Delek Group

Signature of an Agreement for Acquisition of Rights in Oil Assets in the Gulf of Mexico, USA

Tel Aviv, January 8, 2018. Delek Group (TASE: DLEKG, US ADR: DGRLY) ("the Company") hereby announces that further to its Immediate Report dated December 24, 2017 regarding signing of a non-binding letter of intent to invest in and/or acquire oil and gas assets in the Gulf of Mexico, USA, on January 8, 2018, the Delek GOM Investments LLC, a wholly owned foreign subsidiary ("The Buyer"), contracted with Gulf Slope Energy Inc. and Texas South Energy Inc.and Texas South Energy Inc. ("Gulf Slope", "Texas South", respectively, and jointly "the Transferors") in an agreement for the acquisition of oil and gas rights. The Transferors are public companies whose shares are traded on in the USA (OTC).

The Oil Assets under the agreement are 12 federal oil and gas exploration, development and production Leases in the exclusive economic zone of Mexico, USA, in the shallow waters (less than 150m depth) ("The Leases" and "The Oil Assets"). In the Oil Assets areas, the Transferors identified 9 main prospects for exploration drilling ("The Prospects"), of which 7 are in deep layers and 2 in shallow layers. The Buyers undertook in the Agreement to finance 90% of the cost of the two initial drillings in the "Tau" and "Canoe" Prospects Prospects ("The First Stage Assets"), in return for 75% of the rights in the First Stage Assets, in the area of which the drillings will be carried out, at a total which shall not exceed USD 50 million and in addition, the Buyer will have an option to acquire rights in the remaining Prospects based on the mechanism below. The company will provide the Buyer with a shareholders loan to finance the cost of these two drillings from independent sources.

According to a resources report received by the Company from Netherland, Sewell and Associates, Inc. ("NSAI"), prepared in accordance with the guidelines set out in the Petroleum Resources Management System approved by the Society of Petroleum Engineers (SPE-PRMS) and attached as Appendix B to this report below ("The Resources Report"), as of December 31, 2017, in the best estimate (P50), the quantity of prospective resources in the First Stage Assets is 99 million barrels of oil and 177 BCF natural gas (129 MMBOE[1]). Under the Resources Report, the total quantity of resources (seven Prospects) as of December 31, 2017, based on the best estimate (P50), is 194 million barrels of oil and 1.4 TCF natural gas (423 MMBOE).

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[1] Conversion key - the conversion to MMBOE was estimated considering the following data: The conversion ratio of natural gas to MMBOE is 6,000 cubic feet per barrel, whereas the conversion ratio of oil to equivalent oil is one to one. Warning - MMBOE units may be misleading, especially when used without taking into account additional characteristics; the conversion is made according to the energy ratio at the burner and does not represent a value equivalent.

<u>Summary of the main points of the agreement</u>:

1. The exploration drillings in the Prospects will be carried out in four stages In each of the first three stages two exploratory wells will be drilled (one for each prospect) and in the fourth stage, three more exploration wells will be drilled (one well in each Prospect), and a total of nine wells in nine Prospects.. The order of drilling the Prospects in the last three stages will be decided by agreement between the parties.
2. As noted above, the Buyer undertook to finance 90% of the cost of the first two wells in the Tau and Canoe Prospects in return for 75% of the rights in the Leases in the area of which the wells will be drilled (the different stems from coverage of past and entrepreneurship expenses). The drilling at the Canoe Prospect is to shallow layers whereas the drilling at the Tau Prospect is in deep layers. For further information about the First Stage Assets, see Appendix A of this report and the Resources Report (Appendix B).
3. Before starting further exploration drillings in the other stages, the Buyer will have the option to acquire 75% of the rights in the Leases in the area of which the exploration wells will be drilled in the second and third stages, by notice up to 30 days prior to the planned date to release the drilling platform from the second drilling in the previous stage, or from the date when the drilling contractor must inform of release of the drilling platform (whichever is later). If the Buyer elects not to participate in drillings in each of the stages, the option to acquire the additional rights will expire. Moreover, if the Buyer elects to participate in the third stage, it will also be entitled to choose to take part in the fourth stage and receive additional rights in the relevant Leases, when such right will be an ongoing right until the Buyer shall choose not to participate in a given drilling.
4. With regard to all the Prospects in which the Buyer participates, as set out above, it will bear 90% of the costs and expenses of each first exploration drilling in each Prospect until arriving at the target depth, full evaluation, sealing and abandonment according to the joint operating agreement ("Undertaking to Bear Expenses"). The Undertaking to Bear Expenses is limited as follows: (a) In the drillings in the first stage, to a total of USD 50 million; (b) in the drillings in the last stages, a total equivalent to 115% of the approved budget for each drilling[2]. If there are further expenses over the above ceiling, they will be divided according to the joint operating agreement. It is clarified that the Undertaking to Bear Expenses is only applicable to the nine exploration drillings in the nine Prospects, and if the partners decided, according to the provisions of the joint operating agreement, to drill further wells, the Buyer's share in the expenses of these additional drillings will be 75% only. For further information regarding the agreed formula of the joint operating agreement which will apply to the operations of the Leases and regulates the rights and obligations of the partners, see section 1.9 below.
5. The Buyer shall pay a total of USD 1.5 million to the Transferors as reimbursement of expenses for each exploration plan submitted for licenses in the USA in respect of the first, second and third stages, and any other stage. This undertaking is only applicable to nine prospectives in which the Buyer elects to participate.
6. The Agreement includes provision regarding election of the operator of the Leases, with in the first stage Gulf Slope being the operator and following the first commercial discovery, the Buyer will be entitled to be appointed the operator and/or appoint an operator on its behalf (an affiliate).

[2] As noted in sections 1.5, 2.5 and 5 below, the estimated budget of the two drillings in the first stage, as prepared by the Transferors, is USD 42 million for 90% of the rights. It is clarified that the Transferors have not yet prepared an estimated budget with regard to the drillings in the other stages.

7. The agreement also includes a provision that the parties will make reasonable efforts to negotiate on the Area of Mutual Interest within three months from signing the agreement.

8. The Buyer will be entitled to acquire ordinary shares of the Transferors, whereby it will hold up to 20% of the issued capital of each of the Transferors, according to the milestones stipulated in the agreement (5% of the shares at each stage). These shares will be issued to the Buyer at a 10% discount off the average closing price of the shares in the 30 days preceding the acquisition. This right will be valid for 24 months from the date of signature of the agreement. If the Buyer acquires such shares, it will be prohibited from selling the shares acquired so long as the agreement remains in force.

9. Registration of rights in the Leases is subject to regulatory approval of the Bureau of Ocean Energy Management ("BOEM")[3]. Under the agreement, the Buyer's rights in the Leases in the area of the Tau and Canoe Propespects will be registered after signature of the agreement.

<u>Rate of holding of the Leases in the area of the Tau and Canoe Prospects after completion of the transaction under the agreement:</u>

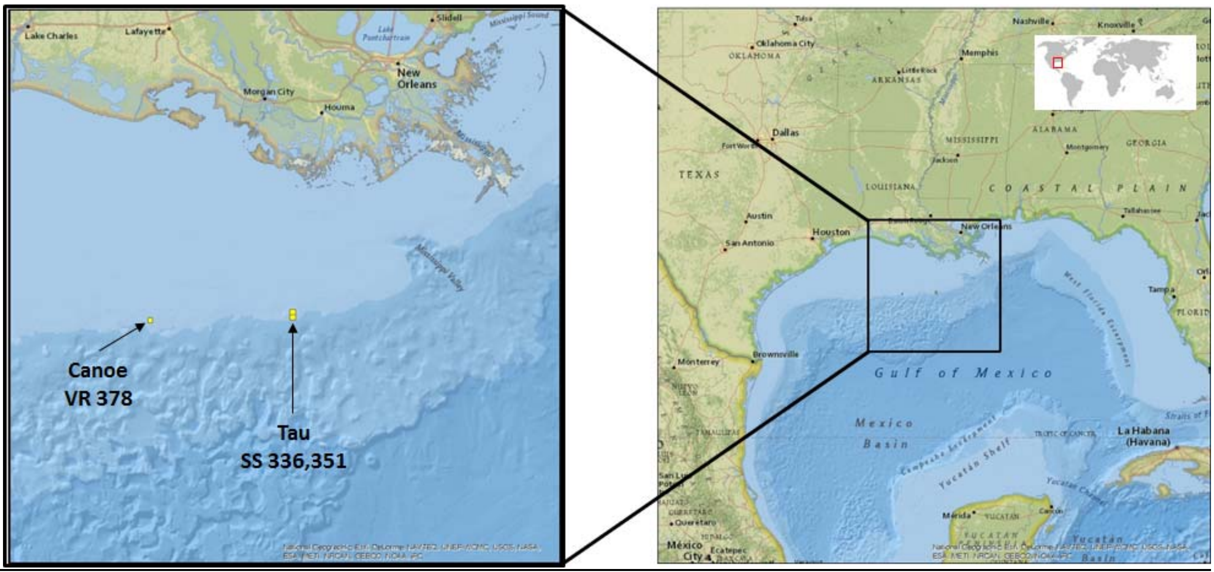
Delek GOM Investments LLC	75%
Gulf Slope Energy, Inc.	20%
Texas South Energy Inc.	5%
Total	100%

Sincerely,
Delek Group Ltd.
Signed by: Asi Bartfeld - CEO
and Barak Mashraki, CFO

[3] The BOEM, Bureau of Ocean Energy Management, is the federal body responsible for management of the development of offshore oil resources in the USA and granting of federal offshore licenses and control and approval of gas and oil exploration and development plans.

Appendix A - Information about the Oil Assets

Map of the Oil Asset



Details of the Leases in the Tau Prospect area ("The Tau Leases") and the Lease in the Canoe Prospect area ("The Canoe Lease").

1. Tau Leases

1.1. Information about the Oil Asset

General information about the Oil Asset	
Name of Oil Asset	Tau
Location	The Tau prospect is the area of two federal Leases. The asset is located in the Gulf of Mexico, USA, off the coast of Louisiana, 218 km south west of New Orleans, USA.
Area	The area of each Lease is 5,000 acres (20.23 sq.km).
Type of Oil Asset and description of permitted operations according to that type:	Federal Lease; Permitted operations - oil and gas exploration, development and production in the defined area called a Lease aunder US government regulation.
Original grant date of the Oil Asset	July 1, 2014 - OCS-G 35244 (Block Ship Shoal 336) November 1, 2014 - OCS-G 36121 (Block Ship Shoal 351)
Original expiry date of the Oil Asset	June 30, 2019 - OCS-G 35244 October 31, 2022 - OCS-G 36121
Decision date for extension of the period of the Oil Asset	-
Current expiry date of the Oil Asset	As stipulated above.
Note whether there is an additional option of extending the period of the Oil Asset: if so, note the period of the possible extension	Subject to the approval of the Commissioner on behalf of BOEM (in OCS-G-36121 Lease) and the approval of the Bureau of Safety and Environmental Enforcement (BSEE) (in the OCS-G 35244 Lease), it may be extended for up to eight years from the original grant, subject to drilling a well with a true vertical depth (TVD) of 25,000 feet from the water surface, in the first five years It is noted that as soon as a finding is discovered, the Lease will be valid so long as oil or gas are produced in commercial quantities, subject to the approval and requirements of BOEM and the relevant regulator.
Operator:	Gulf Slope Energy, Inc.

