Delek Drilling - Limited Partnership
(the "Partnership")

March 10, 2021

Israel Securities Authority
22 Kanfei Nesharim St.
Jerusalem
Via Magna

Tel Aviv Stock Exchange Ltd.
2 Ahuzat Bayit St.
Tel Aviv
Via Magna

Dear Sir/Madam,

Re: **Report on Updated Discounted Cash Flow Figures, Reserves and Contingent Resources in the Leviathan Leases**

Further to the Partnership's immediate report of July 9, 2020 (Ref. No.: 2020-01-065878) regarding the evaluation of the reserves and contingent resources in the Leviathan reservoir, which is located in the area of the I/14 "Leviathan South" and I/15 "Leviathan North" leases (the "**Leviathan Reservoir**" or the "**Reservoir**" or the "**Field**" and the "**Leviathan Leases**", respectively), and regarding the discounted cash flow figures from the reserves and from part of the contingent resources in the Leviathan Leases as of June 30, 2020 (the "**Previous Discounted Cash Flow**"), the Partnership respectfully provides an updated discounted cash flow figures, reserves and contingent resources report, as of December 31, 2020, with respect to the Partnership's share in the Leviathan Leases[1].

1. Reserves and contingent resources in the Leviathan Reservoir

According to a report which the Partnership received from Netherland, Sewell & Associates Inc. ("**NSAI**" or the "**Reserves Evaluator**"), part of the resources in the Leviathan Reservoir are classified as reserves and part are classified as contingent resources. Therefore, NSAI's report includes two parts, as follows:

- An 'on production' reserves report. Discounted cash flow figures with respect to these reserves, as of December 31, 2020, are presented in Section 1(a)(3) below.
- A contingent resources report, in which the resources were divided into two categories, which relate to the stages of development of the Reservoir, as follows:

    (1) Phase I – First Stage: Resources attributed to Phase I – First Stage for development of the Leviathan Reservoir, production of natural gas from which began on December 31, 2019, which are classified as contingent at the development pending stage. These resources are contingent on decisions to drill additional wells (see Section

[1] For a glossary of the professional terms included herein, see the Glossary on page A-363 of the Partnership's periodic report as of December 31, 2019, as released on March 30, 2020 (Ref. No.: 2020-01-032010) (the "**Periodic Report**").

7.2.5(a)(4) of the Periodic Report), on the construction of related infrastructures and on the signing of additional agreements for the sale of natural gas. Discounted cash flow figures with respect to contingent resources at this stage, as of December 31, 2020, are presented in Section 1(b)(4) below.

(2) Future Development: Resources contingent on the adoption of additional investment decisions in accordance with additional stages of development of the Leviathan Reservoir (beyond the Phase I – First Stage stated above), and on the signing of additional agreements for the sale of natural gas.

In H2/2020 (July-December), the Leviathan partners sold approx. 4.2 BCM of natural gas for (gross) financial consideration of approx. U.S. $730 million (in 100% terms, the Partnership's share is approx. U.S. $330 million).

The discounted cash flow figures from reserves and contingent resources at Phase I – First Stage as of December 31, 2020 are presented in Section 1(b)(5) below.

(a) **Reserves in the Leviathan Reservoir**

(1) Quantity data

According to a report which the Partnership received from NSAI and which was prepared according to the SPE-PRMS guidelines, as of December 31, 2020 (the "**Reserve Report**"), the maturity stage of the project to which the natural gas and condensate reserves belong is 'on production'. These reserves are as specified below:

Reserve Category[2]	Total (100%) in the Petroleum Asset (Gross)		The Total Share Attributed to the Holders of the Equity Interests of the Partnership (Net) [3]	
	Natural Gas BCF	Condensate Million Barrels	Natural Gas BCF	Condensate Million Barrels
1P (Proved) Reserves	11,269.6	24.8	4,033.9	8.9
Probable Reserves	1,818.0	4.0	642.9	1.4
Total 2P (Proved+Probable) Reserves	13,087.6	28.8	4,676.8	10.3
Possible Reserves	1,127.6	2.5	398.8	0.9
Total 3P (Proved+Probable+Possible) Reserves	14,215.2	31.3	5,075.6	11.2

Caution – possible reserves are the additional reserves which are not expected to be extracted to the same extent as the probable reserves. There is a 10% chance that the quantities that will actually be extracted will be equal to or higher than the quantity of proved reserves, plus the quantity of probable reserves and plus the quantity of possible reserves.

(2) In the report, NSAI stated, *inter alia*, several assumptions and reservations, including that: (a) The evaluations, as customary in the evaluation of reserves according to the SPE-PRMS guidelines, are not adjusted to reflect risks, such as technical and commercial risks and development risks; (b) NSAI did not visit the Field, and did not check the mechanical operation of the facilities and the wells or the condition thereof; (c) NSAI did not examine possible exposure deriving from environmental matters. However, NSAI stated that as of the date of signing of the Reserve Report, it was not aware of any potential liability regarding environmental matters which may materially affect the quantity of the reserves estimated in the Reserve Report or the commerciality thereof; (d) NSAI assumed that the Reservoir is being developed in accordance with the development plan, will be reasonably operated, that

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[2] The amounts in the table may not add up due to rounding-off differences.

[3] The Reserve Report does not state the Partnership's net share but rather the Partnership's gross share. The Partnership's net share presented in the above table is after payment of royalties to the State and to related and third parties and assuming that return of the investment will be achieved after the sale of a total quantity (in respect of 100% of the interests in the petroleum asset) of approx. 2,130 BCF and of approx. 4.7 million barrels of condensate from Phase I – First Stage (the "**Investment Recovery Date**"). Since the Investment Recovery Date is affected, *inter alia*, by the gas and/or condensate prices, the production rate, the production and development costs, and the rate of the royalties, and since additional agreements are expected to be signed for the sale of natural gas, the total quantity of natural gas and/or condensate that shall be sold by the Investment Recovery Date may be materially different than stated above. The share attributed to the holders of the equity interests of the Partnership before and after the Investment Recovery Date is calculated in accordance with the rates set forth in Section 7.2.7 of the Periodic Report. For details regarding the investment recovery date in the Tamar project, see Sections 7.26.9 and 7.27.7 of the Periodic Report, Section 20(e) of Chapter A (Description of the Partnership's Business) of the Q1/2020 report, as released on June 28, 2020 (Ref. No.: 2020-01-058762) (the "**Q1 Report**"), Section 13(e) of Chapter A (Description of the Partnership's Business) of the Q2/2020 report, as was released on August 20, 2020 (Ref. No.: 2020-01-091527), and Section 14(e) of Chapter A (Description of the Partnership's Business) of the Q3/2020 report, as released on November 18, 2020 (Ref. No.: 2020-01-115504).

no regulation will be instituted that will affect the ability of a holder of the petroleum interests to extract the reserves, and that its forecasts regarding future production will be similar to the functioning of the Reservoir in practice.

Caution regarding forward-looking information – NSAI's estimates regarding the quantities of natural gas and condensate reserves in the Leviathan Reservoir are forward-looking information, within the meaning thereof in the Securities Law, 5728-1968 (the "Securities Law"). The above estimates are based, *inter alia*, on geological, geophysical, engineering and other information received from the wells in the Reservoir and from the operator in the Leviathan Reservoir, and constitute estimates and assumptions of NSAI only, and in respect of which there is no certainty. The natural gas and/or condensate quantities that shall actually be produced may be different to the said estimates and assumptions, *inter alia* as a result of operating and technical conditions and/or regulatory changes and/or supply and demand conditions in the natural gas and/or condensate market and/or commercial conditions and/or geopolitical changes and/or as a result of the actual performance of the Reservoir. The said estimates and assumptions may be updated insofar as additional information shall accumulate and/or as a result of a gamut of factors relating to projects for oil and natural gas exploration and production, including as a result of the actual production data from the Leviathan Reservoir.

(3) Discounted cash flow figures

The discounted cash flow figures are based on various estimates and assumptions provided to NSAI by the Partnership, and mainly:

(a) The projected sale quantities: The assumptions in the cash flow with respect to the natural gas quantities that shall be sold by the Partnership from the Leviathan Reservoir are based on: (i) the Leviathan Reservoir's production capacity in Phase I – First Stage only, without taking into account sales of additional gas quantities which may be rendered possible as a result of the performance of additional development stages, which were classified as contingent resources – future development, including additional sales to the domestic market and/or designated sales via other LNG facilities and/or FLNG facilities (for details, see Sections 7.12.5(b)(3), 7.12.5(c) and 7.13.2(c) of the Periodic Report), if and insofar as such facilities are built, to additional target markets. It is further noted that the actual production rate for each of the resource categories in the cash flow may be lower or higher than the production rate assumed in the cash flow. Furthermore, it is noted that NSAI has not conducted a sensitivity analysis with respect to the production rate of the wells; (ii) the Partnership's assumptions regarding the natural gas quantities that shall be sold to customers of the Partnership under the existing agreements in which the Partnership engaged, including the agreement for the export of natural gas to Egypt signed with

Dolphinus Holdings Limited (see Section 7.12.5(b)(2) of the Periodic Report) (the "**Export to Egypt Agreement**" and "**Dolphinus**", respectively)[4], taking into account, *inter alia*, the forecasts which the Partnership used with respect to the Brent price and its possible impact on the quantities that are sold to Egypt, the agreement for the export of gas to Jordan's national electricity company (NEPCO), which is described in Section 7.12.5(b)(1) of the Periodic Report, the agreement for the supply of natural gas to the Israel Electric Corp. Ltd.[5] (the "**IEC**"), and additional agreements for the supply of natural gas to the domestic market (collectively: the "**Existing Agreements**"); (iii) additional quantities of natural gas which, in the Partnership's estimation, will be sold on the domestic market in Israel, based, *inter alia*, on negotiations for the sale of natural gas from the Leviathan project, being conducted by the Partnership, together with the rest of its partners in the Leviathan project, a forecast of the demand for natural gas in the domestic market in Israel, prepared for the Partnership an outside consultant (BDO Consulting Group, "**BDO**")[6], and in relation to the estimate of the expected supply from other gas sources in the domestic market, and mainly from the Tamar, Karish, Karish North and Tanin reservoirs[7]; and (iv) additional quantities of natural gas, which, in the Partnership's estimation, will be sold in the regional markets, based, *inter alia*, on forecasts of the demand in such markets, which were prepared by consultancy firms.

(b) <u>The sale prices of natural gas and condensate</u>: The assumptions in the cash flow with respect to the prices of natural gas that shall be sold from the Leviathan Reservoir are based, *inter alia*, on a weighted average of the natural gas prices which are stated in the Existing Agreements, according to the price formulas determined therein, the delivery point determined in the agreements, and the Partnership's assumptions regarding the prices that shall be determined in future agreements, based, *inter alia*, on the demand forecast in the domestic

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[4] In June 2020, Dolphinus endorsed the Export to Egypt Agreement to an affiliate – Blue Ocean Energy.

[5] For details regarding this agreement, see Section 7.12.4(b)(2) of the Periodic Report and with respect to the settlement agreement which was signed between the Leviathan partners and the IEC, see the Partnership's immediate report of January 31, 2021 (Ref. No.: 2021-01-012016).

[6] The forecast of the demand for natural gas in the domestic market for the coming years on which the Partnership relied, is as follows (BCM): 2021 – approx. 13.1; 2022 – approx. 15; 2023 – approx. 15.6; 2024 – approx. 16.6; 2025 – approx. 17.9. The aforesaid forecast of the demand is primarily based on a forecast of demand for electricity, which is affected, *inter alia*, by the growth forecasts in Israel and by the COVID-19 crisis, and also based on the mix of energy sources that will be used in the electricity production that is affected by government policy regarding the reduction of the use of coal as a source of electricity production until its complete cessation and regarding the use of renewable energies as a source of electricity production. The demand forecast is forward-looking information, which there is no certainty will materialize, in whole or in part, and it may materialize in a materially different manner, due to various factors, *inter alia*, the method of the continued spread of the COVID-19 pandemic and its impact on local and global economies, the development of growth in the Israeli economy, the climatic conditions in Israel, the rate of cessation of use of coal as a source of electricity production, the rate of entry of renewable energies as a source of electricity production, the rate of entry of electric vehicles into the Israeli market and government policy in other areas which directly or indirectly pertain to the increase in natural gas demand.

[7] The working assumption is that natural gas sales to the domestic market in Israel and commercial production from the Karish reservoir will begin in Q1/2022.

market in the cash flow years, as estimated by BDO, and on the Partnership's estimate of the projected demand and also based on the provisions determined in the Gas Framework with respect to the sale prices of natural gas.

Most of the Existing Agreements include price formulas, and some of them include fixed prices. The price formulas set forth in the Existing Agreements, may change over the years, and include, *inter alia*, partial or full linkage to the electricity production tariff, the ILS/U.S. dollar exchange rate[8], or the Brent oil barrel price (the "**Brent Price**").

It is noted that the electricity production tariff is supervised by the Electricity Authority and reflects the costs of the electricity production component of the IEC, including the IEC's cost of fuels, capital and operating costs attributed to the production component and the cost of purchasing electricity from independent power producers. The assumptions in the cash flow regarding changes in the electricity production tariff over the cash flow years are based on a forecast that was prepared for the Partnership by BDO.

The assumptions in the cash flow with respect to the Brent Price are based on long-term forecasts of third parties, as follows: The United States Department of Energy, the World Bank, IHS Global Insights and Wood Mackenzie. Accordingly, the cash flow assumes a Brent Price of approx. $52 in 2021, increase to approx. $57 in 2022, and from there to approx. $75 in 2027, and being approx. $86 from 2030 until the end of the cash flow period.

It is noted that changes in the sale prices may occur, *inter alia*, due to regulatory intervention, price adjustment mechanisms (as determined in the Export to Egypt Agreement)[9] or changes in the indices that serve as the linkage bases in the price formulas, as specified above.

The assumptions in the cash flow with respect to condensate sale prices are based on the Brent Price. For details regarding agreements for the supply of condensate from the Leviathan project, see Sections 7.12.6(b) and (c) of the Periodic Report.

(c) The operating expenses (or OPEX) taken into account in the cash flow include direct costs at the project level, insurance costs, production well maintenance costs and estimated overhead and general and administrative expenses of the operator, which may be directly attributed to the project, and jointly constitute the operating expenses of the project. These expenses are represented at the Field level and per production unit. The operating expenses in the cash flow are not adjusted to inflation changes. NSAI confirmed that the operating

[8] The dollar rate used is ILS 3.3 per dollar in 2021, which gradually rises to ILS 3.5 per dollar from 2023 forth, and it is based on the exchange rates stated in the aforesaid BDO forecast.

[9] The Export to Egypt Agreement includes a mechanism for updating the price at a rate of up to 10% (up or down) after the fifth year and after the tenth year of the agreement upon fulfillment of certain conditions that are set forth in the agreement. It is noted that no price update on such dates was assumed.

expenses provided by the Partnership are reasonable, based, *inter alia*, on knowledge available thereto from similar projects.

(d) The capital expenses (or CAPEX) taken into account in the cash flow deriving from reserves includes expenses that were approved by the Partnership, including expenses for engineering work and participation in the costs of construction of natural gas transmission infrastructure[10] as well as an estimate of future capital expenditure not yet approved by the Partnership, including, laying an additional infrastructure and engineering work and indirect costs paid to the operator. The capital expenses taken into account in the cash flow deriving from contingent resources exceeds the total costs approved by the Partnership, and includes an estimate of future capital expenses that may be required for the drilling of new wells, for related infrastructures, for additional production equipment, and for various engineering actions, and it exceeds the expenses which were included in the budget for the development of Phase I – First Stage in the development plan for the Leviathan Reservoir, plus indirect costs paid to the operator. The capital expenditure in the cash flow is not adjusted to inflation changes. NSAI has confirmed that the capital expenditure provided by the Partnership is reasonable, based, *inter alia*, on knowledge available thereto.

(e) Decommissioning costs taken into account in the cash flow are costs that were provided to NSAI by the Partnership in accordance with its estimates with respect to the cost of plugging and abandonment of the wells, and the cost of abandonment of the platform and the production facilities, under the assumption that the project will come to an end in 2064 and in accordance with the directives of the Petroleum Commissioner and with the current best industry standards. However, the project may come to an end before or after such year (it is noted that the current date of expiration of the leases is February 13, 2044, but, subject to the Petroleum Law, it is possible to extend it by an additional 20 years). These costs do not take into account the salvage value of the facilities in the Leviathan Leases and are not adjusted to inflation changes.

(f) The calculation of the discounted cash flow took into account the Partnership's estimate whereby the effective rate of the State's royalties is 11.5%, and the effective rate of the royalties to be paid to third and related parties is 4.14% before, and 8.74% after the Investment Recovery Date. The actual rate of the said royalties is not final and may change. For further details on the issue, see Section 7.24.3(b) of the Periodic Report and Section 18 of the Q1 Report.

[10] In order to increase the possible flow capacity via the EMG pipeline, it is necessary to expand the supply capacity in the INGL system and in the EMG systems in Israel and Egypt. For details, see Section 7.13.2(b)(2)(b) of the Periodic Report and the Partnership's immediate report of January 19, 2021 (Ref. no.: 2021-01-008127).

(g) The tax payments and the tax rates which were taken into account in the discounted cash flow were calculated from the perspective of a company that holds the participation units of the Partnership from the date of commencement of the project, to whose credit carried losses are recorded in respect of exploration and development expenses previously incurred by the Partnership in the project, which may be offset against the taxable income. The tax calculations took into account only the corporate tax rate in accordance with the law. It is noted that the calculation was made in dollars. It is further noted that the tax rates, and consequently the tax payments that shall actually be made by the Partnership on account of the tax for which the holders of the participation units of the Partnership are liable in each one of the relevant tax years, according to the provisions of the Taxation of Profits from Natural Resources Law, 5771-2011 (the "**Law**"), may be materially different. The depreciation expenses for tax purposes were calculated according to the depreciation rates set forth in the Law.

(h) The calculation of the discounted cash flow took into account the petroleum profit levy (the "**Levy**") that shall apply to the Partnership pursuant to the provisions of the Law. The calculations of the Levy were made in accordance with the approval of the Tax Authority regarding the consolidation of the ventures operating in the Leviathan Leases for purposes of the Law (the "**Ventures**"). It should be emphasized that the Levy calculations were made, *inter alia*, according to the definitions, the formulas and the mechanisms defined in the Law, to the best of the Partnership's understanding and interpretation, which were expressed in the Levy reports of the Ventures which were filed with the Tax Authority. However, in view of the novelty of the Law and the complexity of the calculation formulas and the various mechanisms defined therein, there is no assurance that this interpretation of the manner of calculation of the Levy will be the same as that which shall be adopted by the tax authorities and/or the same as the interpretation of the Law by the court[11]. In addition, the calculation was made in dollars at the choice of the interest holders of the Ventures pursuant to Section 13(b) of the Law and is based, *inter alia*, on the following assumptions: the payments attributed to the Ventures (the production costs, the main investments, the royalties, etc.) shall be recognized by the tax authorities for the purpose of the Levy calculation; for purposes of calculation of the income attributed to the Ventures, the actual sale prices of the natural gas shall be taken into account.

(i) The calculation of the discounted cash flow took into account expenses and investments which were actually paid and which are expected to be paid by the Partnership from January 1, 2021, as well as revenues deriving from sales of natural gas and condensate produced and expected to be produced from January 1, 2021.

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[11] It is noted that as of this date, levy assessments have been signed with the Tax Authority up to and including for 2017.

(j) Revenues from natural gas and condensate sales that shall be made in a certain year were taken into account in that year regardless of the actual payment date.

The changes in the discounted cash flow relative to the Previous Discounted Cash Flow

The changes in the current discounted cash flow relative to the Previous Discounted Cash Flow, prepared as of June 30, 2020, derive from an update of the following main assumptions:

a. With respect to existing agreements, updates have been made to the assumptions regarding the electricity production tariff, the Brent Price, and additional forecasts, and accordingly, updates have been made to the forecasts of the relevant sale prices linked thereto. Updates were also made to the Partnership's assumptions regarding the sale prices in future agreements.

b. Updates have been made to the forecasts of annual sale volumes of natural gas from the Leviathan project, *inter alia* due to:

- An update of the BDO forecast of the demand for natural gas in the Israeli market.

- The signing of new agreements for the sale of natural gas, including the signing of the settlement agreement between the Leviathan partners and the IEC (for details, see the Partnership's immediate report of January 31, 2021 (Ref. No.: 2021-01-012016)), combined with developments in the domestic market and export markets.

- An update of the forecast of volume of sales to Dolphinus in view of the actual volume of sales to Dolphinus from H2/2020, and the demand forecast in the Egyptian market, taking into consideration the Brent Prices assumed by the Partnership (for details see Section 7.12.5(b)(2)(d) of the Periodic Report).

- An update of the Partnership's assumptions regarding the date of commencement of commercial production from the Karish, Karish North and Tanin project and the sale volumes from this project, following the resource report as of December 31, 2020 that was released by Energean Plc. on February 11, 2021.

c. Updates have been made to the amounts of the investments made until December 31, 2020 and the scheduling of the investments that are required for support of production from Phase I – First Stage (including an update of the date of drilling of future wells in relation to the discounted cash flow figures), in accordance with the Partnership's estimation, *inter alia*, based on updated estimates received from the operator and NSAI's estimates.

d. Updates have been made to assumptions in connection with the scope of production of the condensate from the project, revenues in respect of the sale thereof, which are expected, to the Partnership's estimations, from 2024, and current costs and investments which will allow the export of condensate.

e. The quantity of gas produced and sold during H2/2020 has been reduced.

In accordance with various assumptions, mainly those specified above, set forth below is the estimated discounted cash flow, as of December 31, 2020, in dollars in thousands (after levy and income tax), which is attributed to the Partnership's share from the reserves in the Leviathan Reservoir, for each one of the reserve categories specified above:

Total discounted cash flow from proved reserves as of December 31, 2020 (in dollars in thousands in relation to the Partnership's share)

Cash flow components

Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%[12]	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2021	704	9.06	697,117	109,029	-	77,827	94,917	-	415,344	-	34,240	381,104	371,920	367,570	363,369	355,381	347,899
31.12.2022	604	7.78	626,885	98,045	-	83,631	26,681	-	418,528	-	52,725	365,803	339,988	328,197	317,072	296,620	278,276
31.12.2023	653	8.41	692,925	108,373	-	81,958	11,108	-	491,486	-	65,422	426,064	377,139	355,594	335,732	300,421	270,098
31.12.2024	657	8.45	740,105	115,752	-	81,179	-	-	543,173	-	74,025	469,148	395,501	364,234	336,075	287,652	247,843
31.12.2025	701	9.02	803,484	125,665	-	81,567	-	-	596,252	-	86,233	510,019	409,482	368,340	332,139	271,923	224,528
31.12.2026	701	9.02	828,565	129,588	-	81,513	-	-	617,465	-	91,112	526,353	402,472	353,615	311,614	244,028	193,099
31.12.2027	701	9.02	859,379	164,293	-	81,359	-	-	613,727	-	90,252	523,475	381,211	327,145	281,737	211,038	160,036
31.12.2028	701	9.02	892,107	180,562	-	83,878	-	-	627,666	137,490	61,836	428,341	297,078	249,015	209,577	150,161	109,127
31.12.2029	701	9.02	915,942	185,387	-	104,577	-	-	625,978	191,708	48,977	385,293	254,497	208,362	171,377	117,452	81,799
31.12.2030	701	9.02	932,688	188,776	-	84,035	-	-	659,877	241,342	91,411	327,123	205,785	164,563	132,276	86,713	57,875
31.12.2031	701	9.02	933,829	189,007	-	84,040	-	-	660,782	277,144	84,503	299,135	179,217	139,984	109,962	68,951	44,103
31.12.2032	701	9.02	933,915	189,024	-	84,040	-	-	660,851	305,211	78,409	277,231	158,185	120,682	92,646	55,567	34,061
31.12.2033	701	9.02	933,787	188,999	-	84,039	-	-	660,749	309,231	77,461	274,058	148,928	110,978	83,259	47,766	28,059
31.12.2034	701	9.02	933,255	188,891	-	104,644	-	-	639,720	299,389	75,618	264,713	137,000	99,715	73,110	40,119	22,585
31.12.2035	701	9.02	806,653	163,267	-	74,027	-	-	569,360	266,460	69,667	233,233	114,959	81,727	58,559	30,738	16,583

31.12.2036	701	9.02	806,805	163,297	-	74,027	-	-	569,480	266,517	69,682	233,282	109,508	76,041	53,247	26,734	13,822
31.12.2037	701	9.02	806,981	163,333	-	74,028	-	-	569,620	266,582	69,699	233,339	104,319	70,754	48,418	23,253	11,521
31.12.2038	701	9.02	807,208	163,379	-	74,029	-	-	569,800	266,667	69,721	233,413	99,383	65,838	44,030	20,226	9,604
31.12.2039	685	8.82	791,820	160,264	-	94,543	-	-	537,012	251,322	65,709	219,982	89,204	57,721	37,724	16,576	7,543
31.12.2040	657	8.45	762,202	154,270	-	73,761	-	-	534,172	249,992	65,361	218,818	84,507	53,409	34,113	14,338	6,252
31.12.2041	631	8.12	735,357	148,836	-	73,603	-	-	512,918	240,046	62,761	210,112	77,280	47,706	29,778	11,971	5,003
31.12.2042	608	7.83	711,806	144,070	-	73,464	-	-	494,273	231,320	60,479	202,474	70,925	42,765	26,087	10,031	4,018
31.12.2043	587	7.56	689,854	139,626	-	73,335	-	-	476,893	223,186	58,353	195,354	65,172	38,382	22,882	8,416	3,230
31.12.2044	569	7.32	670,360	135,681	-	93,827	-	-	440,852	206,319	53,943	180,591	57,378	33,006	19,229	6,765	2,488
31.12.2045	552	7.11	653,357	132,240	-	73,119	-	-	447,998	209,663	54,817	183,518	55,532	31,201	17,765	5,978	2,107
31.12.2046	537	6.91	637,148	128,959	-	73,024	-	-	435,165	203,657	53,247	178,261	51,372	28,193	15,687	5,050	1,706
31.12.2047	522	6.72	621,752	125,843	-	72,933	-	-	422,976	197,953	51,755	173,268	47,556	25,491	13,862	4,268	1,382
31.12.2048	509	6.55	608,011	123,061	-	72,852	-	-	412,098	192,862	50,424	168,812	44,126	23,103	12,277	3,616	1,122
31.12.2049	497	6.40	595,913	120,613	-	93,387	-	-	381,913	178,735	46,731	156,447	38,947	19,917	10,344	2,914	866
31.12.2050	486	6.25	583,845	118,170	-	72,709	-	-	392,966	183,908	48,083	160,974	38,166	19,064	9,675	2,607	743
31.12.2051	475	6.11	572,431	115,860	-	72,642	-	-	383,929	179,679	46,978	157,273	35,512	17,326	8,594	2,215	605
31.12.2052	465	5.99	562,636	113,878	-	72,584	-	-	376,174	176,050	46,029	154,096	33,138	15,792	7,655	1,887	494
31.12.2053	456	5.87	552,857	111,898	-	72,527	-	-	368,433	172,426	45,081	150,925	30,911	14,387	6,816	1,607	403

[12] Another discount rate of 7.5% was taken by the Partnership for calculation purposes and as an aid for the investor.

