This report is a translation of the Hebrew-language immediate report and is prepared solely for convenience. Please note that the Hebrew version is the binding version and will prevail in any event of discrepancy.

Tamar Petroleum Ltd.
(the "Company")

January 8, 2020

Israel Securities Authority Through MAGNA	Tel Aviv Stock Exchange Ltd. Through MAGNA

Dear Sir/Madam,

Re: **Updated Discounted Cash Flow Figures and Reserve Report in the Tamar Lease**

Further to the immediate report of March 5, 2019 (Ref.: 2019-01-018906) (the "**Previous Reserve Report**"), regarding the evaluation of reserves in the Tamar project, which includes the Tamar reservoir and the Tamar South-West reservoir ("**Tamar SW**"), in the area of the I/12 Tamar lease (the "**Tamar Project**" and the "**Tamar Lease**", respectively), the Company respectfully submits the following updated discounted cash flow figures and reserve report:

a. Quantity Data

According to a report received by the Company from Netherland, Sewell & Associates, Inc. ("**NSAI**" or the "**Evaluator**"), which was prepared according to the rules of the Petroleum Resources Management System (SPE-PRMS), as of December 31, 2019 (the "**Reserve Report**"), the condensate and natural gas reserves in the Tamar Project (which includes, as aforesaid, the Tamar reservoir and the Tamar SW reservoir[1]), which are classified as reserves on production, are as specified below:

[1] The resources included in the Tamar SW reservoir, which are specified in this Report, do not include the part of the reservoir that overflows into the area of the Eran license. For further details, see Note 4F to the financial statements as of September 30, 2019, which are included in the Q3/2019 report released on November 18, 2019 (Ref.: 2019-01-112237) (the "**Q3/2019 Report**"), the details included in which are incorporated herein by reference.

Reserve Category	Total (100%) in the Petroleum Asset (Gross)						Total (Tamar reservoir and Tamar SW) Share Attributed to the Holders of the Equity Interests of the Company (Net)[2]	
	Tamar Reservoir		Tamar SW Reservoir		Total (Tamar and Tamar SW Reservoirs)			
	Natural Gas BCF	Condensate Million Barrels	Natural Gas BCF	Condensate Million Barrels	Natural Gas BCF	Condensate Million Barrels	In Natural Gas BCF	In Condensate Million Barrels
1P (Proved) Reserves	6,944.5	9.0	796.4	1.0	7,741.0	10.1	1,063.5	1.4
Probable Reserves	2,871.0	3.7	159.1	0.2	3,030.1	3.9	416.3	0.5
Total 2P (Proved+Probable) Reserves	9,815.5	12.8	955.6	1.2	10,771.1	14.0	1,479.8	1.9
Possible Reserves	2,366.0	3.1	102.2	0.1	2,468.3	3.2	339.1	0.4
Total 3P (Proved+Probable+Possible) Reserves	12,181.6	15.8	1,057.8	1.4	13,239.4	17.2	1,818.9	2.4

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

[2] The Reserve Report does not state the Company's net share but rather the Company's gross share. The Company's share in the above table is after payment of royalties to the State, to interested parties and to third parties. The aforesaid royalties are according to their full rate (i.e.: to the State – 12.5% of the Company's total revenue; to interested parties and to third parties – 9.92% of the Company's revenue due to the rights the Company purchased from Delek Drilling – Limited Partnership (i.e.: due to 9.25% (out of 100%) of the rights)). Note that the aforesaid royalties will be calculated *de facto* according to the market value at the wellhead and therefore may in practice be lower than the aforesaid rates. The royalty rate paid to Providence Funds for Teachers and Preschool Teachers – Managing Company Ltd. and to Providence Funds for High School Teachers, Seminar Teachers and Supervisors – Managing Company Ltd. (which acquired the royalty right from Delek Group Ltd. on December 26, 2019) and paid to Delek Royalties (2012) Ltd. (the "**Royalty Holders**"), which was taken into account in the above figures, is 6.5% from the revenue attributed to the rights that the Company purchased from Delek Driling – Limited Partnership, i.e. the royalty rate after the investment recovery date. For details with respect to a mediation proceeding conducted between the Company and Delek Group Ltd., Delek Energy Systems Ltd. and Delek Royalties (2012) Ltd. in relation to the determination of the investment recovery date, see Note 4B to the condensed interim financial statements as of September 30, 2019, which are included in the Q3/2019 Report, the details included in which are incorporated herein by reference.

b. In the Reserve Report, NSAI stated, *inter alia*, several assumptions and reservations, including that: (a) The estimates, as customary in reserve appraisals according to the guidelines of the SPE-PRMS, are not adjusted to the risks; (b) NSAI did not visit the oil field, and did not check the mechanical operation of the facilities and the wells or the condition thereof; (c) NSAI did not examine possible exposure deriving from environmental matters. However, NSAI stated that as of the date of the Reserve Report, it is not aware of any potential liability regarding environmental matters which could materially affect the quantity of the reserves estimated in the Reserve Report or the commerciality thereof, and therefore did not include in the Reserve Report costs which may derive from such liability; (d) NSAI assumed that the reservoirs will be developed in accordance with the existing development plans, will be reasonably operated, that no regulation will be determined that will affect the ability of the holder of the petroleum rights to produce the reserves, and that its forecasts regarding future production will be similar to the functioning of the reservoirs in practice.

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

c. Discounted cash flow figures

With respect to the calculation of the discounted cash flow specified below, it is noted as follows: (a) The discounted cash flow was calculated, *inter alia*, based on a weighted average of the gas prices stated in the present gas sale agreements, which are based on different price formulas, which include, *inter alia*, linkage to the U.S. CPI, the Brent barrel price or the electricity production tariff[3]. It is noted that the prices may change, *inter alia*, due to a price adjustment according to the mechanism determined in the agreement with the Israel Electric Corp. Ltd. (the "**IEC**")[4], in the

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

[4] The agreement with the IEC determines two dates on which each party is entitled to request a price adjustment (according to the mechanism determined in the agreement), if such party is of the opinion that the price determined in the contract is no longer appropriate for a long-term contract with an anchor buyer for the consumption of natural gas for use in the Israeli market: 8 years and 11 years after the date of commercial operation (as defined in the agreement, which occurred on July 1,

agreement with Dolphinus Holdings Limited[5] ("**Dolphinus**" and the "**Agreement for Export to Egypt**") as well as changes in the indices which are the linkage bases in the gas supply agreements. The discounted cash flow assumes that a price adjustment at the rate of 25% will be made in the agreement with the IEC on the first adjustment date (i.e. on July 1, 2021), and that no price adjustment will be made on the second adjustment date (i.e. on July 1, 2024). It was also assumed that a price adjustment at the rate of 5% will be made in the agreement with Dolphinus on the date of adjustment of the first price and that no price adjustment will be made on the second date. For details regarding changes in the discounted cash flow as a result of a change in price, including as a result of a change in the price adjustment rate as noted above, see the sensitivity tables in Sections D.-G. below. It is noted that further to the immediate report of September 24, 2019 (Ref.: 2019-01-082341) with respect to the negotiations for amendment of the IEC agreement conducted by the Tamar partners that have no holdings in the Leviathan project, the discounted cash flow assumes that such amendment will be signed. It is further noted that a change in price as a result of the class action certification motion filed by a consumer of the IEC against the partners in the Tamar Project, as specified in Section 7.21.1 of the Company's periodic report as of December 31, 2018 released on March 22, 2019 (Ref.: 2019-01-023943) (the "**Periodic Report**"), was not taken into account. The Company's legal advisors estimate that chances of the certification motion being granted are lower than 50%. Insofar as the class action certification motion is granted, and a final non-appealable judgment on the class action itself is subsequently issued against the Tamar partners, this may have an adverse effect on the Company's business, including on the prices at which the Company, together with the other Tamar partners, shall sell natural gas to its customers, the extent of which effect will derive from the outcome of the action[6]. The figures regarding the gas and Brent prices as aforesaid were provided to NSAI by the Company[7]; (b) The demand forecast for the domestic market in Israel, which was used in order to estimate the projected future volume of natural gas sales in the domestic market in Israel, was prepared by an outside consultant, BDO Consulting Group; (c) The discounted cash flow was calculated based on the condensate price which is based on the Brent Crude prices and adjusted to quality differences, transportation costs and the price at which condensate is sold in the region; (d) The operating costs that were taken into account are costs that were provided to NSAI by the Company. These costs include direct costs at the project level, insurance costs, production well maintenance costs and the estimated G&A and overhead expenses of

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2013) from the Tamar Project (i.e.: July 1, 2021 and July 1, 2024). On the First Adjustment Date (July 1, 2021 – after 8 years) the adjustment that shall be made to the price will be within a range of up to 25% (up or down), and on the second adjustment date (July 1, 2024 – after 11 years) the adjustment that shall be made to the price will be within a range of up to 10% (up or down).

[5] The agreement with Dolphinus includes a mechanism for update of the price at a rate of up to 10% (increase or decrease) after the fifth year and after the tenth year of the agreement, upon the fulfillment of certain conditions that are stipulated in the agreement.

[6] As pertains to the liability of Delek Drilling and Noble with respect to the certification of the suit as a class action in relation to sums received by them for rights in the Tamar Lease they sold the Company, see Notes 4A and 4B to the financial statements as of December 31, 2018, respectively

[7] For the purpose of calculation of the price forecast, use was made of assumptions that are based on figures that were received from a consulting firm which are based on a weighting of figures of several public and private bodies: (1) annual increase of the U.S. CPI at an average rate of approx. 2% per annum; (2) Brent barrel price of approx. $63 per barrel in 2020, increasing to approx. $80 per barrel in 2025 and to approx. $97 per barrel in 2030, and a gradual rise at an average rate of approx. 2.8% per annum thereafter; (3) The Electricity Production Tariff forecast which is based, *inter alia*, on the ILS-$ exchange rate and on the fuel cost forecast that is based on the price of gas for the IEC.

the operator, which may be directly attributed to the project and together represent the costs of operation of the project. Such costs are divided into expenses at the field level and expenses per output unit, and are not adjusted to inflation changes. The operating costs provided to NSAI by the Company are deemed reasonable thereby, based *inter alia* on NSAI's additional knowledge from similar projects; (e) The amount of the capital expenditure taken into account for the purpose of preparation of the discounted cash flow exceeds the costs approved by the Company, and also includes the estimated costs of future expenses that shall be incurred in the course of production for the purpose of preserving and expanding the production capacity. The capital expenditures taken into account are capital expenditures, that may be required, for the drilling, development and connection of new wells, the placement of additional infrastructure and additional production equipment. The capital expenditure provided to NSAI are deemed reasonable thereby, based *inter alia* on the development plans for the Tamar Project and on additional knowledge that NSAI has from similar projects, and are not adjusted to inflation changes; (f) Abandonment costs that were taken into account are costs that were provided to NSAI by the Company in accordance with its estimates with respect to the cost of abandonment of the wells, the platform and the production facilities. These costs do not take into account the salvage value of the Tamar Lease and the facilities in the Tamar Project and are not adjusted to inflation changes; (g) The tax calculations took into account corporate tax rates pursuant to the law as well as the tax implications in connection with the purchases of the rights from Delek Drilling – Limited Partnership ("**Delek Drilling**") and from Noble Energy Mediterranean Ltd. according to the tax decisions received from the Israel Tax Authority (the "**ITA**") in relation to such purchases of rights; (h) The actual rate of production for each one of the reserve categories specified above may be lower or higher than the rate of production therein that was used for the purpose of estimating the discounted cash flow. In addition, NSAI did not carry out a sensitivity analysis in relation to the production rate of the wells; (i) The discounted cash flow assumes projected sale quantities in each of the project years based on the production capacity of the reservoirs[8] and a forecast in respect of the scope of supply and demand in the domestic market in each of the project years[9]; (j) The calculation of the discounted cash flow assumes sales to the domestic markets in Egypt and in Jordan in a total aggregate amount of approx. 44 BCM, by 2040, based, *inter alia* on the Company's forecasts as to export to Egypt. (see Section 7.4.5 of the Periodic Report and the immediate report of October 2, 2019 (Ref.: 2019-01-100333); (k) The calculation of the discounted cash flow takes into account the Company's estimate with respect to the actual rate of royalties (at the wellhead) which shall be paid by the Company: to the State – royalties at the rate of 11.5% of the Company's total revenues; and to interested parties and third parties – at the rate of 9.13%[10] of the Company's revenues in respect of the rights purchased by the Company from Delek Driling (namely, in respect of 9.25% (out of 100%) of the rights). As of the date of release of this report,

[8] The current gas supply capacity from the Tamar Project to INGL's transmission system, is approx. 1.1 BCF per day at maximum production.

[9] It is noted that in 2019, according to the Company's estimation, the Tamar partners sold approx. 10.4 BCM of natural gas to the domestic market and for export, as well as approx. 482 thousand barrels of condensate.

[10] The 9.13% royalty rate is after the investment recovery date. For details with respect to a mediation proceeding conducted between the Company and Delek Group Ltd., Delek Energy Systems Ltd. and Delek Royalties (2012) Ltd. in relation to the determination of the investment recovery date, see Note 4B to the condensed interim financial statements as of September 30, 2019, which are included in the Q3/2019 Report.

the Tamar partners are in discussions with the Ministry of Energy with respect to the manner of calculation of the actual rate of the royalties to be paid thereby to the State. Therefore, the actual rate of the aforesaid royalties is not final and may change, and there is no certainty that the Tamar partners and/or the Company will succeed in the negotiations and/or in legal proceedings for the determination of a lower rate of royalties in the future. For further details on the matter, see Section 7.18 of the Periodic Report; (l) The calculation of the discounted cash flow takes into account the petroleum profit levy applicable to the Company pursuant to the provisions of the Taxation of Profits from Natural Resources Law, 5771-2011 (in this section: the "**Law**"). It should be emphasized that the levy calculations were made according to the definitions, the formulas and the mechanisms defined in the Law as understood and interpreted by the Company, yet, in view of the novelty of the Law and the complexity of the calculation formulas and the various mechanisms defined therein, there is no assurance that this interpretation of the manner of calculation of the levy will be the same as that which shall be adopted by the tax authorities and/or the same as the interpretation of the Law by the court. It is noted that, as of the date of release of this report, several interpretive disagreements are being clarified with respect to the implementation of the Law in the reports of the Tamar venture to the ITA, in the framework of the objection and appeal proceedings prescribed by the law. The issues to which the disagreements pertain have not yet been addressed in the case law of the Israeli courts. The levy calculations were made according to the transitional provisions set forth in the Law with respect to a venture, the date of commencement of commercial production of which occurred from the date of commencement of the Law until January 1, 2014, and based on the following assumptions: the venture will choose to report in dollars pursuant to Section 13(b) of the Law, all of the venture's payments (the production costs, the investments, the royalties, etc.) shall be recognized by the tax authorities for the purpose of the levy calculation, and the calculation of the venture's income shall take into account the actual sale prices of the gas; (m) The calculation of the discounted cash flow takes into account expenses and investments which were actually paid, and which are expected to be paid by the Company as of January 1, 2020 and revenues deriving from sales of natural gas and condensate to be produced as of January 1, 2020. It is clarified that revenues received in 2020 in respect of sales of natural gas and condensate produced in 2019 were not included in the discounted cash flow.

