Revised Report on Reserves, Contingent Resources and Discounted Cash Flows in the Tamar Leases

Tel Aviv, July 22, 2020. Delek Group (TASE: DLEKG, US ADR: DGRLY) ("the Company") is pleased to announce that, further to the provisions of section 1.7.4(J) of the Company's Periodic Report as at December 31, 2019, published on May 3, 2020 (Ref. No.: 2020-01-043356) (the "Periodic Report") concerning the evaluation of reserves in the Tamar and Tamar South-West reservoirs ("Tamar SW"). that are located in the area of I/12 Tamar lease, ("Tamar Reservoir" or "the Project" and "Tamar Lease", respectively), and section 2A of Part Three of the revised Chapter A (Description of the Corporation's Business) in the first quarter 2020 report as published on June 30, 2020 (Ref. No.: 2020-01-061492) ("Q1 Report"), concerning the effects of the Covid-19 Pandemic on the operations of Delek Drilling – Limited Partnership (the "Partnership") and its projections, and in view of the Company's intention to issue an IPO and/or execute actions with the Company's securities, the Company hereby issues this revised reserves and cash flow data report, as at June 30, 2020, with respect to the Company's share in the Tamar Lease[1].

Further to that provided in section 1.7.23(C) of the Periodic Report concerning exploring of various options for refinancing the loans provided to the Partnership, among others, for financing the Leviathan Project, and further to the update on this matter described in section A.15A of Part Three of the revised Chapter A in the Q1 Report, it is noted that as at the date of this report, the Partnership carried out refinancing and as part thereof the Partnership is exploring options for an offering of non-negotiable debentures to foreign and Israeli classified investors, that can be executed by a wholly controlled subsidiary of the Partnership.

1. Tamar Project Reserves[2] - Quantitative Data:

According to a reserves report the Partnership received from Netherland, Sewell and Associates, Inc. ("NSAI" or the "Reserves Valuator"), which was prepared in accordance with the principles of the Petroleum Resources Management System (SPE-PRMS), as at June 30, 2020 ("the Reserves Report"), the natural gas and condensate reserves in the Tamar Project (which include, as aforesaid, the Tamar and Tamar SW Reservoirs), as set out below[3]:

[1] For a glossary of the professional terminology included in this report, see the Professional Terminology Appendix on page A-279 to the Periodic Report.

[2] For further information about the estimated resources in the Tamar Project carried out by the Ministry of Energy through external consultants, see section 1.7.26(A)(4)B above.

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

Reserve category	Total (100%) in the oil asset (gross)						Total (Tamar and Tamar SW reservoirs) share attributable to equity holders of the Company (net)[4]	
	Tamar Reservoir		Tamar SW reservoir[5]		Total (Tamar and Tamar SW reservoir)			
	Natural gas BCF	Condensate (million barrels)	Natural gas BCF	Condensate (million barrels)	Natural gas BCF	Condensate Million barrels	of natural gas BCF	of condensate Million barrels
Proved Reserves (P1)	7,100.6	9.2	796.4	1.0	7,897.0	10.3	870.8	1.1
Probable reserves	2,595.9	3.4	159.1	0.2	2,755.0	3.6	303.8	0.4
Proved+Probable Reserves (P2)	9,696.5	12.6	955.6	1.2	10,652.0	13.8	1,174.6	1.5
Possible reserves	2,366.0	3.1	102.2	0.1	2,468.3	3.2	272.2	0.4
Proved + Probable + Possible Reserves (P3)	12,062.5	15.7	1,057.8	1.4	13,120.3	17.1	1,446.8	1.9

Forward-looking information: Possible reserves are the additional reserves that are not expected to be produced to the same extent as probable reserves. There is a 10% chance that actual quantities produced will be equivalent to or higher than the proved reserves, with the addition of the quantity of the probable and possible reserves.

4 The Company's share in the above table includes its direct and indirect holdings of 54.7% of the equity of the participating units. The figures regarding the Company's share also include the rights in the Tamar Project attributable to the Partnership indirectly through its holdings of shares of Tamar Petroleum Ltd. ("Tamar Petroleum"), which amount to 25.7855%. The Partnership's share (gross), instead of the Company's share (net) is included in the reserves report. The Company's net share in the above table is after payment of royalties, the rate attributed to equity holders of the Company was calculated according to the rates set out in section 1.7.5(E) of the Periodic Report. For information about the RIO date in the Tamar Project, see section 1.7.30(J)(4) of the Periodic Report and section A-20(e) in Part Three of the update of Chapter A (Description of the Company's Business) in the Q1 Report.

5 The reserves in the table attributed to the Tamar SW reservoir exclude resources in the 353/Eran License area. For further information, see section 1.7.31(H)(1) of the Periodic Report.

2. The NSAI reserves report noted a number of assumptions and reservations, including: (a) The estimate in the report, as is standard in estimating reserves based on the guidelines set out in the Petroleum Resources Management System approved by the Society of Petroleum Engineers (SPE-PRMS), are not adjusted to reflect the risks, such as technical and commercial risks and development risks; (b) NSAI did not visit the oil field or check the mechanical operation of the wells or their state; (c) NSAI did not examine the possible exposure arising from environmental matters. However, according to NSAI, as at the date of the reserves report, it is unaware of any possible environmental liability that could have a material effect on the amount of estimated reserves in the reserves report, or on whether they are commercial; (d) NSAI assumed that the reservoirs are developed in accordance with the development plan and are operated reasonably, that no regulation will be set that will affect the ability of the holder of the oil rights to produce the reserves, and that and forecasts for future production will be similar to actual performance of the reservoirs.

Forward-looking information: The estimates of NSAI in respect of the quantities of natural gas reserves and condensate in the Tamar and Tamar SW reservoirs are forward-looking information as defined in the Israel Securities Law, 1968 ("the Securities Law"). These estimates are partially based on geological, geophysical, engineering and other information received, among others, from Noble Energy Mediterranean, the Tamar Project operator ("the Operator") and are only estimates and assumptions of NSAI, regarding which there is no certainty. Actual quantities of natural gas and/or condensate consumed may be different from these estimates and assumptions, partly due to technical and operational conditions and/or regulatory changes and/or the supply and demand conditions in the natural gas and/or condensate market and/or commercial conditions and/or geopolitical changes and/or from actual performance of the Reservoirs. The estimates and assumptions may be updated if additional information becomes available and/or as the result of a range of factors related to oil and natural gas projects, including due to actual production data from the Tamar Project.

3. Discounted cash flow

The discounted cash flow figures are based on various estimates and assumptions that the Partnership provided to NSAI, the main ones of which are:

(A) Forecasted sales volumes: The cash flow assumptions concerning the natural gas that the Partnership will sell from the Tamar Project are based on: (i) Production capacity of the Tamar Project[6]. It should also be noted that the actual production rate for each of the reserves cash flow categories may be lower or higher than the production rate assumed for the cash flow. Furthermore, NSAI did not conduct a sensitivity analysis with respect to the production rate of the wells; (ii) the Partnership's assumptions regarding the volumes of natural gas to be sold to the Partnership's customers under the existing agreements that the Partnership engaged in, including the agreement for the export of natural gas to Egypt signed with the company Dolphinus Holdings Limited (see sections 1.7.14(H)(2) of the Periodic Report) ("Export Agreement to Egypt" and "Dolphinus", respectively)[7], and the agreement for the supply of natural gas to IEC[8] (jointly: "the Existing Agreements"); (iii) additional quantities of natural gas that the Partnership believes will be sold on the local market in Israel, based partially on negotiations for the sale of natural gas from the Tamar Project, the demand forecast for natural gas on the local Israeli market prepared for the Partnership by external consultants (BDO Consulting Group) ("BDO"), and taking into account the expected supply from other sources, mainly the Leviathan Project and the Karish and Tanin reservoirs[9]; (iv) further quantities of natural cash that the Partnership estimates will be sold on regional markets, based partially on the demand forecast in these markets prepared by external consulting firms. It was assumed that the total aggregate volume of 42 to the local markets in Egypt and Jordan would be 42 BCM until 2040[10], based partially on the Partnership's export forecasts to Egypt and Jordan, as set out in section 1.7.14(E) of the Periodic Report.

(B) Natural gas and condensate selling prices: The cash flow assumptions regarding natural gas prices to be sold from the Tamar Project are based, inter alia, on a weighted average of gas prices in existing agreements, based on the price formula set in them, and in accordance with the Partnership's assumptions regarding the prices that will be set in future agreements, based on, among other things, the projected distribution of demand in the local market during the cash flow years as assessed by external consultants, and based on the provisions set out in the Gas Outline Plan regarding the selling prices of natural gas.