31.12.2054	447	5.75	543,088	109,921	-	93,076	-	-	340,091	159,163	41,614	139,315	27,174	12,354	5,719	1,290	310
31.12.2055	437	5.63	533,279	107,936	-	72,411	-	-	352,932	165,172	43,185	144,575	26,857	11,926	5,396	1,164	268
31.12.2056	429	5.52	524,282	106,115	-	72,358	-	-	345,809	161,838	42,313	141,657	25,062	10,870	4,806	992	219
31.12.2057	420	5.41	515,286	104,294	-	72,306	-	-	338,687	158,505	41,442	138,740	23,377	9,904	4,279	845	179
31.12.2058	412	5.30	506,296	102,474	-	72,253	-	-	331,569	155,174	40,571	135,824	21,796	9,019	3,808	719	146
31.12.2059	404	5.20	498,122	100,820	-	92,812	-	-	304,491	142,502	37,257	124,732	19,063	7,705	3,179	574	112
31.12.2060	395	5.09	489,114	98,997	-	72,152	-	-	317,966	148,808	38,906	130,251	18,959	7,484	3,018	521	97
31.12.2061	388	4.99	480,931	97,341	-	72,104	-	-	311,487	145,776	38,114	127,598	17,688	6,820	2,688	444	79
31.12.2062	380	4.89	472,747	95,684	-	72,055	-	-	305,007	142,743	35,880	126,384	16,685	6,284	2,420	383	65
31.12.2063	372	4.79	464,555	94,026	-	72,007	-	-	298,522	139,708	35,086	123,727	15,557	5,723	2,154	326	53
31.12.2064	44	0.56	54,311	10,993	-	12,636	-	71,601	(40,918)	-	5,616	(46,535)	(5,572)	(2,002)	(737)	(107)	(17)
Total	**24,793**	**319.1**	**29,782,990**	**5,816,534**	**-**	**3,428,875**	**132,706**	**71,601**	**20,333,274**	**7,444,249**	**2,500,726**	**10,388,299**	**5,512,944**	**4,405,905**	**3,663,421**	**2,740,134**	**2,190,392**

Total discounted cash flow from probable reserves as of December 31, 2020 (in dollars in thousands in relation to the Partnership's share)																	
Cash flow components																	
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%[13]	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2021	69	0.89	63,489	9,930	-	433	-	-	53,126	-	12,219	40,907	39,921	39,454	39,003	38,146	37,343
31.12.2022	155	1.99	146,890	22,974	-	989	-	-	122,927	-	28,273	94,654	87,974	84,923	82,045	76,753	72,006
31.12.2023	152	1.96	144,033	22,527	-	972	-	-	120,534	-	27,723	92,811	82,154	77,461	73,134	65,442	58,837
31.12.2024	169	2.17	164,802	25,775	-	1,031	-	-	137,996	-	31,739	106,257	89,576	82,495	76,117	65,150	56,133
31.12.2025	140	1.80	134,439	21,026	-	846	-	-	112,567	-	25,890	86,676	69,590	62,598	56,446	46,213	38,158
31.12.2026	146	1.88	145,175	60,923	-	718	-	-	83,534	-	19,213	64,321	49,183	43,212	38,080	29,821	23,597
31.12.2027	165	2.12	163,681	42,774	-	935	-	-	119,971	184,110	(14,752)	(49,387)	(35,965)	(30,864)	(26,580)	(19,910)	(15,099)
31.12.2028	193	2.48	192,188	38,899	-	1,151	-	-	152,138	124,684	6,314	21,139	14,661	12,289	10,343	7,411	5,386
31.12.2029	181	2.33	181,235	36,682	-	1,084	-	-	143,468	120,332	5,321	17,815	11,767	9,634	7,924	5,431	3,782
31.12.2030	158	2.04	159,790	32,341	-	954	-	-	126,495	120,201	1,447	4,846	3,048	2,438	1,959	1,284	857
31.12.2031	136	1.75	135,708	27,467	-	813	-	-	107,428	82,378	5,761	19,288	11,556	9,026	7,090	4,446	2,844
31.12.2032	114	1.47	112,932	22,857	-	679	-	-	89,395	45,904	10,003	33,488	19,108	14,578	11,191	6,712	4,114
31.12.2033	93	1.20	90,941	18,406	-	549	-	-	71,985	33,689	8,808	29,488	16,024	11,941	8,959	5,140	3,019
31.12.2034	72	0.93	69,125	13,991	-	420	-	-	54,714	25,606	6,695	22,413	11,600	8,443	6,190	3,397	1,912
31.12.2035	52	0.67	60,738	12,293	-	345	-	-	48,100	22,511	5,885	19,703	9,712	6,904	4,947	2,597	1,401

31.12.2036	33	0.42	40,359	8,169	-	225	-	-	31,965	14,960	3,911	13,094	6,147	4,268	2,989	1,501	776
31.12.2037	13	0.17	19,964	4,041	-	105	-	-	15,818	7,403	1,935	6,480	2,897	1,965	1,345	646	320
31.12.2038	(5)	(0.06)	1,177	238	-	(5)	-	-	944	442	115	387	165	109	73	34	16
31.12.2039	(8)	(0.10)	(2,062)	(417)	-	(24)	-	-	(1,620)	(758)	(198)	(664)	(269)	(174)	(114)	(50)	(23)
31.12.2040	83	1.07	93,473	18,919	-	538	46,147	-	27,870	13,043	13,493	1,333	515	325	208	87	38
31.12.2041	94	1.21	104,921	21,236	-	605	-	-	83,080	38,881	9,104	35,094	12,908	7,968	4,974	2,000	836
31.12.2042	98	1.26	109,030	22,068	-	629	-	-	86,333	40,404	9,502	36,427	12,760	7,694	4,693	1,805	723
31.12.2043	102	1.31	113,138	22,899	-	653	-	-	89,585	41,926	9,900	37,759	12,597	7,419	4,423	1,627	624
31.12.2044	103	1.33	114,801	23,236	-	663	-	-	90,902	42,542	10,061	38,298	12,168	7,000	4,078	1,435	528
31.12.2045	103	1.33	114,843	23,244	-	663	-	-	90,936	42,558	10,066	38,312	11,593	6,514	3,709	1,248	440
31.12.2046	103	1.32	114,066	23,087	-	658	-	-	90,320	42,270	9,990	38,060	10,968	6,019	3,349	1,078	364
31.12.2047	102	1.31	113,338	22,940	-	654	-	-	89,745	42,001	9,920	37,824	10,381	5,565	3,026	932	302
31.12.2048	99	1.28	111,465	22,560	-	642	-	-	88,262	41,307	9,738	37,217	9,728	5,093	2,707	797	247
31.12.2049	96	1.24	108,248	21,909	-	623	-	-	85,716	40,115	9,427	36,174	9,005	4,605	2,392	674	200
31.12.2050	93	1.20	105,042	21,261	-	604	-	-	83,178	38,927	9,647	34,604	8,204	4,098	2,080	560	160
31.12.2051	90	1.16	101,784	20,601	-	585	-	-	80,598	37,720	9,862	33,016	7,455	3,637	1,804	465	127
31.12.2052	85	1.10	96,874	19,607	-	556	-	-	76,711	35,901	9,386	31,424	6,758	3,220	1,561	385	101
31.12.2053	82	1.05	92,791	18,781	-	532	-	-	73,478	34,388	8,991	30,100	6,165	2,869	1,359	321	80

[13] Another discount rate of 7.5% was taken by the Partnership for calculation purposes and as an aid for the investor.

31.12.2054	78	1.00	88,709	17,955	-	508	-	-	70,247	32,876	8,595	28,776	5,613	2,552	1,181	266	64
31.12.2055	75	0.96	85,438	17,293	-	489	-	-	67,657	31,663	8,278	27,715	5,149	2,286	1,034	223	51
31.12.2056	71	0.91	81,339	16,463	-	464	-	-	64,412	30,145	7,881	26,386	4,668	2,025	895	185	41
31.12.2057	68	0.87	78,064	15,800	-	445	-	-	61,819	28,931	7,564	25,323	4,267	1,808	781	154	33
31.12.2058	64	0.83	74,789	15,137	-	426	-	-	59,226	27,718	7,247	24,261	3,893	1,611	680	128	26
31.12.2059	61	0.78	70,688	14,307	-	402	-	-	55,979	26,198	6,850	22,931	3,505	1,416	585	106	21
31.12.2060	58	0.75	68,231	13,810	-	387	-	-	54,033	25,288	6,612	22,134	3,222	1,272	513	89	16
31.12.2061	55	0.71	64,949	13,146	-	368	-	-	51,435	24,072	6,294	21,070	2,921	1,126	444	73	13
31.12.2062	53	0.68	62,491	12,648	-	354	-	-	49,489	23,161	6,055	20,273	2,676	1,008	388	61	10
31.12.2063	50	0.64	59,205	11,983	-	334	-	-	46,888	21,943	5,737	19,207	2,415	888	334	51	8
31.12.2064	5	0.07	6,457	1,307	-	36	-	-	5,113	-	1,176	3,937	471	169	62	9	1
Total	**4,000**	**51.5**	**4,258,776**	**873,093**	-	**25,040**	**46,147**	-	**3,314,496**	**1,585,438**	**397,683**	**1,331,375**	**658,855**	**528,890**	**448,402**	**354,919**	**300,435**

Total discounted cash flow from 2P (proved + probable) reserves as of December 31, 2020 (in dollars in thousands in relation to the Partnership's share)																	
Cash flow components																	
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%[14]	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2021	773	9.95	760,606	118,959	-	78,260	94,917	-	468,470	-	46,459	422,011	411,841	407,024	402,372	393,527	385,242
31.12.2022	759	9.77	773,775	121,018	-	84,620	26,681	-	541,455	-	80,998	460,457	427,962	413,120	399,117	373,373	350,282
31.12.2023	806	10.37	836,958	130,900	-	82,929	11,108	-	612,020	-	93,145	518,876	459,293	433,054	408,867	365,863	328,935
31.12.2024	825	10.62	904,906	141,527	-	82,210	-	-	681,169	-	105,764	575,405	485,077	446,729	412,192	352,802	303,976
31.12.2025	841	10.82	937,923	146,691	-	82,413	-	-	708,819	-	112,123	596,695	479,072	430,938	388,585	318,136	262,686
31.12.2026	847	10.90	973,740	190,510	-	82,230	-	-	700,999	-	110,325	590,674	451,655	396,827	349,694	273,848	216,696
31.12.2027	866	11.14	1,023,059	207,067	-	82,294	-	-	733,698	184,110	75,500	474,088	345,246	296,281	255,156	191,127	144,937
31.12.2028	893	11.50	1,084,295	219,461	-	85,029	-	-	779,804	262,174	68,150	449,481	311,739	261,305	219,921	157,571	114,512
31.12.2029	882	11.35	1,097,176	222,068	-	105,662	-	-	769,446	312,040	54,299	403,108	266,264	217,996	179,301	122,882	85,582
31.12.2030	859	11.06	1,092,478	221,118	-	84,989	-	-	786,372	361,544	92,859	331,969	208,833	167,000	134,235	87,997	58,732
31.12.2031	837	10.77	1,069,536	216,474	-	84,852	-	-	768,210	359,522	90,264	318,423	190,773	149,010	117,053	73,397	46,946
31.12.2032	815	10.49	1,046,847	211,882	-	84,719	-	-	750,247	351,115	88,412	310,719	177,293	135,260	103,837	62,279	38,175
31.12.2033	794	10.22	1,024,728	207,405	-	84,589	-	-	732,735	342,920	86,269	303,546	164,952	122,919	92,218	52,906	31,078
31.12.2034	773	9.95	1,002,380	202,882	-	105,065	-	-	694,433	324,995	82,312	287,126	148,599	108,158	79,300	43,516	24,498
31.12.2035	753	9.69	867,391	175,560	-	74,372	-	-	617,460	288,971	75,552	252,936	124,671	88,632	63,506	33,334	17,984

31.12.2036	733	9.44	847,164	171,466	-	74,252	-	-	601,446	281,477	73,593	246,376	115,655	80,310	56,236	28,235	14,598
31.12.2037	714	9.19	826,945	167,374	-	74,133	-	-	585,438	273,985	71,634	239,819	107,216	72,718	49,763	23,898	11,841
31.12.2038	696	8.96	808,385	163,617	-	74,023	-	-	570,744	267,108	69,836	233,800	99,548	65,947	44,103	20,260	9,620
31.12.2039	677	8.72	789,759	159,847	-	94,519	-	-	535,393	250,564	65,511	219,318	88,935	57,546	37,611	16,526	7,520
31.12.2040	740	9.52	855,676	173,189	-	74,299	46,147	-	562,041	263,035	78,855	220,151	85,022	53,735	34,321	14,425	6,291
31.12.2041	725	9.33	840,277	170,072	-	74,208	-	-	595,997	278,927	71,865	245,206	90,188	55,675	34,752	13,971	5,839
31.12.2042	706	9.09	820,836	166,137	-	74,093	-	-	580,606	271,723	69,982	238,901	83,685	50,459	30,780	11,836	4,740
31.12.2043	689	8.87	802,991	162,525	-	73,988	-	-	566,478	265,112	68,253	233,113	77,769	45,801	27,304	10,043	3,855
31.12.2044	672	8.65	785,160	158,916	-	94,490	-	-	531,754	248,861	64,004	218,889	69,547	40,006	23,308	8,200	3,016
31.12.2045	656	8.44	768,201	155,484	-	73,783	-	-	538,934	252,221	64,883	221,830	67,125	37,715	21,473	7,226	2,547
31.12.2046	639	8.23	751,214	152,046	-	73,682	-	-	525,486	245,927	63,237	216,321	62,341	34,212	19,036	6,128	2,070
31.12.2047	624	8.03	735,090	148,782	-	73,587	-	-	512,721	239,953	61,675	211,092	57,937	31,056	16,888	5,200	1,683
31.12.2048	608	7.83	719,475	145,622	-	73,494	-	-	500,360	234,168	60,163	206,029	53,855	28,197	14,984	4,413	1,369
31.12.2049	594	7.64	704,161	142,522	-	94,010	-	-	467,628	218,850	56,158	192,621	47,952	24,522	12,735	3,588	1,067
31.12.2050	579	7.45	688,887	139,431	-	73,313	-	-	476,143	222,835	57,730	195,578	46,370	23,162	11,755	3,168	903
31.12.2051	565	7.27	674,215	136,461	-	73,226	-	-	464,527	217,399	56,840	190,289	42,967	20,963	10,398	2,680	732
31.12.2052	551	7.09	659,510	133,485	-	73,140	-	-	452,886	211,950	55,415	185,520	39,896	19,012	9,216	2,272	595
31.12.2053	538	6.92	645,649	130,679	-	73,058	-	-	441,911	206,814	54,072	181,024	37,075	17,257	8,175	1,928	483

[14]Another discount rate of 7.5% was taken by the Partnership for calculation purposes and as an aid for the investor.

31.12.2054	524	6.75	631,798	127,876	-	93,584	-	-	410,338	192,038	50,209	168,091	32,787	14,906	6,901	1,557	374
31.12.2055	512	6.59	618,717	125,228	-	72,900	-	-	420,589	196,836	51,463	172,290	32,006	14,212	6,430	1,387	320
31.12.2056	500	6.43	605,621	122,578	-	72,823	-	-	410,221	191,983	50,195	168,043	29,730	12,895	5,701	1,177	260
31.12.2057	488	6.28	593,350	120,094	-	72,751	-	-	400,505	187,437	49,006	164,063	27,644	11,711	5,060	999	211
31.12.2058	476	6.13	581,086	117,612	-	72,679	-	-	390,795	182,892	47,818	160,085	25,689	10,630	4,489	848	172
31.12.2059	465	5.98	568,810	115,127	-	93,213	-	-	360,470	168,700	44,107	147,663	22,567	9,121	3,764	680	132
31.12.2060	454	5.84	557,345	112,807	-	72,539	-	-	371,999	174,096	45,518	152,386	22,180	8,756	3,531	610	114
31.12.2061	443	5.70	545,881	110,486	-	72,472	-	-	362,923	169,848	44,407	148,668	20,609	7,946	3,132	518	92
31.12.2062	433	5.57	535,238	108,332	-	72,409	-	-	354,496	165,904	41,935	146,657	19,362	7,292	2,809	444	76
31.12.2063	422	5.43	523,760	106,009	-	72,342	-	-	345,409	161,652	40,824	142,934	17,972	6,611	2,489	376	62
31.12.2064	49	0.63	60,768	12,299	-	12,672	-	71,601	(35,805)	-	6,792	(42,597)	(5,101)	(1,833)	(674)	(98)	(15)
Total	**28,793**	**370.6**	**34,041,766**	**6,689,627**	**-**	**3,453,914**	**178,853**	**71,601**	**23,647,770**	**9,029,687**	**2,898,409**	**11,719,674**	**6,171,799**	**4,934,794**	**4,111,823**	**3,095,053**	**2,490,827**

Total discounted cash flow from possible reserves as of December 31, 2020 (in dollars in thousands in relation to the Partnership's share)																
Cash flow components																
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%[15]	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2021	78	1.01	70,766	11,068	-	487	-	-	59,212	-	13,619	45,593	44,494	43,974	43,471	42,516	41,621
31.12.2022	61	0.78	65,956	10,316	-	422	-	-	55,219	-	12,700	42,518	39,518	38,147	36,854	34,477	32,345
31.12.2023	63	0.81	66,322	10,373	-	430	-	-	55,520	-	12,770	42,750	37,841	35,679	33,687	30,143	27,101
31.12.2024	65	0.84	72,123	11,280	-	433	-	-	60,410	-	13,894	46,515	39,213	36,113	33,321	28,520	24,573
31.12.2025	94	1.21	109,522	33,389	-	568	-	-	75,565	-	17,380	58,185	46,715	42,021	37,891	31,022	25,615
31.12.2026	88	1.13	102,724	27,366	-	551	-	-	74,807	89,286	(3,330)	(11,149)	(8,525)	(7,490)	(6,601)	(5,169)	(4,090)
31.12.2027	69	0.89	86,886	17,586	-	483	-	-	68,817	58,335	2,411	8,071	5,878	5,044	4,344	3,254	2,468
31.12.2028	41	0.53	61,448	12,437	-	325	-	-	48,686	56,927	(1,895)	(6,345)	(4,401)	(3,689)	(3,104)	(2,224)	(1,616)
31.12.2029	37	0.48	56,084	11,351	-	296	-	-	44,437	54,895	(2,406)	(8,053)	(5,319)	(4,355)	(3,582)	(2,455)	(1,710)
31.12.2030	30	0.38	48,359	9,788	-	250	-	-	38,322	24,413	3,199	10,710	6,737	5,388	4,331	2,839	1,895
31.12.2031	25	0.32	42,899	8,683	-	219	-	-	33,997	15,911	4,160	13,927	8,344	6,517	5,119	3,210	2,053
31.12.2032	22	0.28	39,616	8,018	-	199	-	-	31,398	14,694	3,842	12,862	7,339	5,599	4,298	2,578	1,580
31.12.2033	19	0.25	37,143	7,518	-	185	-	-	29,440	13,778	3,602	12,060	6,554	4,884	3,664	2,102	1,235
31.12.2034	19	0.25	37,118	7,513	-	185	-	-	29,420	13,769	3,600	12,052	6,237	4,540	3,328	1,827	1,028
31.12.2035	20	0.26	26,887	5,442	-	147	-	-	21,298	9,968	2,606	8,725	4,300	3,057	2,191	1,150	620

31.12.2036	21	0.27	27,682	5,603	-	152	-	-	21,927	10,262	2,683	8,982	4,217	2,928	2,050	1,029	532
31.12.2037	24	0.31	30,924	6,259	-	171	-	-	24,494	11,463	2,997	10,034	4,486	3,042	2,082	1,000	495
31.12.2038	26	0.33	32,763	6,631	-	181	-	-	25,951	12,145	3,175	10,630	4,526	2,998	2,005	921	437
31.12.2039	30	0.38	37,019	7,493	-	206	-	-	29,321	13,722	3,588	12,011	4,871	3,152	2,060	905	412
31.12.2040	17	0.22	23,614	4,779	-	128	-	-	18,707	8,755	2,289	7,663	2,959	1,870	1,195	502	219
31.12.2041	23	0.29	29,319	5,934	-	161	-	-	23,224	10,869	2,842	9,513	3,499	2,160	1,348	542	227
31.12.2042	30	0.38	36,659	7,420	-	204	-	-	29,035	13,588	3,553	11,894	4,166	2,512	1,532	589	236
31.12.2043	35	0.45	42,794	8,662	-	240	-	-	33,893	15,862	4,147	13,884	4,632	2,728	1,626	598	230
31.12.2044	40	0.52	48,519	9,820	-	273	-	-	38,425	17,983	4,702	15,741	5,001	2,877	1,676	590	217
31.12.2045	45	0.58	53,433	10,815	-	302	-	-	42,316	19,804	5,178	17,334	5,245	2,947	1,678	565	199
31.12.2046	50	0.64	58,352	11,810	-	331	-	-	46,210	21,626	5,654	18,930	5,455	2,994	1,666	536	181
31.12.2047	54	0.70	63,330	12,818	-	360	-	-	50,152	23,471	6,137	20,544	5,639	3,022	1,644	506	164
31.12.2048	59	0.76	68,848	13,935	-	391	-	-	54,522	25,516	6,671	22,334	5,838	3,057	1,624	478	148
31.12.2049	64	0.82	73,799	14,937	-	420	-	-	58,441	27,350	7,151	23,940	5,960	3,048	1,583	446	133
31.12.2050	68	0.87	77,946	15,776	-	445	-	-	61,725	28,887	7,553	25,285	5,995	2,994	1,520	410	117
31.12.2051	71	0.92	82,070	16,611	-	469	-	-	64,990	30,415	7,952	26,623	6,011	2,933	1,455	375	102
31.12.2052	75	0.97	86,193	17,446	-	493	-	-	68,255	31,943	8,352	27,960	6,013	2,865	1,389	342	90
31.12.2053	78	1.01	89,503	18,115	-	512	-	-	70,875	33,170	8,672	29,033	5,946	2,768	1,311	309	78

[15] Another discount rate of 7.5% was taken by the Partnership for calculation purposes and as an aid for the investor.

