Delek Group

Revised Reserves Evaluation Report and Discounted Cash Flows for the Tamar Lease

Tel Aviv, July 2, 2017. Delek Group (TASE: DLEKG, US ADR: DGRLY) ("the Company") announces that Further to that stated in section 1.7.4(I) of the Company's periodic report as at December 31, 2016, as published on March 30, 2017 (Ref. No. 2017-01-033078) (the "Periodic Report") concerning the evaluation of reserves in the Tamar project, which includes the Tamar and Tamar South-West reservoirs ("SW Tamar") in the area covered by the I/12 Tamar lease ("Tamar Project" and "Tamar Lease", respectively), and in view of the information received from the Tamar-8 development drillings and production wells[1], which indicated a significant increase in the volume of the Tamar Project reserves, the Company is pleased to issue an updated reserves evaluation report and discounted cash flow information, as follows:

A. Volumetric data

According to a report Delek Drilling – Limited Partnership (the "Partnership") received from Netherland, Sewell and Associates, Inc. ("NSAI" or the "Reserves Evaluator"), which was prepared according to the guidelines of the Petroleum Resources Management System (SPE-PRMS), as of June 30, 2017 (the "Reserves Report") the natural gas and condensate reserves in the Tamar Project (including, as aforesaid, the Tamar and SW Tamar reservoirs), classified as on-production reserves, are as set out below[2]:

---

[1] The Tamar-8 well was drilled in order to increase reliability and superfluity in the Tamar project's production system, and to increase the production rate at peak demand. Pumping of natural gas began in April 2017 from the Tamar-8 well, after it was drilled, completed and connected to the production system .

[2] To the best of the Company's knowledge, the Ministry of National Infrastructures, Energy and Water (the "Ministry of Energy") conducted an independent evaluation of the volume of reserves in the Tamar reservoir by external consultants, among other things for the purpose of calculating export quotas from the Tamar reservoir, pursuant to the Government decision as set out in section 6.25.5 (a) of the Periodic Report. To the best of the Company's knowledge, there is no material difference between the Ministry of Energy's evaluation and the estimated reserves published in the Periodic Report ("the Previous Reserves Report"). In view of the updated volume of the Tamar project reserves, as set out in this report, to the best of the Company's knowledge, the Ministry of Energy intends to review the foregoing estimate.

Reserve category	Total (100%) of the oil asset (gross)						Total rate attributable to the equity holders of the Company (net)[3]	
	Tamar Reservoir		Tamar SW reservoir		Total (Tamar and Tamar SW reservoir)			
	Natural gas BCF	Condensate (million barrels)	Natural gas BCF	Condensate (million barrels)	Natural gas BCF	Condensate (million barrels)	Natural gas BCF	Condensate (million barrels)
1P Reserves (Proved Reserves)	7,212.7	9.4	796.4	1.0	8,009.2	10.4	1,258.0	1.6
Probable Reserves (Probable reserves)	3,018.1	3.9	203.5	0.3	3,221.6	4.2	506.1	0.7
Total 2P Reserves (Proved+Probable Reserves)	10,230.8	13.3	999.9	1.3	11,230.7	14.6	1,764.1	2.3
Possible Reserves (Possible Reserves)	1,851.6	2.4	217.6	0.3	2,069.2	2.7	325.1	0.4
Total 3P Reserves (Proved + Probable + Possible Reserves)	12,082.4	15.7	1,217.5	1.6	13,300.0	17.3	2,089.2	2.7

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 volumes produced will be equivalent to or higher than the proved reserves, with the addition of the volume of the probable reserves and volume of the possible reserves.

---

[3] The reserves report contains the Partnership's share (gross), and not the Partnership's share (net). The Company’s share in the foregoing table is after payment of royalties (that the Partnership is required to pay). The Partnership estimates that the return on investment date is expected to be in the third quarter of 2017 ("the ROI Date"). As the ROI Date is affected by the price of gas and/or condensate, production capacity, production costs and rate of royalties, it is possible that the total quantity of natural gas and/or condensate sold by the ROI Date will differ materially from the foregoing. It is noted that to calculate the ROI Date, the Partnership takes into account a rate of 11.5% with regard to the actual royalties to be paid to the State.

B. The NSAI report noted a number of assumptions and reservations, including: (a) The estimates, as is customary in the evaluation of reserves in accordance with the guidelines of the SPE-PRMS, are not adjusted to reflect the risks; (b) NSAI did not visit the oil field and did not check the mechanical operation of the facilities and wells or their state; (c) NSAI did not examine possible exposure arising from environmental matters. However, according to NSAI, as of 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, therefore the reserves report does not include the costs that could arise from such liability. (d) NSAI assumed that the reservoirs will be developed in accordance with existing development plans, will be operated reasonably, no new regulation will be adopted that will affect the oil rights holders' ability to produce the reserves and forecasts for future production will be similar to actual performance of the reservoirs.

Forward-looking information: the NSAI estimates of the volume of reserves of natural gas and condensate in the Tamar and SW Tamar reservoirs are forward-looking information as defined in the Securities Law. **These estimates are partially based on geological, geophysical, engineering and other information received from the wells and from the Tamar project Operator, and are NSAI estimates and assumptions only and there can be no certainty in respect thereof. The actual volumes of natural gas and/or condensate produced 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 as a result of actual performance of the reservoirs.** The foregoing 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 exploration and production, including due to the continued production from the Tamar project.

C. Discounted cash flows

With regard to the calculation of the discounted cash flows described below, the following is noted: (a) The discounted cash flow is based on the weighted average gas prices in the gas sales agreements, which are based on different price formulae that include linkage to the US CPI, the Brent price, or the electricity generation price. It is noted that price changes may arise, among other things, due to adjustment of prices based on a mechanism set in the Israel Electric Corp. Ltd. ("IEC") contract[4], and changes in the linkage indices in the gas sales agreements. It is

[4] The IEC agreement stipulates two dates when each party may request price adjustments (based on the mechanism set out in the agreement) if that party believes that the contract price is no longer appropriate for a long-term contract with a significant key buyer for the consumption of natural gas in the Israeli market: After 8 years and 11 years from the date of commercial production (as defined in the agreement) from the Tamar Project or within three months after the commencing gas supply from the Tamar Project (i.e. July 1, 2021 and July 1, 2024). At the first adjustment date (after 8 years - on July 1, 2021) the price adjustment will be up to 25% (increase or reduction), and at the second adjustment date (after 11 years - on July 1, 2024) the adjustment will be up to 10% (increase or reduction).

