Delek Drilling - Limited Partnership
(the "Partnership")

January 10, 2020

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 and Reserves in the Tamar Lease**

Further to the provisions of Section 7.3.11 of the Partnership's periodic report as of December 31, 2018, as released on March 24, 2019 (Ref. No.: 2019-01-023982) (the "**Periodic Report**"), regarding evaluation of the reserves in the Tamar project, which includes the Tamar and Tamar South-West ("**Tamar SW**") reservoirs, which is in the area of the I/12 Tamar lease (the "**Tamar Project**" and the "**Tamar Lease**", respectively), the Partnership respectfully provides a report on updated discounted cash flow figures and reserves, as follows:

(a) Quantity Data

According to a report which the Partnership received from Netherland, Sewell & Associates, Inc. ("**NSAI**" or the "**Reserves Evaluator**"), and which was prepared according to the guidelines of the SPE-PRMS, as of December 31, 2019 (the "**Reserves Report**"), the natural gas and condensate reserves in the Tamar Project (which includes, as aforesaid, the Tamar and Tamar SW reservoirs), which are classified as on production reserves, are as specified below:

Reserve Category	Total (100%) in the Petroleum Asset (Gross)						Total (Tamar and Tamar SW Reservoirs) Share Attributed to the Holders of the Equity Interests of the Partnership (Net)[1]	
	Tamar Reservoir		Tamar SW Reservoir[2]		Total (Tamar and Tamar SW Reservoirs)			
	Natural Gas BCF	Condensate Million Barrels	Natural Gas BCF	Condensate Million Barrels	Natural Gas BCF	Condensate Million Barrels	In Natural Gas BCF	In Condensate Million Barrels
1P (Proved) Reserves	6,944.5	9.0	796.4	1.0	7,741.0	10.1	1,561.5	2.0
Probable Reserves	2,871.0	3.7	159.1	0.2	3,030.1	3.9	611.2	0.8
Total 2P (Proved+Probable) Reserves	9,815.5	12.8	955.6	1.2	10,771.1	14.0	2,172.8	2.8
Possible Reserves	2,366.0	3.1	102.2	0.1	2,468.3	3.2	497.9	0.6
Total 3P (Proved+Probable+Possible) Reserves	12,181.6	15.8	1,057.8	1.4	13,239.4	17.2	2,670.7	3.4

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.

[1] The Reserves Report does not state the Partnership's net share but rather the Partnership's gross share. The Partnership's share in the above table is after payment of royalties to the State, to related parties and to third parties, assuming that the rate of the royalty to the State is 12.5% (at the wellhead) and the rate of the royalty to related parties and to third parties is 9.92% (at the wellhead). The share attributed to the holders of the equity interests of the Partnership was calculated according to all of the Partnership's holdings in the Tamar Project (directly and indirectly through Tamar Petroleum Ltd. ("**Tamar Petroleum**")) which total 25.7855%. For details regarding the investment recovery date in the Tamar Project, see Sections 7.27.12 and 7.28.6 of the Periodic Report, Section 14(d) of the update to the Description of the Partnership's Business chapter in the quarterly report as of March 31, 2019, as released on May 15, 2019 (Ref. No. 2019-01-041607), Sections 19, 20(f) and (g) of the update to the Description of the Partnership's Business chapter in the quarterly report as of June 30, 2019, as released on August 29, 2019 (Ref. No. 2019-01-075699) and Sections 13(b) and (c) of the update to the Description of the Partnership's Business chapter in the quarterly report as of September 30, 2019, as released on November 25, 2019 (Ref. No. 2019-01-101553) (the "**Q1 Report**", the "**Q2 Report**" and the "**Q3 Report**", respectively).

[2] The resources stated in the table that are included in the Tamar SW reservoir do not include resources that are in the area of the 353/Eran license. See the Partnership's immediate report of April 14, 2019 (Ref. No. 2019-01-033858).

(b) In the Reserves Report, NSAI stated, *inter alia*, several assumptions and reservations, including that: (a) The evaluations, as customary in reserve evaluations according to the guidelines of the SPE-PRMS, are not adjusted to the risks; (b) NSAI did not visit the oil 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 the Reserves Report, it is not aware of any potential liability regarding environmental matters which could materially affect the quantity of the reserves estimated in the Reserves Report or the commerciality thereof, and therefore did not include in the Reserves Report costs which may derive from such liability; (d) NSAI assumed that the reservoirs will be developed in accordance with the existing development plans and in accordance with the Partnership's estimates in connection with future development that is required in order to meet the projected production forecast, that the reservoirs will be reasonably operated, that no regulation will be determined that will affect the ability of a holder of the petroleum rights to produce the reserves, and that its forecasts regarding future production will be similar to the functioning of the reservoirs in practice.

Caution regarding forward-looking information – NSAI's estimates regarding quantities of the natural gas and condensate reserves in the Tamar and Tamar SW reservoirs 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 and from the operator in the Tamar Project, and constitute estimates and conjectures 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 conjectures, *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 as a result of the actual performance of the reservoirs. The said estimates and conjectures 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 continued production from the Tamar Project.

(c) Discounted cash flow figures

With respect to the calculation of the discounted cash flow specified below, it is noted as follows: (a) the discounted cash flow was calculated, *inter alia*, based on a weighted average of the gas prices according to the price formulas in existing agreements for the sale of natural gas from the Tamar Project, according to the Partnership's assumptions with respect to prices in future agreements and according to the price formulas in accordance with the provisions of the Gas Framework. Such price formulas include, *inter alia*, partial or full linkage to the electricity production tariff[3], the ILS/U.S $ exchange rate, the U.S. CPI and the Brent barrel price. It is noted that the prices may change, *inter alia*, due to a price adjustment according to the mechanism determined in

[3] The weighted electricity production tariff (the "**Electricity Production Tariff**") is a tariff that is supervised by the Electricity Authority, and reflects the costs of the IEC's electricity production component, including the cost of the fuels of the IEC, the capital and operating costs that are attributed to the production component and the cost of purchasing electricity from private electricity producers.

the agreement with the Israel Electric Corp. Ltd. (the "**IEC**")[4], and in the agreement with Dolphinus Holdings Limited[5] (see the Partnership's immediate reports of October 2, 2019 and December 24, 2019 (Ref. No.: 2019-01-100243 and 2019-01-112932) (the "**Export to Egypt Agreement**"), and due to changes in the indices which are the linkage bases in the price formulas in the gas supply agreements. In the discounted cash flow it was assumed that a 25% price reduction will be made in the agreement with the IEC on the first adjustment date (i.e. on July 1, 2021), and that no price adjustment will be made on the second adjustment date (i.e. on July 1, 2024). Such price reduction was incorporated into the electricity production tariff forecast. For details regarding changes in the discounted cash flow as a result of a change in the price of the natural gas, including as a result of a change in the price adjustment rate as aforesaid, see the sensitivities tables in Sections (d) and (g) below. It is further noted that a change in price as a result of the class certification motion filed by a consumer of the IEC against the partners in the Tamar Project, as specified in Section 7.28.1 of the Periodic Report, Section 14(a) of the Q1 Report, Section 20(a) of the Q2 Report and Section 13(a) of the Q3 Report, was not taken into account. In the estimation of the Partnership's legal advisors, the chances of the certification motion being granted are lower than 50%. As aforesaid, at this stage the parties are at the stage of the hearing of the class certification motion. Insofar as a final and non-appealable decision is issued in the context of acceptance of the said class action (i.e. after the class certification motion is granted (insofar as shall be granted) and a non-appealable decision is issued on the class action on the merits (insofar as shall be issued)) against the Tamar partners, this may have a material adverse effect on the Partnership's business, including on the discounted cash flow figures and on the prices at which the Partnership, together with the other Tamar partners, shall sell natural gas to its customers, the extent of which will derive from the outcome of the action. The figures regarding the gas prices as aforesaid were provided to NSAI by the Partnership[6]; (b) the forecast of the demand in the domestic market in Israel, which was used to appraise the volume of the projected future natural gas sales to the domestic market in Israel, was prepared by an outside consultant, BDO Consulting Group; (c) the discounted cash flow was calculated based on a condensate price which is based on Brent Crude prices. For the purpose of calculation of the Brent price, use was made of an average of oil price forecasts of third parties which provide a long-term price forecast, including the World Bank and others, for the NYMEX ICE Brent Crude price, and which is adjusted to differences in quality, transmission costs and the price at which condensate is sold in the region. The figures regarding the

[4] The agreement with the IEC determines two dates on which each party is entitled to request a price adjustment (according to the mechanism determined in the agreement), if such party is of the opinion that the price determined in the contract is no longer appropriate for a long-term contract with an anchor buyer for the consumption of natural gas for use in the Israeli market: 8 years and 11 years after the date of commercial operation (as defined in the agreement, which occurred on July 1, 2013) from the Tamar Project (i.e.: July 1, 2021 and July 1, 2024, respectively). On the first adjustment date (July 1, 2021 – after 8 years) the adjustment that shall be made to the price will be within a range of up to 25% (up or down), and on the second adjustment date (July 1, 2024 – after 11 years) the adjustment that shall be made to the price will be within a range of up to 10% (up or down).

[5] 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. It is further noted that the price under the Export to Egypt Agreement was adjusted to the delivery point, as determined in the agreement.

[6] For the purpose of calculation of the price forecast, use was made of assumptions based on figures that were received from a consulting firm which are based on a weighting of figures of several public and private bodies: (1) annual growth in the U.S. CPI at an average scope of approx. 2% per annum; (2) a Brent barrel price of approx. $61 per barrel in 2020, which rises to approx. $75 per barrel in 2025 and to approx. $91 per barrel in 2030, and a gradual rise at an average rate of approx. 2.8% per year thereafter; (3) a forecast of the Electricity Production Tariff based, *inter alia*, on a forecast of the ILS to dollar exchange rate and on a forecast of the cost of procurement of the fuels by the IEC.

condensate prices as aforesaid were provided to NSAI by the Partnership; (d) the operation costs that were taken into account are costs that were provided to NSAI by the Partnership. These costs 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 operation costs of the project. These costs are divided into expenses at the field level and expenses per output unit and are not adjusted to inflation changes. The operation costs that were provided to NSAI by the Partnership appear to them to be reasonable, based *inter alia* on additional knowledge that NSAI has from similar projects; (e) the capital expenses that were taken into account for the purpose of preparation of the discounted cash flow are in an amount which exceeds the costs approved by the Partnership, and it includes also the estimated costs of future expenses that shall be incurred in the course of the production for the purpose of preserving and expanding the production capacity. The capital expenses that were taken into account are capital expenses which may be required, such as drilling, development and connection of new wells, laying infrastructures and additional production equipment, including participation in the costs of construction of the pipeline of Israel Natural Gas Lines Ltd. (INGL)[7]. The capital expenses that were provided to NSAI appear to them to be reasonable, based *inter alia* on the development plan for the Tamar Project and on additional knowledge that NSAI has from similar projects, and are not adjusted to inflation changes; (f) abandonment costs that were taken into account are costs that were provided to NSAI by the Partnership in accordance with its estimates with respect to the cost of abandonment of the wells, the platform and the production facilities. These costs do not take into account the salvage value of the facilities in the Tamar Project and are not adjusted to inflation changes; (g) the tax payments and the rate thereof included in the discounted cash flow were calculated from the perspective of the holder of the participation units of the Partnership, which is a company that holds the participation units of the Partnership from the date of commencement of the project. The tax calculations took into account the corporate tax rate pursuant to law. It is noted that the tax payments that shall actually be made in the future 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 (in this section: the "**Law**") and decisions of the competent authorities, may be materially different. The depreciation expenses for tax purposes were calculated pursuant to the depreciation rates set forth in the Law; (h) the actual rate of production for each one of the reserve categories specified above may be lower or higher than the rate of production that was used for the purpose of estimating the discounted cash flow. In addition, NSAI did not carry out a sensitivity analysis in relation to the production rate of the wells; (i) in the discounted cash flow, projected sale volumes were assumed in each one of the project years based on the production capacity from the Tamar project[8], and based on the Partnership's estimates in accordance with forecasts of the scope of the supply and demand in the domestic market and in the export markets of independent consulting firms in each one of the project years; (j) the calculation of the discounted cash flow assumed sales to the local markets

[7] In order to increase the possible flow capacity via the EMG pipeline, expansion of the supply capacity in INGL's system is required. For details, see Section 7.14.2(b)(2)(b) of the Periodic Report.
[8] The current gas supply capacity from the Tamar Project to INGL's transmission system, is approx. 1.1 BCF per day at maximum production.

in Egypt and in Jordan at a total aggregate scope of approx. 50 BCM until 2040[9], *inter alia* based on the Partnership's forecasts for export to Egypt and to Jordan, as specified in Section 7.13.5 of the Periodic Report and the immediate reports of October 2, 2019 and December 24, 2019[10]; (k) the calculation of the discounted cash flow took into account the Partnership's estimate with respect to the actual rate of the royalties to the State, to related and third parties that shall be paid by the Partnership at the rates of 11.5% and of approx. 9.13%, respectively. To the best of the Partnership's knowledge, after discussions that were held between the Tamar partners and the Ministry of Energy with respect to the manner of calculation of the rate of the royalties to be paid by the Partnership to the State, the Ministry of Energy intends to release directives for calculation of the rate of the royalties at the wellhead. Therefore, the actual rate of the royalties to the State, as stated above, is not final and may change[11]. For further details on the matter and regarding arrangements between the parties until completion of the said discussions, see Section 7.27.12(c)(2) of the Periodic Report; (l) the calculation of the discounted cash flow took into account the petroleum profit levy which shall apply to the Partnership pursuant to the provisions of the Law. It should be emphasized that the levy calculations were made according to the definitions, the formulas and the mechanisms defined in the Law, as understood and interpreted by the Partnership, and which were expressed in the Tamar venture's reports to 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. It is noted that as of the report release date, several interpretation disputes are being heard with respect to the implementation of the Law in the Tamar venture's reports vis-à-vis the Tax Authority, in the administrative objection proceedings set forth in the Law. The issues contemplated in these disputes have not yet been addressed in Israeli case law. The levy calculations were made according to the transitional provisions set forth in the Law with respect to a venture, the date of commencement of commercial production in respect of which occurred from the date of commencement of the Law until January 1, 2014, and based on the following assumptions: the venture will choose to report in dollars pursuant to Section 13(b) of the Law, all of the venture's payments (the production costs, the investments, the royalties, etc.) shall be recognized by the tax authorities for the purpose of the levy calculation, and calculation of the venture's income shall take into account the actual sale prices of the gas; (m) the calculation of the discounted cash flow took into account expenses and investments actually paid and which are expected to be paid by the Partnership from January 1, 2020 and income deriving from sales of natural gas and condensate that were produced and shall be produced from January 1, 2020. It is clarified that income received in 2020 in respect of sales of natural gas and condensate produced in 2019 were not included in the

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[9] It was assumed that the total projected volume of sales to the local markets in Egypt and in Jordan is higher than the contractual volume set forth in the existing export agreements.

[10] It is noted that during 2019, the Tamar partners and the Yam Tethys partners produced and sold a total quantity of approx. 10.5 BCM of natural gas. Out of this quantity, the Tamar partners produced and sold a quantity of approx. 10.43 BCM of natural gas to the domestic market and for export, and a quantity of approx. 480 thousand barrels of condensate. The Yam Tethys partners also produced and sold a quantity of approx 0.07 BCM of natural gas, while an additional quantity of approx. 0.07 BCM of natural gas was supplied from the Tamar Project to the Yam Tethys partners.

[11] It is noted that in March 2019, a letter was received from the Ministry of Energy regarding payment of royalty advances in the Tamar Project for 2019, whereby it was determined that the effective royalty rate to be paid as advances in 2019, until further notice, will be 11.3%.

discounted cash flow. It is further noted that income from natural gas and condensate sales that shall be made in a certain year was taken into account in the same year.