31.12.2054	82	1.05	92,821	18,787	-	532	-	-	73,502	34,399	8,994	30,110	5,873	2,670	1,236	279	67
31.12.2055	85	1.09	96,132	19,457	-	551	-	-	76,124	35,626	9,315	31,183	5,793	2,572	1,164	251	58
31.12.2056	87	1.12	98,621	19,961	-	566	-	-	78,094	36,548	9,556	31,990	5,660	2,455	1,085	224	49
31.12.2057	89	1.15	101,114	20,465	-	580	-	-	80,068	37,472	9,797	32,799	5,527	2,341	1,012	200	42
31.12.2058	92	1.18	103,614	20,972	-	595	-	-	82,048	38,398	10,039	33,610	5,394	2,232	942	178	36
31.12.2059	95	1.22	106,941	21,645	-	614	-	-	84,682	39,631	10,362	34,689	5,302	2,143	884	160	31
31.12.2060	96	1.24	108,620	21,985	-	624	-	-	86,011	40,253	10,524	35,234	5,128	2,025	816	141	26
31.12.2061	99	1.27	111,131	22,493	-	639	-	-	87,999	41,184	10,768	36,048	4,997	1,927	759	125	22
31.12.2062	100	1.29	112,823	22,835	-	649	-	-	89,339	41,811	10,932	36,597	4,832	1,820	701	111	19
31.12.2063	103	1.32	115,344	23,346	-	663	-	-	91,335	42,745	11,176	37,414	4,704	1,731	651	98	16
31.12.2064	12	0.16	14,031	2,840	-	81	-	-	11,111	-	2,555	8,555	1,024	368	135	20	3
Total	**2,481**	**31.9**	**2,947,815**	**601,776**	**-**	**16,714**	**-**	**-**	**2,329,324**	**1,096,875**	**283,463**	**948,985**	**379,617**	**288,608**	**238,044**	**186,220**	**159,304**

Total discounted cash flow from 3P (proved + probable + possible) reserves as of December 31, 2020 (in dollars in thousands in relation to the Partnership's share)

Cash flow components

Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%[16]	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2021	852	10.96	831,372	130,027	-	78,747	94,917	-	527,682	-	60,078	467,604	456,335	450,998	445,843	436,043	426,862
31.12.2022	820	10.55	839,731	131,334	-	85,043	26,681	-	596,674	-	93,698	502,975	467,480	451,267	435,971	407,850	382,626
31.12.2023	869	11.18	903,280	141,273	-	83,359	11,108	-	667,540	-	105,914	561,626	497,134	468,733	442,553	396,007	356,036
31.12.2024	890	11.46	977,029	152,807	-	82,643	-	-	741,579	-	119,658	621,920	524,291	482,842	445,513	381,322	328,549
31.12.2025	935	12.03	1,047,445	180,080	-	82,981	-	-	784,383	-	129,503	654,880	525,787	472,959	426,476	349,158	288,301
31.12.2026	935	12.03	1,076,464	217,876	-	82,782	-	-	775,806	89,286	106,995	579,525	443,130	389,337	343,093	268,679	212,606
31.12.2027	935	12.03	1,109,945	224,653	-	82,776	-	-	802,516	242,446	77,911	482,159	351,123	301,325	259,500	194,381	147,405
31.12.2028	935	12.03	1,145,744	231,898	-	85,354	-	-	828,491	319,100	66,255	443,135	307,338	257,616	216,816	155,347	112,896
31.12.2029	919	11.83	1,153,260	233,420	-	105,958	-	-	813,883	366,935	51,893	395,054	260,944	213,641	175,719	120,427	83,872
31.12.2030	889	11.44	1,140,837	230,905	-	85,239	-	-	824,693	385,956	96,058	342,679	215,570	172,388	138,566	90,836	60,627
31.12.2031	862	11.09	1,112,435	225,157	-	85,071	-	-	802,207	375,433	94,424	332,350	199,117	155,527	122,172	76,607	49,000
31.12.2032	837	10.77	1,086,462	219,900	-	84,918	-	-	781,644	365,810	92,254	323,581	184,632	140,859	108,135	64,857	39,756
31.12.2033	813	10.47	1,061,871	214,923	-	84,774	-	-	762,175	356,698	89,871	315,606	171,506	127,802	95,882	55,007	32,313
31.12.2034	792	10.20	1,039,497	210,394	-	105,250	-	-	723,854	338,763	85,912	299,178	154,837	112,698	82,628	45,343	25,526
31.12.2035	773	9.95	894,278	181,002	-	74,519	-	-	638,758	298,939	78,158	261,661	128,971	91,689	65,697	34,484	18,604

31.12.2036	754	9.71	874,846	177,069	-	74,404	-	-	623,373	291,738	76,276	255,358	119,872	83,237	58,286	29,264	15,130
31.12.2037	738	9.50	857,869	173,633	-	74,304	-	-	609,932	285,448	74,631	249,853	111,702	75,761	51,845	24,898	12,337
31.12.2038	722	9.29	841,148	170,248	-	74,205	-	-	596,695	279,253	73,012	244,430	104,074	68,946	46,109	21,181	10,057
31.12.2039	707	9.10	826,778	167,340	-	94,725	-	-	564,713	264,286	69,098	231,329	93,806	60,698	39,670	17,431	7,932
31.12.2040	757	9.74	879,289	177,968	-	74,426	46,147	-	580,748	271,790	81,143	227,814	87,981	55,605	35,516	14,927	6,509
31.12.2041	747	9.62	869,596	176,006	-	74,369	-	-	619,221	289,795	74,707	254,719	93,687	57,835	36,100	14,513	6,065
31.12.2042	736	9.47	857,495	173,557	-	74,297	-	-	609,641	285,312	73,534	250,795	87,851	52,971	32,313	12,426	4,976
31.12.2043	724	9.32	845,786	171,187	-	74,227	-	-	600,371	280,974	72,400	246,997	82,401	48,529	28,931	10,641	4,084
31.12.2044	712	9.17	833,679	168,737	-	94,763	-	-	570,180	266,844	68,706	234,630	74,548	42,883	24,984	8,790	3,233
31.12.2045	701	9.02	821,633	166,299	-	74,085	-	-	581,250	272,025	70,060	239,165	72,370	40,662	23,151	7,791	2,746
31.12.2046	689	8.87	809,565	163,856	-	74,013	-	-	571,696	267,554	68,891	235,251	67,796	37,206	20,702	6,664	2,251
31.12.2047	678	8.73	798,420	161,600	-	73,947	-	-	562,873	263,425	67,812	231,637	63,576	34,079	18,531	5,706	1,847
31.12.2048	667	8.59	788,323	159,557	-	73,885	-	-	554,881	259,685	66,834	228,363	59,693	31,253	16,608	4,891	1,518
31.12.2049	657	8.46	777,959	157,459	-	94,431	-	-	526,070	246,201	63,308	216,561	53,912	27,570	14,318	4,034	1,199
31.12.2050	646	8.32	766,833	155,207	-	73,758	-	-	537,869	251,723	65,283	220,863	52,365	26,156	13,275	3,577	1,019
31.12.2051	636	8.19	756,285	153,072	-	73,695	-	-	529,517	247,814	64,792	216,912	48,979	23,896	11,852	3,055	834
31.12.2052	626	8.06	745,704	150,930	-	73,633	-	-	521,140	243,894	63,767	213,480	45,909	21,877	10,604	2,614	684
31.12.2053	616	7.93	735,152	148,795	-	73,571	-	-	512,786	239,984	62,745	210,058	43,022	20,025	9,486	2,237	561

[16]Another discount rate of 7.5% was taken by the Partnership for calculation purposes and as an aid for the investor.

31.12.2054	606	7.80	724,619	146,663	-	94,116	-	-	483,841	226,437	59,203	198,200	38,660	17,576	8,137	1,835	441
31.12.2055	597	7.68	714,850	144,686	-	73,451	-	-	496,713	232,462	60,778	203,473	37,799	16,785	7,594	1,638	377
31.12.2056	587	7.55	704,242	142,539	-	73,389	-	-	488,315	228,531	59,750	200,033	35,390	15,350	6,787	1,401	309
31.12.2057	577	7.43	694,464	140,560	-	73,331	-	-	480,573	224,908	58,803	196,862	33,171	14,052	6,072	1,199	254
31.12.2058	568	7.31	684,700	138,583	-	73,274	-	-	472,843	221,291	57,857	193,695	31,083	12,862	5,431	1,026	208
31.12.2059	559	7.20	675,752	136,772	-	93,828	-	-	445,151	208,331	54,469	182,352	27,869	11,264	4,648	840	163
31.12.2060	550	7.08	665,965	134,791	-	73,163	-	-	458,010	214,349	56,042	187,619	27,309	10,781	4,348	751	140
31.12.2061	542	6.97	657,012	132,979	-	73,111	-	-	450,922	211,032	55,175	184,716	25,606	9,873	3,891	643	115
31.12.2062	533	6.86	648,061	131,168	-	73,058	-	-	443,835	207,715	52,867	183,254	24,193	9,112	3,510	555	95
31.12.2063	524	6.75	639,104	129,355	-	73,005	-	-	436,744	204,396	51,999	180,349	22,676	8,342	3,140	475	78
31.12.2064	61	0.79	74,799	15,139	-	12,753	-	71,601	(24,694)	-	9,348	(34,042)	(4,076)	(1,465)	(539)	(78)	(12)
Total	**31,274**	**402.5**	**36,989,581**	**7,291,404**	**-**	**3,470,629**	**178,853**	**71,601**	**25,977,094**	**10,126,562**	**3,181,872**	**12,668,659**	**6,551,416**	**5,223,402**	**4,349,866**	**3,281,273**	**2,650,130**

Caution – it is clarified that discounted cash flow figures, whether calculated at a specific cap rate or without a cap rate, represent present value but do not necessarily represent fair value.

Caution regarding forward-looking information – the discounted cash flow figures as aforesaid are forward-looking information, within the meaning thereof in the Securities Law. The above figures are based on various assumptions including in relation to the quantities of gas and condensate that shall be produced, the pace and duration of the natural gas sales from the project, operation costs, capital expenses, abandonment expenses, royalty rates and the sale prices, in respect of which there is no certainty that they will materialize. It is noted that the quantities of natural gas and/or condensate that shall actually be produced, the said expenses and the said income may be materially different from the above estimates and assumptions, *inter alia* as a result of operating and technical conditions and/or regulatory changes and/or supply and demand conditions in the natural gas and/or condensate market and/or the actual performance of the project and/or as a result of the actual sale prices and/or as a result of geopolitical changes that shall occur.

(4) Set forth below is an analysis of sensitivity to the main parameters comprising the discounted cash flow (the gas price and the gas sales volume) as of December 31, 2020 (dollars in thousands) which was performed by the Partnership[17]:

Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
10% increase in the gas price					**10% decrease in the gas price**				
1P (Proved) Reserves	11,309,757	3,946,717	2,955,119	2,368,079	1P (Proved) Reserves	9,467,890	3,371,790	2,516,531	2,004,685
Probable Reserves	1,467,160	481,889	377,698	317,917	Probable Reserves	1,192,445	412,825	329,846	280,477
Total 2P (Proved+Probable) Reserves	12,776,917	4,428,607	3,332,817	2,685,996	Total 2P (Proved+Probable) Reserves	10,660,335	3,784,615	2,846,377	2,285,162
Possible Reserves	1,042,333	258,329	201,057	171,537	Possible Reserves	855,496	221,494	175,472	151,109
Total 3P (Proved+Probable+Possible) Reserves	13,819,250	4,686,935	3,533,875	2,857,533	Total 3P (Proved+Probable+Possible) Reserves	11,515,831	4,006,109	3,021,849	2,436,270
15% increase in the gas price					**15% decrease in the gas price**				
1P (Proved) Reserves	11,773,984	4,088,394	3,062,135	2,456,250	1P (Proved) Reserves	9,012,405	3,224,159	2,402,349	1,909,440
Probable Reserves	1,531,421	497,107	387,979	325,803	Probable Reserves	1,123,261	397,266	319,397	272,292
Total 2P (Proved+Probable) Reserves	13,305,404	4,585,501	3,450,114	2,782,053	Total 2P (Proved+Probable) Reserves	10,135,666	3,621,425	2,721,745	2,181,732
Possible Reserves	1,089,215	266,703	206,315	175,319	Possible Reserves	805,953	209,947	166,904	144,000
Total 3P (Proved+Probable+Possible) Reserves	14,394,619	4,852,205	3,656,430	2,957,372	Total 3P (Proved+Probable+Possible) Reserves	10,941,619	3,831,372	2,888,650	2,325,732

[17] With respect to a sensitivity analysis for the discounted cash flow to the variable of the gas sales volume, it is noted that costs were not included in respect of other wells which may be required in order to make adjustments for growth in the gas sales volume.

Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
20% increase in the gas price					**20% decrease in the gas price**				
1P (Proved) Reserves	12,237,097	4,228,161	3,167,314	2,542,750	1P (Proved) Reserves	8,555,349	3,072,838	2,284,918	1,811,520
Probable Reserves	1,603,265	517,422	402,411	337,073	Probable Reserves	1,056,713	381,725	308,233	262,990
Total 2P (Proved+Probable) Reserves	13,840,362	4,745,583	3,569,724	2,879,823	Total 2P (Proved+Probable) Reserves	9,612,062	3,454,563	2,593,151	2,074,510
Possible Reserves	1,135,871	274,965	211,432	178,921	Possible Reserves	758,336	202,119	161,945	140,188
Total 3P (Proved+Probable+Possible) Reserves	14,976,233	5,020,548	3,781,156	3,058,744	Total 3P (Proved+Probable+Possible) Reserves	10,370,398	3,656,682	2,755,097	2,214,698

Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
10% increase in the gas sales volume				
1P (Proved) Reserves	10,455,209	3,933,039	2,955,450	2,369,977
Probable Reserves	1,316,151	479,186	377,578	318,122
Total 2P (Proved+Probable) Reserves	11,771,359	4,412,225	3,333,028	2,688,099
Possible Reserves	960,127	257,749	201,162	171,648
Total 3P (Proved+Probable+Possible) Reserves	12,731,486	4,669,974	3,534,190	2,859,747
15% increase in the gas sales volume				
1P (Proved) Reserves	10,513,220	4,064,399	3,061,598	2,458,784
Probable Reserves	1,307,600	492,318	387,577	326,038
Total 2P (Proved+Probable) Reserves	11,820,820	4,556,717	3,449,176	2,784,822
Possible Reserves	936,142	265,175	206,387	175,474
Total 3P (Proved+Probable+Possible) Reserves	12,756,962	4,821,893	3,655,563	2,960,296
20% increase in the gas sales volume[18]				
1P (Proved) Reserves	10,552,492	4,190,477	3,164,885	2,545,597
Probable Reserves	1,307,443	510,195	401,640	337,334
Total 2P (Proved+Probable) Reserves	11,859,935	4,700,672	3,566,525	2,882,931

Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
10% decrease in the gas sales volume				
1P (Proved) Reserves	9,441,400	3,365,610	2,512,570	2,001,916
Probable Reserves	1,194,493	415,575	332,108	282,288
Total 2P (Proved+Probable) Reserves	10,635,893	3,781,185	2,844,678	2,284,204
Possible Reserves	846,830	217,647	172,582	148,891
Total 3P (Proved+Probable+Possible) Reserves	11,482,723	3,998,831	3,017,260	2,433,095
15% decrease in the gas sales volume				
1P (Proved) Reserves	8,972,612	3,214,729	2,396,267	1,905,172
Probable Reserves	1,117,248	396,095	318,694	271,817
Total 2P (Proved+Probable) Reserves	10,089,860	3,610,824	2,714,961	2,176,989
Possible Reserves	802,078	209,521	166,697	143,883
Total 3P (Proved+Probable+Possible) Reserves	10,891,938	3,820,345	2,881,658	2,320,872
20% decrease in the gas sales volume				
1P (Proved) Reserves	8,506,588	3,062,138	2,278,089	1,806,720
Probable Reserves	1,044,312	378,079	305,825	261,306
Total 2P (Proved+Probable) Reserves	9,550,901	3,440,216	2,583,914	2,068,026

[18] It is noted that due to infrastructure restrictions, it is not possible to increase the gas quantities at this rate.

Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
Possible Reserves	931,202	273,109	211,617	179,148	Possible Reserves	753,152	201,522	161,631	139,990
Total 3P (Proved+Probable+Possible) Reserves	12,791,137	4,973,781	3,778,142	3,062,079	Total 3P (Proved+Probable+Possible) Reserves	10,304,053	3,641,738	2,745,546	2,208,016

(b) Contingent resources in the Leviathan Reservoir

(1) Quantity Data

According to NSAI's report, the project referring to the contingent gas and condensate resources in the Leviathan Reservoir, is classified as a project at a level of maturity of development pending, and the rate of resources is as specified below:

Natural Gas[19] **BCF**						
Category	**Total (100%) in the Petroleum Asset (Gross)**			**The Total Share Attributed to the Holders of the Equity Interests of the Partnership (Net)[20]**		
	Phase I – First Stage	**Future Development**	**Total**	**Phase I – First Stage**	**Future Development**	**Total**
1C - Low Estimate	4,912.6	544.4	5,457.0	1,739.1	192.5	1,931.6
2C - Best Estimate	4,477.6	5,103.3	9,580.9	1,585.3	1,804.8	3,390.1
3C- High Estimate	3,734.5	9,651.0	13,385.5	1,322.5	3,413.1	4,735.6

Condensate[21] **Million Barrels**						
Category	**Total (100%) in the Petroleum Asset (Gross)**			**The Total Share Attributed to the Holders of the Equity Interests of the Partnership (Net)[2]**		
	Phase I – First Stage	**Future Develop-ment**	**Total**	**Phase I – First Stage**	**Future Develop-ment**	**Total**
1C - Low Estimate	10.8	1.2	12.0	3.8	0.4	4.2
2C - Best Estimate	9.9	11.2	21.1	3.5	4.0	7.5
3C- High Estimate	8.2	21.2	29.4	2.9	7.5	10.4

[19]The amounts in the table may not add up due to rounding-off differences
[20]See Footnote 3 above.
[21]The amounts in the table may not add up due to rounding-off differences

(2) In view of the significant amount of contingent resources attributed to the Leviathan project, the potential markets for these resources are the domestic market and/or the regional market and/or the international market. For a description of the potential markets for such resources, see Section 7.13 of the Periodic Report. For details regarding gas export engagements and an examination of the possibility of exporting additional gas, see Sections 7.13.2 and 7.12.5(b) of the Periodic Report.

(3) The resources report states that reclassification of the contingent resources in the Leviathan project in the Phase I – First Stage category as reserves is contingent on the adoption of decisions to drill additional wells, and on the signing of additional agreements for the sale of natural gas, and that reclassification of the contingent resources in the Leviathan project in the Future Development category as reserves is contingent on the adoption of additional investment decisions and on the signing of additional agreements for the sale of natural gas. Insofar as the said conditions are fulfilled, the contingent resources, in whole or in part, may be classified as reserves.

Caution – There is no certainty that any part of the contingent resources will be commercially recoverable.

Caution regarding forward-looking information – NSAI's estimates regarding quantities of reserves and contingent resources of natural gas and condensate in the Leviathan Reservoir are forward-looking information, within the meaning thereof in the Securities Law. The above estimates are based, *inter alia,* on geological, geophysical, engineering and other information received from the operator, from the wells in the Reservoir and from wells in adjacent reservoirs, and constitute professional estimates and assumptions of NSAI only, and in respect of which there is no certainty. The natural gas and/or condensate quantities that shall actually be extracted may be different to the said estimates and assumptions, *inter alia* as a result of operating and technical conditions and/or regulatory changes and/or supply and demand conditions in the natural gas and/or condensate market and/or commercial conditions and/or geopolitical changes and/or the actual performance of the Reservoir. The said estimates and assumptions may be updated insofar as additional information shall accumulate and/or as a result of a gamut of factors relating to projects for oil and natural gas exploration and production.

(4) <u>Discounted cash flow figures</u>

In accordance with the various assumptions, mainly those specified in Section 1a(3) above, set forth below is the estimated discounted cash flow as of December 31, 2020, in dollars in thousands (after levy and income tax) attributed to the Partnership's share, from the contingent resources in the Leviathan Reservoir, for each one of the contingent resource categories specified above:

Total discounted cash flow from the low estimate contingent resources as of December 31, 2020 (in dollars in thousands in relation to the Partnership's share)

Cash flow components

Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%[22]	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2021	84	1.08	76,592	11,979	-	524	-	-	64,089	-	14,740	49,348	48,159	47,596	47,052	46,018	45,049
31.12.2022	121	1.56	112,694	17,625	-	766	-	-	94,303	-	21,690	72,613	67,489	65,148	62,940	58,880	55,239
31.12.2023	125	1.61	117,862	18,434	-	796	-	-	98,632	-	22,685	75,946	67,225	63,385	59,845	53,550	48,145
31.12.2024	142	1.83	141,500	22,131	-	880	-	-	118,489	-	27,253	91,237	76,914	70,834	65,358	55,941	48,199
31.12.2025	183	2.36	182,655	28,567	-	1,136	-	-	152,952	-	35,179	117,773	94,557	85,057	76,697	62,792	51,848
31.12.2026	193	2.49	199,141	66,812	-	1,051	-	-	131,277	12,595	27,297	91,385	69,877	61,394	54,102	42,368	33,526
31.12.2027	214	2.76	221,137	54,404	-	1,263	-	-	165,471	199,610	(7,852)	(26,287)	(19,143)	(16,428)	(14,148)	(10,597)	(8,036)
31.12.2028	234	3.01	247,533	50,101	-	1,453	-	-	195,980	146,889	11,291	37,799	26,216	21,975	18,494	13,251	9,630
31.12.2029	234	3.01	249,497	50,498	-	1,460	-	-	197,538	152,775	10,295	34,467	22,767	18,640	15,331	10,507	7,318
31.12.2030	234	3.01	251,520	50,908	-	1,468	-	-	199,144	158,884	9,260	31,000	19,501	15,595	12,535	8,217	5,485
31.12.2031	234	3.01	251,564	50,916	-	1,468	176,690	-	22,489	42,626	33,975	(54,113)	(32,420)	(25,323)	(19,892)	(12,473)	(7,978)
31.12.2032	234	3.01	251,650	50,934	-	1,469	-	-	199,247	97,315	19,381	82,552	47,103	35,936	27,587	16,546	10,142
31.12.2033	234	3.01	251,715	50,947	-	1,469	-	-	199,298	93,272	20,322	85,705	46,573	34,705	26,037	14,938	8,775
31.12.2034	234	3.01	251,789	50,962	-	1,469	-	-	199,358	93,299	20,330	85,729	44,368	32,293	23,677	12,993	7,314
31.12.2035	234	3.01	250,478	50,697	-	1,464	-	-	198,317	92,812	20,202	85,303	42,045	29,891	21,417	11,242	6,065

31.12.2036	234	3.01	250,567	50,715	-	1,465	111,990	-	86,398	40,434	30,978	14,986	7,035	4,885	3,421	1,717	888
31.12.2037	234	3.01	250,670	50,736	-	1,465	-	-	198,469	92,884	17,645	87,941	39,316	26,666	18,248	8,763	4,342
31.12.2038	234	3.01	250,803	50,762	-	1,466	88,345	-	110,230	51,588	26,151	32,491	13,834	9,165	6,129	2,815	1,337
31.12.2039	249	3.21	267,087	54,058	-	1,561	-	-	211,467	98,967	17,204	95,297	38,644	25,005	16,342	7,181	3,268
31.12.2040	278	3.58	297,408	60,195	-	1,740	88,345	-	147,128	68,856	28,634	49,638	19,170	12,116	7,738	3,252	1,418
31.12.2041	304	3.91	324,430	65,665	-	1,898	-	-	256,867	120,214	22,759	113,894	41,891	25,860	16,142	6,489	2,712
31.12.2042	326	4.20	348,236	70,483	-	2,038	88,345	-	187,370	87,689	35,590	64,090	22,450	13,537	8,258	3,175	1,272
31.12.2043	347	4.47	370,405	74,970	-	2,168	-	-	293,267	137,249	27,213	128,805	42,971	25,307	15,087	5,549	2,130
31.12.2044	366	4.71	390,160	78,968	-	2,284	212,157	-	96,750	45,279	49,523	1,948	619	356	207	73	27
31.12.2045	382	4.92	407,545	82,487	-	2,386	-	-	322,671	151,010	25,931	145,730	44,097	24,777	14,107	4,747	1,673
31.12.2046	398	5.12	424,121	85,842	-	2,483	188,512	-	147,283	68,929	46,948	31,407	9,051	4,967	2,764	890	301
31.12.2047	413	5.31	439,915	89,039	-	2,576	188,512	-	159,788	74,781	45,430	39,577	10,862	5,823	3,166	975	316
31.12.2048	408	5.25	430,596	87,153	-	2,530	312,325	-	28,589	13,380	53,110	(37,901)	(9,907)	(5,187)	(2,756)	(812)	(252)
31.12.2049	384	4.94	405,192	82,011	-	2,380	-	-	320,801	150,135	14,455	156,211	38,888	19,887	10,328	2,910	865
31.12.2050	360	4.64	380,981	77,111	-	2,237	-	-	301,633	141,164	13,125	147,343	34,934	17,449	8,856	2,386	680
31.12.2051	339	4.36	358,125	72,485	-	2,103	-	-	283,538	132,696	11,927	138,915	31,367	15,304	7,591	1,956	534
31.12.2052	316	4.07	334,405	67,684	-	1,963	-	-	264,758	123,907	10,645	130,206	28,001	13,343	6,468	1,595	417
31.12.2053	295	3.80	312,350	63,220	-	1,834	-	-	247,297	115,735	9,525	122,037	24,994	11,634	5,511	1,300	326

[22] Another discount rate of 7.5% was taken by the Partnership for calculation purposes and as an aid for the investor.