clarified that the discounted cash flows assume that there will be no change in the price based on the foregoing mechanism. It should further be noted that no change in price was taken into account as a result of the motion for the certification of a class action filed by an IEC consumer against the Tamar Project partners, as set out in section 6.29.2 of the Periodic Report . If a final and absolute ruling is handed certifying the foregoing class action suit, the prices at which the Partnership, together with the other Tamar partners, will sell natural gas to their customers may be adversely affected, the extent of which depends on the results of the claim. For further information concerning changes in the discounted cash flows as a result of price changes, see the sensitivity analysis table in this section below. The Partnership provided the information concerning the gas price to NSAI[5]; (b) Furthermore, the discounted cash flow calculation was based on the price of condensate arising from the Brent price and based on the Brent Crude index and was adjusted to the quality differences, transportation costs and the selling price of condensate in the region; (c) The operating costs that were taken into account are the costs that the Partnership provided to NSAI. These costs include only the direct costs of the Project, insurance expenses and the Partnership's estimate of its share in the overheads, general and administrative expenses which can be attributed directly to the Project. These costs are divided into the expenses of the field and the per production unit costs and are not adjusted to inflation changes; (d) The capital expenses taken into account when preparing the discounted cash flows exceed the costs approved by the Partnership, and also include estimated costs of future investments during production with the aim of maintaining and expanding production output. The capital expenditure taken into account is the capital expenditure that might be required for the maintenance of the production wells, for drilling new wells, and for additional production equipment. The capital expenditure data provided to NSAI by the Partnership, which it believes is reasonable, is based, among other things, on the Tamar Project development plan and on NSAI's experience in similar projects. These costs are not adjusted to inflation changes; (e) The abandonment costs that were taken into account are costs that the Partnerships provided to NSAI, based on its assessment of the cost of abandoning wells, platforms and production facilities. These costs do not take into account the salvage value of the Tamar Lease and Tamar Project facilities. As defined by the Partnership, the abandonment costs are not adjusted to inflation changes; (f) The tax calculations include corporate tax rates set by law. Tax payments and rates included in the discounted cash flows were calculated from the aspect of the holder of the Partnership's participation units, which is the company that holds the Partnership's participation unit from the beginning of the project. It is noted that actual future tax payments by the Partnership on account of the holders of the participating units of the Partnership in each of the relevant tax years, in accordance with the provisions of the Natural Resources Profits Tax Law (in this section below: "the Law") could be materially different; (g) Actual production capacity for each of the reserve categories described above could be lower or higher than the

---

[5] For the purpose of calculating the price forecast, assumptions were made based on data received from a consulting firm based on the weighting of the data of a number of public and private entities: (1) Annual increase of 2.2% in the US-CPI; (2) Brent price of USD 52.7 per barrel in 2017, rising to USD 77 per barrel in 2020 and USD 90 per barrel in 2024, and a gradual annual increment of 2.8% in subsequent years (it is noted that the average Brent price per barrel in the first quarter of 2017 was USD 54.66 based on the average per barrel price citations on The ICE website); (3) The projected electricity generation price is based on an average exchange rate of NIS 3.65 in 2017 and a long-term average of NIS 4.3 to USD 1.

production capacity used to estimate the discounted cash flows. Furthermore, NSAI did not conduct sensitivity analysis regarding the production capacity of the wells; (h) The discounted cash flows assumed projected sales volumes for each year of the project based on the production capacity from the reservoirs[6] and assessments regarding the scope of demand in the domestic market in each of the years of the project; (i) The discounted cash flow calculation takes into account revenues from gas exports to the local markets in Egypt and Jordan at total aggregate volumes of 27.5 BCM until 2040, inter alia, based on the export agreements set out in sections 1.7.13(e)(1) a and b of the Periodic Report; (j) The discounted cash flow calculation takes into account revenues relating to the MOU signed with Union Fenosa Gas SA as set out in section 1.7.13(e)(1) c to the Periodic Report[7] and execution of the Tamar expansion project, as specified in section 1.7.4(d)(3) of the Periodic Report; (k) The discounted cash flow calculation takes into account the Partnership's assessment regarding the actual rate of royalties to be paid by the Partnerships to the State, at a rate of 11.5%. As at date of issue of this Report, the Tamar partners are holding discussions with the Ministry of Energy regarding the method for calculating the actual rate of royalties payable to the State. Therefore, the actual rate of these royalties is not final and may change, and there is no certainty that the Partnership will succeed in its negotiations to fix a lower rate for royalties in the future. For further information regarding this matter and regarding the arrangements between the parties until the foregoing discussions are concluded, see section 1.7.37(2)(b) of the Periodic Report; (l) The discounted cash flow calculation took into account the oil profits levy applicable to the Company and the Partnership under the law. It is emphasized that calculation of the levy was based on the definitions, formulas and mechanisms set out in the law as these are understood and interpreted by the Company and the Partnership, however, since the law is new and the calculation formulae 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, insofar as a ruling is required on these issues. At the publication date of this Report, these issues have not been discussed in the rulings handed by 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, based on the following assumptions: The developer will choose to report in US dollars according to section 13(B) of the Law, all of the developer's payments (such as production costs, investments, and royalties) will be recognized by the tax authorities for calculation of the levy, and calculation of the developers revenues will take into account the actual selling prices of the gas; (m) The calculation of the discounted cash flows included expenses and investments that were actually paid and those that are expected to be paid by the Partnership as of July 1, 2017, as well as revenues from sales of natural gas and condensate produced as of July 1, 2017.

[6] Gas supply capacity from the Tamar project (including the Tamar project facilities, and the Yam Tethys project compressor systems and pipeline and handling facilities that were upgraded and adapted for use for the Tamar project) to the INGL pipeline was 1.1 BCF per day at maximum production

[7] As of the date of this Report, the Companyg is unable to assess when a binding contract, as aforesaid, will be signed, or whether it will be signed at all.

It is noted that there has been a change in the discounted cash flow compared to the discounted cash flow as of December 31, 2016, for the following reasons:

In view of the information obtained from the Tamar-8 well indicating a significant increase in the volume of reserves in the Tamar Project, the cash flow period in each of the reserve categories was extended. This positively affects the value arising from the discounted cash flow data, but since the volumes were added to the later years to the project lifespan, the effect on the value of the project is lower than the increase in the volume of the reserves, as set out in the table below[8]:

	Total 1P Reserves	Total 2P Reserves	Total 2P Reserves
Rate of increase in the volume of the reserves	15.00%	13.00%	14.00%
Rate of increase in the estimated discounted cash flows at discount rate of 5%	10.38%	8.14%	8.00%
Rate of increase in the estimated discounted cash flows at discount rate of 10%	6.61%	4.51%	4.02%
Rate of increase in the estimated discounted cash flows at discount rate of 15%	4.73%	3.23%	2.87%

Based on various assumptions, as described above, below is the estimated discounted cash flow as of June 30, 2017, in USD thousands (net of the levy and income tax) attributable to the Company's share in the Tamar Project reserves, for each of the reserve categories set out above:

8 The rate of increase in the volume of the reserves and the estimated discounted cash flows are compared with the information published in the Previous Reserves Report.

