NewMed Energy - Limited Partnership
(the "Partnership")

16 January 2026

To
Israel Securities Authority
22 Kanfei Nesharim St.
Jerusalem
Via Magna

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

Dear Sir/Madam,

Re: **Satisfaction of the conditions precedent in the transaction to increase natural gas export quantities to Egypt;
Final Investment Decision (FID) in the Leviathan Reservoir Expansion Project;
Report on Updated Reserves, Contingent Resources and Discounted Cash Flow Figures in the Leviathan Leases**

Further to the Partnership's immediate report of 7 August 2025 (Ref.: 2025-01-058580) regarding the engagement of the partners in the Leviathan reservoir, which is located in the area of the I/14 "Leviathan South" and I/15 "Leviathan North" leases (the "**Leviathan Partners**", the "**Leviathan Reservoir**" or the "**Reservoir**" or the "**Field**" or the "**Leviathan Project**", and the "**Leviathan Leases**", respectively), with Blue Ocean Energy ("**BOE**") in a transaction for expansion of the export quantities of natural gas to Egypt (the "**Amendment to the Export to Egypt Agreement**"), to the Partnership's immediate report of 21 August 2025 (Ref.: 2025-01-062484) regarding approval of the updated development plan for the Leviathan Reservoir by the Petroleum Commissioner at the Ministry of Energy and Infrastructures (the "**Development Plan**" and the "**Commissioner**", respectively), to the Partnership's immediate reports of 16 September 2025 and 26 October 2025 (Ref.: 2025-01-069899 and 2025-01-079841, respectively) regarding the engagement of Chevron Mediterranean Limited, the operator in the Leviathan Project ("**Chevron**" or the "**Operator**"), with Israel Natural Gas Lines Ltd. ("**INGL**") in an agreement for the transmission of natural gas to Egypt via the Nitzana project, and determination of the rate of the allocation to the Leviathan Project in the Nitzana project, and to the Partnership's immediate report of 17 December 2025 (Ref.: 2025-01-100866) regarding receipt of an export permit in respect of the Amendment to the Export to Egypt Agreement (the "**Export Permit**"), the Partnership respectfully reports as follows:

Satisfaction of the conditions precedent in the transaction to increase natural gas export quantities to Egypt

Further to the Partnership's immediate reports of 30 October 2025, 30 November 2025 and 31 December 2025 (Ref.: 2025-01-082110, 2025-01-094718 and 2025-01-105955, respectively) regarding extensions of the timeframe for satisfaction of the conditions precedent for the taking effect of the Amendment to the Export to Egypt Agreement, the Partnership hereby respectfully reports that on 15 January 2026, all of the conditions precedent for the taking effect of the Amendment to the Export to Egypt Agreement have been satisfied.

Adoption of a final investment decision (FID) on the development of Stage One of the Expansion Project in the Leviathan Reservoir

On 15 January 2026, the Leviathan Partners adopted an FID for the development of stage one of the Leviathan Reservoir expansion project ("**Stage One of the Expansion Project**") in the context of the Development Plan. Stage One of the Expansion Project is intended to increase the total gas production capacity of the Leviathan Project up to approx. 21 BCM per year, and to enable the production of first gas in H2/2029, with a total budget of approx. $2.36 billion (100%). This budget includes a sum of approx. $504 million (100%) which the Leviathan Partners approved in July 2024.

According to the Development Plan, Stage One of the Expansion Project includes the drilling and completion of 3 additional production wells, the addition of supplementary subsea systems and expansion of the processing systems on the platform, with the aim of increasing the installed capacity of the platform up to approx. 23 BCM per year. However, Stage One of the Expansion Project is expected to increase the total gas production capacity of the Leviathan Project up to approx. 21 BCM per year, *inter alia* given restrictions of the subsea pipeline. Expansion of the total gas production capacity of the Leviathan Project up to approx. 23 BCM per year ("**Stage Two of the Expansion Project**") requires receipt of regulatory approvals and performance of additional investments, including investments in the laying of a fourth pipeline between the Field and the platform and in the installation of additional subsea systems, an FID in respect of which is expected to be adopted in the coming years.

Further to Section 9(c) of the update to Chapter A of the Q1/2025 report, as released on 12 May 2025 (Ref.: 2025-01-032985) (the "**Q1 Report**"), regarding alternatives for financing the Partnership's share in the costs of Stage One of the Expansion Project, the Partnership intends to finance its share in the development costs, *inter alia* from its own resources, while using the credit facilities available thereto[1]. The Partnership is also continuing to consider capital raising options, *inter alia* through loans from financial corporations, bonds, various equity instruments and other alternatives, if any.

Caution regarding forward-looking information – the above estimates regarding the amount of the budget and the timetables for development of Stage One of the Expansion Project, the expected production capacity, the date for the production of first gas and the possible date for the adoption of an FID for the performance of Stage Two of the Expansion Project (if adopted), constitute forward-looking information within the meaning thereof in Section 32A of the Securities Law, 5728-1968 (the "Securities Law"), which there is no certainty will materialize at all, or may materialize in a materially different manner than stated above, due to various factors, including changes to the Development Plan, delays in implementation of

[1] For further details, see Section 7.21.3 of the Periodic Report, Section 8(c) of the update to Chapter A of the Q2/2025 report, as released on 7 August 2025 (Ref.: 2025-01-058652) (the "**Q2 Report**"), and Section 12(b) of the update to Chapter A of the Q3/2025 report, as released on 10 November 2025 (Ref.: 2025-01-085255) (the "**Q3 Report**").

the Development Plan, delays in obtaining the required regulatory approvals, changes in the conditions of the domestic and global markets, including changes in the energy prices and in demand, geopolitical changes or changes in the security situation in the region, operating or technical difficulties. The said information is based, *inter alia*, on estimates of the Partnership and Chevron, based on a variety of factors, including the Development Plan and the timetables for implementation thereof, receipt of regulatory approvals, estimated data on the availability of equipment, services and costs, as well as on past experience. The estimates in this report may not materialize or materialize in a materially different manner in the event of changes and/or delays in the range of factors as specified above, as well as in the event of any changes to the estimates received, the market conditions and/or geopolitical conditions and/or the security situation in the region and/or operating or technical difficulties in the development of the Leviathan Reservoir and the construction of the infrastructures and/or changes in the scope or pace of natural gas consumption in the target markets and/or unexpected factors related to oil and natural gas exploration, production and marketing and/or materialization of any of the risk factors entailed by natural gas exploration, development and production specified in the Partnership's 2024 periodic report, as released on 10 March 2025 (Ref.: 2025-01-015633) (the "Periodic Report").

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

Upon adoption of an FID as aforesaid for Stage One of the Expansion Project, the contingencies pertaining to part of the contingent resources in the Leviathan Reservoir, as announced in the Partnership's immediate report of 4 February 2025 (Ref.: 2025-01-008729) regarding the estimated reserves and contingent resources in the Leviathan Reservoir (the "**Previous Resources Report**"), and regarding the discounted cash flow figures from the reserves and from part of the contingent resources in the Leviathan Leases as of 31 December 2024 (collectively: the "**Previous Discounted Cash Flow**"), were met, such that most of these contingent resources have now been classified by the resource evaluator, Netherland, Sewell & Associates Inc. ("**NSAI**" or the "**Evaluator**"), as reserves, all as specified below in the report on reserves, contingent resources and updated discounted cash flow figures, as of 31 December 2025, in relation to the Partnership's share in the Leviathan Leases (the "**Resources Report**", the "**Discounted Cash Flow**" and the "**Current Discounted Cash Flow**" or the "**Cash Flow**", respectively), attached hereto[2].

It is clarified that the estimated quantity recoverable from the Reservoir throughout its life (i.e., reserves + resources + quantity actually produced) in the 2P best estimate totals approx. 22.4 TCF, similar to the estimate in the Previous Resources Report.

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[2] For a glossary of the professional terms included in this report, see the Glossary on page A-227 of Chapter A (Description of the General Development of the Partnership's Business) of the Periodic Report, which is incorporated herein by reference. For details regarding the Leviathan Project, see Section 7.2 of Chapter A of the Periodic Report.

1. Figures on reserves and contingent resources in the Leviathan Reservoir

According to the Resources Report which the Partnership received from NSAI, most of the resources attributed to the Leviathan Reservoir are currently classified as reserves, while part thereof are still classified as contingent resources, and it includes two parts, as follows:

a. A reserves report, which includes 'on production' reserves that shall be produced from the Leviathan Project's facilities, including the two stages of the expansion project, and includes the Discounted Cash Flow figures with respect to the reserves, as of 31 December 2025. The Discounted Cash Flow also includes the expected investments in Stage Two of the Expansion Project, and the income from sales after completion of the expansion, up to 21 BCM per year.

b. A contingent resources report, which includes resources which are classified as contingent at the 'development unclarified' phase, which are contingent on (1) extension of the leases beyond the extension possible under the provisions of the Petroleum Law, 5712-1952 (13 February 2064, the "**Petroleum Law**") or approval of additional wells or additional production facilities which will enable the production of the resources prior to expiration of the said leases; and (2) a commitment to develop the resources.

Below is a summary of the Current Discounted Cash Flow figures compared with the Previous Discounted Cash Flow figures (the Partnership's share). During 2025, the Leviathan Partners sold approx. 10.9 BCM of natural gas and approx. 886 thousand barrels of condensate, for financial consideration (gross) of approx. 2.23 billion U.S. dollars ("**Dollars**" or "**$**") (100%, the Partnership's share was approx. $1.01 billion)[3].

In the context of the Previous Discounted Cash Flow figures which related solely to Phase I – First Stage of the original development plan up to a maximum production capacity of approx. 14 BCM per year, separate Discounted Cash Flow figures were released for the reserves and contingent resources. However, since most of the contingent resources were reclassified as reserves in the current Resources Report, in the present report Discounted Cash Flow figures are presented in relation to reserves only:

	31.12.2025 ($ in billions, the Partnership's share)		31.12.2024 ($ in billions, the Partnership's share)	
	Cap Rate 7.5%	Cap Rate 10%	Cap Rate 7.5%	Cap Rate 10%
2P reserves	7.53	5.99	6.02	4.95
2P+2C	-	-	6.64	5.33

[3] It is clarified that the revenue figures for 2025 are not audited.

For further details regarding the changes in the Current Discounted Cash Flow compared with the Previous Discounted Cash Flow, see Section 1(a)(3) below.

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

(1) Quantity data

According to the report that the Partnership received from NSAI and which was prepared according to the SPE-PRMS guidelines, as of 31 December 2025, the reserves in the Leviathan Project are defined at the 'on production' maturity stage, and are as specified below:

Reserve Category[4]	Total (100%) in the Petroleum Asset (Gross)		Total Share Attributed to the Holders of the Equity Interests of the Partnership (Net)[5]	
	Natural Gas BCF	Condensate Million Barrels	Natural Gas BCF	Condensate Million Barrels
1P (Proved) Reserves	15,461.2	34.0	5,469.3	12.1
Probable Reserves	4,064.8	8.9	1,437.5	3.2
Total 2P (Proved+Probable) Reserves	19,526.0	43.0	6,906.8	15.3
Possible Reserves	2,145.3	4.7	758.7	1.7
Total 3P (Proved+Probable+Possible) Reserves	21,671.3	47.7	7,665.5	16.9

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

(2) In the report that the Partnership received from NSAI, NSAI stated, *inter alia*, several assumptions and reservations, including that: (a) The evaluations, as is standard in the evaluation of reserves according to the SPE-PRMS guidelines, are not adjusted to reflect risks, such as technical and commercial risks and development risks; (b) NSAI did not visit the Field, and did not check the mechanical operation of the facilities and the wells or

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

[5] The report that the Partnership received from NSAI does not state the Partnership's net share but rather the Partnership's gross share. The Partnership's net share presented in the table is after payment of royalties to the State and to related and third parties and according to the assumption regarding the Investment Recovery Date, as defined in Section 1(a)(3) below.

the condition thereof; (c) NSAI did not examine possible exposure deriving from environmental matters. However, NSAI stated that as of the date of signing of the report that the Partnership received from NSAI, it was not aware of any potential liability regarding environmental matters which may materially affect the quantity of the reserves estimated in the report that the Partnership received from NSAI or the commerciality thereof; and (d) NSAI assumed that the Reservoir is being and shall be developed in accordance with the Development Plan, is reasonably operated, that no regulation will be instituted that will affect the ability of a holder of the petroleum interests to produce the reserves, and that its forecasts regarding future production will be similar to the functioning of the Reservoir in practice.

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

(3) Discounted Cash Flow figures

The Discounted Cash Flow figures are based on various estimates and assumptions provided to NSAI by the Partnership, which are primarily:

(a) The projected sale quantities: The assumptions in the Cash Flow with respect to the quantities of natural gas and condensate that shall be sold by the Partnership from the Leviathan Reservoir are based on: (i) the Leviathan Reservoir's production capacity in Phase I – First Stage and after completion of Stage One of the Expansion Project up to a maximum production capacity of 21 BCM per year[6]. The actual rate of production may be lower or higher than the rate of production assumed in the Cash Flow; (ii) the Partnership's assumptions regarding the natural gas quantities that shall be sold to customers of the Partnership under the Existing Agreements, including the export to Egypt agreement and the amendment thereto[7], the agreement for the export of gas to Jordan's national electricity company (NEPCO)[8], and additional agreements for the supply of natural gas to the domestic and regional markets (collectively: the "**Existing Agreements**"); (iii) additional quantities of natural gas which, in the Partnership's estimation, will be sold on the regional export markets and on the domestic market in Israel, based, *inter alia*, on negotiations for the sale of natural gas from the Leviathan Project which are being conducted by the Partnership together with its partners in the Leviathan Project, a forecast on demand for natural gas in the domestic market in Israel, prepared for the Partnership by an outside consultant (BDO Consulting Group, "**BDO**")[9], and in relation to the estimate of the expected supply from other gas sources in the domestic market, and mainly from the Tamar, Karish, Katlan and Tanin leases; and (iv) additional quantities of natural gas, which, in the Partnership's estimation, will be sold in the regional markets, based, *inter alia*, on the forecast for completion of projects for expansion of the natural gas production and transmission capacity, as specified in Section 7.13.2 of Chapter A of the Periodic Report, Section 8 of the update to Chapter A of the Q1 Report, Section 7 of the update to Chapter A of the Q2 Report, and Section 11 of the update to Chapter A of the Q3 Report, as well as on forecasts on the

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[6] The sale quantities do not include sales of additional gas quantities which were classified in the Resources Report as contingent resources.

