unaduited condensed consolidated financial statements.

## DGE III MANAGEMENT, LLC AND SUBSIDIARIES

**CONDENSED CONSOLIDATED STATEMENT OF MEMBERS' CAPITAL**
**(In thousands, except units)**
**(Unaudited)**

| | Units | Capital Contributions | Additional Paid In Capital | Retained Deficit | Total |
|---|---|---|---|---|---|
| BALANCE—December 31, 2017 | 473,415 | $ 468,575 | $ 13,793 | $ (122,832) | $ 359,536 |
| Equity-based compensation | - | - | 2,353 | - | 2,353 |
| Net loss | - | - | - | (17,049) | (17,049) |
| BALANCE—June 30, 2018 | 473,415 | $ 468,575 | $ 16,146 | $ (139,881) | $ 344,840 |

See accompanying notes to the unaudited condensed consolidated financial statements.

## DGE III MANAGEMENT, LLC AND SUBSIDIARIES

**CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS**
**FOR THE SIX MONTHS ENDED JUNE 30, 2018 AND 2017**
**(In thousands)**
**(Unaudited)**

| | 2018 | 2017 |
|---|---|---|
| CASH FLOWS FROM OPERATING ACTIVITIES: | | |
| Net income (loss) | $ (17,049) | $ 24,343 |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | |
| Depreciation, depletion and amortization | 39,028 | 25,395 |
| Exploratory dry hole and impairment | 48,975 | - |
| Amortization of deferred financing costs | 256 | 259 |
| Accretion expense | 794 | 187 |
| Inventory write-down | 2,490 | - |
| Gain on sale of property | (5) | - |
| Unrealized (gain) loss from price risk management | 18,532 | (2,668) |
| Equity-based compensation | 2,353 | 2,355 |
| Net changes in assets and liabilities: | | |
| Accounts receivable | 8,518 | 22,004 |
| Accounts receivable—related party | (909) | 2,185 |
| Prepaid expenditures | (1,218) | 5,853 |
| Inventory | 6,083 | (162) |
| Interest receivable—related party | (67) | (68) |
| Accounts payable | 4,752 | (5,375) |
| Accounts payable—related party | 1,052 | 4,640 |
| Accrued liabilities | (22,544) | (12,087) |
| Interest payable on long term notes payable—related party | 68 | 68 |
| Net cash provided by operating activities | 91,109 | 66,929 |
| CASH FLOWS FROM INVESTING ACTIVITIES: | | |
| Capital expenditures for oil and gas properties | (31,412) | (44,182) |
| Capital expenditures for other property, plant and equipment | (534) | (559) |
| Net cash used in investing activities | (31,946) | (44,741) |
| CASH FLOWS FROM FINANCING ACTIVITIES: | | |
| Payment of debt issuance costs | - | (69) |
| Net cash used in financing activities | - | (69) |
| NET INCREASE IN CASH AND CASH EQUIVALENTS | 59,163 | 22,119 |
| CASH AND CASH EQUIVALENTS—Beginning of period | 24,904 | 11,028 |
| CASH AND CASH EQUIVALENTS—End of period | $ 84,067 | $ 33,147 |

See accompanying notes to the unaudited condensed consolidated financial statements.

## 1. NATURE OF BUSINESS AND BASIS OF PRESENTATION

**Nature of Business**—DGE III Management, LLC, a Delaware limited liability company, and its wholly owned subsidiary, Deep Gulf Energy III, LLC were formed and commenced operations on June 30, 2014. Additionally, during 2016 the Company acquired Deep Gulf Operating, LLC from Deep Gulf Energy LP for no consideration. Deep Gulf Operating LLC has no assets or liabilities. Collectively, DGE III Management, LLC, Deep Gulf Energy III, LLC and Deep Gulf Operating, LLC are referred to as the “Company” throughout these notes to the condensed consolidated financial statements. The purpose of the Company is to acquire, develop, operate, and manage deepwater exploitation and low-risk exploration projects located in the Gulf of Mexico and to produce and market oil, gas and natural gas liquids (NGL) produced from such properties. The Company has a perpetual existence unless and until dissolved and terminated.

**Basis of Presentation**— The interim-period financial information presented in the condensed consolidated financial statements included in this report is unaudited and, in the opinion of management, includes all adjustments of a normal recurring nature necessary to present fairly the condensed consolidated financial position as of June 30, 2018, the changes in the condensed consolidated statement of shareholders’ equity for the six months ended June 30, 2018, the condensed consolidated results of operations for the six months ended June 30, 2018 and 2017, and the condensed consolidated cash flows for the six months ended June 30, 2018 and 2017. The December 31, 2017 condensed consolidated balance sheet was derived from the 2017 audited financial statements. The results of the interim periods shown in this report are not necessarily indicative of the final results to be expected for the full year. The condensed consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States of America (“GAAP”). As permitted under those rules, certain notes or other financial information that are normally required by GAAP have been condensed or omitted from these interim condensed consolidated financial statements. These condensed consolidated financial statements and the accompanying notes should be read in conjunction with our audited consolidated financial statements as of and for the year ended December 31, 2017.

**Principles of Consolidation**—The condensed consolidated financial statements include the accounts of DGE III Management, LLC and its wholly owned subsidiaries. All intercompany account balances and transactions have been eliminated.

## 2. ACCOUNTING POLICIES

**Use of Estimates**—The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities and disclosures of contingent liabilities at the date of the financial statements and the related reported amounts of revenue and expenses. Estimates of reserves are used to determine depletion and to conduct impairment analysis. Estimating reserves has inherent uncertainty, including the projection of future rates of production and the timing of expenditures. Actual results could differ from those estimates. Management believes that its estimates are reasonable.

**Revenue Recognition and Imbalances**—Oil, gas and NGL revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and when collectability of the revenue is probable. The Company uses the sales method of accounting for gas production imbalances. The volumes of gas sold may differ from the volumes to which the Company is entitled, based on its interests in the properties. These differences create imbalances that are recognized as a liability only when the properties' estimated remaining reserves, net to the Company, will not be sufficient to enable the under-produced owner to recoup its entitled share through production. No receivables are recorded for those wells where the Company has taken less than its share of production. There were no imbalances recorded at June 30, 2018.

**Fair Value Measurements**—Current fair value accounting standards define fair value, establish a consistent framework for measuring fair value, and stipulate the related disclosure requirements for each major asset and liability category measured at fair value on either a recurring or nonrecurring basis. These standards also clarify that fair value is an exit price representing the amount that would be received to sell an asset, or paid to transfer a liability, in an orderly transaction between market participants. The Company follows a three-level hierarchy, prioritizing and defining the types of inputs used to measure fair value depending on the degree to which they are observable as follows:

***Level 1***—Inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.

***Level 2***—Inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial statement or quoted prices (unadjusted) for identical assets or liabilities in inactive markets.

***Level 3***—Inputs to the valuation methodology are unobservable (little or no market data), which require the reporting entity to develop its own assumptions, and are significant to the fair value measurement.

Assets and liabilities measured at fair value are based on one or more of three valuation techniques. The valuation techniques are as follows:

***Market Approach***—Prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities.

***Cost Approach***—Amount that would be required to replace the service capacity of an asset (replacement cost).

***Income Approach***—Techniques to convert expected future cash flows to a single present value amount based on market expectations (including present value techniques, option-pricing, and excess earnings models).

Authoritative guidance on financial instruments requires certain fair value disclosures to be presented. The estimated fair value amounts have been determined using available market information and valuation methodologies. Considerable judgment may be required in interpreting market data to develop the estimates of fair value for Level 3 inputs to the valuation methodology. The use of different assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

Financial instruments consisting of cash and cash equivalents, accounts receivable, and accounts payable are reported at their carrying amounts, which approximate fair value due to the short-term nature of these instruments. The fair values of the Company's commodity derivatives are discussed in Note 8. Nonrecurring fair value measurements associated with oil, gas and NGL properties are discussed below.

**Property, Plant and Equipment -** The following table lists the total proved and unproved oil, gas and NGL properties as of June 30, 2018 and December 31, 2017 (in thousands):

| | June 30, 2018 | December 31, 2017 |
|---|---|---|
| Proved properties | $ 350,719 | $ 354,424 |
| Proved properties under development | 19,137 | 31,097 |
| Accumulated depletion | (109,588) | (71,659) |
| Total proved | 260,268 | 313,862 |
| Unproved properties | 25,835 | 25,969 |
| Total oil and gas properties—net of accumulated depletion | $ 286,103 | $ 339,831 |

**Recently Issued Accounting Standards**—In May 2014, the FASB issued Accounting Standards Update (ASU) 2014-09, *Revenue from Contracts with Customers*, which supersedes the revenue recognition requirements in ASC 605, *Revenue Recognition*, and industry-specific guidance in ASC 605 Subtopic 932, *Extractive Activities—Oil and Gas*, and requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. The Company is required to adopt the new standard in 2019 using one of two allowable methods: (1) a full retrospective method, which applies the standard to each period presented in the financial statements, or (2) the modified retrospective method, which applies the standard to only the most current period presented, with a cumulative effect adjustment recorded to retained earnings. The Company is continuing to evaluate the provisions of this ASU and has not yet decided upon the method of adoption or determined the impact this standard may have on its consolidated financial statements and related disclosures.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*, which significantly changes accounting for leases by requiring that lessees recognize a right-of-use asset and a related lease liability representing the obligation to make lease payments, for virtually all lease transactions. Additional disclosures about an entity's lease transactions will also be required. ASU 2016-02 defines a lease as "a contract, or part of a contract, that conveys the right to control the use of identified property, plant or equipment (an identified asset) for a period of time in exchange for consideration." ASU 2016-02 is effective for annual periods beginning after December 31, 2019 and early application is permitted. Lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented in the financial statements using a modified retrospective approach. The Company is continuing to evaluate the provisions of this ASU and has not yet determined the impact this standard may have on its consolidated financial statements and related disclosures.

In July 2018, the FASB issued ASU 2018-11, Leases *(Topic 842): Targeted Improvements*. ASU 2018-11 provide entities with an additional (and optional) transition method to adopt the new lease requirements by allowing entities to initially apply the requirements by recognizing a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. Consequently, an entity's reporting for the comparative periods presented in the financial statements in which the entity adopts the new lease requirements would continue to be in accordance with current GAAP (Topic 840). An entity electing this additional (and optional) transition method must provide the required Topic 840 disclosures for all periods that continue to be in accordance with Topic 840. The amendments do not change the existing disclosure requirements in Topic 840 (for example, they do not create interim disclosure requirements that entities previously were not required to provide. The new standard is effective for fiscal years beginning after periods beginning after December 31, 2019. Early adoption is permitted. The Company is continuing to evaluate the provisions of this ASU and has not yet decided upon the method of adoption or determined the impact this standard may have on its consolidated financial statements and related disclosures.

## 3. EXPLORATORY WELL COSTS

The Company's net changes in capitalized exploratory well costs for the six months ended June 30, 2018 are presented below (in thousands):

| | June 30, 2018 | December 31, 2017 |
|---|---|---|
| Balance at January 1, 2018 | $ 28,552 | $ 48,433 |
| Additions pending the determination of proved reserves | - | 28,552 |
| Reclassifications to proved properties | - | (48,433) |
| Costs charged to expense | (28,552) | - |
| Balance at June 30, 2018 | $ - | $ 28,552 |

The following table provides information about exploratory well costs capitalized pending the determination of proved reserves as of June 30, 2018 and December 31, 2017 (in thousands):

| | June 30, 2018 | December 31, 2017 |
|---|---|---|
| Exploratory well costs capitalized for less than one year | $ - | $ 28,552 |
| Exploratory well costs capitalized for greater than one year | - | - |
| Total capitalized exploratory well costs | $ - | $ 28,552 |

One well, the Mississippi Canyon block 116 well (the "Rampart Deep Well") comprised $28.6 million of exploratory well costs capitalized at December 31, 2017. The Company drilled the Rampart Deep Well in 2017. The Rampart Deep Well had two primary target sands, the M57 sand and the M58 sand. Based on the successful discovery in the M57 sand, the Company decided to drill a second well Mississippi Canyon block 72 (the "Derbio Well") adjacent to Rampart Deep Well in 2018. In 2018, the Company returned to location and drilled the Derbio Well. After evaluation of pay in the M57 sand, the Company determined the Derbio Well was a dry hole, and $16.9 million in exploratory well costs for the Derbio Well were charged to expense. Additionally, as a result of the Derbio Well results, $30.7 million in exploratory well costs, including amounts previously capitalized at December 31, 2017, for the Rampart Deep Well were charged to expense.

## 4. DEBT

On December 15, 2016, the Company entered into a $150 million Bank Credit Facility with an initial borrowing base of $50 million. The borrowing base is redetermined semi-annually with a maximum borrowing base of $150 million. The Bank Credit Facility bears interest based on the borrowing base usage, at the applicable London InterBank Offered Rate, plus applicable margins ranging from 6.0% to 8.0% or an alternate base rate, based on the federal funds effective rate plus applicable margins ranging from 5.0% to 7.0%. In addition, the Company is obligated to pay a commitment fee rate based on the borrowing base usage of 1.0% to 2.0%. The Bank Credit Facility is secured by substantially all of the oil, gas and NGL assets of the Company. As of June 30, 2018, the Company has not drawn on the Bank Credit Facility. The Bank Credit Facility is fully and unconditionally guaranteed by its wholly-owned subsidiary, Deep Gulf Energy III, LLC.

The credit agreement contains customary financial covenants requiring certain ratios to be met on a quarterly, semiannual and annual basis. Other covenants contained in the credit agreement restrict, among other things, asset dispositions, mergers and acquisitions, dividends, additional debt, liens, investments, and affiliate transactions. The credit agreement also contains customary events of default. The Company was in compliance with all covenants at June 30, 2018.

The Company recognized $1.2 million in debt issuance costs associated with the Bank Credit Facility in 2016, all of which were recognized as a deferred financing asset on the condensed consolidated balance sheets at June 30, 2018 and December 31, 2017 in accordance with ASU 2015-03. The deferred financing costs on the Bank Credit Facility are being amortized on a straight-line basis over the life of the Bank Credit Facility, which amortization is not materially different than if the Company had utilized the effective interest method. Cash paid for interest on credit facility was $253 thousand and $250 thousand for the six months ended June 30, 2018 and 2017, respectively.

## 5. RELATED PARTY TRANSACTIONS

The Company’s controlling interest is owned by the same persons who own Deep Gulf Energy Management, LLC; Deep Gulf Energy LP; DGE II Management, LLC; and Deep Gulf Energy II, LLC. Deep Gulf Energy LP; DGE II Management, LLC; and the Company and related parties listed above have entered into Master Services and License Agreements in which operating services, engineering services, and other cost-sharing services are provided to each other. General and administrative expenses are allocated between the parties based on time incurred. In 2015, the Company became the primary related party that allocated shared expense to the related parties. Expenses allocated by the Company to related parties amounted to $0.7 million and $2.0 million for the six months ended June 30, 2018 and 2017, respectively.

As of June 30, 2018, the Company has a $4.7 million receivable from a related-party associated with a one-time charge allocation by the Company to Deep Gulf Energy II, LLC, of which $3.0 million is classified as long-term receivable related-party on the accompanying condensed consolidated balance sheet and will be paid according the following schedule:

| | Long Term Receivable |
|---|---|
| January 2020 | $ 1,630 |
| January 2021 | 1,418 |
| Long term receivable—related-party | $ 3,048 |

These condensed consolidated financial statements have been prepared from the separate records maintained by the Company and may not necessarily be indicative of the conditions that would have existed or the results of operations if the Company had been operated as an unrelated company.

From time to time, the Company enters into notes receivable bearing simple interest at 3.1% with management members to fund capital contributions, as allowed by the members’ equity agreements. These notes have no maturity date. Due to the nature of the notes, they are reflected in the accompanying condensed consolidated financial statements as a reduction of equity. These notes totaled $4.4 million at June 30, 2018. Interest income related to these notes amounted to $67 thousand for both the six months ended June 30, 2018 and 2017.

## 6. SUPPLEMENTARY CASH FLOW INFORMATION

Supplementary noncash investing activities information for the six months ended June 30, 2018 and 2017 consisted of the following (in thousands):

| | 2018 | 2017 |
|---|---|---|
| Capital expenditures in accounts payable | $ 1,382 | $ 4,323 |
| Accrued capital expenditures | 2,919 | 5,021 |
| Prepaid capital expenditures | 678 | 1,496 |

## 7. COMMITMENTS AND CONTINGENCIES

**Insurance**—The Company has insurance policies to mitigate its risk of loss associated with its operations, and it maintains the coverages and amounts of insurance believed to be prudent based on reasonably estimated loss potential. However, not all of the Company's business activities can be insured at the levels it desires because of either limited market availability or unfavorable economics (limited coverage for the underlying cost).

The Company's general property damage insurance provides varying ranges of coverage based upon several factors, including well counts, and cost of replacement facilities. The Company's general liability insurance program provides a limit of $150 million (for its interest) for each occurrence and in the aggregate and includes varying deductibles, and its Offshore Pollution Act insurance is also subject to a maximum of $150 million for each occurrence and in the aggregate and includes a $100,000 (100%) retention. The Company separately maintains an operator's extra expense policy for wells being drilled with additional coverage for an amount up to $1.0 billion and for producing wells with additional coverage for an amount up to $500 million that would cover costs involved in making a well safe after a blowout or getting the well under control, re-drilling a well to the depth reached prior to the well-being out of control or blown out, costs for plugging and abandoning the well, costs for cleanup and containment and for damages caused by contamination and pollution.

The Company customarily has reciprocal agreements with its customers and vendors in which each contracting party is responsible for its respective personnel. Under these agreements, the Company is indemnified against third party claims related to the injury or death of its customers' or vendors' personnel. Although there can be no assurance that the amount of insurance the Company carries is sufficient to protect it fully in all events, the Company believes that its insurance protection is adequate for its business operations.