The price formula set in existing agreements, which may change over the years, include, among other things, partial or full linkage to the electricity generation tariff, the NIS-USD exchange rate[11], the US CPI and Brent price per barrel (the "Brent Price").

It is noted that there may a change in prices partially due to a price adjustment according to the mechanism set out in the agreement with IEC[12] and the export agreement to Egypt[13].

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6 The current daily gas supply capacity from the Tamar project to the INGL transmission system is 1.1 BCF.

7 It is noted that in June 2020 Dolphinus assigned the Egypt Export Agreement to an affiliate, Blue Ocean Energy. It is further noted that further to section A-12 in Part Three of the update of Chapter A to the Q1 Report, in July 2020 gas supply commenced from the Tamar Project under the export agreement to Egypt.

8 For further information concerning this agreement, see section 1.7.14(D)(1)d of the Periodic Report. For further information about the legal proceeding regarding the competitive process of the IEC that was won by Leviathan partners, see Note 24A2(5) to the Periodic Report and Note 6B to the financial statements as at March 31, 2020. For further information see the immediate report issued by the Company on May 31, 2020 (Ref. No: 2020-01-054747) regarding an update on a joint marketing arrangement at the Tamar reservoir that was filed with the regulators.

9 For information about the natural gas sales forecast from the Leviathan Project, see the immediate report issued by the Company on July 12, 2020 (Ref. No.: 2020-01-073839). The working assumption is that the sale of natural gas to the local market in Israel and commercial production from the Karish and Tanin project will begin in the last quarter of 2021.

10 It was assumed that the projected amount of sales to the local markets in Egypt and Jordan is higher than the contractual quantity set out in the existing export agreements.

11 The USD exchange rate used is NIS 3.55 per USD in 2020, gradually rising to NIS 3.90 per USD from 2024 onwards, and is based on the exchange rates quoted in the foregoing BDO forecast.

The cash flows assume a price reduction of 25% in the agreement with the IEC on the first adjustment date (i.e. July 1, 2021), and of 10% on the second adjustment date (i.e. July 1, 2024). The price reduction was included in the forecast for the electricity production tariff. It should also be noted that no change in price has been taken into account as a result of the motion for certification of a class action filed by a consumer of the IEC against the Tamar project partners, as set out in Note 24A2(2) to the financial statements as at December 31, 2019 and Note 6C to the financial statements as at March 31, 2020. In the opinion of the legal counsel of the Partnership, it is more likely than not that the motion for certification will be dismissed. At this stage, the parties are at the hearing stage of the motion for certification of a class action. If a final and absolute ruling is handed down regarding certification of the class action (namely, after the motion for certification as a class action is accepted (if it is accepted) and an absolute ruling on the class action itself is received (if it is received)) against the Tamar Partners, this may have a material adverse effect on the Partnership's business, including on information about the discounted cash flow and on the prices at which the Partnership and the Company, together with the other Tamar Partners, will sell natural gas to its customers, the scope of which will be derived from the results of the claim.

With regard to the price formulas linked to the power generation tariff, it is noted that the electricity generation tariff is controlled by the Electricity Authority and reflects the costs of IEC's power generation segment, and includes the IEC cost of fuels, capital and operating costs attributed to the power generation segment, and the cost of purchasing electricity from independent power producers. The cash flow assumptions with regard to changes in the power generation rate over the flow years are based on a forecast prepared for the Partnership by an external consultant.

The cash flow assumptions regarding the Brent price are based on long-term third party forecasts as follows: the US Department of Energy, the World Bank, IHS Global Insights and Wood Mackenzie. Accordingly, the price assumed for the cash flow was USD 37 per barrel of Brent in 2020, USD 47 per barrel in 2021, increasing to USD 71 per barrel in 2025, and a fixed price per barrel of USD 88 from 2029 through to the end of the cash flow period.[14].

An annual increase in the US CPI of an average of 2% per year was assumed.

It should be noted that change may be caused to the selling prices, due, among other things, to regulatory intervention, price adjustment mechanisms (as set out in the IEC agreement and the Agreement for Export to Egypt, and as set out above) or changes in the underlying linkage indices in the price formula, as set out above.

Cash flow assumptions for condensate selling prices are based on prices the Brent Crude index and adapted to differences in quality, transportation costs and the selling price of condensate in the region. For further information concerning condensate supply agreement from the Tamar Project, see section 1.7.14(F)(1) of the Periodic Report.

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12 The agreement with the IEC specifies two dates on which each party may request a price adjustment (according to the mechanism set out in the agreement). For further information, see section 1.7.14(D)(1) of the Periodic Report.

13 The agreement for export to Egypt includes a mechanism for an update of the price at a rate of up to 10% (addition or reduction) after the fifth year and after the tenth year of the agreement given certain conditions set out in the agreement. It should be noted that a price update on these dates was not assumed. The price set in the Agreement for Export to Egypt was adjusted to the point of delivery, as set out in the Agreement for Export to Egypt.

14 It should be noted that, according to the terms of the agreement for export to Egypt, and given the assumed Brent price lower than USD 50 in 2020 and 2021, it was assumed that the contractual volumes sold under the agreement for export to Egypt would drop to the minimum committed volume under the agreement, which, among other things, would allow Dolphinus to reduce the take or pay (TOP) volume in a year during which the average daily Brent price of (as defined in the agreement) drops to below USD 50 per barrel, so that it will be at 50% of the annual contracted volume. However, the quantities actually sold to Dolphinus might be greater.

(C) The operating costs taken into account in the cash flows include direct costs of the project, insurance costs, maintenance costs for production wells, and estimated overheads and general and administrative expenses of the operator that can be directly attributed to the project and that together constitute the operating costs of the project. These costs are divided into expenses per project and expenses per production unit. The operating costs in the cash flows are not adjusted for changes in inflation. NSAI confirmed that the operating costs provided by the Partnership are reasonable, based, inter alia, on NSAI's knowledge from similar projects.

(D) The capital expenditures taken into account in cash flows are expenses approved by the Partnership as well as estimated future capital expenditure not yet approved by the Partnership, that were expended during production for the purpose of retention and expansion of the production capacity, and include, among others, engineering work expenses, participation in natural gas infrastructure establishment costs[15] and usage fees, Tamar participation fees, as this term is defined in section 1.7.30(F)(3) of the Periodic Report, and indirect costs paid to the Operator. The capital costs in the cash flows are not adjusted for changes in inflation. NSAI confirmed that the capital costs provided by the Partnership are reasonable, based, inter alia, on NSAI's knowledge from similar projects.

(E) The abandonment costs taken into account in the cash flows are those given to NSAI by the Partnership based on its estimates regarding to abandonment costs of the wells, platform and production facilities. These costs do not take into account the salvage value of the Tamar Project facilities and are not adjusted for changes in inflation.

(F) The discounted cash flow calculation takes into account the Partnership's estimate that the effective rate of state royalties is 11.5% and the effective rate of royalties to be paid to related and third parties is 9.13%., (with respect to the Partnership's direct holdings in the Tamar Project). The actual rate of royalties to the State is not final and it may change. For further information, see sections 1.7.30(J)(5) to the Periodic Report and section A.18 to Part Three of the Q1 Report.

(G) The tax payments and rates included in the discounted cash flows were calculated from the perspective of a company that holds the Partnership's participating units since commencement of the project. The tax calculations include corporate tax rates by law. It should be noted that future tax payments that will actually be paid by the Partnership on account of the tax payable by the holders of the Partnership's participating units in each of the relevant tax years, based on the provisions of the Taxation of Profits from Natural Resources Law, 2011 ("the Law"), may be significantly different. Expenses of depreciation for tax purposes were calculated in accordance with the depreciation rates set by law.

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[15] In order to increase the possible supply capacity through the EGM pipeline, the supply capacity in the INGL system as well as the EG systems in Israel and Egypt must be expanded. For information, see section 1.7.15(B)(2)b of the Periodic Report.

(H) The discounted cash flow calculation took into account the oil profits tax applicable to the Company under the provisions of the Law. It should be emphasized that calculation of the tax was based, among other things, on the definitions, formula and mechanisms set out in the Law, to the best understanding and interpretation of the Partnership, and which were reflected in the reports of the Tamar Project to the Tax Authority. However, since the law is new and the calculation formulas and mechanisms set out in the law are complex, it is not certain whether this interpretation of the calculation method for the levy will be the same as that adopted by the tax authorities and/or the same as the interpretations of the law by the court. It should be noted that as at the date of publication of this report, a number of interpretative disputes regarding the implementation of the law in the tax reports of the Tamar Project are being discussed, as part of the objection and appeal proceedings set out in the law. The issues underlying the disputes have not yet been brought before the courts in Israel. The levy was calculated according to the transitional provisions in the law for a project that started commercial production before the Law came into effect, and through to January 1, 2014. In addition, the calculation was in USD, in accordance with the selection of the developer under section 13(B) of the Law, using the following assumptions: All the project payments (production costs, investments, royalties, etc.) will be recognized by the tax authorities for the purpose of calculating the levy; for the purpose of calculating the revenues of the project, the actual sale prices of the gas will be taken into account.