It is noted that the discounted cash flow was updated relative to the discounted cash flow as of December 31, 2018 (the "**Previous Discounted Cash Flow**") for the following main reasons:

1. Update of the sale prices (natural gas and condensate) for the following reasons: (a) update of forecasts of the Electricity Production Tariff, the U.S. CPI and the Brent barrel price; (b) update of forecasts of the prices for future customers in the domestic market and for export; (c) update of a forecast of the rate of the price reduction on the first adjustment date in the agreement with the IEC.

2. Update of forecasts of the sales volumes, *inter alia* in view of an update of a forecast of the demand for natural gas in the domestic market, in view of the taking effect of the Export to Egypt Agreement, as specified in the immediate reports of October 2, 2019 and December 24, 2019, and in view of the gas supply agreement that was signed between the Leviathan partners and the IEC, as specified in the immediate reports of June 12, 2019 and October 29, 2019 (Ref. No.: 2019-01-049854 and 2019-01-091575, respectively).

3. Update of a forecast of the Tamar Project's expenses, including an update of a forecast of the Tamar Project's capital expenses, which mainly derives from the update of a forecast for the future development plan for the Tamar field, including changes in the dates of the drilling of future wells and capital costs in respect of the export to Egypt transaction.

In accordance with various assumptions, primarily as specified above, set forth below is the estimated discounted cash flow as of December 31, 2019, in dollars in thousands (after levy and income tax), attributed to the Partnership's share (directly and indirectly, through its holding in Tamar Petroleum), from the reserves in the Tamar Project, for each one of the reserve categories specified above:

Total discounted cash flow from proved reserves as of December 31, 2019 (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%
31.12.2020	427	9.30	444,839	89,104	-	43,199	28,730	-	283,806	9,669	58,702	215,435	210,243	207,784	205,409	200,894	196,664
31.12.2021	409	8.90	405,425	81,209	-	42,589	71,147	-	210,480	50,951	41,717	117,812	109,498	105,700	102,117	95,530	89,622
31.12.2022	459	10.00	456,609	91,462	-	41,781	72,514	-	250,853	76,076	43,114	131,664	116,545	109,887	103,749	92,837	83,467
31.12.2023	489	10.65	499,910	100,135	-	41,781	47,920	-	310,074	113,867	42,739	153,468	129,376	119,148	109,937	94,097	81,074
31.12.2024	489	10.66	509,968	102,150	-	41,781	-	-	366,037	159,543	34,114	172,381	138,400	124,494	112,259	91,907	75,888
31.12.2025	489	10.65	519,321	104,023	-	41,781	-	-	373,517	174,806	32,328	166,383	127,224	111,780	98,503	77,139	61,040
31.12.2026	489	10.65	525,007	105,162	-	41,781	-	-	378,064	176,934	33,440	167,690	122,117	104,798	90,252	67,604	51,266
31.12.2027	535	11.65	583,879	116,955	-	41,781	-	-	425,144	198,967	40,540	185,636	128,749	107,919	90,828	65,077	47,294
31.12.2028	535	11.65	589,687	118,118	-	41,781	-	-	429,789	201,141	43,958	184,690	121,993	99,878	82,150	56,300	39,210
31.12.2029	535	11.65	594,721	119,126	-	41,781	26,043	-	407,770	190,836	47,454	169,479	106,615	85,258	68,531	44,925	29,984
31.12.2030	535	11.65	601,804	120,545	-	41,781	-	-	439,478	205,676	45,013	188,789	113,107	88,346	69,399	43,516	27,834
31.12.2031	535	11.65	607,996	121,785	-	41,781	-	-	444,430	207,993	46,217	190,220	108,537	82,805	63,568	38,127	23,371
31.12.2032	535	11.65	616,148	123,418	-	41,781	-	-	450,949	211,044	49,267	190,638	103,596	77,198	57,916	33,227	19,518
31.12.2033	534	11.63	623,430	124,877	-	41,781	49,482	-	407,290	190,612	55,937	160,742	83,190	60,550	44,394	24,362	13,715
31.12.2034	512	11.15	604,830	121,151	-	41,781	-	-	441,898	206,808	49,847	185,243	91,305	64,911	46,510	24,413	13,171

31.12.2035	390	8.49	465,258	93,194	-	41,781	-	-	330,283	154,572	36,957	138,754	65,134	45,229	31,671	15,901	8,221
31.12.2036	326	7.11	394,732	79,067	-	41,781	-	-	273,884	128,178	30,335	115,371	51,579	34,983	23,940	11,497	5,696
31.12.2037	306	6.67	373,803	74,875	-	41,781	-	-	257,147	120,345	28,377	108,426	46,166	30,583	20,453	9,396	4,461
31.12.2038	247	5.39	304,959	61,085	-	41,781	-	-	202,093	94,580	21,899	85,614	34,717	22,464	14,682	6,451	2,936
31.12.2039	235	5.11	292,671	58,624	-	41,781	-	-	192,266	89,981	20,754	81,532	31,487	19,900	12,711	5,342	2,330
31.12.2040	226	4.93	285,266	57,141	-	41,781	-	-	186,345	87,209	20,665	78,471	28,862	17,817	11,121	4,471	1,868
31.12.2041	218	4.74	277,140	55,513	-	41,781	-	-	179,846	84,168	17,862	77,816	27,258	16,436	10,026	3,855	1,544
31.12.2042	211	4.59	271,178	54,319	-	41,781	-	-	175,078	81,937	17,308	75,834	25,299	14,899	8,882	3,267	1,254
31.12.2043	206	4.49	268,048	53,692	-	41,781	-	20,626	151,950	71,112	19,242	61,596	19,570	11,258	6,559	2,308	849
31.12.2044	130	2.83	170,719	34,196	-	41,781	-	20,626	74,116	34,686	11,180	28,250	8,548	4,803	2,735	920	324
31.12.2045	63	1.37	83,646	16,755	-	41,781	-	20,626	4,485	2,099	2,947	(562)	(162)	(89)	(49)	(16)	(5)
31.12.2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

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

31.12.2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2057	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**10,064**	**219**	**11,370,994**	**2,277,679**	**-**	**1,088,530**	**295,836**	**61,877**	**7,647,071**	**3,323,790**	**891,910**	**3,431,371**	**2,148,956**	**1,768,741**	**1,488,252**	**1,113,347**	**882,597**

Total discounted cash flow from probable reserves as of December 31, 2019 (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%
31.12.2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2021	-	-	-	-	-	-	(44,795)	-	44,795	12,495	(2,874)	35,174	32,692	31,558	30,488	28,521	26,758
31.12.2022	-	-	-	-	-	-	(72,661)	-	72,661	28,632	(4,934)	48,963	43,341	40,865	38,582	34,524	31,040
31.12.2023	-	-	-	-	-	-	(47,920)	-	47,920	28,346	(4,246)	23,820	20,081	18,493	17,064	14,605	12,584
31.12.2024	-	-	-	-	-	-	20,053	-	(20,053)	(1,404)	4,220	(22,870)	(18,362)	(16,517)	(14,894)	(12,193)	(10,068)
31.12.2025	-	-	-	-	-	-	72,661	-	(72,661)	(34,005)	10,955	(49,610)	(37,934)	(33,329)	(29,370)	(23,000)	(18,200)
31.12.2026	-	-	-	-	-	-	72,661	-	(72,661)	(34,005)	10,214	(48,870)	(35,589)	(30,541)	(26,302)	(19,702)	(14,940)
31.12.2027	-	-	-	-	-	-	-	-	-	-	(209)	209	145	122	102	73	53
31.12.2028	-	-	-	-	-	-	-	-	-	-	(129)	129	85	70	57	39	27
31.12.2029	-	-	-	-	-	-	(26,043)	-	26,043	12,188	(3,012)	16,867	10,611	8,485	6,821	4,471	2,984
31.12.2030	-	-	-	-	-	-	-	-	-	-	390	(390)	(234)	(182)	(143)	(90)	(57)
31.12.2031	-	-	-	-	-	-	-	-	-	-	267	(267)	(152)	(116)	(89)	(54)	(33)
31.12.2032	-	-	-	-	-	-	-	-	-	-	(1,177)	1,177	639	477	357	205	120
31.12.2033	1	0.02	1,072	215	-	-	(49,482)	-	50,340	23,559	(7,022)	33,803	17,495	12,733	9,336	5,123	2,884
31.12.2034	23	0.50	27,121	5,432	-	-	-	-	21,688	10,150	285	11,254	5,547	3,943	2,826	1,483	800

31.12.2035	145	3.16	173,155	34,684	-	-	-	-	138,471	64,804	15,338	58,328	27,381	19,013	13,314	6,684	3,456
31.12.2036	208	4.54	252,031	50,483	-	-	26,043	-	175,504	82,136	26,600	66,769	29,850	20,246	13,855	6,654	3,297
31.12.2037	229	4.98	279,071	55,900	-	-	49,482	-	173,689	81,287	33,772	58,631	24,964	16,538	11,060	5,081	2,412
31.12.2038	287	6.26	354,162	70,941	-	-	-	-	283,221	132,548	34,575	116,099	47,079	30,463	19,910	8,748	3,981
31.12.2039	300	6.54	374,553	75,025	-	-	-	-	299,528	140,179	36,650	122,699	47,386	29,948	19,129	8,040	3,506
31.12.2040	309	6.72	388,821	77,883	-	-	49,482	-	261,455	122,361	42,774	96,321	35,427	21,870	13,651	5,488	2,294
31.12.2041	317	6.91	403,995	80,923	-	-	-	-	323,073	151,198	39,857	132,018	46,245	27,884	17,009	6,541	2,620
31.12.2042	310	6.76	399,363	79,995	-	-	-	-	319,368	149,464	39,403	130,500	43,536	25,640	15,285	5,622	2,158
31.12.2043	229	4.99	297,889	59,669	-	-	-	(20,626)	258,846	121,140	27,254	110,452	35,093	20,187	11,761	4,138	1,522
31.12.2044	241	5.25	316,704	63,438	-	-	-	(20,626)	273,892	128,181	27,961	117,749	35,630	20,019	11,398	3,836	1,352
31.12.2045	281	6.12	372,927	74,700	-	-	-	(20,626)	318,853	149,223	33,463	136,168	39,242	21,536	11,983	3,857	1,303
31.12.2046	329	7.17	441,658	88,467	-	41,781	-	-	311,410	145,740	32,975	132,695	36,420	19,522	10,616	3,269	1,058
31.12.2047	303	6.60	410,822	82,290	-	41,781	-	-	286,751	134,199	30,554	121,997	31,889	16,696	8,873	2,613	811
31.12.2048	255	5.56	349,729	70,053	-	41,781	-	22,088	215,807	100,998	28,088	86,722	21,589	11,040	5,734	1,615	480
31.12.2049	130	2.83	179,885	36,032	-	41,781	-	22,088	79,984	37,433	11,469	31,083	7,370	3,681	1,868	503	143
31.12.2050	41	0.88	56,667	11,351	-	41,781	-	22,088	(18,552)	(8,682)	-	(9,870)	(2,229)	(1,087)	(539)	(139)	(38)
31.12.2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[13] See footnote 12 above.

31.12.2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2057	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**3,939**	**86**	**5,079,625**	**1,017,480**	**-**	**208,905**	**49,482**	**4,386**	**3,799,372**	**1,778,164**	**463,458**	**1,557,749**	**545,237**	**339,256**	**219,740**	**106,557**	**64,306**

Total discounted cash flow from 2P (proved + probable) reserves as of December 31, 2019 (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%
31.12.2020	427	9.30	444,839	89,104	-	43,199	28,730	-	283,806	9,669	58,702	215,435	210,243	207,784	205,409	200,894	196,664
31.12.2021	409	8.90	405,425	81,209	-	42,589	26,352	-	255,274	63,446	38,843	152,985	142,189	137,258	132,605	124,052	116,380
31.12.2022	459	10.00	456,609	91,462	-	41,781	(147)	-	323,514	104,708	38,179	180,627	159,885	150,751	142,331	127,361	114,506
31.12.2023	489	10.65	499,910	100,135	-	41,781	-	-	357,994	142,213	38,493	177,288	149,457	137,642	127,001	108,702	93,658
31.12.2024	489	10.66	509,968	102,150	-	41,781	20,053	-	345,984	158,139	38,334	149,511	120,038	107,978	97,365	79,713	65,820
31.12.2025	489	10.65	519,321	104,023	-	41,781	72,661	-	300,856	140,800	43,282	116,773	89,290	78,451	69,133	54,138	42,840
31.12.2026	489	10.65	525,007	105,162	-	41,781	72,661	-	305,403	142,929	43,654	118,820	86,529	74,257	63,950	47,902	36,326
31.12.2027	535	11.65	583,879	116,955	-	41,781	-	-	425,144	198,967	40,331	185,845	128,894	108,041	90,930	65,150	47,347
31.12.2028	535	11.65	589,687	118,118	-	41,781	-	-	429,789	201,141	43,829	184,819	122,078	99,948	82,207	56,340	39,238
31.12.2029	535	11.65	594,721	119,126	-	41,781	-	-	433,814	203,025	44,442	186,347	117,226	93,744	75,351	49,396	32,969
31.12.2030	535	11.65	601,804	120,545	-	41,781	-	-	439,478	205,676	45,403	188,399	112,874	88,164	69,256	43,426	27,776
31.12.2031	535	11.65	607,996	121,785	-	41,781	-	-	444,430	207,993	46,484	189,953	108,385	82,689	63,479	38,073	23,338
31.12.2032	535	11.65	616,148	123,418	-	41,781	-	-	450,949	211,044	48,090	191,815	104,236	77,674	58,274	33,432	19,639
31.12.2033	535	11.65	624,502	125,092	-	41,781	-	-	457,630	214,171	48,914	194,545	100,685	73,283	53,730	29,485	16,599
31.12.2034	535	11.65	631,950	126,583	-	41,781	-	-	463,586	216,958	50,131	196,496	96,852	68,854	49,336	25,896	13,971

31.12.2035	535	11.65	638,412	127,878	-	41,781	-	-	468,753	219,377	52,295	197,082	92,515	64,242	44,984	22,586	11,677
31.12.2036	535	11.65	646,763	129,551	-	41,781	26,043	-	449,388	210,314	56,935	182,140	81,429	55,229	37,794	18,151	8,993
31.12.2037	535	11.65	652,875	130,775	-	41,781	49,482	-	430,837	201,632	62,148	167,057	71,130	47,121	31,513	14,476	6,874
31.12.2038	535	11.65	659,121	132,026	-	41,781	-	-	485,315	227,127	56,474	201,713	81,796	52,927	34,592	15,199	6,916
31.12.2039	535	11.65	667,224	133,649	-	41,781	-	-	491,794	230,160	57,404	204,231	78,873	49,849	31,839	13,382	5,836
31.12.2040	535	11.65	674,087	135,024	-	41,781	49,482	-	447,800	209,570	63,438	174,791	64,289	39,687	24,773	9,959	4,162
31.12.2041	535	11.65	681,135	136,435	-	41,781	-	-	502,919	235,366	57,718	209,834	73,503	44,319	27,035	10,396	4,164
31.12.2042	521	11.35	670,540	134,313	-	41,781	-	-	494,446	231,401	56,711	206,334	68,835	40,540	24,168	8,889	3,412
31.12.2043	435	9.48	565,937	113,361	-	41,781	-	-	410,795	192,252	46,496	172,048	54,664	31,445	18,320	6,445	2,371
31.12.2044	371	8.08	487,423	97,634	-	41,781	-	-	348,008	162,868	39,141	146,000	44,179	24,822	14,133	4,756	1,677
31.12.2045	344	7.49	456,574	91,454	-	41,781	-	-	323,338	151,322	36,410	135,606	39,080	21,447	11,933	3,841	1,298
31.12.2046	329	7.17	441,658	88,467	-	41,781	-	-	311,410	145,740	32,975	132,695	36,420	19,522	10,616	3,269	1,058
31.12.2047	303	6.60	410,822	82,290	-	41,781	-	-	286,751	134,199	30,554	121,997	31,889	16,696	8,873	2,613	811
31.12.2048	255	5.56	349,729	70,053	-	41,781	-	22,088	215,807	100,998	28,088	86,722	21,589	11,040	5,734	1,615	480
31.12.2049	130	2.83	179,885	36,032	-	41,781	-	22,088	79,984	37,433	11,469	31,083	7,370	3,681	1,868	503	143
31.12.2050	41	0.88	56,667	11,351	-	41,781	-	22,088	(18,552)	(8,682)	-	(9,870)	(2,229)	(1,087)	(539)	(139)	(38)
31.12.2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[14] See footnote 12 above.