[7] For further details, see Section 7.12.3(c) of Chapter A of the Periodic Report and the Partnership's immediate report of 7 August 2025 (Ref.: 2025-01-058580).

[8] For further details, see Section 7.12.3(b) of Chapter A of the Periodic Report.

[9] The forecast on the demand for natural gas in the domestic market for the coming years on which the Partnership relied, is as follows (in BCM): 2026 – approx. 15.5; 2027 – approx. 17; 2028-2030 – approx. 17.6, gradually rising up to approx. 21 in 2040. The said demand forecast is primarily based on a forecast of demand for electricity, which is affected, *inter alia*, by the forecasts on growth in Israel, and is also based on the mix of energy sources that will be used for electricity production that is affected by government policy regarding reduction of the use of coal as a source for electricity production until its complete phase-out, and regarding the use of renewable energies as a source for electricity production. The demand forecast is forward-looking information, within the meaning thereof in the Securities Law, which there is no certainty will materialize, in whole or in part, and may materialize in a materially different manner, due to various factors, and *inter alia* the development of growth in the Israeli economy, the climate conditions in Israel and worldwide, the rate of phasing out of the use of coal as a source in electricity production, the rate of entry of renewable energies as a source for electricity production, the rate of entry of electric vehicles into the Israeli market and government policy in other areas which directly or indirectly pertain to growth in the demand for natural gas.

supply and demand in these markets, which were prepared by consultancy firms.

(b) The sale prices of natural gas and condensate: The assumptions in the Cash Flow with respect to the prices of natural gas that shall be sold from the Leviathan Reservoir are based, *inter alia*, on a weighted average of the natural gas prices which are stated in the Existing Agreements, including in the Amendment to the Export to Egypt Agreement, according to the price formulas determined therein, and the Partnership's assumptions regarding the prices that shall be determined in future agreements, considering the terms of the Export Permit of 17 December 2025, and *inter alia* the price mechanisms and formulas, on the forecast on the demand in the domestic market in the Cash Flow years, as estimated by BDO, and on the Partnership's estimate of the projected supply.

Most of the Existing Agreements include price formulas, and some of them include fixed prices. The price formulas set forth in the Existing Agreements may change over the years and include, *inter alia*, linkage to the Brent oil barrel price (the "**Brent Price**"), to the TOU (time-of-use) tariff released by the Electricity Authority, partial or full linkage to the electricity production tariff and linkage to the ILS/dollar exchange rate. The dollar rate used is approx. ILS 3.3 to the dollar throughout the Cash Flow period.

The electricity production tariff is supervised by the Electricity Authority and reflects the costs of the electricity production component of the Israel Electric Corp. Ltd., including the cost of its fuels, capital and operating costs attributed to the production component and the cost of purchasing electricity from independent power producers. The assumptions in the Cash Flow regarding the changes in the electricity production tariff over the Cash Flow years are based on a forecast that was prepared for the Partnership by BDO, which includes additional costs in respect of carbon tax, in accordance with Government Resolution no. 1261 of 14 January 2024[10].

The assumptions in the Cash Flow with respect to the Brent Price are based on long- and short-term forecasts of third parties, including the U.S. Department of Energy, the World Bank, IHS Global Insights and Wood Mackenzie. Accordingly, the Cash Flow assumes a Brent Price of approx. $63 in 2026,

[10] https://www.gov.il/he/pages/dec1261-2024.

increasing to approx. \$68 in 2027, and gradually rising to approx. \$89 from 2036 until the end of the Cash Flow period.

Changes in the sale prices may occur, *inter alia*, due to regulatory intervention, price adjustment mechanisms (as determined in the Amendment to the Export to Egypt Agreement)[11], increased competition in natural gas sales, or changes in the indices that serve as the linkage bases in the price formulas, as specified above.

The assumptions in the Cash Flow with respect to the sale prices of condensate are based on the Brent Price[12].

(c) The operating expenses (OPEX) taken into account in the Cash Flow include direct costs at the project level, insurance costs, production well maintenance costs, payment of the costs of transmission to third parties and estimated overhead, general and administrative expenses of the operator, which may be directly attributed to the project, and jointly constitute the project's OPEX. These expenses are represented at the Reservoir level and per production unit, and the OPEX in the Cash Flow are not adjusted to inflation changes. NSAI confirmed that the OPEX provided by the Partnership are reasonable, based, *inter alia*, on information available thereto from similar projects.

(d) The capital expenditures ("CAPEX") taken into account in the Cash Flow include expenses that were approved by the Partnership and its partners in the Leviathan Project in the framework of adoption of the FID for development of Stage One of the Expansion Project, expenses in respect of engineering work for improvement of the production system and related systems, participation in the costs of construction of natural gas transmission infrastructures[13], an estimate of future CAPEX not yet approved by the

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[11] The Amendment to the Export to Egypt Agreement includes mechanisms for updating the price, as specified in Section 5(d) of the immediate report of 7 August 2025 (Ref.: 2025-01-058580). No price update on such dates was assumed.

[12] For details regarding an agreement for the supply of condensate from the Leviathan Project to Ashdod Refinery Ltd. via a pipeline of Energy Infrastructures Ltd. and its related systems, see Sections 7.12.4(c) and 7.12.4(d) of Chapter A of the Periodic Report.

[13] In order to increase the transmission capacity to Egypt via the EMG pipeline, expansion of the transmission capacity is required in the INGL system and in the EMG systems in Israel and in Egypt. In addition, the Leviathan Partners approved an investment in other projects for expansion of the natural gas transmission infrastructures for export, including in the project for the construction of a compressor station in the transmission system outside of Israel for the transmission company there, and in the project for the construction of a compressor station in the Ramat Hovav area and a pipeline for a new onshore connection between the Israeli transmission system and the Egyptian transmission system in the Nitzana area. For further details, see Sections 7.13.2(b) and 7.13.2(c) of Chapter A of the Periodic Report, Section 8 of the update to Chapter A of the Q1 Report, Section 7 of the update to Chapter A of the Q2 Report, and Section 11 of the update to Chapter A of the Q3 Report.

Partnership, including costs of various engineering actions, the drilling of additional wells and development of Stage Two of the Expansion Project in a manner that is expected to allow and preserve the production capacity and even increase it as aforesaid to a total quantity of approx. 23 BCM per year, and indirect costs paid to the operator. The CAPEX in the Cash Flow are not adjusted to inflation changes. NSAI has confirmed that the CAPEX provided by the Partnership are reasonable, based, *inter alia*, on information available thereto.

(e) Decommissioning costs taken into account in the Cash Flow are costs that were provided to NSAI by the Partnership in accordance with estimates of expert consultants with respect to the cost of plugging and decommissioning the wells, and the cost of decommissioning the platform, the production facilities and the subsea equipment, assuming that the project will come to an end in 2064 and in accordance with the directives of the Petroleum Commissioner and with the current best industry standards. However, the project may come to an end before or after such year. In this context it is noted that the date of expiration of the Leviathan Leases is 13 February 2044, but, according to the provisions of the Petroleum Law, it may be extended by an additional 20 years. The decommissioning costs do not take into account the salvage value of the facilities in the Leviathan Leases and are not adjusted to inflation changes[14].

(f) The calculation of the Discounted Cash Flow assumed that the effective rate of the State's royalties in the Leviathan Project will be 11.06% in accordance with the royalty rate determined as advances for 2023-2025, and accordingly, the effective rate of the royalties that will be paid to third and related parties will be 3.98% before, and 8.41% after the Investment Recovery Date (as defined below). The actual rate of the said royalties is not final and may change. For details, see Section 7.24.7(c) of Chapter A of the Periodic Report.

(g) The Cash Flow was calculated assuming that for purposes of payment of the royalties to related parties, the date of recovery of the investment will fall in H1/2026, after the sale of a total quantity (from commencement of production in the Reservoir, in respect of 100% of the interests in the petroleum asset) of approx. 2,265 BCF and of approx. 5.1 million barrels of condensate (the "**Investment Recovery Date**"). Since the Investment Recovery Date is affected by various factors

[14] For details regarding a draft policy document on the decommissioning of offshore exploration and production infrastructures released by the Ministry of Energy for public comment, see Section 7.24.9 of Chapter A of the Periodic Report.

(which include, *inter alia*, the gas and/or condensate prices, the rate of production, the production and development costs, etc.), and subject to approval of a calculation of the Investment Recovery Date in an audit by the Partnership's accountants (which has not yet been carried out), it is therefore possible that the total quantity of natural gas and/or condensate that shall be sold by the Investment Recovery Date may be different than stated above. The rate attributed to the holders of the equity interests of the Partnership before and after the Investment Recovery Date is calculated in accordance with the rates specified in Section 7.2.7 of Chapter A of the Periodic Report. For details regarding calculation of the Investment Recovery Date, see Section 7.26.9 of Chapter A of the Periodic Report.

(h) The tax calculations took into account corporate tax at a rate of 23%.

(i) The calculation of the Discounted Cash Flow took into account the petroleum profit levy (the "**Levy**"), which shall apply to the Partnership according to the provisions of the Taxation of Profits from Natural Resources Law, 5771-2011 (the "**Law**"). The Levy calculations were made in accordance with the approval of the Tax Authority regarding the consolidation of the Leviathan Leases for purposes of the Law (the "**Venture**"). It is emphasized that the Levy calculations were made, *inter alia*, according to the definitions, formulas and mechanisms defined in the Law, to the best of the Partnership's understanding and interpretation, which were expressed in the Levy reports of the Venture which were filed with the Tax Authority. However, in view of the novelty of the Law and the complexity of the calculation formulas and the various mechanisms defined therein, there is no assurance that this interpretation of the manner of calculation of the Levy will be the same as that which shall be adopted by the tax authorities and/or the same as the interpretation of the Law by the court. In addition, the calculation was made in Dollars at the choice of the holders of the interests in the Venture pursuant to Section 13(b) of the Law, and is based, *inter alia*, on the following assumptions: the payments attributed to the Venture (the production costs, the main investments, the royalties, etc.) shall be recognized by the tax authorities for purposes of the Levy calculation; and for purposes of calculation of the income attributed to the Venture, the actual sale prices of the natural gas shall be taken into account.

(j) The calculation of the Discounted Cash Flow took into account expenses and investments which were actually paid from 1 January 2026 and which are expected to continue to be paid by the Partnership, as well as revenues deriving from sales of natural gas produced from 1 January 2026 and which is expected to continue to be produced.

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

The changes in the Current Discounted Cash Flow versus the Previous Discounted Cash Flow:

The changes in the Current Discounted Cash Flow relative to the Previous Discounted Cash Flow mainly derive from an update to assumptions, primarily as follows:

(a) Upon adoption of the FID for the development of Stage One of the Expansion Project, the contingencies pertaining to part of the contingent resources in the Leviathan Reservoir were met, such that these resources are now classified as reserves. Accordingly, the Current Discounted Cash Flow includes Discounted Cash Flow for reserves only, unlike the Previous Discounted Cash Flow which also included Discounted Cash Flow for contingent resources.

(b) The capital and operating investments related to development of Stage One of the Expansion Project, capital investments in the development of Stage Two of the Expansion Project, an FID in respect of which is expected to be adopted in the coming years, with a preliminary provisional estimate that has not yet been approved by the Partnership of approx. $800 million (100%), and in the drilling of future wells, were added.

(c) The sale quantities of natural gas according to expansion of the Leviathan Project's production capacity up to approx. 21 BCM per year and, *inter alia*, according to the terms of the Amendment to the Export to Egypt Agreement and the terms of the Export Permit, were added.

(d) Forecasts of third parties, and accordingly the sales forecast for the domestic market and for export, a forecast on the Brent Price and a forecast on the production tariff price and the TOU tariff, as specified in Section 1(a)(3)(b) above, were updated.

In accordance with various assumptions, which are primarily as specified above, presented below is the estimated Discounted Cash Flow as of 31 December 2025, in Dollars in thousands, after levy and income tax, which is attributed to the Partnership's share of the reserves in the Leviathan Reservoir, for each one of the reserve categories specified above[15]:

[15] An additional cap rate of 7.5% was applied by the Partnership for calculation purposes and for the benefit of investors.