General information about the Oil Asset	
Names of the direct partners in the Oil Asset and their direct share in the Oil Asset and, to the best of the Company's knowledge, the names of the controlling owners in the partners	Delek GOM Investments LLC[4] - 75% GulfSlope Energy, Inc.[5] - 20% Texas South Energy Inc.[6] – 5%

1.2. The Company's share in the Oil Asset

General information about the Company's share in the Oil Asset	
Acquisition date of the lease for the acquired Oil Asset:	January 1, 2018, according to the terms of the agreement for the acquisition of the rights described above.
Description of the Company's holding in the Oil Asset	Holding through a wholly owned foreign subsidiary.
Effective share of Oil Asset revenues attributable to equity holders of the Company:	63.28125%
Total share of the Company's equity holders in the cumulative investment in the Oil Asset in the five years preceding the last day of the reporting year (whether recognized as an expense or as an asset in the financial statements):	-

1.3. Operations before holding the Oil Asset

To the best of the Company's knowledge, according to information provided by the Transferors, no material operations will be performed in the area of the Oil Asset until the date of the agreement for the acquisition of rights, other than purchasing and processing seismic information.

1.4. Compliance with the terms of the work plan

According to the terms of the Leases, there is no detailed work plan binding the Leaseaires, however, extending the validity of the Leases is subject to exploration drilling during the term of the Leases, as set out in the table in section 1.1 above.

1.5. Planned Work Plan

Summary of the planned operations in the area of the Leases:

Period	Summary of actual operations in the period or of the planned work plan	Estimated total budget for operations on the level of the Oil Asset (USD thousands)	Actual participation of the Company's equity holders in the budget (USD thousands)[7]
2018 onwards	Preparations for drilling to obtain regulatory approvals, engineering preparations to carry out the drilling; environmental, geophysical and archaeological risk surveys.	738	664
	Exploration drilling, including releasing the drilling platform, sealing and abandonment of the well, and related expenses.	38,736	34,862

Forward-looking information: The Company's estimate regarding the planned operations in the Lease, including regarding the costs, schedules, and actual performance, is

4 The above data are based on the assumption that acquisition of rights in the Leases will be completed, according to the terms of the above rights acquisition agreement.
5 A public US energy company whose main shareholder is Mr. John N. Seitz.
6 A public US energy company without a controlling shareholder.
7 The Subsidiary, at 90% of the exploration expenses, as set out in the above rights transfer agreement.

forward-looking information as defined in the Securities Law, based on assessments regarding the components of the work plan and their costs, which may change from time to time. Implementation of the actual work plan, including schedules and costs, may differ materially from the above estimate and is subject, among other things, to market conditions, regulation, many external circumstances, including technical requirements and capacity, and economic viability.

1.6. Participation rate in the expenses and revenues

Participation rate	**%**	**Percentage grossed up to 100%**	**Explanations**
Actual rate attributable to Company's equity holders in the Oil Asset	75%	100%	See the description of the chain of holdings in section 1.2 above.
Actual share of Oil Asset **revenues** attributable to equity holders of the Company	63.28125%	84.375%	See the calculation in section 1.7 below.
Actual rate of participation of the Company's equity holders in **expenses** arising from exploration, development or production operations in the Oil Asset	**When the Undertaking to Bear Expenses is applicable:** 90% **When the Undertaking to Bear Expenses is not applicable:** 75%	120% 100%	See the calculation in section 0 below.

1.7. Participation rate of the equity holders in revenues from the Oil Asset

Description	**%**	**Summary of the calculation method for royalties or payments (including deduction of expenses and others)**
Projected annual revenues of the Oil Asset	100%	
Royalties or payment (derived from revenues after the discovery)at the level of the oil:		
Royalties to the US Federal Government	(15.625%)	This rate is the average federal royalty rate for the OSC-G-36121 Lease (12.5%) and the OCS-G 35244 Lease (18.75%).
Adjusted revenues at the Oil Asset level	84.375%	
Share of the adjusted Oil Asset revenues attributable to the Company's equity holders (linked)	63.28125%	
Share of the equity holders of the Company in the actual rate of revenues, at the level of the Oil Asset (before other payments at the level of the Company)	75%	

1.8. Participation rate of the Company's equity holders in exploration, development and production expenses of the Oil Asset

Description	When the Undertaking to Bear Expenses is applicable[8]	When the Undertaking to Bear Expenses is not applicable:	Summary of the calculation method for royalties or payment
Theoretical expenses of the Oil Asset	100%		
Payments (derived from the expenses) at the level of the Oil Asset:			
Total actual rate of expenses at the level of the Oil Asset	100%		Excluding payments to the Operator calculated in a percentage of the different expenses, as described in section 1.9.3 below.
Share of the Company's equity holders in the Oil Asset's expenses (linked)	90%	75%	
Share of the equity holders of the Company in the actual rate of expense, at the level of the Oil Asset (before other payments at the level of the Company)	90%	75%	
Total	90%	75%	

1.9. Joint Operating Agreement

The production operations in the Tau and Canoe Leases are regulated in a joint operating agreement, which is valid from January 1, 2018 ("JOA"). The JOA was signed together with signing of the agreement for the acquisition of the rights in the Leases.

The purpose of the JOA is to establish the mutual rights and obligations of the parties in respect of operations in the areas of the Leases (in this section: "The Agreement Area"). In any discrepancy between the rights acquisition agreement and the JOA, the provisions of the rights acquisition agreement will prevail.

Details of the main provisions of the agreement:

1.9.1. Operator identity, rights and obligations

Gulf Slope Energy, Inc. Serves as Operator under the JOA (" the Operator"). Under the rights acquisition agreement, after a commercial find in the exploration drilling in at least one Prospect, Delek will be able to elect to replace Gulf Slope as Operator or to appoint an affiliate as Operator.

Subject to the terms of the agreement, the Operator is exclusively responsible for managing the operations in the Agreement Area. The Operator may employ subcontractors and/or workers to perform such operations. The Operator will decide the number and identity of workers and contractors, their their work hours and the salary that will be paid.

The Operator will carry out its duties with appropriate effort and in accordance with the accepted procedures in the oil industry.

The Operator is required to attain the insurances specified in the JOA according to the provisions included in the JOA.

The Operator is also required to allow the representatives of each party at any reasonable time during standard operating hours, access to the joint accounting records, according to the accounting rules set out in the JOA.

8 For further information, see footnote 6 above.

The Operation will not be liable for any other parties to the agreement for any liability or loss, unless these result from willful misconduct or gross negligence of the Operator.

The Operator will report to the parties and present them, among other things, with a copy of every drilling application and all of its revisions, daily updates regarding the progress of the drilling, a copy of the logs and surveys conducted, the reports sent to regulatory entities, monthly reports regarding quantities of hydrocarbons produced from each well, etc. The Operator will also provide, at the request of any party, any further available information at their expense.

1.9.2. <u>Operator's resignation and removal from office; selection of a replacement Operator</u>

The Operator may resign at any time by written notice to the other parties, except in case of a force majeure or emergency, as defined in the agreement. Moreover, if the Operator ceases to hold participation rights in the Leases, it will be considered to have resigned from office, without the other parties having to take any action for this purpose.

The Operator may also be removed from office by decision of the other parties to the agreement (which are not the Operator), whereby the decision must be made by one or more parties holding at least 51% of the voting rights, in each of the following cases: (1) If the Operator is insolvent, bankrupt or is in receivership proceedings; (2) a receiver is appointed Operator or for a material part of the Operator's assets or interests; (3) endorsement of rights by the Operator (other than endorsement to an affiliate) that reduces the participation rights of the Operator from the participation rights of a party which is not the Operator, whether the rights were endorsed in one or more transfers; (4) the Operator made a material breach of the agreement and failed to remedy it within 30 days from receiving notice of such breach.

Such decision will enter into force, provided that is is passed, within 45 days after one of the parties to the agreement (not the Operator) became aware of one of the above events.

The Operator resignation or removal from office will enter into force on the morning of the first day of the following month starting from: (a) 90 days after the date of the resignation notice or decision to remove the Operator from office; (b) upon appointment of a replacement Operator.

Upon the Operator's resignation or removal from office, a replacement Operator will be elected by the parties to the agreement, whereby the decision must be made by one or more parties holding at least 51% of the voting rights. The Operator's vote will not be counted while it not entitled to vote, prevented from voting or votes only to regain the position of Operator. If there are only two parties to the agreement, the party which is not the Operator at that time will be become the Operator.

1.9.3. <u>Accounting</u>

The accounting rules stipulate that unless decided otherwise, the Operator will pay all expenses under this agreement and the participating parties (as defined in the agreement) will reimburse these expenses based on their rate of holding. The Operator may require the participating parties to pay their share of the estimated expenses according to the provisions of the agreement.

The Operator will charge the participating parties for indirect expenses at a rate of 3% of the direct expenses for development of the joint property (including drillings but excluding legal expenses) and 13% of the direct expenses related to operating the joint property (other than payments under the terms of the Lease and royalties paid by the Operator on behalf of the participating parties, legal expenses and other exceptions). With regard to projects that include construction, installation or expansion of property, plant and equipment; removal, abandonment or restoration of platforms, production equipment and other operating facilities;and disasters;the Operator will charge (in place of the above rates) 1% - 5% for indirect expenses according to the rules prescribed in the accounting rules.

1.9.4. Work plans and budgets

The agreement prescribes a procedure for submission and approval of work plans, budgets and authorizations for expenditure (AFE) for operations in the Agreement Area. The Operator shall not execute a given project whose estimated cost exceeds USD 250,000 without prior written approval (or if approved by a vote of the parties to the agreement), other than operations required in emergencies, at its discretion as a reasonable and cautious the Operator. The Operation must notify the parties of any operation at an estimated cost of over USD 100,000 and up to USD 250,000. The Operator must notify the parties as soon as possible if the budget of an operation which is not yet completed is expected to exceed the permitted expense by over 15% or USD 500,000 (whichever is lower).

1.9.5. Collateral and liens of the rights of the parties

To guarantee their undertakings under the JOA, the parties other than the Operator granted the Operator the right of pledge, among others, of all of their rights in the Leases, the assets to be acquired in respect of the Leases and the operations to be performed under the operating agreements, their rights under all agreements of the project, and their rights in sale agreements and the proceeds of a sale ("Collateral to the Operator"). The agreement clarified that the Collateral to the Operator will have priority over rights acquired by any other individual from the partners in the Leases, and that any acquisition of interests in the Leases, whether by transfer, merger, pledge, action required by law or any other manner, will b subordinated to the Collateral to the Operation and the to the partners' rights under the JOA. In a similar manner, to guarantee the Operator's undertakings under the JOA, the Operator grants the parties which are not the Operator the same right of pledge.

1.9.6. Voting rights

In any matter brought to the vote, each party to the agreement will have voting rights according to their rate of holding of the rights (and in case of a non-consent operation, their rate of participation in that operation), as the case may be.

Unless prescribed otherwise in the agreement, the matter brought to the vote will be passed by one or more parties holding at least 51% of the voting rights. If there are only two parties to the agreement, the party with the majority voting rights will decide, and if the voting rights are equal, the decision will be passed unanimously.