31.12.2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2057	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**14,002**	**305**	**16,450,619**	**3,295,159**	**-**	**1,297,435**	**345,319**	**66,264**	**11,446,443**	**5,101,954**	**1,355,368**	**4,989,120**	**2,694,193**	**2,107,997**	**1,707,992**	**1,219,904**	**946,903**

Total discounted cash flow from possible reserves as of December 31, 2019 (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%
31.12.2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2024	-	-	-	-	-	-	(20,053)	-	20,053	9,524	(1,890)	12,419	9,971	8,969	8,088	6,621	5,467
31.12.2025	-	-	-	-	-	-	(4,688)	-	4,688	2,194	257	2,237	1,710	1,503	1,324	1,037	821
31.12.2026	-	-	-	-	-	-	24,741	-	(24,741)	(11,579)	3,232	(16,395)	(11,939)	(10,246)	(8,824)	(6,609)	(5,012)
31.12.2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2034	-	-	-	-	-	-	-	-	-	-	(301)	301	148	105	75	40	21

31.12.2035	-	-	-	-	-	-	-	-	-	-	(701)	701	329	228	160	80	42
31.12.2036	-	-	-	-	-	-	(26,043)	-	26,043	12,188	(3,372)	17,227	7,702	5,224	3,575	1,717	851
31.12.2037	-	-	-	-	-	-	(23,439)	-	23,439	10,969	(1,924)	14,394	6,129	4,060	2,715	1,247	592
31.12.2038	-	-	-	-	-	-	49,482	-	(49,482)	(23,158)	6,464	(32,789)	(13,296)	(8,603)	(5,623)	(2,471)	(1,124)
31.12.2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2040	-	-	-	-	-	-	(49,482)	-	49,482	23,158	(5,326)	31,651	11,641	7,186	4,486	1,803	754
31.12.2041	-	-	-	-	-	-	49,482	-	(49,482)	(23,158)	6,478	(32,803)	(11,491)	(6,928)	(4,226)	(1,625)	(651)
31.12.2042	14	0.30	17,529	3,511	-	-	-	-	14,018	6,560	1,729	5,728	1,911	1,125	671	247	95
31.12.2043	99	2.17	129,339	25,907	-	-	-	-	103,432	48,406	12,670	42,356	13,458	7,741	4,510	1,587	584
31.12.2044	164	3.57	215,142	43,094	-	-	-	-	172,048	80,519	21,066	70,464	21,322	11,980	6,821	2,295	809
31.12.2045	191	4.16	253,364	50,750	-	-	-	-	202,614	94,823	24,806	82,985	23,915	13,124	7,303	2,351	794
31.12.2046	206	4.48	275,737	55,232	-	-	-	-	220,505	103,196	29,241	88,067	24,171	12,957	7,045	2,169	702
31.12.2047	227	4.95	307,930	61,680	-	-	-	-	246,250	115,245	31,795	99,210	25,933	13,578	7,215	2,125	659
31.12.2048	232	5.06	318,189	63,735	-	-	-	(22,088)	276,542	129,422	29,884	117,236	29,186	14,925	7,751	2,184	649
31.12.2049	325	7.08	450,077	90,153	-	-	-	(22,088)	382,012	178,781	43,923	159,307	37,770	18,866	9,575	2,580	735
31.12.2050	382	8.32	534,471	107,058	-	-	-	(22,088)	449,501	210,367	51,593	187,542	42,347	20,660	10,248	2,641	721
31.12.2051	390	8.50	551,367	110,442	-	41,781	-	-	399,144	186,799	47,701	164,643	35,406	16,872	8,179	2,016	528
31.12.2052	325	7.08	464,274	92,997	-	41,781	-	-	329,496	154,204	38,071	137,221	28,104	13,081	6,197	1,461	366

15 See footnote 12 above.

31.12.2053	260	5.66	375,299	75,175	-	41,781	-	-	258,343	120,905	29,364	108,074	21,080	9,584	4,437	1,001	241
31.12.2054	195	4.25	284,415	56,970	-	41,781	-	22,088	163,576	76,554	22,849	64,174	11,921	5,294	2,395	517	119
31.12.2055	130	2.83	191,591	38,377	-	41,781	-	22,088	89,346	41,814	13,766	33,766	5,974	2,591	1,146	236	52
31.12.2056	70	1.52	103,827	20,797	-	41,781	-	22,088	19,161	8,967	5,178	5,015	845	358	155	31	6
31.12.2057	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**3,209**	**70**	**4,472,551**	**895,879**	**-**	**250,686**	**0**	**-**	**3,325,987**	**1,556,701**	**406,554**	**1,362,731**	**324,248**	**164,236**	**85,397**	**25,282**	**8,821**

Total discounted cash flow from 3P (proved + probable + possible) reserves as of December 31, 2019 (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%
31.12.2020	427	9.30	444,839	89,104	-	43,199	28,730	-	283,806	9,669	58,702	215,435	210,243	207,784	205,409	200,894	196,664
31.12.2021	409	8.90	405,425	81,209	-	42,589	26,352	-	255,274	63,446	38,843	152,985	142,189	137,258	132,605	124,052	116,380
31.12.2022	459	10.00	456,609	91,462	-	41,781	(147)	-	323,514	104,708	38,179	180,627	159,885	150,751	142,331	127,361	114,506
31.12.2023	489	10.65	499,910	100,135	-	41,781	-	-	357,994	142,213	38,493	177,288	149,457	137,642	127,001	108,702	93,658
31.12.2024	489	10.66	509,968	102,150	-	41,781	-	-	366,037	167,663	36,444	161,930	130,009	116,947	105,453	86,335	71,287
31.12.2025	489	10.65	519,321	104,023	-	41,781	67,973	-	305,544	142,994	43,540	119,010	91,000	79,953	70,457	55,175	43,660
31.12.2026	489	10.65	525,007	105,162	-	41,781	97,402	-	280,662	131,350	46,886	102,426	74,590	64,011	55,126	41,293	31,313
31.12.2027	535	11.65	583,879	116,955	-	41,781	-	-	425,144	198,967	40,331	185,845	128,894	108,041	90,930	65,150	47,347
31.12.2028	535	11.65	589,687	118,118	-	41,781	-	-	429,789	201,141	43,829	184,819	122,078	99,948	82,207	56,340	39,238
31.12.2029	535	11.65	594,721	119,126	-	41,781	-	-	433,814	203,025	44,442	186,347	117,226	93,744	75,351	49,396	32,969
31.12.2030	535	11.65	601,804	120,545	-	41,781	-	-	439,478	205,676	45,403	188,399	112,874	88,164	69,256	43,426	27,776
31.12.2031	535	11.65	607,996	121,785	-	41,781	-	-	444,430	207,993	46,484	189,953	108,385	82,689	63,479	38,073	23,338
31.12.2032	535	11.65	616,148	123,418	-	41,781	-	-	450,949	211,044	48,090	191,815	104,236	77,674	58,274	33,432	19,639
31.12.2033	535	11.65	624,502	125,092	-	41,781	-	-	457,630	214,171	48,914	194,545	100,685	73,283	53,730	29,485	16,599
31.12.2034	535	11.65	631,950	126,583	-	41,781	-	-	463,586	216,958	49,831	196,797	97,000	68,960	49,411	25,936	13,992

31.12.2035	535	11.65	638,412	127,878	-	41,781	-	-	468,753	219,377	51,594	197,783	92,844	64,470	45,144	22,666	11,719
31.12.2036	535	11.65	646,763	129,551	-	41,781	-	-	475,432	222,502	53,563	199,367	89,131	60,452	41,369	19,867	9,844
31.12.2037	535	11.65	652,875	130,775	-	41,781	26,043	-	454,276	212,601	60,224	181,450	77,258	51,181	34,228	15,723	7,466
31.12.2038	535	11.65	659,121	132,026	-	41,781	49,482	-	435,832	203,969	62,939	168,924	68,500	44,324	28,969	12,729	5,792
31.12.2039	535	11.65	667,224	133,649	-	41,781	-	-	491,794	230,160	57,404	204,231	78,873	49,849	31,839	13,382	5,836
31.12.2040	535	11.65	674,087	135,024	-	41,781	-	-	497,282	232,728	58,112	206,442	75,931	46,873	29,258	11,762	4,916
31.12.2041	535	11.65	681,135	136,435	-	41,781	49,482	-	453,436	212,208	64,197	177,031	62,013	37,391	22,809	8,771	3,513
31.12.2042	535	11.65	688,069	137,824	-	41,781	-	-	508,464	237,961	58,440	212,062	70,746	41,665	24,839	9,136	3,507
31.12.2043	535	11.65	695,276	139,268	-	41,781	-	-	514,227	240,658	59,165	214,403	68,121	39,186	22,830	8,032	2,954
31.12.2044	535	11.65	702,565	140,728	-	41,781	-	-	520,056	243,386	60,206	216,463	65,501	36,802	20,954	7,052	2,486
31.12.2045	535	11.65	709,938	142,205	-	41,781	-	-	525,952	246,145	61,216	218,591	62,995	34,571	19,236	6,192	2,092
31.12.2046	535	11.65	717,395	143,699	-	41,781	-	-	531,915	248,936	62,216	220,763	60,591	32,479	17,661	5,438	1,760
31.12.2047	530	11.55	718,752	143,970	-	41,781	-	-	533,001	249,444	62,349	221,207	57,822	30,274	16,088	4,738	1,470
31.12.2048	488	10.62	667,918	133,788	-	41,781	-	-	492,349	230,419	57,972	203,958	50,774	25,966	13,485	3,799	1,129
31.12.2049	455	9.91	629,962	126,185	-	41,781	-	-	461,996	216,214	55,392	190,390	45,140	22,547	11,444	3,084	879
31.12.2050	423	9.20	591,139	118,409	-	41,781	-	-	430,949	201,684	51,593	177,672	40,119	19,573	9,708	2,502	683
31.12.2051	390	8.50	551,367	110,442	-	41,781	-	-	399,144	186,799	47,701	164,643	35,406	16,872	8,179	2,016	528
31.12.2052	325	7.08	464,274	92,997	-	41,781	-	-	329,496	154,204	38,071	137,221	28,104	13,081	6,197	1,461	366

[16] See footnote 12 above.

31.12.2053	260	5.66	375,299	75,175	-	41,781	-	-	258,343	120,905	29,364	108,074	21,080	9,584	4,437	1,001	241
31.12.2054	195	4.25	284,415	56,970	-	41,781	-	22,088	163,576	76,554	22,849	64,174	11,921	5,294	2,395	517	119
31.12.2055	130	2.83	191,591	38,377	-	41,781	-	22,088	89,346	41,814	13,766	33,766	5,974	2,591	1,146	236	52
31.12.2056	70	1.52	103,827	20,797	-	41,781	-	22,088	19,161	8,967	5,178	5,015	845	358	155	31	6
31.12.2057	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**17,212**	**375**	**20,923,170**	**4,191,038**	**-**	**1,548,120**	**345,319**	**66,264**	**14,772,430**	**6,658,655**	**1,761,923**	**6,351,852**	**3,018,441**	**2,272,233**	**1,793,388**	**1,245,185**	**955,724**

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, operating costs, capital expenses, abandonment expenses, rates of royalties and the sale prices, including with respect to the price adjustments according to the agreement with the IEC, 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 conjectures, *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. It is further noted that the price adjustment rate on the first adjustment date, as determined in the agreement with the IEC, may be materially different to the Partnership's estimate, *inter alia* as a result of the natural gas prices in the domestic market in practice on the first adjustment date, all according to the adjustment mechanism, as determined in the agreement with the IEC.

(d) 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[17]) as of December 31, 2019 (dollars in thousands) which was performed by the Partnership:

Sensitivity / Category	Total	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity / Category	Total	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
10% growth in the gas price					**10% decrease in the gas price**				
1P (Proved) Reserves	3,802,828	1,642,620	1,227,734	972,883	1P (Proved) Reserves	3,061,784	1,335,057	999,949	793,180
Probable Reserves	1,723,879	239,194	113,606	66,683	Probable Reserves	1,391,722	200,564	99,784	62,192
Total 2P (Proved+Probable) Reserves	5,526,707	1,881,815	1,341,340	1,039,567	Total 2P (Proved+Probable) Reserves	4,453,506	1,535,621	1,099,734	855,373
Possible Reserves	1,508,938	94,113	27,732	9,581	Possible Reserves	1,216,510	76,601	22,768	8,013
Total 3P (Proved+Probable+Possible) Reserves	7,035,645	1,975,927	1,369,072	1,049,147	Total 3P (Proved+Probable+Possible) Reserves	5,670,016	1,612,222	1,122,502	863,385
15% growth in the gas price					**15% decrease in the gas price**				
1P (Proved) Reserves	3,989,900	1,720,987	1,286,063	1,019,128	1P (Proved) Reserves	2,876,155	1,256,979	941,582	746,669
Probable Reserves	1,806,979	249,077	117,269	67,990	Probable Reserves	1,309,425	191,604	96,984	61,683
Total 2P (Proved+Probable) Reserves	5,796,879	1,970,064	1,403,332	1,087,119	Total 2P (Proved+Probable) Reserves	4,185,580	1,448,583	1,038,566	808,351
Possible Reserves	1,582,203	98,455	28,937	9,943	Possible Reserves	1,143,457	72,255	21,558	7,651
Total 3P (Proved+Probable+Possible) Reserves	7,379,082	2,068,519	1,432,269	1,097,062	Total 3P (Proved+Probable+Possible) Reserves	5,329,037	1,520,838	1,060,124	816,002
20% growth in the gas price					**20% decrease in the gas price**				
1P (Proved) Reserves	4,173,662	1,795,825	1,340,810	1,061,764	1P (Proved) Reserves	2,691,686	1,179,671	883,875	700,742

[17] It is emphasized that the said analyses for sensitivity to change in the quantity of gas sold do not take into account changes in the future investments plan, both with respect to the increase and reduction of the quantity.