Total Discounted Cash Flow from 1P (Proved) Reserves as of 31 December 2025 (in Dollars in thousands in relation to the Partnership's share)																	
Cash Flow components																	
										Taxes		Total Discounted Cash Flow after tax					
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas 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%)	Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2026	993	12.8	1,103,552	206,676	-	134,781	278,113	-	483,983	-	108,353	375,630	366,577	362,289	358,149	350,276	342,901
31.12.2027	1,005	12.9	1,178,754	229,451	-	130,889	302,808	-	515,606	-	111,832	403,774	375,279	362,264	349,985	327,409	307,161
31.12.2028	1,008	13.0	1,239,286	241,234	-	109,351	280,897	-	607,803	87,774	100,541	419,488	371,319	350,105	330,551	295,785	265,930
31.12.2029	1,086	14.0	1,432,517	278,848	-	132,630	302,238	-	718,801	183,771	103,631	431,399	363,678	334,927	309,033	264,507	227,900
31.12.2030	1,444	18.6	1,949,027	379,390	-	162,466	149,347	-	1,257,825	439,318	182,073	636,433	510,977	459,637	414,463	339,323	280,180
31.12.2031	1,384	17.8	1,888,654	367,638	-	142,952	120,526	-	1,257,538	542,403	143,029	572,106	437,457	384,353	338,701	265,240	209,884
31.12.2032	1,488	19.2	2,114,519	411,604	-	178,800	-	-	1,524,116	685,583	141,365	697,168	507,700	435,695	375,219	281,062	213,137
31.12.2033	1,471	18.9	2,184,510	425,228	-	184,909	110,546	-	1,463,828	657,368	133,472	672,988	466,753	391,240	329,277	235,925	171,454
31.12.2034	1,484	19.1	2,228,779	433,845	-	209,462	-	-	1,585,472	714,298	145,765	725,409	479,153	392,293	322,660	221,132	154,008
31.12.2035	1,471	18.9	2,243,212	436,655	-	182,850	98,937	-	1,524,770	690,477	153,534	680,758	428,247	342,462	275,272	180,453	120,440
31.12.2036	1,488	19.2	2,324,972	452,570	-	186,890	-	-	1,685,512	765,705	177,092	742,716	444,974	347,563	273,023	171,197	109,501
31.12.2037	1,471	18.9	2,295,628	446,858	-	180,711	110,546	-	1,557,514	705,801	171,077	680,636	388,363	296,290	227,457	136,424	83,624
31.12.2038	1,484	19.1	2,306,553	448,984	-	169,959	98,937	-	1,588,673	720,384	181,681	686,608	373,115	278,037	208,593	119,670	70,298
31.12.2039	1,471	18.9	2,280,325	443,879	-	172,224	110,546	-	1,553,677	704,006	183,994	665,677	344,515	250,755	183,849	100,889	56,796
31.12.2040	1,482	19.1	2,280,203	443,855	-	144,122	98,937	-	1,593,289	726,446	194,026	672,817	331,629	235,762	168,929	88,670	47,838
31.12.2041	1,399	18.0	2,144,071	417,356	-	131,532	-	-	1,595,183	746,545	193,107	655,530	307,722	213,679	149,626	75,124	38,840
31.12.2042	1,273	16.4	1,923,124	374,348	-	107,265	-	-	1,441,512	674,627	176,383	590,501	263,996	179,053	122,530	58,845	29,156
31.12.2043	1,158	14.9	1,721,836	335,166	-	88,330	-	-	1,298,341	607,623	158,865	531,852	226,453	150,018	100,327	46,087	21,884
31.12.2044	1,054	13.6	1,559,632	303,592	-	103,698	-	-	1,152,343	539,296	141,001	472,046	191,418	123,859	80,950	35,569	16,186
31.12.2045	960	12.4	1,419,195	276,255	-	82,736	-	-	1,060,204	496,176	129,727	434,302	167,726	106,005	67,707	28,457	12,410
31.12.2046	873	11.2	1,291,370	251,373	-	82,413	-	-	957,583	448,149	117,170	392,264	144,277	89,065	55,594	22,350	9,340
31.12.2047	795	10.2	1,175,334	228,786	-	82,120	-	-	864,428	404,552	105,771	354,104	124,040	74,791	45,624	17,544	7,026
31.12.2048	723	9.3	1,071,928	208,657	-	81,856	-	-	781,415	365,702	95,614	320,099	106,789	62,892	37,493	13,791	5,293
31.12.2049	658	8.5	975,213	189,831	-	102,217	-	-	683,165	319,721	83,592	279,852	88,916	51,148	29,799	10,484	3,856
31.12.2050	599	7.7	887,708	172,798	-	81,388	-	-	633,523	296,489	77,518	259,516	78,528	44,122	25,121	8,454	2,980
31.12.2051	545	7.0	807,112	157,109	-	81,218	-	-	568,786	266,192	69,597	232,997	67,147	36,850	20,504	6,600	2,230
31.12.2052	496	6.4	734,576	142,990	-	81,114	-	-	510,472	238,901	62,461	209,110	57,393	30,765	16,729	5,151	1,668
31.12.2053	451	5.8	668,948	130,215	-	81,025	-	-	457,708	214,207	56,005	187,496	49,010	25,660	13,636	4,016	1,246
31.12.2054	410	5.3	607,925	118,336	-	101,552	-	-	388,037	181,601	47,480	158,955	39,571	20,236	10,510	2,961	880
31.12.2055	374	4.8	553,810	107,803	-	80,878	-	-	365,129	170,881	44,677	149,572	35,462	17,713	8,990	2,422	690
31.12.2056	340	4.4	504,301	98,165	-	80,822	-	-	325,314	152,247	39,805	133,262	30,091	14,681	7,282	1,877	512
31.12.2057	309	4.0	458,246	89,200	-	80,772	-	-	288,274	134,912	35,273	118,088	25,395	12,102	5,866	1,446	378

Total Discounted Cash Flow from 1P (Proved) Reserves as of 31 December 2025 (in Dollars in thousands in relation to the Partnership's share)																	
Cash Flow components																	
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total Discounted Cash Flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2058	281	3.6	416,797	81,132	-	80,732	-	-	254,933	119,308	31,194	104,431	21,388	9,955	4,716	1,112	279
31.12.2059	256	3.3	379,953	73,960	-	101,309	-	-	204,684	95,792	19,280	89,612	17,479	7,947	3,679	830	199
31.12.2060	218	2.8	322,384	62,754	-	80,633	-	-	178,997	83,771	16,137	79,090	14,692	6,524	2,952	637	147
31.12.2061	202	2.6	299,357	58,272	-	80,631	-	-	160,454	75,093	13,868	71,494	12,649	5,486	2,426	501	110
31.12.2062	198	2.6	293,600	57,151	-	80,662	-	64,103	91,684	42,908	20,197	28,579	4,815	2,040	881	174	37
31.12.2063	189	2.4	279,784	54,462	-	80,678	-	64,103	80,540	37,693	18,833	24,014	3,854	1,595	673	127	26
31.12.2064	20	0.3	30,281	5,894	-	15,113	-	64,103	(54,830)	-	-	(54,830)	(8,380)	(3,387)	(1,398)	(252)	(49)
Total	34,015	438	49,576,977	9,642,319	-	4,473,690	2,062,376	192,310	33,206,282	14,335,720	3,985,020	14,885,542	8,260,166	6,506,471	5,277,378	3,722,264	2,816,377

Total Discounted Cash Flow from Probable Reserves as of 31 December 2025 (in Dollars in thousands in relation to the Partnership's share)																	
Cash Flow components																	
										Taxes		Total Discounted Cash Flow after tax					
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas 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%)	Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2026	52	0.7	52,966	9,920	-	4,457	-	-	38,589	-	8,876	29,714	28,998	28,659	28,331	27,708	27,125
31.12.2027	89	1.1	98,135	19,103	-	2,346	-	-	76,686	-	17,638	59,049	54,881	52,978	51,182	47,881	44,920
31.12.2028	90	1.2	102,476	19,948	-	1,254	-	-	81,274	55,388	5,954	19,933	17,644	16,636	15,707	14,055	12,636
31.12.2029	96	1.2	116,745	22,725	-	3,855	-	-	90,165	42,724	10,911	36,530	30,795	28,361	26,168	22,398	19,298
31.12.2030	46	0.6	40,400	7,864	-	(4,528)	-	-	37,063	43,886	(1,569)	(5,253)	(4,218)	(3,794)	(3,421)	(2,801)	(2,313)
31.12.2031	31	0.4	21,335	4,153	-	(3,715)	-	-	20,897	23,137	(515)	(1,725)	(1,319)	(1,159)	(1,021)	(800)	(633)
31.12.2032	132	1.7	181,449	35,320	-	9,227	-	-	136,902	64,070	16,751	56,080	40,840	35,047	30,183	22,609	17,145
31.12.2033	131	1.7	184,798	35,972	-	8,374	(110,546)	-	250,997	117,467	30,712	102,819	71,310	59,773	50,307	36,044	26,195
31.12.2034	132	1.7	189,527	36,892	-	8,644	110,546	-	33,444	15,652	4,092	13,700	9,049	7,409	6,094	4,176	2,909
31.12.2035	131	1.7	195,808	38,115	-	8,325	(98,937)	-	248,305	116,207	30,383	101,716	63,987	51,169	41,130	26,962	17,996
31.12.2036	132	1.7	201,889	39,299	-	8,033	98,937	-	55,620	26,030	6,806	22,784	13,650	10,662	8,376	5,252	3,359
31.12.2037	131	1.7	199,538	38,841	-	7,962	(110,546)	-	263,281	123,215	32,215	107,850	61,538	46,949	36,042	21,617	13,251
31.12.2038	132	1.7	201,544	39,232	-	8,836	11,609	-	141,867	66,394	17,359	58,115	31,580	23,533	17,655	10,129	5,950
31.12.2039	131	1.7	200,116	38,954	-	10,873	(11,609)	-	161,899	75,769	19,810	66,320	34,323	24,982	18,317	10,051	5,658
31.12.2040	138	1.8	210,587	40,992	-	4,074	(98,937)	-	264,458	123,766	32,359	108,332	53,397	37,961	27,200	14,277	7,702
31.12.2041	203	2.6	315,353	61,385	-	8,315	110,546	-	135,107	63,230	16,532	55,345	25,980	18,041	12,633	6,343	3,279
31.12.2042	342	4.4	536,580	104,448	-	20,037	98,937	-	313,157	146,558	38,318	128,282	57,351	38,898	26,619	12,784	6,334
31.12.2043	422	5.4	661,969	128,856	-	27,765	-	-	505,348	236,503	61,834	207,011	88,141	58,391	39,050	17,938	8,518
31.12.2044	427	5.5	658,224	128,127	-	22,089	-	-	508,008	237,748	62,160	208,100	84,386	54,603	35,687	15,681	7,135
31.12.2045	423	5.4	626,194	121,892	-	10,302	-	-	494,000	231,192	60,446	202,362	78,152	49,393	31,548	13,259	5,782
31.12.2046	416	5.4	615,830	119,875	-	7,113	-	-	488,842	228,778	59,815	200,249	73,653	45,467	28,381	11,409	4,768
31.12.2047	408	5.3	604,331	117,637	-	4,717	-	-	481,977	225,565	58,975	197,437	69,161	41,701	25,438	9,782	3,918
31.12.2048	399	5.1	590,654	114,974	-	1,806	-	-	473,874	221,773	57,983	194,118	64,760	38,139	22,737	8,363	3,210
31.12.2049	389	5.0	576,838	112,285	-	1,683	-	-	462,870	216,623	56,637	189,610	60,244	34,655	20,190	7,103	2,613
31.12.2050	378	4.9	559,567	108,923	-	1,645	-	-	448,999	210,131	54,939	183,928	55,656	31,271	17,804	5,992	2,112
31.12.2051	367	4.7	543,448	105,785	-	1,576	-	-	436,086	204,088	53,359	178,638	51,481	28,253	15,720	5,060	1,709
31.12.2052	355	4.6	526,177	102,424	-	1,457	-	-	422,297	197,635	51,672	172,990	47,479	25,450	13,839	4,261	1,379
31.12.2053	342	4.4	506,604	98,614	-	1,335	-	-	406,656	190,315	49,758	166,583	43,544	22,798	12,115	3,568	1,107
31.12.2054	330	4.3	489,333	95,252	-	1,220	-	-	392,861	183,859	48,071	160,932	40,063	20,488	10,640	2,997	891
31.12.2055	317	4.1	469,760	91,442	-	1,104	-	-	377,215	176,537	46,156	154,522	36,636	18,300	9,288	2,503	713
31.12.2056	304	3.9	450,187	87,632	-	988	-	-	361,567	169,213	44,241	148,112	33,444	16,317	8,093	2,086	570
31.12.2057	292	3.8	432,916	84,270	-	881	-	-	347,765	162,754	42,553	142,459	30,636	14,599	7,077	1,745	457
31.12.2058	280	3.6	414,494	80,684	-	782	-	-	333,028	155,857	40,749	136,422	27,940	13,005	6,161	1,453	364
31.12.2059	237	3.1	351,169	68,357	-	663	-	-	282,149	132,046	34,524	115,579	22,544	10,249	4,745	1,070	257
31.12.2060	229	3.0	339,655	66,116	-	641	-	-	272,898	127,716	33,392	111,790	20,767	9,222	4,172	900	207
31.12.2061	206	2.7	305,114	59,392	-	576	-	-	245,146	114,728	29,996	100,421	17,767	7,706	3,407	703	155
31.12.2062	159	2.1	236,031	45,945	-	446	-	-	189,641	88,752	23,204	77,685	13,090	5,545	2,396	473	100

Total Discounted Cash Flow from Probable Reserves as of 31 December 2025 (in Dollars in thousands in relation to the Partnership's share)																	
Cash Flow components																	
										Taxes		Total Discounted Cash Flow after tax					
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas 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%)	Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2063	113	1.5	166,949	32,498	-	315	-	-	134,136	62,776	16,413	54,948	8,818	3,649	1,541	291	59
31.12.2064	13	0.2	19,170	3,732	-	36	-	-	15,403	-	-	15,403	2,354	951	393	71	14
Total	**8,943**	**115**	**13,193,863**	**2,567,874**	-	**195,512**	-	-	**10,430,477**	**4,878,081**	**1,273,508**	**4,278,887**	**1,560,502**	**1,026,256**	**711,920**	**395,394**	**256,850**

Total Discounted Cash Flow from 2P (Proved + Probable) Reserves as of 31 December 2025 (in Dollars in thousands in relation to the Partnership's share)