Exploration, development and production operations performed by any of the parties, other than the first drilling approved with signing of the operating agreement and lease maintenance operations, will be performed if a decision to perform them is made by majority vote of at least two parties holding at least 51% of the voting rights. If any operation or activity is approved by two or more parties which hold less than 51% of the participation rights, but not by all parties, a party that voted against or elected not to participate in the operation, may cast a late vote within 48 hours from receiving the results of the decision and participate in the operation. If subsequent to the date at which a late vote may be cast, at least one party does not participate in the approved activity or operation, each party which voted for participation is required to notify the Operator within 48 hours whether it limits its rate of participation in the operation to it rate of holdings in the Leases or agrees to bear its pro rata share of the approved operation. If the participating parties agree to bear 100% of the costs and risks of the operation (including the share of the parties which elected not to participate), the Operator must perform it for the benefit of the participating parties.

1.9.7. Non-consent operations

The JOA prescribed that any decision to perform any operation in the Area of the Leases will be brought to the vote of the Lease partners. If this decision is approved by the required majority, but not by all partners, the partners which approved the operation may vote at their expense only, as a non-consent operation ("Non-Consent Operation"). Each partner may vote offer the partners to perform a Non-Consent Operation, provided that the proposed operation will not endanger, thwart or unreasonably interfere with the joint operations. The parties participating in a Non-Consent Operation will be responsible for any damage caused with regard to performance of the operation.

The agreement defines several possible situations for performance of Non-Consent Operations and different results of these operations with respect to the parties not participating in the operation. With respect to such operations which are unnecessary for Lease maintenance of the Leases, according to their terms or a binding regulatory provisions, the agreement prescribes that half of the rights of the non-participating parties with respect to an area in which that operation is to be performed, including the right to receive the oil produced, will be transferred to the parties participating in the operation (for no consideration) so long as the operation continues until the date at which the participating parties have returned their investment (with respect to the share of the parties that did not participate) out of the profits to be received from the production regarding the transferred rights plus a premium of their investment (between 600% and 800% in case of exploration, 300% in case of development and 100% in case of production). After such date, the parties which did not participate in the operation will once again be entitled to the said rights. If there is no production, the participation rights of the non-participating party will be reimbursed, except for rights in wells, platforms and development facilities, which will be remain under the ownership of the participating parties only. If, on the other hand, the Non-Consent Operation is (a) participation in the first exploration drilling (defined in the rights acquisition agreement); (b) a necessary operation for maintenance of the Leases, according to their terms or a binding regulatory provisions, or (c) an operation for construction of the first platform and the development facilities connected to it, the rights of the non-participating parties regarding the area in which the operation is performed will be forfeited and transferred to the parties participating in the operation for no consideration, whereby the non-participating parties will no longer have the right to regain them.

1.9.8. Sanctions applicable to the partners and conditions for their imposition

If a party fails to pay its proportionate share of expenses on time, including advances and interest, or makes another breach of its undertakings ("Breaching Party"), the Operation may send it notice that if it fails to pay within 30 days it will be considered in breach. The Breaching Party will be exposed to the sanctions set out in the agreement, and subject to given terms, the Operation may exercise against the Breaching Party the Collateral to the Operator given by it. So long as the breach continues, the Breaching Party will not be entitled to access to the platform, production systems, facilities, maps, records, data and information regarding the operation in the Leases and will not be entitled to participate in meetings. Moreover, so long as the breach continues, the Breaching Party will not be entitled to vote or make decision on matters set out in the agreement. The Breaching Party may notify the Operator that a specific payment was not paid as the result of a dispute in good faith regarding that payment, however, it must pay the amount in dispute and the Operator will act to settle the dispute as soon as possible.

1.9.9. Dilution of the partners' holdings - transfer of rights

The JOI sets out provisions and terms regarding the right of the partners to transfer or endorse the rights in the Leases. A party may transfer all or part of their rights in the Leases to a third party that has the financial capacity to bear the liabilities under the agreement, subject to provision of notice to the other parties and granting the right of first refusal to the other parties to acquire them under the terms stipulated in the agreement, except in certain cases in which notice or granting of the right of first refusal is not required, including if the party wishes to pledge all or part of its rights, and provided that such pledge will be subject to and deferred over the rights of the other parties to the JOI and the Collateral to the Operator.

1.9.10. Withdrawal from the Joint Operating Agreement

A party seeking to withdraw from the JOA or the Oil Assets must notify the other parties of its decision. Such notice will be unconditional and irrevocable ("The Withdrawal Notice"). Within 30 days after delivery of the Withdrawal Notice, the other parties to the JOA may also submit a Withdrawal Notice. If all parties submit a Withdrawal Notice, they will act to terminate their obligations related to the project and the Oil Assets. If only some of the parties decide to withdraw as set out above, the withdrawing party or parties will act immediately to transfer their rights to the partners which elected not to withdraw ("The Remaining Partners"). The transfer of the rights will be for no consideration and the withdrawing party will cover any expenses arising from withdrawal. The transfer of rights to the Remaining Parties will be divided according to their rate of holdings.

1.10. Reserves, contingent or prospective resources in the Oil Asset

1.10.1. Prospective resources in the Oil Asset

A. Quantitative data

According to the Resources Report, as of December 31, 2017, the prospective resources in the Tau Leases in the area of which the Tau Prospect is located, which comprises four main target layers, are as follows.

		Total in the Oil Asset (Gross)			**Company's Total Share (Net)**[9]		
		Low estimate	**Best estimate**	**High estimate**	**Low estimate**	**Best estimate**	**High estimate**
M1	Oil (MMBO)	12.0	42.9	106.4	9.0	32.2	79.8
	Gas (BCF)	20.4	72.6	181.2	15.3	54.5	135.9
M1A	Oil (MMBO)	10.4	26.6	59.5	7.8	20.0	44.6
	Gas (BCF)	18.0	45.0	100.8	13.5	33.8	75.6
M3	Oil (MMBO)	7.0	15.9	26.5	5.3	12.0	19.9
	Gas (BCF)	11.7	27.4	45.0	8.8	20.5	33.8
M4	Oil (MMBO)	1.9	5.6	12.5	1.4	4.2	9.4
	Gas (BCF)	3.0	9.6	21.0	2.3	7.2	15.8

9 Calculated according to a 75% participation rate.

B. The Resources Report was partially based on a 3D seismic survey conducted in 2003-2005 by TSA, the results of which were processed in 2013, data of adjacent producing fields and wells, and regional geological and engineering information.

C. Basic parameters used to calculate the different scenarios:

Parameter	Area (acres)		Average Net Thickness (Feet)		Porosity (decimal)	
	Low estimate	High estimate	Low estimate	High estimate	Low estimate	High estimate
M1	838	2,157	44	244	0.23	0.27
M1A	437	1,530	100	150	0.26	0.30
M3	581	1,796	50	150	0.23	0.27
M4	157	398	50	150	0.23	0.27

Parameter	Saturation (decimal)		Formation Volume Factor (RB/STB)[10]		Recovery Factor (decimal)	
	Low estimate	High estimate	Low estimate	High estimate	Low estimate	High estimate
M1	0.70	0.80	1.77	1.77	0.15	0.45
M1A	0.70	0.80	1.77	1.77	0.15	0.45
M3	0.70	0.80	1.77	1.77	0.15	0.45
M4	0.70	0.80	1.77	1.77	0.15	0.45

D. Material risks involved in continuation of the process

The significant risks involved in drilling this stage of operations in the Leases are mainly technical-operating risks, including risks of malfunctions in drilling operations and when running logs. If the technical-operating operations are completed, the risks later in the process to achieve a commercial finding include properties of the reservoir and/or the oil and gas that it contains, if any, will not be high enough to allow commercially sufficient quantity, etc.

E. The estimated probability of success of each of the risk factors in the oil exploration process and the total estimated probability of geological success are as follows:

Target layers	Parameter/probability of success (%)				Total probability of success
	Trap integrity	Reservoir quality	Source evaluation	Timing/migration	
M1	70	90	100	80	50
M1A	70	90	100	80	50
M3	65	70	100	80	36
M4	70	70	100	80	39

[10] Ratio between barrel volume in the reservoir and barrel volume on the surface.

F. Estimated probability of development for commercial production

As of the date of this report, and before drilling of the Tau Leases, the Company is unable to provide a reliable statistical estimate of the probability for development of the Prospect for commercial production. However, under the Resources Report, assuming there is a discovery in the well and based on development of similar gas and gas fields in the region and worldwide, the prospective resources in the best estimate category have a reasonable chance of becoming commercial. The potential markets for these resources are mainly the domestic (USA) and international markets. Therefore, if a commercial quantity of oil or natural gas is discovered in a drilling prospect, the Company will consider various alternatives to commercialization of the finding. It is noted that when assessing the potential for commercial production, an option may also be assessed for combining development of any discovery in the drilling, with development plans of other adjacent oil and gas discoveries, including through joint development.

G. The Company's explanations of the basic parameters used to calculate the different scenarios

The parameters used to calculate the different estimates are partially based on the results of the seismic survey, the results of drilling in nearby reservoirs, and knowledge of similar reservoirs in the area and in the world.

There is no certainty that any part of these potential resources will indeed be discovered, and if discovered, there is no certainty that it will be commercially possible to produce any part of the resources. The prospective information is not an evaluation in respect of the contingent reserves and resources, which can only be evaluated after exploration drilling, if at all.

Forward-looking information: The estimates of NSAI in respect of the prospective resources in the Tau Leases is forward-looking information as defined in the Securities Law. These estimates are partially based on geological, geophysical, engineering, and other information accessible to NSAI and from the Operator of the Leases, and are the professional estimates and assumptions only of and there can be no certainty in respect of them. Actual quantities of natural gas produced (if any) may be different from these estimates and assumptions, partly due to technical and operational conditions and/or regulatory changes and/or the supply and demand conditions in the natural gas market and/or commercial conditions, and/or actual performance of the reservoir. The estimates and assumptions may be revised if additional information becomes available and/or as the result of a range of factors related to oil and natural gas exploration and production projects.

1.10.2. The NSAI report noted several assumptions and reservations, including: (a) NSAI did not examine the economics of the Prospect; (b) NSAI did not visit the area of the Prospect; (c) NSAI did not examine possible exposure arising from environmental issues. However, NSAI noted that at the date of the Resources Report, it is unaware of any possible environmental liability that could have a material effect on the estimated quantity of resources in the Resources Report or their commercial viability.

The Company declares that all of the above information has been prepared in compliance with the Petroleum Resources Management System (SPE-PRMS).

1.10.3. <u>Expert opinion of the assessor:</u>

Attached to this report are the prospective Resources Report prepared by NSAI (Appendix B) as of December 31, 2017 and the consent of NSAI (Appendix C) to attach it to this report.

1.10.4. <u>Management declaration</u>

(1) Declaration date: January 8, 2018;

(2) Name of reporting corporation: Delek Group Ltd.

(3) Name of resource assessment officer: Asi Bartfeld, CEO;

(4) We hereby confirm that the assessor received all the information required to perform the work.

(5) We hereby confirm that nothing came to our attention that indicates any dependence between the assessor and the Company.

(6) We hereby confirm that, to the best of our knowledge, the resources reported are the most accurate and updated estimates available to us.

(7) We hereby confirm that the information included in this report was prepared according to professional terminology in chapter G of the Third Addendum to the Securities Regulations (Periodic and Immediate Reports), 1969 and the definition known for them in the Petroleum Resources Management System (2007) published by the Society of Petroleum Engineers (SPE), the American Association of Petroleum Geologists (AAPG), the World Petroleum Council (WPC) and the Society of Petroleum Evaluation Engineers (SPEE) as valid on the report date.