31.12.2054	275	3.54	291,126	58,924	-	1,709	-	-	230,494	107,871	9,908	112,714	21,986	9,995	4,627	1,044	251
31.12.2055	256	3.30	271,481	54,948	-	1,593	-	-	214,940	100,592	10,445	103,903	19,302	8,571	3,878	837	193
31.12.2056	238	3.06	251,815	50,967	-	1,478	-	-	199,370	93,305	10,708	95,357	16,871	7,317	3,235	668	147
31.12.2057	221	2.84	233,794	47,320	-	1,372	-	-	185,102	86,628	13,298	85,177	14,352	6,080	2,627	519	110
31.12.2058	204	2.62	215,777	43,673	-	1,266	-	-	170,838	79,952	17,312	73,574	11,807	4,885	2,063	390	79
31.12.2059	188	2.42	199,393	40,357	-	1,170	-	-	157,866	73,881	19,317	64,668	9,883	3,995	1,648	298	58
31.12.2060	173	2.23	183,814	37,204	-	1,078	-	-	145,532	68,109	17,807	59,616	8,677	3,426	1,381	239	44
31.12.2061	158	2.04	168,235	34,051	-	986	-	-	133,198	62,336	16,298	54,563	7,564	2,916	1,149	190	34
31.12.2062	145	1.87	154,297	31,230	-	905	-	-	122,163	57,172	7,387	57,603	7,605	2,864	1,103	174	30
31.12.2063	133	1.71	141,173	28,573	-	827	-	-	111,772	52,309	6,116	53,347	6,708	2,467	929	140	23
31.12.2064	15	0.19	15,581	3,153	-	92	-	98,615	(86,279)	-	(4,723)	(81,556)	(9,766)	(3,509)	(1,291)	(187)	(29)
Total	**10,808**	**139.1**	**11,426,807**	**2,319,897**	**-**	**67,189**	**1,455,221**	**98,615**	**7,485,886**	**3,587,130**	**896,714**	**3,002,042**	**1,174,438**	**840,598**	**645,991**	**443,447**	**343,912**

Total discounted cash flow from the best estimate contingent resources as of December 31, 2020 (in dollars in thousands in relation to the Partnership's share)

Cash flow components																	
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%[23]	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2021	58	0.75	53,222	8,324	-	364	-	-	44,534	-	10,243	34,291	33,465	33,073	32,695	31,977	31,303
31.12.2022	1	0.01	722	113	-	5	-	-	605	-	139	465	433	418	403	377	354
31.12.2023	40	0.51	37,337	5,839	-	252	-	-	31,245	-	7,186	24,059	21,296	20,079	18,958	16,964	15,252
31.12.2024	50	0.64	49,486	7,740	-	308	-	-	41,439	-	9,531	31,908	26,899	24,772	22,857	19,564	16,856
31.12.2025	82	1.06	82,642	16,039	-	497	-	-	66,106	-	15,204	50,901	40,867	36,761	33,148	27,139	22,409
31.12.2026	88	1.13	92,261	25,248	-	511	-	-	66,502	56,292	2,348	7,862	6,012	5,282	4,654	3,645	2,884
31.12.2027	69	0.89	74,262	15,031	-	434	-	-	58,797	41,666	3,940	13,192	9,606	8,244	7,100	5,318	4,033
31.12.2028	41	0.53	46,675	9,447	-	268	-	-	36,960	39,830	(660)	(2,210)	(1,532)	(1,285)	(1,081)	(775)	(563)
31.12.2029	53	0.68	59,728	12,089	-	343	88,345	-	(41,049)	3,954	8,953	(53,956)	(35,639)	(29,179)	(23,999)	(16,448)	(11,455)
31.12.2030	75	0.97	84,129	17,028	-	485	-	-	66,616	37,385	4,691	24,540	15,438	12,345	9,923	6,505	4,342
31.12.2031	98	1.26	107,759	21,810	-	624	-	-	85,324	39,932	8,408	36,984	22,158	17,307	13,595	8,525	5,453
31.12.2032	120	1.54	130,599	26,433	-	759	88,345	-	15,062	7,049	19,114	(11,101)	(6,334)	(4,833)	(3,710)	(2,225)	(1,364)
31.12.2033	141	1.81	152,628	30,892	-	888	-	-	120,848	56,557	10,723	53,568	29,110	21,692	16,274	9,336	5,485
31.12.2034	162	2.08	174,658	35,351	-	1,018	-	-	138,289	64,719	12,857	60,713	31,421	22,870	16,768	9,201	5,180
31.12.2035	182	2.34	195,884	39,647	-	1,143	-	-	155,094	72,584	14,913	67,597	33,318	23,687	16,972	8,909	4,806

31.12.2036	201	2.59	216,338	43,787	-	1,263	-	-	171,288	80,163	16,895	74,230	34,846	24,196	16,943	8,507	4,398
31.12.2037	221	2.84	236,822	47,933	-	1,383	-	-	187,506	87,753	18,879	80,874	36,156	24,523	16,781	8,059	3,993
31.12.2038	239	3.07	255,722	51,758	-	1,494	-	-	202,470	94,756	20,710	87,004	37,045	24,541	16,412	7,539	3,580
31.12.2039	257	3.31	275,269	55,714	-	1,610	111,990	-	105,955	49,587	34,387	21,982	8,914	5,768	3,770	1,656	754
31.12.2040	195	2.51	210,057	42,515	-	1,226	(46,147)	-	212,463	99,433	11,306	101,724	39,285	24,829	15,859	6,665	2,907
31.12.2041	210	2.70	225,623	45,666	-	1,317	-	-	178,640	83,604	18,312	76,724	28,220	17,420	10,874	4,371	1,827
31.12.2042	228	2.94	245,309	49,650	-	1,433	88,345	-	105,880	49,552	29,729	26,600	9,318	5,618	3,427	1,318	528
31.12.2043	246	3.16	263,361	53,304	-	1,539	-	-	208,518	97,586	21,968	88,963	29,679	17,479	10,420	3,833	1,471
31.12.2044	263	3.38	281,441	56,964	-	1,645	-	-	222,832	104,285	23,719	94,827	30,129	17,331	10,097	3,552	1,307
31.12.2045	279	3.59	298,766	60,470	-	1,746	-	-	236,549	110,705	25,398	100,446	30,395	17,078	9,723	3,272	1,153
31.12.2046	295	3.80	316,104	63,979	-	1,848	88,345	-	161,931	75,784	35,571	50,576	14,575	7,999	4,451	1,433	484
31.12.2047	311	4.00	332,653	67,329	-	1,945	-	-	263,379	123,261	26,649	113,469	31,143	16,694	9,078	2,795	905
31.12.2048	326	4.20	349,243	70,687	-	2,042	-	-	276,514	129,409	28,256	118,850	31,066	16,265	8,644	2,546	790
31.12.2049	341	4.39	365,093	73,895	-	2,135	200,335	-	88,728	41,525	50,340	(3,136)	(781)	(399)	(207)	(58)	(17)
31.12.2050	356	4.58	381,046	77,124	-	2,228	-	-	301,695	141,193	28,774	131,727	31,231	15,600	7,918	2,133	608
31.12.2051	370	4.76	395,965	80,143	-	2,315	200,335	-	113,172	52,964	48,949	11,258	2,542	1,240	615	159	43
31.12.2052	375	4.83	399,602	80,879	-	2,341	188,512	-	127,870	59,843	44,573	23,454	5,044	2,404	1,165	287	75
31.12.2053	371	4.77	392,082	79,357	-	2,302	200,335	-	110,088	51,521	41,660	16,906	3,463	1,612	763	180	45

[23]Another discount rate of 7.5% was taken by the Partnership for calculation purposes and as an aid for the investor.

31.12.2054	367	4.72	388,168	78,565	-	2,278	200,335	-	106,990	50,071	36,674	20,245	3,949	1,795	831	187	45
31.12.2055	362	4.66	383,364	77,593	-	2,250	-	-	303,521	142,048	12,340	149,133	27,704	12,302	5,566	1,201	277
31.12.2056	358	4.61	379,368	76,784	-	2,226	-	-	300,358	140,567	12,969	146,821	25,976	11,266	4,981	1,028	227
31.12.2057	354	4.55	374,564	75,812	-	2,198	-	-	296,555	138,788	13,520	144,247	24,305	10,297	4,449	878	186
31.12.2058	349	4.49	369,786	74,845	-	2,169	-	-	292,772	137,017	13,057	142,698	22,899	9,475	4,001	756	153
31.12.2059	345	4.44	365,829	74,044	-	2,146	-	-	289,639	135,551	14,978	139,111	21,260	8,593	3,546	640	124
31.12.2060	340	4.38	361,034	73,073	-	2,117	-	-	285,844	133,775	16,817	135,252	19,686	7,772	3,134	541	101
31.12.2061	336	4.33	357,086	72,274	-	2,094	-	-	282,718	132,312	18,738	131,668	18,252	7,038	2,774	458	82
31.12.2062	332	4.27	352,326	71,311	-	2,066	-	-	278,950	130,549	15,189	133,213	17,587	6,624	2,551	403	69
31.12.2063	328	4.22	348,393	70,515	-	2,042	-	-	275,836	129,091	19,279	127,465	16,027	5,896	2,219	336	55
31.12.2064	39	0.50	41,360	8,371	-	242	-	98,615	(65,868)	-	(2,333)	(63,535)	(7,608)	(2,734)	(1,006)	(145)	(23)
Total	**9,851**	**126.8**	**10,503,764**	**2,125,373**	**-**	**61,538**	**1,409,074**	**98,615**	**6,809,165**	**3,222,660**	**824,896**	**2,761,608**	**818,823**	**509,756**	**344,339**	**192,544**	**131,120**

Total discounted cash flow from the high estimate contingent resources as of December 31, 2020 (in dollars in thousands in relation to the Partnership's share)

Cash flow components

Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%[24]	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2021	58	0.75	50,993	7,975	-	355	-	-	42,662	-	9,812	32,850	32,058	31,683	31,321	30,633	29,988
31.12.2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2025	-	-	-	422	-	(2)	-	-	(420)	-	(97)	(323)	(259)	(233)	(210)	(172)	(142)
31.12.2026	-	-	-	-	-	-	-	-	-	15,570	(3,581)	(11,989)	(9,167)	(8,055)	(7,098)	(5,558)	(4,398)
31.12.2027	-	-	-	-	-	-	-	-	-	3,778	(869)	(2,909)	(2,119)	(1,818)	(1,566)	(1,173)	(889)
31.12.2028	-	-	-	-	-	-	-	-	-	2,887	(664)	(2,223)	(1,542)	(1,293)	(1,088)	(779)	(566)
31.12.2029	16	0.20	20,026	4,053	-	110	88,345	-	(72,483)	(32,822)	10,181	(49,842)	(32,922)	(26,954)	(22,170)	(15,194)	(10,582)
31.12.2030	46	0.59	53,204	10,769	-	303	-	-	42,133	19,718	3,123	19,291	12,136	9,705	7,801	5,114	3,413
31.12.2031	73	0.94	81,726	16,541	-	471	-	-	64,714	30,286	5,886	28,541	17,100	13,356	10,492	6,579	4,208
31.12.2032	98	1.26	107,826	21,824	-	624	-	-	85,377	39,957	8,415	37,006	21,115	16,109	12,367	7,417	4,547
31.12.2033	121	1.56	132,303	26,778	-	769	88,345	-	16,411	7,680	19,280	(10,549)	(5,732)	(4,272)	(3,205)	(1,839)	(1,080)
31.12.2034	142	1.83	154,334	31,237	-	898	-	-	122,199	57,189	10,888	54,121	28,010	20,387	14,947	8,203	4,618
31.12.2035	162	2.08	174,747	35,369	-	1,018	-	-	138,360	64,752	12,866	60,742	29,939	21,285	15,251	8,005	4,319

31.12.2036	180	2.32	194,384	39,343	-	1,134	-	-	153,907	72,029	14,768	67,110	31,503	21,876	15,318	7,691	3,976
31.12.2037	197	2.53	211,601	42,828	-	1,235	-	-	167,538	78,408	16,436	72,694	32,499	22,042	15,084	7,244	3,589
31.12.2038	213	2.74	228,837	46,317	-	1,336	-	-	181,184	84,794	18,106	78,284	33,332	22,081	14,767	6,784	3,221
31.12.2039	228	2.93	244,290	49,444	-	1,427	-	-	193,418	90,520	20,619	82,280	33,365	21,589	14,110	6,200	2,821
31.12.2040	178	2.29	192,150	38,891	-	1,120	(46,147)	-	198,286	92,798	12,147	93,341	36,048	22,783	14,552	6,116	2,667
31.12.2041	187	2.41	201,998	40,884	-	1,178	111,990	-	47,946	22,439	29,366	(3,859)	(1,419)	(876)	(547)	(220)	(92)
31.12.2042	199	2.56	214,326	43,380	-	1,250	-	-	169,696	79,418	17,218	73,061	25,593	15,431	9,413	3,620	1,450
31.12.2043	211	2.71	226,597	45,863	-	1,323	-	-	179,411	83,965	19,422	76,024	25,363	14,937	8,905	3,275	1,257
31.12.2044	222	2.86	238,941	48,362	-	1,395	-	-	189,184	88,538	21,634	79,012	25,104	14,441	8,413	2,960	1,089
31.12.2045	234	3.01	251,335	50,870	-	1,468	88,345	-	110,652	51,785	31,328	27,538	8,333	4,682	2,666	897	316
31.12.2046	246	3.16	263,737	53,380	-	1,540	-	-	208,817	97,726	22,004	89,086	25,673	14,089	7,840	2,524	852
31.12.2047	256	3.30	275,342	55,729	-	1,608	-	-	218,004	102,026	23,129	92,850	25,484	13,660	7,428	2,287	740
31.12.2048	267	3.44	286,957	58,080	-	1,676	88,345	-	138,856	64,985	32,747	41,124	10,749	5,628	2,991	881	273
31.12.2049	277	3.57	297,834	60,282	-	1,740	-	-	235,813	110,360	23,276	102,177	25,436	13,008	6,756	1,903	566
31.12.2050	288	3.71	309,612	62,666	-	1,808	-	-	245,139	114,725	23,886	106,527	25,257	12,616	6,403	1,725	492
31.12.2051	298	3.84	320,397	64,848	-	1,871	200,335	-	53,343	24,964	44,948	(16,570)	(3,742)	(1,825)	(905)	(233)	(64)
31.12.2052	308	3.97	331,167	67,028	-	1,934	-	-	262,204	122,712	23,412	116,081	24,963	11,896	5,766	1,422	372
31.12.2053	319	4.10	341,979	69,217	-	1,998	200,335	-	70,430	32,961	43,719	(6,251)	(1,280)	(596)	(282)	(67)	(17)

[24]Another discount rate of 7.5% was taken by the Partnership for calculation purposes and as an aid for the investor.

31.12.2054	329	4.23	352,831	71,413	-	2,061	188,512	-	90,845	42,515	39,026	9,303	1,815	825	382	86	21
31.12.2055	331	4.26	353,598	71,568	-	2,069	-	-	279,961	131,022	17,657	131,282	24,388	10,830	4,900	1,057	243
31.12.2056	327	4.21	346,451	70,122	-	2,033	-	-	274,296	128,371	17,980	127,946	22,636	9,818	4,341	896	198
31.12.2057	323	4.16	342,459	69,314	-	2,009	-	-	271,136	126,892	17,593	126,651	21,340	9,041	3,906	771	163
31.12.2058	319	4.10	337,667	68,344	-	1,981	-	-	267,342	125,116	18,145	124,081	19,912	8,239	3,479	657	133
31.12.2059	314	4.04	332,871	67,373	-	1,952	-	-	263,546	123,339	18,696	121,510	18,571	7,506	3,097	559	109
31.12.2060	310	3.99	328,887	66,567	-	1,929	-	-	260,392	121,863	18,310	120,218	17,498	6,908	2,786	481	90
31.12.2061	306	3.94	324,924	65,765	-	1,905	-	-	257,254	120,395	20,230	116,629	16,167	6,234	2,457	406	72
31.12.2062	301	3.88	320,147	64,798	-	1,877	-	-	253,472	118,625	16,527	118,320	15,621	5,883	2,266	358	61
31.12.2063	298	3.83	316,195	63,998	-	1,853	-	-	250,344	117,161	18,448	114,735	14,426	5,307	1,998	302	49
31.12.2064	35	0.45	37,164	7,522	-	218	-	72,317	(42,893)	-	(945)	(41,948)	(5,023)	(1,805)	(664)	(96)	(15)
Total	**8,216**	**105.8**	**8,799,837**	**1,779,163**	-	**51,475**	**1,008,405**	**72,317**	**5,888,477**	**2,779,447**	**715,077**	**2,393,953**	**638,228**	**366,148**	**224,467**	**101,721**	**58,068**

Caution – it is clarified that discounted cash flow figures, whether calculated at a specific cap rate or without a cap rate, represent present value but do not necessarily represent fair value.

Caution regarding forward-looking information – the discounted cash flow figures as aforesaid are forward-looking information, within the meaning thereof in the Securities Law. The above figures are based on various assumptions including in relation to the quantities of gas and condensate that shall be produced, the pace and duration of the natural gas sales from the project, operation costs, capital expenses, abandonment expenses, royalty rates and the sale prices, in respect of which there is no certainty that they will materialize. It is noted that the quantities of natural gas and/or condensate that shall actually be produced, the said expenses and the said income may be materially different from the above estimates and assumptions, *inter alia* as a result of operating and technical conditions and/or regulatory changes and/or supply and demand conditions in the natural gas and/or condensate market and/or the actual performance of the project and/or as a result of the actual sale prices and/or as a result of geopolitical changes that shall occur.

(c) Summary of the figures on the discounted cash flow from the reserves and from the contingent resources classified at the Phase I – First Stage

Set forth below are tables summarizing the figures on the discounted cash flow from the reserves and from the contingent resources which are presented in addition to the figures on the discounted cash flows from the reserves and the contingent resources as stated in Sections 1(a)(3) and 1(b)(4) above.

Total discounted cash flow from the proved reserves and low estimate contingent resources as of December 31, 2020 (in dollars in thousands in relation to the Partnership's share)

Cash flow components

Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%[25]	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2021	788	10.14	773,708	121,008	-	78,351	94,917	-	479,433	-	48,980	430,452	420,079	415,165	410,420	401,399	392,948
31.12.2022	726	9.34	739,578	115,670	-	84,397	26,681	-	512,831	-	74,414	438,416	407,477	393,345	380,012	355,500	333,515
31.12.2023	778	10.02	810,787	126,807	-	82,754	11,108	-	590,117	-	88,107	502,011	444,365	418,978	395,577	353,971	318,244
31.12.2024	799	10.28	881,605	137,883	-	82,059	-	-	661,663	-	101,278	560,385	472,416	435,068	401,432	343,593	296,041
31.12.2025	884	11.38	986,139	154,232	-	82,703	-	-	749,204	-	121,412	627,792	504,039	453,396	408,836	334,715	276,376
31.12.2026	894	11.51	1,027,706	196,400	-	82,564	-	-	748,743	12,595	118,409	617,738	472,349	415,009	365,717	286,396	226,625
31.12.2027	915	11.78	1,080,516	218,696	-	82,621	-	-	779,198	199,610	82,400	497,188	362,068	310,718	267,589	200,440	152,000
31.12.2028	935	12.03	1,139,640	230,663	-	85,331	-	-	823,646	284,379	73,127	466,141	323,294	270,990	228,072	163,412	118,757
31.12.2029	935	12.03	1,165,438	235,885	-	106,038	-	-	823,516	344,483	59,273	419,760	277,263	227,002	186,708	127,959	89,117
31.12.2030	935	12.03	1,184,209	239,684	-	85,503	-	-	859,021	400,226	100,671	358,124	225,286	180,158	144,811	94,930	63,359
31.12.2031	935	12.03	1,185,392	239,923	-	85,508	176,690	-	683,271	319,771	118,478	245,022	146,797	114,661	90,070	56,478	36,125
31.12.2032	935	12.03	1,185,565	239,958	-	85,509	-	-	860,098	402,526	97,789	359,783	205,288	156,619	120,233	72,113	44,203
31.12.2033	935	12.03	1,185,502	239,946	-	85,508	-	-	860,048	402,502	97,783	359,762	195,501	145,683	109,297	62,704	36,834
31.12.2034	935	12.03	1,185,044	239,853	-	106,114	-	-	839,077	392,688	95,947	350,442	181,368	132,008	96,787	53,112	29,900
31.12.2035	935	12.03	1,057,132	213,963	-	75,491	-	-	767,677	359,273	89,869	318,535	157,005	111,618	79,977	41,980	22,648

31.12.2036	935	12.03	1,057,371	214,012	-	75,492	111,990	-	655,878	306,951	100,659	248,268	116,543	80,926	56,667	28,451	14,710
31.12.2037	935	12.03	1,057,651	214,069	-	75,493	-	-	768,090	359,466	87,344	321,280	143,635	97,419	66,666	32,016	15,863
31.12.2038	935	12.03	1,058,011	214,141	-	75,494	88,345	-	680,030	318,254	95,872	265,904	113,217	75,003	50,159	23,042	10,941
31.12.2039	935	12.03	1,058,908	214,323	-	96,105	-	-	748,480	350,289	82,912	315,279	127,848	82,725	54,067	23,757	10,810
31.12.2040	935	12.03	1,059,610	214,465	-	75,500	88,345	-	681,300	318,848	93,996	268,456	103,677	65,525	41,852	17,590	7,671
31.12.2041	935	12.03	1,059,786	214,501	-	75,501	-	-	769,784	360,259	85,519	324,006	119,172	73,566	45,920	18,461	7,715
31.12.2042	935	12.03	1,060,042	214,552	-	75,502	88,345	-	681,642	319,009	96,069	266,564	93,375	56,301	34,345	13,207	5,289
31.12.2043	935	12.03	1,060,259	214,596	-	75,503	-	-	770,160	360,435	85,565	324,160	108,143	63,690	37,969	13,966	5,360
31.12.2044	935	12.03	1,060,520	214,649	-	96,111	212,157	-	537,602	251,598	103,466	182,539	57,997	33,362	19,437	6,838	2,515
31.12.2045	935	12.03	1,060,902	214,727	-	75,505	-	-	770,670	360,673	80,748	329,248	99,629	55,978	31,872	10,726	3,781
31.12.2046	935	12.03	1,061,269	214,801	-	75,507	188,512	-	582,449	272,586	100,195	209,668	60,423	33,160	18,451	5,939	2,006
31.12.2047	935	12.03	1,061,667	214,881	-	75,508	188,512	-	582,765	272,734	97,186	212,845	58,418	31,314	17,028	5,243	1,697
31.12.2048	917	11.80	1,038,606	210,214	-	75,381	312,325	-	440,686	206,241	103,534	130,911	34,219	17,916	9,521	2,804	870
31.12.2049	881	11.34	1,001,105	202,624	-	95,768	-	-	702,714	328,870	61,186	312,658	77,835	39,804	20,672	5,823	1,731
31.12.2050	846	10.89	964,826	195,281	-	74,946	-	-	694,599	325,072	61,209	308,318	73,100	36,513	18,532	4,994	1,423
31.12.2051	813	10.47	930,556	188,345	-	74,745	-	-	667,467	312,375	58,905	296,188	66,880	32,629	16,184	4,171	1,139
31.12.2052	782	10.06	897,041	181,561	-	74,547	-	-	640,933	299,956	56,674	284,302	61,139	29,135	14,122	3,482	911
31.12.2053	751	9.67	865,208	175,118	-	74,360	-	-	615,729	288,161	54,606	272,962	55,905	26,021	12,327	2,907	729

[25]Another discount rate of 7.5% was taken by the Partnership for calculation purposes and as an aid for the investor.

31.12.2054	722	9.29	834,215	168,845	-	94,785	-	-	570,585	267,034	51,522	252,029	49,160	22,349	10,347	2,334	561
31.12.2055	694	8.93	804,760	162,883	-	74,005	-	-	567,872	265,764	53,630	248,478	46,159	20,497	9,273	2,001	461
31.12.2056	667	8.58	776,097	157,082	-	73,836	-	-	545,179	255,144	53,021	237,014	41,933	18,188	8,041	1,660	366
31.12.2057	641	8.25	749,080	151,614	-	73,677	-	-	523,789	245,133	54,739	223,916	37,729	15,984	6,906	1,363	288
31.12.2058	615	7.92	722,074	146,148	-	73,518	-	-	502,407	235,127	57,883	209,398	33,603	13,904	5,871	1,109	225
31.12.2059	592	7.62	697,515	141,177	-	93,981	-	-	462,357	216,383	56,574	189,400	28,946	11,699	4,828	872	169
31.12.2060	569	7.32	672,928	136,201	-	73,230	-	-	463,498	216,917	56,714	189,867	27,636	10,910	4,400	760	142
31.12.2061	546	7.03	649,166	131,391	-	73,090	-	-	444,685	208,113	54,412	182,161	25,252	9,737	3,838	634	113
31.12.2062	525	6.76	627,044	126,914	-	72,960	-	-	427,170	199,916	43,267	183,987	24,290	9,148	3,524	557	95
31.12.2063	505	6.50	605,728	122,599	-	72,835	-	-	410,294	192,018	41,202	177,074	22,264	8,190	3,083	466	76
31.12.2064	58	0.75	69,892	14,146	-	12,727	-	170,216	(127,197)	-	893	(128,090)	(15,338)	(5,511)	(2,027)	(293)	(46)
Total	**35,601**	**458.2**	**41,209,797**	**8,136,431**	**-**	**3,496,063**	**1,587,927**	**170,216**	**27,819,160**	**11,031,378**	**3,397,440**	**13,390,342**	**6,687,381**	**5,246,503**	**4,309,412**	**3,183,581**	**2,534,304**

Total discounted cash flow from the proved + probable reserves and best estimate contingent resources as of December 31, 2020 (in dollars in thousands in relation to the Partnership's share)																	
Cash flow components																	
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%[26]	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2021	831	10.70	813,828	127,283	-	78,624	94,917	-	513,004	-	56,702	456,302	445,306	440,097	435,067	425,504	416,545
31.12.2022	760	9.78	774,498	121,131	-	84,625	26,681	-	542,060	-	81,137	460,923	428,395	413,538	399,520	373,750	350,636
31.12.2023	845	10.88	874,295	136,740	-	83,182	11,108	-	643,265	-	100,331	542,934	480,589	453,133	427,824	382,827	344,187
31.12.2024	875	11.26	954,393	149,267	-	82,518	-	-	722,608	-	115,295	607,313	511,976	471,501	435,049	372,366	320,832
31.12.2025	923	11.88	1,020,565	162,730	-	82,910	-	-	774,925	-	127,328	647,597	519,940	467,699	421,733	345,274	285,095
31.12.2026	935	12.03	1,066,001	215,759	-	82,741	-	-	767,502	56,292	112,673	598,536	457,667	402,109	354,349	277,493	219,580
31.12.2027	935	12.03	1,097,321	222,098	-	82,727	-	-	792,496	225,776	79,441	487,279	354,852	304,525	262,256	196,445	148,970
31.12.2028	935	12.03	1,130,970	228,908	-	85,297	-	-	816,765	302,004	67,490	447,271	310,207	260,020	218,839	156,797	113,949
31.12.2029	935	12.03	1,156,905	234,157	-	106,005	88,345	-	728,398	315,994	63,251	349,152	230,625	188,818	155,302	106,435	74,127
31.12.2030	935	12.03	1,176,607	238,145	-	85,474	-	-	852,988	398,929	97,550	356,509	224,271	179,345	144,159	94,502	63,074
31.12.2031	935	12.03	1,177,295	238,284	-	85,477	-	-	853,534	399,454	98,673	355,407	212,931	166,317	130,648	81,922	52,399
31.12.2032	935	12.03	1,177,446	238,315	-	85,477	88,345	-	765,308	358,164	107,526	299,618	170,958	130,428	100,127	60,054	36,811
31.12.2033	935	12.03	1,177,356	238,297	-	85,477	-	-	853,583	399,477	96,992	357,114	194,062	144,611	108,492	62,242	36,563
31.12.2034	935	12.03	1,177,038	238,232	-	106,083	-	-	832,723	389,714	95,170	347,839	180,021	131,028	96,068	52,718	29,678
31.12.2035	935	12.03	1,063,276	215,207	-	75,515	-	-	772,554	361,555	90,466	320,533	157,989	112,318	80,478	42,243	22,790

31.12.2036	935	12.03	1,063,502	215,253	-	75,516	-	-	772,734	361,639	90,488	320,606	150,501	104,506	73,179	36,741	18,996
31.12.2037	935	12.03	1,063,766	215,306	-	75,517	-	-	772,944	361,738	90,514	320,692	143,372	97,241	66,544	31,958	15,834
31.12.2038	935	12.03	1,064,107	215,375	-	75,518	-	-	773,214	361,864	90,547	320,803	136,592	90,488	60,516	27,799	13,200
31.12.2039	935	12.03	1,065,027	215,562	-	96,129	111,990	-	641,348	300,151	99,897	241,300	97,849	63,314	41,380	18,182	8,274
31.12.2040	935	12.03	1,065,732	215,704	-	75,524	-	-	774,504	362,468	90,161	321,875	124,307	78,564	50,180	21,090	9,197
31.12.2041	935	12.03	1,065,901	215,738	-	75,525	-	-	774,637	362,530	90,177	321,930	118,408	73,095	45,626	18,342	7,666
31.12.2042	935	12.03	1,066,144	215,788	-	75,526	88,345	-	686,486	321,275	99,710	265,500	93,003	56,077	34,208	13,154	5,268
31.12.2043	935	12.03	1,066,352	215,830	-	75,527	-	-	774,996	362,698	90,221	322,077	107,448	63,280	37,725	13,876	5,326
31.12.2044	935	12.03	1,066,601	215,880	-	96,135	-	-	754,586	353,146	87,723	313,716	99,676	57,337	33,405	11,753	4,323
31.12.2045	935	12.03	1,066,966	215,954	-	75,529	-	-	775,483	362,926	90,280	322,277	97,519	54,793	31,197	10,499	3,701
31.12.2046	935	12.03	1,067,317	216,025	-	75,530	88,345	-	687,417	321,711	98,808	266,898	76,916	42,211	23,487	7,560	2,554
31.12.2047	935	12.03	1,067,743	216,111	-	75,532	-	-	776,100	363,215	88,324	324,561	89,080	47,750	25,965	7,995	2,588
31.12.2048	935	12.03	1,068,719	216,309	-	75,536	-	-	776,874	363,577	88,419	324,878	84,921	44,462	23,628	6,959	2,159
31.12.2049	935	12.03	1,069,253	216,417	-	96,145	200,335	-	556,357	260,375	106,497	189,485	47,171	24,123	12,528	3,529	1,049
31.12.2050	935	12.03	1,069,933	216,554	-	75,540	-	-	777,838	364,028	86,505	327,305	77,601	38,762	19,673	5,301	1,510
31.12.2051	935	12.03	1,070,179	216,604	-	75,541	200,335	-	577,699	270,363	105,789	201,547	45,510	22,203	11,013	2,839	775
31.12.2052	926	11.92	1,059,112	214,364	-	75,481	188,512	-	580,755	271,793	99,988	208,974	44,940	21,415	10,381	2,559	670
31.12.2053	908	11.69	1,037,730	210,037	-	75,360	200,335	-	551,999	258,335	95,733	197,931	40,538	18,869	8,938	2,108	529

[26]Another discount rate of 7.5% was taken by the Partnership for calculation purposes and as an aid for the investor.