Cash Flow components

Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total Discounted Cash Flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2026	1,045	13.5	1,156,518	216,596	-	139,238	278,113	-	522,572	-	117,229	405,343	395,575	390,948	386,480	377,985	370,026
31.12.2027	1,094	14.1	1,276,888	248,554	-	133,234	302,808	-	592,292	-	129,470	462,822	430,160	415,242	401,167	375,290	352,081
31.12.2028	1,097	14.1	1,341,762	261,182	-	110,606	280,897	-	689,077	143,161	106,495	439,421	388,962	366,741	346,257	309,839	278,566
31.12.2029	1,182	15.2	1,549,262	301,573	-	136,485	302,238	-	808,966	226,494	114,543	467,929	394,473	363,287	335,201	286,905	247,198
31.12.2030	1,490	19.2	1,989,427	387,254	-	157,938	149,347	-	1,294,888	483,205	180,504	631,180	506,759	455,843	411,042	336,522	277,867
31.12.2031	1,416	18.2	1,909,989	371,791	-	139,237	120,526	-	1,278,435	565,540	142,514	570,381	436,138	383,194	337,680	264,440	209,251
31.12.2032	1,620	20.9	2,295,968	446,924	-	188,027	-	-	1,661,017	749,653	158,116	753,248	548,539	470,742	405,402	303,670	230,282
31.12.2033	1,602	20.6	2,369,308	461,200	-	193,283	-	-	1,714,825	774,835	164,184	775,806	538,063	451,014	379,584	271,969	197,649
31.12.2034	1,616	20.8	2,418,306	470,738	-	218,106	110,546	-	1,618,916	729,949	149,857	739,109	488,202	399,702	328,754	225,308	156,916
31.12.2035	1,602	20.6	2,439,020	474,770	-	191,176	-	-	1,773,075	806,684	183,917	782,474	492,234	393,631	316,402	207,415	138,436
31.12.2036	1,620	20.9	2,526,861	491,869	-	194,923	98,937	-	1,741,132	791,735	183,898	765,500	458,625	358,225	281,399	176,448	112,861
31.12.2037	1,602	20.6	2,495,166	485,699	-	188,673	-	-	1,820,795	829,017	203,292	788,486	449,901	343,239	263,499	158,041	96,875
31.12.2038	1,616	20.8	2,508,098	488,216	-	178,796	110,546	-	1,730,540	786,778	199,040	744,722	404,695	301,570	226,249	129,799	76,248
31.12.2039	1,602	20.6	2,480,442	482,833	-	183,097	98,937	-	1,715,575	779,774	203,804	731,997	378,838	275,737	202,166	110,940	62,454
31.12.2040	1,620	20.9	2,490,790	484,847	-	148,196	-	-	1,857,747	850,212	226,385	781,150	385,026	273,723	196,128	102,947	55,540
31.12.2041	1,602	20.6	2,459,424	478,742	-	139,847	110,546	-	1,730,290	809,776	209,639	710,875	333,702	231,719	162,258	81,466	42,120
31.12.2042	1,616	20.8	2,459,704	478,796	-	127,302	98,937	-	1,754,669	821,185	214,701	718,783	321,347	217,951	149,148	71,628	35,490
31.12.2043	1,580	20.3	2,383,805	464,022	-	116,095	-	-	1,803,688	844,126	220,699	738,863	314,595	208,409	139,377	64,025	30,401
31.12.2044	1,481	19.1	2,217,856	431,719	-	125,786	-	-	1,660,351	777,044	203,161	680,146	275,804	178,462	116,637	51,250	23,321
31.12.2045	1,382	17.8	2,045,390	398,147	-	93,038	-	-	1,554,204	727,367	190,172	636,664	245,878	155,398	99,255	41,716	18,192
31.12.2046	1,289	16.6	1,907,200	371,248	-	89,527	-	-	1,446,426	676,927	176,985	592,514	217,930	134,532	83,975	33,759	14,109
31.12.2047	1,203	15.5	1,779,664	346,422	-	86,837	-	-	1,346,405	630,118	164,746	551,541	193,200	116,492	71,062	27,326	10,944
31.12.2048	1,122	14.4	1,662,582	323,632	-	83,662	-	-	1,255,289	587,475	153,597	514,217	171,548	101,031	60,230	22,154	8,503
31.12.2049	1,047	13.5	1,552,051	302,116	-	103,900	-	-	1,146,034	536,344	140,229	469,461	149,160	85,803	49,989	17,587	6,469
31.12.2050	977	12.6	1,447,276	281,721	-	83,034	-	-	1,082,521	506,620	132,457	443,444	134,184	75,393	42,926	14,446	5,092
31.12.2051	911	11.7	1,350,560	262,895	-	82,794	-	-	1,004,872	470,280	122,956	411,636	118,628	65,102	36,224	11,661	3,939
31.12.2052	851	11.0	1,260,753	245,413	-	82,571	-	-	932,769	436,536	114,134	382,099	104,872	56,215	30,568	9,412	3,047
31.12.2053	793	10.2	1,175,552	228,828	-	82,359	-	-	864,364	404,522	105,764	354,078	92,554	48,458	25,751	7,584	2,353
31.12.2054	740	9.5	1,097,258	213,588	-	102,772	-	-	780,898	365,460	95,551	319,887	79,635	40,724	21,150	5,958	1,771
31.12.2055	691	8.9	1,023,570	199,244	-	81,982	-	-	742,344	347,417	90,833	304,094	72,098	36,013	18,278	4,925	1,403
31.12.2056	644	8.3	954,488	185,797	-	81,810	-	-	686,881	321,460	84,047	281,374	63,535	30,997	15,375	3,963	1,082
31.12.2057	601	7.7	891,163	173,470	-	81,654	-	-	636,039	297,666	77,826	260,547	56,030	26,701	12,942	3,191	835
31.12.2058	561	7.2	831,291	161,816	-	81,515	-	-	587,961	275,166	71,943	240,852	49,329	22,960	10,876	2,565	643
31.12.2059	493	6.4	731,122	142,317	-	101,972	-	-	486,833	227,838	53,803	205,192	40,024	18,196	8,424	1,900	457
31.12.2060	447	5.8	662,039	128,870	-	81,274	-	-	451,895	211,487	49,528	190,880	35,459	15,746	7,124	1,537	354
31.12.2061	408	5.3	604,471	117,664	-	81,207	-	-	405,600	189,821	43,864	171,916	30,416	13,192	5,833	1,204	266

Total Discounted Cash Flow from 2P (Proved + Probable) Reserves as of 31 December 2025 (in Dollars in thousands in relation to the Partnership's share)																	
Cash Flow components																	
										Taxes		Total Discounted Cash Flow after tax					
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas 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%)	Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2062	357	4.6	529,632	103,096	-	81,107	-	64,103	281,325	131,660	43,401	106,264	17,905	7,585	3,278	647	137
31.12.2063	301	3.9	446,733	86,959	-	80,994	-	64,103	214,676	100,469	35,246	78,962	12,671	5,243	2,214	418	85
31.12.2064	33	0.4	49,451	9,626	-	15,150	-	64,103	(39,428)	-	-	(39,428)	(6,026)	(2,435)	(1,005)	(182)	(35)
Total	42,958	553	62,770,840	12,210,193	-	4,669,202	2,062,376	192,310	43,636,759	19,213,801	5,258,528	19,164,430	9,820,667	7,532,727	5,989,298	4,117,659	3,073,227

Total Discounted Cash Flow from Possible Reserves as of 31 December 2025 (in Dollars in thousands in relation to the Partnership's share)																	
Cash Flow components																	
										Taxes		Total Discounted Cash Flow after tax					
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas 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%)	Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2026	21	0.3	20,916	3,917	-	(4,228)	-	-	21,226	-	4,882	16,344	15,950	15,764	15,584	15,241	14,920
31.12.2027	22	0.3	24,818	4,831	-	(6,048)	-	-	26,034	-	5,988	20,046	18,632	17,986	17,376	16,255	15,250
31.12.2028	22	0.3	21,414	4,168	-	(2,089)	-	-	19,335	8,152	2,572	8,610	7,622	7,186	6,785	6,071	5,459
31.12.2029	24	0.3	11,277	2,195	-	(1,386)	-	-	10,468	8,735	399	1,334	1,125	1,036	956	818	705
31.12.2030	105	1.4	129,244	25,158	-	6,051	-	-	98,035	54,921	9,916	33,198	26,654	23,976	21,619	17,700	14,615
31.12.2031	23	0.3	10,030	1,952	-	(5,460)	-	-	13,537	10,826	623	2,087	1,596	1,402	1,236	968	766
31.12.2032	33	0.4	28,662	5,579	-	(7,495)	-	-	30,578	14,311	3,742	12,526	9,122	7,828	6,742	5,050	3,829
31.12.2033	33	0.4	32,113	6,251	-	(7,978)	110,546	-	(76,706)	(35,899)	(9,386)	(31,422)	(21,793)	(18,267)	(15,374)	(11,015)	(8,005)
31.12.2034	33	0.4	34,000	6,618	-	(7,664)	(110,546)	-	145,591	68,137	17,815	59,640	39,394	32,253	26,528	18,181	12,662
31.12.2035	33	0.4	40,255	7,836	-	(7,790)	-	-	40,209	18,818	4,920	16,471	10,362	8,286	6,660	4,366	2,914
31.12.2036	33	0.4	43,061	8,382	-	(8,253)	(98,937)	-	141,869	66,395	17,359	58,115	34,818	27,196	21,363	13,396	8,568
31.12.2037	33	0.4	42,485	8,270	-	(8,457)	98,937	-	(56,265)	(26,332)	(6,885)	(23,048)	(13,151)	(10,033)	(7,702)	(4,620)	(2,832)
31.12.2038	33	0.4	43,160	8,401	-	(8,422)	-	-	43,181	20,209	5,284	17,689	9,612	7,163	5,374	3,083	1,811
31.12.2039	33	0.4	43,064	8,383	-	(8,926)	-	-	43,607	20,408	5,336	17,863	9,245	6,729	4,934	2,707	1,524
31.12.2040	33	0.4	44,899	8,740	-	(1,260)	-	-	37,419	17,512	4,579	15,328	7,555	5,371	3,849	2,020	1,090
31.12.2041	33	0.4	46,346	9,022	-	(4,009)	-	-	41,334	19,344	5,058	16,932	7,948	5,519	3,865	1,940	1,003
31.12.2042	33	0.4	47,684	9,282	-	(359)	-	-	38,761	18,140	4,743	15,878	7,099	4,815	3,295	1,582	784
31.12.2043	10	0.1	12,452	2,424	-	(1,084)	-	-	11,112	5,201	1,360	4,552	1,938	1,284	859	394	187
31.12.2044	40	0.5	59,882	11,656	-	706	-	-	47,520	22,240	5,815	19,466	7,894	5,108	3,338	1,467	667
31.12.2045	71	0.9	110,947	21,597	-	3,418	-	-	85,933	40,217	10,515	35,202	13,595	8,592	5,488	2,307	1,006
31.12.2046	101	1.3	149,524	29,106	-	3,549	-	-	116,870	54,695	14,300	47,874	17,609	10,870	6,785	2,728	1,140
31.12.2047	126	1.6	186,382	36,280	-	4,427	-	-	145,675	68,176	17,825	59,674	20,903	12,604	7,689	2,957	1,184
31.12.2048	148	1.9	219,912	42,807	-	5,224	-	-	171,881	80,440	21,031	70,409	23,489	13,834	8,247	3,033	1,164
31.12.2049	167	2.2	247,545	48,186	-	4,063	-	-	195,296	91,399	23,896	80,001	25,418	14,622	8,519	2,997	1,102
31.12.2050	184	2.4	272,875	53,117	-	2,196	-	-	217,563	101,819	26,621	89,122	26,968	15,152	8,627	2,903	1,023
31.12.2051	198	2.6	293,600	57,151	-	968	-	-	235,481	110,205	28,813	96,462	27,799	15,256	8,489	2,733	923
31.12.2052	210	2.7	310,871	60,513	-	929	-	-	249,429	116,733	30,520	102,176	28,044	15,032	8,174	2,517	815
31.12.2053	221	2.8	326,990	63,651	-	985	-	-	262,355	122,782	32,102	107,471	28,092	14,708	7,816	2,302	714
31.12.2054	229	3.0	339,655	66,116	-	1,031	-	-	272,508	127,534	33,344	111,630	27,790	14,212	7,381	2,079	618
31.12.2055	236	3.0	350,017	68,133	-	1,072	-	-	280,813	131,420	34,360	115,032	27,273	13,623	6,914	1,863	531
31.12.2056	242	3.1	358,077	69,702	-	1,106	-	-	287,270	134,442	35,150	117,677	26,572	12,964	6,430	1,657	453
31.12.2057	246	3.2	363,834	70,822	-	1,133	-	-	291,878	136,599	35,714	119,565	25,712	12,253	5,939	1,464	383

Total Discounted Cash Flow from Possible Reserves as of 31 December 2025 (in Dollars in thousands in relation to the Partnership's share)																	
Cash Flow components																	
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas sales volume (BCM) (100% of the petroleum asset)	Income	Royalties to be paid	Royalties to be received	Operation costs	Develop-ment costs	Abandon-ment and restoration costs	Total cash flow before levy and income tax (discounted at 0%)	Taxes		Total Discounted Cash Flow after tax					
										Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2058	249	3.2	368,439	71,719	-	1,148	-	-	295,573	138,328	36,166	121,078	24,798	11,542	5,468	1,289	323
31.12.2059	280	3.6	415,646	80,908	-	1,179	-	-	333,559	156,106	40,814	136,639	26,652	12,117	5,609	1,265	304
31.12.2060	294	3.8	435,219	84,718	-	1,160	-	-	349,341	163,492	42,745	143,104	26,584	11,805	5,341	1,152	265
31.12.2061	284	3.7	420,251	81,804	-	1,042	-	-	337,405	157,905	41,285	138,215	24,453	10,606	4,689	968	214
31.12.2062	295	3.8	437,522	85,166	-	1,001	-	-	351,354	164,434	42,992	143,929	24,251	10,274	4,439	876	185
31.12.2063	301	3.9	445,581	86,735	-	916	-	-	357,931	167,511	43,796	146,623	23,529	9,736	4,111	776	157
31.12.2064	9	0.1	13,667	2,660	-	26	-	-	10,981	-	2,435	8,545	1,306	528	218	39	8
Total	4,720	61	6,802,316	1,323,957	-	(47,582)	-	-	5,525,940	2,575,354	678,545	2,272,041	652,459	390,930	253,657	133,511	88,431