(8) We hereby confirm that no change has been made to the identity of the assessor that prepared the disclosure regarding the most recent resources issued by the Company.

(9) We consent to inclusion of the above statement in this report.

Asi Bartfeld - CEO

2. Canoe Lease

2.1. Information about the Oil Asset

General information about the Oil Asset	
Name of Oil Asset	Canoe
Location	The Canoe Prospect is the area of a federal Lease. The asset is located in the Gulf of Mexico, USA, off the coast of Louisiana, 218 km south west of New Orleans, USA.
Area	4,020 acres (16.27 sq.km).
Type of Oil Asset and description of permitted operations according to that type:	OCS-G 35589 (Block Vermilion 378) Lease Permitted operations - oil and gas exploration, development and production in the defined area known as a Lease under US government regulation.
Original grant date of the Oil Asset	July 1, 2015
Original expiry date of the Oil Asset	June 30, 2020
Decision date for extension of the term of the Oil Asset	-
Current expiry date of the Oil Asset	As stipulated above.
Note whether there is an additional option of extending the period of the Oil Asset: if so, note the period of the possible extension	Subject to the approval of the Commissioner on behalf of the Bureau of Safety and Environmental Enforcement (BSEE), may be extended for up to eight years from the original grant, subject to drilling a well with a true vertical depth (TVD) of 25,000 feet from the water surface, in the first five years. It is noted that as soon as a finding is discovered, the Lease will be valid so long as oil or gas are produced in commercial quantities, subject to the approval and requirements of BOEM and the relevant regulator.
Operator:	Gulf Slope Energy, Inc.
Names of the direct partners in the Oil Asset and their direct share in the Oil Asset and, to the best of the Company's knowledge, the names of the controlling owners in the partners	Delek GOM Investments LLC[11] - 75% Gulf Slope Energy, Inc.[12] - 20% Texas South Energy Inc.[13] – 5%

2.2. The Company's share in the Oil Asset

General information about the Company's share in the Oil Asset	
Acquisition date of the lease for the acquired Oil Asset:	January 1, 2018, according to the terms of the agreement for the acquisition of the rights described above.
Description of the Company's holding in the Oil Asset	Holding through a wholly owned foreign subsidiary.
Effective share of Oil Asset revenues attributable to equity holders of the Company:	60.9375%
Total share of the Company's equity holders in the cumulative investment in the Oil Asset in the five years preceding the last day of the reporting year (whether recognized as an expense or as an asset in the financial statements):	-

11 For further information, see footnote 4 above.
12 For further information, see footnote 5 above.
13 For further information, see footnote 6 above.

2.3. Operations before holding the Oil Asset

To the best of the Company's knowledge, according to information provided by the Transferors, no material operations will be performed in the area of the Oil Asset until the date of the agreement for the acquisition of rights, other than purchasing and processing seismic information.

2.4. Compliance with the terms of the work plan

According to the terms of the Leases, there is no detailed work plan binding the lease holders, however, extending the validity of the Leases is subject to exploration drilling during the Lease period, as set out in the table in section 2.1 above.

2.5. Planned Work Plan

Summary of the planned operations in the Lease area:

Period	**Summary of actual operations in the period or of the planned work plan**	**Estimated total budget for operations on the level of the Oil Asset (USD thousands)**	**Actual participation of the Company's equity holders in the budget (USD thousands)[14]**
2018 onwards	Preparations for drilling to obtain regulatory approvals, engineering preparations to carry out the drilling; environmental, geophysical and archaeological risk surveys.	738	664
	Exploration drilling, including releasing the drilling platform, sealing and abandonment of the well, and related expenses.	4,559	4,103

Forward-looking information: The Company's estimate regarding the planned operations in the Lease, including the costs, schedules, and actual performance, is forward-looking information as defined in the Securities Law, based on assessments regarding the components of the work plan and their costs, which may change from time to time. Implementation of the actual work plan, including schedules and costs, may differ materially from the above estimate and is subject, among other things, to market conditions, regulation, many external circumstances, including technical requirements and capacity, and economic viability.

2.6. Participation rate in the expenses and revenues

Participation rate	**%**	**Percentage grossed up to 100%**	**Explanations**
Actual rate attributable to Company's equity holders in the Oil Asset	75%	100%	See the description of the chain of holdings in section 2.2 above.
Actual share of Oil Asset **revenues** attributable to equity holders of the Company	60.9375%	81.25%	See the calculation in section 1.7 below.
Actual rate of participation of the Company's equity holders in **expenses** arising from exploration, development or production operations in the Oil Asset	**When the Undertaking to Bear Expenses is applicable:** 90% **When the Undertaking to Bear Expenses is not applicable:** 75%	120% 100%	See the calculation in section 2.8 below.

[14] For further information, see footnote above.7

2.7. Participation rate of the equity holders in revenues from the Oil Asset

Description	**%**	**Summary of the calculation method for royalties or payments (including deduction of expenses and others)**
Projected annual revenues of the Oil Asset	100%	
Royalties or payment (arising from revenues after the finding) related to the Oil Asset:		
Royalties to the US Federal Government	(18.75%)	
Adjusted revenues at the Oil Asset level	81.25%	
Share of the adjusted Oil Asset revenues attributable to the Company's equity holders (linked)	60.9375%	
Share of the equity holders of the Company in the actual rate of revenues, at the level of the Oil Asset (before other payments at the level of the Company)	75%	

2.8. Participation rate of the Company's equity holders in exploration, development and production expenses of the Oil Asset

Description	**When the Undertaking to Bear Expenses is applicable[15]**	**When the Undertaking to Bear Expenses is not applicable:**	**Summary of the calculation method for royalties or payment**
Theoretical expenses for the Oil Asset (without royalties)	100%		
Payments (derived from the expenses) at the level of the Oil Asset:			
Total actual rate of expenses at the level of the Oil Asset	100%		Excluding payments to the Operator calculated in a percentage of the different expenses, as described in section 1.9.3 above.
Share of the Company's equity holders in the Oil Asset's expenses (linked)	90%	75%	
Share of the equity holders of the Company in the actual rate of expense, at the level of the Oil Asset (before other payments at the level of the Company)	90%	75%	
Total	90%	75%	

[15] For further information, see footnote above.7

2.9. Description of material agreements between the partners in the Oil Asset

For further information regarding the JOA, see section 1.9 above.

2.10. Reserves, contingent or prospective resources in the Oil Asset

2.10.1. Prospective resources in the Oil Asset

A. Quantitative data

According to the Resources Report, as of December 31, 2017, the prospective resources in the Canoe Lease in the area of which the Canoe Prospect is located, which comprises four main target layers, are as follows:

Target layers		Total in the Oil Asset (gross)			The Company's share[16] (net)		
		Low estimate	Best estimate	High estimate	Low estimate	Best estimate	High estimate
S1	Oil (MMBO)	0.1	0.6	1.3	0.1	0.4	1.0
	Gas (BCF)	4.8	10.4	17.9	3.6	7.8	13.4
C	Oil (MMBO)	1.9	6.2	16.0	1.4	4.7	12.0
	Gas (BCF)	2.4	9.6	24.0	1.8	7.2	18.0
T3	Oil (MMBO)	0.6	1.7	3.8	0.5	1.3	2.9
	Gas (BCF)	0.6	2.4	6.0	0.5	1.8	4.5

B. The Resources Report was partially based on a 3D seismic survey conducted on 1995-1997 by PGS, the results of which were processed in 2016, data from adjacent producing fields and wells, and regional geological and engineering information.

C. Basic parameters used to calculate the different scenarios:

Parameter	Area (acres)		Average Net Thickness (Feet)		Porosity (decimal)	
	Low estimate	High estimate	Low estimate	High estimate	Low estimate	High estimate
S1	343	595	15	45	0.28	0.33
C	214	783	20	70	0.28	0.33
T3	64	160	25	75	0.28	0.33

[16] See footnote **שגיאה! הסימניה אינה מוגדרת.** above.

Parameter	Saturation (decimal)		Formation Volume Factor (RB/MCF)[17]		Formation Volume Factor (RB/STB)[18]		Recovery Factor (decimal)	
	Low estimate	High estimate	Low estimate	High estimate	Low estimate	High estimate	Low estimate	High estimate
S1	0.80	0.90	1.73	1.58	-	-	0.55	0.75
C	0.75	0.85	-	-	1.51	1.51	0.15	0.45
T3	0.75	0.85	-	-	1.53	1.53	0.15	0.45

D. Material risks involved in continuation of the process

The significant risks involved in drilling this stage of operations in the Lease are mainly technical-operating risks, including risks of malfunctions in drilling activities and when running logs. If the technical-operating operations are completed, the risks later in the process to achieve a commercial finding include properties of the reservoir and/or the oil and gas that it contains, if any, will not be high enough to allow commercially sufficient quantity, etc.

E. The estimated probability of success of each of the risk factors in the oil exploration process and the total estimated probability of geological success are as follows:

Target layers	Parameter / probability of success (%)				Total probability of success
	Trap integrity	Reservoir quality	Source evaluation	Timing / migration	
S1	90	95	100	90	77
C	90	80	100	80	58
T3	80	75	100	80	48

F. Estimated probability of development for commercial production

As of the date of the Resources Report, and before drilling the Canoe Lease, the Company is unable to provide a reliable statistical estimate of the probability for development of the Prospect for commercial production. However, under the Resources Report, assuming there is a discovery in the well and based on development of similar gas and gas fields in the region and in the world, the prospective resources in the best estimate category have a reasonable chance of becoming commercial. The potential markets for these resources are mainly the domestic (USA) and international markets. Therefore, if a commercial quantity of oil or natural gas is discovered in a drilling prospect, the Company will consider various alternatives to commercialization of the finding. It is noted that when assessing the potential for commercial production, an option may also be assessed for combining development of any discovery in the drilling, with development plans of other gas discoveries in the region, including through joint development.

17 Ratio between the barrel volume in the reservoir and a thousand cubic feet.
18 For further information, see footnote 10 above.

G. <u>The Company's explanations of the basic parameters used to calculate the different scenarios</u>

The parameters used to calculate the different estimates are partially based on the results of the seismic survey, the results of drilling in nearby reservoirs, and knowledge of similar reservoirs in the area and in the world.

There is no certainty that any part of these potential resources will indeed be discovered, and if discovered, there is no certainty that it will be commercially possible to produce any part of the resources. The prospective information is not an evaluation in respect of the contingent reserves and resources, which can only be evaluated after exploration drilling, if at all.

Forward-looking information: The estimates of NSAI in respect of the prospective resources in the Canoe Lease is forward-looking information as defined in the Securities Law. These estimates are partially based on geological, geophysical, engineering, and other information accessible to NSAI and received from the Lease Operator, and are the professional estimates and assumptions only of and there can be no certainty in respect of them. Actual quantities of natural gas produced (if any) may be different from these estimates and assumptions, partly due to technical and operational conditions and/or regulatory changes and/or the supply and demand conditions in the natural gas market and/or commercial conditions, and/or actual performance of the reservoir. The estimates and assumptions may be revised if additional information becomes available and/or as the result of a range of factors related to oil and natural gas exploration and production projects.