31.12.2054	891	11.47	1,019,966	206,441	-	95,862	200,335	-	517,328	242,110	86,883	188,336	36,736	16,701	7,732	1,744	419
31.12.2055	874	11.25	1,002,081	202,821	-	75,150	-	-	724,110	338,884	63,804	321,423	59,710	26,515	11,996	2,588	596
31.12.2056	858	11.04	984,989	199,362	-	75,049	-	-	710,578	332,551	63,164	314,864	55,706	24,161	10,683	2,205	487
31.12.2057	841	10.83	967,914	195,906	-	74,948	-	-	697,060	326,224	62,526	308,310	51,949	22,008	9,509	1,877	397
31.12.2058	825	10.62	950,872	192,456	-	74,848	-	-	683,567	319,910	60,875	302,783	48,588	20,105	8,490	1,603	325
31.12.2059	810	10.42	934,639	189,171	-	95,359	-	-	650,109	304,251	59,085	286,773	43,828	17,714	7,310	1,320	256
31.12.2060	794	10.22	918,379	185,880	-	74,656	-	-	657,843	307,870	62,335	287,638	41,867	16,528	6,666	1,152	214
31.12.2061	779	10.03	902,967	182,761	-	74,565	-	-	645,641	302,160	63,146	280,335	38,861	14,984	5,906	976	174
31.12.2062	764	9.84	887,564	179,643	-	74,475	-	-	633,446	296,453	57,124	279,869	36,949	13,916	5,360	847	145
31.12.2063	750	9.65	872,153	176,524	-	74,384	-	-	621,245	290,743	60,103	270,400	33,999	12,507	4,708	712	117
31.12.2064	88	1.13	102,128	20,671	-	12,915	-	170,216	(101,673)	-	4,460	(106,133)	(12,709)	(4,566)	(1,680)	(243)	(38)
Total	**38,644**	**497.4**	**44,545,530**	**8,815,000**	**-**	**3,515,452**	**1,587,927**	**170,216**	**30,456,935**	**12,252,347**	**3,723,305**	**14,481,283**	**6,990,622**	**5,444,551**	**4,456,161**	**3,287,597**	**2,621,947**

Total discounted cash flow from the proved + probable + possible reserves and high estimate contingent resources as of December 31, 2020 (in dollars in thousands in relation to the Partnership's share)

Cash flow components

Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%[27]	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2021	910	11.71	882,365	138,002	-	79,102	94,917	-	570,344	-	69,890	500,454	488,393	482,681	477,165	466,676	456,850
31.12.2022	820	10.55	839,731	131,334	-	85,043	26,681	-	596,674	-	93,698	502,975	467,480	451,267	435,971	407,850	382,626
31.12.2023	869	11.18	903,280	141,273	-	83,359	11,108	-	667,540	-	105,914	561,626	497,134	468,733	442,553	396,007	356,036
31.12.2024	890	11.46	977,029	152,807	-	82,643	-	-	741,579	-	119,658	621,920	524,291	482,842	445,513	381,322	328,549
31.12.2025	935	12.03	1,047,445	180,502	-	82,979	-	-	783,964	-	129,407	654,557	525,528	472,726	426,266	348,985	288,159
31.12.2026	935	12.03	1,076,464	217,876	-	82,782	-	-	775,806	104,857	103,413	567,536	433,962	381,282	335,996	263,121	208,208
31.12.2027	935	12.03	1,109,945	224,653	-	82,776	-	-	802,516	246,224	77,042	479,249	349,005	299,507	257,934	193,208	146,515
31.12.2028	935	12.03	1,145,744	231,898	-	85,354	-	-	828,491	321,988	65,591	440,912	305,796	256,324	215,728	154,568	112,329
31.12.2029	935	12.03	1,173,287	237,473	-	106,068	88,345	-	741,400	334,113	62,074	345,212	228,022	186,687	153,550	105,234	73,290
31.12.2030	935	12.03	1,194,042	241,674	-	85,542	-	-	866,826	405,675	99,181	361,970	227,706	182,093	146,367	95,950	64,040
31.12.2031	935	12.03	1,194,161	241,698	-	85,542	-	-	866,921	405,719	100,311	360,891	216,216	168,884	132,664	83,186	53,208
31.12.2032	935	12.03	1,194,288	241,724	-	85,543	-	-	867,022	405,766	100,669	360,587	205,747	156,969	120,502	72,274	44,302
31.12.2033	935	12.03	1,194,174	241,701	-	85,542	88,345	-	778,586	364,378	109,151	305,057	165,773	123,531	92,677	53,169	31,233
31.12.2034	935	12.03	1,193,832	241,632	-	106,148	-	-	846,052	395,952	96,801	353,299	182,847	133,085	97,576	53,545	30,144
31.12.2035	935	12.03	1,069,025	216,371	-	75,537	-	-	777,118	363,691	91,024	322,402	158,911	112,973	80,948	42,489	22,923

31.12.2036	935	12.03	1,069,230	216,412	-	75,538	-	-	777,280	363,767	91,044	322,469	151,375	105,113	73,604	36,955	19,106
31.12.2037	935	12.03	1,069,470	216,461	-	75,539	-	-	777,470	363,856	91,067	322,547	144,201	97,803	66,929	32,142	15,926
31.12.2038	935	12.03	1,069,984	216,565	-	75,541	-	-	777,879	364,047	91,117	322,714	137,406	91,027	60,876	27,964	13,278
31.12.2039	935	12.03	1,071,068	216,784	-	96,152	-	-	758,132	354,806	89,717	313,609	127,171	82,287	53,780	23,631	10,753
31.12.2040	935	12.03	1,071,439	216,859	-	75,546	-	-	779,034	364,588	93,291	321,155	124,029	78,388	50,068	21,043	9,177
31.12.2041	935	12.03	1,071,595	216,891	-	75,547	111,990	-	667,167	312,234	104,072	250,861	92,268	56,959	35,553	14,293	5,973
31.12.2042	935	12.03	1,071,821	216,937	-	75,548	-	-	779,337	364,730	90,752	323,855	113,444	68,402	41,726	16,045	6,426
31.12.2043	935	12.03	1,072,383	217,050	-	75,550	-	-	779,783	364,938	91,822	323,022	107,764	63,466	37,835	13,917	5,341
31.12.2044	935	12.03	1,072,620	217,098	-	96,158	-	-	759,364	355,382	90,340	313,641	99,652	57,324	33,397	11,750	4,322
31.12.2045	935	12.03	1,072,968	217,169	-	75,552	88,345	-	691,902	323,810	101,389	266,703	80,703	45,344	25,817	8,688	3,063
31.12.2046	935	12.03	1,073,303	217,236	-	75,554	-	-	780,513	365,280	90,896	324,337	93,469	51,296	28,542	9,188	3,104
31.12.2047	935	12.03	1,073,762	217,329	-	75,555	-	-	780,877	365,451	90,940	324,486	89,059	47,739	25,959	7,993	2,588
31.12.2048	935	12.03	1,075,280	217,637	-	75,561	88,345	-	693,737	324,669	99,581	269,487	70,442	36,881	19,599	5,772	1,791
31.12.2049	935	12.03	1,075,793	217,741	-	96,170	-	-	761,882	356,561	86,584	318,737	79,348	40,578	21,074	5,937	1,765
31.12.2050	935	12.03	1,076,446	217,873	-	75,566	-	-	783,007	366,447	89,169	327,391	77,622	38,772	19,678	5,302	1,511
31.12.2051	935	12.03	1,076,682	217,920	-	75,567	200,335	-	582,860	272,779	109,740	200,341	45,237	22,071	10,947	2,822	770
31.12.2052	935	12.03	1,076,871	217,959	-	75,567	-	-	783,345	366,605	87,178	329,561	70,872	33,773	16,371	4,036	1,056
31.12.2053	935	12.03	1,077,131	218,011	-	75,568	200,335	-	583,216	272,945	106,464	203,807	41,741	19,429	9,204	2,170	544

[27]Another discount rate of 7.5% was taken by the Partnership for calculation purposes and as an aid for the investor.

31.12.2054	935	12.03	1,077,450	218,076	-	96,177	188,512	-	574,685	268,953	98,229	207,503	40,475	18,401	8,519	1,922	462
31.12.2055	928	11.94	1,068,448	216,254	-	75,520	-	-	776,674	363,483	78,435	334,756	62,187	27,614	12,493	2,696	621
31.12.2056	914	11.76	1,050,693	212,660	-	75,422	-	-	762,611	356,902	77,730	327,979	58,026	25,168	11,128	2,297	507
31.12.2057	900	11.59	1,036,923	209,873	-	75,340	-	-	751,709	351,800	76,396	323,513	54,511	23,093	9,978	1,970	417
31.12.2058	886	11.41	1,022,367	206,927	-	75,254	-	-	740,185	346,407	76,002	317,777	50,994	21,101	8,910	1,682	341
31.12.2059	873	11.24	1,008,623	204,145	-	95,780	-	-	708,697	331,670	73,165	303,862	46,440	18,769	7,746	1,399	272
31.12.2060	860	11.07	994,852	201,358	-	75,092	-	-	718,402	336,212	74,352	307,837	44,807	17,688	7,134	1,232	229
31.12.2061	848	10.91	981,936	198,744	-	75,016	-	-	708,176	331,427	75,405	301,345	41,773	16,107	6,348	1,049	187
31.12.2062	834	10.74	968,207	195,965	-	74,935	-	-	697,307	326,340	69,394	301,574	39,814	14,995	5,776	913	156
31.12.2063	822	10.58	955,299	193,353	-	74,858	-	-	687,088	321,557	70,447	295,084	37,102	13,649	5,138	777	127
31.12.2064	96	1.24	111,963	22,661	-	12,971	-	143,918	(67,587)	-	8,403	(75,990)	(9,100)	(3,270)	(1,203)	(174)	(27)
Total	**39,490**	**508.3**	**45,789,417**	**9,070,567**	**-**	**3,522,104**	**1,187,258**	**143,918**	**31,865,571**	**12,906,010**	**3,896,949**	**15,062,612**	**7,189,645**	**5,589,550**	**4,574,334**	**3,382,994**	**2,708,199**

(d) Set forth below is an analysis of sensitivity to the main parameters comprising the discounted cash flow of reserves and contingent resources (the gas price and the gas sales volume) as of December 31, 2020 (dollars in thousands) which was performed by the Partnership[28]:

Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
10% increase in the gas price					**10% decrease in the gas price**				
Proved reserves and low estimate contingent resources	14,676,854	4,657,587	3,436,532	2,737,690	Proved reserves and low estimate contingent resources	12,114,526	3,959,575	2,926,846	2,326,230
Probable reserves and best estimate contingent resources	15,869,221	4,811,568	3,545,263	2,829,567	Probable reserves and best estimate contingent resources	13,091,638	4,092,770	3,021,560	2,406,254
Possible reserves and high estimate contingent resources	16,489,924	4,938,053	3,647,445	2,922,004	Possible reserves and high estimate contingent resources	13,632,879	4,203,697	3,111,473	2,487,674
15% increase in the gas price					**15% decrease in the gas price**				
Proved reserves and low estimate contingent resources	15,316,409	4,827,880	3,559,548	2,836,313	Proved reserves and low estimate contingent resources	11,473,399	3,780,086	2,794,184	2,218,371
Probable reserves and best estimate contingent resources	16,561,069	4,985,995	3,670,875	2,930,362	Probable reserves and best estimate contingent resources	12,397,357	3,908,237	2,885,450	2,295,404
Possible reserves and high estimate contingent resources	17,203,307	5,116,659	3,776,016	3,025,181	Possible reserves and high estimate contingent resources	12,919,740	4,015,072	2,971,801	2,373,410
20% increase in the gas price					**20% decrease in the gas price**				
Proved reserves and low estimate contingent resources	15,962,510	5,001,516	3,685,030	2,936,788	Proved reserves and low estimate contingent resources	10,837,120	3,599,918	2,660,073	2,108,799
Probable reserves and best estimate contingent resources	17,261,943	5,164,464	3,799,174	3,032,921	Probable reserves and best estimate contingent resources	11,706,144	3,723,211	2,748,386	2,183,458
Possible reserves and high estimate contingent resources	17,922,881	5,298,268	3,906,689	3,129,824	Possible reserves and high estimate contingent resources	12,209,349	3,826,399	2,831,712	2,258,606

[28] With respect to a sensitivity analysis for the discounted cash flow to the variable of the gas sales volume, it is noted that no changes were made in the drilling forecast for adjustment to the number of required wells.

Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
10% increase in the gas sales volume					**10% decrease in the gas sales volume**				
Proved reserves and low estimate contingent resources	13,434,277	4,636,848	3,436,306	2,739,877	Proved reserves and low estimate contingent resources	12,075,910	3,951,592	2,921,950	2,322,910
Probable reserves and best estimate contingent resources	14,500,329	4,791,611	3,545,546	2,831,947	Probable reserves and best estimate contingent resources	13,049,591	4,084,583	3,016,569	2,402,872
Possible reserves and high estimate contingent resources	15,093,235	4,917,600	3,647,593	2,924,312	Possible reserves and high estimate contingent resources	13,590,137	4,195,565	3,106,544	2,484,348
15% increase in the gas sales volume [29]					**15% decrease in the gas sales volume**				
Proved reserves and low estimate contingent resources	13,412,802	4,789,913	3,557,422	2,839,106	Proved reserves and low estimate contingent resources	11,415,405	3,767,945	2,786,682	2,213,248
Probable reserves and best estimate contingent resources	14,543,546	4,952,417	3,670,256	2,933,615	Probable reserves and best estimate contingent resources	12,334,263	3,895,839	2,877,849	2,290,229
Possible reserves and high estimate contingent resources	15,141,665	5,082,541	3,775,256	3,028,338	Possible reserves and high estimate contingent resources	12,855,536	4,002,735	2,964,281	2,368,312
20% increase in the gas sales volume[30]					**20% decrease in the gas sales volume**				
Proved reserves and low estimate contingent resources	13,492,160	4,945,967	3,680,581	2,940,013	Proved reserves and low estimate contingent resources	10,759,470	3,583,437	2,649,828	2,101,773
Probable reserves and best estimate contingent resources	14,589,555	5,114,424	3,796,875	3,036,836	Probable reserves and best estimate contingent resources	11,622,071	3,706,467	2,738,029	2,176,352
Possible reserves and high estimate contingent resources	15,160,450	5,246,380	3,903,962	3,133,555	Possible reserves and high estimate contingent resources	12,123,627	3,809,702	2,821,450	2,251,599

[29] With respect to a sensitivity analysis for the discounted cash flow to the variable of the gas sales volume, it is noted that no costs were included for additional drillings which may be required in order to accommodate the increase in the amount of gas sales.

[30] With respect to a sensitivity analysis for the discounted cash flow to the variable of the gas sales volume, it is noted that no costs were included for additional drillings which may be required in order to accommodate the increase in the amount of gas sales.

2. Agreement between the report data and data of previous reports pertaining to the petroleum asset

The main differences between the evaluation of the reserves and the contingent resources attributed to the Leviathan Reservoir according to the present resources report and the evaluations included in the previous resources report, prepared as of June 30, 2020, as released in the Partnership's immediate report of July 9, 2020, derive from the production of approx. 148 BCF of natural gas and approx. 331 thousand barrels of condensate performed during H2/2020. In addition, the reserves and contingent resources of condensate were updated based on adjustment of the condensate-to-gas ratio to the actual production data (a rise of approx. 23% in all of the categories).

3. Production data

The following table includes natural gas production data in 2020 in the Leviathan project:[31, 32]

		Q1	Q2	Q3	Q4[33]
		Natural Gas			
Total output from the Reservoir (100%) in MMCF		57,472	50,351	79,120	67,920
Total output attributed to the holders of the equity interests of the Partnership during the period (in MMCF)		26,058	22,829	35,873	30,795
Average price per output unit (attributed to the holders of the equity interests of the Partnership) ($ per MCF and per barrel)		5.43	5.01	5.04	4.89
Average royalties (any payment derived from the output of the producing asset, including from the gross income from the petroleum asset) paid per output unit (attributed to the holders of the equity interests of the Partnership) ($ per MCF and per barrel)	State	0.60	0.54	0.55	0.51
	Third Parties	0.07	0.13	0.13	0.13
	Interested Parties	0.14	0.07	0.07	0.06
Average production costs per output unit (attributed to the holders of the equity interests of the Partnership) ($ per		0.66	0.80	0.69	0.88

[31] The figures presented in the above table in relation to the rate attributed to the holders of the equity interests of the Partnership in the average price per output unit, in the royalties paid, in the production costs and in the net proceeds, were rounded-off up to two digits after the decimal point.

[32] Since the total costs entailed by production of the condensate during 2020 exceeded the total revenues received in respect thereof, and since condensate is a byproduct of the production of natural gas, the above table does not present separate figures in connection with the production of condensate, and all of the costs and expenses in connection with the production of condensate were attributed to the production of natural gas.

[33]The production figures for Q4/2020 are based on non-audited financial figures.

	Q1	Q2	Q3	Q4[33]
	Natural Gas			
MCF and per barrel)[34, 35]				
Oil and gas profit levy	-	-	-	-
Average net proceeds per output unit (attributed to the holders of the equity interests of the Partnership) ($ per MCF and per barrel)	3.96	3.47	3.60	3.31
Depletion rate in the reported period relative to the total gas quantities in the project (in %)	0.43	0.38	0.60	0.52

4. **Opinion of the Evaluator**

A report on reserves and contingent resources in the Leviathan Reservoir prepared by NSAI as of December 31, 2020, and NSAI's consent to the inclusion thereof in this report, are attached hereto as **Annex A**.

5. **Management declaration**

(1) Date of the declaration: March 10, 2021;

(2) Name of the corporation: Delek Drilling, Limited Partnership;

(3) Name and position of the resource evaluation officer at the Partnership: Gabi Last, Chairman of the General Partner's Board of Directors;

(4) We confirm that the evaluator was provided with all of the data required for performance of its work;

(5) We confirm that no information has come to our attention which indicates the existence of dependency between the evaluator and the Partnership;

(6) We confirm that, to the best of our knowledge, the resources reported are the best and most current estimates in our possession;

(7) We confirm that the data included in this report were prepared according to the professional terms listed in Chapter G of the Third Schedule to the Securities Regulations (Details of the Prospectus and Draft Prospectus – Structure and Form), 5729-1969 and within the meaning afforded thereto in Petroleum Resources Management System (2018), as published by the SPE, the AAPG, the WPC and the SPEE, as being at the time of release of the report;

(8) We confirm that no change has been made to the identity of the evaluator who performed the last contingent resource or reserve disclosure released by the Partnership;

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[34] It is emphasized that the average production costs per output unit include only current production costs and exclude the Reservoir's exploration and development costs and tax payments to be paid by the Partnership in the future.

[35] It is noted that the average production costs per output unit include costs for transmission of natural gas via INGL's transmission system to EMG's terminal in Ashkelon for purposes of supplying the gas to Egypt in the sum of approx. $4.7 million in Q1/2020, in the sum of approx. $3.9 million in Q2/2020, in the sum of approx. $7.3 million in Q3/2020, and in the sum of approx. $9.4 million in Q4/2020 (all in 100% terms).

(9) We agree to the inclusion of the foregoing declaration in this report.

Gabi Last
Chairman of the Board of the General Partner

The partners in the Leviathan Reservoir and their holding rates are as follows:

The Partnership	45.34%
Noble Energy Mediterranean Ltd.	39.66%
Ratio Oil Exploration (1992), Limited Partnership	15.00%

Sincerely,

Delek Drilling Management (1993) Ltd.
General Partner of Delek Drilling - Limited Partnership

By Yossi Abu, CEO
and Zvi Karcz, VP Exploration

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

EXECUTIVE COMMITTEE
ROBERT C. BARG
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JOSEPH J. SPELLMAN
RICHARD B. TALLEY, JR.

CHAIRMAN & CEO
C.H. (SCOTT) REES III

PRESIDENT & COO
DANNY D. SIMMONS

March 10, 2021

Mr. Yossi Abu
Delek Drilling Limited Partnership
19 Abba Eban Boulevard
Herzliya 4612001
Israel

Dear Mr. Abu:

As independent consultants, Netherland, Sewell & Associates, Inc. hereby grant permission to Delek Drilling Limited Partnership (Delek Drilling) to use our report dated March 10, 2021, to be filed with the Israel Securities Authority and the Tel Aviv Stock Exchange. This report sets forth our estimates of the proved, probable, and possible reserves and future revenue, as of December 31, 2020, to the Delek Drilling interest in certain gas properties located in Leviathan Field, Leases I/14 and I/15, offshore Israel. The March 10 report also sets forth our estimates of the contingent resources and cash flow, as of December 31, 2020, to the Delek Drilling interest in these properties.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Senior Vice President

RBT:MDK

ESTIMATES

of

RESERVES AND FUTURE REVENUE AND CONTINGENT RESOURCES AND CASH FLOW

to the

DELEK DRILLING LIMITED PARTNERSHIP INTEREST

in

CERTAIN GAS PROPERTIES

located in

LEVIATHAN FIELD, LEASES I/14 AND I/15 OFFSHORE ISRAEL

as of

DECEMBER 31, 2020

BASED ON PRICE AND COST PARAMETERS

specified by

DELEK DRILLING LIMITED PARTNERSHIP

NETHERLAND, SEWELL & ASSOCIATES, INC.

WORLDWIDE PETROLEUM CONSULTANTS

ENGINEERING • GEOLOGY
GEOPHYSICS • PETROPHYSICS

March 10, 2021

Delek Drilling Limited Partnership
19 Abba Eban Boulevard
Herzliya 4612001
Israel

Ladies and Gentlemen:

In accordance with your request, we have estimated the proved, probable, and possible reserves and future revenue, as of December 31, 2020, to the Delek Drilling Limited Partnership (Delek Drilling) interest in certain gas properties located in Leviathan Field, Leases I/14 and I/15, offshore Israel. Also as requested, we have estimated the contingent resources and cash flow, as of December 31, 2020, to the Delek Drilling interest in these properties. It is our understanding that Delek Drilling owns a direct working interest in these properties. We completed our evaluation on or about the date of this letter. For the reserves and the Phase I – First Stage contingent resources, this report has been prepared using price and cost parameters specified by Delek Drilling, as discussed in subsequent paragraphs of this letter. Monetary values shown in this report are expressed in United States dollars ($) or millions of United States dollars (MM$). For reference, the March 8, 2021, exchange rate was 3.34 Israeli New Shekels per United States dollar.

The estimates in this report have been prepared in accordance with the definitions and guidelines set forth in the 2018 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). As presented in the 2018 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resources, or prospective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to quantify; thus reserves, contingent resources, and prospective resources should not be aggregated without extensive consideration of these factors. Definitions are presented immediately following this letter. This report has been prepared for Delek Drilling'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.

RESERVES

Reserves are those quantities of petroleum anticipated to be commercially recoverable from known accumulations by application of development projects from a given date forward under defined conditions. Reserves must be discovered, recoverable, commercial, and remaining as of the evaluation date based on the planned development projects to be applied. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be commercially recoverable; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. There is a 10 percent probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

We estimate the gross (100 percent) reserves and the Delek Drilling working interest reserves for these properties, as of December 31, 2020, to be:

Category	Gas Reserves (BCF)		Condensate Reserves (MMBBL)	
	Gross (100%)	Working Interest	Gross (100%)	Working Interest
Proved Developed Producing	11,269.6	5,109.6	24.8	11.2
Probable	1,818.0	824.3	4.0	1.8
Proved + Probable (2P)	13,087.6	5,933.9	28.8	13.1
Possible	1,127.6	511.3	2.5	1.1
Proved + Probable + Possible (3P)	14,215.2	6,445.2	31.3	14.2

Totals may not add because of rounding.

We estimate the future net revenue after levy and corporate income taxes, discounted at 0, 5, 10, 15, and 20 percent, to the Delek Drilling interest in these properties, as of December 31, 2020, to be:

Category	Future Net Revenue After Levy and Corporate Income Taxes (MM$)				
	Discounted at 0%	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved Developed Producing	10,388.3	5,512.9	3,663.4	2,740.1	2,190.4
Probable	1,331.4	658.9	448.4	354.9	300.4
Proved + Probable (2P)	11,719.7	6,171.8	4,111.8	3,095.1	2,490.8
Possible	949.0	379.6	238.0	186.2	159.3
Proved + Probable + Possible (3P)	12,668.7	6,551.4	4,349.9	3,281.3	2,650.1

Totals may not add because of rounding.