Sensitivity / Category	Total	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity / Category	Total	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
Probable Reserves	1,890,046	259,016	121,010	69,390	Probable Reserves	1,225,816	181,419	93,004	60,038
Total 2P (Proved+Probable) Reserves	6,063,708	2,054,841	1,461,821	1,131,154	Total 2P (Proved+Probable) Reserves	3,917,501	1,361,089	976,879	760,780
Possible Reserves	1,655,461	102,792	30,139	10,302	Possible Reserves	1,070,588	68,031	20,449	7,372
Total 3P (Proved+Probable+Possible) Reserves	7,719,169	2,157,633	1,491,960	1,141,456	Total 3P (Proved+Probable+Possible) Reserves	4,988,090	1,429,120	997,328	768,152

Sensitivity / Category	Total	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity / Category	Total	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
10% growth in the gas sales volume					**10% decrease in the gas sales volume**				
1P (Proved) Reserves	3,462,950	1,603,005	1,213,613	967,931	1P (Proved) Reserves	3,061,806	1,335,068	999,959	793,188
Probable Reserves	1,528,064	239,328	116,621	68,766	Probable Reserves	1,391,734	200,566	99,785	62,192
Total 2P (Proved+Probable) Reserves	4,991,014	1,842,333	1,330,235	1,036,698	Total 2P (Proved+Probable) Reserves	4,453,540	1,535,634	1,099,744	855,381
Possible Reserves	1,338,938	102,673	32,359	11,543	Possible Reserves	1,216,520	76,602	22,768	8,013
Total 3P (Proved+Probable+Possible) Reserves	6,329,952	1,945,006	1,362,593	1,048,241	Total 3P (Proved+Probable+Possible) Reserves	5,670,060	1,612,236	1,122,512	863,393
15% growth in the gas sales volume					**15% decrease in the gas sales volume**				
1P (Proved) Reserves	3,477,432	1,655,752	1,261,574	1,009,937	1P (Proved) Reserves	2,876,187	1,256,996	941,596	746,680
Probable Reserves	1,515,391	249,992	122,718	71,835	Probable Reserves	1,309,442	191,607	96,985	61,683
Total 2P (Proved+Probable) Reserves	4,992,823	1,905,744	1,384,292	1,081,772	Total 2P (Proved+Probable) Reserves	4,185,629	1,448,603	1,038,581	808,363
Possible Reserves	1,298,983	110,556	36,275	13,263	Possible Reserves	1,143,472	72,256	21,559	7,651
Total 3P (Proved+Probable+Possible) Reserves	6,291,806	2,016,300	1,420,568	1,095,036	Total 3P (Proved+Probable+Possible) Reserves	5,329,102	1,520,858	1,060,139	816,014
20% growth in the gas sales volume					**20% decrease in the gas sales volume**				
1P (Proved) Reserves	3,474,819	1,698,942	1,302,567	1,046,473	1P (Proved) Reserves	2,691,726	1,179,692	883,892	700,756
Probable Reserves	1,503,122	262,351	130,256	75,944	Probable Reserves	1,225,839	181,422	93,005	60,039
Total 2P (Proved+Probable) Reserves	4,977,941	1,961,294	1,432,823	1,122,417	Total 2P (Proved+Probable) Reserves	3,917,565	1,361,114	976,897	760,794
Possible Reserves	1,306,674	121,796	41,507	15,566	Possible Reserves	1,070,607	68,032	20,449	7,372
Total 3P (Proved+Probable+Possible) Reserves	6,284,615	2,083,089	1,474,330	1,137,983	Total 3P (Proved+Probable+Possible) Reserves	4,988,172	1,429,146	997,347	768,166

(e) Set forth below is an analysis of sensitivity to the main linkage components of the gas price according to the gas sale agreements in which the Tamar partners have engaged (the U.S. CPI and the electricity production tariff) as of December 31, 2019 (dollars in thousands) which was performed by the Partnership[18]:

Sensitivity / Category	Total	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity / Category	Total	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
10% growth in the CPI forecast					**10% decrease in the CPI forecast**				
1P (Proved) Reserves	3,448,339	1,493,815	1,116,970	885,109	1P (Proved) Reserves	3,414,827	1,482,798	1,109,787	880,125
Probable Reserves	1,568,413	220,995	107,039	64,502	Probable Reserves	1,547,536	218,532	106,091	64,117
Total 2P (Proved+Probable) Reserves	5,016,752	1,714,810	1,224,010	949,611	Total 2P (Proved+Probable) Reserves	4,962,363	1,701,330	1,215,879	944,241
Possible Reserves	1,373,479	86,018	25,450	8,869	Possible Reserves	1,352,545	84,804	25,118	8,772
Total 3P (Proved+Probable+Possible) Reserves	6,390,231	1,800,828	1,249,460	958,480	Total 3P (Proved+Probable+Possible) Reserves	6,314,908	1,786,134	1,240,997	953,014
10% growth in the electricity production tariff forecast					**10% decrease in the electricity production tariff forecast**				
1P (Proved) Reserves	3,563,767	1,538,962	1,149,506	910,163	1P (Proved) Reserves	3,347,539	1,464,097	1,098,415	872,704
Probable Reserves	1,626,049	227,754	109,534	65,399	Probable Reserves	1,481,640	211,116	103,273	62,967
Total 2P (Proved+Probable) Reserves	5,189,816	1,766,716	1,259,040	975,562	Total 2P (Proved+Probable) Reserves	4,829,179	1,675,213	1,201,689	935,671
Possible Reserves	1,425,735	89,130	26,330	9,147	Possible Reserves	1,273,623	80,305	23,890	8,408
Total 3P (Proved+Probable+Possible) Reserves	6,615,551	1,855,846	1,285,369	984,709	Total 3P (Proved+Probable+Possible) Reserves	6,102,802	1,755,518	1,225,578	944,079

[18] Although the electricity production tariff is affected, *inter alia*, by the CPI, in the sensitivity analysis in the table below, this effect was not taken into account.

(f) Set forth below is an analysis of sensitivity to the sale of quantities exceeding the minimum quantities (take or pay) according to the gas sale agreements in which the Partnership has engaged as of December 31, 2019 (dollars in thousands) which was performed by the Partnership:

Sensitivity / Category	**Total**	**Present value discounted at 10%**	**Present value discounted at 15%**	**Present value discounted at 20%**	Sensitivity / Category	**Total**	**Present value discounted at 10%**	**Present value discounted at 15%**	**Present value discounted at 20%**
10% growth in the gas sales volume in respect of quantities exceeding the take or pay					**10% decrease in the gas sales volume in respect of quantities exceeding the take or pay**				
1P (Proved) Reserves	3,469,086	1,548,477	1,160,872	919,723	1P (Proved) Reserves	3,174,197	1,406,604	1,060,249	845,395
Probable Reserves	1,535,081	234,862	114,486	68,050	Probable Reserves	1,391,049	199,633	98,816	61,219
Total 2P (Proved+Probable) Reserves	5,004,168	1,783,339	1,275,358	987,774	Total 2P (Proved+Probable) Reserves	4,565,246	1,606,238	1,159,065	906,614
Possible Reserves	1,346,590	98,911	30,674	10,842	Possible Reserves	1,216,724	76,717	22,856	8,080
Total 3P (Proved+Probable+Possible) Reserves	6,350,757	1,882,250	1,306,032	998,616	Total 3P (Proved+Probable+Possible) Reserves	5,781,970	1,682,955	1,181,921	914,695

(g) Set forth below is an analysis of sensitivity to the price adjustment determined in the agreement with the IEC as of December 31, 2019 (dollars in thousands) which was performed by the Partnership:

Sensitivity / Category	Total	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity / Category	Total	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
0% price reduction					**12.5% price reduction**				
1P (Proved) Reserves	3,912,783	1,673,954	1,247,313	985,946	1P (Proved) Reserves	3,771,406	1,589,976	1,180,078	930,984
Probable Reserves	1,832,847	251,877	118,433	68,603	Probable Reserves	1,833,035	252,300	118,909	69,108
Total 2P (Proved+Probable) Reserves	5,745,630	1,925,831	1,365,746	1,054,549	Total 2P (Proved+Probable) Reserves	5,604,440	1,842,276	1,298,988	1,000,092
Possible Reserves	1,624,715	100,795	29,563	10,123	Possible Reserves	1,624,666	100,763	29,537	10,102
Total 3P (Proved+Probable+Possible) Reserves	7,370,345	2,026,626	1,395,309	1,064,673	Total 3P (Proved+Probable+Possible) Reserves	7,229,106	1,943,038	1,328,524	1,010,194

(h) Agreement between the report data and data of previous reports in relation to the quantity of reserves attributed to the petroleum asset

The main differences between the present Reserves Report and the previous reserves report, which was published in the Periodic Report, derive from the production of approx. 368 BCF of natural gas and approx. 480 thousand barrels of condensate which was performed during 2019.

(i) Production data

Set forth below are production data in the Tamar Project which are attributed to the Partnership in 2017-2019[19]:

Natural Gas[20] [21]		**Y2017**	**Y2018**	**Y2019**
Total output (attributed to the holders of the equity interests of the Partnership) during the period (in MMCF)		97,659	92,698	81,050
Average price per output unit (attributed to the holders of the equity interests of the Partnership) (dollars per MCF)[22]		5.33	5.49	5.49
Average royalties (any payment derived from the output of the producing asset, including from the gross revenues from the petroleum asset) paid per output unit (attributed to the holders of the equity interests of the Partnership) (dollars per MCF)	The State	0.6	0.61	0.61
	Third Parties	0.1	0.09	0.1
	Interested Parties	0.15	0.35[23]	0.38[24]
Average production costs per output unit (attributed to the holders of the equity interests of the Partnership) (dollars per MCF)[25]		0.36	0.39	0.45
Average net income per output unit (attributed to the holders of the equity interests of the Partnership) (dollars per MCF)		4.12	4.05	3.95
Petroleum and gas profit levy		-	-	-

[19] It is noted that from the date of commencement of the piping of the natural gas from the Tamar Project (i.e. March 30, 2013) until December 31, 2019, natural gas was supplied to customers in a total quantity of approx. 60.9 BCM and approx 2.85 million barrels of condensate (the production data for 2019 are based on unaudited financial data). It is further noted that the average daily production volume of natural gas totaled, in the last two years (January 1, 2018 – December 31, 2019), approx. 1 BCF.

[20] The share attributed to the holders of the equity interests of the Partnership in the output, in the royalties paid, in the production costs and in net income, was rounded off up to two digits after the decimal point.

[21] The production data for 2019 are based on unaudited financial data and on the Partnership's direct holding in the Tamar Project at the rate of 22%. For details regarding the change in the accounting treatment of the Partnership's investment in Tamar Petroleum's shares, see Note 4O to the financial statements as of September 30, 2019, as released on November 25, 2019 (Ref. No.: 2019-01-101553).
The production data for 2017 and 2018 include, in addition to the Partnership's direct holding in the Tamar Project, also the Partnership's share in the production data of Tamar Petroleum Ltd. from July 2017.

[22] The average price per output unit weights the actual price of the Partnership which includes the framework for the sale of natural gas between the Tamar Project and the Yam Tethys project, as specified in Sections 7.3.4(e) and 7.28.2 of the Periodic Report and Note 7C(5)(a) of the financial statements as of December 31, 2018.

[23] With respect to the royalty rate taken into account in 2018, see Footnote 1 above.

[24] With respect to the royalty rate taken into account in 2019, see Footnote 1 above.

[25] The figures include current production costs only, and do not include the reservoir's exploration and development costs and tax payments that will be made in the future by the Partnership.

	Y2017	Y2018	Y2019
Average net income per output unit after the petroleum and gas profit levy (attributed to the holders of the equity interests of the Partnership) (dollars per MCF)	4.12	4.05	3.95
Depletion rate in the reported period relative to the total gas quantities in the project (in %)[26]	3.44	3.29	3.31

Condensate[27 28]

		Y2017	Y2018	Y2019
Total output (attributed to the holders of the equity interests of the Partnership) during the period (in barrels in thousands)		129.4	121.51	105.61
Average price per output unit (attributed to the holders of the equity interests of the Partnership) (dollars per barrel)		47.1	63.01	55.79
Average royalties (any payment derived from the output of the producing asset, including from the gross revenues from the petroleum asset) paid per output unit (attributed to the holders of the equity interests of the Partnership) (dollars per barrel)	The State	5.28	7.03	6.18
	Third Parties	0.83	1.05	1.22
	Interested Parties	1.37	4.12[29]	3.66[30]
Average production costs per output unit (attributed to the holders of the equity interests of the Partnership) (dollars per barrel)[31]		2	2.11	2.47
Average net income per output unit (attributed to the holders of the equity interests of the Partnership) (dollars per barrel)		37.62	48.7	42.26
Petroleum and gas profit levy		-	-	-
Average net income per output unit after the petroleum and gas profit levy (attributed to the holders of the equity interests of the Partnership) (dollars per barrel)		37.62	48.7	42.26
Depletion rate in the reported period relative to the total condensate quantities in the project (in %)[32]		3.5	3.31	3.33

The Partnership declares that all of the above data are SPE-PRMS-compliant.

(j) Opinion of the Reserves Evaluator

The Reserves Report of the Tamar Project (which includes the Tamar and Tamar SW reservoirs) prepared by NSAI as of December 31, 2019, and NSAI's consent to the inclusion thereof in this report, is attached hereto as **Annex A**.

[26] The depletion rate is the rate of natural gas produced in the relevant reporting period, out of the balance of proved and probable reserves as of the beginning of such reporting period or as of the date of commencement of production, whichever is later. The said depletion rate is calculated at the end of the year and not in the course thereof.

[27] See Footnote 21 above.

[28] See Footnote 22 above.

[29] See Footnote 1 above

[30] See Footnote 1 above.

[31] See Footnote 25 above.

[32] The quantity of condensate produced from the Tamar Project derives directly from the quantity of natural gas produced from the project.

(k) Management declaration

(1) Date of the declaration: January 10, 2020;
(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 Board of the General Partner;
(4) We confirm that the Reserves 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 Reserves 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 reserves evaluator who performed the last contingent resource or reserve disclosure released by the Partnership;
(9) We agree to the inclusion of the foregoing declaration in this report.

____

Gabi Last

(l) Glossary

Hydrocarbons – Carbon and hydrogen compounds, including gas, oil and condensate.

Lease – Within the meaning thereof in the Petroleum Law, 5712-1952 (the “**Petroleum Law**”).

Commercial quantities – Quantities of oil and/or gas that allow commercial recovery thereof.

Reservoir – A layer or layers of rock, characterized by relatively high porosity and permeability, enabling the storage and flow of liquids and gas. Sometimes also used to describe an oil and/or gas field.

Porosity – The ratio between the pore volume in the rock and the total volume of the rock.

SPE-PRMS – (Petroleum Resources Management System 2018) – A petroleum resources and reserves evaluation reporting system, as published by the SPE, the AAPG, the WPC and the SPEE, and as amended from time to time.

Petroleum Asset – The direct or indirect holding of a preliminary permit, license or lease; in another country – the direct or indirect holding of a right of a similar nature that was granted by the competent body. A right to receive benefits deriving from the lease, either directly or indirectly, in a petroleum asset or in a right of a similar nature (as the case may be) shall also be deemed as a petroleum asset.

Petroleum - Any petroleum fluid, whether liquid or gaseous, including oil, natural gas, natural gasoline, condensates and related fluid hydrocarbons, as well as asphalt and other solid petroleum hydrocarbons when dissolved in and producible with fluid petroleum.

Reserves – Defined according to the SPE-PRMS as quantities of petroleum that are expected to be recoverable by implementing a development plan in respect of accumulations discovered from a certain day forth under defined conditions. Reserves must fulfill four conditions: (1) they have to be discovered; (2) recoverable; (3) commercial; and (4) exist, according to the implemented development project.

Condensate – Hydrocarbons which are in a gas state in reservoir conditions, but which condense to a liquid during production from the reservoir to the surface.

License – Within the meaning thereof in the Petroleum Law.

Proved reserves; probable reserves; possible reserves; reserves in the 1P/ 2P/ 3P category (1P/2P/3P) – Within the meaning of these terms in the SPE-PRMS.

BCF – Billion cubic feet, which are 0.001 TCF or approx. 0.0283 BCM.

BCM – Billion cubic meters.

MMCF – Million cubic feet, which are 0.001 BCF or approx. 0.00003 BCM.

Set forth below are conversion coefficients for the units used in the above report:

BCM	**BCF**	**MMCF**
1	35.3107	35310.7
BCF	**MMCF**	**BCM**
1	1000	0.0283
MMCF	**BCF**	**BCM**
1	0.001	0.00003

The partners in the Tamar Project and their holding rates are as follows:

Noble Energy Mediterranean Ltd.	25.00%
Isramco Negev 2, Limited Partnership	28.75%
Delek Drilling – Limited Partnership	22.00%
Tamar Petroleum Ltd.	16.75%
Dor Gas Exploration – Limited Partnership	4.00%
Everest Infrastructures – Limited Partnership	3.50%

Sincerely,

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

By Yossi Abu, CEO
and Yossi Gvura, Deputy CEO

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

January 10, 2020

Mr. Yossi Abu
Delek Drilling Limited Partnership
19 Abba Eban Boulevard
Herzelia 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 January 10, 2020, 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, 2019, to the Delek Drilling interest in certain gas properties located in Tamar and Tamar Southwest Fields, Tamar Lease I/12, offshore Israel. This interest includes a 22 percent direct working interest and a 3.7855 percent indirect working interest through Delek Drilling's 22.6 percent ownership of Tamar Petroleum Ltd.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.