2.10.2. The NSAI report noted several assumptions and reservations, including: (a) NSAI did not examine the economics of the Prospect; (b) NSAI did not visit the area of the Prospect; (c) NSAI did not examine possible exposure arising from environmental issues. However, NSAI noted that at the date of the Resources Report, it is unaware of any possible environmental liability that could have a material effect on the estimated quantity of resources in the Resources Report or their commercial viability.

The Company declares that all of the above information has been prepared in compliance with the Petroleum Resources Management System (SPE-PRMS).

2.10.3. <u>Expert opinion of the assessor:</u>

Attached to this report are the prospective Resources Report prepared by NSAI (Appendix B) as of December 31, 2017 and the consent of NSAI (Appendix C) to attach it to this report.

2.10.4. <u>Management declaration</u>

(1) Declaration date: January 8, 2018;
(2) Name of reporting corporation: Delek Group Ltd.
(3) Name of resource assessment officer: Asi Bartfeld, CEO;
(4) We hereby confirm that the assessor received all the information required to perform the work.
(5) We hereby confirm that nothing came to our attention that indicates any dependence between the assessor and the Company.
(6) We hereby confirm that, to the best of our knowledge, the resources reported are the most accurate and updated estimates available to us.
(7) We hereby confirm that the information included in this report was prepared according to professional terminology in chapter G of the Third Addendum to the Securities Regulations (Periodic and Immediate Reports), 1969 and the definition known for them in the Petroleum Resources Management System (2007) published by the Society of Petroleum Engineers (SPE), the American Association of Petroleum Geologists (AAPG), the World Petroleum Council (WPC) and the Society

of Petroleum Evaluation Engineers (SPEE) as valid on the report date..

(8) We hereby confirm that no change has been made to the identity of the assessor that prepared the disclosure regarding the most recent resources issued by the Company.

(9) We consent to inclusion of the above statement in this report.

Asi Bartfeld - CEO

This is a convenience translation of the original HEBREW immediate report issued to the Tel Aviv Stock Exchange by the Company on January 8, 2018.

About The Delek Group

Delek Group is an independent E&P and the pioneering visionary behind the development of the East Med. With major finds in the Levant Basin, including the Leviathan (21.4 TCF) and Tamar (11.2 TCF) reservoirs and others, Delek is leading the region's development into a major natural gas export hub. In addition, Delek has embarked on an international expansion with a focus on high-potential opportunities in the North Sea and North America. Delek Group is one of Israel's largest and most prominent companies with a consistent track record of growth. Its shares are traded on the Tel Aviv Stock Exchange (TASE:DLEKG) and are part of the TA 35 Index.

For more information on Delek Group please visit www.delek-group.com

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C.H. (SCOTT) REES III
PRESIDENT & COO
DANNY D. SIMMONS
EXECUTIVE VP
G. LANCE BINDER

January 5, 2018

Delek Group Ltd.
19 Abba Eban Boulevard
Herzelia 4612001
Israel

Ladies and Gentlemen:

In accordance with your request, we have estimated the unrisked prospective resources, as of December 31, 2017, to the Potential Acquisition interest in certain prospects located in federal waters in the Gulf of Mexico. It is our understanding that Delek Group Ltd. (Delek) plans to purchase a 75 percent working interest in these prospects. We completed our evaluation on or about the date of this letter. Prospective resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. The prospective resources included in this report should not be construed as reserves or contingent resources; they represent exploration opportunities and quantify the development potential in the event a petroleum discovery is made. A geologic risk assessment was performed for these prospects, as discussed in subsequent paragraphs. There is no certainty that any portion of the prospective resources will be discovered. If they are discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources. The prospective resources shown in this report include on-lease volumes only. We did not perform an economic analysis on these resources; as such, the economic status of these resources is undetermined. The estimates in this report have been prepared in accordance with the definitions and guidelines set forth in the 2007 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE) and in accordance with internationally recognized standards, as stipulated by the Israel Securities Authority (ISA); definitions are presented immediately following this letter. This report has been prepared for Delek's use in filing with the ISA; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

Totals of unrisked prospective resources beyond the prospect and lead levels are not reflective of volumes that can be expected to be recovered and are therefore not shown. Because of the geologic risk associated with each prospect and lead, meaningful totals beyond these levels can be defined only by summing risked prospective resources. Such risk is often significant.

We estimate the unrisked gross (100 percent) prospective resources by area for these prospects, as of December 31, 2017, to be:

	Unrisked Gross (100%) Prospective Resources					
	Low Estimate		Best Estimate		High Estimate	
Area/Prospect	Oil (MMBBL)	Gas (BCF)	Oil (MMBBL)	Gas (BCF)	Oil (MMBBL)	Gas (BCF)
Canoe						
S1	0.1	4.8	0.6	10.4	1.3	17.9
C	1.9	2.4	6.2	9.6	16.0	24.0
T3	0.6	0.6	1.7	2.4	3.8	6.0
Graviton						
M3	0.5	8.3	0.7	10.3	0.7	11.4
M5	4.6	71.7	9.5	148.6	17.6	274.4
M8E	2.8	43.7	6.9	108.2	14.7	230.9
M10-11	2.0	31.2	5.0	78.4	10.6	165.3

	Unrisked Gross (100%) Prospective Resources					
	Low Estimate		Best Estimate		High Estimate	
Area/Prospect	Oil (MMBBL)	Gas (BCF)	Oil (MMBBL)	Gas (BCF)	Oil (MMBBL)	Gas (BCF)
Photon						
UP2 FB1	0.5	3.0	1.8	9.0	4.1	20.4
UP2 FB2	0.1	0.6	0.4	1.8	0.9	4.2
UP2 FB3	0.8	4.2	2.7	13.2	5.9	29.4
UP2 FB3.1	0.4	1.8	1.3	6.0	2.7	13.8
UP2 FB4	0.9	4.2	3.0	15.6	7.2	36.0
UP2 FB4.1	0.7	3.6	2.4	12.0	5.3	27.0
UP2 FB5	0.5	2.4	1.6	8.4	3.9	19.2
UP2 FB6	0.4	2.4	1.5	7.2	3.6	18.0
UP2 FB7	0.2	0.9	0.5	2.8	1.4	6.7
UMP1 FBE	0.5	2.4	1.7	8.4	3.9	19.8
UMP1 FBE2	0.2	1.2	0.7	3.6	1.9	9.6
UMP1 FBNC	0.3	1.8	1.1	5.4	2.6	13.2
UMP1 FBSC	0.6	3.0	2.0	10.2	4.6	23.4
UMP1 FBS	1.4	7.2	4.9	24.6	11.7	58.8
UMP2 FB1	2.0	9.6	6.8	34.2	15.3	76.8
UMP2 FB2	0.8	4.2	2.9	14.4	6.6	33.0
UMP2 FB3	0.8	3.6	2.7	13.2	5.8	29.4
UMP3 FBW	0.9	4.8	3.1	15.0	6.8	34.8
UMP4 FB1	0.8	4.2	2.8	13.8	6.5	32.4
UMP4 FB2	1.1	5.4	3.6	18.6	8.6	43.2
Pomeron						
PL-5A	0.9	21.3	1.8	46.6	3.9	96.6
PL-5B	0.4	9.7	0.7	15.7	1.0	24.0
DEEP	0.9	21.2	1.9	47.3	3.9	95.1
Quark						
UMP2	0.2	54.4	0.7	135.1	1.3	266.8
LP2	0.1	25.8	0.3	66.6	0.7	143.9
Tanker						
M5	2.3	35.7	5.6	87.2	12.6	197.2
M8	2.8	44.0	6.5	100.9	12.6	196.4
M10	2.8	44.8	7.3	114.6	14.8	231.4
Tau						
M1	12.0	20.4	42.9	72.6	106.4	181.2
M1A	10.4	18.0	26.6	45.0	59.5	100.8
M3	7.0	11.7	15.9	27.4	26.5	45.0
M4	1.9	3.0	5.6	9.6	12.5	21.0

We estimate the unrisked working interest prospective resources to the Potential Acquisition interest in these prospects by area, as of December 31, 2017, to be:

	Unrisked Working Interest Prospective Resources					
	Low Estimate		Best Estimate		High Estimate	
Area/Prospect	Oil (MMBBL)	Gas (BCF)	Oil (MMBBL)	Gas (BCF)	Oil (MMBBL)	Gas (BCF)
Canoe						
S1	0.1	3.6	0.4	7.8	1.0	13.4
C	1.4	1.8	4.7	7.2	12.0	18.0
T3	0.5	0.5	1.3	1.8	2.9	4.5

Area/Prospect	Unrisked Working Interest Prospective Resources: Low Estimate Oil (MMBBL)	Low Estimate Gas (BCF)	Best Estimate Oil (MMBBL)	Best Estimate Gas (BCF)	High Estimate Oil (MMBBL)	High Estimate Gas (BCF)
Graviton						
M3	0.4	6.2	0.5	7.7	0.5	8.5
M5	3.4	53.8	7.1	111.5	13.2	205.8
M8E	2.1	32.8	5.2	81.1	11.1	173.2
M10-11	1.5	23.4	3.8	58.8	7.9	124.0
Photon						
UP2 FB1	0.4	2.3	1.4	6.8	3.1	15.3
UP2 FB2	0.1	0.5	0.3	1.4	0.7	3.2
UP2 FB3	0.6	3.2	2.0	9.9	4.4	22.1
UP2 FB3.1	0.3	1.4	1.0	4.5	2.0	10.4
UP2 FB4	0.7	3.2	2.3	11.7	5.4	27.0
UP2 FB4.1	0.5	2.7	1.8	9.0	4.0	20.3
UP2 FB5	0.4	1.8	1.2	6.3	2.9	14.4
UP2 FB6	0.3	1.8	1.1	5.4	2.7	13.5
UP2 FB7	0.1	0.7	0.4	2.1	1.0	5.0
UMP1 FBE	0.4	1.8	1.3	6.3	2.9	14.9
UMP1 FBE2	0.2	0.9	0.5	2.7	1.4	7.2
UMP1 FBNC	0.2	1.4	0.8	4.1	2.0	9.9
UMP1 FBSC	0.5	2.3	1.5	7.7	3.5	17.6
UMP1 FBS	1.1	5.4	3.7	18.5	8.8	44.1
UMP2 FB1	1.5	7.2	5.1	25.7	11.5	57.6
UMP2 FB2	0.6	3.2	2.2	10.8	5.0	24.8
UMP2 FB3	0.6	2.7	2.0	9.9	4.4	22.1
UMP3 FBW	0.7	3.6	2.3	11.3	5.1	26.1
UMP4 FB1	0.6	3.2	2.1	10.4	4.9	24.3
UMP4 FB2	0.8	4.1	2.7	14.0	6.5	32.4
Pomeron						
PL-5A	0.6	16.0	1.4	35.0	2.9	72.5
PL-5B	0.3	7.3	0.5	11.8	0.8	18.0
DEEP	0.7	15.9	1.4	35.5	2.9	71.3
Quark						
UMP2	0.2	40.8	0.5	101.3	1.0	200.1
LP2	0.1	19.4	0.2	50.0	0.5	107.9
Tanker						
M5	1.7	26.8	4.2	65.4	9.5	147.9
M8	2.1	33.0	4.9	75.7	9.4	147.3
M10	2.1	33.6	5.5	86.0	11.1	173.6
Tau						
M1	9.0	15.3	32.2	54.5	79.8	135.9
M1A	7.8	13.5	20.0	33.8	44.6	75.6
M3	5.3	8.8	12.0	20.5	19.9	33.8
M4	1.4	2.3	4.2	7.2	9.4	15.8

The oil volumes shown include crude oil and condensate. Oil volumes are expressed in millions of barrels (MMBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in billions of cubic feet (BCF) at standard temperature and pressure bases.