Total discounted cash flow from Proved Reserves at June 30, 2017 (in USD thousands, relating to the Company's share)																
Cash flow items																
Until	Volume of condensate sales (K barrels) (100% of the oil asset)	Sales volume (BCM) (100% of the oil asset)	Revenue	Royalties payable	Royalties received	Operating costs	Development costs	Abandonment and restoration costs	Total pre-levy and pre-income ta x cash flow (discounted at 0%)	Taxes		Total discounted cash flow after tax				
										Levy	Income tax	Discounted by 0%	Discounted by 5%	Discounted by 10%	Discounted at 15%	Discounted at 20%
Dec 31, 2017	242	5.27	174,483	31,010	14,712	14,156	5,847	-	138,182	-	24,274	113,908	112,527	111,226	109,996	108,832
Dec 31, 2018	489	10.65	366,618	70,780	40,033	26,894	4,974	-	304,003	-	51,847	252,156	240,149	229,233	219,266	210,130
Dec 31, 2019	489	10.65	376,618	72,710	41,125	27,311	10,079	-	307,642	-	55,556	252,086	228,650	208,336	190,614	175,060
Dec 31, 2020	489	10.65	395,451	76,346	43,181	25,910	3,552	-	332,824	45,342	62,063	225,420	194,726	169,361	148,217	130,451
Dec 31, 2021	489	10.65	410,645	79,280	44,840	26,307	20,419	-	329,480	105,891	51,170	172,419	141,850	117,765	98,581	83,150
Dec 31, 2022	489	10.65	422,370	81,543	46,121	26,731	42,571	-	317,645	130,254	47,600	139,791	109,530	86,799	69,501	56,179
Dec 31, 2023	489	10.65	426,823	82,403	46,607	26,731	-	-	364,296	169,613	39,890	154,792	115,508	87,376	66,921	51,840
Dec 31, 2014	489	10.65	432,298	83,460	47,205	26,731	17,738	-	351,574	164,537	42,602	144,436	102,648	74,118	54,299	40,309
Dec 31, 2025	489	10.65	435,305	84,040	47,533	26,731	-	-	372,066	174,127	40,800	157,139	106,358	73,306	51,369	36,545
Dec 31, 2026	489	10.65	437,472	84,459	47,770	26,731	-	-	374,052	175,056	41,495	157,501	101,526	66,796	44,772	30,525
Dec 31, 2027	489	10.65	442,764	85,480	48,347	26,731	-	-	378,900	177,325	43,296	158,278	97,169	61,023	39,124	25,563
Dec 31, 2028	489	10.65	447,026	86,303	48,813	26,731	-	-	382,805	179,153	44,109	159,543	93,282	55,919	34,293	21,473
Dec 31, 2029	489	10.65	456,376	88,108	49,834	26,731	-	-	391,370	183,161	45,265	162,944	90,733	51,919	30,455	18,275
Dec 31, 2030	489	10.65	463,764	89,535	50,641	26,731	35,476	-	362,663	169,726	50,465	142,472	75,556	41,269	23,156	13,316
Dec 31, 2031	489	10.65	467,355	90,228	51,033	26,731	46,118	-	355,310	166,285	51,291	137,734	69,565	36,270	19,466	10,728
Dec 31, 2032	489	10.65	475,206	91,744	51,890	26,731	17,738	-	390,884	182,934	48,422	159,528	76,736	38,190	19,605	10,354
Dec 31, 2033	489	10.65	482,730	93,196	52,712	26,731	-	-	415,514	194,461	47,814	173,239	79,363	37,702	18,513	9,370
Dec 31, 2034	489	10.65	486,705	93,964	53,146	26,731	17,738	-	401,418	187,863	50,169	163,385	71,284	32,325	15,183	7,364
Dec 31, 2035	489	10.65	494,180	95,407	53,962	26,731	-	-	426,004	199,370	48,821	177,813	73,885	31,981	14,368	6,679
Dec 31, 2036	489	10.65	501,147	96,752	54,723	26,731	-	-	432,387	202,357	49,602	180,428	71,401	29,501	12,678	5,648

Dec 31, 2037	489	10.65	507,828	98,042	55,452	26,731	-	-	438,507	205,221	50,351	182,935	68,946	27,192	11,177	4,772
Dec 31, 2038	226	4.93	237,775	45,905	25,964	26,731	-	10,349	180,754	84,593	21,313	74,848	26,866	10,114	3,977	1,627
Dec 31, 2039	117	2.55	124,740	24,082	13,621	26,731	-	10,349	77,198	36,129	8,642	32,428	11,085	3,984	1,498	587
Dec 31, 2040	47	1.03	50,881	9,823	5,556	26,731	-	10,349	9,534	4,462	362	4,710	1,533	526	189	71
Dec 31, 2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2051	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**10,412**	**227**	**9,516,560**	**1,834,600**	**1,034,821**	**628,467**	**222,250**	**31,047**	**7,835,012**	**3,137,860**	**1,017,219**	**3,679,933**	**2,360,876**	**1,682,231**	**1,297,218**	**1,058,848**

Total discounted cash flow from Probable Reserves at June 30, 2017 (in USD thousands, relating to the Company's share)																
Cash flow items																
Until	Volume of condensate sales (K barrels) (100% of the oil asset)	Sales volume (BCM) (100% of the oil asset)	Revenue	Royalties payable	Royalties received	Operating costs	Development costs[9]	Abandonment and restoration costs	Total pre-levy and pre-income ta x cash flow (discounted at 0%)	Taxes		Total discounted cash flow after tax				
										Levy	Income tax	Discounted by 0%	Discounted by 5%	Discounted by 10%	Discounted at 15%	Discounted at 20%
Dec 31, 2017	-	-	-	-	-	-	-	-	-	-	20	(20)	(20)	(20)	(20)	(19)
Dec 31, 2018	-	-	-	-	-	-	-	-	-	-	39	(39)	(37)	(35)	(34)	(32)
Dec 31, 2019	-	-	-	-	-	-	-	-	-	-	39	(39)	(35)	(32)	(29)	(27)
Dec 31, 2020	-	-	-	-	-	-	-	-	-	-	39	(39)	(34)	(29)	(26)	(22)
Dec 31, 2021	-	-	-	-	-	-	(17,738)	-	17,738	6,980	(1,566)	12,325	10,140	8,418	7,047	5,944
Dec 31, 2022	-	-	-	-	-	-	-	-	-	1,703	55	(1,758)	(1,377)	(1,092)	(874)	(706)
Dec 31, 2023	-	-	-	-	-	-	-	-	-	331	371	(702)	(524)	(396)	(303)	(235)
Dec 31, 2014	-	-	-	-	-	-	-	-	-	-	447	(447)	(318)	(229)	(168)	(125)
Dec 31, 2025	-	-	-	-	-	-	-	-	-	-	447	(447)	(302)	(208)	(146)	(104)
Dec 31, 2026	-	-	-	-	-	-	-	-	-	-	447	(447)	(288)	(189)	(127)	(87)
Dec 31, 2027	-	-	-	-	-	-	-	-	-	-	447	(447)	(274)	(172)	(110)	(72)
Dec 31, 2028	-	-	-	-	-	-	17,738	-	(17,738)	(8,301)	2,351	(11,788)	(6,892)	(4,132)	(2,534)	(1,587)
Dec 31, 2029	-	-	-	-	-	-	-	-	-	-	34	(34)	(19)	(11)	(6)	(4)
Dec 31, 2030	-	-	-	-	-	-	(35,476)	-	35,476	16,603	(3,784)	22,658	12,016	6,563	3,682	2,118
Dec 31, 2031	-	-	-	-	-	-	(46,118)	-	46,118	21,583	(4,114)	28,649	14,470	7,544	4,049	2,231

[9] As the level of certainty required to produce the probable reserves (50%) is lower than the level of certainty required to produce the proven reserves (90%), the date of execution of the capital investments required to produce the probable reserves has been postponed to the date of execution of the capital investments required to produce the proven reserves. Thus, the development costs are stated as negative amounts for certain years in the discounted cash flow table from probable reserves and are stated as positive amounts for later years in the same table; and this compared with development costs stated in the discounted cash flow table from proven reserves. For further information concerning the total capital investments required, see the discounted cash flows from 2P reserves (proven reserves (1P) + probable reserves).