**Performance Obligations**—Regulations with respect to offshore operations govern, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells, and removal of facilities. As of June 30, 2018, the Company had secured performance bonds totaling approximately $187 million for its supplemental bonding requirements stipulated by the Bureau of Ocean Energy Management (BOEM) related to costs anticipated for the plugging and abandonment of certain wells and the removal of certain facilities in its Gulf of Mexico fields. These performance bonds are uncollateralized. If the Company were to have to obtain additional performance bonds for other reasons, it cannot assure that it would be able to secure any such additional performance bonds on acceptable commercial terms or at all.

**Legal Proceedings and Other Contingencies**—The Company or its subsidiaries may be named defendants in legal proceedings that arise in the ordinary course of business. There are also other regulatory rules and orders in various stages of adoption, review and/or implementation. For each of these matters, the Company evaluates the merits of the case or claim, its exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. The Company discloses matters that are reasonably possibly of negative outcome and are material to the condensed consolidated financial statements. If the Company determines that an unfavorable outcome is probable and is reasonably estimable, the Company accrues for such reasonably estimable outcome. While the outcome of the Company's current matters cannot be predicted with certainty and there are still uncertainties related to the costs it may incur, based upon an evaluation and experience, the Company will establish appropriate accruals as it believes are necessary. It is possible; however, that new information or future developments could require the Company to reassess its potential exposure related to these matters and record or adjust accruals accordingly, and these adjustments could be material.

## 8. PRICE RISK MANAGEMENT ACTIVITIES

**Objectives and Strategies**—The Company is exposed to fluctuations in oil, gas and NGL prices on its production. The Company believes it is prudent to manage the variability in cash flows on a portion of its oil production. The Company utilizes various types of derivative financial instruments, including swaps, costless collars and options, to manage fluctuations in cash flows resulting from changes in commodity prices.

**Commodity Derivative Instruments**— As of June 30, 2018, the Company had entered into commodity contracts with the following terms:

| Commodity Contract Type | Period Covered | Volume Oil (MBbls) | Fixed Price |
|---|---|---|---|
| Swaps | July 2018-Dec 2019 | 47.6 | $ 50.05 |
| Swaps | July 2018-Dec 2019 | 225.9 | $ 50.10 |
| Swaps | July 2018-Dec 2019 | 451.8 | $ 50.00 |
| Swaps | July 2018-Dec 2019 | 225.9 | $ 50.10 |
| Swaps | July 2018-Dec 2018 | 82.4 | $ 60.07 |
| Swaps | Jan 2019-June 2019 | 272.7 | $ 54.25 |
| Swaps | July 2019-Dec 2019 | 44.5 | $ 57.00 |
| Swaps | July 2018-Dec 2018 | 395.2 | $ 58.63 |
| Swaps | July 2018-Dec 2018 | 159.9 | $ 51.14 |
| Swaps | July 2019-Dec 2019 | 234.9 | $ 53.21 |
| Swaps | Jan 2019-June 2019 | 53.1 | $ 57.22 |

The following table sets forth the fair values and classification of the Company's outstanding derivatives at June 30, 2018 and December 31, 2017 (in thousands):

| | Gross Amount of Recognized Asset (Liability) June 30, 2018 | Gross Amount of Recognized Asset (Liability) December 31, 2017 |
|---|---|---|
| Current derivative asset | $ - | $ - |
| Current derivative liability | (27,611) | (9,775) |
| Net current derivative liability | $ (27,611) | $ (9,775) |
| Long term derivative asset | $ - | $ - |
| Long term derivative liability | (4,014) | (3,318) |
| Long term derivative liability | $ (4,014) | $ (3,318) |

The Company has entered into master netting arrangements with its counterparties. The amounts above are presented on a net basis in its balance sheets when such amounts are with the same counterparty. The Company recognized a $10.9 million realized loss and a $0.9 million realized gain for the six months ended June 30, 2018 and 2017, respectively, related to its derivative financial instruments. The Company recorded a $18.5 million unrealized loss and a $2.7 million unrealized gain for the six months ended June 30, 2018 and 2017, respectively, related to its derivative financial instruments.

The Company is subject to the risk of loss on its derivative financial instruments that it would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. The Company enters into International Swaps and Derivative Association agreements with counterparties to mitigate this risk, when possible. The Company also maintains credit policies with regard to its counterparties to minimize its overall credit risk. These policies require (i) the evaluation of potential counterparties' financial condition to determine their credit worthiness; (ii) the regular monitoring of oil and natural gas counterparties' credit exposures; (iii) comprehensive credit reviews on significant counterparties from physical and financial transactions on an ongoing basis; (iv) the utilization of contractual language that affords the Company netting or set off opportunities to mitigate exposure risk; and (v) potentially requiring counterparties to post cash collateral, parent guarantees or letters of credit to minimize credit risk. The Company's assets or liabilities from derivatives at June 30, 2018 represent derivative financial instruments from two counterparties; both of which are financial institutions that have an "investment grade" (minimum Standard & Poor's rating of BBB- or better) credit rating and are party under the Company's credit agreement. The Company enters into derivatives directly with these third parties and, subject to the terms of the credit agreement, are not required to post collateral or other securities for credit risk in relation to the derivative financial interests.

**Fair Value Measurement**

The following table presents the fair value hierarchy table for the Company's assets and liabilities that are required to be measured at fair value on a recurring basis (in thousands):

| | Fair Value | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|
| **At June 30, 2018:** | | | | |
| Assets—oil, natural gas and natural gas liquids derivatives | $ - | $ - | $ - | $ - |
| Liabilities—oil, natural gas and natural gas liquids derivatives | 31,625 | - | 31,625 | - |
| **At December 31, 2017:** | | | | |
| Assets—oil, natural gas and natural gas liquids derivatives | $ - | $ - | $ - | $ - |
| Liabilities—oil, natural gas and natural gas liquids derivatives | 13,093 | - | 13,093 | - |

The Company's derivatives consist of over-the-counter ("OTC") contracts which are not traded on a public exchange. As the fair value of these derivatives is based on inputs using market prices obtained from independent brokers or determined using quantitative models that use as their basis readily observable market parameters that are actively quoted and can be validated through external sources, including third party pricing services, brokers and market transactions, the Company has categorized these derivatives as Level 2. The Company values these derivatives using the income approach using inputs such as the forward curve for commodity prices based on quoted market prices and prospective volatility factors related to changes in the forward curves and yield curves based on money market rates and interest rate swap data, such as forward LIBOR curves. The Company's estimates of fair value have been determined at discrete points in time based on relevant market data. There were no changes in valuation techniques or related inputs in 2018.

## 9. EMPLOYEE INCENTIVE PROGRAMS

**Defined Contribution Plan**—The Company has a defined contribution savings plan (the Savings Plan) that is established for the benefit of eligible employees of the Company and complies with Section 401(k) of the Internal Revenue Code. The Savings Plan allows employees to contribute up to the maximum allowable amount as dictated by the Internal Revenue Code. Under the Savings Plan, the Company makes net profit contributions in the amount up to 7.5% of each employee's base salary annually. Participants direct the investment of their accumulated contributions into various plan investment options.

**Employee Share Ownership Program**—The Amended and Restated Operating Agreement of DGE III Management, LLC (the "Operating Agreement") established Common Units and Incentive Units. Incentive Units are generally intended to be used as incentives for Company employees. The Company was initially authorized to issue 50,000 Incentive Units and may be authorized to issue more under the Operating Agreement. As of June 30, 2018, the Company was authorized to issue 50,201 incentive units.

With the exception of annual distributions to cover the assumed tax liability of the Incentive Unit holders, Incentive Units do not participate in cash distributions prior to vesting and until Common Units have received cumulative cash distributions equal to (i) 150% of the original cash contributed to the Company and (ii) a 10% return on investment, compounded annually. After issuance, the Incentive Units fully vest upon (a) occurrence of a Liquidity Event or (b) occurrence of a Termination Event, other than for Discouraged Terms, which occurs after three years from the date of employment (in which case a portion of the Incentive Units shall vest, as calculated in the Restricted Unit Agreement).

The Company has recognized approximately $2.4 million in compensation expense included in general and administrative expense for each of the six-month periods ended June 30, 2018 and 2017. The Incentive Units issued were valued using the option pricing method for valuing securities. In this method, the rights and claims of each security are modeled as a portfolio of Black-Scholes-Merton call options written on the total equity of the Company.

**10. SUBSEQUENT EVENTS**

Subsequent events were evaluated through September 14, 2018, which is the date these consolidated financial statements were available to be issued.

On August 3rd, 2018, the Company along with Deep Gulf Energy Management, LLC; Deep Gulf Energy LP; DGE II Management, LLC; and Deep Gulf Energy II, LLC entered into a securities purchase agreement with Kosmos Energy Gulf of Mexico, LLC to sell all shareholder interests in the Company; Deep Gulf Energy Management, LLC; Deep Gulf Energy LP; DGE II Management, LLC; and Deep Gulf Energy II, LLC for a total consideration of $1.225 billion, subject to certain adjustments. This transaction is expected to close during the third quarter of 2018.

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**Exhibit 99.7**

## KOSMOS ENERGY LTD. AND SUBSIDIARIES
## UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL INFORMATION

The following Unaudited Pro Forma Condensed Combined Balance Sheet as of June 30, 2018 and the Unaudited Pro Forma Condensed Combined Statements of Operations for the six months ended June 30, 2018 and for the year ended December 31, 2017 have been derived from the historical consolidated financial statements of Kosmos Energy Ltd. (together with its subsidiaries, “Kosmos” or “the Company”) and Deep Gulf Energy LP, DGE II Management, LLC, and DGE III Management, LLC (collectively “Deep Gulf Energy”), as adjusted to give effect to the acquisition of Deep Gulf Energy by the Company (the “Acquisition”) through the incurrence of additional debt under Kosmos’ existing credit facilities, the issuance of Kosmos’ common stock (collectively, the “Transactions”), and the use of cash on hand and are intended to reflect the impact of the Transactions on the Company on a pro forma basis as of and for the periods indicated. The Unaudited Pro Forma Condensed Combined Financial Information does not give effect to any potential additional permanent financing of the Transactions.

The Unaudited Pro forma Condensed Combined Financial Information has been prepared by the Company using the asset acquisition method of accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification (“ASC”) Subtopic 805-50-25. The relative fair value of identifiable assets acquired and liabilities assumed from the Acquisition are based on an allocation of the purchase price utilizing a preliminary estimate of the relative fair values using assumptions described in the accompanying notes to the Unaudited Pro Forma Condensed Combined Financial Information that the Company believes are reasonable.

The final purchase price allocation for the Transactions will be performed prior to the Company’s issuance of its financial statements as of and for the three and nine month period ended September 30, 2018. These final valuations will be based on the actual net assets that exist as of the closing of the Acquisition. Any final adjustments may change the allocations of the purchase price, which could affect the purchase price allocated to the assets acquired and liabilities assumed and could result in a change to the Unaudited Pro Forma Condensed Combined Financial Information. Therefore, the result of the final purchase price allocation could be materially different from the preliminary allocation set forth herein.

The following Unaudited Pro Forma Condensed Combined Financial Information is based on, and should be read in conjunction with:

- The historical audited consolidated financial statements of the Company and the related notes and “Management’s Discussion and Analysis of Financial Condition and Results of Operations” included in its Annual Report on Form 10-K for the fiscal year ended December 31, 2017, as filed with the Securities and Exchange Commission (“SEC”) on February 26, 2018;

- The historical unaudited condensed consolidated interim financial statements of the Company and the related notes and “Management’s Discussion and Analysis of Financial Condition and Results of Operations” included in its quarterly report on Form 10-Q for the six months ended June 30, 2018, as filed with the SEC on August 6, 2018;

- The historical audited financial statements of Deep Gulf Energy LP as of and for the year ended December 31, 2017 (included as Exhibit 99.1 to the Current Report on Form 8-K of which this financial information forms an exhibit); and,

- The historical audited consolidated financial statements of DGE II Management, LLC and subsidiary, and DGE III Management, LLC and subsidiaries as of and for the year ended December 31, 2017 (included as Exhibits 99.2 and 99.3, respectively, to the Current Report on Form 8-K of which this financial information forms an exhibit); and,

- The historical unaudited interim financial statements as of June 30, 2018 and December 31, 2017 and for the six months ended June 30, 2018 and 2017 of Deep Gulf Energy LP (included as Exhibit 99.4 to the Current Report on Form 8-K of which this financial information forms an exhibit).

- The historical unaudited condensed interim financial statements as of June 30, 2018 and December 31, 2017 and for the six months ended June 30, 2018 and 2017 of DGE II Management, LLC and subsidiary and DGE III Management, LLC and subsidiaries (included as Exhibits 99.5 and 99.6, respectively, to the Current Report on Form 8-K of which this financial information forms an exhibit).

The Unaudited Pro Forma Condensed Combined Balance Sheet reflects the Transactions as if they had been consummated on June 30, 2018 and includes pro forma adjustments for the allocation of purchase price based on preliminary allocations by management of certain assets and liabilities.

The Unaudited Pro Forma Condensed Combined Statement of Operations for the year ended December 31, 2017 combines the Company’s historical results for the year ended December 31, 2017 with Deep Gulf Energy LP’s, DGE II Management, LLC’s, and DGE III Management, LLC’s historical results for the year ended December 31, 2017 and the Unaudited Pro Forma Condensed Combined Statement of Operations for the six months ended June 30, 2018 combines the Company’s historical results for the six months ended June 30, 2018 with Deep Gulf Energy LP's, DGE II Management, LLC's, and DGE III Management, LLC's historical results for the six months ended June 30, 2018. The Unaudited Pro Forma Condensed Combined Statements of Operations gives effect to the Transactions as if they had been consummated on January 1, 2017.

The Unaudited Pro Forma Condensed Combined Financial Information has been prepared to reflect adjustments to the Company's historical consolidated financial information that are (i) directly attributable to the Transactions, (ii) factually supportable and (iii) with respect to the Unaudited Pro Forma Condensed Combined Statement of Operations, expected to have a continuing impact on the combined results. The differences between the actual valuations reflected in the Company's future balance sheets and the current estimated valuations used in preparing the Unaudited Pro Forma Condensed Combined Financial Information may be material and may affect amounts, including depletion, depreciation and amortization expense, which the Company will recognize in its statement of operations following the Acquisition.

The Unaudited Pro Forma Condensed Combined Financial Information is presented for informational purposes only and is not necessarily indicative of the operating results or financial position that actually would have been achieved if the Transactions had occurred on the dates indicated or that may be achieved in future periods. The Unaudited Pro Forma Condensed Combined Financial Information should be read in conjunction with the financial statements of the Company and Deep Gulf Energy LP, DGE II Management, LLC, and DGE III Management, LLC. It also does not reflect any cost savings, operating synergies or revenue enhancements that the Company may achieve with respect to combining the companies or costs to integrate the business or the impact of any non-recurring activity and one-time transaction related costs. Synergies and integration costs have been excluded from consideration because they do not meet the criteria for unaudited pro forma adjustments.

# KOSMOS ENERGY LTD. AND SUBSIDIARIES

## UNAUDITED PRO FORMA CONDENSED COMBINED BALANCE SHEETS

## AS OF JUNE 30, 2018

## (In thousands, except per share data)

| | Kosmos Historical | Deep Gulf Energy LP | DGE II Management, LLC and Subsidiary | DGE III Management, LLC and Subsidiaries | Pro Forma Adjustments | | Pro Forma Combined Company |
|---|---|---|---|---|---|---|---|
| **Assets** | | | | | | | |
| Current assets: | | | | | | | |
| Cash and cash equivalents | $ 116,941 | $ 9,879 | $ 85,989 | $ 84,067 | $ (245,429) | **(A)** | $ 51,447 |
| Restricted cash | 20,377 | — | — | — | — | | 20,377 |
| Receivables: | | | | | | | |
| Joint interest billings, net | 68,006 | 256 | 1,267 | 18,078 | 10,529 | **(J)** | 98,136 |
| Oil and gas sales | 73,700 | 1,429 | 17,641 | 31,636 | 23,631 | **(J)** | 148,037 |
| Related party | 2,610 | — | 6 | 6,127 | (6,134) | **(B)** | 2,609 |
| Other | 13,501 | 36 | — | 1,109 | (1,145) | **(J)** | 13,501 |
| Inventories | 71,085 | — | 1,816 | 15,879 | (589) | **(J)** | 88,191 |
| Prepaid expenses and other | 33,638 | 278 | 3,570 | 7,732 | (195) | **(J)** | 45,023 |
| Derivatives | 18,053 | — | 49 | — | (49) | **(J)** | 18,053 |
| Total current assets | 417,911 | 11,878 | 110,338 | 164,628 | (219,381) | | 485,374 |
| Property and equipment: | | | | | | | |
| Oil and gas properties, net | 2,253,815 | 10,080 | 216,393 | 286,103 | 857,845 | **(D), (I)** | 3,624,236 |
| Other property, net | 9,249 | — | 216 | 1,686 | 26 | **(J)** | 11,177 |
| Property and equipment, net | 2,263,064 | 10,080 | 216,609 | 287,789 | 857,871 | | 3,635,413 |
| Other assets: | | | | | | | |
| Equity method investment | 151,310 | — | — | — | — | | 151,310 |
| Investments | — | — | 3,819 | — | (3,819) | **(J)** | — |
| Restricted cash | 9,168 | — | — | 140 | — | | 9,308 |
| Long-term receivables - joint interest billings | 28,981 | — | — | — | — | | 28,981 |
| Long-term receivable - related party | — | — | — | 3,048 | (3,048) | **(B)** | — |
| Interest receivable - related party | — | — | 1,688 | 398 | (2,086) | **(B)** | — |
| Deferred financing costs, net of accumulated amortization | 1,141 | — | — | 513 | (513) | **(C)** | 1,141 |
| Long-term deferred tax assets | 20,763 | — | — | — | — | | 20,763 |
| Derivative asset | 10,421 | — | — | — | — | | 10,421 |
| Other | 684 | 875 | 800 | 11,983 | (11,932) | **(J)** | 2,410 |
| Total assets | $ 2,903,443 | $ 22,833 | $ 333,254 | $ 468,499 | $ 617,092 | | $ 4,345,121 |
| **Liabilities and shareholders' equity** | | | | | | | |
| Current liabilities: | | | | | | | |
| Accounts payable | $ 128,471 | $ 267 | $ 987 | $ 8,659 | $ (4,504) | **(J)** | $ 133,880 |
| Accounts payable - Related Party | — | 65 | 6,069 | — | (6,134) | **(B)** | — |
| Accrued liabilities | 145,600 | 6,031 | 28,733 | 59,981 | 18,673 | **(J)** | 259,018 |
| Interest payable | — | — | 357 | — | (357) | **(E)** | — |
| Current portion of asset retirement obligations | — | 3,003 | 777 | — | — | | 3,780 |
| Derivative short-term liability | 162,329 | — | 12,890 | 27,611 | (4,874) | **(J)** | 197,956 |
| Total current liabilities | 436,400 | 9,366 | 49,813 | 96,251 | 2,804 | | 594,634 |
| Long-term liabilities: | | | | | | | |
| Long-term debt, net | 1,167,775 | — | 290,874 | — | 609,126 | **(E)** | 2,067,775 |
| Long-term accounts payable - related party | — | — | 3,048 | — | (3,048) | **(B)** | — |
| Long-term notes payable - related party | — | — | 4,661 | 4,857 | (9,518) | **(B)** | — |
| Long-term interest payable | — | — | 20,310 | — | (20,310) | **(E)** | — |
| Derivative long-term liability | 83,733 | — | 1,918 | 4,014 | (1,294) | **(J)** | 88,371 |
| Asset retirement obligations | 70,122 | 10,377 | 13,015 | 18,537 | 28,933 | **(F)** | 140,984 |
| Deferred tax liabilities | 392,918 | — | — | — | — | | 392,918 |
| Other long-term liabilities | 8,364 | — | — | — | — | | 8,364 |
| Total long-term liabilities | 1,722,912 | 10,377 | 333,826 | 27,408 | 603,889 | | 2,698,412 |
| Members' equity (deficit) | — | 3,090 | (50,385) | 344,840 | (297,545) | **(G)** | — |
| Shareholders' equity: | | | | | | | |
| Preference shares, $0.01 par value; 200,000,000 authorized shares; zero issued at June 30, 2018 | — | — | — | — | — | | — |
| Common shares, $0.01 par value; 2,000,000,000 authorized shares; 407,557,090 issued at June 30, 2018 | 4,076 | — | — | — | 350 | **(H)** | 4,426 |
| Additional paid-in capital | 2,015,463 | — | — | — | 307,594 | **(H)** | 2,323,057 |
| Accumulated deficit | (1,226,701) | — | — | — | — | | (1,226,701) |
| Treasury stock, at cost, 9,263,269 at June 30, 2018 | (48,707) | — | — | — | — | | (48,707) |
| Total shareholders' equity | 744,131 | — | — | — | 307,944 | | 1,052,075 |
| Total liabilities and shareholders' equity | $ 2,903,443 | $ 22,833 | $ 333,254 | $ 468,499 | $ 617,092 | | $ 4,345,121 |