<u>It is noted that the discounted cash flow was revised in relation to the discounted cash flow as of December 31, 2018 primarily for the following reasons</u>:

1. Update of sale prices: (a) In view of the update of the forecasts of the Electricity Production Tariff, the U.S. CPI and the Brent barrel price, the forecasts of the relevant sale prices (natural gas and condensate) that are linked thereto have been revised (b) In view of the update of the forecasts of prices for future customers in the domestic market and for export; (c) In view of the update of the forecast of the price adjustment rate on the first adjustment date in the agreement with the IEC.

2. Update of the forecasts of the quanitities to be sold: (a) In view of the update of the forecasts of sales in the natural gas sector in the Israeli market and from consummation of the Agreement for Export to Egypt, as specified in the immediate report of October 2, 2019 (Ref.: 2019-01-100333); (b) In view of

the proposed amendment to the IEC agreement, as specified in Section C above.

3. In view of the update of the venture's expenditure forecast, including the update of the venture's capital expenditure forecast, which chiefly derives from the update of the forecast for the future development plan of the Tamar field, including changes in the dates of drilling of future wells and capital expenditure in respect of the transaction for export to Egypt.

In accordance with various assumptions, the principal among which assumptions are specified above, the following table shows the estimated discounted cash flow as of December 31, 2019 in dollars in thousands (after levy and income tax), attributed to the Company's share, from the reserves in the Tamar Project, for each one of the reserve categories specified above:

Total discounted cash flow from proved reserves as of December 31, 2019 (in dollars in thousands in relation to the Company's share)

Cash flow components

Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax				
										Levy	Income tax	Discounted at 0%	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2020	427	9.30	280,951	46,476	-	27,770	26,347	-	180,358	3,059	23,874	153,425	149,728	146,285	143,070	140,058
31.12.2021	389	8.47	253,044	41,859	-	27,504	43,793	-	139,887	33,084	12,753	94,050	87,413	81,521	76,263	71,546
31.12.2022	447	9.75	292,721	48,423	-	27,088	10,173	-	207,037	63,067	11,161	132,808	117,558	104,651	93,644	84,192
31.12.2023	477	10.40	321,893	53,249	-	27,088	31,128	-	210,428	78,348	12,790	119,289	100,563	85,453	73,141	63,018
31.12.2024	477	10.40	326,978	54,090	-	27,093	31,128	-	214,667	92,571	10,402	111,693	89,676	72,738	59,551	49,171
31.12.2025	477	10.40	333,320	55,139	-	27,093	-	-	251,088	117,376	5,208	128,504	98,260	76,078	59,577	47,143
31.12.2026	477	10.40	332,867	55,064	-	27,093	-	-	250,710	117,332	5,131	128,247	93,394	69,023	51,702	39,208
31.12.2027	477	10.40	339,361	56,138	-	27,093	-	-	256,130	119,869	7,812	128,449	89,086	62,847	45,029	32,724
31.12.2028	493	10.74	354,182	58,590	-	27,093	-	-	268,499	125,658	19,205	123,636	81,665	54,993	37,689	26,249
31.12.2029	535	11.65	389,241	64,390	-	27,093	-	-	297,758	139,351	21,986	136,421	85,819	55,164	36,162	24,136
31.12.2030	535	11.65	396,207	65,542	-	27,093	-	-	303,572	142,072	22,697	138,803	83,159	51,024	31,994	20,464

Total discounted cash flow from proved reserves as of December 31, 2019 (in dollars in thousands in relation to the Company's share)																
Cash flow components																
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax				
										Levy	Income tax	Discounted at 0%	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2031	535	11.65	403,314	66,718	-	27,093	-	-	309,504	144,848	23,679	140,977	80,440	47,112	28,257	17,321
31.12.2032	535	11.65	410,127	67,845	-	27,093	33,835	-	281,355	131,674	30,302	119,378	64,872	36,267	20,807	12,223
31.12.2033	535	11.65	417,170	69,010	-	27,093	-	-	321,067	150,259	26,775	144,033	74,543	39,779	21,829	12,289
31.12.2034	530	11.55	422,052	69,818	-	27,093	-	-	325,142	152,166	28,072	144,904	71,423	36,382	19,097	10,303
31.12.2035	388	8.45	314,840	52,082	-	27,093	-	-	235,665	110,291	20,671	104,703	49,150	23,899	11,999	6,204
31.12.2036	321	6.98	265,574	43,932	-	27,093	-	-	194,549	91,049	16,920	86,580	38,707	17,965	8,628	4,275
31.12.2037	314	6.84	264,639	43,778	-	27,093	-	-	193,769	90,684	16,950	86,135	36,675	16,248	7,464	3,544
31.12.2038	292	6.36	249,976	41,352	-	27,093	-	-	181,532	84,957	15,872	80,702	32,725	13,840	6,081	2,767
31.12.2039	209	4.55	181,494	30,023	-	27,093	-	-	124,378	58,209	10,467	55,702	21,512	8,684	3,650	1,592
31.12.2040	206	4.48	181,897	30,090	-	27,093	-	-	124,714	58,366	10,562	55,785	20,518	7,906	3,178	1,328
31.12.2041	202	4.40	181,447	30,016	-	27,093	-	-	124,338	58,190	10,588	55,560	19,462	7,158	2,753	1,102
31.12.2042	199	4.34	181,808	30,075	-	27,093	-	-	124,640	58,332	10,198	56,110	18,719	6,572	2,417	928

Total discounted cash flow from proved reserves as of December 31, 2019 (in dollars in thousands in relation to the Company's share)																
Cash flow components																
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax				
										Levy	Income tax	Discounted at 0%	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2043	196	4.28	182,228	30,145	-	27,093	-	-	124,991	58,496	11,072	55,423	17,609	5,901	2,076	764
31.12.2044	194	4.22	182,637	30,213	-	27,093	-	12,448	112,883	52,829	12,506	47,548	14,388	4,603	1,549	546
31.12.2045	130	2.83	124,615	20,614	-	27,093	-	12,448	64,460	30,167	7,793	26,499	7,637	2,332	751	254
31.12.2046	60	1.30	57,994	9,594	-	27,093	-	12,448	8,859	4,146	2,332	2,381	653	190	59	19
31.12.2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**10,057**	**219**	**7,642,580**	**1,264,265**	**-**	**732,587**	**176,404**	**37,345**	**5,431,978**	**2,366,450**	**407,780**	**2,657,748**	**1,645,354**	**1,134,617**	**848,416**	**673,367**

Total discounted cash flow from probable reserves as of December 31, 2019 (in dollars in thousands in relation to the Company's share)																
Cash flow components																
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Development costs[11]	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 10%	Discounted at 15%	Discounted at 20%
31.12.2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2021	-	-	-	-	-	-	(21,429)	-	21,429	5,836	(1,342)	16,935	15,740	14,679	13,732	12,883
31.12.2022	-	-	-	-	-	-	(10,714)	-	10,714	5,402	(710)	6,022	5,331	4,746	4,246	3,818
31.12.2023	-	-	-	-	-	-	(31,128)	-	31,128	15,485	(2,869)	18,512	15,606	13,261	11,351	9,780
31.12.2024	-	-	-	-	-	-	(31,128)	-	31,128	18,659	(2,910)	15,379	12,347	10,015	8,200	6,770
31.12.2025	-	-	-	-	-	-	32,143	-	(32,143)	(14,910)	5,518	(22,751)	(17,397)	(13,469)	(10,548)	(8,347)
31.12.2026	-	-	-	-	-	-	-	-	-	-	1,350	(1,350)	(983)	(726)	(544)	(413)
31.12.2027	-	-	-	-	-	-	31,128	-	(31,128)	(14,568)	4,700	(21,260)	(14,745)	(10,402)	(7,453)	(5,416)
31.12.2028	0	0.01	232	38	-	-	31,128	-	(30,935)	(14,477)	4,363	(20,820)	(13,752)	(9,261)	(6,347)	(4,420)
31.12.2029	-	-	-	-	-	-	-	-	-	-	(82)	82	52	33	22	15
31.12.2030	-	-	-	-	-	-	-	-	-	-	(82)	82	49	30	19	12
31.12.2031	-	-	-	-	-	-	-	-	-	-	(82)	82	47	27	16	10
31.12.2032	-	-	-	-	-	-	(33,835)	-	33,835	15,835	(4,237)	22,237	12,084	6,756	3,876	2,277

[11] Since the degree of certainty required for production of the probable reserves (50%) is lower than the degree of certainty required for the production of the proved reserves (90%), the date of performance of the capital investments required for production of the probable reserves was postponed relative to the date of performance of the capital investments required for production of the proved reserves, in accordance with the production profile. Thus, development costs which are stated as negative in certain years in the table of discounted cash flow figures from probable reserves, are stated as positive in later years in the same table, relative to the development costs in the table of discounted cash flow figures from proved reserves. For details regarding the total capital investments required, see the table of discounted cash flow figures from 2P (proved (1P) + probable reserves).

Total discounted cash flow from probable reserves as of December 31, 2019 (in dollars in thousands in relation to the Company's share)																
Cash flow components																
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs[11]	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax				
										Levy	Income tax	Discounted at 0%	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2033	-	-	-	-	-	-	-	-	-	-	21	(21)	(11)	(6)	(3)	(2)
31.12.2034	5	0.10	3,807	630	-	-	-	-	3,177	1,487	(297)	1,987	980	499	262	141
31.12.2035	147	3.20	119,285	19,733	-	-	-	-	99,552	46,591	10,788	42,174	19,797	9,626	4,833	2,499
31.12.2036	214	4.67	177,387	29,344	-	-	-	-	148,043	69,284	17,461	61,298	27,405	12,719	6,108	3,027
31.12.2037	221	4.81	185,976	30,765	-	-	33,835	-	121,376	56,804	21,980	42,592	18,135	8,034	3,691	1,753
31.12.2038	243	5.29	207,824	34,379	-	-	32,143	-	141,302	66,129	23,612	51,561	20,908	8,842	3,885	1,768
31.12.2039	326	7.10	283,685	46,928	-	-	-	-	236,757	110,802	28,230	97,724	37,741	15,235	6,403	2,792
31.12.2040	329	7.17	290,805	48,106	-	-	-	-	242,699	113,583	28,957	100,158	36,839	14,195	5,707	2,385
31.12.2041	324	7.06	290,952	48,130	-	-	-	-	242,822	113,641	28,972	100,209	35,102	12,911	4,965	1,988
31.12.2042	305	6.65	278,749	46,112	-	-	-	-	232,637	108,874	28,208	95,556	31,878	11,192	4,117	1,580
31.12.2043	246	5.36	228,369	37,778	-	-	-	-	190,591	89,197	22,285	79,110	25,135	8,424	2,964	1,090
31.12.2044	187	4.07	176,324	29,168	-	-	-	(12,448)	159,605	74,695	15,630	69,280	20,964	6,706	2,257	796
31.12.2045	250	5.44	239,253	39,578	-	-	-	(12,448)	212,123	99,274	21,446	91,403	26,341	8,044	2,589	875
31.12.2046	313	6.82	305,128	50,475	-	-	-	(12,448)	267,101	125,003	28,173	113,924	31,268	9,114	2,806	908
31.12.2047	356	7.76	352,743	58,352	-	27,093	-	13,398	253,900	118,825	32,022	103,053	26,937	7,495	2,207	685
31.12.2048	291	6.35	293,359	48,529	-	27,093	-	13,398	204,340	95,631	26,736	81,973	20,407	5,420	1,527	454
31.12.2049	182	3.95	185,732	30,725	-	27,093	-	13,398	114,517	53,594	16,484	44,439	10,536	2,671	720	205

Total discounted cash flow from probable reserves as of December 31, 2019 (in dollars in thousands in relation to the Company's share)																
Cash flow components																
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs[11]	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax				
										Levy	Income tax	Discounted at 0%	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	3,939	86	3,619,610	598,770	-	81,279	32,143	2,849	2,904,569	1,360,674	354,324	1,189,571	404,742	156,811	71,607	39,912

Total discounted cash flow from 2P (proved + probable) reserves as of December 31, 2019 (in dollars in thousands in relation to the Company's share)

Cash flow components

Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax				
										Levy	Income tax	Discounted at 0%	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2020	427	9.30	280,951	46,476	-	27,770	26,347	-	180,358	3,059	23,874	153,425	149,728	146,285	143,070	140,058
31.12.2021	389	8.47	253,044	41,859	-	27,504	22,364	-	161,316	38,921	11,410	110,985	103,153	96,200	89,995	84,429
31.12.2022	447	9.75	292,721	48,423	-	27,088	(541)	-	217,751	68,469	10,452	138,830	122,889	109,396	97,890	88,010
31.12.2023	477	10.40	321,893	53,249	-	27,088	-	-	241,556	93,834	9,921	137,802	116,169	98,714	84,491	72,798
31.12.2024	477	10.40	326,978	54,090	-	27,093	-	-	245,795	111,230	7,493	127,072	102,023	82,753	67,750	55,942
31.12.2025	477	10.40	333,320	55,139	-	27,093	32,143	-	218,945	102,466	10,726	105,753	80,863	62,608	49,029	38,797
31.12.2026	477	10.40	332,867	55,064	-	27,093	-	-	250,710	117,332	6,480	126,897	92,411	68,297	51,158	38,795
31.12.2027	477	10.40	339,361	56,138	-	27,093	31,128	-	225,002	105,301	12,512	107,188	74,341	52,445	37,576	27,308
31.12.2028	493	10.74	354,414	58,629	-	27,093	31,128	-	237,565	111,180	23,568	102,816	67,913	45,732	31,342	21,828
31.12.2029	535	11.65	389,241	64,390	-	27,093	-	-	297,758	139,351	21,904	136,504	85,871	55,197	36,184	24,150
31.12.2030	535	11.65	396,207	65,542	-	27,093	-	-	303,572	142,072	22,615	138,885	83,209	51,054	32,013	20,476
31.12.2031	535	11.65	403,314	66,718	-	27,093	-	-	309,504	144,848	23,597	141,059	80,487	47,139	28,273	17,331

Total discounted cash flow from 2P (proved + probable) reserves as of December 31, 2019 (in dollars in thousands in relation to the Company's share)																
Cash flow components																
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax				
										Levy	Income tax	Discounted at 0%	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2032	535	11.65	410,127	67,845	-	27,093	-	-	315,190	147,509	26,065	141,616	76,957	43,023	24,682	14,499
31.12.2033	535	11.65	417,170	69,010	-	27,093	-	-	321,067	150,259	26,796	144,011	74,532	39,774	21,826	12,287
31.12.2034	535	11.65	425,859	70,447	-	27,093	-	-	328,319	153,653	27,774	146,891	72,402	36,881	19,359	10,444
31.12.2035	535	11.65	434,125	71,815	-	27,093	-	-	335,217	156,882	31,459	146,876	68,947	33,525	16,832	8,702
31.12.2036	535	11.65	442,962	73,276	-	27,093	-	-	342,592	160,333	34,381	147,878	66,112	30,685	14,736	7,302
31.12.2037	535	11.65	450,615	74,543	-	27,093	33,835	-	315,145	147,488	38,930	128,727	54,810	24,283	11,155	5,297
31.12.2038	535	11.65	457,801	75,731	-	27,093	32,143	-	322,833	151,086	39,484	132,263	53,634	22,682	9,966	4,535
31.12.2039	535	11.65	465,179	76,952	-	27,093	-	-	361,135	169,011	38,697	153,427	59,253	23,919	10,053	4,384
31.12.2040	535	11.65	472,701	78,196	-	27,093	-	-	367,412	171,949	39,520	155,944	57,357	22,101	8,885	3,713
31.12.2041	526	11.46	472,399	78,146	-	27,093	-	-	367,160	171,831	39,560	155,769	54,565	20,070	7,718	3,091
31.12.2042	505	10.99	460,557	76,187	-	27,093	-	-	357,277	167,206	38,406	151,666	50,597	17,764	6,534	2,508
31.12.2043	443	9.64	410,597	67,923	-	27,093	-	-	315,581	147,692	33,357	134,533	42,744	14,325	5,040	1,854