Dec 31, 2032	-	-	-	-	-	-	(17,738)	-	17,738	8,301	(284)	9,720	4,676	2,327	1,195	631
Dec 31, 2033	-	-	-	-	-	-	17,738	-	(17,738)	(8,301)	4,045	(13,481)	(6,176)	(2,934)	(1,441)	(729)
Dec 31, 2034	-	-	-	-	-	-	(17,738)	-	17,738	8,301	(182)	9,618	4,196	1,903	894	434
Dec 31, 2035	-	-	-	-	-	-	-	-	-	-	2,407	(2,407)	(1,000)	(433)	(195)	(90)
Dec 31, 2036	-	-	-	-	-	-	-	-	-	-	2,407	(2,407)	(953)	(394)	(169)	(75)
Dec 31, 2037	-	-	-	-	-	-	28,381	-	(28,381)	(13,282)	5,462	(20,561)	(7,749)	(3,056)	(1,256)	(536)
Dec 31, 2038	263	5.73	276,330	53,348	30,174	-	35,476	(10,349)	228,028	106,717	35,315	85,996	30,868	11,621	4,569	1,869
Dec 31, 2039	372	8.10	395,678	76,390	43,206	-	-	(10,349)	372,842	174,490	44,467	153,885	52,606	18,904	7,110	2,787
Dec 31, 2040	442	9.62	475,109	91,725	51,879	-	17,738	(10,349)	427,874	200,245	55,280	172,349	56,112	19,248	6,924	2,602
Dec 31, 2041	489	10.65	532,376	102,781	58,133	26,731	-	-	460,996	215,746	54,014	191,236	59,296	19,415	6,681	2,406
Dec 31, 2042	489	10.65	538,824	104,026	58,837	26,731	-	-	466,904	218,511	54,737	193,656	57,187	17,874	5,883	2,030
Dec 31, 2043	407	8.87	454,003	87,650	49,575	26,731	17,738	-	371,459	173,843	47,138	150,478	42,320	12,626	3,975	1,314
Dec 31, 2044	397	8.65	448,298	86,549	48,952	26,731	-	-	383,969	179,698	44,492	159,779	42,797	12,188	3,670	1,163
Dec 31, 2045	361	7.86	412,383	79,615	45,030	26,731	-	-	351,067	164,299	40,466	146,301	37,321	10,145	2,922	888
Dec 31, 2046	295	6.43	341,368	65,905	37,276	26,731	-	-	286,007	133,851	32,506	119,650	29,069	7,543	2,078	605
Dec 31, 2047	226	4.91	264,064	50,980	28,834	26,731	-	-	215,186	100,707	23,840	90,639	20,972	5,194	1,369	382
Dec 31, 2048	173	3.76	204,408	39,463	22,320	26,731	-	-	160,533	75,130	17,895	67,509	14,876	3,517	887	237
Dec 31, 2049	107	2.32	127,928	24,698	13,969	26,732	-	10,349	80,119	37,496	11,261	31,362	6,582	1,485	358	92
Dec 31, 2050	97	2.12	118,265	22,832	12,914	26,732	-	10,349	71,266	33,352	10,178	27,736	5,544	1,194	275	68
Dec 31, 2051	70	1.53	86,170	16,636	9,409	26,732	-	10,349	41,862	19,592	6,998	15,272	2,907	598	132	31
Dec 31, 2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,188**	**91**	**4,675,204**	**902,598**	**510,508**	**294,044**	**1**	**-**	**3,989,063**	**1,867,595**	**487,714**	**1,633,755**	**477,957**	**154,945**	**56,262**	**23,382**

Total discounted cash flow from 2P Reserves (Proved + Probable Reserves) at June 30, 2017 (in USD thousands, relating to the Company's share)																
Cash flow items																
Until	Volume of condensate sales (K barrels) (100% of the oil asset)	Sales volume (BCM) (100% of the oil asset)	Revenue	Royalties payable	Royalties received	Operating costs	Development costs	Abandonment and restoration costs	Total pre-levy and pre-income ta x cash flow discounted at 0%)	Taxes		Total discounted cash flow after tax				
										Levy	Income tax	Discounted by 0%	Discounted by 5%	Discounted by 10%	Discounted by 15%	Discounted by 20%
Dec 31, 2017	242	5.27	174,483	31,010	14,712	14,156	5,847	-	138,182	-	24,294	113,887	112,507	111,206	109,977	108,813
Dec 31, 2018	489	10.65	366,618	70,780	40,033	26,894	4,974	-	304,003	-	51,886	252,118	240,112	229,198	219,233	210,098
Dec 31, 2019	489	10.65	376,618	72,710	41,125	27,311	10,079	-	307,642	-	55,595	252,048	228,615	208,304	190,584	175,033
Dec 31, 2020	489	10.65	395,451	76,346	43,181	25,910	3,552	-	332,824	45,342	62,102	225,381	194,692	169,332	148,192	130,429
Dec 31, 2021	489	10.65	410,645	79,280	44,840	26,307	2,681	-	347,218	112,871	49,603	184,744	151,989	126,183	105,628	89,093
Dec 31, 2022	489	10.65	422,370	81,543	46,121	26,731	42,571	-	317,645	131,957	47,655	138,034	108,153	85,708	68,627	55,473
Dec 31, 2023	489	10.65	426,823	82,403	46,607	26,731	-	-	364,296	169,944	40,261	154,091	114,985	86,980	66,618	51,605
Dec 31, 2014	489	10.65	432,298	83,460	47,205	26,731	17,738	-	351,574	164,537	43,048	143,989	102,330	73,889	54,131	40,185
Dec 31, 2025	489	10.65	435,305	84,040	47,533	26,731	-	-	372,066	174,127	41,247	156,692	106,055	73,098	51,223	36,442
Dec 31, 2026	489	10.65	437,472	84,459	47,770	26,731	-	-	374,052	175,056	41,942	157,054	101,238	66,606	44,645	30,438
Dec 31, 2027	489	10.65	442,764	85,480	48,347	26,731	-	-	378,900	177,325	43,743	157,831	96,895	60,851	39,014	25,491
Dec 31, 2028	489	10.65	447,026	86,303	48,813	26,731	17,738	-	365,067	170,851	46,460	147,755	86,389	51,787	31,759	19,886
Dec 31, 2029	489	10.65	456,376	88,108	49,834	26,731	-	-	391,370	183,161	45,299	162,910	90,714	51,908	30,449	18,271
Dec 31, 2030	489	10.65	463,764	89,535	50,641	26,731	-	-	398,139	186,329	46,681	165,129	87,572	47,832	26,838	15,434
Dec 31, 2031	489	10.65	467,355	90,228	51,033	26,731	-	-	401,428	187,868	47,177	166,383	84,035	43,814	23,515	12,959
Dec 31, 2032	489	10.65	475,206	91,744	51,890	26,731	-	-	408,621	191,235	48,138	169,248	81,411	40,517	20,800	10,985
Dec 31, 2033	489	10.65	482,730	93,196	52,712	26,731	17,738	-	397,776	186,159	51,859	159,758	73,187	34,768	17,073	8,641
Dec 31, 2034	489	10.65	486,705	93,964	53,146	26,731	-	-	419,155	196,165	49,987	173,004	75,481	34,228	16,077	7,798
Dec 31, 2035	489	10.65	494,180	95,407	53,962	26,731	-	-	426,004	199,370	51,228	175,406	72,885	31,548	14,174	6,588
Dec 31, 2036	489	10.65	501,147	96,752	54,723	26,731	-	-	432,387	202,357	52,009	178,020	70,449	29,108	12,509	5,572
Dec 31, 2037	489	10.65	507,828	98,042	55,452	26,731	28,381	-	410,127	191,939	55,813	162,374	61,197	24,136	9,921	4,235