See accompanying notes.

## KOSMOS ENERGY LTD. AND SUBSIDIARIES

## UNAUDITED PRO FORMA CONDENSED COMBINED STATEMENT OF OPERATIONS

## FOR THE YEAR ENDED DECEMBER 31, 2017

## (In thousands, except per share data)

| | Kosmos Historical | Deep Gulf Energy LP | DGE II Management, LLC and Subsidiary | DGE III Management, LLC and Subsidiaries | Pro Forma Adjustments | | Pro Forma Combined Company |
|---|---|---|---|---|---|---|---|
| Revenues and other income: | | | | | | | |
| Oil and gas revenue | $ 578,139 | $ 8,342 | $ 137,956 | $ 155,458 | $ — | | $ 879,895 |
| Other income, net | 58,697 | — | — | — | — | | 58,697 |
| Total revenues and other income | 636,836 | 8,342 | 137,956 | 155,458 | — | | 938,592 |
| Costs and expenses: | | | | | | | |
| Oil and gas production | 126,850 | 6,182 | 50,390 | 39,754 | (1,885) | **(C)** | 221,291 |
| Facilities insurance modifications, net | (820) | — | — | — | — | | (820) |
| Exploration expenses | 216,050 | 18 | 52 | 36,346 | — | | 252,466 |
| General and administrative | 68,302 | 326 | 3,632 | 12,332 | (2,782) | **(C)** | 81,810 |
| Depletion and depreciation | 255,203 | 2,692 | 57,433 | 57,080 | 70,007 | **(A)** | 442,415 |
| Interest and other financing costs, net | 77,595 | 1 | 58,074 | 1,006 | (21,407) | **(B)** | 115,269 |
| Derivatives, net | 59,968 | — | 2,320 | 12,503 | — | | 74,791 |
| Loss on equity method investments, net | 6,252 | — | — | — | — | | 6,252 |
| Other expenses, net | 5,291 | 3,350 | 2,199 | 4,408 | 7,019 | **(C)** | 22,267 |
| Total costs and expenses | 814,691 | 12,569 | 174,100 | 163,429 | 50,952 | | 1,215,741 |
| Income (loss) before income taxes | (177,855) | (4,227) | (36,144) | (7,971) | (50,952) | | (277,149) |
| Income tax expense (benefit) | 44,937 | — | — | — | (11,568) | **(D)** | 33,369 |
| Net loss | $ (222,792) | $ (4,227) | $ (36,144) | $ (7,971) | $ (39,384) | | $ (310,518) |
| Net loss per share: | | | | | | | |
| Basic | $ (0.57) | | | | | | $ (0.73) |
| Diluted | $ (0.57) | | | | | | $ (0.73) |
| Weighted average number of shares used to compute net loss per share: | | | | | | | |
| Basic | 388,375 | | | | 34,994 | **(E)** | 423,369 |
| Diluted | 388,375 | | | | 34,994 | **(E)** | 423,369 |

See accompanying notes.

## KOSMOS ENERGY LTD. AND SUBSIDIARIES

## UNAUDITED PRO FORMA CONDENSED COMBINED STATEMENT OF OPERATIONS

## FOR THE SIX MONTHS ENDED JUNE 30, 2018

## (In thousands, except per share data)

| | Kosmos Historical | Deep Gulf Energy LP | DGE II Management, LLC and Subsidiary | DGE III Management, LLC and Subsidiaries | Pro Forma Adjustments | | Pro Forma Combined Company |
|---|---|---|---|---|---|---|---|
| Revenues and other income: | | | | | | | |
| Oil and gas revenue | $ 342,387 | $ 6,170 | $ 88,752 | $ 139,285 | $ — | | $ 576,594 |
| Other income, net | 263 | — | — | — | — | | 263 |
| Total revenues and other income | 342,650 | 6,170 | 88,752 | 139,285 | — | | 576,857 |
| Costs and expenses: | | | | | | | |
| Oil and gas production | 96,583 | 2,680 | 25,067 | 30,865 | (1,156) | **(C)** | 154,039 |
| Facilities insurance modifications, net | 9,478 | — | — | — | — | | 9,478 |
| Exploration expenses | 98,674 | — | 45 | 48,756 | — | | 147,475 |
| General and administrative | 39,380 | 11 | 665 | 8,247 | (2,182) | **(C)** | 46,121 |
| Depletion and depreciation | 128,566 | 1,421 | 31,136 | 39,822 | 68,202 | **(A)** | 269,147 |
| Interest and other financing costs, net | 44,564 | — | 29,885 | 502 | (9,747) | **(B)** | 65,204 |
| Derivatives, net | 178,750 | — | 15,378 | 29,389 | — | | 223,517 |
| Loss on equity method investments, net | (34,796) | — | — | — | — | | (34,796) |
| Other expenses, net | 4,643 | (38) | 440 | (1,247) | 4,911 | **(C)** | 8,709 |
| Total costs and expenses | 565,842 | 4,074 | 102,616 | 156,334 | 60,028 | | 888,894 |
| Income (loss) before income taxes | (223,192) | 2,096 | (13,864) | (17,049) | (60,028) | | (312,037) |
| Income tax expense (benefit) | (69,693) | — | — | — | (3,615) | **(D)** | (73,308) |
| Net loss | $ (153,499) | $ 2,096 | $ (13,864) | $ (17,049) | $ (56,413) | | $ (238,729) |
| Net loss per share: | | | | | | | |
| Basic | $ (0.39) | | | | | | $ (0.55) |
| Diluted | $ (0.39) | | | | | | $ (0.55) |
| Weighted average number of shares used to compute net loss per share: | | | | | | | |
| Basic | 396,218 | | | | 34,994 | **(E)** | 431,212 |
| Diluted | 396,218 | | | | 34,994 | **(E)** | 431,212 |

See accompanying notes.

## NOTES TO THE UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL STATEMENTS

**Note 1. Description of Transaction**

On August 3, 2018, Kosmos Energy Gulf of Mexico, LLC (“Purchaser”), a wholly owned subsidiary of Kosmos Energy Ltd. (“Kosmos” or “the Company”), entered into a Securities Purchase Agreement (the “Purchase Agreement”) with certain affiliates of First Reserve Corporation (the sellers under the Purchase Agreement, the “Seller” or "First Reserve") to acquire (the “Acquisition”) 100% of the outstanding equity interests in Deep Gulf Energy LP, DGE II Management, LLC, and DGE III Management, LLC (collectively, “Deep Gulf Energy” or “DGE”). The Acquisition closed on September 14, 2018. In consideration for the Acquisition, Kosmos paid $953 million in cash and 34,993,585 shares of Kosmos’ common stock, subject to post-closing adjustments. Kosmos funded the cash portion of the purchase price using cash on hand and drawings under its existing credit agreements.

On September 14, 2018, Kosmos acquired 100% of the outstanding equity interests in DGE from First Reserve and other shareholders. Deep Gulf Energy is a deepwater company operating in the Gulf of Mexico.

**Note 2. Basis of Presentation**

The Unaudited Pro Forma Condensed Combined Financial Information reflects the consolidated historical results of the Company and DGE, on a pro forma basis to give effect to the Acquisition, the equity issuance to First Reserve, and borrowings under our existing credit facilities (the “Transactions”), as if they had occurred on June 30, 2018 in the Unaudited Pro Forma Condensed Combined Balance Sheet, and on January 1, 2017 in the Unaudited Pro Forma Condensed Combined Statements of Operations.

The Unaudited Pro Forma Condensed Combined Balance Sheet and Statement of Operations as of and for the six months ended June 30, 2018, respectively, were derived from Kosmos’ unaudited condensed consolidated financial statements as of and for the six months ended June 30, 2018 and from Deep Gulf Energy, LP’s unaudited condensed financial statements as of and for the six months ended June 30, 2018 and DGE II Management, LLC’s and DGE III Management, LLC’s unaudited condensed consolidated financial statements as of and for the six months ended June 30, 2018.

The Unaudited Pro Forma Condensed Combined Statement of Operations for the year ended December 31, 2017 was derived from Kosmos’ audited consolidated statement of operations for the year ended December 31, 2017 and from Deep Gulf Energy, LP’s audited financial statements as of and for the year ended December 31, 2017 and DGE II Management, LLC’s and DGE III Management, LLC’s audited consolidated statement of operations for the year ended December 31, 2017.

The Unaudited Pro Forma Condensed Combined Financial Information has been prepared pursuant to the rules and regulations of the Securities and Exchange Commission. Certain information and certain footnote disclosures normally included in financial statements prepared in accordance with generally accepted accounting principles in the United States have been condensed or omitted pursuant to such rules and regulations; however, management believes that the disclosures are adequate to make the information presented not misleading.

The Unaudited Pro forma Condensed Combined Financial Information has been prepared by the Company by accounting for the transaction as an asset acquisition under Financial Accounting Standards Board Accounting Standards Codification (“ASC”) Subtopic 805-50, by allocating the cost of the acquisition to the assets acquired and liabilities assumed based on their relative fair values. The fair value of identifiable assets acquired and liabilities assumed from the Acquisition are based on a preliminary estimate of fair value using assumptions described in the accompanying notes to the Unaudited Pro Forma Condensed Combined Financial Information that the Company believes are reasonable.

The final purchase price allocation for the Transactions will be performed prior to the Company’s issuance of its financial statements as of and for the three and nine month periods ended September 30, 2018. These final valuations will be based on the actual net assets that exist as of the closing of the Acquisition. Any final adjustments may change the allocations of the purchase price, which could affect the fair value assigned to the assets acquired and liabilities assumed and could result in a change to the Unaudited Pro Forma Condensed Combined Financial Information. Therefore, the result of the final purchase price allocation could be materially different from the preliminary allocation set forth herein.

The Unaudited Pro Forma Condensed Combined Financial Information reflects events directly attributable to the described transactions and certain assumptions that the Company believes are reasonable. The Unaudited Pro Forma Condensed Combined Financial Information are not necessarily indicative of financial results that would have been attained had the described transactions occurred on the dates indicated above because they necessarily exclude various operating expenses, such as incremental general and administrative expenses that may be necessary to run the Company following the Transactions. The adjustments are based on currently available information and certain estimates and assumptions. Management believes that the assumptions provide a reasonable basis for presenting the significant effects of the described transactions as contemplated and that the pro forma adjustments give appropriate effect to those assumptions and are properly applied in the unaudited pro forma consolidated and combined financial statements.

The Unaudited Pro Forma Condensed Combined Financial Information are provided for illustrative purposes only and are not intended to represent or be indicative of the results of operations or financial position of the combined company that would have been recorded had the Transactions been completed as of the dates presented and should not be taken as representative of future results of operations or financial position of the combined company. The Unaudited Pro Forma Condensed Combined Financial Information do not reflect the impacts of any potential operational efficiencies, asset dispositions, cost savings or economies of scale that the combined company may achieve with respect to the combined operations.

The Unaudited Pro Forma Condensed Combined Financial Information should be read in conjunction with the Company's financial statements and related notes included on Form 10-K and Form 10-Q filed on February 26, 2018 and August 6, 2018, respectively, and DGE's historical financial statements and accompanying notes included as Exhibits 99.1 through 99.6 to the Current Report on Form 8-K of which this financial information forms an exhibit.

**Note 3. Reclassification of DGE**

Financial information presented in the Deep Gulf Energy, LP, DGE II Management, LLC and DGE III Management, LLC columns in the Unaudited Pro Forma Condensed Combined Balance Sheet and Statement of Operations represents the historical balance sheets of those entities as of June 30, 2018 and the historical statements of operations of those entities for the year ended December 31, 2017 and for the six months ended June 30, 2018, respectively. Certain financial information has been reclassified to conform to the historical presentation in the Company's consolidated financial statements as set forth below. Unless otherwise indicated, defined line items included in the footnotes have the meanings given to them in the historical financial statements of Deep Gulf Energy, LP, DGE II Management, LLC and DGE III Management, LLC.

Reclassification of Deep Gulf Energy LP

| | Before Reclassification (in thousands) | Reclassification Amount (in thousands) | # | After Reclassification (in thousands) |
|---|---|---|---|---|
| ***Balance Sheet - As of June 30, 2018*** | | | | |
| Accounts receivable | $ 1,721 | $ (1,721) | (1) | $ — |
| Joint interest billings, net | — | 256 | (1) | 256 |
| Oil and gas sales | — | 1,429 | (1) | 1,429 |
| Other | — | 36 | (1) | 36 |
| Prepaid expenditures | 278 | (278) | (2) | — |
| Prepaid expenses and other | — | 278 | (2) | 278 |
| Oil and gas properties, successful efforts method, net of accumulated depletion | 10,080 | (10,080) | (3) | - |
| Oil and gas properties, net | — | 10,080 | (3) | 10,080 |
| | | | | |
| ***Statement of Operations - For the Year Ended December 31, 2017*** | | | | |
| Gas Revenue | 1,105 | (1,105) | (4) | — |
| NGL Revenue | 262 | (262) | (4) | — |
| Oil Revenue | 6,975 | (6,975) | (4) | — |
| Oil and gas revenue | — | 8,342 | (4) | 8,342 |
| Transportation expenses | 248 | (248) | (5) | — |
| Workover expense | 1,471 | (1,471) | (5) | — |
| Lease operating expenses | 4,463 | (4,463) | (5) | — |
| Oil and gas production | — | 6,182 | (5) | 6,182 |
| Accretion expense | 786 | (786) | (6) | - |
| Depletion and depreciation | — | 786 | (6) | 786 |
| Interest expense | 1 | (1) | (7) | — |
| Interest and other financing costs, net | — | 1 | (7) | 1 |
| Other operating income | (16) | 16 | (8) | — |
| Impairment | 4,537 | (4,537) | (8) | — |
| Gain on sale of inventory | (1,171) | 1,171 | (8) | — |
| Other expenses, net | — | 3,350 | (8) | 3,350 |
| | | | | |
| ***Statement of Operations - For the Six Months Ended June 30, 2018*** | | | | |
| Gas Revenue | 603 | (603) | (9) | — |
| NGL Revenue | 177 | (177) | (9) | — |
| Oil Revenue | 5,390 | (5,390) | (9) | — |
| Oil and gas revenue | — | 6,170 | (9) | 6,170 |
| Transportation expenses | 149 | (149) | (10) | — |
| Workover expense | 70 | (70) | (10) | — |
| Lease operating expenses | 2,461 | (2,461) | (10) | — |
| Oil and gas production | — | 2,680 | (10) | 2,680 |
| General and administrative expense | (21) | 21 | (11) | — |
| Other operating income | 59 | (59) | (11) | — |
| Other expenses, net | — | (38) | (11) | (38) |
| Accretion expense | 876 | (876) | (12) | — |
| Depletion and depreciation | — | 876 | (12) | 876 |

*Reclassification and classification of the Unaudited Pro Forma Deep Gulf Energy LP Balance Sheet as of June 30, 2018 (in thousands):*

(1) Represents disaggregation and reclassification of "Accounts receivable" of $1,721 into "Joint interest billings, net" of $256, "Oil and gas sales" of $1,429 and "Other" of $36.
(2) Represents reclassification of "Prepaid expenditures" of $278 to "Prepaid expenses and other."
(3) Represents reclassification of "Oil and gas properties, successful efforts method, net of accumulated depletion" of $10,080 to "Oil and gas properties, net."