(I) The discounted cash flow calculation takes into account expenses and investments that were actually paid and that are expected to be paid by the Partnership as of July 1, 2020, as well as income from the sale of natural gas and condensate generated and expected to be generated as of July 1, 2020.

(J) Revenue from natural gas and condensate sales made in any given year were taken into account in that year.

It should be noted that the discounted cash flows as at December 31, 2019 were adjusted for the following main reasons:

1. We updated the operating costs and investments made until June 30, 2020 according to actual investments made. We also updated the forecasts of future operating costs and investments according to the Partnership's estimation, inter alia, based on updated estimates received from the Operator. For further information, see section A.3 to Part Three of the update of Chapter A in the Q1 Report.

2. The forecast of the price reduction rate on the second adjustment date in the agreement with IEC was updated.

3. The assumptions concerning the power generation tariff, Brent price, US CPI and other forecasts that were affected, among other things, by the Covid-19 Pandemic, including setting of the Brent price and power generation tariff, from the tenth year for the cash flow period, and accordingly, the forecasts of the relevant selling prices linked to them were revised. The Partnership's assumptions concerning the selling prices in future agreements were also revised.

4. The contractual volumes to be sold in 2020 and 2021 in accordance with the Egypt Export Agreement were reduced to the minimum committed volume under the agreement (see footnote 14 above).

5. We updated the forecasts of the sales quantities of natural gas from the Tamar Project, inter alia, due to an update of the estimates of the Partnership, the Company and BDO regarding the impact of the Covid-19 crisis on the demand for natural gas on the local market, the sales quantities of LNG by IEC (for information, see section 10.A to Part Three of the update of Chapter A in the Q1 Report, an update of the Partnership's assumptions regarding the start of commercial production from the Karish and Tanin project and the sales quantities from this project, and an update of the Partnership's assumptions regarding the forecasted sales quantities from the Leviathan reservoir to the local market. This, together with the developments in the local and regional markets, resulted in an update of projected annual sales from the Tamar Project.
6. We updated the volumes of natural gas and condensate supplied and sold during the first half of 2020 according to actual figures.

Based on assumptions, which are described above, following is the estimated discounted cash flow as at June 30, 2020, in thousands of USD (after the levy and income tax) attributable to the Company's share (direct and indirect, including through the Partnership's holdings in Tamar Petroleum) in the Tamar Project reserves, for each of the reserve categories described above[16]:

[16] Additional discounting at 7.5% was made by the Company for the purpose of the calculation and as an auxiliary investor tool.

Discounted cash flows from proved reserves as at June 30, 2020 (in USD thousands, with regard to the Company's share)																	
Cash Flow Items																	
Through to	Volume of condensate sales (K barrels) (100% of oil asset)	Sales quantity (BCM) (100% of oil asset)	Total revenue	Royalties payable	Royalties received	Operating costs	Development costs	Abandonment 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%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Dec 31, 2020	204	4.44	113,981	22,831	-	7,731	3,913	-	79,506	-	15,993	63,513	62,743	62,375	62,018	61,332	60,683
Dec 31, 2021	378	8.24	202,586	40,579	-	20,125	10,561	-	131,321	30,722	19,130	81,468	77,589	75,785	74,062	70,842	67,890
Dec 31, 2022	418	9.10	217,112	43,489	-	20,467	15,218	-	137,938	41,131	19,138	77,669	70,448	67,210	64,189	58,729	53,937
Dec 31, 2023	450	9.80	237,100	47,493	-	20,553	43,722	-	125,333	43,796	22,659	58,878	50,861	47,394	44,236	38,713	34,073
Dec 31, 2024	477	10.40	256,313	51,341	-	20,635	13,415	-	170,923	69,313	19,252	82,358	67,756	61,670	56,252	47,088	39,717
Dec 31, 2025	489	10.65	263,600	52,801	-	20,666	-	-	190,134	87,522	16,323	86,288	67,609	60,105	53,578	42,901	34,677
Dec 31, 2026	489	10.65	267,471	53,576	-	20,682	-	-	193,213	90,424	16,668	86,121	64,265	55,803	48,613	37,233	28,842
Dec 31, 2027	512	11.15	284,844	57,056	-	20,757	13,734	-	193,298	90,463	21,049	81,785	58,123	49,297	41,969	30,746	22,825
Dec 31, 2028	535	11.65	303,532	60,799	-	20,837	13,734	-	208,162	97,420	24,047	86,696	58,679	48,610	40,444	28,341	20,163
Dec 31, 2029	535	11.65	306,938	61,482	-	20,851	-	-	224,606	105,115	22,717	96,774	62,381	50,475	41,041	27,509	18,755
Dec 31, 2030	535	11.65	307,249	61,544	-	20,853	-	-	224,853	105,231	22,894	96,727	59,382	46,932	37,293	23,910	15,622
Dec 31, 2031	535	11.65	307,272	61,548	-	20,853	-	-	224,871	105,239	23,047	96,584	56,471	43,593	33,852	20,760	12,999
Dec 31, 2032	535	11.65	305,878	61,269	-	20,847	-	-	223,762	104,721	23,147	95,894	53,397	40,262	30,555	17,923	10,755
Dec 31, 2033	535	11.65	306,020	61,298	-	20,847	41,816	-	182,059	85,204	27,946	68,909	36,544	26,913	19,961	11,200	6,441
Dec 31, 2034	535	11.65	306,061	61,306	-	20,847	-	-	223,908	104,789	24,076	95,043	48,003	34,530	25,028	13,432	7,403
Dec 31, 2035	535	11.65	299,146	59,921	-	20,818	-	-	218,407	102,214	23,882	92,310	44,403	31,198	22,098	11,344	5,991
Dec 31, 2036	462	10.07	258,834	51,846	-	20,646	-	-	186,342	87,208	20,128	79,006	36,194	24,838	17,194	8,443	4,273
Dec 31, 2037	360	7.84	201,587	40,379	-	20,401	-	-	140,807	65,898	14,795	60,114	26,228	17,581	11,893	5,586	2,710
Dec 31, 2038	232	5.05	129,836	26,007	-	20,094	-	-	83,735	39,188	8,427	36,120	15,009	9,826	6,497	2,919	1,357
Dec 31, 2039	219	4.76	122,401	24,518	-	20,062	-	-	77,821	36,420	8,050	33,351	13,198	8,440	5,453	2,343	1,044
Dec 31, 2040	216	4.71	121,149	24,267	-	20,057	-	-	76,825	35,954	7,934	32,937	12,414	7,754	4,896	2,012	859
Dec 31, 2041	213	4.63	119,112	23,859	-	20,048	-	-	75,205	35,196	7,744	32,265	11,581	7,066	4,360	1,714	701
Dec 31, 2042	210	4.57	117,588	23,554	-	20,042	-	-	73,993	34,629	7,321	32,044	10,954	6,528	3,936	1,480	580
Dec 31, 2043	207	4.51	116,064	23,248	-	20,035	-	-	72,781	34,061	7,179	31,541	10,269	5,977	3,522	1,267	476

Discounted cash flows from proved reserves as at June 30, 2020 (in USD thousands, with regard to the Company's share)																	
Cash Flow Items																	
Through to	Volume of condensate sales (K barrels) (100% of oil asset)	Sales quantity (BCM) (100% of oil asset)	Total revenue	Royalties payable	Royalties received	Operating costs	Development costs	Abandonment 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%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Dec 31, 2044	204	4.44	114,283	22,892	-	20,028	-	11,856	59,508	27,850	9,251	22,407	6,948	3,950	2,275	783	282
Dec 31, 2045	130	2.83	72,855	14,593	-	19,850	-	11,856	26,555	12,428	5,391	8,736	2,580	1,433	806	265	92
Dec 31, 2046	118	2.57	66,173	13,255	-	19,822	-	11,856	21,240	9,940	4,769	6,531	1,837	996	548	173	57
Dec 31, 2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**10,266**	**224**	**5,724,987**	**1,146,750**	**-**	**539,452**	**156,113**	**35,567**	**3,847,105**	**1,682,076**	**442,958**	**1,722,071**	**1,085,866**	**896,540**	**756,570**	**568,990**	**453,204**

Discounted cash flows from probable reserves as at June 30, 2020 (in USD thousands, with regard to the Company's share)