Total Discounted Cash Flow from 3P (Proved + Probable + Possible) Reserves as of 31 December 2025 (in Dollars in thousands in relation to the Partnership's share)																	
Cash Flow components																	
										Taxes		Total Discounted Cash Flow after tax					
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas 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%)	Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2026	1,066	13.7	1,177,434	220,513	-	135,010	278,113	-	543,798	-	122,111	421,688	411,525	406,712	402,064	393,226	384,947
31.12.2027	1,117	14.4	1,301,706	253,385	-	127,187	302,808	-	618,326	-	135,458	482,869	448,792	433,228	418,543	391,545	367,331
31.12.2028	1,120	14.4	1,363,176	265,350	-	108,517	280,897	-	708,412	151,313	109,067	448,031	396,584	373,927	353,042	315,910	284,024
31.12.2029	1,206	15.5	1,560,539	303,768	-	135,098	302,238	-	819,434	235,229	114,941	469,263	395,598	364,323	336,157	287,723	247,903
31.12.2030	1,595	20.5	2,118,671	412,412	-	163,989	149,347	-	1,392,923	538,126	190,420	664,378	533,412	479,818	432,661	354,221	292,482
31.12.2031	1,439	18.5	1,920,018	373,743	-	133,777	120,526	-	1,291,972	576,366	143,137	572,468	437,734	384,596	338,916	265,408	210,017
31.12.2032	1,653	21.3	2,324,631	452,503	-	180,532	-	-	1,691,596	763,964	161,857	765,775	557,661	478,571	412,144	308,720	234,112
31.12.2033	1,635	21.0	2,401,420	467,451	-	185,305	110,546	-	1,638,119	738,936	154,798	744,384	516,271	432,747	364,210	260,954	189,643
31.12.2034	1,649	21.2	2,452,306	477,356	-	210,443	-	-	1,764,507	798,086	167,672	798,749	527,596	431,955	355,281	243,489	169,578
31.12.2035	1,635	21.0	2,479,275	482,606	-	183,386	-	-	1,813,284	825,502	188,837	798,945	502,595	401,917	323,062	211,781	141,350
31.12.2036	1,653	21.3	2,569,922	500,251	-	186,670	-	-	1,883,002	858,130	201,257	823,615	493,443	385,421	302,762	189,844	121,429
31.12.2037	1,635	21.0	2,537,652	493,969	-	180,216	98,937	-	1,764,530	802,685	196,407	765,438	436,750	333,206	255,796	153,421	94,043
31.12.2038	1,649	21.2	2,551,258	496,618	-	170,373	110,546	-	1,773,721	806,986	204,324	762,411	414,308	308,733	231,622	132,882	78,059
31.12.2039	1,635	21.0	2,523,505	491,215	-	174,171	98,937	-	1,759,182	800,182	209,140	749,860	388,083	282,466	207,100	113,647	63,978
31.12.2040	1,653	21.3	2,535,689	493,587	-	146,936	-	-	1,895,166	867,724	230,963	796,478	392,581	279,094	199,977	104,968	56,630
31.12.2041	1,635	21.0	2,505,770	487,763	-	135,838	110,546	-	1,771,623	829,120	214,697	727,807	341,650	237,238	166,123	83,406	43,123
31.12.2042	1,649	21.2	2,507,387	488,078	-	126,943	98,937	-	1,793,430	839,325	219,444	734,661	328,446	222,765	152,443	73,210	36,274
31.12.2043	1,590	20.5	2,396,258	466,446	-	115,011	-	-	1,814,801	849,327	222,059	743,415	316,533	209,693	140,236	64,420	30,589
31.12.2044	1,520	19.6	2,277,739	443,375	-	126,492	-	-	1,707,871	799,284	208,975	699,612	283,697	183,570	119,976	52,717	23,989
31.12.2045	1,454	18.7	2,156,337	419,744	-	96,456	-	-	1,640,137	767,584	200,687	671,866	259,472	163,990	104,743	44,022	19,198
31.12.2046	1,390	17.9	2,056,725	400,354	-	93,076	-	-	1,563,295	731,622	191,285	640,388	235,539	145,402	90,760	36,487	15,249
31.12.2047	1,329	17.1	1,966,047	382,703	-	91,263	-	-	1,492,080	698,294	182,571	611,216	214,104	129,096	78,750	30,282	12,128
31.12.2048	1,270	16.4	1,882,495	366,439	-	88,886	-	-	1,427,170	667,915	174,628	584,626	195,038	114,865	68,477	25,187	9,667
31.12.2049	1,214	15.6	1,799,596	350,302	-	107,963	-	-	1,341,330	627,743	164,125	549,463	174,578	100,424	58,507	20,584	7,571
31.12.2050	1,161	14.9	1,720,151	334,838	-	85,229	-	-	1,300,084	608,439	159,078	532,566	161,152	90,545	51,553	17,349	6,116
31.12.2051	1,109	14.3	1,644,160	320,046	-	83,762	-	-	1,240,353	580,485	151,770	508,098	146,427	80,358	44,713	14,393	4,862
31.12.2052	1,061	13.7	1,571,624	305,926	-	83,500	-	-	1,182,198	553,269	144,654	484,275	132,916	71,247	38,742	11,929	3,862
31.12.2053	1,014	13.1	1,502,542	292,479	-	83,344	-	-	1,126,719	527,304	137,865	461,549	120,646	63,166	33,567	9,886	3,067
31.12.2054	970	12.5	1,436,913	279,704	-	103,804	-	-	1,053,406	492,994	128,895	431,517	107,424	54,936	28,530	8,037	2,390
31.12.2055	927	11.9	1,373,588	267,377	-	83,054	-	-	1,023,157	478,838	125,194	419,126	99,371	49,636	25,192	6,788	1,934
31.12.2056	886	11.4	1,312,565	255,499	-	82,916	-	-	974,151	455,903	119,197	399,051	90,106	43,961	21,805	5,620	1,535
31.12.2057	847	10.9	1,254,996	244,293	-	82,786	-	-	927,917	434,265	113,540	380,112	81,743	38,953	18,882	4,655	1,218
31.12.2058	810	10.4	1,199,731	233,535	-	82,662	-	-	883,533	413,494	108,109	361,931	74,126	34,502	16,344	3,854	967
31.12.2059	774	10.0	1,146,767	223,225	-	103,151	-	-	820,391	383,943	94,618	341,831	66,676	30,313	14,033	3,165	761
31.12.2060	740	9.5	1,097,258	213,588	-	82,434	-	-	801,236	374,979	92,274	333,984	62,043	27,551	12,465	2,689	619
31.12.2061	691	8.9	1,024,722	199,468	-	82,249	-	-	743,005	347,726	85,149	310,130	54,869	23,798	10,522	2,172	479
31.12.2062	653	8.4	967,153	188,262	-	82,108	-	64,103	632,679	296,094	86,393	250,192	42,157	17,859	7,717	1,523	322
31.12.2063	602	7.8	892,314	173,694	-	81,909	-	64,103	572,607	267,980	79,042	225,584	36,200	14,979	6,325	1,194	242

Total Discounted Cash Flow from 3P (Proved + Probable + Possible) Reserves as of 31 December 2025 (in Dollars in thousands in relation to the Partnership's share)																	
Cash Flow components																	
										Taxes		Total Discounted Cash Flow after tax					
Until	Condensate sales volume (thousands of barrels) (100% of the petroleum asset)	Gas 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%)	Levy	Income Tax	Discounted at 0%	Discounted at 5%	Discounted at 7.5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
31.12.2064	43	0.5	63,118	12,286	-	15,175	-	64,103	(28,447)	-	2,435	(30,882)	(4,720)	(1,908)	(787)	(142)	(28)
Total	47,677	614	69,573,156	13,534,151	-	4,621,620	2,062,376	192,310	49,162,699	21,789,156	5,937,073	21,436,471	10,473,126	7,923,657	6,242,955	4,251,170	3,161,659

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

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

(4) Set forth below is an analysis of sensitivity to the main parameters comprising the Discounted Cash Flow (the gas price and the gas sales volume) as of 31 December 2025 (Dollars in thousands) which was performed by the Partnership[16]

Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
10% increase in the gas price					**10% decrease in the gas price**				
1P (Proved) Reserves	16,479,329	5,831,238	4,117,142	3,120,485	1P (Proved) Reserves	13,289,979	4,719,188	3,322,586	2,507,283
Probable Reserves	4,709,969	784,889	435,448	282,111	Probable Reserves	3,859,098	647,202	362,144	237,162
Total 2P (Proved+Probable) Reserves	21,189,298	6,616,128	4,552,589	3,402,596	Total 2P (Proved+Probable) Reserves	17,149,078	5,366,389	3,684,730	2,744,445
Possible Reserves	2,485,430	270,435	138,893	89,721	Possible Reserves	2,048,362	226,888	118,629	78,121
Total 3P (Proved+Probable+Possible) Reserves	23,674,728	6,886,562	4,691,482	3,492,317	Total 3P (Proved+Probable+Possible) Reserves	19,197,439	5,593,277	3,803,359	2,822,566
15% increase in the gas price					**15% decrease in the gas price**				
1P (Proved) Reserves	17,283,433	6,112,327	4,317,730	3,274,904	1P (Proved) Reserves	12,490,788	4,437,508	3,120,006	2,349,980
Probable Reserves	4,920,333	818,044	452,768	292,534	Probable Reserves	3,644,105	610,773	341,829	223,951
Total 2P (Proved+Probable) Reserves	22,203,766	6,930,371	4,770,498	3,567,438	Total 2P (Proved+Probable) Reserves	16,134,893	5,048,282	3,461,835	2,573,931
Possible Reserves	2,594,458	281,181	143,910	92,639	Possible Reserves	1,940,537	216,747	114,107	75,597
Total 3P (Proved+Probable+Possible) Reserves	24,798,224	7,211,552	4,914,408	3,660,077	Total 3P (Proved+Probable+Possible) Reserves	18,075,430	5,265,029	3,575,942	2,649,528

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

Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
20% increase in the gas price					20% decrease in the gas price				
1P (Proved) Reserves	18,079,924	6,386,074	4,511,192	3,422,436	1P (Proved) Reserves	11,694,928	4,156,027	2,916,756	2,191,414
Probable Reserves	5,129,573	850,189	469,130	302,045	Probable Reserves	3,431,887	578,316	325,763	215,132
Total 2P (Proved+Probable) Reserves	23,209,497	7,236,263	4,980,322	3,724,481	Total 2P (Proved+Probable) Reserves	15,126,815	4,734,342	3,242,518	2,406,547
Possible Reserves	2,710,836	298,706	155,417	101,768	Possible Reserves	1,828,512	203,041	106,304	70,054
Total 3P (Proved+Probable+Possible) Reserves	25,920,333	7,534,969	5,135,739	3,826,249	Total 3P (Proved+Probable+Possible) Reserves	16,955,327	4,937,383	3,348,822	2,476,601

Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
10% increase in the gas sales volume					**10% decrease in the gas sales volume**				
1P (Proved) Reserves	15,222,304	5,770,156	4,105,613	3,120,804	1P (Proved) Reserves	13,272,545	4,713,749	3,318,384	2,503,697
Probable Reserves	4,198,390	777,284	436,019	283,077	Probable Reserves	3,842,049	642,265	359,140	235,256
Total 2P (Proved+Probable) Reserves	19,420,694	6,547,441	4,541,632	3,403,881	Total 2P (Proved+Probable) Reserves	17,114,593	5,356,014	3,677,523	2,738,953
Possible Reserves	2,188,228	271,708	140,815	90,655	Possible Reserves	2,046,055	226,105	118,004	77,615
Total 3P (Proved+Probable+Possible) Reserves	21,608,922	6,819,148	4,682,447	3,494,536	Total 3P (Proved+Probable+Possible) Reserves	19,160,648	5,582,119	3,795,528	2,816,567
15% increase in the gas sales volume					**15% decrease in the gas sales volume**				
1P (Proved) Reserves	15,309,304	5,994,778	4,290,244	3,271,449	1P (Proved) Reserves	12,467,302	4,430,466	3,114,431	2,345,078
Probable Reserves	4,170,916	810,326	455,896	295,162	Probable Reserves	3,627,808	608,626	341,684	224,849
Total 2P (Proved+Probable) Reserves	19,480,220	6,805,105	4,746,140	3,566,611	Total 2P (Proved+Probable) Reserves	16,095,110	5,039,093	3,456,115	2,569,927
Possible Reserves	2,174,565	287,718	148,830	94,871	Possible Reserves	1,928,765	210,524	108,874	71,078
Total 3P (Proved+Probable+Possible) Reserves	21,654,784	7,092,822	4,894,970	3,661,482	Total 3P (Proved+Probable+Possible) Reserves	18,023,875	5,249,616	3,564,989	2,641,005

Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%	Sensitivity / Category	Present value discounted at 0%	Present value discounted at 10%	Present value discounted at 15%	Present value discounted at 20%
20% increase in the gas sales volume[17]					**20% decrease in the gas sales volume**				
1P (Proved) Reserves	15,364,153	6,197,701	4,460,952	3,412,099	1P (Proved) Reserves	11,664,840	4,147,173	2,909,654	2,185,074
Probable Reserves	4,158,113	843,994	476,097	307,144	Probable Reserves	3,411,162	572,495	322,082	212,683
Total 2P (Proved+Probable) Reserves	19,522,266	7,041,695	4,937,049	3,719,243	Total 2P (Proved+Probable) Reserves	15,076,002	4,719,667	3,231,736	2,397,757
Possible Reserves	2,186,747	314,030	165,293	106,378	Possible Reserves	1,824,784	204,459	108,115	72,020
Total 3P (Proved+Probable+Possible) Reserves	21,709,013	7,355,725	5,102,343	3,825,621	Total 3P (Proved+Probable+Possible) Reserves	16,900,786	4,924,127	3,339,851	2,469,777

[17] Due to infrastructure restrictions, it may not be possible to increase the gas quantities at this rate.

(b) **Contingent resources in the Leviathan Reservoir**

(1) Quantity Data

According to the report that the Partnership received from NSAI, the project relating to the contingent gas and condensate resources in the Leviathan Reservoir, is classified as a project at 'development unclarified' maturity level, and the quantities of the contingent resources attributed thereto are as specified below:

Natural Gas[18] BCF		
Category	**Total (100%) in the Petroleum Asset (Gross)**	**The Total Rate Attributed to the Holders of the Equity Interests of the Partnership (Net)[19]**
1C - Low Estimate	-	-
2C - Best Estimate	679.6	240.3
3C - High Estimate	3,471.6	1,227.7

Condensate[20] Million Barrels		
Category	**Total (100%) in the Petroleum Asset (Gross)**	**The Total Rate Attributed to the Holders of the Equity Interests of the Partnership (Net)[21]**
1C - Low Estimate	-	-
2C - Best Estimate	1.5	0.5
3C - High Estimate	7.6	2.7

(2) The Resources Report states that reclassification of the contingent resources in the Leviathan Project as reserves is contingent on (1) extension of the leases beyond the current expiry date (13 February 2064) or approval of additional wells or additional production facilities which

[18] The Partnership's share is after the Investment Recovery Date, as stated in Section 1(a)(3) above.
[19] The report that the Partnership received from NSAI did not state the Partnership's net share, but rather the Partnership's gross share. The Partnership's net share which is presented in the table is after payment of royalties to the State and to related and third parties and based on an assumption regarding the Investment Recovery Date, as defined in Section 1(a)(3) above.
[20] The Partnership's share is after the Investment Recovery Date, as stated in Section 1(a)(3) above.
[21] The report that the Partnership received from NSAI did not state the Partnership's net share, but rather the Partnership's gross share. The Partnership's net share which is presented in the table is after payment of royalties to the State and to related and third parties and based on an assumption regarding the Investment Recovery Date, as defined in Section 1(a)(3) above.

will enable the production of the resources prior to expiration of the said leases; and (2) a commitment to develop the resources. Insofar as the said conditions are fulfilled, the contingent resources, in whole or in part, may be classified as reserves.

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

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

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

The main differences between the estimates of the reserves and the contingent resources according to the Resources Report and those included in the Previous Resources Report, derive from satisfaction of the contingencies pertaining to approval of the Development Plan by the Commissioner and adoption of an FID for Stage One of the Expansion Project, as a result of which, the vast majority of the contingent resources in the Leviathan Reservoir have been classified as reserves. In addition, the changes in this report derive from an update to the geological model and the flow model in the Reservoir as well as from production of approx. 390 BCF in 2025. Accordingly, all of the 1C contingent resources have been reclassified as 1P reserves, such that the quantity of 1P reserves has risen by approx. 2,345 BCF. All of the 2C contingent resources, except approx. 680 BCF, have been reclassified as 2P reserves, such that the quantity of 2P reserves has risen by approx. 4,692 BCF. All of the 3C contingent resources, except approx. 3,472 BCF, have been reclassified as 3P reserves, such that the quantity of 3P reserves has risen by approx. 5,663 BCF. It is emphasized that the current estimate of the total quantity recoverable from the Reservoir throughout its life, i.e., reserves + resources + quantities produced, has risen by approx. 677 BCF in the low estimate (i.e., 1P + 1C + production), has risen by approx. 102 BCF in the best estimate (i.e., 2P + 2C + quantities produced), and has decreased by approx. 1,354 BCF in the high estimate (i.e., 3P + 3C + quantities produced).