Dec 31, 2038	489	10.65	514,105	99,254	56,138	26,731	35,476	-	408,782	191,310	56,628	160,844	57,734	21,735	8,546	3,496
Dec 31, 2039	489	10.65	520,418	100,472	56,827	26,731	-	-	450,041	210,619	53,109	186,313	63,691	22,888	8,608	3,375
Dec 31, 2040	489	10.65	525,990	101,548	57,435	26,731	17,738	-	437,408	204,707	55,643	177,058	57,645	19,774	7,113	2,673
Dec 31, 2041	489	10.65	532,376	102,781	58,133	26,731	-	-	460,996	215,746	54,014	191,236	59,296	19,415	6,681	2,406
Dec 31, 2042	489	10.65	538,824	104,026	58,837	26,731	-	-	466,904	218,511	54,737	193,656	57,187	17,874	5,883	2,030
Dec 31, 2043	407	8.87	454,003	87,650	49,575	26,731	17,738	-	371,459	173,843	47,138	150,478	42,320	12,626	3,975	1,314
Dec 31, 2044	397	8.65	448,298	86,549	48,952	26,731	-	-	383,969	179,698	44,492	159,779	42,797	12,188	3,670	1,163
Dec 31, 2045	361	7.86	412,383	79,615	45,030	26,731	-	-	351,067	164,299	40,466	146,301	37,321	10,145	2,922	888
Dec 31, 2046	295	6.43	341,368	65,905	37,276	26,731	-	-	286,007	133,851	32,506	119,650	29,069	7,543	2,078	605
Dec 31, 2047	226	4.91	264,064	50,980	28,834	26,731	-	-	215,186	100,707	23,840	90,639	20,972	5,194	1,369	382
Dec 31, 2048	173	3.76	204,408	39,463	22,320	26,731	-	-	160,533	75,130	17,895	67,509	14,876	3,517	887	237
Dec 31, 2049	107	2.32	127,928	24,698	13,969	26,732	-	10,349	80,119	37,496	11,261	31,362	6,582	1,485	358	92
Dec 31, 2050	97	2.12	118,265	22,832	12,914	26,732	-	10,349	71,266	33,352	10,178	27,736	5,544	1,194	275	68
Dec 31, 2051	70	1.53	86,170	16,636	9,409	26,732	-	10,349	41,862	19,592	6,998	15,272	2,907	598	132	31
Dec 31, 2052	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2053	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec 31, 2055	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**14,600**	**318**	**14,191,764**	**2,737,199**	**1,545,329**	**922,511**	**222,251**	**31,047**	**11,824,075**	**5,005,454**	**1,504,932**	**5,313,689**	**2,838,832**	**1,837,177**	**1,353,484**	**1,082,229**

Total discounted cash flow from Possible Reserves at June 30 2017 (in USD thousands, relating to the Company's share)

Cash flow items

Until	Quantity of condensate sales (thousands of barrels) (100% of the oil asset)	Sales quantity (BCM) (100% of the oil asset)	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 by 0%	Discounted by 5%	Discounted by 10%	Discounted at 15%	Discounted at 20%
Dec 31, 2017	-	-	-	-	-	-	-	-	-	-	5	(5)	(5)	(5)	(5)	(5)
Dec 31, 2018	-	-	-	-	-	-	-	-	-	-	9	(9)	(9)	(8)	(8)	(8)
Dec 31, 2019	-	-	-	-	-	-	-	-	-	-	9	(9)	(8)	(8)	(7)	(6)
Dec 31, 2020	-	-	-	-	-	-	-	-	-	-	9	(9)	(8)	(7)	(6)	(5)
Dec 31, 2021	-	-	-	-	-	-	-	-	-	-	9	(9)	(8)	(6)	(5)	(4)
Dec 31, 2022	-	-	-	-	-	-	-	-	-	-	9	(9)	(7)	(6)	(5)	(4)
Dec 31, 2023	-	-	-	-	-	-	17,738	-	(17,738)	(8,334)	1,926	(11,330)	(8,455)	(6,396)	(4,898)	(3,794)
Dec 31, 2024	-	-	-	-	-	-	(17,738)	-	17,738	8,301	(2,308)	11,744	8,347	6,027	4,415	3,278
Dec 31, 2025	-	-	-	-	-	-	-	-	-	-	9	(9)	(6)	(4)	(3)	(2)
Dec 31, 2026	-	-	-	-	-	-	-	-	-	-	9	(9)	(6)	(4)	(3)	(2)
Dec 31, 2027	-	-	-	-	-	-	-	-	-	-	9	(9)	(6)	(4)	(2)	(2)
Dec 31, 2028	-	-	-	-	-	-	-	-	-	-	9	(9)	(5)	(3)	(2)	(1)
Dec 31, 2029	-	-	-	-	-	-	-	-	-	-	9	(9)	(5)	(3)	(2)	(1)
Dec 31, 2030	-	-	-	-	-	-	-	-	-	-	9	(9)	(5)	(3)	(2)	(1)
Dec 31, 2031	-	-	-	-	-	-	-	-	-	-	9	(9)	(5)	(2)	(1)	(1)
Dec 31, 2032	-	-	-	-	-	-	-	-	-	-	9	(9)	(4)	(2)	(1)	(1)
Dec 31, 2033	-	-	-	-	-	-	(17,738)	-	17,738	8,301	(1,900)	11,337	5,193	2,467	1,211	613
Dec 31, 2034	-	-	-	-	-	-	-	-	-	-	821	(821)	(358)	(162)	(76)	(37)
Dec 31, 2035	-	-	-	-	-	-	-	-	-	-	417	(417)	(173)	(75)	(34)	(16)
Dec 31, 2036	-	-	-	-	-	-	17,738	-	(17,738)	(8,301)	2,327	(11,763)	(4,655)	(1,923)	(827)	(368)
Dec 31, 2037	-	-	-	-	-	-	(10,643)	-	10,643	4,981	(1,136)	6,798	2,562	1,011	415	177

Dec 31, 2038	-	-	-	-	-	-	(35,476)	-	35,476	16,603	(3,564)	22,438	8,054	3,032	1,192	488
Dec 31, 2039	-	-	-	-	-	-	-	-	-	-	1,070	(1,070)	(366)	(131)	(49)	(19)
Dec 31, 2040	-	-	-	-	-	-	(17,738)	-	17,738	8,301	(839)	10,276	3,346	1,148	413	155
Dec 31, 2041	-	-	-	-	-	-	-	-	-	-	1,495	(1,495)	(464)	(152)	(52)	(19)
Dec 31, 2042	-	-	-	-	-	-	46,118	-	(46,118)	(21,583)	6,459	(30,994)	(9,153)	(2,861)	(942)	(325)
Dec 31, 2043	82	1.78	91,366	17,639	9,977	-	-	-	83,703	39,173	10,677	33,854	9,521	2,841	894	296
Dec 31, 2044	92	2.00	103,696	20,020	11,323	-	-	-	95,000	44,460	11,748	38,792	10,390	2,959	891	282
Dec 31, 2045	128	2.79	146,323	28,249	15,978	-	-	-	134,051	62,736	16,526	54,789	13,976	3,799	1,094	332
Dec 31, 2046	194	4.22	224,146	43,274	24,476	-	-	-	205,347	96,103	25,250	83,995	20,406	5,295	1,459	425
Dec 31, 2047	263	5.74	308,350	59,530	33,670	-	-	-	282,490	132,205	35,102	115,183	26,651	6,601	1,740	485
Dec 31, 2048	317	6.89	374,955	72,389	40,943	-	-	-	343,509	160,762	42,239	140,508	30,962	7,320	1,845	493
Dec 31, 2049	311	6.77	372,691	71,952	40,696	-	-	(10,349)	351,784	164,635	40,046	147,103	30,872	6,967	1,680	430
Dec 31, 2050	326	7.10	395,550	76,365	43,192	-	17,738	(10,349)	354,988	166,134	44,518	144,336	28,849	6,215	1,433	352
Dec 31, 2051	204	4.45	251,045	48,467	27,413	-	-	(10,349)	240,340	112,479	25,201	102,659	19,542	4,018	886	209
Dec 31, 2052	248	5.40	308,301	59,521	33,665	26,732	-	-	255,713	119,674	31,289	104,750	18,990	3,727	787	177
Dec 31, 2053	206	4.49	259,397	50,079	28,325	26,732	-	10,349	200,561	93,862	26,921	79,777	13,774	2,581	521	113
Dec 31, 2054	169	3.68	214,972	41,503	23,474	26,733	-	10,349	159,862	74,815	21,941	63,106	10,377	1,856	358	74
Dec 31, 2055	151	3.28	194,104	37,474	21,195	26,733	-	10,349	140,743	65,868	19,602	55,274	8,656	1,478	273	54
Total	**2,691**	**59**	**3,244,896**	**626,462**	**354,327**	**106,930**	**(1)**	-	**2,865,830**	**1,341,175**	**355,950**	**1,168,707**	**246,757**	**57,577**	**14,577**	**3,812**