Cash Flow Items

Through to	Volume of condensate sales (K barrels) (100% of oil asset)	Sales quantity (BCM) (100% of oil asset)	Total revenue	Royalties payable	Royalties received	Operating costs	Development costs	Abandonment 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%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Dec 31, 2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2021	-	-	-	-	-	-	(4,271)	-	4,271	1,152	(265)	3,384	3,223	3,148	3,076	2,943	2,820
Dec 31, 2022	-	-	-	-	-	-	(13,415)	-	13,415	4,794	(999)	9,620	8,725	8,324	7,950	7,274	6,680
Dec 31, 2023	-	-	-	-	-	-	(43,722)	-	43,722	18,280	(4,080)	29,522	25,502	23,764	22,180	19,411	17,084
Dec 31, 2024	-	-	-	-	-	-	7,749	-	(7,749)	26	2,169	(9,945)	(8,181)	(7,447)	(6,792)	(5,686)	(4,796)
Dec 31, 2025	-	-	-	-	-	-	26,830	-	(26,830)	(11,592)	4,276	(19,513)	(15,289)	(13,592)	(12,116)	(9,701)	(7,842)
Dec 31, 2026	-	-	-	-	-	-	26,830	-	(26,830)	(12,556)	3,969	(18,242)	(13,613)	(11,820)	(10,297)	(7,887)	(6,109)
Dec 31, 2027	-	-	-	-	-	-	(13,734)	-	13,734	6,427	(1,536)	8,842	6,284	5,330	4,537	3,324	2,468
Dec 31, 2028	-	-	-	-	-	-	(13,734)	-	13,734	6,427	(1,176)	8,482	5,741	4,756	3,957	2,773	1,973
Dec 31, 2029	-	-	-	-	-	-	-	-	-	-	575	(575)	(370)	(300)	(244)	(163)	(111)
Dec 31, 2030	-	-	-	-	-	-	-	-	-	-	575	(575)	(353)	(279)	(222)	(142)	(93)
Dec 31, 2031	-	-	-	-	-	-	-	-	-	-	575	(575)	(336)	(259)	(201)	(123)	(77)
Dec 31, 2032	-	-	-	-	-	-	-	-	-	-	476	(476)	(265)	(200)	(152)	(89)	(53)
Dec 31, 2033	-	-	-	-	-	-	(41,816)	-	41,816	19,570	(4,302)	26,548	14,079	10,369	7,690	4,315	2,481
Dec 31, 2034	-	-	-	-	-	-	-	-	-	-	(378)	378	191	137	100	53	29
Dec 31, 2035	-	-	-	-	-	-	6,867	-	(6,867)	(3,214)	666	(4,319)	(2,078)	(1,460)	(1,034)	(531)	(280)
Dec 31, 2036	73	1.58	40,608	8,134	-	174	31,055	-	1,245	583	7,592	(6,930)	(3,175)	(2,179)	(1,508)	(741)	(375)
Dec 31, 2037	175	3.81	97,954	19,621	-	419	31,362	-	46,553	21,787	13,631	11,135	4,858	3,257	2,203	1,035	502
Dec 31, 2038	303	6.60	169,675	33,987	-	725	6,867	-	128,096	59,949	16,893	51,254	21,297	13,943	9,218	4,142	1,925
Dec 31, 2039	316	6.89	177,162	35,487	-	757	20,601	-	120,317	56,308	18,670	45,338	17,942	11,474	7,413	3,186	1,419
Dec 31, 2040	319	6.94	178,498	35,754	-	763	-	-	141,980	66,447	16,109	59,424	22,396	13,989	8,833	3,631	1,550
Dec 31, 2041	316	6.89	177,242	35,503	-	758	-	-	140,982	65,979	15,987	59,015	21,183	12,924	7,975	3,136	1,283
Dec 31, 2042	297	6.48	166,724	33,396	-	713	-	-	132,616	62,064	15,245	55,307	18,907	11,267	6,794	2,555	1,002
Dec 31, 2043	231	5.04	129,699	25,980	-	554	-	-	103,165	48,281	11,641	43,242	14,078	8,194	4,829	1,737	653

Discounted cash flows from probable reserves as at June 30, 2020 (in USD thousands, with regard to the Company's share)																	
Cash Flow Items																	
Through to	**Volume of condensate sales (K barrels) (100% of oil asset)**	**Sales quantity (BCM) (100% of oil asset)**	**Total revenue**	**Royalties payable**	**Royalties received**	**Operating costs**	**Development costs**	**Abandonment 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%**	**Discounted at 10%**	**Discounted at 15%**	**Discounted at 20%**
Dec 31, 2044	177	3.85	99,095	19,849	-	424	-	(11,856)	90,678	42,437	6,425	41,816	12,966	7,371	4,245	1,461	526
Dec 31, 2045	250	5.44	140,045	28,052	-	599	-	(11,856)	123,250	57,681	10,410	55,159	16,288	9,045	5,091	1,676	578
Dec 31, 2046	256	5.57	143,416	28,727	-	613	-	(11,856)	125,932	58,936	10,521	56,475	15,883	8,615	4,739	1,492	493
Dec 31, 2047	358	7.79	200,612	40,184	-	20,397	-	-	140,032	65,535	15,406	59,091	15,828	8,385	4,507	1,357	430
Dec 31, 2048	291	6.34	163,299	32,710	-	20,237	-	12,653	97,699	45,723	13,857	38,119	9,724	5,032	2,643	761	231
Dec 31, 2049	117	2.55	65,692	13,158	-	19,820	-	12,653	20,060	9,388	4,515	6,157	1,496	756	388	107	31
Dec 31, 2050	103	2.25	57,973	11,612	-	19,787	-	12,653	13,921	6,515	4,238	3,168	733	362	182	48	13
Dec 31, 2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**3,582**	**78**	**2,007,695**	**402,153**	**-**	**86,739**	**27,468**	**2,392**	**1,488,942**	**696,929**	**181,686**	**610,326**	**213,664**	**132,905**	**85,985**	**41,352**	**24,436**

Discounted cash flows from probable reserves + proved reserves (P2) as at June 30, 2020 (in USD thousands, with regard to the Partnership's share)																	
Cash Flow Items																	
Through to	Volume of condensate sales (K barrels) (100% of oil asset)	Sales quantity (BCM) (100% of oil asset)	Total revenue	Royalties payable	Royalties received	Operating costs	Development costs	Abandonment 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%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Dec 31, 2020	204	4.44	113,981	22,831	-	7,731	3,913	-	79,506	-	15,993	63,513	62,743	62,375	62,018	61,332	60,683
Dec 31, 2021	378	8.24	202,586	40,579	-	20,125	6,290	-	135,592	31,874	18,865	84,853	80,812	78,933	77,139	73,785	70,710
Dec 31, 2022	418	9.10	217,112	43,489	-	20,467	1,803	-	151,353	45,925	18,139	87,289	79,174	75,534	72,139	66,003	60,617
Dec 31, 2023	450	9.80	237,100	47,493	-	20,553	-	-	169,055	62,076	18,579	88,399	76,363	71,158	66,416	58,124	51,157
Dec 31, 2024	477	10.40	256,313	51,341	-	20,635	21,164	-	163,174	69,339	21,421	72,413	59,575	54,223	49,459	41,403	34,922
Dec 31, 2025	489	10.65	263,600	52,801	-	20,666	26,830	-	163,304	75,929	20,599	66,775	52,320	46,513	41,462	33,199	26,836
Dec 31, 2026	489	10.65	267,471	53,576	-	20,682	26,830	-	166,383	77,867	20,637	67,879	50,652	43,983	38,316	29,346	22,732
Dec 31, 2027	512	11.15	284,844	57,056	-	20,757	-	-	207,032	96,891	19,513	90,627	64,407	54,626	46,506	34,070	25,292
Dec 31, 2028	535	11.65	303,532	60,799	-	20,837	-	-	221,896	103,847	22,871	95,178	64,420	53,366	44,401	31,114	22,135
Dec 31, 2029	535	11.65	306,938	61,482	-	20,851	-	-	224,606	105,115	23,291	96,199	62,011	50,176	40,798	27,346	18,644
Dec 31, 2030	535	11.65	307,249	61,544	-	20,853	-	-	224,853	105,231	23,469	96,153	59,030	46,653	37,071	23,768	15,529
Dec 31, 2031	535	11.65	307,272	61,548	-	20,853	-	-	224,871	105,239	23,621	96,010	56,135	43,333	33,651	20,637	12,922
Dec 31, 2032	535	11.65	305,878	61,269	-	20,847	-	-	223,762	104,721	23,624	95,418	53,132	40,062	30,403	17,834	10,702
Dec 31, 2033	535	11.65	306,020	61,298	-	20,847	-	-	223,875	104,773	23,645	95,457	50,623	37,282	27,650	15,514	8,922
Dec 31, 2034	535	11.65	306,061	61,306	-	20,847	-	-	223,908	104,789	23,698	95,421	48,194	34,668	25,127	13,486	7,432
Dec 31, 2035	535	11.65	299,146	59,921	-	20,818	6,867	-	211,540	99,001	24,548	87,991	42,325	29,738	21,064	10,814	5,711
Dec 31, 2036	535	11.65	299,441	59,980	-	20,819	31,055	-	187,588	87,791	27,720	72,076	33,019	22,660	15,686	7,702	3,898
Dec 31, 2037	535	11.65	299,541	60,000	-	20,820	31,362	-	187,360	87,684	28,426	71,249	31,086	20,837	14,096	6,621	3,211
Dec 31, 2038	535	11.65	299,511	59,994	-	20,819	6,867	-	211,831	99,137	25,320	87,374	36,306	23,770	15,715	7,060	3,282
Dec 31, 2039	535	11.65	299,563	60,004	-	20,820	20,601	-	198,138	92,729	26,721	78,689	31,140	19,914	12,866	5,529	2,463
Dec 31, 2040	535	11.65	299,647	60,021	-	20,820	-	-	218,806	102,401	24,043	92,362	34,810	21,743	13,729	5,643	2,409
Dec 31, 2041	529	11.52	296,354	59,362	-	20,806	-	-	216,187	101,175	23,731	91,280	32,764	19,989	12,335	4,850	1,984
Dec 31, 2042	507	11.05	284,313	56,950	-	20,754	-	-	206,609	96,693	22,566	87,350	29,861	17,794	10,731	4,036	1,582