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

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. Our study indicates that as of December 31, 2020, there are no proved developed non-producing or proved undeveloped reserves for these properties. The project maturity subclass for these reserves is on production. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Working interest revenue shown in this report is Delek Drilling's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Delek Drilling's share of royalties, capital costs, abandonment costs, operating expenses, and Delek Drilling's estimates of its oil and gas profits levy and corporate income taxes. The future net revenue has been discounted at annual rates of 0, 5, 10, 15, and 20 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties. Tables I through V present revenue, costs, and taxes by reserves category. Table VI presents Delek Drilling's historical production and operating expense data.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Delek Drilling interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Delek Drilling receiving its net revenue interest share of estimated future gross production.

CONTINGENT RESOURCES

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. The contingent resources shown in this report are contingent upon finalization of additional gas contracts, sanctioning of additional Phase I – First Stage drilling, and project sanctioning for additional future development. If these contingencies are successfully addressed, some portion of the contingent resources estimated in this report may be reclassified as reserves; our estimates have not been risked to account for the possibility that the contingencies are not successfully addressed. There is no certainty that it will be commercially viable to produce any portion of the contingent resources. The project maturity subclass for these contingent resources is development pending.

We estimate the gross (100 percent) contingent resources by development phase for these properties, as of December 31, 2020, to be:

	Gross (100%) Contingent Resources					
	Gas (BCF)			Condensate (MMBBL)		
Development Phase	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)
Phase I – First Stage[(1)]	4,912.6	4,477.6	3,734.5	10.8	9.9	8.2
Future Development	544.4	5,103.3	9,651.0	1.2	11.2	21.2
Total	5,457.0	9,580.9	13,385.5	12.0	21.1	29.4

(1) The contingent resources shown in this report represent volumes that are incrementally recoverable over volumes classified as reserves. For the Phase I – First Stage, the 2C and 3C contingent resources are less than the 1C contingent resources because a larger portion of the estimated volumes for the best and high estimate cases have been classified as reserves.

We estimate the Delek Drilling working interest contingent resources by development phase for these properties, as of December 31, 2020, to be:

	Working Interest Contingent Resources					
	Gas (BCF)			Condensate (MMBBL)		
Development Phase	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)
Phase I – First Stage[(1)]	2,227.4	2,030.1	1,693.2	4.9	4.5	3.7
Future Development	246.8	2,313.8	4,375.8	0.5	5.1	9.6
Total	2,474.2	4,344.0	6,069.0	5.4	9.6	13.4

Totals may not add because of rounding.

(1) The contingent resources shown in this report represent volumes that are incrementally recoverable over volumes classified as reserves. For the Phase I – First Stage, the 2C and 3C contingent resources are less than the 1C contingent resources because a larger portion of the estimated volumes for the best and high estimate cases have been classified as reserves.

As requested, economic analysis was only performed on the Phase I – First Stage contingent resources. We estimate the net contingent cash flow after levy and corporate income taxes, discounted at 0, 5, 10, 15, and 20 percent, to the Delek Drilling interest in these properties, as of December 31, 2020, to be:

	Net Contingent Cash Flow After Levy and Corporate Income Taxes (MM$)				
Category	Discounted at 0%	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Low Estimate (1C)	3,002.0	1,174.4	646.0	443.4	343.9
Best Estimate (2C)	2,761.6	818.8	344.3	192.5	131.1
High Estimate (3C)	2,394.0	638.2	224.5	101.7	58.1

The contingent resources shown in this report have been estimated using deterministic methods. Once all contingencies have been successfully addressed, the approximate probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is generally inferred to be 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. The estimates of contingent resources included herein have not been adjusted for development risk.

Working interest contingent revenue shown in this report is Delek Drilling's share of the gross (100 percent) revenue from the properties prior to any deductions. Net contingent cash flow is after deductions for Delek Drilling's share of royalties, capital costs, abandonment costs, operating expenses, and Delek Drilling's estimates of its oil and gas profits levy and corporate income taxes. The net contingent cash flow has been discounted at annual rates of 0, 5, 10, 15, and 20 percent to indicate the effect of time on the value of money; the contingent cash flow, whether discounted or undiscounted, should not be construed as being the fair market value of the properties. Tables VII through IX present cash flow, costs, and taxes by resources category for the Phase I – First Stage contingent resources. As requested, we have included an appendix to this report that presents tables of cash flow, costs, and taxes resulting from aggregating our estimates of reserves and the Phase I – First Stage contingent resources.

ECONOMIC PARAMETERS

As requested, this report has been prepared using gas and condensate prices specified by Delek Drilling. Gas prices are based on Delek Drilling's estimates of expected approved and future sales contracts. These contract prices are derived from various formulae that include indexation mainly to the Power Generation Tariffs, published by The Electricity Authority, or to an average of long-term forecasts for Brent Crude prices provided by various institutions. Condensate prices are based on Brent Crude prices.

Operating costs used in this report are based on operating expense records of Delek Drilling. Operating costs include direct project-level costs, insurance costs, workover costs, and Delek Drilling's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project; Noble Energy Mediterranean Ltd. is the operator of the properties. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated operating costs to be reasonable. Operating costs have been divided into field-level costs and per-unit-of-production costs and, as requested, are not escalated for inflation.

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

GENERAL INFORMATION

This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which contingent resources have been estimated. For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; however, we are not currently aware of any possible environmental liability that would have any material effect on the reserves or resources quantities estimated in this report or the commerciality of such estimates. Therefore, our estimates do not include any costs due to such possible liability.

The reserves and contingent resources shown in this report are estimates only and should not be construed as exact quantities. Estimates may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Delek Drilling, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the volumes, and that our projections of future production will prove consistent with actual performance. If these volumes are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received, and costs incurred may vary from assumptions made while preparing this report. It should be noted that the actual production profile for each category may be lower or higher than the production profile used to calculate the estimates of future net revenue used in this report, and no sensitivity analysis was performed with respect to the production profile of the wells.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, core data, well test data, production data, historical price and cost information, and property ownership interests. We were provided with all the necessary data to prepare the estimates for these properties, and we were not limited from access to any material we believe may be relevant. The reserves and contingent resources in this report have been estimated using deterministic 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, analogy, and reservoir modeling, that we considered to be appropriate and necessary to classify, categorize, and estimate volumes in accordance with the 2018 PRMS definitions and guidelines. Certain parameters used in our volumetric analysis are summarized in Table X. 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.

Netherland, Sewell & Associates, Inc. (NSAI) was engaged on December 15, 2020, by Mr. Yossi Abu, Chief Executive Officer of Delek Drilling, to perform this assessment. The data used in our estimates were obtained from Delek Drilling, Noble Energy Mediterranean Ltd., other interest owners, 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 properties 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 properties nor are we employed on a contingent basis. Furthermore, no limitations or restrictions were placed upon NSAI by officials of Delek Drilling.

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 primarily 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

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

By:
Richard B. Talley, Jr., P.E. 102425
Senior Vice President

Date Signed: March 10, 2021

By:
Zachary R. Long, P.G. 11792
Vice President

Date Signed: March 10, 2021

RBT:MDK

NETHERLAND, SEWELL & ASSOCIATES, INC.

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, June 2018

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 SPE, World Petroleum Council, American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers, Society of Exploration Geophysicists, Society of Petrophysicists and Well Log Analysts, and European Association of Geoscientists & Engineers.

Preamble

Petroleum resources are the quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resources assessments estimate 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 projects, and presenting results within a comprehensive classification framework.

This updated PRMS provides fundamental principles for the evaluation and classification of petroleum reserves and resources. If there is any conflict with prior SPE and PRMS guidance, approved training, or the Application Guidelines, the current PRMS shall prevail. It is understood that these definitions and guidelines allow flexibility for entities, governments, and regulatory agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein must be clearly identified. The terms "shall" or "must" indicate that a provision herein is mandatory for PRMS compliance, while "should" indicates a recommended practice and "may" indicates that a course of action is permissible. 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

1.0.0.1 A classification system of petroleum resources is a fundamental element that provides a common language for communicating both the confidence of a project's resources maturation status and the range of potential outcomes to the various entities. The PRMS provides transparency by requiring the assessment of various criteria that allow for the classification and categorization of a project's resources. The evaluation elements consider the risk of geologic discovery and the technical uncertainties together with a determination of the chance of achieving the commercial maturation status of a petroleum project.

1.0.0.2 The technical estimation of petroleum resources quantities involves the assessment of quantities and values that have an inherent degree of uncertainty. These quantities are associated with exploration, appraisal, and development projects at various stages of design and implementation. The commercial aspects considered will relate the project's maturity status (e.g., technical, economical, regulatory, and legal) to the chance of project implementation.

1.0.0.3 The use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios. The application of PRMS must consider both technical and commercial factors that impact the project's feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

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

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

1.1.0.3 Figure 1.1 graphically represents the PRMS resources classification system. The system classifies resources into discovered and undiscovered and defines the recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Petroleum.

1.1.0.4 The horizontal axis reflects the range of uncertainty of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the chance of commerciality, P_c, which is the chance that a project will be committed for development and reach commercial producing status.

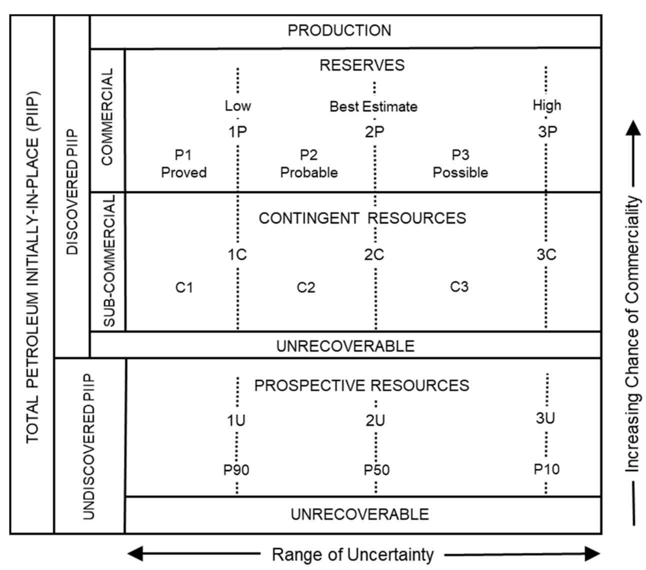

Figure 1.1—Resources classification framework

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1.1.0.5 The following definitions apply to the major subdivisions within the resources classification:

A. **Total Petroleum Initially-In-Place** (PIIP) is all quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.

B. **Discovered PIIP** is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production.

C. **Production** is the cumulative quantities of petroleum that have 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 Section 3.2, Production Measurement).

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

A. 1. **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: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

2. Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO) (see Section 3.2.2), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves.

3. Reserves are further categorized in accordance with the range of uncertainty and should be sub-classified based on project maturity and/or characterized by development and production status.

B. **Contingent Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. Contingent Resources have an associated chance of development. 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 range of uncertainty associated with the estimates and should be sub-classified based on project maturity and/or economic status.

C. **Undiscovered PIIP** is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

D. **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 geologic discovery and a chance of development. Prospective Resources are further categorized in accordance with the range of uncertainty associated with recoverable estimates, assuming discovery and development, and may be sub-classified based on project maturity.

E. **Unrecoverable Resources** are that portion of either discovered or undiscovered PIIP evaluated, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered because of physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

1.1.0.7 The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." Importantly, these quantities should not be aggregated without due consideration of the technical and commercial risk involved with their classification. When such terms are used, each classification component of the summation must be provided.

1.1.0.8 Other terms used in resource assessments include the following:

A. **Estimated Ultimate Recovery (EUR)** is not a resources category or class, but a term that can be applied to an accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities already produced from the accumulation or group of accumulations. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.

B. **Technically Recoverable Resources (TRR)** are those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial considerations. TRR may be used for specific Projects or for groups of Projects, or, can be an undifferentiated estimate within an area (often basin-wide) of recovery potential.

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1.2 Project-Based Resources Evaluations

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

1.2.0.2 The concept of a project-based classification system is further clarified by examining the elements contributing to an evaluation of net recoverable resources (see Figure 1.2).

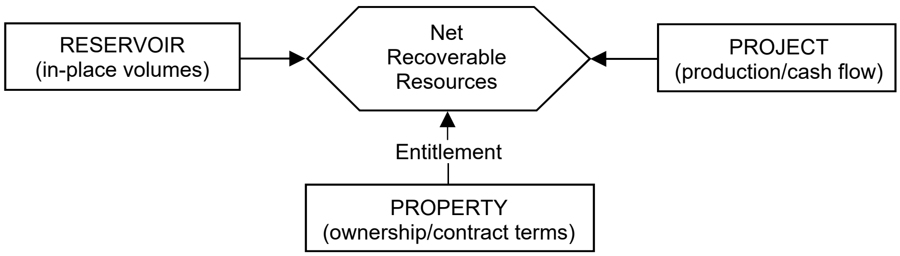

Figure 1.2—Resources evaluation

1.2.0.3 **The reservoir** (contains the petroleum accumulation): Key attributes include the types and quantities of PIIP and the fluid and rock properties that affect petroleum recovery.

1.2.0.4 **The project:** A project may constitute the development of a well, a single reservoir, or a small field; an incremental development in a producing field; or the integrated development of a field or several fields together with the associated processing facilities (e.g., compression). Within a project, a specific reservoir's development generates a unique production and cash-flow schedule at each level of certainty. The integration of these schedules taken to the project's earliest truncation caused by technical, economic, or the contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to total PIIP quantities defines the project's recovery efficiency. Each project should have an associated recoverable resources range (low, best, and high estimate).

1.2.0.5 **The property** (lease or license area): Each property may have unique associated contractual rights and obligations, including the fiscal terms. This information allows definition of each participating entity'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 that may be spatially unrelated to a potential single field designation.

1.2.0.6 An entity's net recoverable resources are the entitlement share of future production legally accruing under the terms of the development and production contract or license.

1.2.0.7 In the context of this relationship, the project is the primary element considered in the resources classification, and the net recoverable resources are the quantities derived from each project. A project represents a defined activity or set of activities to develop the petroleum accumulation(s) and the decisions taken to mature the resources to reserves. In general, it is recommended that an individual project has assigned to it a specific maturity level sub-class (See Section 2.1.3.5, Project Maturity Sub-Classes) 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 the project (See Section 2.2.1, Range of Uncertainty). For completeness, a developed field is also considered to be a project.

1.2.0.8 An accumulation or potential accumulation of petroleum is often 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 resources classes simultaneously.

1.2.0.10 Not all technically feasible development projects will be commercial. The commercial viability of a development project within a field's development plan is dependent on a forecast of the conditions that will exist during the time period encompassed by the project (see Section 3.1, Assessment of Commerciality). Conditions include technical, economic (e.g., hurdle rates, commodity prices), operating and capital costs, marketing, sales route(s), and legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions (e.g., inflation, market factors, and contingencies), exchange rates, transportation and processing infrastructure, fiscal terms, and taxes.

1.2.0.11 The resources being estimated are those quantities producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Section 3.2.1, Reference Point) and may permit forecasts of CiO quantities (see Section 3.2.2., Consumed in Operations). The cumulative production forecast from the effective date forward to cessation of production is the remaining recoverable resources quantity (see Section 3.1.1, Net Cash-Flow Evaluation).

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1.2.0.12 The supporting data, analytical processes, and assumptions describing the technical and commercial basis used in an evaluation must be documented in sufficient detail to allow, as needed, a qualified reserves evaluator or qualified reserves auditor to clearly understand each project's basis for the estimation, categorization, and classification of recoverable resources quantities and, if appropriate, associated commercial assessment.

2.0 Classification and Categorization Guidelines

2.1 Resources Classification

2.1.0.1 The PRMS classification establishes criteria for the classification of the total PIIP. A determination of a discovery differentiates between discovered and undiscovered PIIP. The application of a project further differentiates the recoverable from unrecoverable resources. The project is then evaluated to determine its maturity status to allow the classification distinction between commercial and sub-commercial projects. PRMS requires the project's recoverable resources quantities to be classified as either Reserves, Contingent Resources, or Prospective Resources.

2.1.1 Determination of Discovery Status

2.1.1.1 A discovered petroleum accumulation is determined to exist when one or more exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In the absence of a flow test or sampling, the discovery determination requires confidence in the presence of hydrocarbons and evidence of producibility, which may be supported by suitable producing analogs (see Section 4.1.1, Analogs). In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place quantity demonstrated by the well(s) and for evaluating the potential for commercial recovery.

2.1.1.2 Where a discovery has identified potentially recoverable hydrocarbons, but it is not considered viable to apply a project with established technology or with technology under development, such quantities may be classified as Discovered Unrecoverable with no Contingent Resources. In future evaluations, as appropriate for petroleum resources management purposes, a portion of these unrecoverable quantities may become recoverable resources as either commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

2.1.2.1 Discovered recoverable quantities (Contingent Resources) may be considered commercially mature, and thus attain Reserves classification, if the entity claiming commerciality has demonstrated a firm intention to proceed with development. This means the entity has satisfied the internal decision criteria (typically rate of return at or above the weighted average cost-of-capital or the hurdle rate). Commerciality is achieved with the entity's commitment to the project and all of the following criteria:

A. Evidence of a technically mature, feasible development plan.
B. Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.
C. Evidence to support a reasonable time-frame for development.
D. A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria. This assessment is performed on the estimated entitlement forecast quantities and associated cash flow on which the investment decision is made (see Section 3.1.1, Net Cash-Flow Evaluation).
E. A reasonable expectation that there will be a market for forecast sales quantities of the production required to justify development. There should also be similar confidence that all produced streams (e.g., oil, gas, water, CO2) can be sold, stored, re-injected, or otherwise appropriately disposed.
F. Evidence that the necessary production and transportation facilities are available or can be made available.
G. Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns.

2.1.2.2 The commerciality test for Reserves determination is applied to the best estimate (P50) forecast quantities, which upon qualifying all commercial and technical maturity criteria and constraints become the 2P Reserves. Stricter cases [e.g., low estimate (P90)] may be used for decision purposes or to investigate the range of commerciality (see Section 3.1.2, Economic Criteria). Typically, the low- and high-case project scenarios may be evaluated for sensitivities when considering project risk and upside opportunity.

2.1.2.3 To be included in the Reserves class, a project must be sufficiently defined to establish both its technical and commercial viability as noted in Section 2.1.2.1. There must be a reasonable expectation that all required internal and external approvals will be forthcoming and 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 five years is recommended as a benchmark, a longer time-frame could be applied where justifiable; for example, development of economic projects that take longer than five years to be developed or are deferred to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

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2.1.2.4 While PRMS guidelines require financial appropriations evidence, they do not require that project financing be confirmed before classifying projects as Reserves. However, this may be another external reporting requirement. In many cases, financing is conditional upon the same criteria as above. In general, if there is not a reasonable expectation that financing or other forms of commitment (e.g., farm-outs) can be arranged so that the development will be initiated within a reasonable time-frame, then the project should be classified as Contingent Resources. If financing is reasonably expected to be in place at the time of the final investment decision (FID), the project's resources may be classified as Reserves.

2.2 Resources Categorization

2.2.0.1 The horizontal axis in the resources classification in Figure 1.1 defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project or group of projects. These estimates include the uncertainty components as follows:

A. The total petroleum remaining within the accumulation (in-place resources).
B. The technical uncertainty in the portion of the total petroleum that can be recovered by applying a defined development project or projects (i.e., the technology applied).
C. Known variations in the commercial terms that may impact the quantities recovered and sold (e.g., market availability; contractual changes, such as production rate tiers or product quality specifications) are part of project's scope and are included in the horizontal axis, while the chance of satisfying the commercial terms is reflected in the classification (vertical axis).

2.2.0.2 The uncertainty in a project's recoverable quantities is reflected by the 1P, 2P, 3P, Proved (P1), Probable (P2), Possible (P3), 1C, 2C, 3C, C1, C2, and C3; or 1U, 2U, and 3U resources categories. The commercial chance of success is associated with resources classes or sub-classes and not with the resources categories reflecting the range of recoverable quantities.

2.2.1 Range of Uncertainty

2.2.1.1 Uncertainty is inherent in a project's resources estimation and is communicated in PRMS by reporting a range of category outcomes. The range of uncertainty of the recoverable and/or potentially recoverable quantities may be represented by either deterministic scenarios or by a probability distribution (see Section 4.2, Resources Assessment Methods).

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

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

2.2.1.3 In some projects, the range of uncertainty may be limited, and the three scenarios may result in resources estimates that are not significantly different. In these situations, a single value estimate may be appropriate to describe the expected result.

2.2.1.4 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 method, quantities for each confidence segment are estimated discretely (see Section 2.2.2, Category Definitions and Guidelines).

2.2.1.5 Project resources are initially estimated using the above uncertainty range forecasts that incorporate the subsurface elements together with technical constraints related to wells and facilities. The technical forecasts then have additional commercial criteria applied (e.g., economics and license cutoffs are the most common) to estimate the entitlement quantities attributed and the resources classification status: Reserves, Contingent Resources, and Prospective Resources.

2.2.2 Category Definitions and Guidelines

2.2.2.1 Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental method, the deterministic scenario (cumulative) method, geostatistical methods, or probabilistic methods (see Section 4.2, Resources Assessment Methods). Also, combinations of these methods may be used.

2.2.2.2 Use of consistent terminology (Figures 1.1 and 2.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high forecasts are used to estimate the resulting 1P/2P/3P quantities, respectively. The associated incremental quantities are termed Proved (P1), Probable (P2) and Possible (P3). Reserves are a subset of, and must be viewed within the context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, the criteria can be equally applied to Contingent and Prospective Resources. Upon satisfying the commercial maturity criteria for discovery and/or development, the project quantities will then move to the appropriate resources sub-class. Table 3 provides criteria for the Reserves categories determination.

2.2.2.3 For Contingent Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1C/2C/3C quantities, respectively. The terms C1, C2, and C3 are defined for incremental quantities of Contingent Resources.

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2.2.2.4 For Prospective Resources, the general cumulative terms low/best/high estimates also apply and are used to estimate the resulting 1U/2U/3U quantities. No specific terms are defined for incremental quantities within Prospective Resources.

2.2.2.5 Quantities in different classes and sub-classes cannot be aggregated without considering the varying degrees of technical uncertainty and commercial likelihood involved with the classification(s) and without considering the degree of dependency between them (see Section 4.2.1, Aggregating Resources Classes).

2.2.2.6 Without new technical information, there should be no change in the distribution of technically recoverable resources and the categorization boundaries when conditions are satisfied to reclassify a project from Contingent Resources to Reserves.

2.2.2.7 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 Section 3.1, Assessment of Commerciality).

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: discovered, recoverable, commercial, and remaining 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 the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that 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 five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is 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 maturity and economic 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 or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or 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.

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Class/Sub-Class	Definition	Guidelines
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.	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 (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame). There must be no known contingencies that could preclude the development from proceeding (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 owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. 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 the 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 reclassification 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 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 commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, 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.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.

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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 because of 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 further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic 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 geologic 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 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 geologic 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 that requires more data acquisition and/or evaluation 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 geologic 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	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	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals that 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 that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

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Status	Definition	Guidelines
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (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	Those quantities of petroleum that, 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 (P90) 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 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. Reserves in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. 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	Those additional Reserves that analysis of geoscience and engineering data indicates 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.

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the Society of Petroleum Engineers (SPE) Board of Directors, June 2018

Category	Definition	Guidelines
Possible Reserves	Those additional reserves that analysis of geoscience and engineering data indicates 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 (P10) 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 economic production from the reservoir by a defined, commercially mature 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 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 mature and economically 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 elevation and there exists the potential for an associated gas cap, Proved Reserves of oil 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.

REVENUE, COSTS, AND TAXES
PROVED DEVELOPED PRODUCING RESERVES
DELEK DRILLING LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2020

Period Ending	Working Interest Revenue (MM$)	Royalties: State (MM$)	Royalties: Interested Party (MM$)	Royalties: Third Party (MM$)	Royalties: Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[1] (MM$)	Future Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2021	697.1	80.2	9.6	19.2	109.0	94.9	0.0	77.8	415.3
12-31-2022	626.9	72.1	8.7	17.3	98.0	26.7	0.0	83.6	418.5
12-31-2023	692.9	79.7	9.6	19.1	108.4	11.1	0.0	82.0	491.5
12-31-2024	740.1	85.1	10.2	20.4	115.8	0.0	0.0	81.2	543.2
12-31-2025	803.5	92.4	11.1	22.2	125.7	0.0	0.0	81.6	596.3
12-31-2026	828.6	95.3	11.4	22.9	129.6	0.0	0.0	81.5	617.5
12-31-2027	859.4	98.8	41.7	23.7	164.3	0.0	0.0	81.4	613.7
12-31-2028	892.1	102.6	53.3	24.6	180.6	0.0	0.0	83.9	627.7
12-31-2029	915.9	105.3	54.8	25.3	185.4	0.0	0.0	104.6	626.0
12-31-2030	932.7	107.3	55.8	25.7	188.8	0.0	0.0	84.0	659.9
12-31-2031	933.8	107.4	55.8	25.8	189.0	0.0	0.0	84.0	660.8
12-31-2032	933.9	107.4	55.8	25.8	189.0	0.0	0.0	84.0	660.9
12-31-2033	933.8	107.4	55.8	25.8	189.0	0.0	0.0	84.0	660.7
12-31-2034	933.3	107.3	55.8	25.8	188.9	0.0	0.0	104.6	639.7
12-31-2035	806.7	92.8	48.2	22.3	163.3	0.0	0.0	74.0	569.4
Subtotal	12,530.6	1,441.0	537.8	345.8	2,324.7	132.7	0.0	1,272.3	8,801.0
Remaining	17,252.4	1,984.0	1,031.7	476.2	3,491.9	0.0	71.6	2,156.6	11,532.3
Total	29,783.0	3,425.0	1,569.5	822.0	5,816.5	132.7	71.6	3,428.9	20,333.3

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Revenue After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2021	0.0	0.0	415.3	23.0	34.2	381.1	371.9	363.4	355.4	347.9
12-31-2022	0.0	0.0	418.5	23.0	52.7	365.8	340.0	317.1	296.6	278.3
12-31-2023	0.0	0.0	491.5	23.0	65.4	426.1	377.1	335.7	300.4	270.1
12-31-2024	0.0	0.0	543.2	23.0	74.0	469.1	395.5	336.1	287.7	247.8
12-31-2025	0.0	0.0	596.3	23.0	86.2	510.0	409.5	332.1	271.9	224.5
12-31-2026	0.0	0.0	617.5	23.0	91.1	526.4	402.5	311.6	244.0	193.1
12-31-2027	0.0	0.0	613.7	23.0	90.3	523.5	381.2	281.7	211.0	160.0
12-31-2028	21.9	137.5	490.2	23.0	61.8	428.3	297.1	209.6	150.2	109.1
12-31-2029	30.6	191.7	434.3	23.0	49.0	385.3	254.5	171.4	117.5	81.8
12-31-2030	36.6	241.3	418.5	23.0	91.4	327.1	205.8	132.3	86.7	57.9
12-31-2031	41.9	277.1	383.6	23.0	84.5	299.1	179.2	110.0	69.0	44.1
12-31-2032	46.2	305.2	355.6	23.0	78.4	277.2	158.2	92.6	55.6	34.1
12-31-2033	46.8	309.2	351.5	23.0	77.5	274.1	148.9	83.3	47.8	28.1
12-31-2034	46.8	299.4	340.3	23.0	75.6	264.7	137.0	73.1	40.1	22.6
12-31-2035	46.8	266.5	302.9	23.0	69.7	233.2	115.0	58.6	30.7	16.6
Subtotal		2,028.0	6,773.0		1,081.9	5,691.1	4,173.4	3,208.5	2,564.5	2,116.0
Remaining		5,416.3	6,116.0		1,418.8	4,697.2	1,339.6	454.9	175.6	74.4
Total		7,444.2	12,889.0		2,500.7	10,388.3	5,512.9	3,663.4	2,740.1	2,190.4

Notes: Remaining represents estimates after December 31, 2035, through the end of production in 2064.
Totals may not add because of rounding.