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

RBT:MDK

2100 ROSS AVENUE, SUITE 2200 • DALLAS, TEXAS 75201 • PH: 214-969-5401 • FAX: 214-969-5411
1301 MCKINNEY STREET, SUITE 3200 • HOUSTON, TEXAS 77010 • PH: 713-654-4950 • FAX: 713-654-4951
info@nsai-petro.com
netherlandsewell.com

January 10, 2020

Delek Drilling Limited Partnership
19 Abba Eban Boulevard
Herzelia 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, 2019, to the Delek Drilling Limited Partnership (Delek Drilling) interest in certain gas properties located in Tamar and Tamar Southwest Fields, Tamar Lease I/12, offshore Israel. It is our understanding that Delek Drilling owns a 22 percent direct working interest and a 3.7855 percent indirect working interest in these properties; this indirect working interest is through Delek Drilling's 22.6 percent ownership of Tamar Petroleum Ltd. Reserves in Tamar Southwest Field that extend into the Eran License have not been included in this report. We completed our evaluation on or about the date of this letter. This report has been prepared using price and cost parameters specified by Delek Drilling, as discussed in subsequent paragraphs of this letter. 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). 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.

We estimate the gross (100 percent) reserves and the working interest reserves to the Delek Drilling interest in these properties, as of December 31, 2019, to be:

	Gas Reserves (BCF)		Condensate Reserves (MMBBL)	
Category	Gross (100%)	Working Interest	Gross (100%)	Working Interest
Proved (1P)	7,741.0	1,996.0	10.1	2.6
Probable	3,030.1	781.3	3.9	1.0
Proved + Probable (2P)	10,771.1	2,777.4	14.0	3.6
Possible	2,468.3	636.5	3.2	0.8
Proved + Probable + Possible (3P)	13,239.4	3,413.8	17.2	4.4

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, 2019, to be:

	Future Net Revenue After Levy and Corporate Income Taxes (MM$)				
Category	Discounted at 0%	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved (1P)	3,431.4	2,149.0	1,488.3	1,113.3	882.6
Probable	1,557.7	545.2	219.7	106.6	64.3
Proved + Probable (2P)	4,989.1	2,694.2	1,708.0	1,219.9	946.9
Possible	1,362.7	324.2	85.4	25.3	8.8
Proved + Probable + Possible (3P)	6,351.9	3,018.4	1,793.4	1,245.2	955.7

Totals may not add because of rounding.

We estimate the gross (100 percent) reserves for these properties by field, as of December 31, 2019, to be:

	Tamar		Tamar Southwest		Total	
Category	Gas (BCF)	Condensate (MMBBL)	Gas (BCF)	Condensate (MMBBL)	Gas (BCF)	Condensate (MMBBL)
Proved (1P)	6,944.5	9.0	796.4	1.0	7,741.0	10.1
Probable	2,871.0	3.7	159.1	0.2	3,030.1	3.9
Proved + Probable (2P)	9,815.5	12.8	955.6	1.2	10,771.1	14.0
Possible	2,366.0	3.1	102.2	0.1	2,468.3	3.2
Proved + Probable + Possible (3P)	12,181.6	15.8	1,057.8	1.4	13,239.4	17.2

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. Monetary values shown in this report are expressed in United States dollars ($), thousands of United States dollars (M$), or millions of United States dollars (MM$). For reference, the January 8, 2020, exchange rate was 3.47 Israeli New Shekels per United States dollar.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The 1P reserves are inclusive of proved developed producing and proved undeveloped reserves. Our study indicates that as of December 31, 2019, there are no proved developed non-producing 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. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

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.

As requested, this report has been prepared using gas and condensate price parameters specified by Delek Drilling. Gas prices are based on a weighted average of all sales contracts according to their relative volume. These contract prices are mainly derived from various formulae that include indexation to the Consumer Price Index, the Power Generation Tariff, or an average of long-term forecasts for Brent Crude prices provided by various institutions. Condensate prices are based on Brent Crude prices and are adjusted for quality, transportation fees, and market differentials.

Operating costs used in this report are based on operating expense records of Delek Drilling. Operating costs are limited to direct project-level costs, insurance 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 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 estimates of future expenditures for the purpose of preserving and expanding the production capacity. Capital costs are those amounts of expenditures already authorized by the partners and amounts forecasted by Delek Drilling that are required for the above purpose, including new development wells, additional infrastructure, and production equipment. It is our understanding that Tamar and Tamar Southwest Fields are being developed under the Tamar Development Plan. Based on our understanding of this future development plan, 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; these estimates do not include any salvage value for the lease and well equipment. As requested, capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; however, we are not currently aware of any possible environmental liability that would have any material effect on the reserves estimated in this report or the commerciality of such estimates. Therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the 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.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be 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 chance that the quantities will be equal to, or greater than, the quantities of the proved plus probable plus possible reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with the current development plan 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 reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report. The near-term gas sales forecasts used in this report were provided by Delek Drilling. 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 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 reserves in accordance with the 2018 PRMS definitions and guidelines. Certain parameters used in our volumetric analyses are summarized in Tables VII and VIII. 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 16, 2019, by Mr. Yossi Abu, Chief Executive Officer of Delek Drilling, to perform this assessment. The data used in our estimates were obtained from Noble Energy Mediterranean Ltd., Delek Drilling, 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: January 10, 2020

STATE OF TEXAS
R. B. TALLEY, JR.
102425
LICENSED
PROFESSIONAL ENGINEER

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

Date Signed: January 10, 2020

STATE OF TEXAS
Z. R. LONG
GEOLOGY
11792
LICENSED
PROFESSIONAL GEOSCIENTIST

RBT:MDK

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.

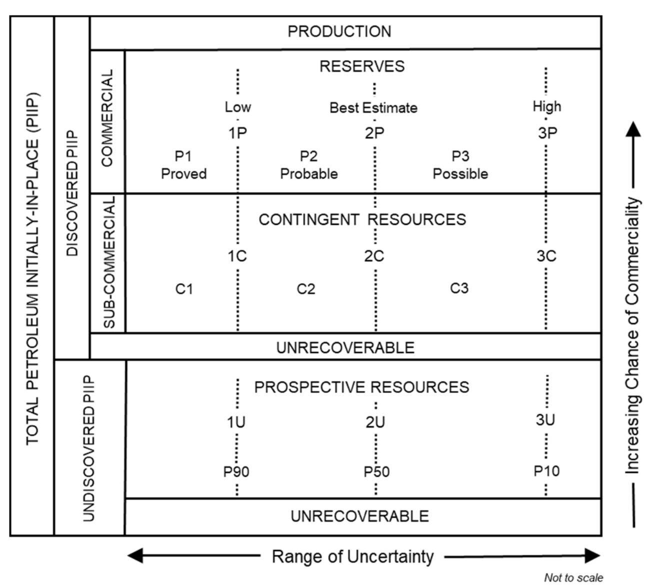

Figure 1.1—Resources classification framework

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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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.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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

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).

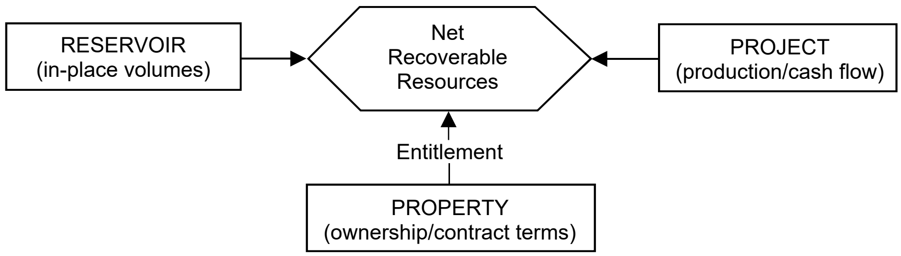

Figure 1.2—Resources evaluation

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).

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, CO_2) 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.

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.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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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.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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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.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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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.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS
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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.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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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.

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROVED (1P) RESERVES
DELEK DRILLING LIMITED PARTNERSHIP
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2019

Period Ending	Working Interest Revenue (M$)	Royalties: State (M$)	Royalties: Interested Party (M$)	Royalties: Third Party (M$)	Royalties: Total (M$)	Net Capital Costs (M$)	Net Abandonment Costs (M$)	Net Operating Expenses[1] (M$)	Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (M$)
12-31-2020	444,838.6	51,156.4	30,349.0	7,598.4	89,103.9	28,730.4	-	43,198.8	283,805.6
12-31-2021	405,424.7	46,623.8	27,660.0	6,925.2	81,209.0	71,146.7	-	42,589.3	210,479.7
12-31-2022	456,609.3	52,510.1	31,152.0	7,799.5	91,461.6	72,513.9	-	41,780.9	250,852.9
12-31-2023	499,909.8	57,489.6	34,106.2	8,539.1	100,135.0	47,919.8	-	41,780.9	310,074.2
12-31-2024	509,967.6	58,646.3	34,792.4	8,710.9	102,149.6	-	-	41,780.9	366,037.1
12-31-2025	519,320.7	59,721.9	35,430.5	8,870.7	104,023.1	-	-	41,780.9	373,516.7
12-31-2026	525,007.0	60,375.8	35,818.5	8,967.8	105,162.1	-	-	41,780.9	378,064.0
12-31-2027	583,879.0	67,146.1	39,835.0	9,973.4	116,954.5	-	-	41,780.9	425,143.6
12-31-2028	589,687.4	67,814.1	40,231.3	10,072.6	118,118.0	-	-	41,780.9	429,788.5
12-31-2029	594,720.7	68,392.9	40,574.7	10,158.6	119,126.2	26,043.4	-	41,780.9	407,770.3
12-31-2030	601,804.2	69,207.5	41,057.9	10,279.6	120,545.0	-	-	41,780.9	439,478.2
12-31-2031	607,996.4	69,919.6	41,480.4	10,385.4	121,785.4	-	-	41,780.9	444,430.1
12-31-2032	616,148.3	70,857.1	42,036.6	10,524.6	123,418.2	-	-	41,780.9	450,949.2
12-31-2033	623,430.3	71,694.5	42,533.4	10,649.0	124,876.9	49,482.4	-	41,780.9	407,290.1
12-31-2034	604,829.6	69,555.4	41,264.3	10,331.3	121,151.0	-	-	41,780.9	441,897.7
12-31-2035	465,257.7	53,504.6	31,742.1	7,947.2	93,193.9	-	-	41,780.9	330,282.8
12-31-2036	394,732.1	45,394.2	26,930.5	6,742.5	79,067.2	-	-	41,780.9	273,884.0
12-31-2037	373,803.5	42,987.4	25,502.6	6,385.1	74,875.1	-	-	41,780.9	257,147.4
12-31-2038	304,959.2	35,070.3	20,805.8	5,209.1	61,085.2	-	-	41,780.9	202,093.1
12-31-2039	292,671.2	33,657.2	19,967.4	4,999.2	58,623.8	-	-	41,780.9	192,266.5
12-31-2040	285,266.0	32,805.6	19,462.2	4,872.7	57,140.5	-	-	41,780.9	186,344.6
12-31-2041	277,139.6	31,871.1	18,907.8	4,733.9	55,512.7	-	-	41,780.9	179,845.9
12-31-2042	271,177.7	31,185.4	18,501.0	4,632.1	54,318.5	-	-	41,780.9	175,078.2
12-31-2043	268,048.1	30,825.5	18,287.5	4,578.6	53,691.6	-	20,625.7	41,780.9	151,949.8
12-31-2044	170,719.0	19,632.7	11,647.3	2,916.1	34,196.1	-	20,625.7	41,780.9	74,116.3
12-31-2045	83,646.2	9,619.3	5,706.7	1,428.8	16,754.8	-	20,625.7	41,780.9	4,484.7
12-31-2046	-	-	-	-	-	-	-	-	-
12-31-2047	-	-	-	-	-	-	-	-	-
12-31-2048	-	-	-	-	-	-	-	-	-
12-31-2049	-	-	-	-	-	-	-	-	-
12-31-2050	-	-	-	-	-	-	-	-	-
12-31-2051	-	-	-	-	-	-	-	-	-
12-31-2052	-	-	-	-	-	-	-	-	-
12-31-2053	-	-	-	-	-	-	-	-	-
12-31-2054	-	-	-	-	-	-	-	-	-
12-31-2055	-	-	-	-	-	-	-	-	-
12-31-2056	-	-	-	-	-	-	-	-	-
Total	11,370,994.0	1,307,664.3	775,783.0	194,231.6	2,277,678.9	295,836.4	61,877.2	1,088,530.3	7,647,071.2

(1) Operating expenses are limited to direct project-level costs, insurance 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.

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

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROVED (1P) RESERVES
DELEK DRILLING LIMITED PARTNERSHIP
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2019

						Future Net Revenue After Levy and Corporate Income Taxes				
Period Ending	Levy Rate (%)	Levy (M$)	Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (M$)	Corporate Income Tax Rate[1] (%)	Corporate Income Taxes[1] (M$)	Discounted at 0% (M$)	Discounted at 5% (M$)	Discounted at 10% (M$)	Discounted at 15% (M$)	Discounted at 20% (M$)
12-31-2020	3.4	9,668.9	274,136.7	23.0	58,701.5	215,435.1	210,243.1	205,409.3	200,894.3	196,664.4
12-31-2021	24.2	50,951.0	159,528.6	23.0	41,716.9	117,811.7	109,497.6	102,117.3	95,530.4	89,622.4
12-31-2022	30.3	76,075.6	174,777.3	23.0	43,113.7	131,663.6	116,544.7	103,749.0	92,837.0	83,466.6
12-31-2023	36.7	113,867.1	196,207.1	23.0	42,739.2	153,467.9	129,376.4	109,936.9	94,096.9	81,074.3
12-31-2024	43.6	159,542.7	206,494.4	23.0	34,113.9	172,380.5	138,400.1	112,259.0	91,906.8	75,887.9
12-31-2025	46.8	174,805.8	198,710.9	23.0	32,327.7	166,383.2	127,223.8	98,503.0	77,138.5	61,039.7
12-31-2026	46.8	176,933.9	201,130.0	23.0	33,439.8	167,690.3	122,117.4	90,251.7	67,603.9	51,266.0
12-31-2027	46.8	198,967.2	226,176.4	23.0	40,540.2	185,636.2	128,748.7	90,827.5	65,077.2	47,293.7
12-31-2028	46.8	201,141.0	228,647.5	23.0	43,957.7	184,689.8	121,992.7	82,149.5	56,300.4	39,210.5
12-31-2029	46.8	190,836.5	216,933.8	23.0	47,454.4	169,479.4	106,615.1	68,530.9	44,924.9	29,984.4
12-31-2030	46.8	205,675.8	233,802.4	23.0	45,013.0	188,789.4	113,107.1	69,399.2	43,516.1	27,833.9
12-31-2031	46.8	207,993.3	236,436.8	23.0	46,216.8	190,220.1	108,537.4	63,568.3	38,126.9	23,370.7
12-31-2032	46.8	211,044.2	239,905.0	23.0	49,266.9	190,638.1	103,596.1	57,916.3	33,226.7	19,518.4
12-31-2033	46.8	190,611.8	216,678.3	23.0	55,936.8	160,741.5	83,190.3	44,394.3	24,361.7	13,714.5
12-31-2034	46.8	206,808.1	235,089.6	23.0	49,846.8	185,242.7	91,305.4	46,510.1	24,413.1	13,170.8
12-31-2035	46.8	154,572.4	175,710.5	23.0	36,956.9	138,753.6	65,134.4	31,670.7	15,901.1	8,221.2
12-31-2036	46.8	128,177.7	145,706.3	23.0	30,335.4	115,370.9	51,579.0	23,939.6	11,496.9	5,696.5
12-31-2037	46.8	120,345.0	136,802.4	23.0	28,376.6	108,425.8	46,165.8	20,453.2	9,395.5	4,461.3
12-31-2038	46.8	94,579.6	107,513.5	23.0	21,899.4	85,614.1	34,717.1	14,681.8	6,451.1	2,935.6
12-31-2039	46.8	89,980.7	102,285.8	23.0	20,753.7	81,532.1	31,487.4	12,710.7	5,342.2	2,329.7
12-31-2040	46.8	87,209.3	99,135.3	23.0	20,664.6	78,470.7	28,862.0	11,121.4	4,471.0	1,868.5
12-31-2041	46.8	84,167.9	95,678.0	23.0	17,861.8	77,816.3	27,258.4	10,026.0	3,855.4	1,544.1
12-31-2042	46.8	81,936.6	93,141.6	23.0	17,308.0	75,833.6	25,299.0	8,882.3	3,267.1	1,254.0
12-31-2043	46.8	71,112.5	80,837.3	23.0	19,241.7	61,595.6	19,570.5	6,558.8	2,307.5	848.8
12-31-2044	46.8	34,686.4	39,429.9	23.0	11,179.7	28,250.2	8,548.4	2,734.6	920.3	324.4
12-31-2045	46.8	2,098.9	2,385.9	23.0	2,947.4	-561.5	-161.8	-49.4	-15.9	-5.4
12-31-2046	-	-	-	23.0	-	-	-	-	-	-
12-31-2047	-	-	-	23.0	-	-	-	-	-	-
12-31-2048	-	-	-	23.0	-	-	-	-	-	-
12-31-2049	-	-	-	23.0	-	-	-	-	-	-
12-31-2050	-	-	-	23.0	-	-	-	-	-	-
12-31-2051	-	-	-	23.0	-	-	-	-	-	-
12-31-2052	-	-	-	23.0	-	-	-	-	-	-
12-31-2053	-	-	-	23.0	-	-	-	-	-	-
12-31-2054	-	-	-	23.0	-	-	-	-	-	-
12-31-2055	-	-	-	23.0	-	-	-	-	-	-
12-31-2056	-	-	-	23.0	-	-	-	-	-	-
Total		3,323,789.9	4,323,281.3		891,910.4	3,431,370.9	2,148,955.8	1,488,252.1	1,113,347.0	882,596.9