Discounted cash flows from probable reserves + proved reserves (P2) as at June 30, 2020 (in USD thousands, with regard to the Partnership's share)

Cash Flow Items

Through to	Volume of condensate sales (K barrels) (100% of oil asset)	Sales quantity (BCM) (100% of oil asset)	Total revenue	Royalties payable	Royalties received	Operating costs	Development costs	Abandonment 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%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Dec 31, 2043	438	9.55	245,764	49,228	-	20,590	-	-	175,946	82,343	18,820	74,783	24,347	14,171	8,352	3,004	1,129
Dec 31, 2044	381	8.29	213,378	42,741	-	20,451	-	-	150,186	70,287	15,676	64,223	19,914	11,321	6,520	2,244	808
Dec 31, 2045	380	8.27	212,899	42,645	-	20,449	-	-	149,805	70,109	15,802	63,895	18,868	10,477	5,897	1,941	670
Dec 31, 2046	374	8.14	209,589	41,982	-	20,435	-	-	147,172	68,877	15,290	63,006	17,720	9,611	5,287	1,664	550
Dec 31, 2047	358	7.79	200,612	40,184	-	20,397	-	-	140,032	65,535	15,406	59,091	15,828	8,385	4,507	1,357	430
Dec 31, 2048	291	6.34	163,299	32,710	-	20,237	-	12,653	97,699	45,723	13,857	38,119	9,724	5,032	2,643	761	231
Dec 31, 2049	117	2.55	65,692	13,158	-	19,820	-	12,653	20,060	9,388	4,515	6,157	1,496	756	388	107	31
Dec 31, 2050	103	2.25	57,973	11,612	-	19,787	-	12,653	13,921	6,515	4,238	3,168	733	362	182	48	13
Dec 31, 2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**13,848**	**302**	**7,732,679**	**1,548,904**	**-**	**626,193**	**183,582**	**37,959**	**5,336,050**	**2,379,004**	**624,644**	**2,332,397**	**1,299,532**	**1,029,445**	**842,554**	**610,342**	**477,637**

Discounted cash flows from possible reserves as at June 30, 2020 (in USD thousands, with regard to the Partnership's share)																	
Cash Flow Items																	
Through to	Volume of condensate sales (K barrels) (100% of oil asset)	Sales quantity (BCM) (100% of oil asset)	Total revenue	Royalties payable	Royalties received	Operating costs	Development costs	Abandonment 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%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Dec 31, 2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2024	-	-	-	-	-	-	(16,892)	-	16,892	7,935	(1,825)	10,782	8,870	8,074	7,364	6,165	5,200
Dec 31, 2025	-	-	-	-	-	-	16,892	-	(16,892)	(7,600)	2,262	(11,555)	(9,053)	(8,048)	(7,175)	(5,745)	(4,644)
Dec 31, 2026	-	-	-	-	-	-	-	-	-	-	433	(433)	(323)	(280)	(244)	(187)	(145)
Dec 31, 2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2035	-	-	-	-	-	-	-	-	-	-	(514)	514	247	174	123	63	33
Dec 31, 2036	-	-	-	-	-	-	(10,454)	-	10,454	4,892	(1,558)	7,119	3,261	2,238	1,549	761	385
Dec 31, 2037	-	-	-	-	-	-	(31,362)	-	31,362	14,677	(3,135)	19,820	8,647	5,796	3,921	1,842	893
Dec 31, 2038	-	-	-	-	-	-	(6,867)	-	6,867	3,214	223	3,431	1,425	933	617	277	129
Dec 31, 2039	-	-	-	-	-	-	(20,601)	-	20,601	9,641	(1,098)	12,057	4,772	3,051	1,971	847	377
Dec 31, 2040	-	-	-	-	-	-	41,816	-	(41,816)	(19,570)	6,095	(28,341)	(10,681)	(6,672)	(4,213)	(1,732)	(739)
Dec 31, 2041	6	0.13	3,344	670	-	14	-	-	2,660	1,245	957	458	164	100	62	24	10
Dec 31, 2042	28	0.60	15,437	3,092	-	66	27,468	-	(15,189)	(7,109)	5,091	(13,172)	(4,503)	(2,683)	(1,618)	(609)	(239)

Discounted cash flows from possible reserves as at June 30, 2020 (in USD thousands, with regard to the Partnership's share)																	
Cash Flow Items																	
										Taxes		**Total discounted cash flow after tax**					
Through to	**Volume of condensate sales (K barrels) (100% of oil asset)**	**Sales quantity (BCM) (100% of oil asset)**	**Total revenue**	**Royalties payable**	**Royalties received**	**Operating costs**	**Development costs**	**Abandonment and restoration costs**	**Total cash flow before levy and income tax (discounted at 0%)**	**Levy**	**Income tax**	**Discounted at 0%**	**Discounted at 5%**	**Discounted at 7.5%**	**Discounted at 10%**	**Discounted at 15%**	**Discounted at 20%**
Dec 31, 2043	96	2.10	54,037	10,824	-	231	-	-	42,982	20,116	5,259	17,607	5,732	3,337	1,966	707	266
Dec 31, 2044	154	3.36	86,474	17,321	-	370	-	-	68,783	32,191	8,416	28,176	8,737	4,967	2,861	984	354
Dec 31, 2045	155	3.38	87,004	17,427	-	372	-	-	69,205	32,388	8,468	28,349	8,372	4,649	2,616	861	297
Dec 31, 2046	161	3.51	90,366	18,101	-	386	-	-	71,879	33,639	9,171	29,069	8,175	4,434	2,439	768	254
Dec 31, 2047	163	3.54	91,154	18,259	-	390	-	-	72,506	33,933	9,007	29,566	7,919	4,195	2,255	679	215
Dec 31, 2048	226	4.92	126,714	25,382	-	542	-	(12,653)	113,444	53,092	10,385	49,968	12,746	6,596	3,465	998	303
Dec 31, 2049	370	8.07	207,886	41,641	-	889	-	(12,653)	178,010	83,309	18,127	76,574	18,603	9,402	4,827	1,330	387
Dec 31, 2050	352	7.66	197,360	39,532	-	844	-	(12,653)	169,637	79,390	16,629	73,618	17,034	8,409	4,219	1,112	310
Dec 31, 2051	422	9.20	237,082	47,489	-	20,553	-	-	169,041	79,111	20,052	69,878	15,398	7,425	3,641	918	245
Dec 31, 2052	358	7.79	200,784	40,218	-	20,397	-	-	140,169	65,599	16,236	58,333	12,242	5,766	2,763	666	171
Dec 31, 2053	292	6.37	164,213	32,893	-	20,241	-	-	111,079	51,985	13,216	45,878	9,170	4,218	1,975	456	112
Dec 31, 2054	228	4.96	127,886	25,616	-	20,086	-	12,653	69,531	32,540	11,042	25,948	4,939	2,219	1,016	224	53
Dec 31, 2055	104	2.27	58,538	11,726	-	19,789	-	12,653	14,370	6,725	4,293	3,352	608	267	119	25	6
Dec 31, 2056	93	2.03	52,358	10,488	-	19,763	-	12,653	9,455	4,425	3,692	1,338	231	99	43	9	2
Dec 31, 2057	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**3,208**	**70**	**1,800,638**	**360,679**	**-**	**124,932**	**-**	**-**	**1,315,028**	**615,768**	**160,922**	**538,337**	**132,735**	**68,665**	**36,565**	**11,445**	**4,236**