3. Production data

Below is a table which includes data on natural gas and condensate production in 2024 and 2025 in the Leviathan Project:[22,23,24]

<table>
<tr><th colspan="2"></th><th colspan="2">Y2024</th><th colspan="2">Q4/2025</th><th colspan="2">Y2025</th></tr>
<tr><th colspan="2"></th><th>Natural Gas</th><th>Condensate</th><th>Natural Gas</th><th>Condensate</th><th>Natural Gas</th><th>Condensate</th></tr>
<tr><td colspan="2">Total output (attributed to the holders of the Partnership's equity interests) in the period (in MMCF for natural gas and in thousands of barrels for condensate, as applicable)</td><td>179,395.53</td><td>254.55</td><td>45,220.65</td><td>96.34</td><td>174,443.42</td><td>388.45</td></tr>
<tr><td colspan="2">Average price per output unit (attributed to the holders of the Partnership's equity interests) (Dollars per MCF and per barrel, as applicable)</td><td>6.24</td><td>65.87</td><td>5.52</td><td>48.84</td><td>5.69</td><td>52.70</td></tr>
<tr><td rowspan="3">Average royalties (any payment derived from the output of the producing asset, including from the gross income from the petroleum asset) paid per output unit (attributed to the holders of the Partnership's equity interests) (Dollars per MCF and per barrel, as applicable)</td><td>The State</td><td>0.66</td><td>6.96</td><td>0.59</td><td>5.20</td><td>0.61</td><td>5.61</td></tr>
<tr><td>Third parties</td><td>0.16</td><td>1.67</td><td>0.14</td><td>1.25</td><td>0.15</td><td>1.35</td></tr>
<tr><td>Interested parties</td><td>0.08</td><td>0.84</td><td>0.07</td><td>0.62</td><td>0.07</td><td>0.67</td></tr>
<tr><td colspan="2">Average production costs per output unit (attributed to the holders of the Partnership's equity interests) (Dollars per MCF and per barrel, as applicable)[25,26]</td><td>0.93</td><td>5.71</td><td>0.86</td><td>8.26</td><td>0.84</td><td>6.90</td></tr>
<tr><td colspan="2">Average net revenues per output unit (attributed to the holders of the Partnership's equity interests) (Dollars per MCF and per barrel, as applicable)</td><td>4.41</td><td>50.69</td><td>3.86</td><td>33.51</td><td>4.02</td><td>38.17</td></tr>
<tr><td colspan="2">Depletion rate in the reported period relative to the total quantities of gas in the project (in %)</td><td colspan="2">2.61</td><td colspan="2">0.51</td><td colspan="2">2.43</td></tr>
</table>

4. Opinion of the Evaluator

Attached hereto as **Annex A** is a report on reserves and contingent resources in the Leviathan Reservoir prepared by NSAI as of 31 December 2025, and NSAI's consent to its inclusion herein is attached to this chapter as **Annex A**.

[22] The data presented in the table above on the rate attributed to the holders of the Partnership's equity interests on the average price per output unit, royalties paid, production costs and revenues, net, have been rounded off to two digits after the decimal point.

[23] The data presented in the table on the production of condensate do not include additional quantities of condensate which were not sold. The costs and expenses in connection with such additional quantities of condensate were attributed to costs of natural gas production.

[24] It is clarified that the production data for 2025 are based on unaudited financial data.

[25] The data include current production costs only, and do not include the Reservoir's exploration and development costs, and future tax payments to be made by the Partnership.

[26] The average production costs per output unit of natural gas include costs for the transmission of natural gas via the INGL transmission system to the delivery point of EMG in Ashkelon, to the delivery point on the Jordanian border, and costs of transmission via the regional transmission system to the delivery point in Aqaba in Jordan, for the supply of the gas to Egypt in the sum of approx. $158.5 million in 2024, in the sum of approx. $25.3 million in Q4/2025, and in the sum of approx. $115.6 million in 2025 (100%). In addition, the average production costs per output unit of condensate include costs for transmission of the condensate via the Energy Infrastructures (PEI) pipeline and the Europe Asia Pipeline (EAPC) pipeline in the sum of approx. $1.8 million in 2024, in the sum of approx. $1.0 million in Q4/2025, and in the sum of approx. $3.3 million in 2025 (100%).

5. Management declaration

(1) Date of the declaration: 16 January 2026;

(2) Name of the corporation: NewMed Energy - Limited Partnership;

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

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

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

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

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

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

____

Gabi Last, Chairman of the General Partner's Board

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

The Partnership	45.34%
Chevron	39.66%
Ratio Energies - Limited Partnership	15.00%

Sincerely,

NewMed Energy Management Ltd.

General Partner of NewMed Energy – Limited Partnership

By: Yossi Abu, CEO

and Zvi Karcz, VP Exploration

January 16, 2026

NewMed Energy Limited Partnership
19 Abba Eban Boulevard
Herzliya 4612001
Israel

Ladies and Gentlemen:

As independent consultants, Netherland, Sewell & Associates, Inc. hereby grant permission to NewMed Energy Limited Partnership (NewMed) to use our report dated January 16, 2026, 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, 2025, to the NewMed interest in certain gas properties located in Leviathan Field, Leases I/14 and I/15, offshore Israel. The January 16 report also sets forth our estimates of the contingent resources, as of December 31, 2025, to the NewMed working interest in these properties.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Chairman and Chief Executive Officer

JRC:MDK

ESTIMATES

of

RESERVES AND FUTURE REVENUE AND CONTINGENT RESOURCES

to the

NEWMED ENERGY LIMITED PARTNERSHIP INTEREST

in

CERTAIN GAS PROPERTIES

located in

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

as of

DECEMBER 31, 2025

BASED ON PRICE AND COST PARAMETERS

specified by

NEWMED ENERGY LIMITED PARTNERSHIP

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

January 16, 2026

NewMed Energy Limited Partnership
19 Abba Eban Boulevard
Herzliya 4612001
Israel

Ladies and Gentlemen:

In accordance with your request, we have estimated the proved, probable, and possible reserves and future revenue, as of December 31, 2025, to the NewMed Energy Limited Partnership (NewMed) interest in certain gas properties located in Leviathan Field, Leases I/14 and I/15, offshore Israel. Also as requested, we have estimated the contingent resources, as of December 31, 2025, to the NewMed working interest in these properties. It is our understanding that NewMed owns a direct working interest in these properties. It is also our understanding that an updated development plan for Leviathan Field was approved by the Israeli Ministry of National Infrastructures on August 21, 2025, and that on January 15, 2026, the Leviathan Field partners reached the final investment decision on Leviathan Expansion Stage 1. The reserves in this report reflect the impact of these two milestones. We completed our evaluation on or about the date of this letter. For the reserves, this report has been prepared using price and cost parameters specified by NewMed, as discussed in subsequent paragraphs of this letter. Monetary values shown in this report are expressed in United States dollars ($) or millions of United States dollars (MM$). For reference, the December 31, 2025, exchange rate was 3.19 New Israeli Shekels per United States dollar.

The estimates in this report have been prepared in accordance with the definitions and guidelines set forth in the 2018 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE) and in accordance with internationally recognized standards, as stipulated by the Israel Securities Authority (ISA). As presented in the 2018 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resources, or prospective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to quantify; thus reserves, contingent resources, and prospective resources should not be aggregated without extensive consideration of these factors. Definitions are presented immediately following this letter. This report has been prepared for NewMed's use in filing with the ISA; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

RESERVES

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

We estimate the gross (100 percent) reserves and the NewMed working interest reserves for these properties, as of December 31, 2025, to be:

	Gas Reserves (BCF)		Condensate Reserves (MMBBL)	
Category	Gross (100%)	Working Interest	Gross (100%)	Working Interest
Proved (1P)	15,461.2	7,010.1	34.0	15.4
Probable	4,064.8	1,843.0	8.9	4.1
Proved + Probable (2P)	19,526.0	8,853.1	43.0	19.5
Possible	2,145.3	972.7	4.7	2.1
Proved + Probable + Possible (3P)	21,671.3	9,825.8	47.7	21.6

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 NewMed interest in these properties, as of December 31, 2025, 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)	14,885.5	8,260.2	5,277.4	3,722.3	2,816.4
Probable	4,278.9	1,560.5	711.9	395.4	256.9
Proved + Probable (2P)	19,164.4	9,820.7	5,989.3	4,117.7	3,073.2
Possible	2,272.0	652.5	253.7	133.5	88.4
Proved + Probable + Possible (3P)	21,436.5	10,473.1	6,243.0	4,251.2	3,161.7

Totals may not add because of rounding.

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

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The 1P reserves are inclusive of proved developed producing and proved undeveloped reserves. Our study indicates that as of December 31, 2025, 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.

Working interest revenue for the reserves shown in this report is NewMed's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for NewMed's share of royalties, capital costs, abandonment costs, operating expenses, and NewMed'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 NewMed's historical production and operating expense data.

As requested, this report has been prepared using gas and condensate price parameters specified by NewMed. Gas prices are based on NewMed's estimates of approved and future sales contracts. These contract prices are derived mainly from various formulae that include indexation to the Power Generation Tariffs published by The Electricity Authority or to an average of long-term forecasts for Brent Crude prices provided by various institutions. Condensate prices are based on these Brent Crude prices and are adjusted for quality and market differentials. The forecasted Brent Crude prices are held constant through December 31, 2026, then escalated on January 1 of each year through December 31, 2036, and then held constant thereafter; the escalation rates have been specified by NewMed.

Operating costs used in this report are based on operating expense records of NewMed. Operating costs include the overhead expenses allowed under joint operating agreements, direct project-level costs, insurance costs, workover costs, and transportation costs. Since all properties are nonoperated, headquarters general and administrative overhead expenses of NewMed are not included. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated operating costs to be reasonable. Operating costs have been divided into field-level costs and per-unit-of-production costs and, as requested, are not escalated for inflation.

Capital costs used in this report were provided by NewMed and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for new facilities, including the Regional Export Module and the third and fourth gathering lines; regional midstream infrastructure; new development wells and flowlines; and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are NewMed's estimates of the costs to abandon the wells, platform, and production facilities, net of any salvage value. As requested, capital costs and abandonment costs are not escalated for inflation.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the NewMed 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 NewMed receiving its net revenue interest share of estimated future gross production.

CONTINGENT RESOURCES

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. The contingent resources shown in this report are contingent upon (1) extension of the lease term beyond its current expiration date of February 13, 2064, or approval of additional drilling or processing facilities sufficient to recover the volumes prior to expiration of the current lease term; and

(2) commitment to develop the resources. If these contingencies are successfully addressed, some portion of the contingent resources estimated in this report may be reclassified as reserves; our estimates have not been risked to account for the possibility that the contingencies are not successfully addressed. There is no certainty that it will be commercially viable to produce any portion of the contingent resources. The project maturity subclass for these contingent resources is development unclarified.

We estimate the gross (100 percent) contingent resources and the NewMed working interest contingent resources for these properties, as of December 31, 2025, to be:

	Gas Reserves (BCF)		Condensate Reserves (MMBBL)	
Category	Gross (100%)	Working Interest	Gross (100%)	Working Interest
Low Estimate (1C)[1]	0.0	0.0	0.0	0.0
Best Estimate (2C)	679.6	308.1	1.5	0.7
High Estimate (3C)	3,471.6	1,574.0	7.6	3.5

[1] The contingent resources shown in this report represent volumes that are incrementally recoverable over volumes classified as reserves. There are no 1C contingent resources because all of the estimated volumes for the low estimate case have been classified as reserves.

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

GENERAL INFORMATION

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

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

It should be noted that the actual production profile for each category may be lower or higher than the production profile used to calculate the estimates of future net revenue used in this report, and no sensitivity analysis was performed with respect to the production profile of the wells.

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

Netherland, Sewell & Associates, Inc. (NSAI) was engaged on December 15, 2025, by Mr. Yossi Abu, Chief Executive Officer of NewMed, to perform this assessment. The data used in our estimates were obtained from NewMed; Chevron Mediterranean Limited, the operator of the properties; 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 NewMed.

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. John R. Cliver and Mr. Zachary R. Long. Mr. Cliver 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. Cliver is a Licensed Professional Engineer (Texas Registration No. 107216). He has been practicing consulting petroleum engineering at NSAI since 2009 and has over 5 years of prior industry experience.

Mr. Long is a Licensed Professional Geoscientist (Texas Registration No. 11792). He has been practicing consulting petroleum geoscience 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: Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Chairman and Chief Executive Officer

By: John R. Cliver
John R. Cliver, P.E. 107216
Senior Vice President

Date Signed: January 16, 2026

STATE OF TEXAS
J. R. CLIVER
107216
LICENSED
PROFESSIONAL ENGINEER

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

Date Signed: January 16, 2026

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

JRC:MDK

NETHERLAND, SEWELL
& ASSOCIATES, INC.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the 2018 Petroleum Resources Management System (PRMS), version 1.03
Approved by the Society of Petroleum Engineers (SPE) Board of Directors

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 Resources.

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

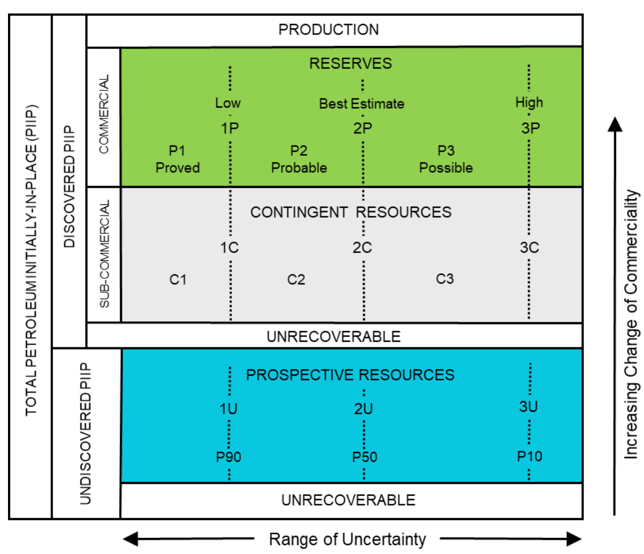

Figure 1.1—Resources classification framework

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

1.1.0.8 Other terms used in resource assessments include the following:

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

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

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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).