*Reclassification and classification of the Unaudited Pro Forma Deep Gulf Energy LP Statement of Operations for the year ended December 31, 2017 (in thousands):*

(4) Represents reclassification of “Gas revenue” of $1,105, reclassification of “NGLs revenue” of $262 and reclassification of “Oil revenue” of $6,975 to “Oil and gas revenue.”

(5) Represents reclassification of “Transportation expenses” of $248, reclassification of “Workover expense” of $1,471 and reclassification of “Lease operating expenses” of $4,463 to “Oil and gas production.”

(6) Represents reclassification of “Accretion expense” of $786 to “Depletion and depreciation.”

(7) Represents reclassification of “Interest expense” of $1 to “Interest and other financing costs, net.”

(8) Represents reclassification of “Other operating income” of $16, reclassification of “Impairment” of $4,537 and reclassification of “Gain on sale of inventory” of $1,171 to “Other expenses, net.”

*Reclassification and classification of the Unaudited Pro Forma Deep Gulf Energy LP Statement of Operations for the six months ended June 30, 2018 (in thousands):*

(9) Represents reclassification of “Gas revenue” of $603, reclassification of “NGLs revenue” of $177 and reclassification of “Oil revenue” of $5,390 to “Oil and gas revenue.”

(10) Represents reclassification of “Transportation expenses” of $149, reclassification of “Workover expense” of $70 and reclassification of “Lease operating expenses” of $2,461 to “Oil and gas production.”

(11) Represents reclassification of “General and administrative expense” of $21 and reclassification of “Other operating income” of $59 to “Other expenses, net.”

(12) Represents reclassification of “Accretion expense” of $876 to “Depletion and depreciation.”

Reclassification of DGE II Management, LLC

| | Before Reclassification (in thousands) | Reclassification Amount (in thousands) | # | After Reclassification (in thousands) |
|---|---|---|---|---|
| ***Balance Sheet - As of June 30, 2018*** | | | | |
| Accounts receivable | $ 18,855 | $ (18,855) | (1) | $ — |
| Joint interest billings, net | — | 1,267 | (1) | 1,267 |
| Oil and gas sales | — | 17,641 | (1) | 17,641 |
| Accrued liabilities | — | (53) | (1) | (53) |
| Current asset from price risk management activities | 49 | (49) | (2) | — |
| Derivatives | — | 49 | (2) | 49 |
| Prepaid expenditures | 3,570 | (3,570) | (3) | — |
| Prepaid expenses and other | — | 3,570 | (3) | 3,570 |
| Other property, plant, and equipment, net of accumulated depreciation | 216 | (216) | (4) | — |
| Other property, net | — | 216 | (4) | 216 |
| Oil and gas properties, successful efforts method, net of accumulated depletion | 216,393 | (216,393) | (5) | — |
| Oil and gas properties, net | — | 216,393 | (5) | 216,393 |
| Current liability from price risk management activities | 12,890 | (12,890) | (6) | — |
| Derivative short-term liability | — | 12,890 | (6) | 12,890 |
| Liability from price risk management activities | 1,918 | (1,918) | (7) | — |
| Derivative long-term liability | — | 1,918 | (7) | 1,918 |

| | Before Reclassification (in thousands) | Reclassification Amount (in thousands) | # | After Reclassification (in thousands) |
|---|---|---|---|---|
| ***Statement of Operations - For the Year Ended December 31, 2017*** | | | | |
| Gas Revenue | $ 9,013 | $ (9,013) | (8) | $ — |
| NGL Revenue | 6,451 | (6,451) | (8) | — |
| Oil Revenue | 122,492 | (122,492) | (8) | — |
| Oil and gas revenue | — | 137,956 | (8) | 137,956 |
| Income (loss) from price risk management activities | 2,320 | (2,320) | (9) | — |
| Derivatives, net | — | 2,320 | (9) | 2,320 |
| Transportation expenses | 7,703 | (7,703) | (10) | — |
| Workover expense | 11,792 | (11,792) | (10) | — |
| Lease operating expenses | 30,895 | (30,895) | (10) | — |
| Oil and gas production | — | 50,390 | (10) | 50,390 |
| Accretion expense | 1,559 | (1,559) | (11) | — |
| Depreciation, depletion, and amortization | 55,874 | (55,874) | (11) | — |
| Depletion and depreciation | — | 57,433 | (11) | 57,433 |
| Interest expense | 58,074 | (58,074) | (12) | — |
| Interest and other financing costs, net | — | 58,074 | (12) | 58,074 |
| Inventory write-off | 1,316 | (1,316) | (13) | — |
| Other operating income | (2,799) | 2,799 | (13) | — |
| Loss on settlement of asset retirement obligations | 138 | (138) | (13) | — |
| Impairment | 1,778 | (1,778) | (13) | — |
| Other expenses, net | — | 433 | (13) | 433 |
| ***Statement of Operations - For the Six Months Ended June 30, 2018*** | | | | |
| Gas Revenue | 3,430 | (3,430) | (14) | — |
| NGL Revenue | 3,429 | (3,429) | (14) | — |
| Oil Revenue | 81,893 | (81,893) | (14) | — |
| Oil and gas revenue | — | 88,752 | (14) | 88,752 |
| Other operating income | (71) | 71 | (15) | — |
| Inventory write-off | 511 | (511) | (15) | — |
| Other expenses, net | — | 440 | (15) | 440 |
| Transportation expenses | 1,730 | (1,730) | (16) | — |
| Workover expense | 7,904 | (7,904) | (16) | — |
| Lease operating expenses | 15,433 | (15,433) | (16) | — |
| Oil and gas production | — | 25,067 | (16) | 25,067 |
| Accretion expense | 1,114 | (1,114) | (17) | — |
| Depreciation, depletion, and amortization | 30,022 | (30,022) | (17) | — |
| Depletion and depreciation | — | 31,136 | (17) | 31,136 |
| Income (loss) from price risk management activities | 15,378 | (15,378) | (18) | — |
| Derivatives, net | — | 15,378 | (18) | 15,378 |
| Interest expense | 29,885 | (29,885) | (19) | — |
| Interest and other financing costs, net | — | 29,885 | (19) | 29,885 |

*Reclassification and classification of the Unaudited Pro Forma DGE II Management, LLC Balance Sheet as of June 30, 2018 (in thousands):*

(1) Represents disaggregation and reclassification of “Accounts receivable” of $18,855 into “Joint interest billings, net” of $1,267, “Oil and gas sales” of $17,641 and “Accrued liabilities” of ($53).
(2) Represents reclassification of “Current asset from price risk management activities” of $49 to “Derivative asset.”
(3) Represents reclassification of “Prepaid expenditures” of $3,570 to “Prepaid expenses and other.”
(4) Represents reclassification of “Other property, plant, and equipment, net of accumulated depreciation” of $216 to “Other property, net.”
(5) Represents reclassification of “Oil and gas properties, successful efforts method, net of accumulated depletion” of $216,393 to “Oil and gas properties, net.”
(6) Represents reclassification of “Current liability from price risk management activities” of $12,890 to “Derivative short-term liability.”
(7) Represents reclassification of “Liability from price risk management activities” of $1,918 to “Derivative long-term liability.”

*Reclassification and classification of the Unaudited Pro Forma DGE II Management, LLC Statement of Operations for the year ended December 31, 2017 (in thousands):*

(8) Represents reclassification of “Gas revenue” of $9,013, reclassification of “NGLs revenue” of $6,451 and reclassification of “Oil revenue” of $122,492 to “Oil and gas revenue.”
(9) Represents reclassification of “Income (loss) from price risk management activities” of $2,320 to “Derivatives, net.”
(10) Represents reclassification of “Transportation expenses” of $7,703, reclassification of “Workover expense” of $11,792 and reclassification of “Lease operating expenses” of $30,895 to “Oil and gas production.”
(11) Represents reclassification of “Accretion expense” of $1,559 and reclassification of “Depreciation, depletion, and amortization” of $55,874 to “Depletion and depreciation.”
(12) Represents reclassification of “Interest expense” of $58,074 to “Interest and other financing costs, net.”
(13) Represents reclassification of “Inventory write-off” of $1,316, reclassification of “Other operating income” of $2,799, reclassification of “Loss on settlement of asset retirement obligations” of $138 and reclassification of “Impairment” of $1,778 to “Other expenses, net.”

*Reclassification and classification of the Unaudited Pro Forma DGE II Management, LLC Statement of Operations for the six months ended June 30, 2018 (in thousands):*

(14) Represents reclassification of “Gas revenue” of $3,430, reclassification of “NGLs revenue” of $3,429 and reclassification of “Oil revenue” of $81,893 and to “Oil and gas revenue.”
(15) Represents reclassification of “Other operating income” of $71 and reclassification of “Inventory write-off” of $511 to “Other expenses, net.”
(16) Represents reclassification of “Transportation expenses” of $1,730, reclassification of “Workover expenses” of $7,904 and reclassification of “Lease operating expenses” of $15,433 to “Oil and gas production.”
(17) Represents reclassification of “Accretion expense” of $1,114 and reclassification of “Depreciation, depletion, and amortization” of $30,022 to “Depletion and depreciation.”
(18) Represents reclassification of “Income (loss) from price risk management activities” of $15,378 to “Derivatives, net.”
(19) Represents reclassification of “Interest expense” of $29,885 to “Interest and other financing costs, net.”

Reclassification of DGE III Management, LLC

| | Before Reclassification (in thousands) | Reclassification Amount (in thousands) | # | After Reclassification (in thousands) |
|---|---|---|---|---|
| ***Balance Sheet - As of June 30, 2018*** | | | | |
| Accounts receivable | $ 50,823 | $ (50,823) | (1) | $ — |
| Joint interest billings, net | — | 18,078 | (1) | 18,078 |
| Oil and gas sales | — | 31,636 | (1) | 31,636 |
| Other | — | 1,109 | (1) | 1,109 |
| Prepaid expenditures | 7,732 | (7,732) | (2) | — |
| Prepaid expenses and other | — | 7,732 | (2) | 7,732 |
| Other | 140 | (140) | (3) | — |
| Restricted cash | — | 140 | (3) | 140 |
| Other property, plant, and equipment, net of accumulated depreciation | 1,686 | (1,686) | (4) | — |
| Other property, net | — | 1,686 | (4) | 1,686 |
| Oil and gas properties, successful efforts method, net of accumulated depletion | 286,103 | (286,103) | (5) | — |
| Oil and gas properties, net | — | 286,103 | (5) | 286,103 |
| Accounts payable - related-party | 1,052 | (1,052) | (6) | — |
| Accounts payable | — | 1,052 | (6) | 1,052 |
| Current liability from price risk management activities | 27,611 | (27,611) | (7) | — |
| Derivative short-term liability | — | 27,611 | (7) | 27,611 |
| Liability from price risk management activities | 4,014 | (4,014) | (8) | — |
| Derivative long-term liability | — | 4,014 | (8) | 4,014 |

| | Before Reclassification (in thousands) | Reclassification Amount (in thousands) | # | After Reclassification (in thousands) |
|---|---|---|---|---|
| ***Statement of Operations - For the Year Ended December 31, 2017*** | | | | |
| Gas Revenue | $ 8,009 | $ (8,009) | (9) | $ — |
| NGL Revenue | 6,647 | (6,647) | (9) | — |
| Oil Revenue | 140,802 | (140,802) | (9) | — |
| Oil and gas revenue | — | 155,458 | (9) | 155,458 |
| Transportation expenses | 6,945 | (6,945) | (10) | — |
| Workover expense | 4,482 | (4,482) | (10) | — |
| Lease operating expenses | 28,327 | (28,327) | (10) | — |
| Oil and gas production | — | 39,754 | (10) | 39,754 |
| Income (loss) from price risk management activities | 12,503 | (12,503) | (11) | — |
| Derivatives, net | — | 12,503 | (11) | 12,503 |
| Accretion expense | 380 | (380) | (12) | — |
| Depreciation, depletion, and amortization | 56,700 | (56,700) | (12) | — |
| Depletion and depreciation | — | 57,080 | (12) | 57,080 |
| Interest expense | 1,006 | (1,006) | (13) | — |
| Interest and other financing costs, net | — | 1,006 | (13) | 1,006 |
| Inventory write-off | 5,787 | (5,787) | (14) | — |
| Other operating income | (4,205) | 4,205 | (14) | — |
| Gain on sale of property | (44) | 44 | (14) | — |
| Impairment | 2,870 | (2,870) | (14) | — |
| Other expenses, net | — | 4,408 | (14) | 4,408 |
| ***Statement of Operations - For the Six Months Ended June 30, 2018*** | | | | |
| Gas Revenue | 5,150 | (5,150) | (15) | — |
| NGL Revenue | 4,688 | (4,688) | (15) | — |
| Oil Revenue | 129,447 | (129,447) | (15) | — |
| Oil and gas revenue | — | 139,285 | (15) | 139,285 |
| Income (loss) from price risk management activities | 29,389 | (29,389) | (16) | — |
| Derivatives, net | — | 29,389 | (16) | 29,389 |
| Transportation expenses | 4,006 | (4,006) | (17) | — |
| Workover expense | 4,076 | (4,076) | (17) | — |
| Lease operating expenses | 22,783 | (22,783) | (17) | — |
| Oil and gas production | — | 30,865 | (17) | 30,865 |
| Accretion expense | 794 | (794) | (18) | — |
| Depreciation, depletion, and amortization | 39,028 | (39,028) | (18) | — |
| Depletion and depreciation | | 39,822 | (18) | 39,822 |
| Inventory write-off | 2,490 | (2,490) | (19) | — |
| Other operating income | (4,781) | 4,781 | (19) | — |
| Impairment | 1,044 | (1,044) | (19) | — |
| Other expenses, net | — | (1,247) | (19) | (1,247) |
| Interest and other expense, net | 502 | (502) | (20) | — |
| Interest and other financing costs, net | — | 498 | (20) | 498 |
| Other expenses, net | — | 3 | (20) | 3 |

*Reclassification and classification of the Unaudited Pro Forma DGE III Management, LLC Balance Sheet as of June 30, 2018 (in thousands):*

(1) Represents disaggregation and reclassification of “Accounts receivable” of $50,823 into “Joint interest billings, net” of $18,078, “Oil and gas sales” of $31,636 and “Other” of $1,109.

(2) Represents reclassification of “Prepaid expenditures” of $7,732 to “Prepaid expenses and other.”

(3) Represents reclassification of “Other” of $140 to “Restricted cash.”

(4) Represents reclassification of “Other property, plant, and equipment, net of accumulated depreciation” of $1,686 to “Other property, net.”

(5) Represents reclassification of “Oil and gas properties, successful efforts method, net of accumulated depletion” of $286,103 to “Oil and gas properties, net.”

(6) Represents reclassification of “Accounts payable – related-party” of $1,052 to “Accounts payable”. DGE historically disclosed a $1.05 million, third party revenue payable related to its joint venture with Houston Energy Deepwater Venture, as a related party payable.

(7) Represents reclassification of “Current liability from price risk management activities” of $27,611 to “Derivative short-term liability.”
(8) Represents reclassification of “Liability from price risk management activities” of $4,014 to “Derivative long-term liability.”

*Reclassification and classification of the Unaudited Pro Forma DGE III Management, LLC Statement of Operations for the year ended December 31, 2017 (in thousands):*

(9) Represents reclassification of “Gas revenue” of $8,009, reclassification of “NGLs revenue” of $6,647 and reclassification of “Oil revenue” of $140,802 to “Oil and gas revenue.”
(10) Represents reclassification of “Transportation expenses” of $6,945, reclassification of “Workover expense” of $4,482 and reclassification of “Lease operating expenses” of $28,327 to “Oil and gas production.”
(11) Represents reclassification of “Income (loss) from price risk management activities” of $12,503 to “Derivatives, net.”
(12) Represents reclassification of “Accretion expense” of $380 and reclassification of “Depreciation, depletion, and amortization” of $56,700 to “Depletion and depreciation.”
(13) Represents reclassification of “Interest and other expense, net” of $1,006 to “Interest and other financing costs, net.”
(14) Represents reclassification of “Inventory write-off” of $5,787, reclassification of “Other operating income” of $4,205, reclassification of "Gain on sale of property" of $44, and reclassification of “Impairment” of $2,870 to “Other expenses, net.”

*Reclassification and classification of the Unaudited Pro Forma DGE III Management, LLC Statement of Operations for the six months ended June 30, 2018 (in thousands):*

(15) Represents reclassification of “Gas revenue” of $5,150, reclassification of “NGLs revenue” of $4,688 and reclassification of “Oil revenue” of $129,447 to “Oil and gas revenue.”
(16) Represents reclassification of “Income (loss) from price risk management activities” of $29,389 to “Derivatives, net.”
(17) Represents reclassification of “Transportation expenses” of $4,006, reclassification of “Workover expense” of $4,076 and reclassification of “Lease operating expenses” of $22,783 to “Oil and gas production.”
(18) Represents reclassification of “Accretion expense” of $794 and reclassification of “Depreciation, depletion, and amortization” of $39,028 to “Depletion and depreciation.”
(19) Represents reclassification of “Inventory write-off” of $2,490, reclassification of “Other operating income” of $4,781, and reclassification of "Impairment" of $1,044 to “Other expenses, net.”
(20) Represents reclassification of “Interest and other expense, net” of $502 to “Interest and other financing costs, net” of $498 and "Other expenses, net" of $3.

**Note 4. Preliminary Purchase Price Allocation**

The aggregate purchase price for the DGE acquisition consisted of $953 million in cash and 34,993,585 shares of Kosmos common stock. Additionally, we incurred $14.1 million of acquisition related costs which have been capitalized as part of the purchase price.

The preliminary purchase price allocation of the Acquisition under the asset acquisition method of accounting is shown below. The final purchase price allocation will be determined when the Company has completed the valuations and necessary calculations subsequent to the Acquisition. The final purchase price allocation will likely differ from these estimates and could differ materially from the preliminary allocation used in the pro forma adjustments.

The fair value measurements of oil and gas assets acquired and asset retirement obligations liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair value of oil and gas properties and asset retirement obligations were measured using the discounted cash flow technique of valuation.