Discounted cash flows from proved reserves + probable reserves + possible reserves (P3) as at June 30, 2020 (in USD thousands, with regard to the Company's share)

Cash Flow Items

Through to	Volume of condensate sales (K barrels) (100% of oil asset)	Sales quantity (BCM) (100% of oil asset)	Total revenue	Royalties payable	Royalties received	Operating costs	Develop ment costs	Abandon ment and restorati on 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%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Dec 31, 2020	204	4.44	113,981	22,831	-	7,731	3,913	-	79,506	-	15,993	63,513	62,743	62,375	62,018	61,332	60,683
Dec 31, 2021	378	8.24	202,586	40,579	-	20,125	6,290	-	135,592	31,874	18,865	84,853	80,812	78,933	77,139	73,785	70,710
Dec 31, 2022	418	9.10	217,112	43,489	-	20,467	1,803	-	151,353	45,925	18,139	87,289	79,174	75,534	72,139	66,003	60,617
Dec 31, 2023	450	9.80	237,100	47,493	-	20,553	-	-	169,055	62,076	18,579	88,399	76,363	71,158	66,416	58,124	51,157
Dec 31, 2024	477	10.40	256,313	51,341	-	20,635	4,271	-	180,066	77,275	19,596	83,195	68,445	62,297	56,824	47,567	40,121
Dec 31, 2025	489	10.65	263,600	52,801	-	20,666	43,722	-	146,412	68,329	22,862	55,221	43,267	38,465	34,288	27,455	22,192
Dec 31, 2026	489	10.65	267,471	53,576	-	20,682	26,830	-	166,383	77,867	21,070	67,446	50,329	43,702	38,072	29,159	22,588
Dec 31, 2027	512	11.15	284,844	57,056	-	20,757	-	-	207,032	96,891	19,513	90,627	64,407	54,626	46,506	34,070	25,292
Dec 31, 2028	535	11.65	303,532	60,799	-	20,837	-	-	221,896	103,847	22,871	95,178	64,420	53,366	44,401	31,114	22,135
Dec 31, 2029	535	11.65	306,938	61,482	-	20,851	-	-	224,606	105,115	23,291	96,199	62,011	50,176	40,798	27,346	18,644
Dec 31, 2030	535	11.65	307,249	61,544	-	20,853	-	-	224,853	105,231	23,469	96,153	59,030	46,653	37,071	23,768	15,529
Dec 31, 2031	535	11.65	307,272	61,548	-	20,853	-	-	224,871	105,239	23,621	96,010	56,135	43,333	33,651	20,637	12,922
Dec 31, 2032	535	11.65	305,878	61,269	-	20,847	-	-	223,762	104,721	23,624	95,418	53,132	40,062	30,403	17,834	10,702
Dec 31, 2033	535	11.65	306,020	61,298	-	20,847	-	-	223,875	104,773	23,645	95,457	50,623	37,282	27,650	15,514	8,922
Dec 31, 2034	535	11.65	306,061	61,306	-	20,847	-	-	223,908	104,789	23,698	95,421	48,194	34,668	25,127	13,486	7,432
Dec 31, 2035	535	11.65	299,146	59,921	-	20,818	6,867	-	211,540	99,001	24,034	88,506	42,573	29,912	21,188	10,877	5,744
Dec 31, 2036	535	11.65	299,441	59,980	-	20,819	20,601	-	198,041	92,683	26,162	79,196	36,280	24,898	17,235	8,463	4,284
Dec 31, 2037	535	11.65	299,541	60,000	-	20,820	-	-	218,722	102,362	25,291	91,069	39,733	26,633	18,018	8,463	4,105
Dec 31, 2038	535	11.65	299,511	59,994	-	20,819	-	-	218,698	102,351	25,543	90,804	37,731	24,703	16,332	7,337	3,411
Dec 31, 2039	535	11.65	299,563	60,004	-	20,820	-	-	218,739	102,370	25,623	90,746	35,911	22,965	14,838	6,376	2,840
Dec 31, 2040	535	11.65	299,647	60,021	-	20,820	41,816	-	176,990	82,831	30,138	64,021	24,129	15,071	9,516	3,912	1,670
Dec 31, 2041	535	11.65	299,698	60,031	-	20,820	-	-	218,846	102,420	24,688	91,738	32,929	20,090	12,397	4,874	1,994

Discounted cash flows from proved reserves + probable reserves + possible reserves (P3) as at June 30, 2020 (in USD thousands, with regard to the Company's share)																	
	Cash Flow Items																
Through to	Volume of condensate sales (K barrels) (100% of oil asset)	Sales quantity (BCM) (100% of oil asset)	Total revenue	Royalties payable	Royalties received	Operating costs	Development costs	Abandonment 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%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Dec 31, 2042	535	11.65	299,749	60,042	-	20,820	27,468	-	191,419	89,584	27,656	74,179	25,358	15,111	9,113	3,427	1,344
Dec 31, 2043	535	11.65	299,801	60,052	-	20,821	-	-	218,928	102,458	24,079	92,390	30,080	17,508	10,318	3,712	1,395
Dec 31, 2044	535	11.65	299,852	60,062	-	20,821	-	-	218,969	102,478	24,092	92,400	28,650	16,288	9,381	3,228	1,162
Dec 31, 2045	535	11.65	299,903	60,072	-	20,821	-	-	219,010	102,497	24,269	92,244	27,240	15,126	8,514	2,802	967
Dec 31, 2046	535	11.65	299,955	60,083	-	20,821	-	-	219,051	102,516	24,460	92,075	25,895	14,045	7,726	2,432	804
Dec 31, 2047	520	11.33	291,766	58,443	-	20,786	-	-	212,537	99,468	24,413	88,657	23,747	12,580	6,763	2,036	645
Dec 31, 2048	517	11.26	290,014	58,091	-	20,779	-	-	211,143	98,815	24,242	88,086	22,470	11,627	6,108	1,759	534
Dec 31, 2049	488	10.62	273,578	54,799	-	20,709	-	-	198,070	92,697	22,642	82,731	20,099	10,158	5,215	1,437	418
Dec 31, 2050	455	9.91	255,333	51,145	-	20,631	-	-	183,558	85,905	20,867	76,786	17,767	8,771	4,401	1,160	323
Dec 31, 2051	422	9.20	237,082	47,489	-	20,553	-	-	169,041	79,111	20,052	69,878	15,398	7,425	3,641	918	245
Dec 31, 2052	358	7.79	200,784	40,218	-	20,397	-	-	140,169	65,599	16,236	58,333	12,242	5,766	2,763	666	171
Dec 31, 2053	292	6.37	164,213	32,893	-	20,241	-	-	111,079	51,985	13,216	45,878	9,170	4,218	1,975	456	112
Dec 31, 2054	228	4.96	127,886	25,616	-	20,086	-	12,653	69,531	32,540	11,042	25,948	4,939	2,219	1,016	224	53
Dec 31, 2055	104	2.27	58,538	11,726	-	19,789	-	12,653	14,370	6,725	4,293	3,352	608	267	119	25	6
Dec 31, 2056	93	2.03	52,358	10,488	-	19,763	-	12,653	9,455	4,425	3,692	1,338	231	99	43	9	2
Dec 31, 2057	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**17,056**	**372**	**9,533,316**	**1,909,582**	**-**	**751,125**	**183,581**	**37,959**	**6,651,076**	**2,994,773**	**785,566**	**2,870,734**	**1,432,265**	**1,098,110**	**879,123**	**621,787**	**481,875**

Note: It is clarified that the discounted cash flow figures, whether calculated at a specific discount rate or without a discount rate, represent the present value but not necessarily the fair value.

Notice regarding forward-looking information: The discounted cash flows set out above are forward-looking information as defined in the Securities Law. The information above is based on various assumptions, including the rate and duration of natural gas and condensate sales from the project, operational costs, capital expenditure, abandonment expenses, rates of royalties, and selling prices, including price adjustments according to the agreement with IEC, the agreement for export to Egypt, and there is no certainly whether these will materialize. It is noted that actual quantities of natural gas and/or condensate produced, the above expenses and revenues may be materially different from these estimates and assumptions, partly due to the market conditions and/or technical and operational conditions and/or regulatory changes and/or the supply and demand conditions in the local and/or export markets for natural gas and/or condensate and/or actual performance of the project and/or as a result of actual selling prices and/or due to geo-political changes. It should also be noted that price adjustment at the price adjustment dates set out in the IEC agreement and the agreement for export to Egypt may differ materially from the Partnership's assessment, among other things, due to actual natural gas prices in the local market at the price adjustment dates, all in accordance with the adjustment mechanism set out in these agreements.