Total discounted cash flow from 2P (proved + probable) reserves as of December 31, 2019 (in dollars in thousands in relation to the Company's share)

Cash flow components

Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax				
										Levy	Income tax	Discounted at 0%	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2044	381	8.29	358,961	59,381	-	27,093	-	-	272,488	127,524	28,136	116,827	35,351	11,309	3,806	1,342
31.12.2045	380	8.27	363,868	60,193	-	27,093	-	-	276,583	129,441	29,240	117,902	33,978	10,376	3,340	1,128
31.12.2046	373	8.12	363,122	60,069	-	27,093	-	-	275,960	129,149	30,506	116,305	31,921	9,304	2,865	927
31.12.2047	356	7.76	352,743	58,352	-	27,093	-	13,398	253,900	118,825	32,022	103,053	26,937	7,495	2,207	685
31.12.2048	291	6.35	293,359	48,529	-	27,093	-	13,398	204,340	95,631	26,736	81,973	20,407	5,420	1,527	454
31.12.2049	182	3.95	185,732	30,725	-	27,093	-	13,398	114,517	53,594	16,484	44,439	10,536	2,671	720	205
31.12.2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**13,998**	**305**	**11,262,188**	**1,863,037**	**-**	**813,868**	**208,547**	**40,194**	**8,336,548**	**3,727,126**	**762,105**	**3,847,316**	**2,050,097**	**1,291,427**	**920,022**	**713,279**

Total discounted cash flow from possible reserves as of December 31, 2019 (in dollars in thousands in relation to the Company's share)																
Cash flow components																
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax				
										Levy	Income tax	Discounted at 0%	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2021	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2022	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2023	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2024	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2025	-	-	-	-	-	-	(32,143)	-	32,143	15,043	(3,460)	20,560	15,721	12,172	9,532	7,543
31.12.2026	-	-	-	-	-	-	16,072	-	(16,072)	(7,522)	2,469	(11,019)	(8,025)	(5,931)	(4,442)	(3,369)
31.12.2027	-	-	-	-	-	-	16,072	-	(16,072)	(7,522)	2,100	(10,650)	(7,386)	(5,211)	(3,733)	(2,713)
31.12.2028	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2029	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2031	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Total discounted cash flow from possible reserves as of December 31, 2019 (in dollars in thousands in relation to the Company’s share)																
Cash flow components																
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax				
										Levy	Income tax	Discounted at 0%	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2034	(0)	(0.00)	(4)	(1)	-	-	-	-	(3)	(1)	(0)	(1)	(1)	(0)	(0)	(0)
31.12.2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31.12.2036	-	-	-	-	-	-	-	-	-	-	(739)	739	331	153	74	37
31.12.2037	-	-	-	-	-	-	(33,835)	-	33,835	15,835	(4,012)	22,012	9,372	4,152	1,907	906
31.12.2038	-	-	-	-	-	-	(15,226)	-	15,226	7,126	(861)	8,961	3,634	1,537	675	307
31.12.2039	-	-	-	-	-	-	16,918	-	(16,918)	(7,917)	2,949	(11,950)	(4,615)	(1,863)	(783)	(341)
31.12.2040	-	-	-	-	-	-	16,072	-	(16,072)	(7,522)	2,469	(11,019)	(4,053)	(1,562)	(628)	(262)
31.12.2041	9	0.19	7,869	1,302	-	-	16,072	-	(9,505)	(4,448)	2,903	(7,960)	(2,788)	(1,026)	(394)	(158)
31.12.2042	30	0.66	27,618	4,569	-	-	-	-	23,049	10,787	2,820	9,442	3,150	1,106	407	156
31.12.2043	92	2.01	85,614	14,163	-	-	-	-	71,452	33,439	8,743	29,269	9,300	3,117	1,097	403
31.12.2044	154	3.36	145,415	24,055	-	-	-	-	121,360	56,796	14,850	49,714	15,043	4,812	1,619	571
31.12.2045	155	3.38	148,805	24,616	-	-	-	-	124,189	58,120	15,805	50,263	14,485	4,423	1,424	481
31.12.2046	162	3.53	157,982	26,134	-	-	-	-	131,848	61,705	16,743	53,400	14,656	4,272	1,315	426

Total discounted cash flow from possible reserves as of December 31, 2019 (in dollars in thousands in relation to the Company's share)																	
Cash flow components																	
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	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 10%	Discounted at 15%	Discounted at 20%
31.12.2047	179	3.89	176,927	29,268	-	-	-	(13,398)	161,057	75,375	17,235	68,447	17,892	4,978	1,466	455
31.12.2048	229	4.98	230,078	38,060	-	-	-	(13,398)	205,416	96,135	21,885	87,397	21,757	5,778	1,628	484
31.12.2049	306	6.66	313,054	51,787	-	-	-	(13,398)	274,666	128,544	30,008	116,114	27,530	6,979	1,881	536
31.12.2050	455	9.91	473,182	78,276	-	27,093	-	-	367,813	172,137	44,266	151,410	34,189	8,273	2,132	582
31.12.2051	423	9.20	446,588	73,876	-	27,093	-	-	345,619	161,750	41,311	142,559	30,657	7,081	1,746	457
31.12.2052	358	7.79	384,081	63,536	-	27,093	-	-	293,452	137,335	35,297	120,819	24,745	5,456	1,287	323
31.12.2053	293	6.37	319,399	52,836	-	27,093	-	13,398	226,072	105,802	30,134	90,136	17,582	3,700	835	201
31.12.2054	228	4.96	252,494	41,769	-	27,093	-	13,398	170,234	79,670	23,302	67,263	12,495	2,510	542	125
31.12.2055	138	3.00	155,440	25,713	-	27,093	-	13,398	89,235	41,762	13,391	34,082	6,030	1,156	239	53
31.12.2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**3,209**	**70**	**3,324,540**	**549,958**	**-**	**162,557**	**(0)**	**-**	**2,612,025**	**1,222,428**	**319,607**	**1,069,990**	**251,700**	**66,066**	**19,824**	**7,200**

Total discounted cash flow from 3P (proved + probable + possible) reserves as of December 31, 2019 (in dollars in thousands in relation to the Company's share)																
Cash flow components																
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax				
										Levy	Income tax	Discounted at 0%	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2020	427	9.30	280,951	46,476	-	27,770	26,347	-	180,358	3,059	23,874	153,425	149,728	146,285	143,070	140,058
31.12.2021	389	8.47	253,044	41,859	-	27,504	22,364	-	161,316	38,921	11,410	110,985	103,153	96,200	89,995	84,429
31.12.2022	447	9.75	292,721	48,423	-	27,088	(541)	-	217,751	68,469	10,452	138,830	122,889	109,396	97,890	88,010
31.12.2023	477	10.40	321,893	53,249	-	27,088	-	-	241,556	93,834	9,921	137,802	116,169	98,714	84,491	72,798
31.12.2024	477	10.40	326,978	54,090	-	27,093	-	-	245,795	111,230	7,493	127,072	102,023	82,753	67,750	55,942
31.12.2025	477	10.40	333,320	55,139	-	27,093	-	-	251,088	117,509	7,266	126,313	96,584	74,780	58,561	46,339
31.12.2026	477	10.40	332,867	55,064	-	27,093	16,072	-	234,639	109,811	8,950	115,878	84,386	62,366	46,716	35,426
31.12.2027	477	10.40	339,361	56,138	-	27,093	47,200	-	208,930	97,779	14,612	96,539	66,955	47,234	33,843	24,595
31.12.2028	493	10.74	354,414	58,629	-	27,093	31,128	-	237,565	111,180	23,568	102,816	67,913	45,732	31,342	21,828
31.12.2029	535	11.65	389,241	64,390	-	27,093	-	-	297,758	139,351	21,904	136,504	85,871	55,197	36,184	24,150
31.12.2030	535	11.65	396,207	65,542	-	27,093	-	-	303,572	142,072	22,615	138,885	83,209	51,054	32,013	20,476
31.12.2031	535	11.65	403,314	66,718	-	27,093	-	-	309,504	144,848	23,597	141,059	80,487	47,139	28,273	17,331
31.12.2032	535	11.65	410,127	67,845	-	27,093	-	-	315,190	147,509	26,065	141,616	76,957	43,023	24,682	14,499
31.12.2033	535	11.65	417,170	69,010	-	27,093	-	-	321,067	150,259	26,796	144,011	74,532	39,774	21,826	12,287

Total discounted cash flow from 3P (proved + probable + possible) reserves as of December 31, 2019 (in dollars in thousands in relation to the Company's share)																	
Cash flow components																	
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax					
										Levy	Income tax	Discounted at 0%	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%	
31.12.2034	535	11.65	425,855	70,447	-	27,093	-	-	328,316	153,652	27,774	146,890	72,401	36,881	19,359	10,444	
31.12.2035	535	11.65	434,125	71,815	-	27,093	-	-	335,217	156,882	31,459	146,876	68,947	33,525	16,832	8,702	
31.12.2036	535	11.65	442,962	73,276	-	27,093	-	-	342,592	160,333	33,642	148,617	66,442	30,838	14,810	7,338	
31.12.2037	535	11.65	450,615	74,543	-	27,093	-	-	348,980	163,323	34,918	150,739	64,182	28,435	13,062	6,202	
31.12.2038	535	11.65	457,801	75,731	-	27,093	16,918	-	338,059	158,212	38,623	141,224	57,267	24,218	10,641	4,842	
31.12.2039	535	11.65	465,179	76,952	-	27,093	16,918	-	344,217	161,094	41,646	141,477	54,638	22,056	9,270	4,043	
31.12.2040	535	11.65	472,701	78,196	-	27,093	16,072	-	351,341	164,427	41,989	144,924	53,304	20,540	8,257	3,451	
31.12.2041	535	11.65	480,268	79,448	-	27,093	16,072	-	357,655	167,383	42,463	147,809	51,776	19,044	7,323	2,933	
31.12.2042	535	11.65	488,175	80,756	-	27,093	-	-	380,327	177,993	41,226	161,108	53,747	18,870	6,941	2,664	
31.12.2043	535	11.65	496,211	82,085	-	27,093	-	-	387,033	181,131	42,099	163,802	52,044	17,442	6,136	2,257	
31.12.2044	535	11.65	504,376	83,436	-	27,093	-	-	393,847	184,321	42,986	166,541	50,395	16,121	5,425	1,912	
31.12.2045	535	11.65	512,673	84,808	-	27,093	-	-	400,772	187,561	45,045	168,166	48,463	14,799	4,764	1,609	
31.12.2046	535	11.65	521,104	86,203	-	27,093	-	-	407,808	190,854	47,248	169,705	46,578	13,577	4,180	1,353	
31.12.2047	535	11.65	529,670	87,620	-	27,093	-	-	414,957	194,200	49,257	171,500	44,829	12,473	3,673	1,140	
31.12.2048	520	11.33	523,437	86,589	-	27,093	-	-	409,755	191,765	48,620	169,370	42,164	11,198	3,155	938	

Total discounted cash flow from 3P (proved + probable + possible) reserves as of December 31, 2019 (in dollars in thousands in relation to the Company's share)															
Cash flow components															
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total discounted cash flow after tax				
										Levy	Income tax	Discounted at 0%	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2049	488	10.62	498,786	82,511	-	27,093	-	-	389,182	182,137	46,492	160,553	38,066	9,650	2,600	741
31.12.2050	455	9.91	473,182	78,276	-	27,093	-	-	367,813	172,137	44,266	151,410	34,189	8,273	2,132	582
31.12.2051	423	9.20	446,588	73,876	-	27,093	-	-	345,619	161,750	41,311	142,559	30,657	7,081	1,746	457
31.12.2052	358	7.79	384,081	63,536	-	27,093	-	-	293,452	137,335	35,297	120,819	24,745	5,456	1,287	323
31.12.2053	293	6.37	319,399	52,836	-	27,093	-	13,398	226,072	105,802	30,134	90,136	17,582	3,700	835	201
31.12.2054	228	4.96	252,494	41,769	-	27,093	-	13,398	170,234	79,670	23,302	67,263	12,495	2,510	542	125
31.12.2055	138	3.00	155,440	25,713	-	27,093	-	13,398	89,235	41,762	13,391	34,082	6,030	1,156	239	53
31.12.2056	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**17,206**	**375**	**14,586,731**	**2,412,994**	**-**	**976,423**	**208,547**	**40,195**	**10,948,572**	**4,949,552**	**1,081,712**	**4,917,308**	**2,301,796**	**1,357,494**	**939,847**	**720,479**

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

Warning regarding forward-looking information – The aforesaid discounted cash flow figures are forward-looking information, within the meaning thereof in the Securities Law. The above figures are based on various assumptions, *inter alia*, in relation to the quantities of gas and condensate that shall be produced (including in connection with the proposed amendment to the IEC agreement), the pace and duration of sales of natural gas from the project, operating costs, capital expenditure, abandonment expenses, royalty rates and sale prices, including with respect to the price adjustments according to the agreement with the IEC, and there is no certainty that such assumptions will materialize. It is noted that the quantities of natural gas and/or condensate that shall actually be produced, such expenses and such revenues may materially differ from the above assumptions and estimations, *inter alia*, as a result of the competition conditions prevailing on the market and/or operating and technical conditions and/or regulatory changes and/or supply and demand conditions on the domestic market and/or export markets of the natural gas and/or condensate and/or the actual performance of the project and/or as a result of the actual sale prices and/or as a result of geopolitical changes that shall occur. It is further noted that the price adjustment rate on the price adjustment dates as set forth in the agreement with the IEC may materially differ from the Company's assumptions made above, *inter alia* as a result of the actual natural gas prices on the domestic market on the price adjustment dates and all according to the adjustment mechanism as stipulated in the agreement with the IEC.

d. Set forth below is an analysis of sensitivity to the main parameters comprising the discounted cash flow (the gas price and the gas sales volume[12]) as of December 31, 2019 (dollars in thousands) which was performed by the Company:

Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
10% increase in gas price					**10% decrease in gas price**				
1P (Proved) Reserves	2,918,291	1,239,115	925,286	733,832	1P (Proved) Reserves	2,397,961	1,030,247	771,498	612,730
Probable Reserves	1,313,470	171,579	77,265	42,147	Probable Reserves	1,066,202	142,572	66,455	38,153
Total 2P (Proved+Probable) Reserves	4,231,761	1,410,694	1,002,551	775,979	Total 2P (Proved+Probable) Reserves	3,464,163	1,172,819	837,952	650,883
Possible Reserves	1,183,648	72,673	21,638	7,738	Possible Reserves	956,243	59,407	17,968	6,630
Total 3P (Proved+Probable+Possible) Reserves	5,415,409	1,483,367	1,024,189	783,717	Total 3P (Proved+Probable+Possible) Reserves	4,420,406	1,232,225	855,920	657,512
15% increase in gas price					**15% decrease in gas price**				
1P (Proved) Reserves	3,047,453	1,290,067	962,374	762,686	1P (Proved) Reserves	2,268,582	978,248	733,122	582,417
Probable Reserves	1,375,482	179,012	80,137	43,303	Probable Reserves	1,003,958	134,830	63,247	36,643
Total 2P (Proved+Probable) Reserves	4,422,935	1,469,079	1,042,511	805,989	Total 2P (Proved+Probable) Reserves	3,272,540	1,113,078	796,369	619,060
Possible Reserves	1,240,477	75,977	22,546	8,007	Possible Reserves	899,196	55,974	16,960	6,281

[12] Sensitivity to a change in the gas quantity that is sold. It is emphasized that the aforesaid analyses do not take into account changes in the investment plan that is required for the purpose of increasing or decreasing the annual quantity of gas sold.

Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
Total 3P (Proved+Probable+Possible) Reserves	5,663,412	1,545,055	1,065,056	813,996	Total 3P (Proved+Probable+Possible) Reserves	4,171,737	1,169,052	813,329	625,340
20% increase in gas price					**20% decrease in gas price**				
1P (Proved) Reserves	3,178,594	1,342,942	1,001,364	793,424	1P (Proved) Reserves	2,136,758	924,205	692,862	550,358
Probable Reserves	1,437,495	186,465	83,034	44,486	Probable Reserves	944,941	129,751	62,493	37,409
Total 2P (Proved+Probable) Reserves	4,616,089	1,529,407	1,084,398	837,910	Total 2P (Proved+Probable) Reserves	3,081,699	1,053,956	755,355	587,767
Possible Reserves	1,297,306	79,280	23,453	8,276	Possible Reserves	842,341	52,668	16,055	6,017
Total 3P (Proved+Probable+Possible) Reserves	5,913,395	1,608,688	1,107,851	846,186	Total 3P (Proved+Probable+Possible) Reserves	3,924,040	1,106,624	771,410	593,784

Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
10% increase in gas sales volume					**10% decrease in gas sales volume**				
1P (Proved) Reserves	2,660,153	1,216,952	920,529	734,589	1P (Proved) Reserves	2,397,976	1,030,254	771,504	612,735
Probable Reserves	1,146,321	168,844	78,228	43,090	Probable Reserves	1,066,210	142,573	66,455	38,153
Total 2P (Proved+Probable) Reserves	3,806,474	1,385,795	998,757	777,678	Total 2P (Proved+Probable) Reserves	3,464,186	1,172,828	837,959	650,888
Possible Reserves	1,035,489	77,969	24,728	9,062	Possible Reserves	956,250	59,407	17,968	6,630

Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
Total 3P (Proved+Probable+Possible) Reserves	4,841,963	1,463,764	1,023,485	786,740	Total 3P (Proved+Probable+Possible) Reserves	4,420,436	1,232,235	855,927	657,518
15% increase in gas sales volume					**15% decrease in gas sales volume**				
1P (Proved) Reserves	2,659,257	1,252,005	952,567	762,440	1P (Proved) Reserves	2,268,603	978,259	733,131	582,424
Probable Reserves	1,122,237	175,379	82,277	45,246	Probable Reserves	1,003,971	134,832	63,248	36,643
Total 2P (Proved+Probable) Reserves	3,781,494	1,427,384	1,034,844	807,686	Total 2P (Proved+Probable) Reserves	3,272,574	1,113,091	796,379	619,067
Possible Reserves	1,015,051	84,267	27,679	10,314	Possible Reserves	899,206	55,975	16,960	6,281
Total 3P (Proved+Probable+Possible) Reserves	4,796,545	1,511,651	1,062,524	818,000	Total 3P (Proved+Probable+Possible) Reserves	4,171,781	1,169,066	813,339	625,348
20% increase in gas sales volume					**20% decrease in gas sales volume**				
1P (Proved) Reserves	2,649,843	1,284,564	984,088	790,879	1P (Proved) Reserves	2,136,785	924,219	692,873	550,367
Probable Reserves	1,111,537	184,185	87,626	48,172	Probable Reserves	944,958	129,753	62,494	37,409
Total 2P (Proved+Probable) Reserves	3,761,380	1,468,749	1,071,714	839,051	Total 2P (Proved+Probable) Reserves	3,081,743	1,053,973	755,367	587,777
Possible Reserves	997,111	91,016	31,009	11,801	Possible Reserves	842,354	52,668	16,055	6,017
Total 3P (Proved+Probable+Possible) Reserves	4,758,491	1,559,766	1,102,723	850,852	Total 3P (Proved+Probable+Possible) Reserves	3,924,097	1,106,641	771,422	593,793

e. <u>Set forth below is an analysis of sensitivity to the main linkage components of the gas price according to the gas sale agreements in which the Tamar partners have engaged (the U.S. CPI and the Electricity Production Tariff) as of December 31, 2019 (dollars in thousands) which was performed by the Company[13]</u>:

Sensitivity / Category	**Present value discounted at 0%**	**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 CPI forecast					**10% decrease in the CPI forecast**				
1P (Proved) Reserves	2,659,945	1,135,881	849,405	674,153	1P (Proved) Reserves	2,655,572	1,133,364	847,437	672,587
Probable Reserves	1,189,582	156,816	71,610	39,914	Probable Reserves	1,189,567	156,811	71,608	39,913
Total 2P (Proved+Probable) Reserves	3,849,527	1,292,697	921,015	714,067	Total 2P (Proved+Probable) Reserves	3,845,139	1,290,175	919,044	712,500
Possible Reserves	1,069,990	66,066	19,824	7,200	Possible Reserves	1,069,990	66,066	19,824	7,200
Total 3P (Proved+Probable+Possible) Reserves	4,919,517	1,358,763	940,838	721,267	Total 3P (Proved+Probable+Possible) Reserves	4,915,129	1,356,241	938,868	719,700
10% increase in the Electricity Production Tariff forecast					**10% decrease in the Electricity Production Tariff forecast**				
1P (Proved) Reserves	2,664,757	1,138,730	851,697	676,043	1P (Proved) Reserves	2,655,274	1,133,389	847,513	672,685
Probable Reserves	1,189,578	156,805	71,598	39,901	Probable Reserves	1,189,566	156,809	71,606	39,912
Total 2P (Proved+Probable) Reserves	3,854,335	1,295,535	923,295	715,943	Total 2P (Proved+Probable) Reserves	3,844,840	1,290,198	919,119	712,597
Possible Reserves	1,069,990	66,066	19,824	7,200	Possible Reserves	1,069,990	66,066	19,824	7,200

[13] Although the Electricity ProductionTtariff is affected, *inter alia*, by the CPI, such effect was not taken into account in the sensitivity analysis in the table below.

Sensitivity / Category	Present value discounted at 0%	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%
Total 3P (Proved+Probable+Possible) Reserves	4,924,325	1,361,601	943,119	723,143	Total 3P (Proved+Probable+Possible) Reserves	4,914,830	1,356,265	938,943	719,797

f. Set forth below is an analysis of sensitivity to the sale of quantities exceeding the minimum quantities ("take or pay") according to the gas sale agreements in which the Company has engaged as of December 31, 2019 (dollars in thousands) which was 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 gas sales volume in respect of quantities exceeding the "take or pay"					**10% decrease in the gas sales volume in respect of quantities exceeding the "take or pay"**				
1P (Proved) Reserves	2,671,916	1,177,058	881,806	699,230	1P (Proved) Reserves	2,474,238	1,079,249	812,820	648,503
Probable Reserves	1,153,410	165,779	76,626	42,388	Probable Reserves	1,065,805	142,020	65,881	37,577
Total 2P (Proved+Probable) Reserves	3,825,326	1,342,836	958,433	741,618	Total 2P (Proved+Probable) Reserves	3,540,043	1,221,269	878,701	686,081
Possible Reserves	1,044,326	75,540	23,643	8,623	Possible Reserves	956,338	59,459	18,009	6,662
Total 3P (Proved+Probable+Possible) Reserves	4,869,652	1,418,376	982,075	750,242	Total 3P (Proved+Probable+Possible) Reserves	4,496,381	1,280,728	896,710	692,743

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

Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
0% price reduction					**12.5% price reduction**				
1P (Proved) Reserves	2,726,166	1,177,698	883,632	702,643	1P (Proved) Reserves	2,691,949	1,156,166	866,037	688,019
Probable Reserves	1,189,665	156,776	71,537	39,819	Probable Reserves	1,189,609	156,785	71,564	39,858
Total 2P (Proved+Probable) Reserves	3,915,831	1,334,473	955,169	742,462	Total 2P (Proved+Probable) Reserves	3,881,559	1,312,950	937,600	727,877
Possible Reserves	1,069,990	66,066	19,824	7,200	Possible Reserves	1,069,990	66,066	19,824	7,200
Total 3P (Proved+Probable+Possible) Reserves	4,985,821	1,400,539	974,993	749,662	Total 3P (Proved+Probable+Possible) Reserves	4,951,549	1,379,017	957,424	735,077

h. Agreement between the report data and data of previous reports in respect of the quantity of reserves attributed to the petroleum asset

The main differences between the present Reserve Report and the Previous Reserve Report derive from the production of approx. 369 BCF and approx. 482 thousands barrels of condensate from the reservoir in the course of 2019.

i. Production data

Set forth below are production data in the Tamar Project which are attributed to the Company in 2017-2019[14]:

Natural Gas[15,16]				
		Y2017	**Y2018**	**Y2019**
Total output (attributed to the holders of the equity interests of the Company) during the period (in MMCF)		31,732	55,881	61,765
Average price per output unit (attributed to the holders of the equity interests of the Company) (dollars per MCF)[17]		5.41	5.49	5.59
Average royalties (any payment derived from the output of the producing asset, including from the gross revenues from the petroleum asset) paid per output unit (attributed to the holders of the equity interests of the Company) (dollars per MCF)	The State	0.61	0.61	0.62
	Third parties	0.10	0.06	0.06
	Interested Parties	0.15	0.21	0.20
Average production costs per output unit (attributed to the holders of the equity interests of the Company) (dollars per MCF)		0.37	0.39	0.45
Average net revenues per output unit (attributed to the holders of the equity interests of the Company) (dollars per MCF)		4.18	4.22	4.26
Petroleum and gas profit levy		-	-	-
Average net income per output unit after the petroleum and gas profit levy (attributed to the holders of the equity interests of the Company) (dollars per MCF)		4.18	4.22	4.26
Depletion rate in the reported period relative to the total gas quantities in the project (in %)[18]		3.4	3.3	3.3

[14] It is noted that from the date of commencement of the piping of natural gas from the Tamar Project (i.e. March 30, 2013) until December 31, 2019, the aggregate quantity of natural gas supplied to customers was approx. 60.9 BCM. It is further noted that the average daily production volume of natural gas totaled, in the past two years (January 1, 2018 to December 31, 2019), approx. 1,002 MMCF (1.002 BCF). The production data for 2019 are based on unaudited financial data.
[15] The rate attributed to the holders of the equity interest of the Company in the production, in royalties that were paid, in the production costs and in the net revenues was rounded off to two digits after the decimal point.
[16] Until March 14, 2018, the data are calculated according to a holding rate of 9.25% (assuming that the Company is holding such interests during all of the aforesaid period), and as of March 14, 2018 the data are calculated according to a holding rate of 16.75%.
[17] The average price per output unit weights the actual price of the Company which includes the framework for the sale of natural gas between the Tamar Project and the Yam Tethys project, as specified in Section 7.2.9 of the Periodic Report.
[18] The depletion rate is the rate of natural gas produced in the relevant reporting period, out of the balance of proved and probable reserves as of the beginning of such reporting period or as of the date of commencement of production, whichever is later. The said depletion rate is calculated at the end of the year and not in the course thereof.

Condensate[19,20]

		Y2017	Y2018	Y2019
Total output (attributed to the holders of the equity interests of the Company) during the period (in barrels in thousands)		42.1	73.2	80.8
Average price per output unit (attributed to the holders of the equity interests of the Company) (dollars per barrel)		47.5	63.4	56.3
Average royalties (any payment derived from the output of the producing asset, including from the gross revenues from the petroleum asset) paid per output unit (attributed to the holders of the equity interests of the Company) (dollars per barrel)	The State	5.3	7.1	6.2
	Third Parties	0.8	0.7	0.6
	Interested Parties	1.4	2.3	2.1
Average production costs per output unit (attributed to the holders of the equity interests of the Company) (dollars per barrel)		2.0	2.1	2.5
Average net revenues per output unit (attributed to the holders of the equity interests of the Company) (dollars per barrel)		38	51.2	44.9
Petroleum and gas profit levy		-	-	-
Average net income per output unit after the petroleum and gas profit levy (attributed to the holders of the equity interests of the Company) (dollars per barrel)		38	51.2	44.9
Depletion rate in the reported period relative to the total condensate quantities in the project (in %)[21]		3.5	3.3	3.3

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

[19] The rate attributed to the holders of the equity interest of the Company in the production, in royalties that were paid, in the production costs and in the net revenues was rounded off to one digit after the decimal point.
[20] See Footnote 15.
[21] The quantity of condensate produced from the Tamar Project derives directly from the quantity of natural gas produced from the project.

j. Opinion of the evaluator

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

k. Management declaration

(1) Date of the declaration: January 8, 2020;
(2) Name of the corporation: Tamar Petroleum Ltd.;
(3) Name and position of the resource evaluation officer at the Company: Ran Efrati, director;
(4) We confirm that the evaluator was provided with all of the data required for performance of its work;
(5) We confirm that no information has come to our attention which indicates the existence of dependency between the evaluator and the Company;
(6) We confirm that, to the best of our knowledge, the resources reported are the best and most current estimates in our possession;
(7) We confirm that the data included in this report were prepared according to the professional terms listed in Chapter G of the Third Schedule to the Securities Regulations (Details of the Prospectus and Draft Prospectus – Structure and Form), 5729-1969 and within the meaning afforded thereto in Petroleum Resources Management System (2007), as published by the SPE, the AAPG, the WPC and the SPEE, as being at the time of release of the report;
(8) We confirm that no change has been made to the identity of the evaluator who performed the last contingent resource or reserve disclosure released by the Company;
(9) We agree to the inclusion of the foregoing declaration in this report.

____

Ran Efrati

<u>Glossary</u>

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

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

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

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

SPE-PRMS – (Petroleum Resources Management System 2007) – A petroleum resources and reserves evaluation reporting system, as published by the SPE, the AAPG, the WPC and the SPEE, and as amended from time to time.

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

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

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

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

License – Within the meaning thereof in the Petroleum Law.

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

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

BCM – Billion cubic meters.

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

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

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

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

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

Sincerely,

Tamar Petroleum Ltd.
By Liami Vaisman, CEO
and Yuval Raikin, CFO

Annex A

January 8, 2020

Mr. Yuval Raikin
Tamar Petroleum Ltd.
11 Galgalei Haplada Street
Herzelia 4672211
Israel

Dear Mr. Raikin:

As independent consultants, Netherland, Sewell & Associates, Inc. hereby grants permission to Tamar Petroleum Ltd. to use our report dated January 8, 2020, to be filed with the Israel Securities Authority and the Tel Aviv Stock Exchange. This report sets forth our estimates of the proved, probable, and possible reserves and future revenue, as of December 31, 2019, to the Tamar Petroleum Ltd. interest in certain gas properties located in Tamar and Tamar Southwest Fields, Tamar Lease I/12, offshore Israel.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.