Significant inputs to the valuation of oil and gas properties include estimates of: (i) reserves, (ii) future operating and development costs, (iii) future commodity prices, (iv) future plugging and abandonment costs, (v) estimated future cash flows, and (vi) a market-based weighted average cost of capital rate. These inputs require significant judgments and estimates and are the most sensitive and subject to change.

| | | Preliminary Purchase Price Allocation (in thousands) |
|---|---|---|
| **Fair value of assets acquired:** | | |
| Proved oil and gas properties | $ | 1,096,337 |
| Unproved oil and gas properties | | 274,084 |
| Accounts receivable and other | | 137,951 |
| Total assets acquired | $ | 1,508,372 |
| **Fair value of liabilities assumed:** | | |
| Asset retirement obligations | $ | 74,642 |
| Accrued liabilities and other | | 118,827 |
| Derivative liabilities | | 40,265 |
| Total liabilities assumed | $ | 233,734 |
| Cash consideration paid | $ | 952,586 |
| Fair value of common stock(1) | | 307,944 |
| Transaction related costs | | 14,108 |
| **Total purchase price** | $ | 1,274,638 |

(1) Based on 34,993,585 common shares issued at a price of $8.80, which is the opening Kosmos common stock price on September 14, 2018, the closing date of the Acquisition.

**Note 5. Pro Forma Balance Sheet Adjustments**

A. Adjustment to reduce DGE cash by $178.7 million to cash acquired of $1.2 million. Additional $66.7 million decrease reflects the use of $66.7 million from cash on the Company's balance sheet to fund a portion of the cash purchase price, as shown in the following table:

| | | (in thousands) |
|---|---|---|
| **Sources of funds:** | | |
| Borrowing under secured credit facility | $ | 900,000 |
| Cash on hand | | 66,694 |
| **Total Sources of funds** | $ | 966,694 |
| **Uses of funds:** | | |
| Cash paid to seller at closing | $ | 952,586 |
| Transaction related costs | | 14,108 |
| **Total uses of funds** | $ | 966,694 |

B. Adjustment to eliminate related party balances owed among DGE that will eliminate upon consolidation into Kosmos.

C. Write-off of deferred financing costs in connection with the application of asset acquisition accounting for $0.5 million.

D. Represents the impact of the preliminary purchase price allocation on proved and unproved properties.

E. Represents an increase of $900 million attributable to the draw on existing credit facilities to finance the acquisition, net of the pay down of $290.8 million of DGE debt and $20.7 million of accrued interest.

F. Represents an adjustment to the DGE asset retirement obligation attributable to the preliminary purchase price adjustment.

G. Represents an adjustment to eliminate the historical equity of DGE.

H. Represents an increase to Common shares and Additional paid in capital to reflect the issuance of 34,993,585 Kosmos common shares as part of the purchase price based on the opening share price of $8.80 as of close date September 14, 2018.

I. DGE records the recovery of the Council of Petroleum Accountants Societies, Inc. ("COPAS") overhead from the partners as Other Income; whereas, Kosmos records it as a reduction to the actual expenditures incurred. The pro forma adjustment reflects the reclassification of such COPAS overhead recovery from other income to general and administrative and oil and gas production on the statement of operations and oil and gas properties on the balance sheet.

J. Represents preliminary adjustment to acquired working capital as of the acquisition date.

**Note 6. Pro Forma Statement of Operations Adjustments**

A. Reflects an increase in depletion and depreciation of $68.6 million and $68.9 million for the year ended December 31, 2017 and six months ended June 30, 2018, respectively, attributable to the relative fair value allocation to oil and gas properties and an increase and decrease to accretion expense of $1.4 million and $0.7 million for the year ended December 31, 2017 and the six months ended June 30, 2018, respectively, attributable to the preliminary purchase price adjustment and application of Kosmos' credit adjusted discount rate to DGE's asset retirement obligations.

B. Kosmos borrowed an additional $600 million under its Reserve Based Loan Facility, which will bear interest at LIBOR plus 3.25%, and $300 million under its Corporate Revolver, which will bear interest of LIBOR plus 5%. The adjustment reflects the following: i) the removal of $59.1 million and $30.3 million of DGE interest expense for the year ended December 31, 2017 and six months ended June 30, 2018, respectively, related to DGE debt that was paid off at closing, ii) an increase in interest expense of $50.9 million and $26.3 million for the year ended December 31, 2017 and six months ended June 30, 2018, respectively, for the borrowings used to finance the Acquisition and iii) a decrease in interest expense of $13.3 million and $5.6 million for the year ended December 31, 2017 and six months ended June 30, 2018, respectively, for the reduction in commitment fees under existing credit facilities due to the increase in actual borrowings. A hypothetical 0.125% increase or decrease in the expected weighted average interest rate would result in an increase or decrease in interest expense of $2.1 million and $1.0 million for the year ended December 31, 2017 and six months ended June 30, 2018, respectively.

C. DGE records the recovery of COPAS overhead from the partners as Other Income; whereas, Kosmos records it as a reduction to the actual expenditures incurred. The pro forma adjustment reflects the reclassification of such COPAS overhead recovery from other income to general and administrative and oil and gas production on the statement of operations and oil and gas properties on the balance sheet.

D. Reflects the impact of applying a 35% statutory tax rate for the year ended December 31, 2017 and a 21% statutory tax rate for the six months ended June 30, 2018 to DGE Income (loss) before income taxes and to the pro forma adjustments. The DGE entities had not historically been subject to income tax expense but will be subject to income tax after the Acquisition.

E. Pro forma basic and diluted net loss per share was calculated by dividing pro forma net loss by the weighted average shares of Kosmos common stock, adjusted for the issuance of 34,993,585 Kosmos common shares in connection with the Acquisition, as if such shares were issued and outstanding on January 1, 2017.

**Note 7. Pro Forma Supplemental Oil and Natural Gas Reserve Information**

The following tables set forth certain unaudited pro forma information concerning the Company's proved oil and natural gas, including both dry gas and natural gas liquids ("NGLs"), reserves for the year ended December 31, 2017, giving effect to the DGE acquisition as if it had occurred on January 1, 2017. There are numerous uncertainties inherent in estimating the quantities of proved reserves and projecting future rates of production and timing of development costs. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and natural gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future. The estimates of reserves, and the standardized measure of future net cash flow, shown below, reflects DGE's development plan for the properties acquired by the Company pursuant to the DGE acquisition, rather than the Company's development plan for such properties. The Company's estimate of proved oil and natural gas may be materially different than the estimates determined by DGE's management team. The following reserve data represent estimates only and should not be construed as being precise.

| | Kosmos Historical | | | DGE Acquisition(1) | | | Pro Forma Combined Company |
|---|---|---|---|---|---|---|---|
| | Oil (MMBbl) | Natural Gas (Bcf) | Total (MMBoe) | Oil (MMBbl) | Natural Gas (Bcf) | Total (MMBoe) | Total (MMBoe) |
| Net proved developed and undeveloped reserves at December 31, 2016 | 74 | 15 | 77 | 40 | 67 | 51 | 128 |
| Extensions and discoveries | 1 | - | 1 | 3 | 4 | 3 | 4 |
| Production | (11) | (1) | (12) | (5) | (9) | (7) | (19) |
| Revision in estimate | 18 | 35 | 24 | 5 | 27 | 9 | 33 |
| Purchases of minerals-in-place | 20 | 13 | 21 | - | - | - | 21 |
| Net proved developed and undeveloped reserves at December 31, 2017 | 101 | 62 | 110 | 42 | 88 | 57 | 168 |
| Proved developed reserves | | | | | | | |
| December 31, 2017 | 77 | 51 | 85 | 26 | 50 | 34 | 119 |
| Proved undeveloped reserves | | | | | | | |
| December 31, 2017 | 24 | 11 | 25 | 16 | 38 | 23 | 48 |

(1) Includes Deep Gulf Energy LP, DGE II Management, LLC and subsidiary, and DGE III Management, LLC and subsidiaries reserves. The individual reserve disclosures for Deep Gulf Energy LP, DGE II Management, LLC and subsidiary, and DGE III Management, LLC and subsidiaries can be found in their respective audited financial statements as filed as an exhibit to this 8-K. Totals may not add as a result of rounding.

**Standardized Measure of Discounted Future Net Cash Flows**

Summarized in the following table is information for the standardized measure of discounted cash flows relating to proved reserves as of December 31, 2017, giving effect to the DGE acquisition. The standardized measure of discounted future net cash flows does not purport to be, nor should it be interpreted to present, the fair value of the oil and natural gas reserves of the property. An estimate of fair value would take into account, among other things, the recovery of reserves not presently classified as proved, the value of unproved properties, and consideration of expected future economic and operating conditions.

The estimates of future cash flows and future production and development costs as of December 31, 2017 are based on the unweighted arithmetic average first-day-of-the-month price for the preceding 12-month period.

Estimated future production of proved reserves and estimated future production and development costs of proved reserves are based on current costs and economic conditions. All wellhead prices are held flat over the forecast period for all reserve categories. The estimated future net cash flows are then discounted at a rate of 10%.

| At December 31, 2017 | Kosmos Historical | DGE Acquisition(1) | Pro Forma Combined |
|---|---|---|---|
| | | (in millions) | |
| Future cash inflows | $ 5,476 | $ 2,273 | $ 7,749 |
| Future production costs | (2,398) | (587) | (2,985) |
| Future development costs | (1,355) | (430) | (1,785) |
| Future tax expenses(2) | (428) | — | (428) |
| Future net cash flows | 1,295 | 1,256 | 2,551 |
| 10% annual discount for estimating timing of cash flows | (194) | (358) | (552) |
| Standardized measure of discounted future net cash flows | $ 1,101 | $ 898 | $ 1,999 |

(1) Includes Deep Gulf Energy LP, DGE II Management, LLC and subsidiary, and DGE III Management, LLC and subsidiaries reserves. The individual reserve disclosures for Deep Gulf Energy LP, DGE II Management, LLC and subsidiary, and DGE III Management, LLC and subsidiaries can be found in their respective audited financial statements as filed as an exhibit to this 8-K.

(2) The Company is a tax exempt company incorporated pursuant to the laws of Bermuda. The Company has not been and does not expect to be subject to future income tax expense related to its proved oil and gas reserves levied at a corporate parent level. Accordingly, the Company's Standardized Measure for the years ended December 31, 2017 only reflects the effects of future tax expense levied at an asset level. Future net cash flows for the assets acquired from DGE do not include

the effects of income taxes on future revenues because DGE were limited liability companies not subject to entity-level income taxation. Accordingly, no provision for federal income taxes has been provided because taxable income was passed through to their equity holders.

In the foregoing determination of future cash inflows, sales prices used for gas and oil for December 31, 2017 were estimated using the average price during the 12-month period, determined as the unweighted arithmetic average of the first-day-of-the-month price for each month. Prices were adjusted by lease for quality, transportation fees and regional price differentials. Future costs of developing and producing the proved gas and oil reserves reported at the end of each year shown were based on costs determined at each such year-end, assuming the continuation of existing economic conditions.

It is not intended that the standardized measure of discounted future net cash flows represents the fair market value of the Company's proved reserves. The Company cautions that the disclosures shown are based on estimates of proved reserve quantities and future production schedules which are inherently imprecise and subject to revision, and the 10% discount rate is arbitrary. In addition, costs and prices as of the measurement date are used in the determinations, and no value may be assigned to probable or possible reserves.

Changes in the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves are as follows:

| | Kosmos Historical | DGE Acquisition(1) | Pro Forma Combined |
|---|---|---|---|
| | | (in millions) | |
| ***Balance at December 31, 2016*** | $ 846 | $ 615 | $ 1,461 |
| Purchase of minerals in place | 146 | — | 146 |
| Sales and transfers 2017 | (467) | (205) | (672) |
| Extensions and discoveries | 21 | 29 | 50 |
| Net changes in prices and costs | 485 | 190 | 675 |
| Previously estimated development costs incurred during the period | 6 | 58 | 64 |
| Net changes in development costs | (388) | (59) | (447) |
| Revisions of previous quantity estimates | 415 | 192 | 607 |
| Net changes in tax expenses(2) | (8) | — | (8) |
| Accretion of discount | 98 | 61 | 159 |
| Changes in timing and other | (53) | 17 | (36) |
| ***Balance at December 31, 2017*** | $ 1,101 | $ 898 | $ 1,999 |

(1) Includes Deep Gulf Energy LP, DGE II Management LLC and subsidiary, and DGE III Management LLC and subsidiaries reserves. The individual reserve disclosures for Deep Gulf Energy LP, DGE II Management LLC and subsidiary, and DGE III Management LLC and subsidiaries can be found in their respective audited financial statements as filed as an exhibit to this 8-K.

(2) The Company is a tax exempt company incorporated pursuant to the laws of Bermuda. The Company has not been and does not expect to be subject to future income tax expense related to its proved oil and gas reserves levied at a corporate parent level. Accordingly, the Company's Standardized Measure for the years ended December 31, 2017 only reflects the effects of future tax expense levied at an asset level. Future net cash flows for the assets acquired from DGE do not include the effects of income taxes on future revenues because DGE is a limited liability company not subject to entity-level income taxation. Accordingly, no provision for federal income taxes has been provided because taxable income was passed through to their equity holders. Although the DGE entities were not historically subject to income tax expense, they will be subject to U.S. federal and certain state income taxes after the Acquisition.

Estimates of economically recoverable oil and natural gas reserves and of future net revenues are based upon a number of variable factors and assumptions, all of which are to some degree subjective and may vary considerably from actual results. Therefore, actual production, revenues, development and operating expenditures may not occur as estimated. The reserve data are estimates only, are subject to many uncertainties and are based on data gained from production histories and on assumptions as to geologic formations and other matters. Actual quantities of oil and natural gas may differ materially from the amounts estimated.

**Exhibit 99.8**

**DEEP GULF ENERGY LP**

**Estimated**

**Future Reserves and Income**

**Attributable to Certain**

**Leasehold and Royalty Interests**

**SEC Parameters**

**(Proved Reserves)**

**As of**

**December 31, 2017**

| | |
|---|---|
| \s\ John E. Hamlin | \s\ Christine E. Neylon |
| John E. Hamlin, P.E. | Christine E. Neylon, P.E. |
| TBPE License No. 65319 | TBPE License No. 122128 |
| Advising Senior Vice President | Vice President |

**[SEAL]** **[SEAL]**

**RYDER SCOTT COMPANY, L.P.**
TBPE Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580
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September 12, 2018

Deep Gulf Energy LP
738 Highway 6 South, Suite 800
Houston, Texas 77079

Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of Deep Gulf Energy LP (DGE) as of December 31, 2017. The subject properties are located in the federal waters offshore Louisiana and Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on January 10, 2018 and presented herein, was prepared for public disclosure by Kosmos Energy Ltd (Kosmos) in accordance with the SEC regulations.

The properties evaluated by Ryder Scott represent 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of total net proved gas reserves of DGE as of December 31, 2017.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2017 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

**SEC PARAMETERS**
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
**Deep Gulf Energy LP**
As of December 31, 2017

| | Proved | | |
|---|---|---|---|
| | Developed | | Total |
| | Producing* | Non-Producing** | Proved** |
| ***Net Remaining Reserves*** | | | |
| Oil/Condensate – Mbbl | 982 | 26 | 1,008 |
| Plant Products – Mbbl | 58 | 0 | 58 |
| Gas – MMcf | 1,178 | 14 | 1,192 |
| ***Income Data ($M)*** | | | |
| Future Gross Revenue | $ 50,240 | $ 1,247 | $ 51,487 |
| Deductions | 49,469 | 3,361 | 52,830 |
| Future Net Income (FNI) | $ 771 | $(2,114) | $ (1,343) |
| Discounted FNI @ 10% | $ 593 | $(1,784) | $ (1,191) |

** Proved depleted summary consisting of certain P&A liability costs included with Proved Developed Producing Summary.*
*** Negative Future Net Income attributable to certain P&A liability costs.*

Liquid hydrocarbons are expressed in standard 42 gallon barrels and shown herein as thousands of barrels (Mbbl). All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of 60$^{O}$ Fahrenheit and 14.73 psia. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package PHDWin Petroleum Economic Evaluation Software, a copyrighted program of TRC Consultants L.C. The program was used at the request of DGE. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The deductions incorporate the normal direct costs of operating the wells, recompletion costs, development costs, and certain abandonment costs net of salvage. Certain gas, oil and condensate processing and handling fees, including compression fees where applicable are included as other deductions in the cash flows. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income. Liquid hydrocarbon reserves account for approximately 96 percent and gas reserves account for the remaining 4 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded annually. Future net income was discounted at four other discount rates which were also compounded annually. These results are shown in summary form as follows.

| | Discounted Future Net Income ($M) As of December 31, 2017 |
|---|---|
| Discount Rate Percent | Total Proved |
| 5 | $(1,160) |
| 15 | $(1,297) |
| 20 | $(1,419) |
| 25 | $(1,531) |

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

***Reserves Included in This Report***

The proved reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "Petroleum Reserves Definitions" is included as an attachment to this report.

The various reserve status categories are defined under the attachment entitled "Petroleum Reserves Status Definitions and Guidelines" in this report. The proved developed non-producing reserves included herein consist of the behind pipe category.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as 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." All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At DGE's request, this report addresses the proved reserves attributable to the properties evaluated herein.

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." The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental

agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

DGE's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which DGE owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

***Estimates of Reserves***

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely than not to be achieved." The SEC states that "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." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods or the volumetric method. Approximately 26 percent of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis and/or material balance which utilized extrapolations of historical production and pressure data available through November 2017 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by DGE or obtained from public data sources and were considered sufficient for the purpose thereof. The remaining 74 percent of the proved producing reserves were estimated by the volumetric method. This method was used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate.