4. Sensitivity analysis for the main parameters of the discounted cash flow (gas price and quantity of gas sold)[17] as at June 30, 2020 (USD thousands), performed by the Company:

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% increase in the price of gas					**10% decrease in the price of gas**				
Proved reserves (P1)	1,908,757	834,665	626,983	499,049	Proved reserves (P1)	1,536,577	679,304	511,720	408,006
Probable reserves	675,336	93,440	43,988	25,284	Probable reserves	545,471	78,655	38,827	23,687
Proved+Probable Reserves (P2)	2,584,093	928,105	670,971	524,334	Proved+Probable Reserves (P2)	2,082,048	757,959	550,547	431,693
Possible reserves	597,142	40,247	12,522	4,592	Possible reserves	479,865	33,107	10,554	4,038
Proved + probable + possible reserves (P3)	3,181,235	968,351	683,493	528,926	Proved + probable + possible reserves (P3)	2,561,913	791,066	561,101	435,731
15% increase in the price of gas					**15% decrease in the price of gas**				
Proved reserves (P1)	2,001,280	872,737	654,960	520,921	Proved reserves (P1)	1,444,294	640,950	483,315	385,603
Probable reserves	707,877	97,218	45,359	25,761	Probable reserves	513,030	74,995	37,575	23,327
Proved+Probable Reserves (P2)	2,709,158	969,956	700,318	546,682	Proved+Probable Reserves (P2)	1,957,325	715,945	520,890	408,930
Possible reserves	626,529	42,084	13,060	4,772	Possible reserves	450,624	31,372	10,103	3,932
Proved + probable + possible reserves (P3)	3,335,686	1,012,040	713,378	551,454	Proved + probable + possible reserves (P3)	2,407,949	747,317	530,993	412,862
20% increase in the price of gas					**20% decrease in the price of gas**				
Proved reserves (P1)	2,094,603	911,618	683,749	543,609	Proved reserves (P1)	1,351,908	602,356	454,640	362,916
Probable reserves	740,477	101,034	46,759	26,262	Probable reserves	480,559	71,321	36,313	22,959
Proved+Probable Reserves (P2)	2,835,080	1,012,652	730,508	569,871	Proved+Probable Reserves (P2)	1,832,466	673,676	490,953	385,875
Possible reserves	655,902	43,912	13,591	4,945	Possible reserves	421,304	29,592	9,617	3,800
Proved + probable + possible reserves (P3)	3,490,981	1,056,564	744,099	574,817	Proved + probable + possible reserves (P3)	2,253,770	703,268	500,569	389,675

[17] It is emphasized that the foregoing information on the sensitivity to changes in the quantity of gas sold does not take into account changes in the future investment plan, with respect to both an increase or decrease in 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%
10% increase in the volume of gas sales					**10% decrease in the volume of gas sales**				
Proved reserves (P1)	1,761,198	820,941	624,247	500,209	Proved reserves (P1)	1,534,062	676,418	508,708	404,894
Probable reserves	609,705	93,971	45,232	26,078	Probable reserves	545,555	78,739	38,911	23,770
Proved+Probable Reserves (P2)	2,370,903	914,912	669,478	526,287	Proved+Probable Reserves (P2)	2,079,617	755,157	547,619	428,664
Possible reserves	546,308	44,296	14,545	5,437	Possible reserves	479,884	33,117	10,563	4,045
Proved + probable + possible reserves (P3)	2,917,211	959,208	684,024	531,723	Proved + probable + possible reserves (P3)	2,559,501	788,275	558,182	432,708
15% increase in the volume of gas sales					**15% decrease in the volume of gas sales**				
Proved reserves (P1)	1,776,275	849,290	649,422	522,048	Proved reserves (P1)	1,439,908	635,974	478,149	380,292
Probable reserves	601,434	98,206	47,702	27,331	Probable reserves	513,136	75,106	37,686	23,436
Proved+Probable Reserves (P2)	2,377,709	947,496	697,124	549,379	Proved+Probable Reserves (P2)	1,953,044	711,079	515,835	403,728
Possible reserves	546,257	48,672	16,514	6,276	Possible reserves	450,643	31,382	10,112	3,940
Proved + probable + possible reserves (P3)	2,923,966	996,169	713,638	555,655	Proved + probable + possible reserves (P3)	2,403,687	742,462	525,946	407,668
20% increase in the volume of gas sales					**20% decrease in the volume of gas sales**				
Proved reserves (P1)	1,781,587	875,033	673,610	543,766	Proved reserves (P1)	1,346,565	596,174	448,187	356,254
Probable reserves	603,883	104,596	51,360	29,262	Probable reserves	479,762	70,533	35,537	22,197
Proved+Probable Reserves (P2)	2,385,470	979,630	724,970	573,028	Proved+Probable Reserves (P2)	1,826,327	666,707	483,724	378,451
Possible reserves	546,183	53,350	18,732	7,265	Possible reserves	421,316	29,598	9,623	3,806
Proved + probable + possible reserves (P3)	2,931,653	1,032,980	743,703	580,294	Proved + probable + possible reserves (P3)	2,247,643	696,305	493,347	382,257

5. Sensitivity analysis of the main linkage components of gas price according to the agreements of the Tamar Partners agreements for gas sales (US-CPI and Electricity Generation Price as at June 30, 2020 (USD thousands), performed by the Company[18]:

[18] Although the power generation tariff is partially affected by the CPI, this effect was not taken into account in the sensitivity analysis in the table below.

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% increase in the projected CPI					**10% decrease in the projected CPI**				
Proved reserves (P1)	1,723,402	757,366	569,624	453,717	Proved reserves (P1)	1,720,751	755,779	568,361	452,695
Probable reserves	610,323	85,982	41,348	24,432	Probable reserves	610,329	85,989	41,355	24,439
Proved+Probable Reserves (P2)	2,333,725	843,348	610,972	478,149	Proved+Probable Reserves (P2)	2,331,080	841,768	609,716	477,134
Possible reserves	538,337	36,564	11,444	4,236	Possible reserves	538,337	36,565	11,445	4,237
Proved + probable + possible reserves (P3)	2,872,062	879,912	622,416	482,385	Proved + probable + possible reserves (P3)	2,869,418	878,334	621,161	481,371
10% increase in the projected Cost of Electricity Generation					**10% decrease in the projected Cost of Electricity Generation**				
Proved reserves (P1)	1,825,777	792,828	593,558	470,995	Proved reserves (P1)	1,656,012	735,391	555,353	443,848
Probable reserves	655,937	91,381	43,374	25,202	Probable reserves	578,406	82,162	39,886	23,849
Proved+Probable Reserves (P2)	2,481,714	884,209	636,932	496,197	Proved+Probable Reserves (P2)	2,234,418	817,553	595,240	467,698
Possible reserves	579,062	39,076	12,154	4,451	Possible reserves	509,907	34,823	10,958	4,093
Proved + probable + possible reserves (P3)	3,060,776	923,285	649,086	500,648	Proved + probable + possible reserves (P3)	2,744,325	852,376	606,198	471,791

6. Below is a sensitivity analysis for sales volume over and above minimum volumes (TOP - take or pay) under the Partnership's agreements for the sale of gas as at June 30, 2020 (USD thousand), which was prepared by the Company:

10% increase in the gas sales volume over the TOP volume					**20% increase in the gas sales volume over the TOP volume**				
Proved reserves (P1)	1,744,680	789,347	594,900	473,641	Proved reserves (P1)	1,591,391	713,784	540,534	432,725
Probable reserves	619,977	92,975	44,674	25,912	Probable reserves	545,112	78,292	38,476	23,352
Proved+Probable Reserves (P2)	2,364,657	882,322	639,574	499,553	Proved+Probable Reserves (P2)	2,136,503	792,076	579,010	456,077
Possible reserves	546,250	42,634	13,812	5,120	Possible reserves	479,691	32,981	10,446	3,945
Proved + probable + possible reserves (P3)	2,910,907	924,956	653,385	504,673	Proved + probable + possible reserves (P3)	2,616,193	825,056	589,456	460,022

7. Reconciliation between the data in the report and data in previous reports relating to the oil asset

The major differences between the current reserves report and that published in the Periodic Report is due to production of 119 BCF of natural gas and 157.5 thousands of barrels of condensate in the first half of 2020 and an update of the reservoir model, based on production figures that indicate an increase in the quantity of proved reserves (P1) in the project, despite the above production, of 2% from 7.7 TCF and 10.1 million barrels of condensate in the previous report to 7.9 TCF and 10.3 million barrels of condensate in the current report.