[1] 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
PROBABLE RESERVES
DELEK DRILLING LIMITED PARTNERSHIP
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2019

Period Ending	Working Interest Revenue (M$)	Royalties: State (M$)	Royalties: Interested Party (M$)	Royalties: Third Party (M$)	Royalties: Total (M$)	Net Capital Costs (M$)	Net Abandonment Costs (M$)	Net Operating Expenses[1] (M$)	Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (M$)
12-31-2020	-	-	-	-	-	-	-	-	-
12-31-2021	-	-	-	-	-	-44,794.6	-	-	44,794.6
12-31-2022	-	-	-	-	-	-72,661.0	-	-	72,661.0
12-31-2023	-	-	-	-	-	-47,919.8	-	-	47,919.8
12-31-2024	-	-	-	-	-	20,053.4	-	-	-20,053.4
12-31-2025	-	-	-	-	-	72,661.0	-	-	-72,661.0
12-31-2026	-	-	-	-	-	72,661.0	-	-	-72,661.0
12-31-2027	-	-	-	-	-	-	-	-	-
12-31-2028	-	-	-	-	-	-	-	-	-
12-31-2029	-	-	-	-	-	-26,043.4	-	-	26,043.4
12-31-2030	-	-	-	-	-	-	-	-	-
12-31-2031	-	-	-	-	-	-	-	-	-
12-31-2032	-	-	-	-	-	-	-	-	-
12-31-2033	1,072.0	123.3	73.1	18.3	214.7	-49,482.4	-	-	50,339.7
12-31-2034	27,120.5	3,118.9	1,850.3	463.3	5,432.4	-	-	-	21,688.1
12-31-2035	173,154.6	19,912.8	11,813.4	2,957.7	34,683.9	-	-	-	138,470.7
12-31-2036	252,030.9	28,983.6	17,194.7	4,305.0	50,483.3	26,043.4	-	-	175,504.2
12-31-2037	279,071.3	32,093.2	19,039.6	4,766.9	55,899.7	49,482.4	-	-	173,689.3
12-31-2038	354,162.3	40,728.7	24,162.6	6,049.6	70,940.9	-	-	-	283,221.5
12-31-2039	374,553.1	43,073.6	25,553.8	6,397.9	75,025.2	-	-	-	299,527.8
12-31-2040	388,821.0	44,714.4	26,527.2	6,641.6	77,883.2	49,482.4	-	-	261,455.4
12-31-2041	403,995.4	46,459.5	27,562.5	6,900.8	80,922.7	-	-	-	323,072.7
12-31-2042	399,362.8	45,926.7	27,246.4	6,821.6	79,994.8	-	-	-	319,368.0
12-31-2043	297,888.8	34,257.2	20,323.4	5,088.3	59,668.9	-	-20,625.7	-	258,845.6
12-31-2044	316,703.7	36,420.9	21,607.0	5,409.7	63,437.7	-	-20,625.7	-	273,891.7
12-31-2045	372,927.4	42,886.6	25,442.9	6,370.1	74,699.6	-	-20,625.7	-	318,853.5
12-31-2046	441,658.0	50,790.7	30,132.0	7,544.1	88,466.8	-	-	41,780.9	311,410.3
12-31-2047	410,821.7	47,244.5	28,028.2	7,017.4	82,290.1	-	-	41,780.9	286,750.7
12-31-2048	349,728.9	40,218.8	23,860.2	5,973.8	70,052.8	-	22,087.9	41,780.9	215,807.3
12-31-2049	179,885.2	20,686.8	12,272.6	3,072.7	36,032.1	-	22,087.9	41,780.9	79,984.3
12-31-2050	56,667.4	6,516.8	3,866.1	968.0	11,350.8	-	22,087.9	41,780.9	-18,552.2
12-31-2051	-	-	-	-	-	-	-	-	-
12-31-2052	-	-	-	-	-	-	-	-	-
12-31-2053	-	-	-	-	-	-	-	-	-
12-31-2054	-	-	-	-	-	-	-	-	-
12-31-2055	-	-	-	-	-	-	-	-	-
12-31-2056	-	-	-	-	-	-	-	-	-
Total	5,079,624.9	584,156.9	346,556.0	86,766.7	1,017,479.6	49,482.4	4,386.5	208,904.6	3,799,371.8

[1] Operating expenses are limited to direct project-level costs, insurance 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.

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROBABLE RESERVES
DELEK DRILLING LIMITED PARTNERSHIP
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2019

Period Ending	Levy Rate (%)	Levy (M$)	Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (M$)	Corporate Income Tax Rate[1] (%)	Corporate Income Taxes[1] (M$)	Future Net Revenue After Levy and Corporate Income Taxes: Discounted at 0% (M$)	Discounted at 5% (M$)	Discounted at 10% (M$)	Discounted at 15% (M$)	Discounted at 20% (M$)
12-31-2020	3.4	-	-	23.0	-	-	-	-	-	-
12-31-2021	24.9	12,494.5	32,300.0	23.0	-2,873.7	35,173.8	32,691.5	30,488.1	28,521.5	26,757.6
12-31-2022	32.4	28,632.2	44,028.8	23.0	-4,934.3	48,963.1	43,340.6	38,582.2	34,524.2	31,039.6
12-31-2023	39.7	28,345.9	19,573.9	23.0	-4,246.4	23,820.3	20,081.0	17,063.7	14,605.1	12,583.8
12-31-2024	45.7	-1,403.6	-18,649.8	23.0	4,220.1	-22,869.9	-18,361.7	-14,893.5	-12,193.4	-10,068.1
12-31-2025	46.8	-34,005.3	-38,655.6	23.0	10,954.6	-49,610.2	-37,934.1	-29,370.5	-23,000.3	-18,200.1
12-31-2026	46.8	-34,005.3	-38,655.6	23.0	10,214.4	-48,870.0	-35,588.7	-26,302.1	-19,701.8	-14,940.5
12-31-2027	46.8	-	-	23.0	-209.1	209.1	145.0	102.3	73.3	53.3
12-31-2028	46.8	-	-	23.0	-128.8	128.8	85.1	57.3	39.3	27.4
12-31-2029	46.8	12,188.3	13,855.1	23.0	-3,012.4	16,867.4	10,610.9	6,820.5	4,471.2	2,984.2
12-31-2030	46.8	-	-	23.0	389.9	-389.9	-233.6	-143.3	-89.9	-57.5
12-31-2031	46.8	-	-	23.0	267.2	-267.2	-152.5	-89.3	-53.6	-32.8
12-31-2032	46.8	-	-	23.0	-1,176.7	1,176.7	639.4	357.5	205.1	120.5
12-31-2033	46.8	23,559.0	26,780.7	23.0	-7,022.4	33,803.1	17,494.5	9,335.9	5,123.1	2,884.1
12-31-2034	46.8	10,150.0	11,538.1	23.0	284.5	11,253.5	5,546.8	2,825.5	1,483.1	800.1
12-31-2035	46.8	64,804.3	73,666.4	23.0	15,338.0	58,328.4	27,380.8	13,313.5	6,684.4	3,456.0
12-31-2036	46.8	82,136.0	93,368.3	23.0	26,599.5	66,768.7	29,850.4	13,854.6	6,653.6	3,296.7
12-31-2037	46.8	81,286.6	92,402.7	23.0	33,771.7	58,631.0	24,964.0	11,060.0	5,080.6	2,412.4
12-31-2038	46.8	132,547.6	150,673.8	23.0	34,574.7	116,099.1	47,078.9	19,909.7	8,748.2	3,980.8
12-31-2039	46.8	140,179.0	159,348.8	23.0	36,650.2	122,698.6	47,385.8	19,128.6	8,039.5	3,505.9
12-31-2040	46.8	122,361.1	139,094.3	23.0	42,773.6	96,320.7	35,427.4	13,651.2	5,488.0	2,293.5
12-31-2041	46.8	151,198.0	171,874.7	23.0	39,856.6	132,018.0	46,244.8	17,009.5	6,540.8	2,619.6
12-31-2042	46.8	149,464.2	169,903.8	23.0	39,403.3	130,500.5	43,536.4	15,285.4	5,622.3	2,157.9
12-31-2043	46.8	121,139.7	137,705.8	23.0	27,253.9	110,451.9	35,093.4	11,761.0	4,137.8	1,522.0
12-31-2044	46.8	128,181.3	145,710.4	23.0	27,961.0	117,749.4	35,630.4	11,398.2	3,835.8	1,352.1
12-31-2045	46.8	149,223.4	169,630.1	23.0	33,462.5	136,167.5	39,241.6	11,982.8	3,857.3	1,303.0
12-31-2046	46.8	145,740.0	165,670.3	23.0	32,975.0	132,695.3	36,419.9	10,615.7	3,268.6	1,058.2
12-31-2047	46.8	134,199.3	152,551.4	23.0	30,554.4	121,996.9	31,889.2	8,872.6	2,613.1	810.7
12-31-2048	46.8	100,997.8	114,809.5	23.0	28,087.9	86,721.5	21,589.0	5,733.7	1,615.2	480.2
12-31-2049	46.8	37,432.7	42,551.6	23.0	11,468.6	31,083.0	7,369.5	1,868.3	503.4	143.4
12-31-2050	46.8	-8,682.4	-9,869.8	23.0	-	-9,869.8	-2,228.6	-539.3	-139.0	-38.0
12-31-2051	-	-	-	23.0	-	-	-	-	-	-
12-31-2052	-	-	-	23.0	-	-	-	-	-	-
12-31-2053	-	-	-	23.0	-	-	-	-	-	-
12-31-2054	-	-	-	23.0	-	-	-	-	-	-
12-31-2055	-	-	-	23.0	-	-	-	-	-	-
12-31-2056	-	-	-	23.0	-	-	-	-	-	-
Total		1,778,164.5	2,021,207.4		463,457.9	1,557,749.5	545,237.2	219,739.7	106,556.8	64,306.2

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

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

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROVED + PROBABLE (2P) RESERVES
DELEK DRILLING LIMITED PARTNERSHIP
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2019

Period Ending	Working Interest Revenue (M$)	Royalties: State (M$)	Royalties: Interested Party (M$)	Royalties: Third Party (M$)	Royalties: Total (M$)	Net Capital Costs (M$)	Net Abandonment Costs (M$)	Net Operating Expenses[1] (M$)	Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (M$)
12-31-2020	444,838.6	51,156.4	30,349.0	7,598.4	89,103.9	28,730.4	-	43,198.8	283,805.6
12-31-2021	405,424.7	46,623.8	27,660.0	6,925.2	81,209.0	26,352.1	-	42,589.3	255,274.2
12-31-2022	456,609.3	52,510.1	31,152.0	7,799.5	91,461.6	-147.1	-	41,780.9	323,513.9
12-31-2023	499,909.8	57,489.6	34,106.2	8,539.1	100,135.0	-	-	41,780.9	357,994.0
12-31-2024	509,967.6	58,646.3	34,792.4	8,710.9	102,149.6	20,053.4	-	41,780.9	345,983.7
12-31-2025	519,320.7	59,721.9	35,430.5	8,870.7	104,023.1	72,661.0	-	41,780.9	300,855.8
12-31-2026	525,007.0	60,375.8	35,818.5	8,967.8	105,162.1	72,661.0	-	41,780.9	305,403.0
12-31-2027	583,879.0	67,146.1	39,835.0	9,973.4	116,954.5	-	-	41,780.9	425,143.6
12-31-2028	589,687.4	67,814.1	40,231.3	10,072.6	118,118.0	-	-	41,780.9	429,788.5
12-31-2029	594,720.7	68,392.9	40,574.7	10,158.6	119,126.2	-	-	41,780.9	433,813.6
12-31-2030	601,804.2	69,207.5	41,057.9	10,279.6	120,545.0	-	-	41,780.9	439,478.2
12-31-2031	607,996.4	69,919.6	41,480.4	10,385.4	121,785.4	-	-	41,780.9	444,430.1
12-31-2032	616,148.3	70,857.1	42,036.6	10,524.6	123,418.2	-	-	41,780.9	450,949.2
12-31-2033	624,502.3	71,817.8	42,606.5	10,667.3	125,091.6	-	-	41,780.9	457,629.8
12-31-2034	631,950.1	72,674.3	43,114.6	10,794.5	126,583.4	-	-	41,780.9	463,585.8
12-31-2035	638,412.2	73,417.4	43,555.5	10,904.9	127,877.8	-	-	41,780.9	468,753.5
12-31-2036	646,763.0	74,377.8	44,125.2	11,047.6	129,550.6	26,043.4	-	41,780.9	449,388.2
12-31-2037	652,874.8	75,080.6	44,542.2	11,152.0	130,774.8	49,482.4	-	41,780.9	430,836.7
12-31-2038	659,121.5	75,799.0	44,968.4	11,258.7	132,026.0	-	-	41,780.9	485,314.5
12-31-2039	667,224.3	76,730.8	45,521.2	11,397.1	133,649.1	-	-	41,780.9	491,794.3
12-31-2040	674,087.0	77,520.0	45,989.4	11,514.3	135,023.7	49,482.4	-	41,780.9	447,800.0
12-31-2041	681,135.0	78,330.5	46,470.3	11,634.7	136,435.5	-	-	41,780.9	502,918.6
12-31-2042	670,540.5	77,112.2	45,747.4	11,453.7	134,313.3	-	-	41,780.9	494,446.3
12-31-2043	565,936.8	65,082.7	38,610.9	9,666.9	113,360.6	-	-	41,780.9	410,795.3
12-31-2044	487,422.7	56,053.6	33,254.3	8,325.8	97,633.7	-	-	41,780.9	348,008.1
12-31-2045	456,573.6	52,506.0	31,149.6	7,798.9	91,454.5	-	-	41,780.9	323,338.2
12-31-2046	441,658.0	50,790.7	30,132.0	7,544.1	88,466.8	-	-	41,780.9	311,410.3
12-31-2047	410,821.7	47,244.5	28,028.2	7,017.4	82,290.1	-	-	41,780.9	286,750.7
12-31-2048	349,728.9	40,218.8	23,860.2	5,973.8	70,052.8	-	22,087.9	41,780.9	215,807.3
12-31-2049	179,885.2	20,686.8	12,272.6	3,072.7	36,032.1	-	22,087.9	41,780.9	79,984.3
12-31-2050	56,667.4	6,516.8	3,866.1	968.0	11,350.8	-	22,087.9	41,780.9	-18,552.2
12-31-2051	-	-	-	-	-	-	-	-	-
12-31-2052	-	-	-	-	-	-	-	-	-
12-31-2053	-	-	-	-	-	-	-	-	-
12-31-2054	-	-	-	-	-	-	-	-	-
12-31-2055	-	-	-	-	-	-	-	-	-
12-31-2056	-	-	-	-	-	-	-	-	-
Total	16,450,618.9	1,891,821.2	1,122,339.0	280,998.3	3,295,158.5	345,318.8	66,263.7	1,297,434.9	11,446,443.0

[1] Operating expenses are limited to direct project-level costs, insurance 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.