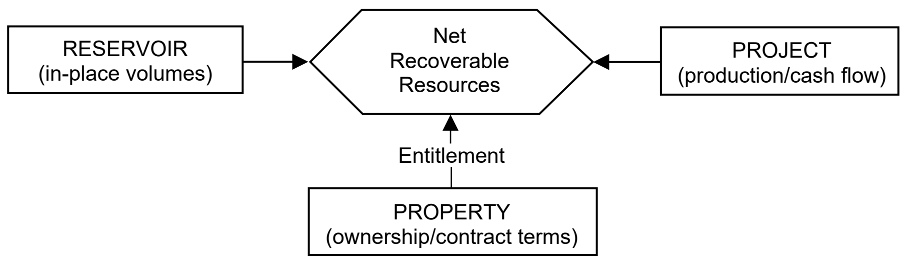

Figure 1.2—Resources evaluation

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).

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

2.0 Classification and Categorization Guidelines

2.1 Resources Classification

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

2.1.1 Determination of Discovery Status

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

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

2.1.2 Determination of Commerciality

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

A. Evidence of a technically mature, feasible development plan.
B. Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.
C. Evidence to support a reasonable time-frame for development.
D. A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria. This assessment is performed on the estimated entitlement forecast quantities and associated cash flow on which the investment decision is made (see Section 3.1.1, Net Cash-Flow Evaluation).
E. A reasonable expectation that there will be a market for forecast sales quantities of the production required to justify development. There should also be similar confidence that all produced streams (e.g., oil, gas, water, CO_2) can be sold, stored, re-injected, or otherwise appropriately disposed.
F. Evidence that the necessary production and transportation facilities are available or can be made available.
G. Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns.

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

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

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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

2.2 Resources Categorization

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

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

2.2.0.2 The uncertainty in a project's recoverable quantities is reflected by the 1P, 2P, 3P, Proved (P1), Probable (P2), Possible (P3) reserves; 1C, 2C, 3C, C1, C2, and C3 contingent resources; or 1U, 2U, and 3U prospective resources categories. The chance of commerciality 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.
2.2.2.4 For Prospective Resources, the general cumulative terms low/best/high estimates also apply and are used to estimate the resulting 1U/2U/3U quantities. No specific terms are defined for incremental quantities within Prospective Resources.

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

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

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

Table 1—Recoverable Resources Classes and Sub-Classes

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

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the 2018 Petroleum Resources Management System (PRMS), version 1.03
Approved by the Society of Petroleum Engineers (SPE) Board of Directors

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

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

Table 2—Reserves Status Definitions and Guidelines

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

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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

Table 3—Reserves Category Definitions and Guidelines

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

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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

REVENUE, COSTS, AND TAXES
PROVED (1P) RESERVES
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2025

Period Ending	Working Interest Revenue (MM$)	Royalties: State (MM$)	Royalties: Interested Party (MM$)	Royalties: Third Party (MM$)	Royalties: Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[1] (MM$)	Future Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2026	1,103.6	122.1	55.3	29.3	206.7	278.1	0.0	134.8	484.0
12-31-2027	1,178.8	130.4	67.8	31.3	229.5	302.8	0.0	130.9	515.6
12-31-2028	1,239.3	137.1	71.3	32.9	241.2	280.9	0.0	109.4	607.8
12-31-2029	1,432.5	158.4	82.4	38.0	278.8	302.2	0.0	132.6	718.8
12-31-2030	1,949.0	215.6	112.1	51.7	379.4	149.3	0.0	162.5	1,257.8
12-31-2031	1,888.7	208.9	108.6	50.1	367.6	120.5	0.0	143.0	1,257.5
12-31-2032	2,114.5	233.9	121.6	56.1	411.6	0.0	0.0	178.8	1,524.1
12-31-2033	2,184.5	241.6	125.6	58.0	425.2	110.5	0.0	184.9	1,463.8
12-31-2034	2,228.8	246.5	128.2	59.2	433.8	0.0	0.0	209.5	1,585.5
12-31-2035	2,243.2	248.1	129.0	59.5	436.7	98.9	0.0	182.9	1,524.8
12-31-2036	2,325.0	257.1	133.7	61.7	452.6	0.0	0.0	186.9	1,685.5
12-31-2037	2,295.6	253.9	132.0	60.9	446.9	110.5	0.0	180.7	1,557.5
12-31-2038	2,306.6	255.1	132.7	61.2	449.0	98.9	0.0	170.0	1,588.7
12-31-2039	2,280.3	252.2	131.1	60.5	443.9	110.5	0.0	172.2	1,553.7
12-31-2040	2,280.2	252.2	131.1	60.5	443.9	98.9	0.0	144.1	1,593.3
Subtotal	29,050.5	3,213.0	1,662.6	771.1	5,646.7	2,062.4	0.0	2,423.0	18,918.4
Remaining	20,526.5	2,270.2	1,180.5	544.9	3,995.6	0.0	192.3	2,050.7	14,287.9
Total	49,577.0	5,483.2	2,843.1	1,316.0	9,642.3	2,062.4	192.3	4,473.7	33,206.3

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Revenue After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2026	0.0	0.0	484.0	23.0	108.4	375.6	366.6	358.1	350.3	342.9
12-31-2027	0.0	0.0	515.6	23.0	111.8	403.8	375.3	350.0	327.4	307.2
12-31-2028	14.9	87.8	520.0	23.0	100.5	419.5	371.3	330.6	295.8	265.9
12-31-2029	27.9	183.8	535.0	23.0	103.6	431.4	363.7	309.0	264.5	227.9
12-31-2030	36.7	439.3	818.5	23.0	182.1	636.4	511.0	414.5	339.3	280.2
12-31-2031	45.3	542.4	715.1	23.0	143.0	572.1	437.5	338.7	265.2	209.9
12-31-2032	46.8	685.6	838.5	23.0	141.4	697.2	507.7	375.2	281.1	213.1
12-31-2033	46.8	657.4	806.5	23.0	133.5	673.0	466.8	329.3	235.9	171.5
12-31-2034	46.8	714.3	871.2	23.0	145.8	725.4	479.2	322.7	221.1	154.0
12-31-2035	46.8	690.5	834.3	23.0	153.5	680.8	428.2	275.3	180.5	120.4
12-31-2036	46.8	765.7	919.8	23.0	177.1	742.7	445.0	273.0	171.2	109.5
12-31-2037	46.8	705.8	851.7	23.0	171.1	680.6	388.4	227.5	136.4	83.6
12-31-2038	46.8	720.4	868.3	23.0	181.7	686.6	373.1	208.6	119.7	70.3
12-31-2039	46.8	704.0	849.7	23.0	184.0	665.7	344.5	183.8	100.9	56.8
12-31-2040	46.8	726.4	866.8	23.0	194.0	672.8	331.6	168.9	88.7	47.8
Subtotal		7,623.3	11,295.1		2,231.5	9,063.6	6,189.7	4,465.2	3,378.0	2,661.1
Remaining		6,712.4	7,575.5		1,753.6	5,821.9	2,070.4	812.2	344.3	155.3
Total		14,335.7	18,870.6		3,985.0	14,885.5	8,260.2	5,277.4	3,722.3	2,816.4

Totals may not add because of rounding.

Note: Remaining represents estimates after December 31, 2040, through the end of the lease term in 2064.

(1) Operating costs include the overhead expenses allowed under joint operating agreements, direct project-level costs, insurance costs, workover costs, and transportation costs.
(2) Oil and gas profits levy rates and estimates are provided by NewMed.
(3) Corporate income tax rates and estimates of corporate income taxes are provided by NewMed and are its expected corporate income taxes per year.

REVENUE, COSTS, AND TAXES
PROBABLE RESERVES
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2025

Period Ending	Working Interest Revenue (MM$)	Royalties: State (MM$)	Royalties: Interested Party (MM$)	Royalties: Third Party (MM$)	Royalties: Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[1] (MM$)	Future Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2026	53.0	5.9	2.7	1.4	9.9	0.0	0.0	4.5	38.6
12-31-2027	98.1	10.9	5.6	2.6	19.1	0.0	0.0	2.3	76.7
12-31-2028	102.5	11.3	5.9	2.7	19.9	0.0	0.0	1.3	81.3
12-31-2029	116.7	12.9	6.7	3.1	22.7	0.0	0.0	3.9	90.2
12-31-2030	40.4	4.5	2.3	1.1	7.9	0.0	0.0	-4.5	37.1
12-31-2031	21.3	2.4	1.2	0.6	4.2	0.0	0.0	-3.7	20.9
12-31-2032	181.4	20.1	10.4	4.8	35.3	0.0	0.0	9.2	136.9
12-31-2033	184.8	20.4	10.6	4.9	36.0	-110.5	0.0	8.4	251.0
12-31-2034	189.5	21.0	10.9	5.0	36.9	110.5	0.0	8.6	33.4
12-31-2035	195.8	21.7	11.3	5.2	38.1	-98.9	0.0	8.3	248.3
12-31-2036	201.9	22.3	11.6	5.4	39.3	98.9	0.0	8.0	55.6
12-31-2037	199.5	22.1	11.5	5.3	38.8	-110.5	0.0	8.0	263.3
12-31-2038	201.5	22.3	11.6	5.3	39.2	11.6	0.0	8.8	141.9
12-31-2039	200.1	22.1	11.5	5.3	39.0	-11.6	0.0	10.9	161.9
12-31-2040	210.6	23.3	12.1	5.6	41.0	-98.9	0.0	4.1	264.5
Subtotal	2,197.3	243.0	126.0	58.3	427.3	-209.5	0.0	78.0	1,901.4
Remaining	10,996.5	1,216.2	632.4	291.9	2,140.5	209.5	0.0	117.5	8,529.0
Total	13,193.9	1,459.2	758.4	350.2	2,567.9	0.0	0.0	195.5	10,430.5

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Revenue After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2026	0.0	0.0	38.6	23.0	8.9	29.7	29.0	28.3	27.7	27.1
12-31-2027	0.0	0.0	76.7	23.0	17.6	59.0	54.9	51.2	47.9	44.9
12-31-2028	21.4	55.4	25.9	23.0	6.0	19.9	17.6	15.7	14.1	12.6
12-31-2029	30.2	42.7	47.4	23.0	10.9	36.5	30.8	26.2	22.4	19.3
12-31-2030	39.1	43.9	-6.8	23.0	-1.6	-5.3	-4.2	-3.4	-2.8	-2.3
12-31-2031	46.4	23.1	-2.2	23.0	-0.5	-1.7	-1.3	-1.0	-0.8	-0.6
12-31-2032	46.8	64.1	72.8	23.0	16.8	56.1	40.8	30.2	22.6	17.1
12-31-2033	46.8	117.5	133.5	23.0	30.7	102.8	71.3	50.3	36.0	26.2
12-31-2034	46.8	15.7	17.8	23.0	4.1	13.7	9.0	6.1	4.2	2.9
12-31-2035	46.8	116.2	132.1	23.0	30.4	101.7	64.0	41.1	27.0	18.0
12-31-2036	46.8	26.0	29.6	23.0	6.8	22.8	13.7	8.4	5.3	3.4
12-31-2037	46.8	123.2	140.1	23.0	32.2	107.9	61.5	36.0	21.6	13.3
12-31-2038	46.8	66.4	75.5	23.0	17.4	58.1	31.6	17.7	10.1	6.0
12-31-2039	46.8	75.8	86.1	23.0	19.8	66.3	34.3	18.3	10.1	5.7
12-31-2040	46.8	123.8	140.7	23.0	32.4	108.3	53.4	27.2	14.3	7.7
Subtotal		893.7	1,007.7		231.8	776.0	506.5	352.2	259.6	201.2
Remaining		3,984.4	4,544.7		1,041.7	3,502.9	1,054.0	359.7	135.8	55.7
Total		4,878.1	5,552.4		1,273.5	4,278.9	1,560.5	711.9	395.4	256.9

Totals may not add because of rounding.

Note: Remaining represents estimates after December 31, 2040, through the end of the lease term in 2064.

(1) Operating costs include the overhead expenses allowed under joint operating agreements, direct project-level costs, insurance costs, workover costs, and transportation costs.
(2) Oil and gas profits levy rates and estimates are provided by NewMed.
(3) Corporate income tax rates and estimates of corporate income taxes are provided by NewMed and are its expected corporate income taxes per year.

REVENUE, COSTS, AND TAXES
PROVED + PROBABLE (2P) RESERVES
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2025

Period Ending	Working Interest Revenue (MM$)	Royalties: State (MM$)	Royalties: Interested Party (MM$)	Royalties: Third Party (MM$)	Royalties: Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[(1)] (MM$)	Future Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2026	1,156.5	127.9	58.0	30.7	216.6	278.1	0.0	139.2	522.6
12-31-2027	1,276.9	141.2	73.4	33.9	248.6	302.8	0.0	133.2	592.3
12-31-2028	1,341.8	148.4	77.2	35.6	261.2	280.9	0.0	110.6	689.1
12-31-2029	1,549.3	171.3	89.1	41.1	301.6	302.2	0.0	136.5	809.0
12-31-2030	1,989.4	220.0	114.4	52.8	387.3	149.3	0.0	157.9	1,294.9
12-31-2031	1,910.0	211.2	109.8	50.7	371.8	120.5	0.0	139.2	1,278.4
12-31-2032	2,296.0	253.9	132.0	60.9	446.9	0.0	0.0	188.0	1,661.0
12-31-2033	2,369.3	262.0	136.3	62.9	461.2	0.0	0.0	193.3	1,714.8
12-31-2034	2,418.3	267.5	139.1	64.2	470.7	110.5	0.0	218.1	1,618.9
12-31-2035	2,439.0	269.8	140.3	64.7	474.8	0.0	0.0	191.2	1,773.1
12-31-2036	2,526.9	279.5	145.3	67.1	491.9	98.9	0.0	194.9	1,741.1
12-31-2037	2,495.2	276.0	143.5	66.2	485.7	0.0	0.0	188.7	1,820.8
12-31-2038	2,508.1	277.4	144.2	66.6	488.2	110.5	0.0	178.8	1,730.5
12-31-2039	2,480.4	274.3	142.7	65.8	482.8	98.9	0.0	183.1	1,715.6
12-31-2040	2,490.8	275.5	143.3	66.1	484.8	0.0	0.0	148.2	1,857.7
Subtotal	31,247.8	3,456.0	1,788.6	829.4	6,074.0	1,852.9	0.0	2,501.0	20,819.9
Remaining	31,523.0	3,486.4	1,813.0	836.7	6,136.1	209.5	192.3	2,168.2	22,816.9
Total	62,770.8	6,942.5	3,601.5	1,666.2	12,210.2	2,062.4	192.3	4,669.2	43,636.8