8. Production Information

The following table includes natural gas and condensate production data in the Tamar Project in 2017 to 2019 and the first two quarters of 2020:

Natural gas[19], [20]						
		2017	**2018**	**2019**	**Q1 2020**	**Q2 2020[21]**
Total output (attributable to equity holders of the Company) in the period (in MMcf)		54,926	52,925	48,529	9,376	5,841
Average price per production unit (attributable to equity holders of the Company) (USD per MCF) [22]		5.33	5.49	5.46	5.28	5.00
Average royalties (every payment derived from the output of the producing asset, including from the gross income from the oil asset) paid per production unit (attributable to equity holders of the Company) (USD per MCF)	The State	0.6	0.61	0.62	0.61	0.55
	Third parties	0.1	0.09	0.11	0.18	0.22
	Interested parties[23]	0.15	0.35	0.39	0.31	0.22
Average intake for royalties (all compensation arising from the output of the producing asset, including from the gross income from the oil asset) received per production unit (attributable to the Company's share) (USD per MCF)		0.2	0.4	0.27	0.09	- [24]
Average production costs per production unit (attributable to equity holders of the Company) (USD per MCF)[25]		0.36	0.39	0.46	0.34	0.54
Average net intake per production unit (attributable to equity holders of the Company) (USD per MCF)		4.32	4.45	4.15	3.93	3.47
Oil and gas profits levy		-	-	-	-	-
Average net intake per production unit after oil and gas profits tax (attributable to equity holders of the Company) (USD per MCF)		4.32	4.45	4.15	3.93	3.47
Depletion rate in the reporting period in relation to the overall quantity of gas in the project (%)[26]		3.44	3.29	3.31	0.66	0.45

19 The figures presented in the foregoing table with regard to the rate attributable to the Company's equity holders at an average price per unit of output, royalties, production costs and net receipts, have been rounded up to two digits after the decimal point.

20 The production data as from 2019 is based on the Partnership's direct holdings in the Tamar Project of 22%.

21 The production figures for the second quarter of 2020 are based on unreviewed financial data.

22 The average price per output unit weights the effective price of the Partnership, which includes the outline for the sale of natural gas from the Tamar project to the Yam Tethys project. In this regard, see section 1.7.10 of the Periodic Report.

23 The royalty rate taken into account is 6.5%, which is the rate of royalties after ROI. On April 19, 2020, the Company sold 100% of its holdings in Cohen Development Gas and Oil Ltd, that was eligible for overriding royalties from the Partnership. Therefore, it is no longer considered an interested party.

24 On April 19, 2020, the Company sold 100% of its holdings in Cohen Development Gas and Oil Ltd, that was eligible for overriding royalties from the Partnership.

25 It should be emphasized that the average production costs per unit of output include current production costs only and do not include the exploration and development costs of the reservoir and tax payments that will be paid in the future by the Partnership.

26 The depletion rate is the rate of natural gas produced in the relevant reporting period from the balance of the proved and expected reserves at the beginning of the reporting period or at the date production started, whichever is later. The depletion rate is calculated at the end of the year and not during the year.

Condensate[27, 28]

		2017	2018	2019	Q1 2020	Q2 2020[29]
Total output (attributable to equity holders of the Company) in the period (thousands of barrels)		73	69.2	63.5	12.2	7.8
Average price per production unit (attributable to equity holders of the Company) (USD per barrel)		47.1	63.0	56.42	33.93	28.18
Average royalties (every payment derived from the output of the producing asset, including from the gross income from the oil asset) paid per production unit (attributable to equity holders of the Company) (USD per barrel)	The State	5.3	7.0	6.38	3.88	3.10
	Third parties	0.8	1.1	1.31	1.11	1.20
	Interested parties[30]	1.4	4.1	3.73	1.96	1.21
Average intake for royalties (all compensation arising from the output of the producing asset, including from the gross income from the oil asset) received per production unit (attributable to the Company's share) (USD per barrel)		2	4.6	2.68	0.54	-[31]
Average production costs per production unit (attributable to equity holders of the Company) (USD per barrel) [32]		2	2.1	2.5	1.89	2.94
Average net intake per production unit (attributable to equity holders of the Company) (USD per barrel)		39.6	53.3	45.18	25.63	19.73
Oil and gas profits levy		-	-	-	-	-
Average net intake per production unit after oil and gas profits tax (attributable to equity holders of the Company) (USD per barrel)		39.6	53.3	45.18	25.63	19.73
Depletion rate in the reporting period in relation to the overall quantity of condensate in the project (%)[33]		3.5	3.31	3.35	0.67	0.47

9. Opinion of the Valuator

Attached to this report, by way of reference to Appendix A of the immediate report issued by the Partnership on July 22, 2020 (Ref. No.: 2020-01-071242) is the Reserves Report of the Tamar Project (that includes the Tamar and Tamar SW reservoirs) prepared by NSAI, as at June 30, 2020. Attached to this report as **Appendix A** is NSAI's consent to include it in this report by way of reference.

27 The figures presented in the foregoing table with regard to the rate attributable to the Company's equity holders at an average price per unit of output, royalties, production costs and net receipts, have been rounded up to two digits after the decimal point.

28 · The production data as from 2019 is based on the Partnership's direct holdings in the Tamar Project of 22%

29 The production figures for the second quarter of 2020 are based on unreviewed financial data.

30 The royalty rate taken into account is 6.5%, which is the rate of royalties after ROI. On April 19, 2020, the Company sold 100% of its holdings in Cohen Development Gas and Oil Ltd, that was eligible for overriding royalties from the Partnership. Therefore, it is no longer considered an interested party.

31 On April 19, 2020, the Company sold 100% of its holdings in Cohen Development Gas and Oil Ltd, that was eligible for overriding royalties from the Partnership.

32 It should be emphasized that the average production costs per unit of output include current production costs only and do not include the exploration and development costs of the reservoir and tax payments that will be paid in the future by the Partnership.

33 The quantity of condensate produced from the Tamar Project derives directly from the quantity of natural gas produced from the project.

10. Management declaration

(1) Date of Declaration: Jul 22, 2020

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

(3) Name and position of the resource valuation officer in the Company: Gabriel Last, Chairman of the board of directors

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

(5) We hereby confirm that nothing came to our attention that indicates any dependence between the 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 available to us.

(7) We hereby confirm that the data included in this Report were prepared in accordance with the professional terms under Chapter Seven of the Third Schedule to the Securities Regulations (Details of the Prospectus and Draft Prospectus - Structure and Form), 1969, and the meanings given to them in Petroleum Resources Management System (2018) published by the Petroleum Engineers Association (SPE), the American Association of Petroleum Geologists (AAPG), the World Petroleum Council (WPC) and the Association of Petroleum Assessment Engineers (SPEE), as in effect at the time of publication of the Report;

(8) We confirm that no change has been made to the identity of the Reserves Valuator preparing the disclosure of the most recent reserves or contingent resources report issued by the Partnership.

(9) We agree to include this statement in this report.

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Gabriel Last, Chairman of the Board of Directors

Partners in the Tamar Project and rate of their holdings:

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	4.00%
Everest Infrastructures, Limited	3.50%

Sincerely,

Delek Group Ltd.

Approved for reporting by:

Idan Wallace, CEO

Barak Mashraki, Deputy CEO and CFO

This is a convenience translation of the original HEBREW immediate report issued to the Tel Aviv Stock Exchange by the Company on July 22, 2020.

About The Delek Group

Delek Group is an independent E&P company with activities in the UK North Sea and the East Mediterranean. Delek Group has significant holdings in the Leviathan and Tamar natural gas reservoirs in the East Mediterranean (Israel's territorial water), with reserves and resources of more than 30 TCF and annual production of approximately 20 BCM. These reservoirs are a major natural gas supplier to the growing markets of Israel, Egypt and Jordan and Delek continues to lead the region's development into a major natural gas export hub. Through its wholly owned subsidiary Ithaca, Delek Group holds high-quality oil and natural gas assets in the UK North Sea totaling more than 270 million barrels of oil equivalent (boe) and producing about 27 million boe per year. Delek Group is one of Israel's largest and most prominent companies with a consistent track record of growth. Its shares are traded on the Tel Aviv Stock Exchange (DLEKG:IT) And its ADRs are traded on the US OTC market (DGRLY:US).

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

Contact

Investors

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