(1) Operating costs include direct project-level costs, insurance costs, workover costs, and Delek Drilling's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

(2) Oil and gas profits levy rates and estimates are provided by Delek Drilling.

(3) Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.

REVENUE, COSTS, AND TAXES
PROBABLE RESERVES
DELEK DRILLING LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2020

Period Ending	Working Interest Revenue (MM$)	Royalties: State (MM$)	Royalties: Interested Party (MM$)	Royalties: Third Party (MM$)	Royalties: Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[1] (MM$)	Future Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2021	63.5	7.3	0.9	1.8	9.9	0.0	0.0	0.4	53.1
12-31-2022	146.9	16.9	2.0	4.1	23.0	0.0	0.0	1.0	122.9
12-31-2023	144.0	16.6	2.0	4.0	22.5	0.0	0.0	1.0	120.5
12-31-2024	164.8	19.0	2.3	4.5	25.8	0.0	0.0	1.0	138.0
12-31-2025	134.4	15.5	1.9	3.7	21.0	0.0	0.0	0.8	112.6
12-31-2026	145.2	16.7	40.2	4.0	60.9	0.0	0.0	0.7	83.5
12-31-2027	163.7	18.8	19.4	4.5	42.8	0.0	0.0	0.9	120.0
12-31-2028	192.2	22.1	11.5	5.3	38.9	0.0	0.0	1.2	152.1
12-31-2029	181.2	20.8	10.8	5.0	36.7	0.0	0.0	1.1	143.5
12-31-2030	159.8	18.4	9.6	4.4	32.3	0.0	0.0	1.0	126.5
12-31-2031	135.7	15.6	8.1	3.7	27.5	0.0	0.0	0.8	107.4
12-31-2032	112.9	13.0	6.8	3.1	22.9	0.0	0.0	0.7	89.4
12-31-2033	90.9	10.5	5.4	2.5	18.4	0.0	0.0	0.5	72.0
12-31-2034	69.1	7.9	4.1	1.9	14.0	0.0	0.0	0.4	54.7
12-31-2035	60.7	7.0	3.6	1.7	12.3	0.0	0.0	0.3	48.1
Subtotal	1,965.2	226.0	128.6	54.2	408.9	0.0	0.0	11.9	1,544.4
Remaining	2,293.6	263.8	137.2	63.3	464.2	46.1	0.0	13.1	1,770.1
Total	4,258.8	489.8	265.8	117.5	873.1	46.1	0.0	25.0	3,314.5

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Revenue After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2021	0.0	0.0	53.1	23.0	12.2	40.9	39.9	39.0	38.1	37.3
12-31-2022	0.0	0.0	122.9	23.0	28.3	94.7	88.0	82.0	76.8	72.0
12-31-2023	0.0	0.0	120.5	23.0	27.7	92.8	82.2	73.1	65.4	58.8
12-31-2024	0.0	0.0	138.0	23.0	31.7	106.3	89.6	76.1	65.1	56.1
12-31-2025	0.0	0.0	112.6	23.0	25.9	86.7	69.6	56.4	46.2	38.2
12-31-2026	0.0	0.0	83.5	23.0	19.2	64.3	49.2	38.1	29.8	23.6
12-31-2027	25.1	184.1	-64.1	23.0	-14.8	-49.4	-36.0	-26.6	-19.9	-15.1
12-31-2028	33.6	124.7	27.5	23.0	6.3	21.1	14.7	10.3	7.4	5.4
12-31-2029	40.6	120.3	23.1	23.0	5.3	17.8	11.8	7.9	5.4	3.8
12-31-2030	46.0	120.2	6.3	23.0	1.4	4.8	3.0	2.0	1.3	0.9
12-31-2031	46.8	82.4	25.0	23.0	5.8	19.3	11.6	7.1	4.4	2.8
12-31-2032	46.8	45.9	43.5	23.0	10.0	33.5	19.1	11.2	6.7	4.1
12-31-2033	46.8	33.7	38.3	23.0	8.8	29.5	16.0	9.0	5.1	3.0
12-31-2034	46.8	25.6	29.1	23.0	6.7	22.4	11.6	6.2	3.4	1.9
12-31-2035	46.8	22.5	25.6	23.0	5.9	19.7	9.7	4.9	2.6	1.4
Subtotal		759.4	785.0		180.5	604.4	479.9	396.8	338.0	294.3
Remaining		826.0	944.1		217.1	727.0	178.9	51.6	16.9	6.1
Total		1,585.4	1,729.1		397.7	1,331.4	658.9	448.4	354.9	300.4

Notes: Remaining represents estimates after December 31, 2035, through the end of production in 2064.
Totals may not add because of rounding.

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NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROVED + PROBABLE (2P) RESERVES
DELEK DRILLING LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2020

Period Ending	Working Interest Revenue (MM$)	Royalties: State (MM$)	Royalties: Interested Party (MM$)	Royalties: Third Party (MM$)	Royalties: Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[1] (MM$)	Future Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2021	760.6	87.5	10.5	21.0	119.0	94.9	0.0	78.3	468.5
12-31-2022	773.8	89.0	10.7	21.4	121.0	26.7	0.0	84.6	541.5
12-31-2023	837.0	96.3	11.6	23.1	130.9	11.1	0.0	82.9	612.0
12-31-2024	904.9	104.1	12.5	25.0	141.5	0.0	0.0	82.2	681.2
12-31-2025	937.9	107.9	12.9	25.9	146.7	0.0	0.0	82.4	708.8
12-31-2026	973.7	112.0	51.7	26.9	190.5	0.0	0.0	82.2	701.0
12-31-2027	1,023.1	117.7	61.2	28.2	207.1	0.0	0.0	82.3	733.7
12-31-2028	1,084.3	124.7	64.8	29.9	219.5	0.0	0.0	85.0	779.8
12-31-2029	1,097.2	126.2	65.6	30.3	222.1	0.0	0.0	105.7	769.4
12-31-2030	1,092.5	125.6	65.3	30.2	221.1	0.0	0.0	85.0	786.4
12-31-2031	1,069.5	123.0	64.0	29.5	216.5	0.0	0.0	84.9	768.2
12-31-2032	1,046.8	120.4	62.6	28.9	211.9	0.0	0.0	84.7	750.2
12-31-2033	1,024.7	117.8	61.3	28.3	207.4	0.0	0.0	84.6	732.7
12-31-2034	1,002.4	115.3	59.9	27.7	202.9	0.0	0.0	105.1	694.4
12-31-2035	867.4	99.8	51.9	23.9	175.6	0.0	0.0	74.4	617.5
Subtotal	14,495.8	1,667.0	666.4	400.1	2,733.5	132.7	0.0	1,284.2	10,345.3
Remaining	19,546.0	2,247.8	1,168.8	539.5	3,956.1	46.1	71.6	2,169.7	13,302.4
Total	34,041.8	3,914.8	1,835.3	939.6	6,689.6	178.9	71.6	3,453.9	23,647.8

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Revenue After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2021	0.0	0.0	468.5	23.0	46.5	422.0	411.8	402.4	393.5	385.2
12-31-2022	0.0	0.0	541.5	23.0	81.0	460.5	428.0	399.1	373.4	350.3
12-31-2023	0.0	0.0	612.0	23.0	93.1	518.9	459.3	408.9	365.9	328.9
12-31-2024	0.0	0.0	681.2	23.0	105.8	575.4	485.1	412.2	352.8	304.0
12-31-2025	0.0	0.0	708.8	23.0	112.1	596.7	479.1	388.6	318.1	262.7
12-31-2026	0.0	0.0	701.0	23.0	110.3	590.7	451.7	349.7	273.8	216.7
12-31-2027	25.1	184.1	549.6	23.0	75.5	474.1	345.2	255.2	191.1	144.9
12-31-2028	33.6	262.2	517.6	23.0	68.2	449.5	311.7	219.9	157.6	114.5
12-31-2029	40.6	312.0	457.4	23.0	54.3	403.1	266.3	179.3	122.9	85.6
12-31-2030	46.0	361.5	424.8	23.0	92.9	332.0	208.8	134.2	88.0	58.7
12-31-2031	46.8	359.5	408.7	23.0	90.3	318.4	190.8	117.1	73.4	46.9
12-31-2032	46.8	351.1	399.1	23.0	88.4	310.7	177.3	103.8	62.3	38.2
12-31-2033	46.8	342.9	389.8	23.0	86.3	303.5	165.0	92.2	52.9	31.1
12-31-2034	46.8	325.0	369.4	23.0	82.3	287.1	148.6	79.3	43.5	24.5
12-31-2035	46.8	289.0	328.5	23.0	75.6	252.9	124.7	63.5	33.3	18.0
Subtotal		2,787.4	7,557.9		1,262.4	6,295.5	4,653.3	3,605.4	2,902.6	2,410.3
Remaining		6,242.3	7,060.1		1,636.0	5,424.2	1,518.5	506.5	192.5	80.6
Total		9,029.7	14,618.1		2,898.4	11,719.7	6,171.8	4,111.8	3,095.1	2,490.8

Notes: Remaining represents estimates after December 31, 2035, through the end of production in 2064.
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REVENUE, COSTS, AND TAXES
POSSIBLE RESERVES
DELEK DRILLING LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2020

Period Ending	Working Interest Revenue (MM$)	Royalties: State (MM$)	Royalties: Interested Party (MM$)	Royalties: Third Party (MM$)	Royalties: Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[1] (MM$)	Future Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2021	70.8	8.1	1.0	2.0	11.1	0.0	0.0	0.5	59.2
12-31-2022	66.0	7.6	0.9	1.8	10.3	0.0	0.0	0.4	55.2
12-31-2023	66.3	7.6	0.9	1.8	10.4	0.0	0.0	0.4	55.5
12-31-2024	72.1	8.3	1.0	2.0	11.3	0.0	0.0	0.4	60.4
12-31-2025	109.5	12.6	17.8	3.0	33.4	0.0	0.0	0.6	75.6
12-31-2026	102.7	11.8	12.7	2.8	27.4	0.0	0.0	0.6	74.8
12-31-2027	86.9	10.0	5.2	2.4	17.6	0.0	0.0	0.5	68.8
12-31-2028	61.4	7.1	3.7	1.7	12.4	0.0	0.0	0.3	48.7
12-31-2029	56.1	6.4	3.4	1.5	11.4	0.0	0.0	0.3	44.4
12-31-2030	48.4	5.6	2.9	1.3	9.8	0.0	0.0	0.2	38.3
12-31-2031	42.9	4.9	2.6	1.2	8.7	0.0	0.0	0.2	34.0
12-31-2032	39.6	4.6	2.4	1.1	8.0	0.0	0.0	0.2	31.4
12-31-2033	37.1	4.3	2.2	1.0	7.5	0.0	0.0	0.2	29.4
12-31-2034	37.1	4.3	2.2	1.0	7.5	0.0	0.0	0.2	29.4
12-31-2035	26.9	3.1	1.6	0.7	5.4	0.0	0.0	0.1	21.3
Subtotal	923.9	106.2	60.4	25.5	192.1	0.0	0.0	5.2	726.5
Remaining	2,024.0	232.8	121.0	55.9	409.6	0.0	0.0	11.5	1,602.8
Total	2,947.8	339.0	181.4	81.4	601.8	0.0	0.0	16.7	2,329.3

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Revenue After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2021	0.0	0.0	59.2	23.0	13.6	45.6	44.5	43.5	42.5	41.6
12-31-2022	0.0	0.0	55.2	23.0	12.7	42.5	39.5	36.9	34.5	32.3
12-31-2023	0.0	0.0	55.5	23.0	12.8	42.8	37.8	33.7	30.1	27.1
12-31-2024	0.0	0.0	60.4	23.0	13.9	46.5	39.2	33.3	28.5	24.6
12-31-2025	0.0	0.0	75.6	23.0	17.4	58.2	46.7	37.9	31.0	25.6
12-31-2026	11.5	89.3	-14.5	23.0	-3.3	-11.1	-8.5	-6.6	-5.2	-4.1
12-31-2027	30.2	58.3	10.5	23.0	2.4	8.1	5.9	4.3	3.3	2.5
12-31-2028	38.5	56.9	-8.2	23.0	-1.9	-6.3	-4.4	-3.1	-2.2	-1.6
12-31-2029	45.1	54.9	-10.5	23.0	-2.4	-8.1	-5.3	-3.6	-2.5	-1.7
12-31-2030	46.8	24.4	13.9	23.0	3.2	10.7	6.7	4.3	2.8	1.9
12-31-2031	46.8	15.9	18.1	23.0	4.2	13.9	8.3	5.1	3.2	2.1
12-31-2032	46.8	14.7	16.7	23.0	3.8	12.9	7.3	4.3	2.6	1.6
12-31-2033	46.8	13.8	15.7	23.0	3.6	12.1	6.6	3.7	2.1	1.2
12-31-2034	46.8	13.8	15.7	23.0	3.6	12.1	6.2	3.3	1.8	1.0
12-31-2035	46.8	10.0	11.3	23.0	2.6	8.7	4.3	2.2	1.1	0.6
Subtotal		352.0	374.6		86.2	288.4	234.9	199.2	173.8	154.7
Remaining		744.9	857.9		197.3	660.6	144.7	38.8	12.4	4.6
Total		1,096.9	1,232.4		283.5	949.0	379.6	238.0	186.2	159.3

Notes: Remaining represents estimates after December 31, 2035, through the end of production in 2064.
Totals may not add because of rounding.

(1) Operating costs include direct project-level costs, insurance costs, workover costs, and Delek Drilling's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

(2) Oil and gas profits levy rates and estimates are provided by Delek Drilling.

(3) Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROVED + PROBABLE + POSSIBLE (3P) RESERVES
DELEK DRILLING LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2020

Period Ending	Working Interest Revenue (MM$)	Royalties: State (MM$)	Royalties: Interested Party (MM$)	Royalties: Third Party (MM$)	Royalties: Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[1] (MM$)	Future Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2021	831.4	95.6	11.5	22.9	130.0	94.9	0.0	78.7	527.7
12-31-2022	839.7	96.6	11.6	23.2	131.3	26.7	0.0	85.0	596.7
12-31-2023	903.3	103.9	12.5	24.9	141.3	11.1	0.0	83.4	667.5
12-31-2024	977.0	112.4	13.5	27.0	152.8	0.0	0.0	82.6	741.6
12-31-2025	1,047.4	120.5	30.7	28.9	180.1	0.0	0.0	83.0	784.4
12-31-2026	1,076.5	123.8	64.4	29.7	217.9	0.0	0.0	82.8	775.8
12-31-2027	1,109.9	127.6	66.4	30.6	224.7	0.0	0.0	82.8	802.5
12-31-2028	1,145.7	131.8	68.5	31.6	231.9	0.0	0.0	85.4	828.5
12-31-2029	1,153.3	132.6	69.0	31.8	233.4	0.0	0.0	106.0	813.9
12-31-2030	1,140.8	131.2	68.2	31.5	230.9	0.0	0.0	85.2	824.7
12-31-2031	1,112.4	127.9	66.5	30.7	225.2	0.0	0.0	85.1	802.2
12-31-2032	1,086.5	124.9	65.0	30.0	219.9	0.0	0.0	84.9	781.6
12-31-2033	1,061.9	122.1	63.5	29.3	214.9	0.0	0.0	84.8	762.2
12-31-2034	1,039.5	119.5	62.2	28.7	210.4	0.0	0.0	105.2	723.9
12-31-2035	894.3	102.8	53.5	24.7	181.0	0.0	0.0	74.5	638.8
Subtotal	15,419.7	1,773.3	726.8	425.6	2,925.7	132.7	0.0	1,289.4	11,071.9
Remaining	21,569.9	2,480.5	1,289.9	595.3	4,365.8	46.1	71.6	2,181.2	14,905.2
Total	36,989.6	4,253.8	2,016.7	1,020.9	7,291.4	178.9	71.6	3,470.6	25,977.1

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Revenue After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2021	0.0	0.0	527.7	23.0	60.1	467.6	456.3	445.8	436.0	426.9
12-31-2022	0.0	0.0	596.7	23.0	93.7	503.0	467.5	436.0	407.8	382.6
12-31-2023	0.0	0.0	667.5	23.0	105.9	561.6	497.1	442.6	396.0	356.0
12-31-2024	0.0	0.0	741.6	23.0	119.7	621.9	524.3	445.5	381.3	328.5
12-31-2025	0.0	0.0	784.4	23.0	129.5	654.9	525.8	426.5	349.2	288.3
12-31-2026	11.5	89.3	686.5	23.0	107.0	579.5	443.1	343.1	268.7	212.6
12-31-2027	30.2	242.4	560.1	23.0	77.9	482.2	351.1	259.5	194.4	147.4
12-31-2028	38.5	319.1	509.4	23.0	66.3	443.1	307.3	216.8	155.3	112.9
12-31-2029	45.1	366.9	446.9	23.0	51.9	395.1	260.9	175.7	120.4	83.9
12-31-2030	46.8	386.0	438.7	23.0	96.1	342.7	215.6	138.6	90.8	60.6
12-31-2031	46.8	375.4	426.8	23.0	94.4	332.3	199.1	122.2	76.6	49.0
12-31-2032	46.8	365.8	415.8	23.0	92.3	323.6	184.6	108.1	64.9	39.8
12-31-2033	46.8	356.7	405.5	23.0	89.9	315.6	171.5	95.9	55.0	32.3
12-31-2034	46.8	338.8	385.1	23.0	85.9	299.2	154.8	82.6	45.3	25.5
12-31-2035	46.8	298.9	339.8	23.0	78.2	261.7	129.0	65.7	34.5	18.6
Subtotal		3,139.4	7,932.5		1,348.6	6,583.9	4,888.2	3,804.6	3,076.3	2,565.0
Remaining		6,987.2	7,918.0		1,833.3	6,084.7	1,663.2	545.3	204.9	85.2
Total		10,126.6	15,850.5		3,181.9	12,668.7	6,551.4	4,349.9	3,281.3	2,650.1

Notes: Remaining represents estimates after December 31, 2035, through the end of production in 2064.
Totals may not add because of rounding.

(1) Operating costs include direct project-level costs, insurance costs, workover costs, and Delek Drilling's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

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(3) Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.

HISTORICAL PRODUCTION AND OPERATING EXPENSE DATA
DELEK DRILLING LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2020

Year	Delek Drilling Working Interest Production (BCF)	Average Per Production Unit ($/MCF)				Reserves Depletion Rate[1] (%)
		Price Received	Royalties Paid	Production Costs	Net Revenue	
2020[2]	116.2	5.06	0.74	0.76	3.56	1.9

Note: Values in this table have been provided by Delek Drilling; these values are based on historical data since January 2020.

(1) The reserves depletion rate is the percentage of yearly gas produced to the estimated proved plus probable reserves at the beginning of that year.
(2) The 2020 data are representative of unaudited financial data.

CASH FLOW, COSTS, AND TAXES
PHASE 1 - FIRST STAGE LOW ESTIMATE (1C) CONTINGENT RESOURCES
DELEK DRILLING LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2020

Period Ending	Working Interest Revenue (MM$)	Royalties State (MM$)	Royalties Interested Party (MM$)	Royalties Third Party (MM$)	Royalties Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[1] (MM$)	Future Net Cash Flow Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2021	76.6	8.8	1.1	2.1	12.0	0.0	0.0	0.5	64.1
12-31-2022	112.7	13.0	1.6	3.1	17.6	0.0	0.0	0.8	94.3
12-31-2023	117.9	13.6	1.6	3.3	18.4	0.0	0.0	0.8	98.6
12-31-2024	141.5	16.3	2.0	3.9	22.1	0.0	0.0	0.9	118.5
12-31-2025	182.7	21.0	2.5	5.0	28.6	0.0	0.0	1.1	153.0
12-31-2026	199.1	22.9	38.4	5.5	66.8	0.0	0.0	1.1	131.3
12-31-2027	221.1	25.4	22.9	6.1	54.4	0.0	0.0	1.3	165.5
12-31-2028	247.5	28.5	14.8	6.8	50.1	0.0	0.0	1.5	196.0
12-31-2029	249.5	28.7	14.9	6.9	50.5	0.0	0.0	1.5	197.5
12-31-2030	251.5	28.9	15.0	6.9	50.9	0.0	0.0	1.5	199.1
12-31-2031	251.6	28.9	15.0	6.9	50.9	176.7	0.0	1.5	22.5
12-31-2032	251.7	28.9	15.0	6.9	50.9	0.0	0.0	1.5	199.2
12-31-2033	251.7	28.9	15.1	6.9	50.9	0.0	0.0	1.5	199.3
12-31-2034	251.8	29.0	15.1	6.9	51.0	0.0	0.0	1.5	199.4
12-31-2035	250.5	28.8	15.0	6.9	50.7	0.0	0.0	1.5	198.3
Subtotal	3,057.3	351.6	189.9	84.4	625.9	176.7	0.0	18.1	2,236.6
Remaining	8,369.5	962.5	500.5	231.0	1,694.0	1,278.5	98.6	49.1	5,249.3
Total	11,426.8	1,314.1	690.4	315.4	2,319.9	1,455.2	98.6	67.2	7,485.9

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Cash Flow After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Cash Flow After Levy and Corporate Income Taxes Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2021	0.0	0.0	64.1	23.0	14.7	49.3	48.2	47.1	46.0	45.0
12-31-2022	0.0	0.0	94.3	23.0	21.7	72.6	67.5	62.9	58.9	55.2
12-31-2023	0.0	0.0	98.6	23.0	22.7	75.9	67.2	59.8	53.6	48.1
12-31-2024	0.0	0.0	118.5	23.0	27.3	91.2	76.9	65.4	55.9	48.2
12-31-2025	0.0	0.0	153.0	23.0	35.2	117.8	94.6	76.7	62.8	51.8
12-31-2026	1.7	12.6	118.7	23.0	27.3	91.4	69.9	54.1	42.4	33.5
12-31-2027	25.6	199.6	-34.1	23.0	-7.9	-26.3	-19.1	-14.1	-10.6	-8.0
12-31-2028	34.5	146.9	49.1	23.0	11.3	37.8	26.2	18.5	13.3	9.6
12-31-2029	41.8	152.8	44.8	23.0	10.3	34.5	22.8	15.3	10.5	7.3
12-31-2030	46.6	158.9	40.3	23.0	9.3	31.0	19.5	12.5	8.2	5.5
12-31-2031	46.8	42.6	-20.1	23.0	34.0	-54.1	-32.4	-19.9	-12.5	-8.0
12-31-2032	46.8	97.3	101.9	23.0	19.4	82.6	47.1	27.6	16.5	10.1
12-31-2033	46.8	93.3	106.0	23.0	20.3	85.7	46.6	26.0	14.9	8.8
12-31-2034	46.8	93.3	106.1	23.0	20.3	85.7	44.4	23.7	13.0	7.3
12-31-2035	46.8	92.8	105.5	23.0	20.2	85.3	42.0	21.4	11.2	6.1
Subtotal		1,090.1	1,146.5		286.0	860.5	621.2	477.0	384.2	320.7
Remaining		2,497.1	2,752.2		610.7	2,141.6	553.2	169.0	59.3	23.2
Total		3,587.1	3,898.8		896.7	3,002.0	1,174.4	646.0	443.4	343.9

Notes: Remaining represents estimates after December 31, 2035, through the end of production in 2064.
Totals may not add because of rounding.

(1) Operating costs include direct project-level costs, insurance costs, workover costs, and Delek Drilling's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.
(2) Oil and gas profits levy rates and estimates are provided by Delek Drilling.
(3) Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.