All of the proved developed non-producing reserves included herein were estimated by the volumetric method. The volumetric analysis utilized pertinent well and seismic data furnished to Ryder Scott by DGE or which we have obtained from public data sources that were available through November 2017. The data utilized from the analogues as well as well and seismic data incorporated into our volumetric analysis were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

DGE has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by DGE with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by DGE. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange

Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

***Future Production Rates***

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those wells that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by DGE. Wells that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

***Hydrocarbon Prices***

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

DGE furnished us with the above mentioned average prices in effect on December 31, 2017. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic area included in the report.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, NGL processing fees, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by DGE. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by DGE to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves by reserve category for the geographic area and presented in accordance with SEC disclosure requirements for each of the geographic areas included in the report.

| Geographic Area | Product | Price Reference | Average Benchmark Prices | Average Realized Prices |
|---|---|---|---|---|
| United States | Oil/Condensate | WTI Cushing | $51.34/bbl | $47.87/bbl |
| | NGLs | WTI Cushing | $51.34/bbl | $18.33/bbl |
| | Gas | Henry Hub | $2.98/MMBTU | $1.81/Mcf |

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

***Costs***

Operating costs for the leases and wells in this report were furnished by DGE and are based on the operating expense reports of DGE and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. Certain gas, oil and condensate processing and handling fees, including compression fees where applicable are included as other deductions. The operating costs furnished by DGE were reviewed by us for their reasonableness using information furnished by DGE for this purpose. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by DGE and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were significant. The estimates of the net abandonment costs furnished by DGE were accepted without independent verification.

The proved developed non-producing reserves in this report have been incorporated herein in accordance with DGE's plans to develop these reserves as of December 31, 2017. The implementation of DGE's development plans as presented to us and incorporated herein is subject to the approval process adopted by DGE's management. As the result of our inquiries during the course of preparing this report, DGE has informed us that the development activities included herein have been subjected to and received the internal approvals required by DGE's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to DGE. Additionally, DGE has informed us that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2017, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by DGE were held constant throughout the life of the properties.

***Standards of Independence and Professional Qualification***

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to DGE. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

***Terms of Usage***

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Kosmos.

Kosmos makes periodic filings on Forms 8-K and 10-K with the SEC under the 1934 Exchange Act. Furthermore, Kosmos has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Forms S-3 and S-8 of Kosmos Energy Ltd of the references to our name as well as to the reference of our third party report for DGE. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Kosmos Energy Ltd.

We have provided DGE with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Kosmos and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

**RYDER SCOTT COMPANY, L.P.**
TBPE Firm Registration No. F-1580

\s\ John E. Hamlin

John E. Hamlin, P.E.
TBPE License No. 65319
Advising Senior Vice President

**[SEAL]**

\s\ Christine E. Neylon

Christine E. Neylon, P.E.
TBPE License No. 122128
Vice President

**[SEAL]**

JEH-CEN/pl

## Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. John E. Hamlin was the primary technical person responsible for overseeing the estimate of the reserves, future production, and income presented herein.

Mr. Hamlin, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 1979, is an Advising Senior Vice President, responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Hamlin served in a number of engineering positions with Phillips Petroleum Corporation. For more information regarding Mr. Hamlin's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Mr. Hamlin earned a Bachelor of Science degree in Petroleum Engineering from the University of Texas at Austin in 1975 and is a licensed Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Hamlin fulfills. As part of his 2017 continuing education hours, Mr. Hamlin attended internally presented 5 hours of formalized training and 10 hours of formalized external training covering topics such as SEC Comment Letters, Deep Water Depositions, Type Well Profile Analysis, SEC Hot Button Topics, Issues and Comment Letters and ethics training.

Based on his educational background, professional training and more than 35 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Hamlin has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

# PETROLEUM RESERVES DEFINITIONS

**As Adapted From:**
**RULE 4-10(a) of REGULATION S-X PART 210**
**UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)**

***PREAMBLE***

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the “Modernization of Oil and Gas Reporting; Final Rule” in the Federal Register of National Archives and Records Administration (NARA). The “Modernization of Oil and Gas Reporting; Final Rule” includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The “Modernization of Oil and Gas Reporting; Final Rule”, including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the “SEC regulations”. The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

*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.* All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale.

Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

**RESERVES (SEC DEFINITIONS)**

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

***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).*

**PROVED RESERVES (SEC DEFINITIONS)**

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

***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.*

**PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES**

**As Adapted From:**
**RULE 4-10(a) of REGULATION S-X PART 210**
**UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)**

**and**

**PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)**
**Sponsored and Approved by:**
**SOCIETY OF PETROLEUM ENGINEERS (SPE)**
**WORLD PETROLEUM COUNCIL (WPC)**
**AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)**
**SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)**

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

## DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

*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.*

## Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

***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***
*Developed Non-Producing Reserves include shut-in and behind-pipe reserves.*

***Shut-In***
*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 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***
*Behind-pipe Reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion 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.*

**UNDEVELOPED RESERVES (SEC DEFINITIONS)**

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

*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.*

*(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.*

Exhibit 99.9

**DEEP GULF ENERGY II LLC**

**Estimated**

**Future Reserves and Income**

**Attributable to Certain**

**Leasehold and Royalty Interests**

**SEC Parameters**

**(Proved Reserves)**

**As of**

**December 31, 2017**

\s\ John E. Hamlin
John E. Hamlin, P.E.
TBPE License No. 65319
Advising Senior Vice President

\s\ Christine E. Neylon
Christine E. Neylon, P.E.
TBPE License No. 122128
Vice President

**[SEAL]**

**[SEAL]**

**RYDER SCOTT COMPANY, L.P.**
TBPE Firm Registration No. F-1580

TBPE REGISTERED ENGINEERING FIRM F-1580
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294
FAX (713) 651-0849
TELEPHONE (713) 651-9191

September 12, 2018

Deep Gulf Energy II LLC
738 Highway 6 South, Suite 800
Houston, Texas 77079

Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of Deep Gulf Energy II LLC (DGE II) as of December 31, 2017. The subject properties are located in the federal waters offshore Louisiana. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on January 11, 2018 and presented herein, was prepared for public disclosure by Kosmos Energy Ltd (Kosmos) in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations; with the exception that DGE II's development plans are to commingle 3 reservoirs and simultaneously produce them in OCS-G-24102 location No. 4 which requires governmental approval not permitted yet. DGE II's development plans are to initially complete location No. 4 in the S2 sand, a reservoir that lies just below the Q4-Q10 sand series and lies just above the U4 sand. Plans are to produce the S2 sand for approximately one year and then add perforations in the deeper U4/U8 sands at the time that the reservoir pressures equalize and then produce location No. 4 as a commingled producer from the 3 reservoirs. We have accepted and included DGE II's accelerated depletion plan in our evaluation concerning proved reserves production profiles as this commingling precedence has been established in the current active producing well OCS-G-24107 No. 2 of the Q4-Q10 sand series with the U4/U8 sands. We believe that the perfunctory approval of this commingling permit in location No. 4 will occur as evidence of this precedence.

The properties evaluated by Ryder Scott account for a portion of DGE II's total net proved reserves as of December 31, 2017. Based on information provided by DGE II, the third party estimate conducted by Ryder Scott addresses 28 percent of the total proved developed net liquid hydrocarbon reserves, 14 percent of the total proved developed net gas reserves, 17 percent of the total proved undeveloped net liquid hydrocarbon reserves, and 6 percent of the total proved undeveloped net gas reserves of DGE II.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2017 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized below.

**SEC PARAMETERS**
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
**Deep Gulf Energy II LLC**
As of December 31, 2017

| | Proved | | | |
|---|---|---|---|---|
| | Developed | | | Total |
| | Producing * ** | Non-Producing | Undeveloped | Proved |
| ***Net Remaining Reserves*** | | | | |
| Oil/Condensate – Mbbl | 316 | 2,338 | 1,289 | 3,943 |
| Plant Products – Mbbl | 37 | 204 | 118 | 359 |
| Gas – MMcf | 792 | 1,310 | 759 | 2,861 |
| ***Income Data ($M)*** | | | | |
| Future Gross Revenue | $ 17,781 | $ 128,761 | $ 71,165 | $217,707 |
| Deductions | 30,228 | 50,116 | 66,735 | 147,079 |
| Future Net Income (FNI) | $(12,447) | $ 78,645 | $ 4,430 | $ 70,628 |
| Discounted FNI @ 10% | $ (5,717) | $ 67,388 | $(2,830) | $ 58,841 |

** Proved depleted summary consisting of certain P&A liability costs included with Proved Developed Producing Summary.*
*** Negative future net income attributable to certain P&A liability costs.*

Liquid hydrocarbons are expressed in standard 42 gallon barrels and are shown herein as thousands of barrels (Mbbl). All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of 60$^{O}$ Fahrenheit and 14.73 psia. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package PHDWin Petroleum Economic Evaluation Software, a copyrighted program of TRC Consultants L.C. The program was used at the request of DGE II. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The deductions incorporate the normal direct costs of operating the wells, recompletion costs, development costs, and certain abandonment costs net of salvage. Certain gas, oil and condensate processing and handling fees, including compression fees where applicable are included as other deductions in the cash flows. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income. Liquid hydrocarbon reserves account for approximately 96 percent and gas reserves account for the remaining 4 percent of total future gross revenue from proved reserves

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded annually. Future net income was discounted at four other discount rates which were also compounded annually. These results are shown in summary form as follows.

| Discount Rate Percent | Discounted Future Net Income ($M) As of December 31, 2017 Total Proved |
|---|---|
| 5 | $64,550 |
| 15 | $53,658 |
| 20 | $49,037 |
| 25 | $44,954 |

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

***Reserves Included in This Report***

The proved reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "Petroleum Reserves Definitions" is included as an attachment to this report.

The various reserve status categories are defined under the attachment entitled "Petroleum Reserves Status Definitions and Guidelines" in this report. The proved developed non-producing reserves included herein consist of the behind pipe category.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as 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." All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At DGE II's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

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." The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental

agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

DGE II's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which DGE II owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

***Estimates of Reserves***

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely than not to be achieved." The SEC states that "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." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods or the volumetric method. Approximately 38 percent of the proved producing reserves attributable to wells and/or reservoirs were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis and/or material balance which utilized extrapolations of historical production and pressure data available through November 2017 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by DGE II or obtained from public data sources and were considered sufficient for the purpose thereof. The remaining 62 percent of the proved producing reserves were estimated by the volumetric method. This method was used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate.

All of the proved non-producing and undeveloped reserves included herein were estimated by the volumetric method. The volumetric analysis utilized pertinent well and seismic data furnished to Ryder Scott by DGE II or which we have obtained from public data sources that were available through November 2017. The data utilized from the analogues as well as well and seismic data incorporated into our volumetric analysis were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

DGE II has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by DGE II with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by DGE II. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange

Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations, with the exception of the commingling of zones in OCS-G-24102 location No. 4 as previously discussed.

***Future Production Rates***

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by DGE II. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

***Hydrocarbon Prices***

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

DGE II furnished us with the above mentioned average prices in effect on December 31, 2017. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used for the geographic area included in the report.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, NGL processing fees, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by DGE II. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by DGE II to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves by reserve category for the geographic area and presented in accordance with SEC disclosure requirements for each of the geographic areas included in the report.

| Geographic Area | Product | Price Reference | Average Benchmark Prices | Average Realized Prices |
|---|---|---|---|---|
| United States | Oil/Condensate | WTI Cushing | $51.34/bbl | $51.90/bbl |
| | NGLs | WTI Cushing | $51.34/bbl | $15.03/bbl |
| | Gas | Henry Hub | $2.98/MMBTU | $2.70/Mcf |

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

***Costs***

Operating costs for the leases and wells in this report were furnished by DGE II and are based on the operating expense reports of DGE II and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. Certain gas, oil and condensate processing and handling fees, including compression fees where applicable are included as other deductions. The operating costs furnished by DGE II were reviewed by us for their reasonableness using information furnished by DGE II for this purpose. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by DGE II and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were significant. The estimates of the net abandonment costs furnished by DGE II were accepted without independent verification.

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with DGE II’s plans to develop these reserves as of December 31, 2017. The implementation of DGE II’s development plans as presented to us and incorporated herein is subject to the approval process adopted by DGE II’s management. As the result of our inquiries during the course of preparing this report, DGE II has informed us that the development activities included herein have been subjected to and received the internal approvals required by DGE II’s management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to DGE II. Additionally, DGE II has informed us that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2017, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by DGE II were held constant throughout the life of the properties.

***Standards of Independence and Professional Qualification***

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to DGE II. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

***Terms of Usage***

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Kosmos.

Kosmos makes periodic filings on Forms 8-K and 10-K with the SEC under the 1934 Exchange Act. Furthermore, Kosmos has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Forms S-3 and S-8 of Kosmos Energy Ltd of the references to our name as well as to the reference of our third party report for

DGE II. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Kosmos Energy Ltd.

We have provided DGE II with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Kosmos and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

**RYDER SCOTT COMPANY, L.P.**
TBPE Firm Registration No. F-1580

\s\ John E. Hamlin

John E. Hamlin, P.E.
TBPE License No. 65319
Advising Senior Vice President

**[SEAL]**

\s\ Christine E. Neylon

Christine E. Neylon, P.E.
TBPE License No. 122128
Vice President

**[SEAL]**

JEH-CEN/pl

**Professional Qualifications of Primary Technical Person**

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. John E. Hamlin was the primary technical person responsible for overseeing the estimate of the reserves, future production, and income presented herein.

Mr. Hamlin, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 1979, is an Advising Senior Vice President, responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Hamlin served in a number of engineering positions with Phillips Petroleum Corporation. For more information regarding Mr. Hamlin's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Mr. Hamlin earned a Bachelor of Science degree in Petroleum Engineering from the University of Texas at Austin in 1975 and is a licensed Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Hamlin fulfills. As part of his 2017 continuing education hours, Mr. Hamlin attended internally presented 5 hours of formalized training and 10 hours of formalized external training covering topics such as SEC Comment Letters, Deep Water Depositions, Type Well Profile Analysis, SEC Hot Button Topics, Issues and Comment Letters and ethics training.

Based on his educational background, professional training and more than 35 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Hamlin has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

# PETROLEUM RESERVES DEFINITIONS

**As Adapted From:**
**RULE 4-10(a) of REGULATION S-X PART 210**
**UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)**

***PREAMBLE***

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

*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.* All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale.

Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

## RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

***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).*

## PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

***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.*

**PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES**

**As Adapted From:**
**RULE 4-10(a) of REGULATION S-X PART 210**

**UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)**

**and**

**PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)**
**Sponsored and Approved by:**
**SOCIETY OF PETROLEUM ENGINEERS (SPE)**
**WORLD PETROLEUM COUNCIL (WPC)**
**AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)**
**SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)**

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

**DEVELOPED RESERVES (SEC DEFINITIONS)**

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

*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.*

**Developed Producing (SPE-PRMS Definitions)**

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

***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***
*Developed Non-Producing Reserves include shut-in and behind-pipe reserves.*

***Shut-In***
*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 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***
*Behind-pipe Reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion 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.*

**UNDEVELOPED RESERVES (SEC DEFINITIONS)**

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

*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.*

*(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.*

**DEEP GULF ENERGY III LLC**

**Estimated**

**Future Reserves and Income**

**Attributable to Certain**

**Leasehold and Royalty Interests**

**SEC Parameters**

**(Proved Reserves)**

**As of**

**December 31, 2017**

| | |
|---|---|
| \s\ John E. Hamlin | \s\ Christine E. Neylon |
| John E. Hamlin, P.E.<br>TBPE License No. 65319<br>Advising Senior Vice President | Christine E. Neylon, P.E.<br>TBPE License No. 122128<br>Vice President |

**[SEAL]** **[SEAL]**

**RYDER SCOTT COMPANY, L.P.**
TBPE Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294
FAX (713) 651-0849
TELEPHONE (713) 651-9191

September 12, 2018

Deep Gulf Energy III LLC
738 Highway 6 South, Suite 800
Houston, Texas 77079

Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of Deep Gulf Energy III LLC (DGE III) as of December 31, 2017. The subject properties are located in the federal waters offshore Louisiana. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on January 11, 2018 and presented herein, was prepared for public disclosure by Kosmos Energy Ltd (Kosmos) in accordance with the SEC regulations; with the exception that DGE II's development plans are to commingle 3 reservoirs and simultaneously produce them in OCS-G-24102 location No. 4 which requires governmental approval not permitted yet. DGE II's development plans are to initially complete location No. 4 in the S2 sand, a reservoir that lies just below the Q4-Q10 sand series and lies just above the U4 sand. Plans are to produce the S2 sand for approximately one year and then add perforations in the deeper U4/U8 sands at the time that the reservoir pressures equalize and then produce location No. 4 as a commingled producer from the 3 reservoirs. We have accepted and included DGE II's accelerated depletion plan in our evaluation concerning proved reserves production profiles as this commingling precedence has been established in the current active producing well OCS-G-24107 No. 2 of the Q4-Q10 sand series with the U4/U8 sands. We believe that the perfunctory approval of this commingling permit in location No. 4 will occur as evidence of this precedence.

The properties evaluated by Ryder Scott account for a portion of DGE III's total net proved reserves as of December 31, 2017. Based on information provided by DGE III, the third party estimate conducted by Ryder Scott addresses 30 percent of the total proved developed net liquid hydrocarbon reserves, 16 percent of the total proved developed net gas reserves, 7 percent of the total proved undeveloped net liquid hydrocarbon reserves, and 3 percent of the total proved undeveloped net gas reserves of DGE III.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2017 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

**SEC PARAMETERS**
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
**Deep Gulf Energy III LLC**
As of December 31, 2017

| | Proved | | | |
|---|---|---|---|---|
| | Developed | | | Total |
| | Producing | Non-Producing | Undeveloped | Proved |
| ***Net Remaining Reserves*** | | | | |
| Oil/Condensate – Mbbl | 3,649 | 1,200 | 604 | 5,453 |
| Plant Products – Mbbl | 107 | 101 | 55 | 263 |
| Gas – MMcf | 1,795 | 728 | 354 | 2,877 |
| ***Income Data ($M)*** | | | | |
| Future Gross Revenue | $173,780 | $65,355 | $33,329 | $272,464 |
| Deductions | 59,325 | 24,967 | 30,258 | 114,550 |
| Future Net Income (FNI) | $114,455 | $40,388 | $ 3,071 | $157,914 |
| Discounted FNI @ 10% | $ 97,301 | $33,963 | $ (530) | $130,734 |

Liquid hydrocarbons are expressed in standard 42 gallon barrels and are shown herein as thousands of barrels (Mbbl). All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of 60$^{O}$ Fahrenheit and 14.73 psia. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package PHDWin Petroleum Economic Evaluation Software, a copyrighted program of TRC Consultants L.C. The program was used at the request of DGE III. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The deductions incorporate the normal direct costs of operating the wells, recompletion costs, development costs, and certain abandonment costs net of salvage. Certain gas, oil and condensate processing and handling fees, including compression fees where applicable are included as other deductions in the cash flows. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income. Liquid hydrocarbon reserves account for approximately 98 percent and gas reserves account for the remaining 2 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded annually. Future net income was discounted at four other discount rates which were also compounded annually. These results are shown in summary form as follows.

| Discount Rate Percent | Discounted Future Net Income ($M) As of December 31, 2017 Total Proved |
|---|---|
| 5 | $143,271 |
| 15 | $119,985 |
| 20 | $110,737 |
| 25 | $102,744 |

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

***Reserves Included in This Report***

The proved reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "Petroleum Reserves Definitions" is included as an attachment to this report.