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

RBT:MDK

January 8, 2020

Tamar Petroleum Ltd.
11 Galgalei Haplada Street
Herzelia 4672211
Israel

Ladies and Gentlemen:

In accordance with your request, we have estimated the proved, probable, and possible reserves and future revenue, as of December 31, 2019, to the Tamar Petroleum Ltd. (Tamar Petroleum) interest in certain gas properties located in Tamar and Tamar Southwest Fields, Tamar Lease I/12, offshore Israel. It is our understanding that Tamar Petroleum owns a 16.75 percent direct interest in these properties. Reserves in Tamar Southwest Field that extend into the Eran License have not been included in this report. We completed our evaluation on or about the date of this letter. This report has been prepared using price and cost parameters specified by Tamar Petroleum, as discussed in subsequent paragraphs of this letter. The estimates in this report have been prepared in accordance with the definitions and guidelines set forth in the 2018 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE) and in accordance with internationally recognized standards, as stipulated by the Israel Securities Authority (ISA). Definitions are presented immediately following this letter. This report has been prepared for Tamar Petroleum's use in filing with the ISA; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

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

	Gas Reserves (BCF)		Condensate Reserves (MMBBL)	
Category	Gross (100%)	Working Interest	Gross (100%)	Working Interest
Proved (1P)	7,741.0	1,296.6	10.1	1.7
Probable	3,030.1	507.5	3.9	0.7
Proved + Probable (2P)	10,771.1	1,804.2	14.0	2.3
Possible	2,468.3	413.4	3.2	0.5
Proved + Probable + Possible (3P)	13,239.4	2,217.6	17.2	2.9

Totals may not add because of rounding.

We estimate the future net revenue after levy and corporate income taxes, discounted at 0, 5, 10, 15, and 20 percent, to the Tamar Petroleum interest in these properties, as of December 31, 2019, to be:

	Future Net Revenue After Levy and Corporate Income Taxes (MM$)				
Category	Discounted at 0%	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved (1P)	2,657.7	1,645.4	1,134.6	848.4	673.4
Probable	1,189.6	404.7	156.8	71.6	39.9
Proved + Probable (2P)	3,847.3	2,050.1	1,291.4	920.0	713.3
Possible	1,070.0	251.7	66.1	19.8	7.2
Proved + Probable + Possible (3P)	4,917.3	2,301.8	1,357.5	939.8	720.5

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

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

Totals may not add because of rounding.

Gas volumes are expressed in billions of cubic feet (BCF) at standard temperature and pressure bases. Condensate volumes are expressed in millions of barrels (MMBBL); a barrel is equivalent to 42 United States gallons. Monetary values shown in this report are expressed in United States dollars ($), thousands of United States dollars (M$), or millions of United States dollars (MM$). For reference, the January 6, 2020, exchange rate was 3.47 Israeli New Shekels per United States dollar.

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

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

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

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

Capital costs used in this report were provided by Tamar Petroleum and are based on estimates of future expenditures for the purpose of preserving and expanding the production capacity. Capital costs are those amounts of expenditures already authorized by the partners and amounts forecasted by Tamar Petroleum that are required for the above purpose, including new development wells, additional infrastructure, and production equipment. It is our understanding that Tamar and Tamar Southwest Fields are being developed under the Tamar Development Plan. Based on our understanding of this future development plan, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Tamar Petroleum's estimates of the costs to abandon the wells, platform, and production facilities; these estimates do not include any salvage value for the lease and well equipment. As requested, capital costs and abandonment costs are not escalated for inflation.

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

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

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be commercially recoverable; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. There is a 10 percent chance that the quantities will be equal to, or greater than, the quantities of the proved plus probable plus possible reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with the current development plan as provided to us by Tamar Petroleum, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report. The near-term gas sales forecasts used in this report were provided by Tamar Petroleum. It should be noted that the actual production profile for each category may be lower or higher than the production profile used to calculate the estimates of future net revenue used in this report, and no sensitivity analysis was performed with respect to the production profile of the wells.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, core data, well test data, production data, historical price and cost information, and property ownership interests. We were provided with all the necessary data to prepare the estimates for these properties, and we were not limited from access to any material we believe may be relevant. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to classify, categorize, and estimate reserves in accordance with the 2018 PRMS definitions and guidelines. Certain parameters used in our volumetric analyses are summarized in Tables VII and VIII. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

Netherland, Sewell & Associates, Inc. (NSAI) was engaged on December 16, 2019, by Mr. Yuval Raikin, Chief Financial Officer of Tamar Petroleum, to perform this assessment. The data used in our estimates were obtained from Noble Energy Mediterranean Ltd., Tamar Petroleum, other interest owners, public data sources, and the nonconfidential files of NSAI and were accepted as accurate. Supporting work data are on file in our office. We have not examined the contractual rights to the properties or independently confirmed the actual degree or type of interest owned. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis. Furthermore, no limitations or restrictions were placed upon NSAI by officials of Tamar Petroleum.

QUALIFICATIONS

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

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

Sincerely,

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

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

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

Date Signed: January 8, 2020

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

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

Date Signed: January 8, 2020

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

RBT:MDK

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, June 2018

This document contains information excerpted from definitions and guidelines prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the SPE, World Petroleum Council, American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers, Society of Exploration Geophysicists, Society of Petrophysicists and Well Log Analysts, and European Association of Geoscientists & Engineers.

Preamble

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

This updated PRMS provides fundamental principles for the evaluation and classification of petroleum reserves and resources. If there is any conflict with prior SPE and PRMS guidance, approved training, or the Application Guidelines, the current PRMS shall prevail. It is understood that these definitions and guidelines allow flexibility for entities, governments, and regulatory agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein must be clearly identified. The terms "shall" or "must" indicate that a provision herein is mandatory for PRMS compliance, while "should" indicates a recommended practice and "may" indicates that a course of action is permissible. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

1.0 Basic Principles and Definitions

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

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

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

1.1 Petroleum Resources Classification Framework

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

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

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

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

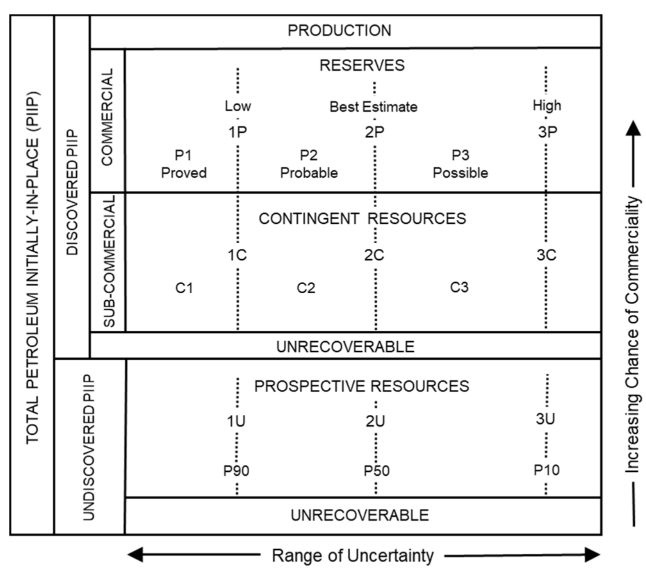

Figure 1.1—Resources classification framework

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
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1.1.0.5 The following definitions apply to the major subdivisions within the resources classification:

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

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

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

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

A. 1. **Reserves** are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

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

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

B. **Contingent Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. Contingent Resources have an associated chance of development. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the range of uncertainty associated with the estimates and should be sub-classified based on project maturity and/or economic status.

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

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

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

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

1.1.0.8 Other terms used in resource assessments include the following:

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

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

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
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1.2 Project-Based Resources Evaluations

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

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

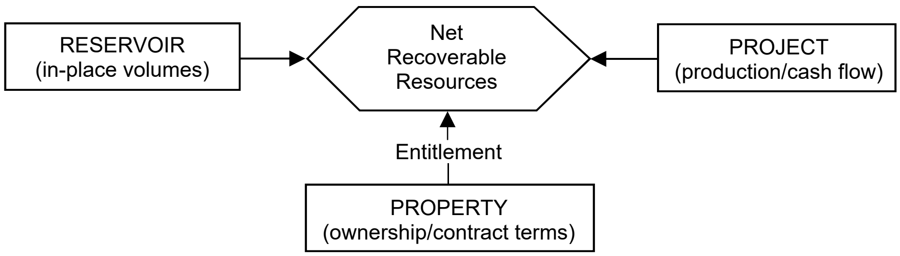

Figure 1.2—Resources evaluation

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

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

1.2.0.5 **The property** (lease or license area): Each property may have unique associated contractual rights and obligations, including the fiscal terms. This information allows definition of each participating entity's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations that may be spatially unrelated to a potential single field designation.

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

1.2.0.7 In the context of this relationship, the project is the primary element considered in the resources classification, and the net recoverable resources are the quantities derived from each project. A project represents a defined activity or set of activities to develop the petroleum accumulation(s) and the decisions taken to mature the resources to reserves. In general, it is recommended that an individual project has assigned to it a specific maturity level sub-class (See Section 2.1.3.5, Project Maturity Sub-Classes) at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for the project (See Section 2.2.1, Range of Uncertainty). For completeness, a developed field is also considered to be a project.

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

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

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

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

2.0 Classification and Categorization Guidelines

2.1 Resources Classification

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

2.1.1 Determination of Discovery Status

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

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

2.1.2 Determination of Commerciality

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

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

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

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

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

2.2 Resources Categorization

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

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

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

2.2.1 Range of Uncertainty

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

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

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

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

2.2.1.4 When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental method, quantities for each confidence segment are estimated discretely (see Section 2.2.2, Category Definitions and Guidelines).

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

2.2.2 Category Definitions and Guidelines

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

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

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

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

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

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

2.2.2.7 All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Section 3.1, Assessment of Commerciality).

Table 1—Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.

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Class/Sub-Class	Definition	Guidelines
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame). There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.

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

Table 2—Reserves Status Definitions and Guidelines

Status	Definition	Guidelines
Developed Reserves	Expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-producing.
Developed Producing Reserves	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

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

Table 3—Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves. Reserves in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

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Category	Definition	Guidelines
Possible Reserves	Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic production from the reservoir by a defined, commercially mature project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	See above for separate criteria for Probable Reserves and Possible Reserves.	The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROVED (1P) RESERVES
TAMAR PETROLEUM LTD.
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2019

Period Ending	Working Interest Revenue (M$)	Royalties: State (M$)	Royalties: Interested Party (M$)	Royalties: Third Party (M$)	Royalties: Total (M$)	Net Capital Costs (M$)	Net Abandonment Costs (M$)	Net Operating Expenses[1] (M$)	Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (M$)
12-31-2020	280,950.5	32,309.3	9,010.4	5,156.2	46,475.9	26,346.5	-	27,770.0	180,358.1
12-31-2021	253,043.8	29,100.0	8,115.4	4,644.0	41,859.5	43,793.1	-	27,504.1	139,887.1
12-31-2022	292,721.0	33,662.9	9,387.9	5,372.2	48,423.1	10,173.1	-	27,088.2	207,036.7
12-31-2023	321,893.4	37,017.7	10,323.5	5,907.6	53,248.9	31,128.2	-	27,088.2	210,428.1
12-31-2024	326,977.9	37,602.5	10,486.6	6,000.9	54,090.0	31,128.2	-	27,092.9	214,666.9
12-31-2025	333,320.3	38,331.8	10,690.0	6,117.3	55,139.2	-	-	27,092.9	251,088.3
12-31-2026	332,867.4	38,279.8	10,675.5	6,109.0	55,064.2	-	-	27,092.9	250,710.3
12-31-2027	339,361.1	39,026.5	10,883.7	6,228.2	56,138.4	-	-	27,092.9	256,129.8
12-31-2028	354,182.4	40,731.0	11,359.1	6,500.2	58,590.2	-	-	27,092.9	268,499.3
12-31-2029	389,240.9	44,762.7	12,483.4	7,143.6	64,389.7	-	-	27,092.9	297,758.2
12-31-2030	396,207.3	45,563.8	12,706.9	7,271.4	65,542.2	-	-	27,092.9	303,572.3
12-31-2031	403,314.4	46,381.2	12,934.8	7,401.9	66,717.8	-	-	27,092.9	309,503.6
12-31-2032	410,127.3	47,164.6	13,153.3	7,526.9	67,844.9	33,835.0	-	27,092.9	281,354.5
12-31-2033	417,169.6	47,974.5	13,379.2	7,656.2	69,009.8	-	-	27,092.9	321,066.9
12-31-2034	422,052.5	48,536.0	13,535.8	7,745.8	69,817.6	-	-	27,092.9	325,142.0
12-31-2035	314,840.0	36,206.6	10,097.3	5,778.1	52,082.1	-	-	27,092.9	235,665.1
12-31-2036	265,574.5	30,541.1	8,517.3	4,874.0	43,932.4	-	-	27,092.9	194,549.2
12-31-2037	264,639.2	30,433.5	8,487.3	4,856.8	43,777.7	-	-	27,092.9	193,768.7
12-31-2038	249,976.5	28,747.3	8,017.1	4,587.7	41,352.1	-	-	27,092.9	181,531.5
12-31-2039	181,494.0	20,871.8	5,820.7	3,330.9	30,023.4	-	-	27,092.9	124,377.7
12-31-2040	181,896.7	20,918.1	5,833.7	3,338.3	30,090.1	-	-	27,092.9	124,713.7
12-31-2041	181,446.7	20,866.4	5,819.2	3,330.0	30,015.6	-	-	27,092.9	124,338.2
12-31-2042	181,808.4	20,908.0	5,830.8	3,336.7	30,075.4	-	-	27,092.9	124,640.0
12-31-2043	182,228.3	20,956.3	5,844.3	3,344.4	30,144.9	-	-	27,092.9	124,990.5
12-31-2044	182,636.9	21,003.2	5,857.4	3,351.9	30,212.5	-	12,448.4	27,092.9	112,883.1
12-31-2045	124,615.3	14,330.8	3,996.6	2,287.0	20,614.3	-	12,448.4	27,092.9	64,459.6
12-31-2046	57,993.8	6,669.3	1,859.9	1,064.3	9,593.6	-	12,448.4	27,092.9	8,858.9
12-31-2047	-	-	-	-	-	-	-	-	-
12-31-2048	-	-	-	-	-	-	-	-	-
12-31-2049	-	-	-	-	-	-	-	-	-
12-31-2050	-	-	-	-	-	-	-	-	-
12-31-2051	-	-	-	-	-	-	-	-	-
12-31-2052	-	-	-	-	-	-	-	-	-
12-31-2053	-	-	-	-	-	-	-	-	-
12-31-2054	-	-	-	-	-	-	-	-	-
12-31-2055	-	-	-	-	-	-	-	-	-
Total	7,642,579.8	878,896.7	245,107.2	140,261.5	1,264,265.4	176,404.1	37,345.3	732,586.6	5,431,978.4

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

REVENUE, COSTS, AND TAXES
PROVED (1P) RESERVES
TAMAR PETROLEUM LTD.
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2019