The prospective resources shown in this report have been estimated using probabilistic methods and are dependent on a petroleum discovery being made. If a discovery is made and development is undertaken, the probability that the recoverable volumes will equal or exceed the unrisked estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate.

Unrisked prospective resources are estimated ranges of recoverable oil and gas volumes assuming their discovery and development and are based on estimated ranges of undiscovered in-place volumes. Geologic risking of prospective resources addresses the probability of success for the discovery of a significant quantity of potentially moveable petroleum; this risk analysis is conducted independent of estimations of petroleum volumes and without regard to the chance of development. Principal geologic risk elements of the petroleum system include (1) trap and seal characteristics; (2) reservoir presence and quality; (3) source rock capacity, quality, and maturity; and (4) timing, migration, and preservation of petroleum in relation to trap and seal formation. Risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators and is subject to revision with further data acquisition or interpretation. The primary geologic risks and overall probability of geologic success by area for each prospect are shown in Table I. A summary of seismic data sets used in this assessment is shown in Table II.

Each prospect was evaluated to determine ranges of in-place and recoverable petroleum and was risked as an independent entity without dependency between potential prospect drilling outcomes. If petroleum discoveries are made, smaller-volume prospects may not be commercial to independently develop, although they may become candidates for satellite developments and tie-backs to existing infrastructure at some future date. The development infrastructure and data obtained from early discoveries will alter both geologic risk and future economics of subsequent discoveries and developments.

It should be understood that the prospective resources discussed and shown herein are those undiscovered, highly speculative resources estimated beyond reserves or contingent resources where geological and geophysical data suggest the potential for discovery of petroleum but where the level of proof is insufficient for classification as reserves or contingent resources. The unrisked prospective resources shown in this report are the range of volumes that could reasonably be expected to be recovered in the event of the discovery and development of these prospects.

For the purposes of this report, we did not perform any field inspection of the prospects. We have not investigated possible environmental liability related to the prospects; however, we are not currently aware of any possible environmental liability that would have any material effect on the resources quantities estimated in this report or the commerciality of such estimates.

For the purposes of this report, we used technical data including, but not limited to, well logs from offset discoveries, geologic maps, seismic data, well test and production data from analog wells, and property ownership interests. We were provided with all the necessary data to prepare the estimates for these prospects, and we were not limited from access to any material we believe may be relevant. The resources in this report have been estimated using probabilistic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to classify, categorize, and estimate volumes in accordance with the 2007 PRMS definitions and guidelines. Certain parameters used in our volumetric analysis are summarized in Tables III through X. These resources are for undeveloped locations; such resources 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 prospective information is not an assessment regarding the reserves and contingent resources, which can be assessed only after exploratory drilling, if at all.

Netherland, Sewell & Associates, Inc. (NSAI) was engaged on August 25, 2017, by Mr. Assi Bartfeld, Chief Executive Officer of Delek, to perform this assessment. The data used in our estimates were obtained from Delek, public data sources, and the nonconfidential files of NSAI and were accepted as accurate. Supporting work data are on file in our office. We have not examined the contractual rights to the prospects or independently confirmed the actual degree or type of interest owned. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these prospects nor are we employed on a contingent basis. Furthermore, no limitations or restrictions were placed upon NSAI by officials of Delek.

QUALIFICATIONS

NSAI performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. We provide a complete range of geological, geophysical, petrophysical, and engineering services, and we have the technical expertise and ability to perform these services in any oil and gas producing area in the world. The staff are familiar with the recognized industry reserves and resources definitions, specifically those promulgated by the U.S. Securities and Exchange Commission, by the Alberta Securities Commission, and by the SPE, Society of Petroleum Evaluation Engineers, World Petroleum Council, and American Association of Petroleum Geologists. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards.

This assessment has been led by Mr. Richard B. Talley, Jr. and Mr. Zachary R. Long. Mr. Talley is a Senior Vice President and Mr. Long is a Vice President in the firm's Houston office at 1301 McKinney Street, Suite 3200, Houston, Texas 77010, USA. Mr. Talley is a Licensed Professional Engineer (Texas Registration No. 102425). He has been practicing petroleum engineering consulting at NSAI since 2004 and has over 5 years of prior industry experience. Mr. Long is a Licensed Professional Geoscientist (Texas Registration No. 11792). He has been practicing petroleum geoscience consulting at NSAI since 2007 and has over 2 years of prior industry experience.

Sincerely,

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

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PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, March 2007

This document contains information excerpted from definitions and guidelines prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE).

Preamble

Petroleum resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating development projects, and presenting results within a comprehensive classification framework.

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum resources. It is expected that this document will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

1.0 Basic Principles and Definitions

The estimation of petroleum resource quantities involves the interpretation of volumes and values that have an inherent degree of uncertainty. These quantities are associated with development projects at various stages of design and implementation. Use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios according to forecast production profiles and recoveries. Such a system must consider both technical and commercial factors that impact the project's economic feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide and sulfur. In rare cases, non-hydrocarbon content could be greater than 50%.

The term "resources" as used herein is intended to encompass all quantities of petroleum naturally occurring on or within the Earth's crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered "conventional" or "unconventional."

Figure 1-1 is a graphical representation of the SPE/WPC/AAPG/SPEE resources classification system. The system defines the major recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.

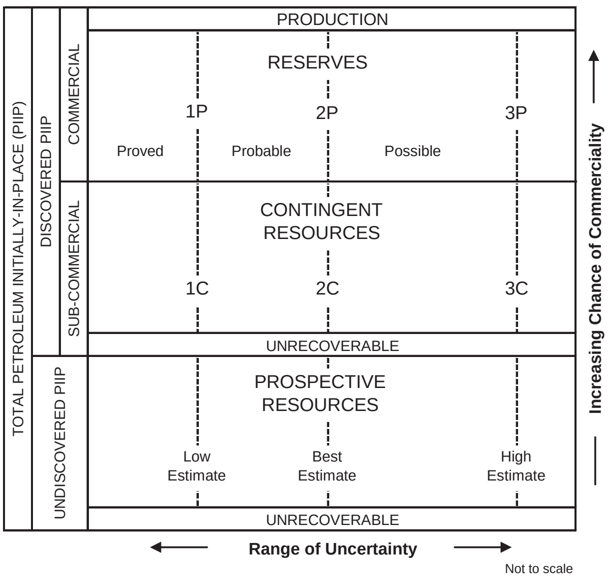

Figure 1-1: Resources Classification Framework.

The "Range of Uncertainty" reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the "Chance of

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Commerciality", that is, the chance that the project that will be developed and reach commercial producing status. The following definitions apply to the major subdivisions within the resources classification:

TOTAL PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

DISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

PRODUCTION is the cumulative quantity of petroleum that has been recovered at a given date. While all recoverable resources are estimated and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Production Measurement, section 3.2).

Multiple development projects may be applied to each known accumulation, and each project will recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into Commercial and Sub-Commercial, with the estimated recoverable quantities being classified as Reserves and Contingent Resources respectively, as defined below.

RESERVES are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

CONTINGENT RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be subclassified based on project maturity and/or characterized by their economic status.

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

PROSPECTIVE RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

UNRECOVERABLE is that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Estimated Ultimate Recovery (EUR) is not a resources category, but a term that may be applied to any accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable under defined technical and commercial conditions plus those quantities already produced (total of recoverable resources).

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1.2 Project-Based Resources Evaluations

The resources evaluation process consists of identifying a recovery project, or projects, associated with a petroleum accumulation(s), estimating the quantities of Petroleum Initially-in-Place, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on its maturity status or chance of commerciality.

This concept of a project-based classification system is further clarified by examining the primary data sources contributing to an evaluation of net recoverable resources (see Figure 1-2) that may be described as follows:

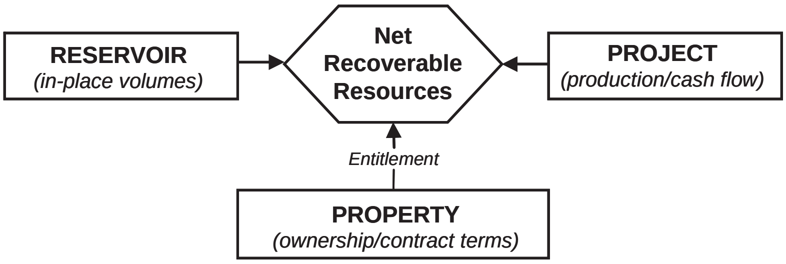

Figure 1-2: Resources Evaluation Data Sources.

- The Reservoir (accumulation): Key attributes include the types and quantities of Petroleum Initially-in-Place and the fluid and rock properties that affect petroleum recovery.

- The Project: Each project applied to a specific reservoir development generates a unique production and cash flow schedule. The time integration of these schedules taken to the project's technical, economic, or contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to Total Initially-in-Place quantities defines the ultimate recovery efficiency for the development project(s). A project may be defined at various levels and stages of maturity; it may include one or many wells and associated production and processing facilities. One project may develop many reservoirs, or many projects may be applied to one reservoir.

- The Property (lease or license area): Each property may have unique associated contractual rights and obligations including the fiscal terms. Such information allows definition of each participant's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations.

In context of this data relationship, "project" is the primary element considered in this resources classification, and net recoverable resources are the incremental quantities derived from each project. Project represents the link between the petroleum accumulation and the decision-making process. A project may, for example, constitute the development of a single reservoir or field, or an incremental development for a producing field, or the integrated development of several fields and associated facilities with a common ownership. In general, an individual project will represent the level at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for that project.

An accumulation or potential accumulation of petroleum may be subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resource classes simultaneously.

In order to assign recoverable resources of any class, a development plan needs to be defined consisting of one or more projects. Even for Prospective Resources, the estimates of recoverable quantities must be stated in terms of the sales products derived from a development program assuming successful discovery and commercial development. Given the major uncertainties involved at this early stage, the development program will not be of the detail expected in later stages of maturity. In most cases, recovery efficiency may be largely based on analogous projects. In-place quantities for which a feasible project cannot be defined using current, or reasonably forecast improvements in, technology are classified as Unrecoverable.

Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on a forecast of the conditions that will exist during the time period encompassed by the project's activities (see

Commercial Evaluations, section 3.1). "Conditions" include technological, economic, legal, environmental, social, and governmental factors. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions, transportation and processing infrastructure, fiscal terms, and taxes.

The resource quantities being estimated are those volumes producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Reference Point, section 3.2.1). The cumulative production from the evaluation date forward to cessation of production is the remaining recoverable quantity. The sum of the associated annual net cash flows yields the estimated future net revenue. When the cash flows are discounted according to a defined discount rate and time period, the summation of the discounted cash flows is termed net present value (NPV) of the project (see Evaluation and Reporting Guidelines, section 3.0).

The supporting data, analytical processes, and assumptions used in an evaluation should be documented in sufficient detail to allow an independent evaluator or auditor to clearly understand the basis for estimation and categorization of recoverable quantities and their classification.