Total discounted cash flow from 3P Reserves (Proved + Probable + Possible Reserves) at June 30, 2017 (in USD thousands, relating to the Company's share)																
Cash flow items																
Until	Volume of condensate sales (K barrels) (100% of the oil asset)	Sales volume (BCM) (100% of the oil asset)	Revenue	Royalties payable	Royalties received	Operating costs	Development costs	Abandonment and restoration costs	Total pre-levy and pre-income tax cash flow (discounted at 0%)	Taxes		Total discounted cash flow after tax				
										Levy	Income tax	Discounted by 0%	Discounted by 5%	Discounted by 10%	Discounted by 15%	Discounted by 20%
Dec 31, 2017	242	5.27	174,483	31,010	14,712	14,156	5,847	-	138,182	-	24,299	113,883	112,502	111,201	109,972	108,808
Dec 31, 2018	489	10.65	366,618	70,780	40,033	26,894	4,974	-	304,003	-	51,895	252,108	240,103	229,189	219,225	210,090
Dec 31, 2019	489	10.65	376,618	72,710	41,125	27,311	10,079	-	307,642	-	55,604	252,038	228,606	208,296	190,577	175,027
Dec 31, 2020	489	10.65	395,451	76,346	43,181	25,910	3,552	-	332,824	45,342	62,111	225,372	194,684	169,325	148,185	130,423
Dec 31, 2021	489	10.65	410,645	79,280	44,840	26,307	2,681	-	347,218	112,871	49,613	184,735	151,982	126,176	105,623	89,089
Dec 31, 2022	489	10.65	422,370	81,543	46,121	26,731	42,571	-	317,645	131,957	47,664	138,024	108,146	85,702	68,622	55,469
Dec 31, 2023	489	10.65	426,823	82,403	46,607	26,731	17,738	-	346,558	161,610	42,187	142,760	106,530	80,585	61,719	47,810
Dec 31, 2014	489	10.65	432,298	83,460	47,205	26,731	-	-	369,312	172,838	40,740	155,733	110,677	79,916	58,546	43,462
Dec 31, 2025	489	10.65	435,305	84,040	47,533	26,731	-	-	372,066	174,127	41,256	156,683	106,049	73,094	51,220	36,439
Dec 31, 2026	489	10.65	437,472	84,459	47,770	26,731	-	-	374,052	175,056	41,951	157,045	101,232	66,602	44,642	30,436
Dec 31, 2027	489	10.65	442,764	85,480	48,347	26,731	-	-	378,900	177,325	43,752	157,822	96,889	60,847	39,011	25,489
Dec 31, 2028	489	10.65	447,026	86,303	48,813	26,731	17,738	-	365,067	170,851	46,470	147,746	86,384	51,784	31,757	19,885
Dec 31, 2029	489	10.65	456,376	88,108	49,834	26,731	-	-	391,370	183,161	45,308	162,901	90,709	51,905	30,447	18,270
Dec 31, 2030	489	10.65	463,764	89,535	50,641	26,731	-	-	398,139	186,329	46,690	165,120	87,567	47,829	26,837	15,433
Dec 31, 2031	489	10.65	467,355	90,228	51,033	26,731	-	-	401,428	187,868	47,186	166,373	84,030	43,811	23,513	12,958
Dec 31, 2032	489	10.65	475,206	91,744	51,890	26,731	-	-	408,621	191,235	48,148	169,239	81,407	40,514	20,799	10,985
Dec 31, 2033	489	10.65	482,730	93,196	52,712	26,731	-	-	415,514	194,461	49,959	171,095	78,380	37,235	18,284	9,254
Dec 31, 2034	489	10.65	486,705	93,964	53,146	26,731	-	-	419,155	196,165	50,808	172,183	75,123	34,066	16,000	7,761
Dec 31, 2035	489	10.65	494,180	95,407	53,962	26,731	-	-	426,004	199,370	51,646	174,989	72,711	31,473	14,140	6,573
Dec 31, 2036	489	10.65	501,147	96,752	54,723	26,731	17,738	-	414,649	194,056	54,336	166,257	65,794	27,184	11,682	5,204
Dec 31, 2037	489	10.65	507,828	98,042	55,452	26,731	17,738	-	420,770	196,920	54,677	169,173	63,759	25,146	10,336	4,413

Dec 31, 2038	489	10.65	514,105	99,254	56,138	26,731	-	-	444,258	207,913	53,063	183,282	65,788	24,767	9,738	3,984
Dec 31, 2039	489	10.65	520,418	100,472	56,827	26,731	-	-	450,041	210,619	54,179	185,243	63,325	22,756	8,558	3,355
Dec 31, 2040	489	10.65	525,990	101,548	57,435	26,731	-	-	455,146	213,008	54,803	187,334	60,991	20,921	7,526	2,828
Dec 31, 2041	489	10.65	532,376	102,781	58,133	26,731	-	-	460,996	215,746	55,510	189,740	58,832	19,264	6,628	2,387
Dec 31, 2042	489	10.65	538,824	104,026	58,837	26,731	46,118	-	420,786	196,928	61,197	162,661	48,034	15,013	4,941	1,705
Dec 31, 2043	489	10.65	545,369	105,289	59,551	26,731	17,738	-	455,162	213,016	57,815	184,331	51,841	15,466	4,869	1,610
Dec 31, 2044	489	10.65	551,994	106,568	60,275	26,731	-	-	478,969	224,158	56,240	198,571	53,187	15,147	4,561	1,446
Dec 31, 2045	489	10.65	558,705	107,864	61,008	26,731	-	-	485,118	227,035	56,992	201,090	51,297	13,944	4,017	1,220
Dec 31, 2046	489	10.65	565,513	109,178	61,751	26,731	-	-	491,355	229,954	57,756	203,645	49,475	12,838	3,537	1,029
Dec 31, 2047	489	10.65	572,414	110,511	62,505	26,731	-	-	497,677	232,913	58,942	205,822	47,623	11,795	3,109	867
Dec 31, 2048	489	10.65	579,363	111,852	63,263	26,731	-	-	504,042	235,892	60,134	208,017	45,838	10,837	2,732	730
Dec 31, 2049	418	9.09	500,619	96,650	54,665	26,732	-	-	431,902	202,130	51,307	178,465	37,454	8,453	2,038	522
Dec 31, 2050	423	9.22	513,815	99,198	56,106	26,732	17,738	-	426,254	199,487	54,695	172,072	34,392	7,409	1,709	419
Dec 31, 2051	275	5.98	337,215	65,103	36,822	26,732	-	-	282,202	132,070	32,200	117,931	22,449	4,616	1,018	240
Dec 31, 2052	248	5.40	308,301	59,521	33,665	26,732	-	-	255,713	119,674	31,289	104,750	18,990	3,727	787	177
Dec 31, 2053	206	4.49	259,397	50,079	28,325	26,732	-	10,349	200,561	93,862	26,921	79,777	13,774	2,581	521	113
Dec 31, 2054	169	3.68	214,972	41,503	23,474	26,733	-	10,349	159,862	74,815	21,941	63,106	10,377	1,856	358	74
Dec 31, 2055	151	3.28	194,104	37,474	21,195	26,733	-	10,349	140,743	65,868	19,602	55,274	8,656	1,478	273	54
Total	**17,291**	**377**	**17,436,658**	**3,363,661**	**1,899,655**	**1,029,441**	**222,250**	**31,047**	**14,689,906**	**6,346,630**	**1,860,886**	**6,482,390**	**3,085,587**	**1,894,748**	**1,368,057**	**1,086,038**

Note: It is clarified that the discounted cash flow figures, whether they have been 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, 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 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 actual performance of the project and/or as a result of actual selling prices and/or due to geo-political changes.