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

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROVED + PROBABLE (2P) RESERVES
DELEK DRILLING LIMITED PARTNERSHIP
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2019

Period Ending	Levy Rate (%)	Levy (M$)	Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (M$)	Corporate Income Tax Rate[1] (%)	Corporate Income Taxes[1] (M$)	Future Net Revenue After Levy and Corporate Income Taxes: Discounted at 0% (M$)	Discounted at 5% (M$)	Discounted at 10% (M$)	Discounted at 15% (M$)	Discounted at 20% (M$)
12-31-2020	3.4	9,668.9	274,136.7	23.0	58,701.5	215,435.1	210,243.1	205,409.3	200,894.3	196,664.4
12-31-2021	24.9	63,445.6	191,828.7	23.0	38,843.2	152,985.5	142,189.1	132,605.4	124,051.9	116,380.0
12-31-2022	32.4	104,707.8	218,806.1	23.0	38,179.4	180,626.7	159,885.3	142,331.2	127,361.2	114,506.1
12-31-2023	39.7	142,213.0	215,781.0	23.0	38,492.7	177,288.2	149,457.4	127,000.5	108,702.0	93,658.1
12-31-2024	45.7	158,139.1	187,844.6	23.0	38,334.0	149,510.6	120,038.4	97,365.5	79,713.5	65,819.8
12-31-2025	46.8	140,800.5	160,055.3	23.0	43,282.3	116,773.0	89,289.7	69,132.6	54,138.3	42,839.6
12-31-2026	46.8	142,928.6	162,474.4	23.0	43,654.1	118,820.3	86,528.7	63,949.6	47,902.1	36,325.6
12-31-2027	46.8	198,967.2	226,176.4	23.0	40,331.1	185,845.3	128,893.7	90,929.8	65,150.5	47,347.0
12-31-2028	46.8	201,141.0	228,647.5	23.0	43,828.9	184,818.6	122,077.8	82,206.8	56,339.6	39,237.8
12-31-2029	46.8	203,024.8	230,788.8	23.0	44,442.0	186,346.8	117,225.9	75,351.4	49,396.1	32,968.6
12-31-2030	46.8	205,675.8	233,802.4	23.0	45,402.9	188,399.5	112,873.5	69,255.9	43,426.3	27,776.4
12-31-2031	46.8	207,993.3	236,436.8	23.0	46,484.0	189,952.9	108,384.9	63,479.0	38,073.3	23,337.9
12-31-2032	46.8	211,044.2	239,905.0	23.0	48,090.2	191,814.8	104,235.5	58,273.8	33,431.7	19,638.9
12-31-2033	46.8	214,170.7	243,459.1	23.0	48,914.4	194,544.7	100,684.8	53,730.2	29,484.8	16,598.6
12-31-2034	46.8	216,958.1	246,627.6	23.0	50,131.4	196,496.3	96,852.2	49,335.6	25,896.2	13,971.0
12-31-2035	46.8	219,376.6	249,376.9	23.0	52,294.8	197,082.0	92,515.2	44,984.2	22,585.5	11,677.2
12-31-2036	46.8	210,313.7	239,074.5	23.0	56,934.9	182,139.6	81,429.4	37,794.2	18,150.6	8,993.2
12-31-2037	46.8	201,631.6	229,205.1	23.0	62,148.3	167,056.9	71,129.8	31,513.2	14,476.1	6,873.7
12-31-2038	46.8	227,127.2	258,187.3	23.0	56,474.1	201,713.2	81,796.0	34,591.5	15,199.3	6,916.4
12-31-2039	46.8	230,159.7	261,634.6	23.0	57,403.9	204,230.6	78,873.2	31,839.3	13,381.8	5,835.6
12-31-2040	46.8	209,570.4	238,229.6	23.0	63,438.2	174,791.4	64,289.4	24,772.5	9,959.0	4,162.0
12-31-2041	46.8	235,365.9	267,552.7	23.0	57,718.4	209,834.3	73,503.3	27,035.5	10,396.2	4,163.7
12-31-2042	46.8	231,400.8	263,045.4	23.0	56,711.3	206,334.1	68,835.4	24,167.7	8,889.3	3,411.9
12-31-2043	46.8	192,252.2	218,543.1	23.0	46,495.6	172,047.5	54,663.8	18,319.8	6,445.4	2,370.8
12-31-2044	46.8	162,867.8	185,140.3	23.0	39,140.7	145,999.6	44,178.8	14,132.9	4,756.1	1,676.5
12-31-2045	46.8	151,322.3	172,015.9	23.0	36,410.0	135,606.0	39,079.7	11,933.4	3,841.4	1,297.6
12-31-2046	46.8	145,740.0	165,670.3	23.0	32,975.0	132,695.3	36,419.9	10,615.7	3,268.6	1,058.2
12-31-2047	46.8	134,199.3	152,551.4	23.0	30,554.4	121,996.9	31,889.2	8,872.6	2,613.1	810.7
12-31-2048	46.8	100,997.8	114,809.5	23.0	28,087.9	86,721.5	21,589.0	5,733.7	1,615.2	480.2
12-31-2049	46.8	37,432.7	42,551.6	23.0	11,468.6	31,083.0	7,369.5	1,868.3	503.4	143.4
12-31-2050	46.8	-8,682.4	-9,869.8	23.0	-	-9,869.8	-2,228.6	-539.3	-139.0	-38.0
12-31-2051	-	-	-	23.0	-	-	-	-	-	-
12-31-2052	-	-	-	23.0	-	-	-	-	-	-
12-31-2053	-	-	-	23.0	-	-	-	-	-	-
12-31-2054	-	-	-	23.0	-	-	-	-	-	-
12-31-2055	-	-	-	23.0	-	-	-	-	-	-
12-31-2056	-	-	-	23.0	-	-	-	-	-	-
Total		5,101,954.3	6,344,488.7		1,355,368.4	4,989,120.3	2,694,193.0	1,707,991.8	1,219,903.8	946,903.1

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

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

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
POSSIBLE RESERVES
DELEK DRILLING LIMITED PARTNERSHIP
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2019

Period Ending	Working Interest Revenue (M$)	Royalties: State (M$)	Royalties: Interested Party (M$)	Royalties: Third Party (M$)	Royalties: Total (M$)	Net Capital Costs (M$)	Net Abandonment Costs (M$)	Net Operating Expenses[(1)] (M$)	Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (M$)
12-31-2020	-	-	-	-	-	-	-	-	-
12-31-2021	-	-	-	-	-	-	-	-	-
12-31-2022	-	-	-	-	-	-	-	-	-
12-31-2023	-	-	-	-	-	-	-	-	-
12-31-2024	-	-	-	-	-	-20,053.4	-	-	20,053.4
12-31-2025	-	-	-	-	-	-4,687.8	-	-	4,687.8
12-31-2026	-	-	-	-	-	24,741.2	-	-	-24,741.2
12-31-2027	-	-	-	-	-	-	-	-	-
12-31-2028	-	-	-	-	-	-	-	-	-
12-31-2029	-	-	-	-	-	-	-	-	-
12-31-2030	-	-	-	-	-	-	-	-	-
12-31-2031	-	-	-	-	-	-	-	-	-
12-31-2032	-	-	-	-	-	-	-	-	-
12-31-2033	-	-	-	-	-	-	-	-	-
12-31-2034	-	-	-	-	-	-	-	-	-
12-31-2035	-	-	-	-	-	-	-	-	-
12-31-2036	-	-	-	-	-	-26,043.4	-	-	26,043.4
12-31-2037	-	-	-	-	-	-23,439.0	-	-	23,439.0
12-31-2038	-	-	-	-	-	49,482.4	-	-	-49,482.4
12-31-2039	-	-	-	-	-	-	-	-	-
12-31-2040	-	-	-	-	-	-49,482.4	-	-	49,482.4
12-31-2041	-	-	-	-	-	49,482.4	-	-	-49,482.4
12-31-2042	17,528.6	2,015.8	1,195.9	299.4	3,511.1	-	-	-	14,017.5
12-31-2043	129,339.2	14,874.0	8,824.1	2,209.3	25,907.4	-	-	-	103,431.8
12-31-2044	215,142.4	24,741.4	14,678.0	3,674.9	43,094.3	-	-	-	172,048.1
12-31-2045	253,364.0	29,136.9	17,285.7	4,327.8	50,750.3	-	-	-	202,613.7
12-31-2046	275,736.8	31,709.7	18,812.1	4,710.0	55,231.8	-	-	-	220,505.1
12-31-2047	307,930.1	35,412.0	21,008.4	5,259.9	61,680.3	-	-	-	246,249.8
12-31-2048	318,189.3	36,591.8	21,708.4	5,435.1	63,735.2	-	-22,087.9	-	276,541.9
12-31-2049	450,076.7	51,758.8	30,706.4	7,687.9	90,153.1	-	-22,087.9	-	382,011.5
12-31-2050	534,471.3	61,464.2	36,464.2	9,129.5	107,057.8	-	-22,087.9	-	449,501.3
12-31-2051	551,366.9	63,407.2	37,616.9	9,418.1	110,442.1	-	-	41,780.9	399,143.9
12-31-2052	464,273.7	53,391.5	31,674.9	7,930.4	92,996.8	-	-	41,780.9	329,496.0
12-31-2053	375,298.7	43,159.3	25,604.7	6,410.6	75,174.6	-	-	41,780.9	258,343.2
12-31-2054	284,414.9	32,707.7	19,404.1	4,858.2	56,970.0	-	22,087.9	41,780.9	163,576.0
12-31-2055	191,591.5	22,033.0	13,071.3	3,272.6	38,376.9	-	22,087.9	41,780.9	89,345.7
12-31-2056	103,827.3	11,940.1	7,083.6	1,773.5	20,797.2	-	22,087.9	41,780.9	19,161.2
Total	4,472,551.4	514,343.4	305,138.6	76,397.1	895,879.1	-	-	250,685.5	3,325,986.8

(1) Operating expenses are limited to direct project-level costs, insurance 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.

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

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
POSSIBLE RESERVES
DELEK DRILLING LIMITED PARTNERSHIP
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2019

Period Ending	Levy Rate (%)	Levy (M$)	Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (M$)	Corporate Income Tax Rate[1] (%)	Corporate Income Taxes[1] (M$)	Future Net Revenue After Levy and Corporate Income Taxes: Discounted at 0% (M$)	Discounted at 5% (M$)	Discounted at 10% (M$)	Discounted at 15% (M$)	Discounted at 20% (M$)
12-31-2020	3.4	-	-	23.0	-	-	-	-	-	-
12-31-2021	24.9	-	-	23.0	-	-	-	-	-	-
12-31-2022	32.4	-	-	23.0	-	-	-	-	-	-
12-31-2023	39.7	-	-	23.0	-	-	-	-	-	-
12-31-2024	45.8	9,524.3	10,529.0	23.0	-1,889.9	12,419.0	9,970.9	8,087.6	6,621.3	5,467.3
12-31-2025	46.8	2,193.9	2,493.9	23.0	257.3	2,236.6	1,710.2	1,324.1	1,036.9	820.5
12-31-2026	46.8	-11,578.9	-13,162.3	23.0	3,232.2	-16,394.5	-11,939.0	-8,823.6	-6,609.4	-5,012.1
12-31-2027	46.8	-	-	23.0	-	-	-	-	-	-
12-31-2028	46.8	-	-	23.0	-	-	-	-	-	-
12-31-2029	46.8	-	-	23.0	-	-	-	-	-	-
12-31-2030	46.8	-	-	23.0	-	-	-	-	-	-
12-31-2031	46.8	-	-	23.0	-	-	-	-	-	-
12-31-2032	46.8	-	-	23.0	-	-	-	-	-	-
12-31-2033	46.8	-	-	23.0	-	-	-	-	-	-
12-31-2034	46.8	-	-	23.0	-300.7	300.7	148.2	75.5	39.6	21.4
12-31-2035	46.8	-	-	23.0	-700.5	700.5	328.9	159.9	80.3	41.5
12-31-2036	46.8	12,188.3	13,855.1	23.0	-3,372.4	17,227.4	7,701.9	3,574.7	1,716.7	850.6
12-31-2037	46.8	10,969.5	12,469.6	23.0	-1,924.0	14,393.5	6,128.5	2,715.2	1,247.3	592.2
12-31-2038	46.8	-23,157.8	-26,324.6	23.0	6,464.4	-32,789.0	-13,296.2	-5,622.9	-2,470.7	-1,124.3
12-31-2039	46.8	-	-	23.0	-	-	-	-	-	-
12-31-2040	46.8	23,157.8	26,324.6	23.0	-5,326.3	31,650.9	11,641.4	4,485.8	1,803.4	753.7
12-31-2041	46.8	-23,157.8	-26,324.6	23.0	6,478.3	-32,802.9	-11,490.6	-4,226.4	-1,625.2	-650.9
12-31-2042	46.8	6,560.2	7,457.3	23.0	1,729.1	5,728.2	1,911.0	670.9	246.8	94.7
12-31-2043	46.8	48,406.1	55,025.7	23.0	12,669.8	42,355.9	13,457.5	4,510.1	1,586.8	583.7
12-31-2044	46.8	80,518.5	91,529.6	23.0	21,065.7	70,463.9	21,322.0	6,821.0	2,295.5	809.1
12-31-2045	46.8	94,823.2	107,790.5	23.0	24,805.7	82,984.7	23,915.0	7,302.7	2,350.7	794.1
12-31-2046	46.8	103,196.4	117,308.7	23.0	29,241.4	88,067.3	24,171.2	7,045.4	2,169.3	702.3
12-31-2047	46.8	115,244.9	131,004.9	23.0	31,794.7	99,210.2	25,932.9	7,215.4	2,125.0	659.3
12-31-2048	46.8	129,421.6	147,120.3	23.0	29,883.9	117,236.4	29,185.5	7,751.2	2,183.6	649.2
12-31-2049	46.8	178,781.4	203,230.1	23.0	43,923.1	159,307.1	37,770.3	9,575.3	2,580.2	735.2
12-31-2050	46.8	210,366.6	239,134.7	23.0	51,592.8	187,541.9	42,347.2	10,247.6	2,641.3	721.2
12-31-2051	46.8	186,799.3	212,344.5	23.0	47,701.2	164,643.4	35,406.4	8,178.5	2,016.3	527.6
12-31-2052	46.8	154,204.1	175,291.9	23.0	38,070.7	137,221.2	28,104.0	6,196.7	1,461.3	366.5
12-31-2053	46.8	120,904.6	137,438.6	23.0	29,364.4	108,074.1	21,080.5	4,436.8	1,000.8	240.5
12-31-2054	46.8	76,553.6	87,022.5	23.0	22,848.9	64,173.5	11,921.3	2,395.0	516.7	119.0
12-31-2055	46.8	41,813.8	47,531.9	23.0	13,766.1	33,765.8	5,973.9	1,145.6	236.4	52.2
12-31-2056	46.8	8,967.5	10,193.8	23.0	5,178.3	5,015.4	845.1	154.7	30.5	6.5
Total		1,556,701.2	1,769,285.6		406,554.4	1,362,731.2	324,248.1	85,396.7	25,281.5	8,821.0