2.0 Classification and Categorization Guidelines

2.1 Resources Classification

The basic classification requires establishment of criteria for a petroleum discovery and thereafter the distinction between commercial and sub-commercial projects in known accumulations (and hence between Reserves and Contingent Resources).

2.1.1 Determination of Discovery Status

A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons.

In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery. Estimated recoverable quantities within such a discovered (known) accumulation(s) shall initially be classified as Contingent Resources pending definition of projects with sufficient chance of commercial development to reclassify all, or a portion, as Reserves. Where in-place hydrocarbons are identified but are not considered currently recoverable, such quantities may be classified as Discovered Unrecoverable, if considered appropriate for resource management purposes; a portion of these quantities may become recoverable resources in the future as commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

Discovered recoverable volumes (Contingent Resources) may be considered commercially producible, and thus Reserves, if the entity claiming commerciality has demonstrated firm intention to proceed with development and such intention is based upon all of the following criteria:

- Evidence to support a reasonable timetable for development.
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria.
- A reasonable expectation that there will be a market for all or at least the expected sales quantities of production required to justify development.
- Evidence that the necessary production and transportation facilities are available or can be made available.
- Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.

To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

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To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

2.2 Resources Categorization

The horizontal axis in the Resources Classification (Figure 1.1) defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project. These estimates include both technical and commercial uncertainty components as follows:

- The total petroleum remaining within the accumulation (in-place resources).
- That portion of the in-place petroleum that can be recovered by applying a defined development project or projects.
- Variations in the commercial conditions that may impact the quantities recovered and sold (e.g., market availability, contractual changes).

Where commercial uncertainties are such that there is significant risk that the complete project (as initially defined) will not proceed, it is advised to create a separate project classified as Contingent Resources with an appropriate chance of commerciality.

2.2.1 Range of Uncertainty

The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution (see Deterministic and Probabilistic Methods, section 4.2).

When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

- There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental (risk-based) approach, quantities at each level of uncertainty are estimated discretely and separately (see Category Definitions and Guidelines, section 2.2.2).

These same approaches to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources. While there may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable quantities independently of such a risk or consideration of the resource class to which the quantities will be assigned.

2.2.2 Category Definitions and Guidelines

Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental (risk-based) approach, the deterministic scenario (cumulative) approach, or probabilistic methods (see "2001 Supplemental Guidelines," Chapter 2.5). In many cases, a combination of approaches is used.

Use of consistent terminology (Figure 1.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high estimates are denoted as 1P/2P/3P, respectively. The associated incremental quantities are termed Proved, Probable and Possible. Reserves are a subset of, and must be viewed within context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, they can be equally applied to Contingent and Prospective Resources conditional upon their satisfying the criteria for discovery and/or development.

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For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively. For Prospective Resources, the general cumulative terms low/best/high estimates still apply. No specific terms are defined for incremental quantities within Contingent and Prospective Resources.

Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorization boundaries when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves. All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Commercial Evaluations, section 3.1).

Based on additional data and updated interpretations that indicate increased certainty, portions of Possible and Probable Reserves may be re-categorized as Probable and Proved Reserves.

Uncertainty in resource estimates is best communicated by reporting a range of potential results. However, if it is required to report a single representative result, the "best estimate" is considered the most realistic assessment of recoverable quantities. It is generally considered to represent the sum of Proved and Probable estimates (2P) when using the deterministic scenario or the probabilistic assessment methods. It should be noted that under the deterministic incremental (risk-based) approach, discrete estimates are made for each category, and they should not be aggregated without due consideration of their associated risk (see "2001 Supplemental Guidelines," Chapter 2.5).

Table 1: Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	**Definition**	**Guidelines**
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project "chance of commerciality" can be said to be 100%. The project "decision gate" is the decision to initiate commercial production from the project.

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Class/Sub-Class	**Definition**	**Guidelines**
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project "decision gate" is the decision to start investing capital in the construction of production facilities and/or drilling development wells.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity's assumptions of future prices, costs, etc. ("forecast case") and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to demonstrate commerciality. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class). The project "decision gate" is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/evaluation results could lead to a re-classification of the project to "On Hold" or "Not Viable" status. The project "decision gate" is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development Unclarified or on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, could lead to a reclassification of the project to "Not Viable" status. The project "decision gate" is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.

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Class/Sub-Class	Definition	Guidelines
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project "decision gate" is the decision not to undertake any further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2: Reserves Status Definitions and Guidelines

Status	Definition	Guidelines
Developed Reserves	Developed Reserves are expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified 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 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 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.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, March 2007

Status	Definition	Guidelines
Undeveloped Reserves	Undeveloped Reserves are quantities expected to be recovered through future investments:	(1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3: Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term reasonable certainty is intended to express 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. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see "2001 Supplemental Guidelines," Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that: • The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive. • Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, March 2007

Category	Definition	Guidelines
Possible Reserves	Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	(See above for separate criteria for Probable Reserves and Possible Reserves.)	The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or 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 minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

The 2007 Petroleum Resources Management System can be viewed in its entirety at
http://www.spe.org/spe-app/spe/industry/reserves/prms.htm.

PRIMARY GEOLOGIC RISKS AND PROBABILITY OF GEOLOGIC SUCCESS
FEDERAL WATERS IN THE GULF OF MEXICO
AS OF DECEMBER 31, 2017

		Geologic Risk Element (%)				Probability of Geologic Success
Area/Prospect	Primary Geologic Risks	Trap Integrity	Reservoir Quality	Source Evaluation	Timing/ Migration	(%)
Canoe						
S1	Reservoir Quality and Timing/Migration	90	95	100	90	77
C	Reservoir Quality and Timing/Migration	90	80	100	80	58
T3	Reservoir Quality and Timing/Migration	80	75	100	80	48
Graviton						
M3	Trap Integrity and Timing/Migration	80	90	100	70	50
M5	Trap Integrity and Timing/Migration	70	90	100	70	44
M8E	Trap Integrity and Timing/Migration	60	90	100	70	38
M10-11	Trap Integrity and Timing/Migration	60	65	100	70	27
Photon						
UP2 FB1	Trap Integrity	75	80	90	80	43
UP2 FB2	Trap Integrity	70	75	90	80	38
UP2 FB3	Trap Integrity	75	80	90	80	43
UP2 FB3.1	Trap Integrity	75	80	90	80	43
UP2 FB4	Trap Integrity	75	80	90	80	43
UP2 FB4.1	Trap Integrity	75	80	90	80	43
UP2 FB5	Trap Integrity	75	80	90	80	43
UP2 FB6	Trap Integrity	75	80	90	80	43
UP2 FB7	Trap Integrity	75	80	90	80	43
UMP1 FBE	Trap Integrity	75	80	90	80	43
UMP1 FBE2	Trap Integrity	75	80	90	80	43
UMP1 FBNC	Trap Integrity	75	80	90	80	43
UMP1 FBSC	Trap Integrity	75	80	90	80	43
UMP1 FBS	Trap Integrity	70	75	90	80	38
UMP2 FB1	Trap Integrity	75	80	90	80	43
UMP2 FB2	Trap Integrity	75	80	90	80	43
UMP2 FB3	Trap Integrity	65	65	90	80	30
UMP3 FBW	Trap Integrity	75	80	90	80	43
UMP4 FB1	Trap Integrity	75	80	90	80	43
UMP4 FB2	Trap Integrity	65	75	90	80	35
Pomeron						
PL-5A	Trap Integrity	50	70	90	70	22
PL-5B	Trap Integrity	50	70	90	70	22
DEEP	Trap Integrity	50	65	90	70	20
Quark						
UMP2	Trap Integrity	60	70	90	70	26
LP2	Trap Integrity	60	70	90	70	26
Tanker						
M5	Trap Integrity and Timing/Migration	70	90	100	70	44
M8	Trap Integrity and Timing/Migration	60	90	100	70	38
M10	Trap Integrity and Timing/Migration	60	65	100	70	27
Tau						
M1	Trap Integrity	70	90	100	80	50
M1A	Trap Integrity	70	90	100	80	50
M3	Trap Integrity	65	70	100	80	36
M4	Trap Integrity	70	70	100	80	39

SUMMARY OF SEISMIC DATA SETS
FEDERAL WATERS IN THE GULF OF MEXICO
AS OF DECEMBER 31, 2017

Area	Seismic Data Type	Acquisition Company	Acquisition Year(s)	Processing Type	Processing Year
Canoe	PSTM	Seismic Exchange, Inc.	1995-96	PSTM Merg	2009
Graviton	PSTM/PSDM "E-Bear"	Western Geophysical	Unknown	Kirchoff PSTM/ WEM-RTM PSDM	2010
Photon	PSTM/PSDM "E-Bear"	Western Geophysical	Unknown	Kirchoff PSTM/ WEM-RTM PSDM	2010
Pomeron	TGS La. Renaissance	TGS-NOPEC Geophysical Company	1997	Kirchoff PSTM	2003
Quark	Post Stack Migration	Western Geophysical	Unknown	Post Stack Migration	Unknown
Tanker	TGS La. Renaissance	TGS-NOPEC Geophysical Company	1997	Kirchoff PSTM	2003
Tau	Post Stack Migration	Western Geophysical	Unknown	Post Stack Migration	Unknown

Notes: The abbreviation PSTM represents Prestack Time Migration.
The abbreviation PSDM represents Prestack Depth Migration.
The abbreviation WEM represents Wavefield Extrapolation Migration.
The abbreviation RTM represents Reverse Time Migration.

MONTE CARLO INPUT DISTRIBUTION SUMMARY
PROSPECTIVE GAS RESOURCES
CANOE AREA
AS OF DECEMBER 31, 2017

	Area (acres) Lognormal Distribution		Average Net Thickness (feet) Normal Distribution		Porosity (decimal) Normal Distribution	
Prospect	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
S1	343	595	15	45	0.28	0.33

	Gas Saturation (decimal) Normal Distribution		Gas Formation Volume Factor (RB/MCF)[1] Normal Distribution		Gas Recovery Factor (decimal) Normal Distribution	
Prospect	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
S1	0.80	0.90	1.73	1.58	0.55	0.75

Note: For the purposes of this report, we used technical data including, but not limited to, well logs from offset discoveries, geologic maps, seismic data, well test and production data from analog wells, and property ownership interests.

(1) The abbreviation RB/MCF represents reservoir barrels per thousand standard cubic feet.

MONTE CARLO INPUT DISTRIBUTION SUMMARY
PROSPECTIVE OIL RESOURCES
CANOE AREA
AS OF DECEMBER 31, 2017

Prospect	Area (acres) Lognormal Distribution		Average Net Thickness (feet) Normal Distribution		Porosity (decimal) Normal Distribution	
	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
C	214	783	20	70	0.28	0.33
T3	64	160	25	75	0.28	0.33

Prospect	Oil Saturation (decimal) Normal Distribution		Oil Formation Volume Factor (RB/STB)[1] Uniform Distribution		Oil Recovery Factor (decimal) Normal Distribution	
	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
C	0.75	0.85	1.51	1.51	0.15	0.45
T3	0.75	0.85	1.53	1.53	0.15	0.45

Note: For the purposes of this report, we used technical data including, but not limited to, well logs from offset discoveries, geologic maps, seismic data, well test and production data from analog wells, and property ownership interests.

(1) The abbreviation RB/STB represents reservoir barrels per stock tank barrel.