Sensitivity analysis for the main parameters of the discounted cash flow (gas price and volume of gas sold) at June 30, 2017 (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**				
1P Proved Reserves	4,014,525	1,816,409	1,396,251	1,137,557	1P Proved Reserves	3,343,240	1,544,891	1,194,872	976,821
Probable Reserves	1,809,098	170,020	61,130	24,998	Probable Reserves	1,458,697	139,978	51,484	21,840
Total 2P Reserves (Proved + Probable Reserves)	5,823,623	1,986,429	1,457,381	1,162,555	Total 2P Reserves (Proved + Probable Reserves)	4,801,936	1,684,869	1,246,356	998,661
Possible Reserves	1,290,452	63,282	15,984	4,183	Possible Reserves	1,047,283	52,051	13,312	3,549
Total 3P Reserves (Proved + Probable + Possible Reserves)	7,114,074	2,049,711	1,473,365	1,166,738	Total 3P Reserves (Proved + Probable + Possible Reserves)	5,849,220	1,736,920	1,259,668	1,002,209
15% increase in the price of gas					**15% decrease in the price of gas**				
1P Proved Reserves	4,814,081	1,884,000	1,445,724	1,176,468	1P Proved Reserves	3,176,564	1,475,929	1,142,894	934,679
(Probable Reserves	1,896,992	177,705	63,686	25,909	Probable Reserves	1,371,819	132,896	49,440	21,370
Total 2P Reserves (Proved + Probable Reserves)	6,081,073	2,061,705	1,509,410	1,202,377	Total 2P Reserves (Proved + Probable Reserves)	4,548,384	1,608,825	1,192,334	956,049
Possible Reserves	1,351,340	66,142	16,692	4,372	Possible Reserves	986,403	49,168	12,578	3,333
Total 3P Reserves (Proved + Probable + Possible Reserves)	7,432,412	2,127,847	1,526,102	1,206,749	Total 3P Reserves (Proved + Probable + Possible Reserves)	5,534,786	1,657,994	1,204,911	959,382
20% increase in the price of gas					**20% decrease in the price of gas**				
1P Proved Reserves	4,353,293	1,950,869	1,494,389	1,214,522	1P Proved Reserves	3,011,041	1,406,852	1,090,515	891,973
ProbableReserves	1,984,919	185,442	66,296	26,873	Probable Reserves	1,282,675	124,182	45,999	19,701
Total 2P Reserves (Proved + Probable Reserves)	6,338,212	2,136,312	1,560,684	1,241,395	Total 2P Reserves (Proved + Probable Reserves)	4,293,716	1,531,034	1,136,514	911,674
Possible Reserves	1,412,228	69,003	17,400	4,561	Possible Reserves	925,182	46,114	11,720	3,025
Total 3P Reserves (Proved + Probable + Possible Reserves)	7,750,440	2,205,314	1,578,085	1,245,956	Total 3P Reserves (Proved + Probable + Possible Reserves)	5,218,898	1,577,148	1,148,233	914,699

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 quantity of gas sales					**10% decrease in the quantity of gas sales**				
1P Proved Reserves	3,656,704	1,765,128	1,375,482	1,128,803	1P Proved Reserves	3,508,170	1,560,906	1,200,317	978,770
Probable Reserves	1,596,612	187,286	72,692	31,104	Probable Reserves	1,494,966	129,304	47,058	20,107
Total 2P Reserves (Proved + Probable Reserves)	5,253,316	1,952,415	1,448,174	1,159,907	Total 2P Reserves (Proved + Probable Reserves)	5,003,136	1,690,211	1,247,375	998,877
Possible Reserves	1,149,715	70,790	19,419	5,480	Possible Reserves	1,320,790	172,629	136,187	131,389
Total 3P Reserves (Proved + Probable + Possible Reserves)	6,403,031	2,023,204	1,467,593	1,165,387	Total 3P Reserves (Proved + Probable + Possible Reserves)	6,323,926	1,862,839	1,383,562	1,130,266
15% increase in the quantity of gas sales					**15% decrease in the quantity of gas sales**				
1P Proved Reserves	3,620,454	1,799,476	1,410,738	1,161,406	1P Proved Reserves	3,520,193	1,501,929	1,150,948	937,352
Probable Reserves	1,603,565	206,115	82,752	36,171	Probable Reserves	1,213,962	111,860	42,339	18,903
Total 2P Reserves (Proved + Probable Reserves)	5,224,019	2,005,590	1,493,490	1,197,578	Total 2P Reserves (Proved + Probable Reserves)	4,734,155	1,613,789	1,193,287	956,255
Possible Reserves	1,118,757	77,308	22,316	6,637	Possible Reserves	1,685,721	173,318	130,926	125,335
Total 3P Reserves (Proved + Probable + Possible Reserves)	6,342,776	2,082,898	1,515,806	1,204,215	Total 3P Reserves (Proved + Probable + Possible Reserves)	6,419,875	1,787,108	1,324,213	1,081,590
20% increase in the quantity of gas sales					**20% decrease in the quantity of gas sales**				
1P Proved Reserves	3,604,232	1,833,704	1,444,857	1,192,746	1P Proved Reserves	3,540,561	1,437,967	1,099,450	894,790
Probable Reserves	1,591,623	222,111	92,119	41,230	Probable Reserves	923,497	97,652	37,951	17,079
Total 2P Reserves (Proved + Probable Reserves)	5,195,855	2,055,815	1,536,976	1,233,976	Total 2P Reserves (Proved + Probable Reserves)	4,464,059	1,535,619	1,137,401	911,869
Possible Reserves	1,100,565	84,769	25,698	8,040	Possible Reserves	2,052,466	175,341	128,614	122,365
Total 3P Reserves (Proved + Probable + Possible Reserves)	6,296,420	2,140,584	1,562,674	1,242,016	Total 3P Reserves (Proved + Probable + Possible Reserves)	6,516,525	1,710,961	1,266,015	1,034,234

Sensitivity analysis of the key gas price linkage components under the Partnerships' for gas sales agreements (US-CPI and Public Utilities Authority rate) as of June 30, 2017 (USD thousands), performed by the Company[10]:

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 projected CPI					**10% decrease in projected CPI**				
1P Proved Reserves	3,694,624	1,688,175	1,301,460	1,062,047	1P Proved Reserves	3,667,393	1,677,608	1,294,054	1,056,543
Probable Reserves	1,637,631	155,302	56,383	23,423	Probable Reserves	1,630,121	154,619	56,158	23,348
Total 2P Reserves (Proved + Probable Reserves)	5,332,255	1,843,477	1,357,842	1,085,470	Total 2P Reserves (Proved + Probable Reserves)	5,297,514	1,832,227	1,350,212	1,079,891
Possible Reserves	1,170,304	57,653	14,597	3,816	Possible Reserves	1,167,266	57,510	14,568	3,814
Total 3P Reserves (Proved + Probable + Possible Reserves)	6,502,559	1,901,131	1,372,439	1,089,286	Total 3P Reserves (Proved + Probable + Possible Reserves)	6,464,780	1,889,738	1,364,780	1,083,704
10% increase in projected electricity generation price					**10% decrease in projected electricity generation price**				
1P Proved Reserves	3,852,229	1,742,206	1,338,097	1,088,858	1P Proved Reserves	3,520,094	1,632,823	1,266,125	1,037,933
Probable Reserves	1,751,781	165,037	59,544	24,501	Probable Reserves	1,515,813	144,869	52,988	22,262
Total 2P Reserves (Proved + Probable Reserves)	5,604,010	1,907,243	1,397,641	1,113,359	Total 2P Reserves (Proved + Probable Reserves)	5,035,907	1,777,693	1,319,113	1,060,195
Possible Reserves	1,256,458	61,645	15,575	4,072	Possible Reserves	1,081,052	53,514	13,588	3,556
Total 3P Reserves (Proved + Probable + Possible Reserves)	6,860,468	1,968,888	1,413,216	1,117,431	Total 3P Reserves (Proved + Probable + Possible Reserves)	6,116,959	1,831,206	1,332,701	1,063,751

[10] Although the electricity generation price is affected, among other things, by the CPI, the sensitivity analysis in the table below does not take this into account.

Sensitivity analysis for sales of volumes exceeding the minimum volumes (take or pay) in accordance with the Partnerships' gas sales agreements at June 30, 2017 (USD thousand), 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%
An increase in the sales quantity of gas for quantities that are beyond the take of pay, at 10%					**A decrease in the sales quantity of gas for quantities that are beyond the take of pay, at 10%**				
1P Proved Reserves	3,809,805	1,782,258	1,379,257	1,126,707	1P Proved Reserves	3,854,222	1,679,071	1,288,224	1,050,519
Probable Reserves	1,624,192	161,985	59,724	24,992	Probable Reserves	1,674,534	138,559	49,318	20,744
Total 2P Reserves (Proved + Probable Reserves)	5,433,998	1,944,242	1,438,981	1,151,699	Total 2P Reserves (Proved + Probable Reserves)	5,528,756	1,817,630	1,337,542	1,071,263
Possible Reserves	1,152,954	58,797	15,032	3,966	Possible Reserves	861,247	46,699	12,370	3,386
Total 3P Reserves (Proved + Probable + Possible Reserves)	6,586,951	2,003,039	1,454,014	1,155,665	Total 3P Reserves (Proved + Probable + Possible Reserves)	6,390,003	1,864,330	1,349,912	1,074,649

D. **Reconciliation of the information in the report and information in previous reports relating to the oil asset**

The main differences between the Previous Reserves Report and the current Reserves Report are mainly due to data received from the Tamar-8 well and revised mapping of the Tamar and SW Tamar SW reservoirs, indicating a substantial increase in the volume of reserves in the Tamar Project, as follows:

The volumes of the natural gas and condensate in the Tamar Lease have increased in the proved reserves (1P) category by 15% (from 7.0 TCF and 9.1 million barrels of condensate in the Previous Reserves Report to 8.0 TCF and 10.4 million barrels of condensate in the current Reserves Report); in the Proved + Probable (2P) category by 13% (from 10.0 TCF and 13.0 million barrels of condensate in the Previous Reserves Report to 11.2 TCF and 14.6 million barrels of condensate in the current Reserves Report); in the Proved + Probable + Possible (3P) category by 14% (from 11.7 TCF and 15.2 million barrels of condensate in the Previous Reserves Report to 13.3 TCF and 17.3 million barrels of condensate in the current Reserves Report).

The main reasons for these changes are an increase in the gross rock volume assessment, a decrease in the water saturation assessment, an increase in porosity and increase in the gas recovery factor, all as aforesaid, based on analysis of the results of the Tamar-8 well, revised analysis of the seismic survey, the logs and rock samples from the reservoir wells and from the analysis of the up-to-date production figures.

E. **Production Figures**

With regard to the Tamar Project production figures attributable to the Company in 2014-2016 and in the three months ended March 31, 2017[11], see the Periodic Report and Q1 2017 quarterly report of the Company, which was published on May 29, 2017 (Ref. No.: 2017-01-054909).

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

F. **Expert opinion of the assessor:**

A reserves report prepared by NSAI for the Tamar Project (which includes the Tamar and Tamar SW reservoirs) as of June30, 2017, is attached to this report by way of reference to the attached Reserves Report as Appendix A to the Immediate Report of the Partnership dated July 2, 2017 (Ref. No.: 2017-01-055915) and NSAI's consent to include the report in this report is attached as Appendix A to this Report.

G. **Glossary**

---

[11] It should be noted that since the commencement of natural gas pumping from the Tamar Project (i.e. March 30, 2013) through March 30, 2017 a total volume of 32.9 BCM of natural gas has been supplied to customers. It is further noted that the average per day production natural gas in the past two years (April 1, 2015 through March 31, 2017) is 875 MMCF (0.875 BCF).

Lease – as defined in the Petroleum Law, 1952 ("the Petroleum Law").

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

Petroleum Resources Management System (2007) - (SPE-PRMS) – a system for reporting assessments of oil reserves and resources, as published by the Society of Petroleum Engineers, the American Association of Petroleum Geologists (AAPG), the World Petroleum Council (WPC) and the Society of Petroleum Evaluation Engineers (SPEE) and as revised from time to time

Oil asset – the lease, direct or indirect, in a preliminary permit, license or lease; in another country – the lease, direct or indirect, in a similar right granted by a competent party. The oil asset is also regarded as the right to receive benefits arising from the lease, direct or indirect, in the oil asset or in a similar right (as the case may be).

Oil – any petroleum fluid, whether liquid or gaseous and includes oil, natural gas, natural gasoline, condensates and (carbons) hydrocarbons and also asphalt and other solid petroleum hydrocarbons when dissolved in and producible with fluid petroleum

Reserves – defined under the Petroleum Resources Management System (SPE-PRMS) as the volumes of oil estimated to be recoverable by executing a development plan for discovered deposits from a certain date onwards, under defined conditions. Reserves are required to meet four conditions: (1) they must be discoverable; (2) recoverable; (3) commercially viable; (4) sustainable, based on the executed development project.

Condensate – gaseous hydrocarbons found in the reservoir conditions, but which liquefy when transmitted from the reservoir to the surface.

License – as defined in the Petroleum Law

BCF – billions of cubic feet, which is 0.001 TCF or 0.0283 BCM

BCM – billion cubic meters

MMCF – millions of cubic feet, which is 0.001 BCF or 0.0003 BCM

Conversion table for units used in the report:

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

Partners in the Tamar Project and the rate of their holdings are as follows:

Noble Energy Mediterranean Ltd.	32.50%
Isramco Negev 2 Limited Partnership	28.75%
Delek Drilling Limited Partnership	31.25%
Dor Gas Exploration Limited Partnership	4.00%
Everest Infrastructures Limited Partnership	3.50%

This is a convenience translation of the original HEBREW immediate report issued to the Tel Aviv Stock Exchange by the Company on July 02, 2017.

About The Delek Group

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

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

Contact

Investors

Dina Vince
Head of Investor Relations
Delek Group Ltd.
Tel: +972 9 863 8444
investor@delek-group.com

Media

Nilly Richman
Head of Communications
Delek Group Ltd.
Tel : +972 9 863 8444
media@delek-group.com