Period Ending	Levy Rate (%)	Levy (M$)	Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (M$)	Corporate Income Tax Rate[1] (%)	Corporate Income Taxes[1] (M$)	Future Net Revenue After Levy and Corporate Income Taxes				
						Discounted at 0% (M$)	Discounted at 5% (M$)	Discounted at 10% (M$)	Discounted at 15% (M$)	Discounted at 20% (M$)
12-31-2020	1.7	3,058.7	177,299.4	23.0	23,873.9	153,425.4	149,727.9	146,285.4	143,069.9	140,057.6
12-31-2021	23.7	33,084.2	106,802.9	23.0	12,752.8	94,050.2	87,412.9	81,521.2	76,262.8	71,546.4
12-31-2022	30.5	63,067.2	143,969.5	23.0	11,161.4	132,808.1	117,557.8	104,650.9	93,644.0	84,192.1
12-31-2023	37.2	78,348.5	132,079.7	23.0	12,790.4	119,289.3	100,563.1	85,452.9	73,140.7	63,018.4
12-31-2024	43.1	92,571.4	122,095.5	23.0	10,402.5	111,693.0	89,675.6	72,737.6	59,550.6	49,171.2
12-31-2025	46.7	117,376.3	133,712.0	23.0	5,207.7	128,504.3	98,259.9	76,077.8	59,577.1	47,143.4
12-31-2026	46.8	117,332.4	133,377.9	23.0	5,130.8	128,247.0	93,393.6	69,023.2	51,702.5	39,207.5
12-31-2027	46.8	119,868.7	136,261.0	23.0	7,812.1	128,448.9	89,086.3	62,847.1	45,029.5	32,724.4
12-31-2028	46.8	125,657.7	142,841.6	23.0	19,205.2	123,636.4	81,665.3	54,993.2	37,689.0	26,248.6
12-31-2029	46.8	139,350.9	158,407.4	23.0	21,985.9	136,421.5	85,819.2	55,163.6	36,162.1	24,135.8
12-31-2030	46.8	142,071.8	161,500.4	23.0	22,697.3	138,803.1	83,159.5	51,024.2	31,994.3	20,464.3
12-31-2031	46.8	144,847.7	164,655.9	23.0	23,679.2	140,976.7	80,439.7	47,112.0	28,256.8	17,320.6
12-31-2032	46.8	131,673.9	149,680.6	23.0	30,302.2	119,378.4	64,872.3	36,267.5	20,806.7	12,222.5
12-31-2033	46.8	150,259.3	170,807.6	23.0	26,775.1	144,032.5	74,542.7	39,779.5	21,829.3	12,288.9
12-31-2034	46.8	152,166.5	172,975.6	23.0	28,071.6	144,904.0	71,422.6	36,382.0	19,096.8	10,302.7
12-31-2035	46.8	110,291.2	125,373.8	23.0	20,671.0	104,702.8	49,150.1	23,898.5	11,998.9	6,203.7
12-31-2036	46.8	91,049.0	103,500.2	23.0	16,920.3	86,579.9	38,707.4	17,965.4	8,627.8	4,274.9
12-31-2037	46.8	90,683.7	103,084.9	23.0	16,949.7	86,135.3	36,674.8	16,248.3	7,464.0	3,544.1
12-31-2038	46.8	84,956.7	96,574.8	23.0	15,872.4	80,702.3	32,725.3	13,839.5	6,081.0	2,767.2
12-31-2039	46.8	58,208.8	66,168.9	23.0	10,466.8	55,702.2	21,512.0	8,683.9	3,649.8	1,591.6
12-31-2040	46.8	58,366.0	66,347.7	23.0	10,562.4	55,785.3	20,518.2	7,906.2	3,178.4	1,328.3
12-31-2041	46.8	58,190.3	66,147.9	23.0	10,587.8	55,560.2	19,462.3	7,158.5	2,752.7	1,102.5
12-31-2042	46.8	58,331.5	66,308.5	23.0	10,198.2	56,110.3	18,719.0	6,572.2	2,417.4	927.8
12-31-2043	46.8	58,495.6	66,495.0	23.0	11,072.0	55,422.9	17,609.2	5,901.5	2,076.3	763.7
12-31-2044	46.8	52,829.3	60,053.8	23.0	12,506.0	47,547.8	14,387.7	4,602.7	1,548.9	546.0
12-31-2045	46.8	30,167.1	34,292.5	23.0	7,793.3	26,499.2	7,636.7	2,331.9	750.6	253.6
12-31-2046	46.8	4,146.0	4,713.0	23.0	2,332.3	2,380.7	653.4	190.5	58.6	19.0
12-31-2047	-	-	-	23.0	-	-	-	-	-	-
12-31-2048	-	-	-	23.0	-	-	-	-	-	-
12-31-2049	-	-	-	23.0	-	-	-	-	-	-
12-31-2050	-	-	-	23.0	-	-	-	-	-	-
12-31-2051	-	-	-	23.0	-	-	-	-	-	-
12-31-2052	-	-	-	23.0	-	-	-	-	-	-
12-31-2053	-	-	-	23.0	-	-	-	-	-	-
12-31-2054	-	-	-	23.0	-	-	-	-	-	-
12-31-2055	-	-	-	23.0	-	-	-	-	-	-
Total		2,366,450.4	3,065,528.0		407,780.2	2,657,747.7	1,645,354.5	1,134,617.1	848,416.5	673,366.6

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

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROBABLE RESERVES
TAMAR PETROLEUM LTD.
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2019

Period Ending	Working Interest Revenue (M$)	Royalties: State (M$)	Royalties: Interested Party (M$)	Royalties: Third Party (M$)	Royalties: Total (M$)	Net Capital Costs (M$)	Net Abandonment Costs (M$)	Net Operating Expenses(1) (M$)	Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (M$)
12-31-2020	-	-	-	-	-	-	-	-	-
12-31-2021	-	-	-	-	-	-21,428.8	-	-	21,428.8
12-31-2022	-	-	-	-	-	-10,714.4	-	-	10,714.4
12-31-2023	-	-	-	-	-	-31,128.2	-	-	31,128.2
12-31-2024	-	-	-	-	-	-31,128.2	-	-	31,128.2
12-31-2025	-	-	-	-	-	32,143.3	-	-	-32,143.3
12-31-2026	-	-	-	-	-	-	-	-	-
12-31-2027	-	-	-	-	-	31,128.2	-	-	-31,128.2
12-31-2028	232.0	26.7	7.4	4.3	38.4	31,128.2	-	-	-30,934.6
12-31-2029	-	-	-	-	-	-	-	-	-
12-31-2030	-	-	-	-	-	-	-	-	-
12-31-2031	-	-	-	-	-	-	-	-	-
12-31-2032	-	-	-	-	-	-33,835.0	-	-	33,835.0
12-31-2033	-	-	-	-	-	-	-	-	-
12-31-2034	3,806.5	437.8	122.1	69.9	629.7	-	-	-	3,176.8
12-31-2035	119,285.0	13,717.8	3,825.6	2,189.2	19,732.6	-	-	-	99,552.4
12-31-2036	177,387.1	20,399.5	5,689.0	3,255.5	29,344.1	-	-	-	148,043.0
12-31-2037	185,976.1	21,387.3	5,964.5	3,413.2	30,764.9	33,835.0	-	-	121,376.2
12-31-2038	207,824.1	23,899.8	6,665.2	3,814.1	34,379.1	32,143.3	-	-	141,301.7
12-31-2039	283,685.3	32,623.8	9,098.1	5,206.4	46,928.3	-	-	-	236,757.0
12-31-2040	290,804.5	33,442.5	9,326.5	5,337.0	48,106.0	-	-	-	242,698.5
12-31-2041	290,952.3	33,459.5	9,331.2	5,339.7	48,130.5	-	-	-	242,821.8
12-31-2042	278,749.1	32,056.1	8,939.8	5,115.8	46,111.8	-	-	-	232,637.3
12-31-2043	228,368.6	26,262.4	7,324.1	4,191.2	37,777.6	-	-	-	190,591.0
12-31-2044	176,324.4	20,277.3	5,654.9	3,236.0	29,168.3	-	-12,448.4	-	159,604.6
12-31-2045	239,253.1	27,514.1	7,673.2	4,390.9	39,578.2	-	-12,448.4	-	212,123.4
12-31-2046	305,128.0	35,089.7	9,785.8	5,599.9	50,475.5	-	-12,448.4	-	267,100.9
12-31-2047	352,742.8	40,565.4	11,312.9	6,473.8	58,352.1	-	13,398.2	27,092.9	253,899.6
12-31-2048	293,359.4	33,736.3	9,408.4	5,383.9	48,528.7	-	13,398.2	27,092.9	204,339.6
12-31-2049	185,732.2	21,359.2	5,956.7	3,408.7	30,724.5	-	13,398.2	27,092.9	114,516.6
12-31-2050	-	-	-	-	-	-	-	-	-
12-31-2051	-	-	-	-	-	-	-	-	-
12-31-2052	-	-	-	-	-	-	-	-	-
12-31-2053	-	-	-	-	-	-	-	-	-
12-31-2054	-	-	-	-	-	-	-	-	-
12-31-2055	-	-	-	-	-	-	-	-	-
Total	3,619,610.4	416,255.2	116,085.5	66,429.4	598,770.1	32,143.3	2,849.3	81,278.6	2,904,569.1

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

REVENUE, COSTS, AND TAXES
PROBABLE RESERVES
TAMAR PETROLEUM LTD.
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2019

Period Ending	Levy Rate (%)	Levy (M$)	Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (M$)	Corporate Income Tax Rate[(1)] (%)	Corporate Income Taxes[(1)] (M$)	Future Net Revenue After Levy and Corporate Income Taxes: Discounted at 0% (M$)	Discounted at 5% (M$)	Discounted at 10% (M$)	Discounted at 15% (M$)	Discounted at 20% (M$)
12-31-2020	1.7	-	-	23.0	-	-	-	-	-	-
12-31-2021	24.1	5,836.4	15,592.4	23.0	-1,342.4	16,934.8	15,739.7	14,678.8	13,732.0	12,882.7
12-31-2022	31.4	5,401.6	5,312.8	23.0	-709.5	6,022.4	5,330.8	4,745.5	4,246.4	3,817.8
12-31-2023	38.8	15,485.2	15,643.0	23.0	-2,869.4	18,512.3	15,606.2	13,261.3	11,350.6	9,779.7
12-31-2024	45.3	18,658.8	12,469.4	23.0	-2,909.6	15,379.1	12,347.5	10,015.3	8,199.6	6,770.4
12-31-2025	46.8	-14,910.0	-17,233.2	23.0	5,518.2	-22,751.5	-17,396.8	-13,469.4	-10,548.0	-8,346.7
12-31-2026	46.8	-	-	23.0	1,349.6	-1,349.6	-982.9	-726.4	-544.1	-412.6
12-31-2027	46.8	-14,568.0	-16,560.2	23.0	4,700.3	-21,260.5	-14,745.3	-10,402.3	-7,453.1	-5,416.4
12-31-2028	46.8	-14,477.4	-16,457.2	23.0	4,363.1	-20,820.3	-13,752.4	-9,260.8	-6,346.8	-4,420.2
12-31-2029	46.8	-	-	23.0	-82.2	82.2	51.7	33.3	21.8	14.6
12-31-2030	46.8	-	-	23.0	-82.2	82.2	49.3	30.2	19.0	12.1
12-31-2031	46.8	-	-	23.0	-82.2	82.2	46.9	27.5	16.5	10.1
12-31-2032	46.8	15,834.8	18,000.2	23.0	-4,237.1	22,237.3	12,084.2	6,755.8	3,875.8	2,276.8
12-31-2033	46.8	-	-	23.0	21.0	-21.0	-10.9	-5.8	-3.2	-1.8
12-31-2034	46.8	1,486.8	1,690.1	23.0	-297.2	1,987.3	979.5	499.0	261.9	141.3
12-31-2035	46.8	46,590.5	52,961.9	23.0	10,788.2	42,173.6	19,797.3	9,626.2	4,833.1	2,498.8
12-31-2036	46.8	69,284.1	78,758.9	23.0	17,460.8	61,298.0	27,404.6	12,719.4	6,108.5	3,026.6
12-31-2037	46.8	56,804.1	64,572.1	23.0	21,979.9	42,592.2	18,135.0	8,034.5	3,690.8	1,752.5
12-31-2038	46.8	66,129.2	75,172.5	23.0	23,611.6	51,560.9	20,908.3	8,842.1	3,885.2	1,767.9
12-31-2039	46.8	110,802.3	125,954.7	23.0	28,230.3	97,724.4	37,740.9	15,235.1	6,403.2	2,792.3
12-31-2040	46.8	113,582.9	129,115.6	23.0	28,957.3	100,158.3	36,838.9	14,195.1	5,706.7	2,384.9
12-31-2041	46.8	113,640.6	129,181.2	23.0	28,972.4	100,208.8	35,102.3	12,911.1	4,964.8	1,988.4
12-31-2042	46.8	108,874.3	123,763.1	23.0	28,207.5	95,555.5	31,878.4	11,192.3	4,116.7	1,580.1
12-31-2043	46.8	89,196.6	101,394.4	23.0	22,284.5	79,109.9	25,135.2	8,423.7	2,963.7	1,090.1
12-31-2044	46.8	74,694.9	84,909.6	23.0	15,629.9	69,279.7	20,963.7	6,706.3	2,256.9	795.5
12-31-2045	46.8	99,273.7	112,849.6	23.0	21,446.4	91,403.2	26,341.1	8,043.6	2,589.2	874.7
12-31-2046	46.8	125,003.2	142,097.7	23.0	28,173.5	113,924.2	31,268.0	9,114.0	2,806.2	908.5
12-31-2047	46.8	118,825.0	135,074.6	23.0	32,021.5	103,053.1	26,937.4	7,494.8	2,207.3	684.8
12-31-2048	46.8	95,630.9	108,708.7	23.0	26,735.6	81,973.1	20,406.9	5,419.8	1,526.8	453.9
12-31-2049	46.8	53,593.8	60,922.8	23.0	16,484.1	44,438.7	10,536.0	2,671.0	719.7	205.1
12-31-2050	-	-	-	23.0	-	-	-	-	-	-
12-31-2051	-	-	-	23.0	-	-	-	-	-	-
12-31-2052	-	-	-	23.0	-	-	-	-	-	-
12-31-2053	-	-	-	23.0	-	-	-	-	-	-
12-31-2054	-	-	-	23.0	-	-	-	-	-	-
12-31-2055	-	-	-	23.0	-	-	-	-	-	-
Total		1,360,674.3	1,543,894.8		354,324.0	1,189,570.7	404,741.6	156,810.9	71,607.0	39,912.0

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

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROVED + PROBABLE (2P) RESERVES
TAMAR PETROLEUM LTD.
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2019