MONTE CARLO INPUT DISTRIBUTION SUMMARY
PROSPECTIVE GAS RESOURCES
GRAVITON AREA
AS OF DECEMBER 31, 2017

	Area[1] (acres) Lognormal Distribution		Average Net Thickness (feet) Normal Distribution		Porosity (decimal) Normal Distribution	
Prospect	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
M3	282	565	85	135	0.28	0.32
M5	778	1,500	50	125	0.22	0.27
M8E	393	1,363	50	150	0.20	0.24
M10-11	252	844	50	200	0.20	0.24

	Gas Saturation (decimal) Normal Distribution		Gas Formation Volume Factor (RB/MCF)[2] Uniform Distribution		Gas Recovery Factor (decimal) Normal Distribution	
Prospect	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
M3	0.70	0.80	0.49	0.49	0.50	0.70
M5	0.70	0.80	0.48	0.48	0.50	0.70
M8E	0.70	0.80	0.47	0.47	0.50	0.70
M10-11	0.70	0.80	0.47	0.47	0.50	0.70

Note: For the purposes of this report, we used technical data including, but not limited to, well logs from offset discoveries, geologic maps, seismic data, well test and production data from analog wells, and property ownership interests.

(1) The area shown includes both on-lease and off-lease acres for the prospects.
(2) The abbreviation RB/MCF represents reservoir barrels per thousand standard cubic feet.

MONTE CARLO INPUT DISTRIBUTION SUMMARY
PROSPECTIVE OIL RESOURCES
PHOTON AREA
AS OF DECEMBER 31, 2017

	Area (acres) Lognormal Distribution		Average Net Thickness (feet) Normal Distribution		Porosity (decimal) Normal Distribution	
Prospect	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
UP2 FB1	85	161	20	100	0.24	0.30
UP2 FB2	17	35	20	100	0.24	0.30
UP2 FB3	130	225	20	100	0.24	0.30
UP2 FB3.1	66	100	20	100	0.24	0.30
UP2 FB4	125	296	20	100	0.24	0.30
UP2 FB4.1	114	205	20	100	0.24	0.30
UP2 FB5	70	160	20	100	0.24	0.30
UP2 FB6	57	155	20	100	0.24	0.30
UP2 FB7	20	60	20	100	0.24	0.30

	Oil Saturation (decimal) Normal Distribution		Oil Formation Volume Factor (RB/STB)[1] Uniform Distribution		Oil Recovery Factor (decimal) Normal Distribution	
Prospect	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
UP2 FB1	0.70	0.80	1.66	1.66	0.15	0.45
UP2 FB2	0.70	0.80	1.66	1.66	0.15	0.45
UP2 FB3	0.70	0.80	1.66	1.66	0.15	0.45
UP2 FB3.1	0.70	0.80	1.66	1.66	0.15	0.45
UP2 FB4	0.70	0.80	1.64	1.64	0.15	0.45
UP2 FB4.1	0.70	0.80	1.66	1.66	0.15	0.45
UP2 FB5	0.70	0.80	1.69	1.69	0.15	0.45
UP2 FB6	0.70	0.80	1.66	1.66	0.15	0.45
UP2 FB7	0.70	0.80	1.64	1.64	0.15	0.45

Note: For the purposes of this report, we used technical data including, but not limited to, well logs from offset discoveries, geologic maps, seismic data, well test and production data from analog wells, and property ownership interests.

[1] The abbreviation RB/STB represents reservoir barrels per stock tank barrel.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

MONTE CARLO INPUT DISTRIBUTION SUMMARY
PROSPECTIVE OIL RESOURCES
PHOTON AREA
AS OF DECEMBER 31, 2017

Prospect	Area (acres) Lognormal Distribution Low Estimate	High Estimate	Average Net Thickness (feet) Normal Distribution Low Estimate	High Estimate	Porosity (decimal) Normal Distribution Low Estimate	High Estimate
UMP1 FBE	77	172	20	100	0.24	0.28
UMP1 FBE2	28	93	20	100	0.24	0.28
UMP1 FBNC	50	111	20	100	0.24	0.28
UMP1 FBSC	93	199	20	100	0.24	0.28
UMP1 FBS	218	522	20	100	0.24	0.28
UMP2 FB1	348	655	20	100	0.22	0.28
UMP2 FB2	145	291	20	100	0.22	0.28
UMP2 FB3	146	242	20	100	0.22	0.28
UMP3 FBW	146	272	20	100	0.24	0.29
UMP4 FB1	137	264	20	100	0.24	0.29
UMP4 FB2	171	355	20	100	0.24	0.29

Prospect	Oil Saturation (decimal) Normal Distribution Low Estimate	High Estimate	Oil Formation Volume Factor (RB/STB)(1) Uniform Distribution Low Estimate	High Estimate	Oil Recovery Factor (decimal) Normal Distribution Low Estimate	High Estimate
UMP1 EAST	0.70	0.80	1.70	1.70	0.15	0.45
UMP1 EAST2	0.70	0.80	1.70	1.70	0.15	0.45
UMP1 NCENT	0.70	0.80	1.70	1.70	0.15	0.45
UMP1 SCENT	0.70	0.80	1.70	1.70	0.15	0.45
UMP1 SOUTH	0.70	0.80	1.70	1.70	0.15	0.45
UMP2 FB1	0.70	0.80	1.71	1.71	0.15	0.45
UMP2 FB2	0.70	0.80	1.71	1.71	0.15	0.45
UMP2 FB3	0.70	0.80	1.71	1.71	0.15	0.45
UMP3 WEST	0.70	0.80	1.67	1.67	0.15	0.45
UMP4 FB1	0.70	0.80	1.69	1.69	0.15	0.45
UMP4 FB2	0.70	0.80	1.69	1.69	0.15	0.45

Note: For the purposes of this report, we used technical data including, but not limited to, well logs from offset discoveries, geologic maps, seismic data, well test and production data from analog wells, and property ownership interests.

(1) The abbreviation RB/STB represents reservoir barrels per stock tank barrel.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

MONTE CARLO INPUT DISTRIBUTION SUMMARY
PROSPECTIVE GAS RESOURCES
POMERON AREA
AS OF DECEMBER 31, 2017

Prospect	Area (acres) Lognormal Distribution		Average Net Thickness (feet) Normal Distribution		Porosity (decimal) Normal Distribution	
	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
PL-5A	186	654	50	100	0.24	0.30
PL-5B	94	142	50	100	0.24	0.30
DEEP	183	527	50	125	0.22	0.30

Prospect	Gas Saturation (decimal) Normal Distribution		Gas Formation Volume Factor (RB/MCF)[1] Uniform Distribution		Gas Recovery Factor (decimal) Normal Distribution	
	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
PL-5A	0.70	0.80	0.51	0.51	0.50	0.70
PL-5B	0.70	0.80	0.50	0.50	0.50	0.70
DEEP	0.70	0.80	0.50	0.50	0.50	0.70

Note: For the purposes of this report, we used technical data including, but not limited to, well logs from offset discoveries, geologic maps, seismic data, well test and production data from analog wells, and property ownership interests.

[1] The abbreviation RB/MCF represents reservoir barrels per thousand standard cubic feet.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

MONTE CARLO INPUT DISTRIBUTION SUMMARY
PROSPECTIVE GAS RESOURCES
QUARK AREA
AS OF DECEMBER 31, 2017

	Area (acres) Lognormal Distribution		Average Net Thickness (feet) Normal Distribution		Porosity (decimal) Normal Distribution	
Prospect	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
UMP2	379	906	50	175	0.24	0.30
LP2	171	528	50	175	0.24	0.28

	Gas Saturation (decimal) Normal Distribution		Gas Formation Volume Factor (RB/MCF)[1] Uniform Distribution		Gas Recovery Factor (decimal) Normal Distribution	
Prospect	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
UMP2	0.70	0.80	0.44	0.44	0.50	0.70
LP2	0.70	0.80	0.43	0.43	0.50	0.70

Note: For the purposes of this report, we used technical data including, but not limited to, well logs from offset discoveries, geologic maps, seismic data, well test and production data from analog wells, and property ownership interests.

(1) The abbreviation RB/MCF represents reservoir barrels per thousand standard cubic feet.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

MONTE CARLO INPUT DISTRIBUTION SUMMARY
PROSPECTIVE GAS RESOURCES
TANKER AREA
AS OF DECEMBER 31, 2017

	Area (acres) Lognormal Distribution		Average Net Thickness (feet) Normal Distribution		Porosity (decimal) Normal Distribution	
Prospect	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
M5	304	1,151	50	125	0.22	0.26
M8	402	1,013	50	150	0.20	0.24
M10	380	871	50	200	0.20	0.24

	Gas Saturation (decimal) Normal Distribution		Gas Formation Volume Factor (RB/MCF)[1] Uniform Distribution		Gas Recovery Factor (decimal) Normal Distribution	
Prospect	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
M5	0.70	0.80	0.47	0.47	0.50	0.70
M8	0.70	0.80	0.47	0.47	0.50	0.70
M10	0.70	0.80	0.46	0.46	0.50	0.70

Note: For the purposes of this report, we used technical data including, but not limited to, well logs from offset discoveries, geologic maps, seismic data, well test and production data from analog wells, and property ownership interests.

[1] The abbreviation RB/MCF represents reservoir barrels per thousand standard cubic feet.

MONTE CARLO INPUT DISTRIBUTION SUMMARY
PROSPECTIVE OIL RESOURCES
TAU AREA
AS OF DECEMBER 31, 2017

	Area (acres) Lognormal Distribution		Average Net Thickness (feet) Normal Distribution		Porosity (decimal) Normal Distribution	
Prospect	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
M1	838	2,157	44	244	0.23	0.27
M1A	437	1,530	100	150	0.26	0.30
M3[1]	581	1,796	50	150	0.23	0.27
M4	157	398	50	150	0.23	0.27

	Oil Saturation (decimal) Normal Distribution		Oil Formation Volume Factor (RB/STB)[2] Uniform Distribution		Oil Recovery Factor (decimal) Normal Distribution	
Prospect	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
M1	0.70	0.80	1.77	1.77	0.15	0.45
M1A	0.70	0.80	1.77	1.77	0.15	0.45
M3	0.70	0.80	1.77	1.77	0.15	0.45
M4	0.70	0.80	1.77	1.77	0.15	0.45

Note: For the purposes of this report, we used technical data including, but not limited to, well logs from offset discoveries, geologic maps, seismic data, well test and production data from analog wells, and property ownership interests.

(1) The area shown includes both on-lease and off-lease acres for the M3 Prospect.
(2) The abbreviation RB/STB represents reservoir barrels per stock tank barrel.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL
& ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

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DANNY D. SIMMONS
EXECUTIVE VP
G. LANCE BINDER

January 5, 2018

Delek Group Ltd.
19 Abba Eban Boulevard
Herzelia 4612001
Israel

Ladies and Gentlemen:

As independent consultants, Netherland, Sewell & Associates, Inc. hereby grants permission to Delek Group Ltd. to use our report dated January 5, 2018, to be filed with the Israel Securities Authority. This report sets forth our estimates of the unrisked prospective resources, as of December 31, 2017, to the Potential Acquisition interest in certain prospects located in federal waters in the Gulf of Mexico.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: Danny D. Simmons
Danny D. Simmons, P.E.
President and Chief Operating Officer

RBT:LNH

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