CASH FLOW, COSTS, AND TAXES
PHASE 1 - FIRST STAGE BEST ESTIMATE (2C) CONTINGENT RESOURCES
DELEK DRILLING LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2020

Period Ending	Working Interest Revenue (MM$)	Royalties: State (MM$)	Royalties: Interested Party (MM$)	Royalties: Third Party (MM$)	Royalties: Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[1] (MM$)	Future Net Cash Flow Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2021	53.2	6.1	0.7	1.5	8.3	0.0	0.0	0.4	44.5
12-31-2022	0.7	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.6
12-31-2023	37.3	4.3	0.5	1.0	5.8	0.0	0.0	0.3	31.2
12-31-2024	49.5	5.7	0.7	1.4	7.7	0.0	0.0	0.3	41.4
12-31-2025	82.6	9.5	4.3	2.3	16.0	0.0	0.0	0.5	66.1
12-31-2026	92.3	10.6	12.1	2.5	25.2	0.0	0.0	0.5	66.5
12-31-2027	74.3	8.5	4.4	2.0	15.0	0.0	0.0	0.4	58.8
12-31-2028	46.7	5.4	2.8	1.3	9.4	0.0	0.0	0.3	37.0
12-31-2029	59.7	6.9	3.6	1.6	12.1	88.3	0.0	0.3	-41.0
12-31-2030	84.1	9.7	5.0	2.3	17.0	0.0	0.0	0.5	66.6
12-31-2031	107.8	12.4	6.4	3.0	21.8	0.0	0.0	0.6	85.3
12-31-2032	130.6	15.0	7.8	3.6	26.4	88.3	0.0	0.8	15.1
12-31-2033	152.6	17.6	9.1	4.2	30.9	0.0	0.0	0.9	120.8
12-31-2034	174.7	20.1	10.4	4.8	35.4	0.0	0.0	1.0	138.3
12-31-2035	195.9	22.5	11.7	5.4	39.6	0.0	0.0	1.1	155.1
Subtotal	1,342.0	154.3	79.7	37.0	271.0	176.7	0.0	7.9	886.4
Remaining	9,161.8	1,053.6	547.9	252.9	1,854.3	1,232.4	98.6	53.6	5,922.8
Total	10,503.8	1,207.9	627.5	289.9	2,125.4	1,409.1	98.6	61.5	6,809.2

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Cash Flow After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Cash Flow After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2021	0.0	0.0	44.5	23.0	10.2	34.3	33.5	32.7	32.0	31.3
12-31-2022	0.0	0.0	0.6	23.0	0.1	0.5	0.4	0.4	0.4	0.4
12-31-2023	0.0	0.0	31.2	23.0	7.2	24.1	21.3	19.0	17.0	15.3
12-31-2024	0.0	0.0	41.4	23.0	9.5	31.9	26.9	22.9	19.6	16.9
12-31-2025	0.0	0.0	66.1	23.0	15.2	50.9	40.9	33.1	27.1	22.4
12-31-2026	7.3	56.3	10.2	23.0	2.3	7.9	6.0	4.7	3.6	2.9
12-31-2027	28.5	41.7	17.1	23.0	3.9	13.2	9.6	7.1	5.3	4.0
12-31-2028	37.0	39.8	-2.9	23.0	-0.7	-2.2	-1.5	-1.1	-0.8	-0.6
12-31-2029	43.4	4.0	-45.0	23.0	9.0	-54.0	-35.6	-24.0	-16.4	-11.5
12-31-2030	46.8	37.4	29.2	23.0	4.7	24.5	15.4	9.9	6.5	4.3
12-31-2031	46.8	39.9	45.4	23.0	8.4	37.0	22.2	13.6	8.5	5.5
12-31-2032	46.8	7.0	8.0	23.0	19.1	-11.1	-6.3	-3.7	-2.2	-1.4
12-31-2033	46.8	56.6	64.3	23.0	10.7	53.6	29.1	16.3	9.3	5.5
12-31-2034	46.8	64.7	73.6	23.0	12.9	60.7	31.4	16.8	9.2	5.2
12-31-2035	46.8	72.6	82.5	23.0	14.9	67.6	33.3	17.0	8.9	4.8
Subtotal		420.0	466.4		127.6	338.8	226.5	164.6	128.0	105.0
Remaining		2,802.7	3,120.1		697.3	2,422.8	592.3	179.8	64.5	26.1
Total		3,222.7	3,586.5		824.9	2,761.6	818.8	344.3	192.5	131.1

Notes: Remaining represents estimates after December 31, 2035, through the end of production in 2064.
Totals may not add because of rounding.

[1] Operating costs include direct project-level costs, insurance costs, workover costs, and Delek Drilling's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.

[2] Oil and gas profits levy rates and estimates are provided by Delek Drilling.

[3] Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.

NETHERLAND, SEWELL & ASSOCIATES, INC.

CASH FLOW, COSTS, AND TAXES
PHASE 1 - FIRST STAGE HIGH ESTIMATE (3C) CONTINGENT RESOURCES
DELEK DRILLING LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2020

Period Ending	Working Interest Revenue (MM$)	Royalties: State (MM$)	Royalties: Interested Party (MM$)	Royalties: Third Party (MM$)	Royalties: Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[1] (MM$)	Future Net Cash Flow Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2021	51.0	5.9	0.7	1.4	8.0	0.0	0.0	0.4	42.7
12-31-2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2025	0.0	0.0	0.4	0.0	0.4	0.0	0.0	0.0	-0.4
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2029	20.0	2.3	1.2	0.6	4.1	88.3	0.0	0.1	-72.5
12-31-2030	53.2	6.1	3.2	1.5	10.8	0.0	0.0	0.3	42.1
12-31-2031	81.7	9.4	4.9	2.3	16.5	0.0	0.0	0.5	64.7
12-31-2032	107.8	12.4	6.4	3.0	21.8	0.0	0.0	0.6	85.4
12-31-2033	132.3	15.2	7.9	3.7	26.8	88.3	0.0	0.8	16.4
12-31-2034	154.3	17.7	9.2	4.3	31.2	0.0	0.0	0.9	122.2
12-31-2035	174.7	20.1	10.4	4.8	35.4	0.0	0.0	1.0	138.4
Subtotal	775.2	89.1	44.4	21.4	155.0	176.7	0.0	4.5	439.0
Remaining	8,024.7	922.8	479.9	221.5	1,624.2	831.7	72.3	46.9	5,449.5
Total	8,799.8	1,012.0	524.3	242.9	1,779.2	1,008.4	72.3	51.5	5,888.5

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Cash Flow After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Cash Flow After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2021	0.0	0.0	42.7	23.0	9.8	32.8	32.1	31.3	30.6	30.0
12-31-2022	0.0	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2023	0.0	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2024	0.0	0.0	0.0	23.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2025	0.0	0.0	-0.4	23.0	-0.1	-0.3	-0.3	-0.2	-0.2	-0.1
12-31-2026	13.5	15.6	-15.6	23.0	-3.6	-12.0	-9.2	-7.1	-5.6	-4.4
12-31-2027	30.7	3.8	-3.8	23.0	-0.9	-2.9	-2.1	-1.6	-1.2	-0.9
12-31-2028	38.9	2.9	-2.9	23.0	-0.7	-2.2	-1.5	-1.1	-0.8	-0.6
12-31-2029	45.1	-32.8	-39.7	23.0	10.2	-49.8	-32.9	-22.2	-15.2	-10.6
12-31-2030	46.8	19.7	22.4	23.0	3.1	19.3	12.1	7.8	5.1	3.4
12-31-2031	46.8	30.3	34.4	23.0	5.9	28.5	17.1	10.5	6.6	4.2
12-31-2032	46.8	40.0	45.4	23.0	8.4	37.0	21.1	12.4	7.4	4.5
12-31-2033	46.8	7.7	8.7	23.0	19.3	-10.5	-5.7	-3.2	-1.8	-1.1
12-31-2034	46.8	57.2	65.0	23.0	10.9	54.1	28.0	14.9	8.2	4.6
12-31-2035	46.8	64.8	73.6	23.0	12.9	60.7	29.9	15.3	8.0	4.3
Subtotal		209.0	230.0		75.2	154.7	88.6	56.8	41.2	33.4
Remaining		2,570.5	2,879.1		639.8	2,239.2	549.6	167.6	60.5	24.6
Total		2,779.4	3,109.0		715.1	2,394.0	638.2	224.5	101.7	58.1

Notes: Remaining represents estimates after December 31, 2035, through the end of production in 2064.
Totals may not add because of rounding.

(1) Operating costs include direct project-level costs, insurance costs, workover costs, and Delek Drilling's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.
(2) Oil and gas profits levy rates and estimates are provided by Delek Drilling.
(3) Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.

Table IX

NETHERLAND, SEWELL & ASSOCIATES, INC.

VOLUMETRIC INPUT SUMMARY
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2020

Reservoir	Gross Rock Volume (acre-feet) Low Estimate	Gross Rock Volume (acre-feet) Best Estimate	Gross Rock Volume (acre-feet) High Estimate	Area (acres) Low Estimate	Area (acres) Best Estimate	Area (acres) High Estimate	Average Gross Thickness[1][2] (feet) Low Estimate	Average Gross Thickness[1][2] (feet) Best Estimate	Average Gross Thickness[1][2] (feet) High Estimate	Net-to-Gross Ratio (decimal) Low Estimate	Net-to-Gross Ratio (decimal) Best Estimate	Net-to-Gross Ratio (decimal) High Estimate
A Sand	10,743,043	11,378,939	11,448,743	82,537	83,800	84,167	130	136	136	0.71	0.81	0.87
B Sand	4,674,890	5,197,367	5,273,916	41,177	48,371	49,071	114	107	107	0.30	0.34	0.39
C Sand	1,930,119	2,327,957	2,464,265	19,413	24,373	25,789	99	96	96	0.66	0.73	0.74

Reservoir	Porosity[3] (decimal) Low Estimate	Porosity[3] (decimal) Best Estimate	Porosity[3] (decimal) High Estimate	Gas Saturation (decimal) Low Estimate	Gas Saturation (decimal) Best Estimate	Gas Saturation (decimal) High Estimate	Gas Formation Volume Factor (SCF/RCF)[4] Low Estimate	Gas Formation Volume Factor (SCF/RCF)[4] Best Estimate	Gas Formation Volume Factor (SCF/RCF)[4] High Estimate	Gas Recovery Factor (decimal) Low Estimate	Gas Recovery Factor (decimal) Best Estimate	Gas Recovery Factor (decimal) High Estimate
A Sand	0.23	0.23	0.23	0.73	0.75	0.79	374	374	374	0.60	0.65	0.70
B Sand	0.24	0.23	0.22	0.69	0.70	0.72	374	374	374	0.60	0.65	0.70
C Sand	0.23	0.22	0.22	0.74	0.76	0.81	374	374	374	0.60	0.65	0.70

Note: For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, core data, well test data, production data, historical price and cost information, and property ownership interests.

(1) Average gross thickness is calculated by dividing the gross rock volume by the area.
(2) The structural character of the B and C Sands results in a lower average gross thickness in the best and high estimate case relative to the low estimate case.
(3) The increasing net-to-gross ratio between cases includes lower porosity rock which results in a lower porosity in the best and high estimate cases relative to the low estimate case.
(4) The abbreviation SCF/RCF represents standard cubic feet per reservoir cubic foot.

APPENDIX

CASH FLOW, COSTS, AND TAXES
PHASE 1 - FIRST STAGE LOW ESTIMATE (1C) CONTINGENT RESOURCES (INCLUDING 1P RESERVES)
DELEK DRILLING LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LICENSE I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2020

Period Ending	Working Interest Revenue (MM$)	Royalties: State (MM$)	Royalties: Interested Party (MM$)	Royalties: Third Party (MM$)	Royalties: Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[1] (MM$)	Future Net Cash Flow Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2021	773.7	89.0	10.7	21.4	121.0	94.9	0.0	78.4	479.4
12-31-2022	739.6	85.1	10.2	20.4	115.7	26.7	0.0	84.4	512.8
12-31-2023	810.8	93.2	11.2	22.4	126.8	11.1	0.0	82.8	590.1
12-31-2024	881.6	101.4	12.2	24.3	137.9	0.0	0.0	82.1	661.7
12-31-2025	986.1	113.4	13.6	27.2	154.2	0.0	0.0	82.7	749.2
12-31-2026	1,027.7	118.2	49.8	28.4	196.4	0.0	0.0	82.6	748.7
12-31-2027	1,080.5	124.3	64.6	29.8	218.7	0.0	0.0	82.6	779.2
12-31-2028	1,139.6	131.1	68.2	31.5	230.7	0.0	0.0	85.3	823.6
12-31-2029	1,165.4	134.0	69.7	32.2	235.9	0.0	0.0	106.0	823.5
12-31-2030	1,184.2	136.2	70.8	32.7	239.7	0.0	0.0	85.5	859.0
12-31-2031	1,185.4	136.3	70.9	32.7	239.9	176.7	0.0	85.5	683.3
12-31-2032	1,185.6	136.3	70.9	32.7	240.0	0.0	0.0	85.5	860.1
12-31-2033	1,185.5	136.3	70.9	32.7	239.9	0.0	0.0	85.5	860.0
12-31-2034	1,185.0	136.3	70.9	32.7	239.9	0.0	0.0	106.1	839.1
12-31-2035	1,057.1	121.6	63.2	29.2	214.0	0.0	0.0	75.5	767.7
Subtotal	15,588.0	1,792.6	727.7	430.2	2,950.6	309.4	0.0	1,290.4	11,037.5
Remaining	25,621.8	2,946.5	1,532.2	707.2	5,185.9	1,278.5	170.2	2,205.6	16,781.6
Total	41,209.8	4,739.1	2,259.9	1,137.4	8,136.4	1,587.9	170.2	3,496.1	27,819.2

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Cash Flow After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Cash Flow After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2021	0.0	0.0	479.4	23.0	49.0	430.5	420.1	410.4	401.4	392.9
12-31-2022	0.0	0.0	512.8	23.0	74.4	438.4	407.5	380.0	355.5	333.5
12-31-2023	0.0	0.0	590.1	23.0	88.1	502.0	444.4	395.6	354.0	318.2
12-31-2024	0.0	0.0	661.7	23.0	101.3	560.4	472.4	401.4	343.6	296.0
12-31-2025	0.0	0.0	749.2	23.0	121.4	627.8	504.0	408.8	334.7	276.4
12-31-2026	1.7	12.6	736.1	23.0	118.4	617.7	472.3	365.7	286.4	226.6
12-31-2027	25.6	199.6	579.6	23.0	82.4	497.2	362.1	267.6	200.4	152.0
12-31-2028	34.5	284.4	539.3	23.0	73.1	466.1	323.3	228.1	163.4	118.8
12-31-2029	41.8	344.5	479.0	23.0	59.3	419.8	277.3	186.7	128.0	89.1
12-31-2030	46.6	400.2	458.8	23.0	100.7	358.1	225.3	144.8	94.9	63.4
12-31-2031	46.8	319.8	363.5	23.0	118.5	245.0	146.8	90.1	56.5	36.1
12-31-2032	46.8	402.5	457.6	23.0	97.8	359.8	205.3	120.2	72.1	44.2
12-31-2033	46.8	402.5	457.5	23.0	97.8	359.8	195.5	109.3	62.7	36.8
12-31-2034	46.8	392.7	446.4	23.0	95.9	350.4	181.4	96.8	53.1	29.9
12-31-2035	46.8	359.3	408.4	23.0	89.9	318.5	157.0	80.0	42.0	22.6
Subtotal		3,118.1	7,919.5		1,367.9	6,551.6	4,794.6	3,685.5	2,948.7	2,436.7
Remaining		7,913.3	8,868.3		2,029.5	6,838.8	1,892.8	623.9	234.9	97.6
Total		11,031.4	16,787.8		3,397.4	13,390.3	6,687.4	4,309.4	3,183.6	2,534.3

Notes: As requested, cash flows presented in this table include revenue and costs from proved (1P) reserves; 1P is inclusive of proved developed producing reserves. As presented in the 2018 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resrouces, or propsective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to qauantify; thus reserves, contingent resources, and prospective resources should not be aggregated without extensive consideration of these factors.
Remaining represents estimates after December 31, 2035, through the end of production in 2064.
Totals may not add because of rounding.

(1) Operating costs include direct project-level costs, insurance costs, workover costs, and Delek Drilling's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.
(2) Oil and gas profits levy rates and estimates are provided by Delek Drilling.
(3) Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.

CASH FLOW, COSTS, AND TAXES
PHASE 1 - FIRST STAGE BEST ESTIMATE (2C) CONTINGENT RESOURCES (INCLUDING 2P RESERVES)
DELEK DRILLING LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LICENSE I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2020

Period Ending	Working Interest Revenue (MM$)	Royalties State (MM$)	Royalties Interested Party (MM$)	Royalties Third Party (MM$)	Royalties Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[1] (MM$)	Future Net Cash Flow Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2021	813.8	93.6	11.2	22.5	127.3	94.9	0.0	78.6	513.0
12-31-2022	774.5	89.1	10.7	21.4	121.1	26.7	0.0	84.6	542.1
12-31-2023	874.3	100.5	12.1	24.1	136.7	11.1	0.0	83.2	643.3
12-31-2024	954.4	109.8	13.2	26.3	149.3	0.0	0.0	82.5	722.6
12-31-2025	1,020.6	117.4	17.2	28.2	162.7	0.0	0.0	82.9	774.9
12-31-2026	1,066.0	122.6	63.7	29.4	215.8	0.0	0.0	82.7	767.5
12-31-2027	1,097.3	126.2	65.6	30.3	222.1	0.0	0.0	82.7	792.5
12-31-2028	1,131.0	130.1	67.6	31.2	228.9	0.0	0.0	85.3	816.8
12-31-2029	1,156.9	133.0	69.2	31.9	234.2	88.3	0.0	106.0	728.4
12-31-2030	1,176.6	135.3	70.4	32.5	238.1	0.0	0.0	85.5	853.0
12-31-2031	1,177.3	135.4	70.4	32.5	238.3	0.0	0.0	85.5	853.5
12-31-2032	1,177.4	135.4	70.4	32.5	238.3	88.3	0.0	85.5	765.3
12-31-2033	1,177.4	135.4	70.4	32.5	238.3	0.0	0.0	85.5	853.6
12-31-2034	1,177.0	135.4	70.4	32.5	238.2	0.0	0.0	106.1	832.7
12-31-2035	1,063.3	122.3	63.6	29.3	215.2	0.0	0.0	75.5	772.6
Subtotal	15,837.8	1,821.3	746.1	437.1	3,004.6	309.4	0.0	1,292.1	11,231.7
Remaining	28,707.7	3,301.4	1,716.7	792.3	5,810.4	1,278.5	170.2	2,223.3	19,225.2
Total	44,545.5	5,122.7	2,462.8	1,229.5	8,815.0	1,587.9	170.2	3,515.5	30,456.9

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Cash Flow After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Cash Flow After Levy and Corporate Income Taxes Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2021	0.0	0.0	513.0	23.0	56.7	456.3	445.3	435.1	425.5	416.5
12-31-2022	0.0	0.0	542.1	23.0	81.1	460.9	428.4	399.5	373.7	350.6
12-31-2023	0.0	0.0	643.3	23.0	100.3	542.9	480.6	427.8	382.8	344.2
12-31-2024	0.0	0.0	722.6	23.0	115.3	607.3	512.0	435.0	372.4	320.8
12-31-2025	0.0	0.0	774.9	23.0	127.3	647.6	519.9	421.7	345.3	285.1
12-31-2026	7.3	56.3	711.2	23.0	112.7	598.5	457.7	354.3	277.5	219.6
12-31-2027	28.5	225.8	566.7	23.0	79.4	487.3	354.9	262.3	196.4	149.0
12-31-2028	37.0	302.0	514.8	23.0	67.5	447.3	310.2	218.8	156.8	113.9
12-31-2029	43.4	316.0	412.4	23.0	63.3	349.2	230.6	155.3	106.4	74.1
12-31-2030	46.8	398.9	454.1	23.0	97.6	356.5	224.3	144.2	94.5	63.1
12-31-2031	46.8	399.5	454.1	23.0	98.7	355.4	212.9	130.6	81.9	52.4
12-31-2032	46.8	358.2	407.1	23.0	107.5	299.6	171.0	100.1	60.1	36.8
12-31-2033	46.8	399.5	454.1	23.0	97.0	357.1	194.1	108.5	62.2	36.6
12-31-2034	46.8	389.7	443.0	23.0	95.2	347.8	180.0	96.1	52.7	29.7
12-31-2035	46.8	361.6	411.0	23.0	90.5	320.5	158.0	80.5	42.2	22.8
Subtotal		3,207.4	8,024.4		1,390.0	6,634.3	4,879.8	3,769.9	3,030.6	2,515.2
Remaining		9,045.0	10,180.2		2,333.3	7,847.0	2,110.8	686.2	257.0	106.7
Total		12,252.3	18,204.6		3,723.3	14,481.3	6,990.6	4,456.2	3,287.6	2,621.9

Notes: As requested, cash flows presented in this table include revenue and costs from proved plus probable (2P) reserves. As presented in the 2018 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resrouces, or propspective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to qauantify; thus reserves, contingent resources, and prospective resources should not be aggregated without extensive consideration of these factors.
Remaining represents estimates after December 31, 2035, through the end of production in 2064.
Totals may not add because of rounding.

(1) Operating costs include direct project-level costs, insurance costs, workover costs, and Delek Drilling's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.
(2) Oil and gas profits levy rates and estimates are provided by Delek Drilling.
(3) Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.

CASH FLOW, COSTS, AND TAXES
PHASE 1 - FIRST STAGE HIGH ESTIMATE (3C) CONTINGENT RESOURCES (INCLUDING 3P RESERVES)
DELEK DRILLING LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LICENSE I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2020

Period Ending	Working Interest Revenue (MM$)	Royalties: State (MM$)	Royalties: Interested Party (MM$)	Royalties: Third Party (MM$)	Royalties: Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[1] (MM$)	Future Net Cash Flow Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2021	882.4	101.5	12.2	24.4	138.0	94.9	0.0	79.1	570.3
12-31-2022	839.7	96.6	11.6	23.2	131.3	26.7	0.0	85.0	596.7
12-31-2023	903.3	103.9	12.5	24.9	141.3	11.1	0.0	83.4	667.5
12-31-2024	977.0	112.4	13.5	27.0	152.8	0.0	0.0	82.6	741.6
12-31-2025	1,047.4	120.5	31.1	28.9	180.5	0.0	0.0	83.0	784.0
12-31-2026	1,076.5	123.8	64.4	29.7	217.9	0.0	0.0	82.8	775.8
12-31-2027	1,109.9	127.6	66.4	30.6	224.7	0.0	0.0	82.8	802.5
12-31-2028	1,145.7	131.8	68.5	31.6	231.9	0.0	0.0	85.4	828.5
12-31-2029	1,173.3	134.9	70.2	32.4	237.5	88.3	0.0	106.1	741.4
12-31-2030	1,194.0	137.3	71.4	33.0	241.7	0.0	0.0	85.5	866.8
12-31-2031	1,194.2	137.3	71.4	33.0	241.7	0.0	0.0	85.5	866.9
12-31-2032	1,194.3	137.3	71.4	33.0	241.7	0.0	0.0	85.5	867.0
12-31-2033	1,194.2	137.3	71.4	33.0	241.7	88.3	0.0	85.5	778.6
12-31-2034	1,193.8	137.3	71.4	32.9	241.6	0.0	0.0	106.1	846.1
12-31-2035	1,069.0	122.9	63.9	29.5	216.4	0.0	0.0	75.5	777.1
Subtotal	16,194.8	1,862.4	771.2	447.0	3,080.6	309.4	0.0	1,294.0	11,510.8
Remaining	29,594.6	3,403.4	1,769.8	816.8	5,989.9	877.9	143.9	2,228.1	20,354.7
Total	45,789.4	5,265.8	2,541.0	1,263.8	9,070.6	1,187.3	143.9	3,522.1	31,865.6

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Cash Flow After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Cash Flow After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2021	0.0	0.0	570.3	23.0	69.9	500.5	488.4	477.2	466.7	456.9
12-31-2022	0.0	0.0	596.7	23.0	93.7	503.0	467.5	436.0	407.8	382.6
12-31-2023	0.0	0.0	667.5	23.0	105.9	561.6	497.1	442.6	396.0	356.0
12-31-2024	0.0	0.0	741.6	23.0	119.7	621.9	524.3	445.5	381.3	328.5
12-31-2025	0.0	0.0	784.0	23.0	129.4	654.6	525.5	426.3	349.0	288.2
12-31-2026	13.5	104.9	670.9	23.0	103.4	567.5	434.0	336.0	263.1	208.2
12-31-2027	30.7	246.2	556.3	23.0	77.0	479.2	349.0	257.9	193.2	146.5
12-31-2028	38.9	322.0	506.5	23.0	65.6	440.9	305.8	215.7	154.6	112.3
12-31-2029	45.1	334.1	407.3	23.0	62.1	345.2	228.0	153.5	105.2	73.3
12-31-2030	46.8	405.7	461.2	23.0	99.2	362.0	227.7	146.4	95.9	64.0
12-31-2031	46.8	405.7	461.2	23.0	100.3	360.9	216.2	132.7	83.2	53.2
12-31-2032	46.8	405.8	461.3	23.0	100.7	360.6	205.7	120.5	72.3	44.3
12-31-2033	46.8	364.4	414.2	23.0	109.2	305.1	165.8	92.7	53.2	31.2
12-31-2034	46.8	396.0	450.1	23.0	96.8	353.3	182.8	97.6	53.5	30.1
12-31-2035	46.8	363.7	413.4	23.0	91.0	322.4	158.9	80.9	42.5	22.9
Subtotal		3,348.4	8,162.5		1,423.8	6,738.6	4,976.8	3,861.4	3,117.6	2,598.4
Remaining		9,557.6	10,797.1		2,473.1	8,324.0	2,212.8	712.9	265.4	109.8
Total		12,906.0	18,959.6		3,896.9	15,062.6	7,189.6	4,574.3	3,383.0	2,708.2

Notes: As requested, cash flows presented in this table include revenue and costs from proved plus probable plus possible (3P) reserves. As presented in the 2018 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resrouces, or propsective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to qauantify; thus reserves, contingent resources, and prospective resources should not be aggregated without extensive consideration of these factors.
Remaining represents estimates after December 31, 2035, through the end of production in 2064.
Totals may not add because of rounding.

(1) Operating costs include direct project-level costs, insurance costs, workover costs, and Delek Drilling's estimate of the portion of the operator's headquarters general and administrative overhead expenses that can be directly attributed to this project.
(2) Oil and gas profits levy rates and estimates are provided by Delek Drilling.
(3) Corporate income tax rates and estimates of corporate income taxes are provided by Delek Drilling and are its expected corporate income taxes per year.