		Royalties							
Period Ending	Working Interest Revenue (M$)	State (M$)	Interested Party (M$)	Third Party (M$)	Total (M$)	Net Capital Costs (M$)	Net Abandonment Costs (M$)	Net Operating Expenses[1] (M$)	Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (M$)
12-31-2020	280,950.5	32,309.3	9,010.4	5,156.2	46,475.9	26,346.5	-	27,770.0	180,358.1
12-31-2021	253,043.8	29,100.0	8,115.4	4,644.0	41,859.5	22,364.3	-	27,504.1	161,315.9
12-31-2022	292,721.0	33,662.9	9,387.9	5,372.2	48,423.1	-541.4	-	27,088.2	217,751.1
12-31-2023	321,893.4	37,017.7	10,323.5	5,907.6	53,248.9	-	-	27,088.2	241,556.3
12-31-2024	326,977.9	37,602.5	10,486.6	6,000.9	54,090.0	-	-	27,092.9	245,795.1
12-31-2025	333,320.3	38,331.8	10,690.0	6,117.3	55,139.2	32,143.3	-	27,092.9	218,945.1
12-31-2026	332,867.4	38,279.8	10,675.5	6,109.0	55,064.2	-	-	27,092.9	250,710.3
12-31-2027	339,361.1	39,026.5	10,883.7	6,228.2	56,138.4	31,128.2	-	27,092.9	225,001.6
12-31-2028	354,414.3	40,757.6	11,366.5	6,504.4	58,628.6	31,128.2	-	27,092.9	237,564.7
12-31-2029	389,240.9	44,762.7	12,483.4	7,143.6	64,389.7	-	-	27,092.9	297,758.2
12-31-2030	396,207.3	45,563.8	12,706.9	7,271.4	65,542.2	-	-	27,092.9	303,572.3
12-31-2031	403,314.4	46,381.2	12,934.8	7,401.9	66,717.8	-	-	27,092.9	309,503.6
12-31-2032	410,127.3	47,164.6	13,153.3	7,526.9	67,844.9	-	-	27,092.9	315,189.5
12-31-2033	417,169.6	47,974.5	13,379.2	7,656.2	69,009.8	-	-	27,092.9	321,066.9
12-31-2034	425,859.0	48,973.8	13,657.8	7,815.6	70,447.3	-	-	27,092.9	328,318.9
12-31-2035	434,125.0	49,924.4	13,922.9	7,967.3	71,814.7	-	-	27,092.9	335,217.5
12-31-2036	442,961.5	50,940.6	14,206.3	8,129.5	73,276.4	-	-	27,092.9	342,592.2
12-31-2037	450,615.3	51,820.8	14,451.8	8,270.0	74,542.5	33,835.0	-	27,092.9	315,144.9
12-31-2038	457,800.5	52,647.1	14,682.2	8,401.8	75,731.2	32,143.3	-	27,092.9	322,833.2
12-31-2039	465,179.4	53,495.6	14,918.9	8,537.3	76,951.8	-	-	27,092.9	361,134.7
12-31-2040	472,701.2	54,360.6	15,160.1	8,675.3	78,196.1	-	-	27,092.9	367,412.3
12-31-2041	472,398.9	54,325.9	15,150.4	8,669.8	78,146.1	-	-	27,092.9	367,160.0
12-31-2042	460,557.5	52,964.1	14,770.7	8,452.4	76,187.2	-	-	27,092.9	357,277.4
12-31-2043	410,596.9	47,218.6	13,168.4	7,535.5	67,922.5	-	-	27,092.9	315,581.5
12-31-2044	358,961.3	41,280.5	11,512.3	6,587.9	59,380.8	-	-	27,092.9	272,487.6
12-31-2045	363,868.4	41,844.9	11,669.7	6,677.9	60,192.5	-	-	27,092.9	276,583.0
12-31-2046	363,121.8	41,759.0	11,645.8	6,664.2	60,069.0	-	-	27,092.9	275,959.9
12-31-2047	352,742.8	40,565.4	11,312.9	6,473.8	58,352.1	-	13,398.2	27,092.9	253,899.6
12-31-2048	293,359.4	33,736.3	9,408.4	5,383.9	48,528.7	-	13,398.2	27,092.9	204,339.6
12-31-2049	185,732.2	21,359.2	5,956.7	3,408.7	30,724.5	-	13,398.2	27,092.9	114,516.6
12-31-2050	-	-	-	-	-	-	-	-	-
12-31-2051	-	-	-	-	-	-	-	-	-
12-31-2052	-	-	-	-	-	-	-	-	-
12-31-2053	-	-	-	-	-	-	-	-	-
12-31-2054	-	-	-	-	-	-	-	-	-
12-31-2055	-	-	-	-	-	-	-	-	-
Total	11,262,190.2	1,295,151.9	361,192.7	206,690.9	1,863,035.5	208,547.3	40,194.6	813,865.2	8,336,547.5

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

REVENUE, COSTS, AND TAXES
PROVED + PROBABLE (2P) RESERVES
TAMAR PETROLEUM LTD.
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2019

						Future Net Revenue After Levy and Corporate Income Taxes				
Period Ending	Levy Rate (%)	Levy (M$)	Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (M$)	Corporate Income Tax Rate[1] (%)	Corporate Income Taxes[1] (M$)	Discounted at 0% (M$)	Discounted at 5% (M$)	Discounted at 10% (M$)	Discounted at 15% (M$)	Discounted at 20% (M$)
12-31-2020	1.7	3,058.7	177,299.4	23.0	23,873.9	153,425.4	149,727.9	146,285.4	143,069.9	140,057.6
12-31-2021	24.1	38,920.6	122,395.3	23.0	11,410.4	110,984.9	103,152.6	96,200.0	89,994.8	84,429.1
12-31-2022	31.4	68,468.8	149,282.3	23.0	10,451.9	138,830.5	122,888.6	109,396.4	97,890.4	88,009.9
12-31-2023	38.8	93,833.7	147,722.6	23.0	9,921.0	137,801.6	116,169.4	98,714.3	84,491.3	72,798.1
12-31-2024	45.3	111,230.1	134,564.9	23.0	7,492.8	127,072.1	102,023.1	82,752.9	67,750.1	55,941.6
12-31-2025	46.8	102,466.3	116,478.8	23.0	10,725.9	105,752.8	80,863.2	62,608.3	49,029.1	38,796.7
12-31-2026	46.8	117,332.4	133,377.9	23.0	6,480.5	126,897.4	92,410.7	68,296.8	51,158.4	38,794.9
12-31-2027	46.8	105,300.7	119,700.8	23.0	12,512.4	107,188.4	74,341.0	52,444.8	37,576.3	27,307.9
12-31-2028	46.8	111,180.3	126,384.4	23.0	23,568.2	102,816.2	67,912.9	45,732.4	31,342.2	21,828.3
12-31-2029	46.8	139,350.9	158,407.4	23.0	21,903.7	136,503.7	85,870.9	55,196.8	36,183.9	24,150.3
12-31-2030	46.8	142,071.8	161,500.4	23.0	22,615.1	138,885.4	83,208.7	51,054.4	32,013.2	20,476.4
12-31-2031	46.8	144,847.7	164,655.9	23.0	23,596.9	141,059.0	80,486.6	47,139.5	28,273.2	17,330.7
12-31-2032	46.8	147,508.7	167,680.8	23.0	26,065.1	141,615.7	76,956.5	43,023.2	24,682.5	14,499.3
12-31-2033	46.8	150,259.3	170,807.6	23.0	26,796.1	144,011.5	74,531.8	39,773.7	21,826.1	12,287.1
12-31-2034	46.8	153,653.2	174,665.6	23.0	27,774.4	146,891.2	72,402.1	36,880.9	19,358.7	10,444.0
12-31-2035	46.8	156,881.8	178,335.7	23.0	31,459.3	146,876.4	68,947.4	33,524.7	16,832.0	8,702.5
12-31-2036	46.8	160,333.2	182,259.1	23.0	34,381.2	147,877.9	66,111.9	30,684.8	14,736.3	7,301.5
12-31-2037	46.8	147,487.8	167,657.1	23.0	38,929.6	128,727.5	54,809.8	24,282.8	11,154.7	5,296.6
12-31-2038	46.8	151,086.0	171,747.3	23.0	39,484.0	132,263.2	53,633.6	22,681.6	9,966.2	4,535.1
12-31-2039	46.8	169,011.0	192,123.7	23.0	38,697.0	153,426.6	59,252.9	23,919.0	10,052.9	4,384.0
12-31-2040	46.8	171,948.9	195,463.3	23.0	39,519.7	155,943.6	57,357.1	22,101.3	8,885.1	3,713.2
12-31-2041	46.8	171,830.9	195,329.1	23.0	39,560.1	155,769.0	54,564.6	20,069.6	7,717.5	3,090.9
12-31-2042	46.8	167,205.8	190,071.6	23.0	38,405.7	151,665.9	50,597.4	17,764.5	6,534.1	2,507.9
12-31-2043	46.8	147,692.1	167,889.3	23.0	33,356.6	134,532.8	42,744.4	14,325.2	5,040.0	1,853.8
12-31-2044	46.8	127,524.2	144,963.4	23.0	28,135.9	116,827.5	35,351.5	11,309.0	3,805.8	1,341.5
12-31-2045	46.8	129,440.8	147,142.1	23.0	29,239.7	117,902.4	33,977.8	10,375.5	3,339.9	1,128.2
12-31-2046	46.8	129,149.2	146,810.6	23.0	30,505.7	116,304.9	31,921.4	9,304.5	2,864.9	927.5
12-31-2047	46.8	118,825.0	135,074.6	23.0	32,021.5	103,053.1	26,937.4	7,494.8	2,207.3	684.8
12-31-2048	46.8	95,630.9	108,708.7	23.0	26,735.6	81,973.1	20,406.9	5,419.8	1,526.8	453.9
12-31-2049	46.8	53,593.8	60,922.8	23.0	16,484.1	44,438.7	10,536.0	2,671.0	719.7	205.1
12-31-2050	-	-	-	23.0	-	-	-	-	-	-
12-31-2051	-	-	-	23.0	-	-	-	-	-	-
12-31-2052	-	-	-	23.0	-	-	-	-	-	-
12-31-2053	-	-	-	23.0	-	-	-	-	-	-
12-31-2054	-	-	-	23.0	-	-	-	-	-	-
12-31-2055	-	-	-	23.0	-	-	-	-	-	-
Total		3,727,124.8	4,609,422.7		762,104.3	3,847,318.5	2,050,096.1	1,291,428.0	920,023.4	713,278.6

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

NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
POSSIBLE RESERVES
TAMAR PETROLEUM LTD.
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2019

Period Ending	Working Interest Revenue (M$)	Royalties: State (M$)	Royalties: Interested Party (M$)	Royalties: Third Party (M$)	Royalties: Total (M$)	Net Capital Costs (M$)	Net Abandonment Costs (M$)	Net Operating Expenses[(1)] (M$)	Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (M$)
12-31-2020	-	-	-	-	-	-	-	-	-
12-31-2021	-	-	-	-	-	-	-	-	-
12-31-2022	-	-	-	-	-	-	-	-	-
12-31-2023	-	-	-	-	-	-	-	-	-
12-31-2024	-	-	-	-	-	-	-	-	-
12-31-2025	-	-	-	-	-	-32,143.3	-	-	32,143.3
12-31-2026	-	-	-	-	-	16,071.6	-	-	-16,071.6
12-31-2027	-	-	-	-	-	16,071.6	-	-	-16,071.6
12-31-2028	-	-	-	-	-	-	-	-	-
12-31-2029	-	-	-	-	-	-	-	-	-
12-31-2030	-	-	-	-	-	-	-	-	-
12-31-2031	-	-	-	-	-	-	-	-	-
12-31-2032	-	-	-	-	-	-	-	-	-
12-31-2033	-	-	-	-	-	-	-	-	-
12-31-2034	-3.7	-0.4	-0.1	-0.1	-0.6	-	-	-	-3.1
12-31-2035	-	-	-	-	-	-	-	-	-
12-31-2036	-	-	-	-	-	-	-	-	-
12-31-2037	-	-	-	-	-	-33,835.0	-	-	33,835.0
12-31-2038	-	-	-	-	-	-15,225.8	-	-	15,225.8
12-31-2039	-	-	-	-	-	16,917.5	-	-	-16,917.5
12-31-2040	-	-	-	-	-	16,071.6	-	-	-16,071.6
12-31-2041	7,868.7	904.9	252.4	144.4	1,301.7	16,071.6	-	-	-9,504.6
12-31-2042	27,617.8	3,176.0	885.7	506.9	4,568.6	-	-	-	23,049.2
12-31-2043	85,614.1	9,845.6	2,745.8	1,571.2	14,162.6	-	-	-	71,451.5
12-31-2044	145,415.0	16,722.7	4,663.6	2,668.7	24,055.1	-	-	-	121,359.8
12-31-2045	148,805.0	17,112.6	4,772.4	2,731.0	24,615.9	-	-	-	124,189.1
12-31-2046	157,981.9	18,167.9	5,066.7	2,899.4	26,134.0	-	-	-	131,847.9
12-31-2047	176,927.1	20,346.6	5,674.3	3,247.1	29,268.0	-	-13,398.2	-	161,057.3
12-31-2048	230,077.8	26,458.9	7,378.9	4,222.5	38,060.4	-	-13,398.2	-	205,415.6
12-31-2049	313,054.1	36,001.2	10,040.0	5,745.4	51,786.6	-	-13,398.2	-	274,665.7
12-31-2050	473,181.8	54,415.9	15,175.5	8,684.1	78,275.6	-	-	27,092.9	367,813.4
12-31-2051	446,587.8	51,357.6	14,322.6	8,196.1	73,876.3	-	-	27,092.9	345,618.7
12-31-2052	384,080.6	44,169.3	12,318.0	7,048.9	63,536.1	-	-	27,092.9	293,451.6
12-31-2053	319,399.1	36,730.9	10,243.5	5,861.8	52,836.2	-	13,398.2	27,092.9	226,071.8
12-31-2054	252,493.8	29,036.8	8,097.8	4,633.9	41,768.5	-	13,398.2	27,092.9	170,234.2
12-31-2055	155,439.5	17,875.5	4,985.1	2,852.7	25,713.4	-	13,398.2	27,092.9	89,235.0
Total	3,324,540.4	382,322.2	106,622.2	61,014.1	549,958.5	-	-	162,557.3	2,612,024.7

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

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

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
POSSIBLE RESERVES
TAMAR PETROLEUM LTD.
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2019