The various reserve status categories are defined under the attachment entitled "Petroleum Reserves Status Definitions and Guidelines" in this report. The proved developed non-producing reserves included herein consist of the behind pipe category.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as 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." All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At DGE III's request, this report addresses the proved reserves attributable to the properties evaluated herein.

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." The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

DGE III's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which DGE III owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

***Estimates of Reserves***

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely than not to be achieved." The SEC states that "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." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods or the volumetric method. These performance methods include, but may not be limited to, decline curve analysis which utilized extrapolations of historical production and pressure data available through November 2017 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by DGE III or obtained from public data sources and were considered sufficient for the purpose thereof. All of the proved producing reserves were estimated by the volumetric method. This method was used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate. However, available performance data were used to ensure the volumetric parameters in our estimates were appropriate.

Approximately 16 percent of the proved developed non-producing reserves were estimated by performance methods. The remaining 84 percent of proved developed non-producing reserves and all of the proved undeveloped reserves for the properties included herein were estimated by the volumetric method. The volumetric analysis utilized pertinent well and seismic data furnished to Ryder Scott by DGE III or which we have obtained from public data sources that were available through November 2017. The data utilized from the analogues as well as well and seismic data incorporated into our volumetric analysis were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

DGE III has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by DGE III with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by DGE III. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations; with the exception of the commingling of zones in OCS-G-24102 location No. 4 as previously discussed.

***Future Production Rates***

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by DGE III. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

***Hydrocarbon Prices***

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

DGE III furnished us with the above mentioned average prices in effect on December 31, 2017. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic area included in the report.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, NGL processing fees, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by DGE III. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by DGE III to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves by reserve category for the geographic area and presented in accordance with SEC disclosure requirements for each of the geographic areas included in the report.

| Geographic Area | Product | Price Reference | Average Benchmark Prices | Average Realized Prices |
|---|---|---|---|---|
| United States | Oil/Condensate | WTI Cushing | $51.34/bbl | $48.35/bbl |
| | NGLs | WTI Cushing | $51.34/bbl | $13.03/bbl |
| | Gas | Henry Hub | $2.98/MMBTU | $1.87/Mcf |

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

***Costs***

Operating costs for the leases and wells in this report were furnished by DGE III and are based on the operating expense reports of DGE III and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. Certain gas, oil and condensate processing and handling fees, including compression fees where applicable are included as other deductions. The operating costs furnished by DGE III were reviewed by us for their reasonableness using information furnished by DGE III for this purpose. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by DGE III and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were significant. The estimates of the net abandonment costs furnished by DGE III were accepted without independent verification.

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with DGE III's plans to develop these reserves as of December 31, 2017. The implementation of DGE III's development plans as presented to us and incorporated herein is subject to the approval process adopted by DGE III's management. As the result of our inquiries during the course of preparing this report, DGE III has informed us that the development activities included herein have been subjected to and received the internal approvals required by DGE III's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to DGE III. Additionally, DGE III has informed us that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2017, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by DGE III were held constant throughout the life of the properties.

***Standards of Independence and Professional Qualification***

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to DGE III. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

***Terms of Usage***

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Kosmos.

Kosmos makes periodic filings on Forms 8-K and 10-K with the SEC under the 1934 Exchange Act. Furthermore, Kosmos has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Forms S-3 and S-8 of Kosmos Energy Ltd of the references to our name as well as to the reference of our third party report for DGE III. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Kosmos Energy Ltd.

We have provided DGE III with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Kosmos and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

**RYDER SCOTT COMPANY, L.P.**
TBPE Firm Registration No. F-1580

\s\ John E. Hamlin

John E. Hamlin, P.E.
TBPE License No. 65319
Advising Senior Vice President

**[SEAL]**

\s\ Christine E. Neylon

Christine E. Neylon, P.E.
TBPE License No. 122128
Vice President

**[SEAL]**

JEH-CEN/pl

**Professional Qualifications of Primary Technical Person**

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. John E. Hamlin was the primary technical person responsible for overseeing the estimate of the reserves, future production, and income presented herein.

Mr. Hamlin, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 1979, is an Advising Senior Vice President, responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Hamlin served in a number of engineering positions with Phillips Petroleum Corporation. For more information regarding Mr. Hamlin's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Mr. Hamlin earned a Bachelor of Science degree in Petroleum Engineering from the University of Texas at Austin in 1975 and is a licensed Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Hamlin fulfills. As part of his 2017 continuing education hours, Mr. Hamlin attended internally presented 5 hours of formalized training and 10 hours of formalized external training covering topics such as SEC Comment Letters, Deep Water Depositions, Type Well Profile Analysis, SEC Hot Button Issues and Comment Letters and ethics training.

Based on his educational background, professional training and more than 35 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Hamlin has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

## PETROLEUM RESERVES DEFINITIONS

**As Adapted From:**
**RULE 4-10(a) of REGULATION S-X PART 210**
**UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)**

***PREAMBLE***

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

*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.* All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale.

Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

**RESERVES (SEC DEFINITIONS)**

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

***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).*

**PROVED RESERVES (SEC DEFINITIONS)**

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

***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.*

**PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES**

**As Adapted From:**
**RULE 4-10(a) of REGULATION S-X PART 210**
**UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)**

**and**

**PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)**
**Sponsored and Approved by:**
**SOCIETY OF PETROLEUM ENGINEERS (SPE)**
**WORLD PETROLEUM COUNCIL (WPC)**
**AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)**
**SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)**

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

## DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

*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.*

## Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

***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***
*Developed Non-Producing Reserves include shut-in and behind-pipe reserves.*

***Shut-In***
*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 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***
*Behind-pipe Reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion 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.*

**UNDEVELOPED RESERVES (SEC DEFINITIONS)**

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

*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.*
>
> *(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.*

Exhibit 99.11

**DEEP GULF ENERGY III LLC SHARE OF**

**HOUSTON ENERGY DEEPWATER VENTURES V, LLC**

**Estimated**

**Future Reserves and Income**

**Attributable to Certain**

**Leasehold and Royalty Interests**

**SEC Parameters (Proved Reserves)**

**As of**

**December 31, 2017**

| | |
|---|---|
| \s\ John E. Hamlin | \s\ Christine E. Neylon |
| John E. Hamlin, P.E. | Christine E. Neylon, P.E. |
| TBPE License No. 65319 | TBPE License No. 122128 |
| Advising Senior Vice President | Vice President |

**[SEAL]** **[SEAL]**

**RYDER SCOTT COMPANY, L.P.**
TBPE Firm Registration No. F-1580

TBPE REGISTERED ENGINEERING FIRM F-1580
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294
FAX (713) 651-0849
TELEPHONE (713) 651-9191

September 12, 2018

Deep Gulf Energy III LLC (DGE III) Share of
Houston Energy Deepwater Ventures V, LLC
738 Highway 6 South, Suite 800
Houston, Texas 77079

Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of Deep Gulf Energy III LLC (DGE III) Share of Houston Energy Deepwater Ventures V, LLC (HEDV V) as of December 31, 2017. The subject properties are located in the federal waters offshore Louisiana. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on December 29, 2017 and presented herein, was prepared for public disclosure by Kosmos Energy Ltd (Kosmos) in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott represent 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves of DGE III Share of HEDV V as of December 31, 2017.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2017 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

**SEC PARAMETERS**
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
**DEEP GULF ENERGY III LLC SHARE OF**
**HOUSTON ENERGY DEEPWATER VENTURES V, LLC**
As of December 31, 2017

| | Proved | | |
|---|---|---|---|
| | Developed Producing | Undeveloped | Total Proved |
| ***Net Remaining Reserves*** | | | |
| Oil/Condensate – Mbbl | 512 | 395 | 907 |
| Plant Products – Mbbl | 21 | 18 | 39 |
| Gas – MMcf | 287 | 253 | 540 |
| | | | |
| ***Income Data ($M)*** | | | |
| Future Gross Revenue | $26,097 | $20,220 | $46,317 |
| Deductions | 8,796 | 16,188 | 24,984 |
| Future Net Income (FNI) | $17,301 | $ 4,032 | $21,333 |
| | | | |
| Discounted FNI @ 10% | $15,105 | $ 1,669 | $16,774 |

Liquid hydrocarbons are expressed in standard 42 gallon barrels and are shown as thousands of barrels (Mbbl). All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of $60^{o}$ Fahrenheit and 14.73 psia. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package PHDWin Petroleum Economic Evaluation Software, a copyrighted program of TRC Consultants L.C. The program was used at the request of DGE III. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The deductions incorporate the normal direct costs of operating the wells, recompletion costs, and development costs. DGE III advises that their contractual share of HEDV V P&A liability is zero. Certain gas, oil and condensate processing and handling fees are included as “Other” deductions in the cash flows. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income. Liquid hydrocarbon reserves account for approximately 97 percent and gas reserves account for the remaining 3 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded annually. Future net income was discounted at four other discount rates which were also compounded annually. These results are shown in summary form as follows.

| Discount Rate Percent | Discounted Future Net Income ($M) As of December 31, 2017 Total Proved |
|---|---|
| 5 | $18,835 |
| 15 | $15,054 |
| 20 | $13,608 |
| 25 | $12,380 |

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

***Reserves Included in This Report***

The proved reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "Petroleum Reserves Definitions" is included as an attachment to this report.

The various reserve status categories are defined under the attachment entitled "Petroleum Reserves Status Definitions and Guidelines" in this report.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as 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." All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At DGE III's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

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." The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental

agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

DGE III's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which DGE III owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

***Estimates of Reserves***

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely than not to be achieved." The SEC states that "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." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

All of the proved reserves for the properties included herein were estimated by the volumetric method. The data utilized in this analysis were furnished to Ryder Scott by DGE III or obtained from public data sources and were considered sufficient for the purpose thereof. The volumetric method was used as there were inadequate historical performance data to establish a definitive trend and the use of production performance data as a basis for the reserve estimates was considered to be inappropriate. However, available performance data were used to ensure the volumetric parameters in our estimates were appropriate.

The volumetric analysis utilized pertinent well and seismic data furnished to Ryder Scott by DGE III or which we have obtained from public data sources that were available through November 2017. The data utilized from the analogues as well as well and seismic data incorporated into our volumetric analysis were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

DGE III has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by DGE III with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by DGE III. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

***Future Production Rates***

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by DGE III. Locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

***Hydrocarbon Prices***

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

DGE III furnished us with the above mentioned average prices in effect on December 31, 2017. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic area included in the report.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, NGL processing fees, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by DGE III. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by DGE III to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves by reserve category for the geographic area and presented in accordance with SEC disclosure requirements for each of the geographic areas included in the report.

| Geographic Area | Product | Price Reference | Average Benchmark Prices | Average Realized Prices |
|---|---|---|---|---|
| North America | | | | |
| United States | Oil/Condensate | WTI Cushing | $51.34/bbl | $49.04/bbl |
| | NGLs | WTI Cushing | $51.34/bbl | $17.60/bbl |
| | Gas | Henry Hub | $2.98/MMBTU | $2.17/Mcf |

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

***Costs***

Operating costs for the leases and wells in this report were furnished by DGE III. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. Certain gas, oil and condensate processing and handling fees, are included as “Other” deductions. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by DGE III. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by DGE III and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. DGE III advises that their contractual share of HEDV V P&A liability is zero.

The proved undeveloped reserves in this report have been incorporated herein in accordance with DGE III’s plans to develop these reserves as of December 31, 2017. The implementation of DGE III’s development plans as presented to us and incorporated herein is subject to the approval process adopted by DGE III’s management. As the result of our inquiries during the course of preparing this report, DGE III has informed us that the development activities included herein have been subjected to and received the internal approvals required by DGE III’s management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to DGE III. Additionally, DGE III has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2017, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by DGE III were held constant throughout the life of the properties.

***Standards of Independence and Professional Qualification***

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to DGE III. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

***Terms of Usage***

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Kosmos.

Kosmos makes periodic filings on Forms 8-K and 10-K with the SEC under the 1934 Exchange Act. Furthermore, Kosmos has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Forms S-3 and S-8 of Kosmos Energy Ltd of the references to our name as well as to the reference of our third party report for DGE III. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Kosmos Energy Ltd.

We have provided DGE III with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Kosmos and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

**RYDER SCOTT COMPANY, L.P.**
TBPE Firm Registration No. F-1580

\s\ John E. Hamlin

John E. Hamlin, P.E.
TBPE License No. 65319
Advising Senior Vice President

**[SEAL]**

\s\ Christine E. Neylon

Christine E. Neylon, P.E.
TBPE License No. 122128
Vice President

**[SEAL]**

JEH-CEN/pl

**Professional Qualifications of Primary Technical Person**

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. John E. Hamlin was the primary technical person responsible for overseeing the estimate of the reserves, future production, and income presented herein.

Mr. Hamlin, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 1979, is an Advising Senior Vice President, responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Hamlin served in a number of engineering positions with Phillips Petroleum Corporation. For more information regarding Mr. Hamlin’s geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Mr. Hamlin earned a Bachelor of Science degree in Petroleum Engineering from the University of Texas at Austin in 1975 and is a licensed Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Hamlin fulfills. As part of his 2017 continuing education hours, Mr. Hamlin attended internally presented 5 hours of formalized training and 10 hours of formalized external training covering topics such as SEC Comment Letters, Deep Water Depositions, Type Well Profile Analysis, SEC Hot Button Topics, Issues and Comment Letters and ethics training.

Based on his educational background, professional training and more than 35 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Hamlin has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information” promulgated by the Society of Petroleum Engineers as of February 19, 2007.

**PETROLEUM RESERVES DEFINITIONS**

**As Adapted From:**
**RULE 4-10(a) of REGULATION S-X PART 210**
**UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)**

***PREAMBLE***

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the “Modernization of Oil and Gas Reporting; Final Rule” in the Federal Register of National Archives and Records Administration (NARA). The “Modernization of Oil and Gas Reporting; Final Rule” includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The “Modernization of Oil and Gas Reporting; Final Rule”, including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the “SEC regulations”. The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

*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.* All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

**RESERVES (SEC DEFINITIONS)**

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

***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).*

**PROVED RESERVES (SEC DEFINITIONS)**

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

***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.*

**PROVED RESERVES (SEC DEFINITIONS) CONTINUED**

*(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.*

**PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES**

**As Adapted From:**
**RULE 4-10(a) of REGULATION S-X PART 210**
**UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)**

**and**

**PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)**
**Sponsored and Approved by:**
**SOCIETY OF PETROLEUM ENGINEERS (SPE)**
**WORLD PETROLEM COUNCIL (WPC)**
**AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)**
**SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)**

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

**DEVELOPED RESERVES (SEC DEFINITIONS)**

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

*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.*

**Developed Producing (SPE-PRMS Definitions)**

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

***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***
*Developed Non-Producing Reserves include shut-in and behind-pipe reserves.*

***Shut-In***
*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 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***
*Behind-pipe Reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion 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.*

**UNDEVELOPED RESERVES (SEC DEFINITIONS)**

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

*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.*

*(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.*

September 14, 2018

Mr. Tom Campbell
Deep Gulf Energy II, LLC
738 Highway 6 South, Suite 800
Houston, Texas 77079

Dear Mr. Campbell:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2017, to the Deep Gulf Energy II, LLC (DGE II) interest in certain oil and gas properties located in federal waters in the Gulf of Mexico. We completed our evaluation on or about February 1, 2018. It is our understanding that the proved reserves estimated in this report constitute approximately 80 percent of all proved reserves owned by DGE II. 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, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for 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 DGE II interest in these properties, as of December 31, 2017, to be:

| | Net Reserves | | | Future Net Revenue (M$) | |
|---|---|---|---|---|---|
| Category | Oil (MBBL) | NGL (MBBL) | Gas (MMCF) | Total | Present Worth at 10% |
| Proved Developed Producing | 3,925.1 | 515.0 | 5,108.8 | 129,550.4 | 118,515.3 |
| Proved Developed Non-Producing | 2,139.5 | 781.7 | 7,725.2 | 96,291.6 | 67,759.9 |
| Proved Undeveloped | 5,728.3 | 1,248.9 | 12,405.5 | 182,337.5 | 97,498.8 |
| Total Proved | 11,792.9 | 2,545.6 | 25,239.5 | 408,179.6 | 283,774.0 |

*Totals may not add because of rounding.*

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.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. As requested, probable and possible reserves that exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. 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.

Gross revenue is DGE II's share of the gross (100 percent) revenue from the properties after deductions for Delta House pipeline fees. Future net revenue is after deductions for DGE II's share of 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.

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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 January through December 2017. For oil and NGL volumes, the average West Texas Intermediate spot price of $51.34 per barrel is adjusted by field for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.976 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. The average adjusted product prices weighted by production over the remaining lives of the properties are $50.47 per barrel of oil, $18.18 per barrel of NGL, and $1.998 per MCF of gas.

Operating costs used in this report are based on operating expense records of DGE II. 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. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs and include production handling agreement fees. Headquarters general and administrative overhead expenses of DGE II are included to the extent that they are covered under joint operating agreements for the operated properties. Operating costs are not escalated for inflation.