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

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

REVENUE, COSTS, AND TAXES
PROVED + PROBABLE + POSSIBLE (3P) RESERVES
DELEK DRILLING LIMITED PARTNERSHIP
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2019

Period Ending	Working Interest Revenue (M$)	Royalties State (M$)	Royalties Interested Party (M$)	Royalties Third Party (M$)	Royalties Total (M$)	Net Capital Costs (M$)	Net Abandonment Costs (M$)	Net Operating Expenses[1] (M$)	Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (M$)
12-31-2020	444,838.6	51,156.4	30,349.0	7,598.4	89,103.9	28,730.4	-	43,198.8	283,805.6
12-31-2021	405,424.7	46,623.8	27,660.0	6,925.2	81,209.0	26,352.1	-	42,589.3	255,274.2
12-31-2022	456,609.3	52,510.1	31,152.0	7,799.5	91,461.6	-147.1	-	41,780.9	323,513.9
12-31-2023	499,909.8	57,489.6	34,106.2	8,539.1	100,135.0	-	-	41,780.9	357,994.0
12-31-2024	509,967.6	58,646.3	34,792.4	8,710.9	102,149.6	-	-	41,780.9	366,037.1
12-31-2025	519,320.7	59,721.9	35,430.5	8,870.7	104,023.1	67,973.2	-	41,780.9	305,543.6
12-31-2026	525,007.0	60,375.8	35,818.5	8,967.8	105,162.1	97,402.1	-	41,780.9	280,661.8
12-31-2027	583,879.0	67,146.1	39,835.0	9,973.4	116,954.5	-	-	41,780.9	425,143.6
12-31-2028	589,687.4	67,814.1	40,231.3	10,072.6	118,118.0	-	-	41,780.9	429,788.5
12-31-2029	594,720.7	68,392.9	40,574.7	10,158.6	119,126.2	-	-	41,780.9	433,813.6
12-31-2030	601,804.2	69,207.5	41,057.9	10,279.6	120,545.0	-	-	41,780.9	439,478.2
12-31-2031	607,996.4	69,919.6	41,480.4	10,385.4	121,785.4	-	-	41,780.9	444,430.1
12-31-2032	616,148.3	70,857.1	42,036.6	10,524.6	123,418.2	-	-	41,780.9	450,949.2
12-31-2033	624,502.3	71,817.8	42,606.5	10,667.3	125,091.6	-	-	41,780.9	457,629.8
12-31-2034	631,950.1	72,674.3	43,114.6	10,794.5	126,583.4	-	-	41,780.9	463,585.8
12-31-2035	638,412.2	73,417.4	43,555.5	10,904.9	127,877.8	-	-	41,780.9	468,753.5
12-31-2036	646,763.0	74,377.8	44,125.2	11,047.6	129,550.6	-	-	41,780.9	475,431.6
12-31-2037	652,874.8	75,080.6	44,542.2	11,152.0	130,774.8	26,043.4	-	41,780.9	454,275.7
12-31-2038	659,121.5	75,799.0	44,968.4	11,258.7	132,026.0	49,482.4	-	41,780.9	435,832.2
12-31-2039	667,224.3	76,730.8	45,521.2	11,397.1	133,649.1	-	-	41,780.9	491,794.3
12-31-2040	674,087.0	77,520.0	45,989.4	11,514.3	135,023.7	-	-	41,780.9	497,282.4
12-31-2041	681,135.0	78,330.5	46,470.3	11,634.7	136,435.5	49,482.4	-	41,780.9	453,436.3
12-31-2042	688,069.1	79,127.9	46,943.3	11,753.1	137,824.4	-	-	41,780.9	508,463.8
12-31-2043	695,276.0	79,956.7	47,435.0	11,876.2	139,268.0	-	-	41,780.9	514,227.1
12-31-2044	702,565.1	80,795.0	47,932.3	12,000.7	140,728.0	-	-	41,780.9	520,056.2
12-31-2045	709,937.6	81,642.8	48,435.3	12,126.7	142,204.8	-	-	41,780.9	525,951.9
12-31-2046	717,394.8	82,500.4	48,944.1	12,254.1	143,698.5	-	-	41,780.9	531,915.4
12-31-2047	718,751.8	82,656.5	49,036.6	12,277.2	143,970.3	-	-	41,780.9	533,000.5
12-31-2048	667,918.1	76,810.6	45,568.5	11,408.9	133,788.0	-	-	41,780.9	492,349.2
12-31-2049	629,961.9	72,445.6	42,979.0	10,760.6	126,185.2	-	-	41,780.9	461,995.8
12-31-2050	591,138.7	67,981.0	40,330.3	10,097.4	118,408.7	-	-	41,780.9	430,949.1
12-31-2051	551,366.9	63,407.2	37,616.9	9,418.1	110,442.1	-	-	41,780.9	399,143.9
12-31-2052	464,273.7	53,391.5	31,674.9	7,930.4	92,996.8	-	-	41,780.9	329,496.0
12-31-2053	375,298.7	43,159.3	25,604.7	6,410.6	75,174.6	-	-	41,780.9	258,343.2
12-31-2054	284,414.9	32,707.7	19,404.1	4,858.2	56,970.0	-	22,087.9	41,780.9	163,576.0
12-31-2055	191,591.5	22,033.0	13,071.3	3,272.6	38,376.9	-	22,087.9	41,780.9	89,345.7
12-31-2056	103,827.3	11,940.1	7,083.6	1,773.5	20,797.2	-	22,087.9	41,780.9	19,161.2
Total	20,923,170.3	2,406,164.6	1,427,477.6	357,395.4	4,191,037.7	345,318.8	66,263.7	1,548,120.4	14,772,429.8

[1] Operating expenses are limited to direct project-level costs, insurance 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.

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

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROVED + PROBABLE + POSSIBLE (3P) RESERVES
DELEK DRILLING LIMITED PARTNERSHIP
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2019

						Future Net Revenue After Levy and Corporate Income Taxes				
Period Ending	Levy Rate (%)	Levy (M$)	Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (M$)	Corporate Income Tax Rate[1] (%)	Corporate Income Taxes[1] (M$)	Discounted at 0% (M$)	Discounted at 5% (M$)	Discounted at 10% (M$)	Discounted at 15% (M$)	Discounted at 20% (M$)
12-31-2020	3.4	9,668.9	274,136.7	23.0	58,701.5	215,435.1	210,243.1	205,409.3	200,894.3	196,664.4
12-31-2021	24.9	63,445.6	191,828.7	23.0	38,843.2	152,985.5	142,189.1	132,605.4	124,051.9	116,380.0
12-31-2022	32.4	104,707.8	218,806.1	23.0	38,179.4	180,626.7	159,885.3	142,331.2	127,361.2	114,506.1
12-31-2023	39.7	142,213.0	215,781.0	23.0	38,492.7	177,288.2	149,457.4	127,000.5	108,702.0	93,658.1
12-31-2024	45.8	167,663.5	198,373.6	23.0	36,444.0	161,929.6	130,009.3	105,453.0	86,334.8	71,287.0
12-31-2025	46.8	142,994.4	162,549.2	23.0	43,539.6	119,009.6	90,999.9	70,456.7	55,175.2	43,660.1
12-31-2026	46.8	131,349.7	149,312.1	23.0	46,886.3	102,425.8	74,589.7	55,126.0	41,292.7	31,313.5
12-31-2027	46.8	198,967.2	226,176.4	23.0	40,331.1	185,845.3	128,893.7	90,929.8	65,150.5	47,347.0
12-31-2028	46.8	201,141.0	228,647.5	23.0	43,828.9	184,818.6	122,077.8	82,206.8	56,339.6	39,237.8
12-31-2029	46.8	203,024.8	230,788.8	23.0	44,442.0	186,346.8	117,225.9	75,351.4	49,396.1	32,968.6
12-31-2030	46.8	205,675.8	233,802.4	23.0	45,402.9	188,399.5	112,873.5	69,255.9	43,426.3	27,776.4
12-31-2031	46.8	207,993.3	236,436.8	23.0	46,484.0	189,952.9	108,384.9	63,479.0	38,073.3	23,337.9
12-31-2032	46.8	211,044.2	239,905.0	23.0	48,090.2	191,814.8	104,235.5	58,273.8	33,431.7	19,638.9
12-31-2033	46.8	214,170.7	243,459.1	23.0	48,914.4	194,544.7	100,684.8	53,730.2	29,484.8	16,598.6
12-31-2034	46.8	216,958.1	246,627.6	23.0	49,830.7	196,796.9	97,000.4	49,411.1	25,935.8	13,992.3
12-31-2035	46.8	219,376.6	249,376.9	23.0	51,594.3	197,782.6	92,844.0	45,144.1	22,665.8	11,718.7
12-31-2036	46.8	222,502.0	252,929.6	23.0	53,562.5	199,367.0	89,131.2	41,368.9	19,867.3	9,843.8
12-31-2037	46.8	212,601.0	241,674.7	23.0	60,224.3	181,450.4	77,258.3	34,228.3	15,723.4	7,466.0
12-31-2038	46.8	203,969.5	231,862.7	23.0	62,938.5	168,924.2	68,499.9	28,968.6	12,728.6	5,792.1
12-31-2039	46.8	230,159.7	261,634.6	23.0	57,403.9	204,230.6	78,873.2	31,839.3	13,381.8	5,835.6
12-31-2040	46.8	232,728.2	264,554.2	23.0	58,111.9	206,442.3	75,930.8	29,258.3	11,762.3	4,915.7
12-31-2041	46.8	212,208.2	241,228.1	23.0	64,196.7	177,031.4	62,012.7	22,809.1	8,771.0	3,512.8
12-31-2042	46.8	237,961.0	270,502.7	23.0	58,440.5	212,062.3	70,746.4	24,838.7	9,136.1	3,506.6
12-31-2043	46.8	240,658.3	273,568.8	23.0	59,165.4	214,403.4	68,121.3	22,829.9	8,032.2	2,954.4
12-31-2044	46.8	243,386.3	276,669.9	23.0	60,206.4	216,463.4	65,500.8	20,953.8	7,051.6	2,485.7
12-31-2045	46.8	246,145.5	279,806.4	23.0	61,215.7	218,590.7	62,994.8	19,236.2	6,192.1	2,091.8
12-31-2046	46.8	248,936.4	282,979.0	23.0	62,216.4	220,762.6	60,591.1	17,661.2	5,437.9	1,760.4
12-31-2047	46.8	249,444.2	283,556.3	23.0	62,349.1	221,207.1	57,822.0	16,087.9	4,738.1	1,470.0
12-31-2048	46.8	230,419.4	261,929.8	23.0	57,971.8	203,957.9	50,774.5	13,484.9	3,798.8	1,129.5
12-31-2049	46.8	216,214.0	245,781.8	23.0	55,391.7	190,390.1	45,139.8	11,443.5	3,083.6	878.6
12-31-2050	46.8	201,684.2	229,264.9	23.0	51,592.8	177,672.1	40,118.6	9,708.3	2,502.3	683.3
12-31-2051	46.8	186,799.3	212,344.5	23.0	47,701.2	164,643.4	35,406.4	8,178.5	2,016.3	527.6
12-31-2052	46.8	154,204.1	175,291.9	23.0	38,070.7	137,221.2	28,104.0	6,196.7	1,461.3	366.5
12-31-2053	46.8	120,904.6	137,438.6	23.0	29,364.4	108,074.1	21,080.5	4,436.8	1,000.8	240.5
12-31-2054	46.8	76,553.6	87,022.5	23.0	22,848.9	64,173.5	11,921.3	2,395.0	516.7	119.0
12-31-2055	46.8	41,813.8	47,531.9	23.0	13,766.1	33,765.8	5,973.9	1,145.6	236.4	52.2
12-31-2056	46.8	8,967.5	10,193.8	23.0	5,178.3	5,015.4	845.1	154.7	30.5	6.5
Total		6,658,655.5	8,113,774.3		1,761,922.7	6,351,851.6	3,018,441.1	1,793,388.5	1,245,185.3	955,724.1

[1] 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
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2019

Year	Delek Drilling Working Interest Production (BCF)	Average Per Production Unit ($/MCF)				Reserves Depletion Rate[1] (%)
		Price Received	Royalties Paid	Production Costs	Net Revenue	
2019[2]	81.63	5.52	1.10	0.45	3.97	3.3
2018[3]	93.36	5.53	1.08	0.39	4.07	3.3
2017[3]	98.40	5.36	0.85	0.37	4.14	3.4

Note: Values in this table have been provided by Delek Drilling; these values are based on historical production data since January 2017 and include condensate revenue and costs.

[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 2019 data is representative of unaudited financial data.
[3] The 2017 and 2018 data include the Delek Drilling indirect interest in Tamar Field through Tamar Petroleum Ltd.

VOLUMETRIC INPUT SUMMARY
TAMAR FIELD, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2019

	Gross Rock Volume (acre-feet)			Area (acres)			Average Gross Thickness[1] (feet)			Net-to-Gross Ratio (decimal)		
Reservoir	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
A Sand	2,309,629	2,594,825	2,845,871	20,275	21,711	22,935	114	120	124	0.88	0.93	0.93
B Sand	1,576,608	1,693,767	1,782,698	14,263	15,027	15,158	111	113	118	0.72	0.85	0.85
C Sand	1,839,279	1,964,971	2,063,220	9,095	9,095	9,095	202	216	227	0.87	0.90	0.90

	Porosity[2] (decimal)			Gas Saturation (decimal)			Gas Formation Volume Factor (SCF/RCF)[3]			Gas Recovery Factor (decimal)		
Reservoir	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
A Sand	0.26	0.26	0.25	0.75	0.78	0.83	372	372	372	0.62	0.67	0.72
B Sand	0.25	0.24	0.24	0.76	0.79	0.82	372	372	372	0.62	0.67	0.72
C Sand	0.25	0.24	0.24	0.78	0.81	0.83	372	372	372	0.62	0.67	0.72

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 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.
(3) The abbreviation SCF/RCF represents standard cubic feet per reservoir cubic feet.

VOLUMETRIC INPUT SUMMARY
TAMAR SOUTHWEST FIELD, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2019

	Gross Rock Volume (acre-feet)			Area (acres)			Average Gross Thickness[1] (feet)			Net-to-Gross Ratio (decimal)		
Reservoir	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
A Sand	300,301	318,108	318,108	2,517	2,517	2,517	119	126	126	0.99	1.00	1.00
B Sand	128,228	137,183	137,183	1,065	1,065	1,065	120	129	129	0.82	0.87	0.88

	Porosity (decimal)			Gas Saturation (decimal)			Gas Formation Volume Factor (SCF/RCF)[2]			Gas Recovery Factor (decimal)		
Reservoir	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
A Sand	0.24	0.24	0.24	0.84	0.87	0.89	372	372	372	0.62	0.67	0.72
B Sand	0.22	0.22	0.22	0.78	0.81	0.85	372	372	372	0.62	0.67	0.72

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 and cost information, and property ownership interests.

(1) Average gross thickness is calculated by dividing the gross rock volume by the area.
(2) The abbreviation SCF/RCF represents standard cubic feet per reservoir cubic feet.