						Future Net Revenue After Levy and Corporate Income Taxes				
Period Ending	Levy Rate (%)	Levy (M$)	Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (M$)	Corporate Income Tax Rate[(1)] (%)	Corporate Income Taxes[(1)] (M$)	Discounted at 0% (M$)	Discounted at 5% (M$)	Discounted at 10% (M$)	Discounted at 15% (M$)	Discounted at 20% (M$)
12-31-2020	1.7	-	-	23.0	-	-	-	-	-	-
12-31-2021	24.1	-	-	23.0	-	-	-	-	-	-
12-31-2022	31.4	-	-	23.0	-	-	-	-	-	-
12-31-2023	38.8	-	-	23.0	-	-	-	-	-	-
12-31-2024	45.3	-	-	23.0	-	-	-	-	-	-
12-31-2025	46.8	15,043.0	17,100.2	23.0	-3,459.9	20,560.1	15,721.1	12,172.1	9,532.1	7,542.7
12-31-2026	46.8	-7,521.5	-8,550.1	23.0	2,469.2	-11,019.3	-8,024.6	-5,930.7	-4,442.4	-3,368.8
12-31-2027	46.8	-7,521.5	-8,550.1	23.0	2,099.6	-10,649.7	-7,386.1	-5,210.7	-3,733.4	-2,713.2
12-31-2028	46.8	-	-	23.0	-	-	-	-	-	-
12-31-2029	46.8	-	-	23.0	-	-	-	-	-	-
12-31-2030	46.8	-	-	23.0	-	-	-	-	-	-
12-31-2031	46.8	-	-	23.0	-	-	-	-	-	-
12-31-2032	46.8	-	-	23.0	-	-	-	-	-	-
12-31-2033	46.8	-	-	23.0	-	-	-	-	-	-
12-31-2034	46.8	-1.4	-1.6	23.0	-0.4	-1.3	-0.6	-0.3	-0.2	-0.1
12-31-2035	46.8	-	-	23.0	-	-	-	-	-	-
12-31-2036	46.8	-	-	23.0	-739.3	739.3	330.5	153.4	73.7	36.5
12-31-2037	46.8	15,834.8	18,000.2	23.0	-4,011.6	22,011.9	9,372.3	4,152.3	1,907.4	905.7
12-31-2038	46.8	7,125.7	8,100.1	23.0	-860.7	8,960.8	3,633.7	1,536.7	675.2	307.3
12-31-2039	46.8	-7,917.4	-9,000.1	23.0	2,949.4	-11,949.5	-4,614.9	-1,862.9	-783.0	-341.4
12-31-2040	46.8	-7,521.5	-8,550.1	23.0	2,469.2	-11,019.3	-4,053.0	-1,561.7	-627.8	-262.4
12-31-2041	46.8	-4,448.2	-5,056.5	23.0	2,903.1	-7,959.6	-2,788.2	-1,025.5	-394.4	-157.9
12-31-2042	46.8	10,787.0	12,262.2	23.0	2,820.3	9,441.9	3,149.9	1,105.9	406.8	156.1
12-31-2043	46.8	33,439.3	38,012.2	23.0	8,742.8	29,269.4	9,299.6	3,116.6	1,096.5	403.3
12-31-2044	46.8	56,796.4	64,563.4	23.0	14,849.6	49,713.8	15,043.2	4,812.3	1,619.5	570.9
12-31-2045	46.8	58,120.5	66,068.6	23.0	15,805.5	50,263.1	14,485.1	4,423.2	1,423.8	481.0
12-31-2046	46.8	61,704.8	70,143.1	23.0	16,742.6	53,400.5	14,656.4	4,272.1	1,315.4	425.8
12-31-2047	46.8	75,374.8	85,682.5	23.0	17,235.1	68,447.4	17,891.7	4,978.0	1,466.1	454.9
12-31-2048	46.8	96,134.5	109,281.1	23.0	21,884.6	87,396.5	21,757.0	5,778.3	1,627.8	484.0
12-31-2049	46.8	128,543.5	146,122.1	23.0	30,007.8	116,114.3	27,529.7	6,979.1	1,880.6	535.8
12-31-2050	46.8	172,136.7	195,676.7	23.0	44,266.3	151,410.4	34,188.7	8,273.3	2,132.4	582.3
12-31-2051	46.8	161,749.5	183,869.1	23.0	41,310.5	142,558.6	30,657.1	7,081.5	1,745.9	456.9
12-31-2052	46.8	137,335.3	156,116.2	23.0	35,297.0	120,819.2	24,744.8	5,456.0	1,286.6	322.7
12-31-2053	46.8	105,801.6	120,270.2	23.0	30,134.0	90,136.2	17,581.6	3,700.4	834.7	200.6
12-31-2054	46.8	79,669.6	90,564.6	23.0	23,301.7	67,262.9	12,495.2	2,510.3	541.6	124.7
12-31-2055	46.8	41,762.0	47,473.0	23.0	13,390.7	34,082.3	6,029.9	1,156.3	238.6	52.7
Total		1,222,427.6	1,389,597.1		319,607.3	1,069,989.8	251,700.0	66,066.1	19,823.6	7,200.0

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

NETHERLAND, SEWELL & ASSOCIATES, INC.

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

Period Ending	Working Interest Revenue (M$)	Royalties				Net Capital Costs (M$)	Net Abandonment Costs (M$)	Net Operating Expenses[1] (M$)	Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (M$)
		State (M$)	Interested Party (M$)	Third Party (M$)	Total (M$)				
12-31-2020	280,950.5	32,309.3	9,010.4	5,156.2	46,475.9	26,346.5	-	27,770.0	180,358.1
12-31-2021	253,043.8	29,100.0	8,115.4	4,644.0	41,859.5	22,364.3	-	27,504.1	161,315.9
12-31-2022	292,721.0	33,662.9	9,387.9	5,372.2	48,423.1	-541.4	-	27,088.2	217,751.1
12-31-2023	321,893.4	37,017.7	10,323.5	5,907.6	53,248.9	-	-	27,088.2	241,556.3
12-31-2024	326,977.9	37,602.5	10,486.6	6,000.9	54,090.0	-	-	27,092.9	245,795.1
12-31-2025	333,320.3	38,331.8	10,690.0	6,117.3	55,139.2	-	-	27,092.9	251,088.3
12-31-2026	332,867.4	38,279.8	10,675.5	6,109.0	55,064.2	16,071.6	-	27,092.9	234,638.7
12-31-2027	339,361.1	39,026.5	10,883.7	6,228.2	56,138.4	47,199.8	-	27,092.9	208,930.0
12-31-2028	354,414.3	40,757.6	11,366.5	6,504.4	58,628.6	31,128.2	-	27,092.9	237,564.7
12-31-2029	389,240.9	44,762.7	12,483.4	7,143.6	64,389.7	-	-	27,092.9	297,758.2
12-31-2030	396,207.3	45,563.8	12,706.9	7,271.4	65,542.2	-	-	27,092.9	303,572.3
12-31-2031	403,314.4	46,381.2	12,934.8	7,401.9	66,717.8	-	-	27,092.9	309,503.6
12-31-2032	410,127.3	47,164.6	13,153.3	7,526.9	67,844.9	-	-	27,092.9	315,189.5
12-31-2033	417,169.6	47,974.5	13,379.2	7,656.2	69,009.8	-	-	27,092.9	321,066.9
12-31-2034	425,855.3	48,973.4	13,657.7	7,815.6	70,446.6	-	-	27,092.9	328,315.8
12-31-2035	434,125.0	49,924.4	13,922.9	7,967.3	71,814.7	-	-	27,092.9	335,217.5
12-31-2036	442,961.5	50,940.6	14,206.3	8,129.5	73,276.4	-	-	27,092.9	342,592.2
12-31-2037	450,615.3	51,820.8	14,451.8	8,270.0	74,542.5	-	-	27,092.9	348,979.9
12-31-2038	457,800.5	52,647.1	14,682.2	8,401.8	75,731.2	16,917.5	-	27,092.9	338,059.0
12-31-2039	465,179.4	53,495.6	14,918.9	8,537.3	76,951.8	16,917.5	-	27,092.9	344,217.2
12-31-2040	472,701.2	54,360.6	15,160.1	8,675.3	78,196.1	16,071.6	-	27,092.9	351,340.6
12-31-2041	480,267.6	55,230.8	15,402.8	8,814.2	79,447.7	16,071.6	-	27,092.9	357,655.4
12-31-2042	488,175.3	56,140.2	15,656.4	8,959.3	80,755.9	-	-	27,092.9	380,326.5
12-31-2043	496,211.1	57,064.3	15,914.1	9,106.8	82,085.2	-	-	27,092.9	387,033.0
12-31-2044	504,376.3	58,003.3	16,176.0	9,256.6	83,435.9	-	-	27,092.9	393,847.5
12-31-2045	512,673.3	58,957.4	16,442.1	9,408.9	84,808.4	-	-	27,092.9	400,772.0
12-31-2046	521,103.6	59,926.9	16,712.5	9,563.6	86,203.0	-	-	27,092.9	407,807.8
12-31-2047	529,669.9	60,912.0	16,987.2	9,720.8	87,620.1	-	-	27,092.9	414,956.9
12-31-2048	523,437.2	60,195.3	16,787.3	9,606.5	86,589.0	-	-	27,092.9	409,755.3
12-31-2049	498,786.3	57,360.4	15,996.7	9,154.0	82,511.2	-	-	27,092.9	389,182.3
12-31-2050	473,181.8	54,415.9	15,175.5	8,684.1	78,275.6	-	-	27,092.9	367,813.4
12-31-2051	446,587.8	51,357.6	14,322.6	8,196.1	73,876.3	-	-	27,092.9	345,618.7
12-31-2052	384,080.6	44,169.3	12,318.0	7,048.9	63,536.1	-	-	27,092.9	293,451.6
12-31-2053	319,399.1	36,730.9	10,243.5	5,861.8	52,836.2	-	13,398.2	27,092.9	226,071.8
12-31-2054	252,493.8	29,036.8	8,097.8	4,633.9	41,768.5	-	13,398.2	27,092.9	170,234.2
12-31-2055	155,439.5	17,875.5	4,985.1	2,852.7	25,713.4	-	13,398.2	27,092.9	89,235.0
Total	14,586,730.7	1,677,474.0	467,815.0	267,705.0	2,412,994.0	208,547.3	40,194.6	976,422.5	10,948,572.2

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

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

NETHERLAND, SEWELL & ASSOCIATES, INC.

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

						Future Net Revenue After Levy and Corporate Income Taxes				
Period Ending	Levy Rate (%)	Levy (M$)	Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (M$)	Corporate Income Tax Rate[1] (%)	Corporate Income Taxes[1] (M$)	Discounted at 0% (M$)	Discounted at 5% (M$)	Discounted at 10% (M$)	Discounted at 15% (M$)	Discounted at 20% (M$)
12-31-2020	1.7	3,058.7	177,299.4	23.0	23,873.9	153,425.4	149,727.9	146,285.4	143,069.9	140,057.6
12-31-2021	24.1	38,920.6	122,395.3	23.0	11,410.4	110,984.9	103,152.6	96,200.0	89,994.8	84,429.1
12-31-2022	31.4	68,468.8	149,282.3	23.0	10,451.9	138,830.5	122,888.6	109,396.4	97,890.4	88,009.9
12-31-2023	38.8	93,833.7	147,722.6	23.0	9,921.0	137,801.6	116,169.4	98,714.3	84,491.3	72,798.1
12-31-2024	45.3	111,230.1	134,564.9	23.0	7,492.8	127,072.1	102,023.1	82,752.9	67,750.1	55,941.6
12-31-2025	46.8	117,509.3	133,579.0	23.0	7,266.0	126,312.9	96,584.3	74,780.4	58,561.2	46,339.5
12-31-2026	46.8	109,810.9	124,827.8	23.0	8,949.7	115,878.0	84,386.1	62,366.1	46,716.0	35,426.1
12-31-2027	46.8	97,779.2	111,150.7	23.0	14,612.0	96,538.7	66,954.8	47,234.2	33,842.9	24,594.7
12-31-2028	46.8	111,180.3	126,384.4	23.0	23,568.2	102,816.2	67,912.9	45,732.4	31,342.2	21,828.3
12-31-2029	46.8	139,350.9	158,407.4	23.0	21,903.7	136,503.7	85,870.9	55,196.8	36,183.9	24,150.3
12-31-2030	46.8	142,071.8	161,500.4	23.0	22,615.1	138,885.4	83,208.7	51,054.4	32,013.2	20,476.4
12-31-2031	46.8	144,847.7	164,655.9	23.0	23,596.9	141,059.0	80,486.6	47,139.5	28,273.2	17,330.7
12-31-2032	46.8	147,508.7	167,680.8	23.0	26,065.1	141,615.7	76,956.5	43,023.2	24,682.5	14,499.3
12-31-2033	46.8	150,259.3	170,807.6	23.0	26,796.1	144,011.5	74,531.8	39,773.7	21,826.1	12,287.1
12-31-2034	46.8	153,651.8	174,664.0	23.0	27,774.0	146,890.0	72,401.5	36,880.6	19,358.6	10,443.9
12-31-2035	46.8	156,881.8	178,335.7	23.0	31,459.3	146,876.4	68,947.4	33,524.7	16,832.0	8,702.5
12-31-2036	46.8	160,333.2	182,259.1	23.0	33,641.9	148,617.2	66,442.4	30,838.3	14,810.0	7,338.0
12-31-2037	46.8	163,322.6	185,657.3	23.0	34,918.0	150,739.3	64,182.1	28,435.1	13,062.1	6,202.3
12-31-2038	46.8	158,211.6	179,847.4	23.0	38,623.4	141,224.0	57,267.3	24,218.3	10,641.4	4,842.3
12-31-2039	46.8	161,093.6	183,123.5	23.0	41,646.4	141,477.1	54,638.0	22,056.1	9,270.0	4,042.5
12-31-2040	46.8	164,427.4	186,913.2	23.0	41,989.0	144,924.2	53,304.1	20,539.6	8,257.2	3,450.8
12-31-2041	46.8	167,382.7	190,272.7	23.0	42,463.3	147,809.4	51,776.4	19,044.0	7,323.2	2,933.0
12-31-2042	46.8	177,992.8	202,333.7	23.0	41,226.0	161,107.7	53,747.4	18,870.4	6,940.9	2,664.0
12-31-2043	46.8	181,131.4	205,901.6	23.0	42,099.4	163,802.2	52,044.1	17,441.8	6,136.5	2,257.1
12-31-2044	46.8	184,320.6	209,526.9	23.0	42,985.5	166,541.3	50,394.6	16,121.3	5,425.3	1,912.4
12-31-2045	46.8	187,561.3	213,210.7	23.0	45,045.2	168,165.5	48,462.9	14,798.7	4,763.7	1,609.2
12-31-2046	46.8	190,854.0	216,953.7	23.0	47,248.3	169,705.4	46,577.8	13,576.6	4,180.3	1,353.3
12-31-2047	46.8	194,199.8	220,757.1	23.0	49,256.6	171,500.5	44,829.1	12,472.9	3,673.5	1,139.7
12-31-2048	46.8	191,765.5	217,989.8	23.0	48,620.2	169,369.7	42,163.9	11,198.1	3,154.6	937.9
12-31-2049	46.8	182,137.3	207,045.0	23.0	46,491.9	160,553.0	38,065.7	9,650.2	2,600.4	740.9
12-31-2050	46.8	172,136.7	195,676.7	23.0	44,266.3	151,410.4	34,188.7	8,273.3	2,132.4	582.3
12-31-2051	46.8	161,749.5	183,869.1	23.0	41,310.5	142,558.6	30,657.1	7,081.5	1,745.9	456.9
12-31-2052	46.8	137,335.3	156,116.2	23.0	35,297.0	120,819.2	24,744.8	5,456.0	1,286.6	322.7
12-31-2053	46.8	105,801.6	120,270.2	23.0	30,134.0	90,136.2	17,581.6	3,700.4	834.7	200.6
12-31-2054	46.8	79,669.6	90,564.6	23.0	23,301.7	67,262.9	12,495.2	2,510.3	541.6	124.7
12-31-2055	46.8	41,762.0	47,473.0	23.0	13,390.7	34,082.3	6,029.9	1,156.3	238.6	52.7
Total		4,949,552.3	5,999,019.9		1,081,711.6	4,917,308.3	2,301,796.1	1,357,494.1	939,847.1	720,478.6

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

HISTORICAL PRODUCTION AND OPERATING EXPENSE DATA
TAMAR PETROLEUM LTD.
TAMAR AND TAMAR SOUTHWEST FIELDS, TAMAR LEASE I/12, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2019

Year	Tamar Petroleum Working Interest Production (BCF)	Average Per Production Unit ($/MCF) Price Received	Royalties Paid	Production Costs	Net Revenue	Reserves Depletion Rate[1] (%)
2019[2]	62.2	5.63	0.89	0.45	4.29	3.3
2018[3]	56.3	5.53	0.88	0.39	4.26	3.3
2017	32.0	5.43	0.86	0.37	4.20	3.4

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

(1) The reserves depletion rate is the percentage of yearly gas produced to the estimated proved plus probable reserves at the beginning of that year.
(2) The 2019 data is representative of unaudited financial data.
(3) The Tamar Petroleum working interest in these properties increased from 9.25 percent to 16.75 percent on March 14, 2018.

NETHERLAND, SEWELL & ASSOCIATES, INC.

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

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

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

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

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

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

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

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

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

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