For Odd Job Field, capital costs used in this report were provided by DGE II. For Marmalard and SOB2 Fields, capital costs used in this report were provided by LLOG Exploration Offshore, LLC (LLOG), the operator of the fields. Capital costs are based on authorizations for expenditure, actual costs from recent activity, and internal planning budgets. 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 DGE II's estimates of the costs to abandon the wells, platform, 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 DGE II 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 DGE II 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 DGE II and LLOG, 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. A substantial portion of these reserves are for behind-pipe zones, undeveloped locations, and producing wells that lack sufficient production history upon which performance-related estimates of reserves can be based; such reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. 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 DGE II, LLOG, other interest owners, 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. John R. Cliver, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2009 and has over 5 years of prior industry experience. Zachary R. Long, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2007 and has over 2 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/ John R. Cliver
John R. Cliver, P.E. 107216
Vice President

Date Signed: September 14, 2018

By: /s/ Zachary R. Long
Zachary R. Long, P.G. 11792
Vice President

Date Signed: September 14, 2018

JRC: JSM

# DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

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:

(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.

**DEFINITIONS OF OIL AND GAS RESERVES**
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(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.

(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

**DEFINITIONS OF OIL AND GAS RESERVES**
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(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.

**DEFINITIONS OF OIL AND GAS RESERVES**
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(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.

(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.

(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.*

**DEFINITIONS OF OIL AND GAS RESERVES**
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

> 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.

(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:*
>
> Ÿ *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);*
>
> Ÿ *The company's historical record at completing development of comparable long-term projects;*
>
> Ÿ *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
>
> Ÿ *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*
>
> Ÿ *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.

September 14, 2018

Mr. Tom Campbell
Deep Gulf Energy III, LLC
738 Highway 6 South, Suite 800
Houston, Texas 77079

Dear Mr. Campbell:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2017, to the Deep Gulf Energy III, LLC (DGE III) interest in certain oil and gas properties located in federal waters in the Gulf of Mexico. We completed our evaluation on or about February 1, 2018. It is our understanding that the proved reserves estimated in this report constitute approximately 77 percent of all proved reserves owned by DGE III. 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, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for 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 DGE III interest in these properties, as of December 31, 2017, to be:

| | Net Reserves | | | Future Net Revenue (M$) | |
|---|---|---|---|---|---|
| Category | Oil (MBBL) | NGL (MBBL) | Gas (MMCF) | Total | Present Worth at 10% |
| Proved Developed Producing | 8,546.8 | 805.0 | 9,046.2 | 335,156.0 | 290,705.9 |
| Proved Developed Non-Producing | 2,007.0 | 379.5 | 4,221.5 | 62,517.6 | 21,629.9 |
| Proved Undeveloped | 8,295.3 | 932.8 | 10,002.9 | 201,415.5 | 96,218.4 |
| Total Proved | 18,849.0 | 2,117.4 | 23,270.6 | 599,089.0 | 408,554.3 |

*Totals may not add because of rounding.*

The oil volumes shown include crude oil only. 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.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. As requested, probable and possible reserves that exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. 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.

Gross revenue is DGE III's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for DGE III's share of capital costs, abandonment costs, operating expenses, and Tornado Field production handling agreement fees 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 January through December 2017. For oil and NGL volumes, the average West

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Texas Intermediate spot price of $51.34 per barrel is adjusted by field for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.976 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. The average adjusted product prices weighted by production over the remaining lives of the properties are $48.50 per barrel of oil, $21.27 per barrel of NGL, and $1.783 per MCF of gas.

Operating costs used in this report are based on operating expense records of DGE III. These costs include production handling agreement fees for Odd Job Field and 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. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs. Headquarters general and administrative overhead expenses of DGE III are included to the extent that they are covered under joint operating agreements for the operated properties. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by DGE III and are based on authorizations for expenditure, actual costs from recent activity, and internal planning budgets. Capital costs are included as required for recurring maintenance projects, 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 DGE III'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 DGE III 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 DGE III 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 DGE III, 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. A substantial portion of these reserves are for behind-

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

pipe zones, undeveloped locations, and producing wells that lack sufficient production history upon which performance-related estimates of reserves can be based; such reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. 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 DGE III; Talos Energy LLC, the operator of Tornado Field; other interest owners; 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. John R. Cliver, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2009 and has over 5 years of prior industry experience. Zachary R. Long, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2007 and has over 2 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/ John R. Cliver
John R. Cliver, P.E. 107216
Vice President

Date Signed: September 14, 2018

By: /s/ Zachary R. Long
Zachary R. Long, P.G. 11792
Vice President

Date Signed: September 14, 2018

JRC:JSM

# DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

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:

(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.

(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.

(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

**DEFINITIONS OF OIL AND GAS RESERVES**
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

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.

(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.*

**DEFINITIONS OF OIL AND GAS RESERVES**
Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

> 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.

(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:*
>
> Ÿ *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);*
>
> Ÿ *The company's historical record at completing development of comparable long-term projects;*
>
> Ÿ *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
>
> Ÿ *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*
>
> Ÿ *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.

**Exhibit 99.14**

# KOSMOS ENERGY LTD.

## Estimated

## Future Reserves and Income

## Attributable to Certain

## Leasehold and Royalty Interests of Recent Acquisition of

## Deep Gulf Energy II LLC,
## Deep Gulf Energy III LLC,
## Deep Gulf Energy LP, and
## Deep Gulf Energy III's Share of Houston Energy Deepwater Ventures V LLC

## Gulf of Mexico

## SEC Parameters

## Proved Reserves

**As of**

**July 1, 2018**

| | |
|---|---|
| \s\ Tosin Famurewa | \s\ Christine E. Neylon |
| Tosin Famurewa, P.E., S.P.E.C. | Christine E. Neylon, P.E. |
| TBPE License No. 100569 | TBPE License No. 122128 |
| Managing Senior Vice President | Vice President |
| **[SEAL]** | **[SEAL]** |

**RYDER SCOTT COMPANY, L.P.**
TBPE Firm Registration No. F-1580

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**GULF OF MEXICO**

RYDER SCOTT COMPANY
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September 17, 2018

Kosmos Energy Ltd.
8176 Park Lane, Suite 500
Dallas, Texas 75231

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of Kosmos Energy Ltd.'s (Kosmos) recent acquisition of Deep Gulf Energy II LLC (DGE II), Deep Gulf Energy III LLC (DGE III), Deep Gulf Energy LP (DGE I), and DGE III's Share of Houston Energy Deepwater Ventures V LLC (HEDV V) as of July 1, 2018. The subject properties are located in the federal waters offshore Louisiana and Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations).

Our third party study, completed on August 3, 2018 and presented herein, was prepared for public disclosure by Kosmos in filings made with the SEC in accordance with the SEC regulations; with the exception of the following:

- DGE II and DGE III's development plans in Kodiak field are to commingle three (3) reservoirs and simultaneously produce them in OCS-G-24102 location No. 4, which requires governmental approval not permitted yet. DGE II's development plans are to initially complete location No. 4 in the S2 sand, a reservoir that lies just below the Q4-Q10 sand series and lies just above the U4 sand. Plans are to produce the S2 sand for approximately one year and then add perforations in the deeper U4/U8 sands at the time that the reservoir pressures equalize and then produce location No. 4 as a commingled producer from the 3 reservoirs. We have accepted and included DGE II and DGE III's accelerated depletion plan in our evaluation concerning proved reserves production profiles as this commingling precedence has been established in the current active producing well OCS-G-24107 No. 2 of the Q4-Q10 sand series with the U4/U8 sands. We believe that the perfunctory approval of this commingling permit in location No. 4 will occur as evidence of this precedence.

- In one instance, well log data from a well that was logged on July 19, 2018, a few days after the as of date of this report, was used.

The properties evaluated by Ryder Scott represents 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves of Kosmos in the Gulf of Mexico as of July 1, 2018.

The estimated reserves and future net income amounts presented in this report, as of July 1, 2018 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized below.

**SEC PARAMETERS**
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
**Kosmos Energy Ltd.'s recent Gulf of Mexico Properties Acquisition**
As of July 1, 2018

| | Proved | | | |
|---|---|---|---|---|
| | Developed | | | Total |
| | Producing* | Non-Producing | Undeveloped | Proved |
| ***Net Remaining Reserves*** | | | | |
| Oil/Condensate – Mbbl | 19,290 | 3,284 | 17,527 | 40,101 |
| Plant Products – Mbbl | 1,475 | 634 | 1,920 | 4,029 |
| Gas – MMcf | 14,930 | 5,918 | 17,582 | 38,430 |
| ***Income Data ($M)*** | | | | |
| Future Gross Revenue | $1,197,353 | $215,376 | $1,118,035 | $2,530,764 |
| Deductions | 360,854 | 68,287 | 469,032 | 898,173 |
| Future Net Income (FNI) | $ 836,499 | $147,089 | $ 649,003 | $1,632,591 |
| Discounted FNI @ 10% | $ 713,536 | $ 97,869 | $ 381,970 | $1,193,375 |

** Proved depleted summary consisting of certain P&A liability costs included with Proved Developed Producing Summary.*

Liquid hydrocarbons are expressed in standard 42 gallon barrels and are shown herein as thousands of barrels (Mbbl). All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of 60$^{O}$ Fahrenheit and 14.73 psia. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package PHDWin Petroleum Economic Evaluation Software, a copyrighted program of TRC Consultants L.C. The program was used at the request of Kosmos. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The deductions incorporate the normal direct costs of operating the wells, recompletion costs, development costs, and certain abandonment costs net of salvage. DGE III advises that their contractual share of HEDV V P&A liability is zero. Certain gas, oil and condensate processing and handling fees, including compression fees where applicable are included as "Other" and "Ad Valorem Taxes" deductions in the cash flows. The later are not true ad valorem taxes but represent Kosmos' throughput fee to Talos for processing and handling of the production volumes from the Tornado field. The separate tracking of this throughput fee in the "Ad Valorem Taxes" column of the cash flows was done at Kosmos' request. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Liquid hydrocarbon reserves account for approximately 97 percent and gas reserves account for the remaining 3 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded annually. Future net income was discounted at four other discount rates, which were also compounded annually. These results are shown in summary form as follows.

| | Discounted Future Net Income ($M) As of July 1, 2018 |
|---|---|
| Discount Rate Percent | Total Proved |
| 5 | $1,384,645 |
| 8 | $1,264,084 |
| 12 | $1,129,371 |
| 15 | $1,044,268 |

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

***Reserves Included in This Report***

The proved reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "Petroleum Reserves Definitions" is included as an attachment to this report.

The various proved reserve status categories are defined under the attachment entitled "Petroleum Reserves Status Definitions and Guidelines" in this report. The proved developed non-producing reserves included herein consist of the behind pipe category.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as 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." All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Kosmos' request, this report addresses the proved reserves attributable to the properties evaluated herein.

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.” The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a “high degree of confidence that the quantities will be recovered.”

Proved reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that “as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.” Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Kosmos’ operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which Kosmos owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

***Estimates of Reserves***

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission’s Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods, which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the “quantities actually recovered are much more likely than not to be achieved.” The SEC states that “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.” The SEC states that “possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves.” All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods or the volumetric method. These performance methods include, but may not be limited to, decline curve analysis which utilized extrapolations of historical production and pressure data available through April 2018 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Kosmos, DGE II, DGE III, DGE I or obtained from public data sources and were considered sufficient for the purpose thereof. All of the proved producing reserves were estimated by the volumetric method. This method was used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate. However, available performance data were used to ensure the volumetric parameters in our estimates were appropriate.

Approximately one percent of the proved developed non-producing reserves were estimated by performance methods. The remaining 99 percent of proved developed non-producing reserves and all of the proved undeveloped reserves for the properties included herein were estimated by the volumetric method. The volumetric analysis utilized pertinent well and seismic data furnished to Ryder Scott by Kosmos, DGE II, DGE III, DGE I or obtained from public data sources that were available through April 2018. In one instance, well log data from a well that was logged on July 19, 2018, a few days after the as of date of this report, was used. The data utilized from the analogues as well as well and seismic data incorporated into our volumetric analysis were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data, which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Kosmos, DGE II, DGE III, and DGE I has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by Kosmos, DGE II, DGE III, and DGE I with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, recompletion and development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Kosmos, DGE II, DGE III, or DGE I. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations, with the exception of the approval of the commingling of zones in OCS-G-24102 location No. 4 and the usage of well data from a well logged a few days after the as of date of this report as previously discussed.

***Future Production Rates***

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were projected based on a type well derived from analogy to surrounding historical well production. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Kosmos, DGE II, DGE III or DGE I . Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

***Hydrocarbon Prices***

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

Kosmos furnished us with the above mentioned average prices in effect on July 1, 2018. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used for the geographic area included in the report.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, NGL processing fees, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by Kosmos. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Kosmos to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the "average realized prices." The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves by reserve category for the geographic area and presented in accordance with SEC disclosure requirements for each of the geographic areas included in the report.

| Geographic Area | Product | Price Reference | Average Benchmark Prices | Average Realized Prices |
|---|---|---|---|---|
| United States | Oil/Condensate | Heavy Louisiana Sweet crude | $61.50/bbl | $59.12/bbl |
| | NGLs | Heavy Louisiana Sweet crude | $61.50/bbl | $22.98/bbl |
| | Gas | Henry Hub | $2.92/MMBTU | $1.75/Mcf |

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

***Costs***

Operating costs for the leases and wells in this report were furnished by Kosmos, DGE II, DGE III, and DGE I and are based on the operating expense reports of DGE II, DGE III, and DGE I and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. Certain gas, oil and condensate processing and handling fees, including compression fees where applicable are included as "Other" and "Ad Valorem Taxes" deductions in the cash flows. The later are not true ad valorem taxes but represent Kosmos' throughput fee to Talos for processing and handling of the production volumes from the Tornado field. The separate tracking of this throughput fee in the "Ad Valorem Taxes" column of the cash flows was done at Kosmos' request. The operating costs furnished by Kosmos, DGE II, DGE III, and DGE I were reviewed by us for their reasonableness using information furnished by Kosmos, DGE II, DGE III, and DGE I for this purpose. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by Kosmos, DGE II, DGE III, and DGE I and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were significant. The estimates of the net abandonment costs furnished by Kosmos, DGE II, DGE III, and DGE I were accepted without independent verification. DGE III advises that their contractual share of HEDV V P&A liability is zero.

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with Kosmos' plans to develop these reserves as of July 1, 2018. The implementation of Kosmos' development plans as presented to us and incorporated herein is subject to the approval process adopted by Kosmos' management. As the result of our inquiries during the course of preparing this report, Kosmo has informed us that the development activities included herein have been subjected to and received the internal approvals required by Kosmos' management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Kosmos. Additionally, Kosmos has informed us that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of July 1, 2018, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by Kosmos were held constant throughout the life of the properties.

***Standards of Independence and Professional Qualification***

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to Kosmos. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

***Terms of Usage***

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosures as an exhibit in filings made with the SEC by Kosmos.

Kosmos makes periodic filings on Forms 8-K and 10-K with the SEC under the 1934 Exchange Act. Furthermore, Kosmos has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Forms S-3 and S-8 of Kosmos Energy Ltd of the references to our name as well as to the reference of our third party report for Kosmos. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Kosmos Energy Ltd.

We have provided Kosmos with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Kosmos and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

**RYDER SCOTT COMPANY, L.P.**
TBPE Firm Registration No. F-1580

\s\ Tosin Famurewa

Tosin Famurewa, P.E., S.P.E.C.
TBPE License No. 100569
Managing Senior Vice President **[SEAL]**

\s\ Christine E. Neylon

Christine E. Neylon, P.E.
TBPE License No. 122128
Vice President **[SEAL]**

TF-CEN (DPR)/pl

**Professional Qualifications of Primary Technical Person**

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Tosin Famurewa was the primary technical person responsible for overseeing the estimate of the reserves, future production and income prepared by Ryder Scott presented herein.

Mr. Famurewa, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Famurewa served in a number of engineering positions with Chevron and Texaco. For more information regarding Mr. Famurewa's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Mr. Famurewa earned double Bachelor of Science degrees in Chemical Engineering and Material Science and Engineering from University of California at Berkeley in 2000 and a Master of Science degree in Petroleum Engineering from University of Southern California in 2007. He is a licensed Professional Engineer (PE) in the State of Texas and a SPE Certified Petroleum Engineer (SPEC). He is also a member of the Society of Petroleum Engineers (SPE) and an officer in the Society of Petroleum Evaluation Engineers (SPEE).

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Famurewa fulfills. As part of his 2017 continuing education hours, Mr. Famurewa attended and internally received 12 hours of formalized training as well as a day-long public forum, the 2017 RSC Reserves Conference relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register. Mr. Famurewa is a regular speaker on reserve related topics at the annual Sub-Saharan Africa Oil and Gas Conference in Houston, TX.

Based on his educational background, professional training and more than 17 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Famurewa has attained the professional qualifications as a Reserves Estimator and Reserves Auditor as set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

**PETROLEUM RESERVES DEFINITIONS**

**As Adapted From:**
**RULE 4-10(a) of REGULATION S-X PART 210**
**UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)**

***PREAMBLE***

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

*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.* All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale.

Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

**RESERVES (SEC DEFINITIONS)**

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

***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).*

**PROVED RESERVES (SEC DEFINITIONS)**

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

***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.*

**PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES**

**As Adapted From:**
**RULE 4-10(a) of REGULATION S-X PART 210**
**UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)**

**and**

**PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)**
**Sponsored and Approved by:**
**SOCIETY OF PETROLEUM ENGINEERS (SPE)**
**WORLD PETROLEUM COUNCIL (WPC)**
**AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)**
**SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)**

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

**DEVELOPED RESERVES (SEC DEFINITIONS)**

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

*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.*

**Developed Producing (SPE-PRMS Definitions)**

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

***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***
*Developed Non-Producing Reserves include shut-in and behind-pipe reserves.*

***Shut-In***
*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 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***
*Behind-pipe Reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion 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.*

**UNDEVELOPED RESERVES (SEC DEFINITIONS)**

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

*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.*

*(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.*