Period Ending	Levy Rate[(2)] (%)	Levy[(2)] (MM$)	Future Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[(3)] (%)	Corporate Income Taxes[(3)] (MM$)	Future Net Revenue After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2026	0.0	0.0	522.6	23.0	117.2	405.3	395.6	386.5	378.0	370.0
12-31-2027	0.0	0.0	592.3	23.0	129.5	462.8	430.2	401.2	375.3	352.1
12-31-2028	21.4	143.2	545.9	23.0	106.5	439.4	389.0	346.3	309.8	278.6
12-31-2029	30.2	226.5	582.5	23.0	114.5	467.9	394.5	335.2	286.9	247.2
12-31-2030	39.1	483.2	811.7	23.0	180.5	631.2	506.8	411.0	336.5	277.9
12-31-2031	46.4	565.5	712.9	23.0	142.5	570.4	436.1	337.7	264.4	209.3
12-31-2032	46.8	749.7	911.4	23.0	158.1	753.2	548.5	405.4	303.7	230.3
12-31-2033	46.8	774.8	940.0	23.0	164.2	775.8	538.1	379.6	272.0	197.6
12-31-2034	46.8	729.9	889.0	23.0	149.9	739.1	488.2	328.8	225.3	156.9
12-31-2035	46.8	806.7	966.4	23.0	183.9	782.5	492.2	316.4	207.4	138.4
12-31-2036	46.8	791.7	949.4	23.0	183.9	765.5	458.6	281.4	176.4	112.9
12-31-2037	46.8	829.0	991.8	23.0	203.3	788.5	449.9	263.5	158.0	96.9
12-31-2038	46.8	786.8	943.8	23.0	199.0	744.7	404.7	226.2	129.8	76.2
12-31-2039	46.8	779.8	935.8	23.0	203.8	732.0	378.8	202.2	110.9	62.5
12-31-2040	46.8	850.2	1,007.5	23.0	226.4	781.1	385.0	196.1	102.9	55.5
Subtotal		8,517.0	12,302.8		2,463.2	9,839.6	6,696.2	4,817.4	3,637.5	2,862.3
Remaining		10,696.8	12,120.1		2,795.3	9,324.9	3,124.5	1,171.9	480.1	211.0
Total		19,213.8	24,423.0		5,258.5	19,164.4	9,820.7	5,989.3	4,117.7	3,073.2

Totals may not add because of rounding.

Note: Remaining represents estimates after December 31, 2040, through the end of the lease term in 2064.

(1) Operating costs include the overhead expenses allowed under joint operating agreements, direct project-level costs, insurance costs, workover costs, and transportation costs.
(2) Oil and gas profits levy rates and estimates are provided by NewMed.
(3) Corporate income tax rates and estimates of corporate income taxes are provided by NewMed and are its expected corporate income taxes per year.

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
POSSIBLE RESERVES
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2025

Period Ending	Working Interest Revenue (MM$)	Royalties State (MM$)	Royalties Interested Party (MM$)	Royalties Third Party (MM$)	Royalties Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[(1)] (MM$)	Future Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2026	20.9	2.3	1.0	0.6	3.9	0.0	0.0	-4.2	21.2
12-31-2027	24.8	2.7	1.4	0.7	4.8	0.0	0.0	-6.0	26.0
12-31-2028	21.4	2.4	1.2	0.6	4.2	0.0	0.0	-2.1	19.3
12-31-2029	11.3	1.2	0.6	0.3	2.2	0.0	0.0	-1.4	10.5
12-31-2030	129.2	14.3	7.4	3.4	25.2	0.0	0.0	6.1	98.0
12-31-2031	10.0	1.1	0.6	0.3	2.0	0.0	0.0	-5.5	13.5
12-31-2032	28.7	3.2	1.6	0.8	5.6	0.0	0.0	-7.5	30.6
12-31-2033	32.1	3.6	1.8	0.9	6.3	110.5	0.0	-8.0	-76.7
12-31-2034	34.0	3.8	2.0	0.9	6.6	-110.5	0.0	-7.7	145.6
12-31-2035	40.3	4.5	2.3	1.1	7.8	0.0	0.0	-7.8	40.2
12-31-2036	43.1	4.8	2.5	1.1	8.4	-98.9	0.0	-8.3	141.9
12-31-2037	42.5	4.7	2.4	1.1	8.3	98.9	0.0	-8.5	-56.3
12-31-2038	43.2	4.8	2.5	1.1	8.4	0.0	0.0	-8.4	43.2
12-31-2039	43.1	4.8	2.5	1.1	8.4	0.0	0.0	-8.9	43.6
12-31-2040	44.9	5.0	2.6	1.2	8.7	0.0	0.0	-1.3	37.4
Subtotal	569.4	63.0	32.6	15.1	110.7	0.0	0.0	-79.4	538.1
Remaining	6,232.9	689.4	358.5	165.4	1,213.3	0.0	0.0	31.8	4,987.8
Total	6,802.3	752.3	391.1	180.6	1,324.0	0.0	0.0	-47.6	5,525.9

Period Ending	Levy Rate[(2)] (%)	Levy[(2)] (MM$)	Future Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[(3)] (%)	Corporate Income Taxes[(3)] (MM$)	Future Net Revenue After Levy and Corporate Income Taxes Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2026	0.0	0.0	21.2	23.0	4.9	16.3	16.0	15.6	15.2	14.9
12-31-2027	0.0	0.0	26.0	23.0	6.0	20.0	18.6	17.4	16.3	15.2
12-31-2028	21.9	8.2	11.2	23.0	2.6	8.6	7.6	6.8	6.1	5.5
12-31-2029	30.9	8.7	1.7	23.0	0.4	1.3	1.1	1.0	0.8	0.7
12-31-2030	40.3	54.9	43.1	23.0	9.9	33.2	26.7	21.6	17.7	14.6
12-31-2031	46.8	10.8	2.7	23.0	0.6	2.1	1.6	1.2	1.0	0.8
12-31-2032	46.8	14.3	16.3	23.0	3.7	12.5	9.1	6.7	5.0	3.8
12-31-2033	46.8	-35.9	-40.8	23.0	-9.4	-31.4	-21.8	-15.4	-11.0	-8.0
12-31-2034	46.8	68.1	77.5	23.0	17.8	59.6	39.4	26.5	18.2	12.7
12-31-2035	46.8	18.8	21.4	23.0	4.9	16.5	10.4	6.7	4.4	2.9
12-31-2036	46.8	66.4	75.5	23.0	17.4	58.1	34.8	21.4	13.4	8.6
12-31-2037	46.8	-26.3	-29.9	23.0	-6.9	-23.0	-13.2	-7.7	-4.6	-2.8
12-31-2038	46.8	20.2	23.0	23.0	5.3	17.7	9.6	5.4	3.1	1.8
12-31-2039	46.8	20.4	23.2	23.0	5.3	17.9	9.2	4.9	2.7	1.5
12-31-2040	46.8	17.5	19.9	23.0	4.6	15.3	7.6	3.8	2.0	1.1
Subtotal		246.2	291.9		67.1	224.8	156.7	115.9	90.2	73.3
Remaining		2,329.2	2,658.7		611.4	2,047.3	495.7	137.7	43.3	15.2
Total		2,575.4	2,950.6		678.5	2,272.0	652.5	253.7	133.5	88.4

Totals may not add because of rounding.

Note: Remaining represents estimates after December 31, 2040, through the end of the lease term in 2064.

(1) Operating costs include the overhead expenses allowed under joint operating agreements, direct project-level costs, insurance costs, workover costs, and transportation costs.
(2) Oil and gas profits levy rates and estimates are provided by NewMed.
(3) Corporate income tax rates and estimates of corporate income taxes are provided by NewMed and are its expected corporate income taxes per year.

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

REVENUE, COSTS, AND TAXES
PROVED + PROBABLE + POSSIBLE (3P) RESERVES
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2025

Period Ending	Working Interest Revenue (MM$)	Royalties: State (MM$)	Royalties: Interested Party (MM$)	Royalties: Third Party (MM$)	Royalties: Total (MM$)	Net Capital Costs (MM$)	Net Abandonment Costs (MM$)	Net Operating Expenses[1] (MM$)	Future Net Revenue Before Levy and Corporate Income Taxes Discounted at 0% (MM$)
12-31-2026	1,177.4	130.2	59.0	31.3	220.5	278.1	0.0	135.0	543.8
12-31-2027	1,301.7	144.0	74.9	34.6	253.4	302.8	0.0	127.2	618.3
12-31-2028	1,363.2	150.8	78.4	36.2	265.4	280.9	0.0	108.5	708.4
12-31-2029	1,560.5	172.6	89.7	41.4	303.8	302.2	0.0	135.1	819.4
12-31-2030	2,118.7	234.3	121.8	56.2	412.4	149.3	0.0	164.0	1,392.9
12-31-2031	1,920.0	212.4	110.4	51.0	373.7	120.5	0.0	133.8	1,292.0
12-31-2032	2,324.6	257.1	133.7	61.7	452.5	0.0	0.0	180.5	1,691.6
12-31-2033	2,401.4	265.6	138.1	63.7	467.5	110.5	0.0	185.3	1,638.1
12-31-2034	2,452.3	271.2	141.0	65.1	477.4	0.0	0.0	210.4	1,764.5
12-31-2035	2,479.3	274.2	142.6	65.8	482.6	0.0	0.0	183.4	1,813.3
12-31-2036	2,569.9	284.2	147.8	68.2	500.3	0.0	0.0	186.7	1,883.0
12-31-2037	2,537.7	280.7	145.9	67.4	494.0	98.9	0.0	180.2	1,764.5
12-31-2038	2,551.3	282.2	146.7	67.7	496.6	110.5	0.0	170.4	1,773.7
12-31-2039	2,523.5	279.1	145.1	67.0	491.2	98.9	0.0	174.2	1,759.2
12-31-2040	2,535.7	280.4	145.8	67.3	493.6	0.0	0.0	146.9	1,895.2
Subtotal	31,817.2	3,519.0	1,821.2	844.6	6,184.7	1,852.9	0.0	2,421.6	21,358.0
Remaining	37,756.0	4,175.8	2,171.4	1,002.2	7,349.4	209.5	192.3	2,200.0	27,804.7
Total	69,573.2	7,694.8	3,992.6	1,846.7	13,534.2	2,062.4	192.3	4,621.6	49,162.7

Period Ending	Levy Rate[2] (%)	Levy[2] (MM$)	Future Net Revenue After Levy and Before Corporate Income Taxes Discounted at 0% (MM$)	Corporate Income Tax Rate[3] (%)	Corporate Income Taxes[3] (MM$)	Future Net Revenue After Levy and Corporate Income Taxes: Discounted at 0% (MM$)	Discounted at 5% (MM$)	Discounted at 10% (MM$)	Discounted at 15% (MM$)	Discounted at 20% (MM$)
12-31-2026	0.0	0.0	543.8	23.0	122.1	421.7	411.5	402.1	393.2	384.9
12-31-2027	0.0	0.0	618.3	23.0	135.5	482.9	448.8	418.5	391.5	367.3
12-31-2028	21.9	151.3	557.1	23.0	109.1	448.0	396.6	353.0	315.9	284.0
12-31-2029	30.9	235.2	584.2	23.0	114.9	469.3	395.6	336.2	287.7	247.9
12-31-2030	40.3	538.1	854.8	23.0	190.4	664.4	533.4	432.7	354.2	292.5
12-31-2031	46.8	576.4	715.6	23.0	143.1	572.5	437.7	338.9	265.4	210.0
12-31-2032	46.8	764.0	927.6	23.0	161.9	765.8	557.7	412.1	308.7	234.1
12-31-2033	46.8	738.9	899.2	23.0	154.8	744.4	516.3	364.2	261.0	189.6
12-31-2034	46.8	798.1	966.4	23.0	167.7	798.7	527.6	355.3	243.5	169.6
12-31-2035	46.8	825.5	987.8	23.0	188.8	798.9	502.6	323.1	211.8	141.3
12-31-2036	46.8	858.1	1,024.9	23.0	201.3	823.6	493.4	302.8	189.8	121.4
12-31-2037	46.8	802.7	961.8	23.0	196.4	765.4	436.8	255.8	153.4	94.0
12-31-2038	46.8	807.0	966.7	23.0	204.3	762.4	414.3	231.6	132.9	78.1
12-31-2039	46.8	800.2	959.0	23.0	209.1	749.9	388.1	207.1	113.6	64.0
12-31-2040	46.8	867.7	1,027.4	23.0	231.0	796.5	392.6	200.0	105.0	56.6
Subtotal		8,763.2	12,594.7		2,530.4	10,064.4	6,852.9	4,933.3	3,727.7	2,935.5
Remaining		13,025.9	14,778.8		3,406.7	11,372.1	3,620.2	1,309.6	523.4	226.1
Total		21,789.2	27,373.5		5,937.1	21,436.5	10,473.1	6,243.0	4,251.2	3,161.7

Totals may not add because of rounding.

Note: Remaining represents estimates after December 31, 2040, through the end of the lease term in 2064.

(1) Operating costs include the overhead expenses allowed under joint operating agreements, direct project-level costs, insurance costs, workover costs, and transportation costs.
(2) Oil and gas profits levy rates and estimates are provided by NewMed.
(3) Corporate income tax rates and estimates of corporate income taxes are provided by NewMed and are its expected corporate income taxes per year.

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

HISTORICAL PRODUCTION AND OPERATING EXPENSE DATA
NEWMED ENERGY LIMITED PARTNERSHIP INTEREST
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2025

Year	NewMed Working Interest Production (BCF)	Average Per Production Unit ($/MCF)				Reserves Depletion Rate[1] (%)
		Price Received	Royalties Paid	Production Costs	Net Revenue	
2025[2]	176.7	5.73	0.83	0.85	4.05	2.6
2024	180.8	6.28	0.90	0.93	4.45	2.6
2023	175.6	6.23	0.91	0.84	4.48	2.5

Note: Values in this table have been provided by NewMed; these values are based on historical data since January 2023 and include condensate production, revenue, and costs beginning in 2024.

[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 2025 data are representative of unaudited financial data.

VOLUMETRIC INPUT SUMMARY
LEVIATHAN FIELD, LEASES I/14 AND I/15, OFFSHORE ISRAEL
AS OF DECEMBER 31, 2025

Reservoir	Gross Rock Volume (acre-feet) Low Estimate	Best Estimate	High Estimate	Area (acres) Low Estimate	Best Estimate	High Estimate	Average Gross Thickness[1][2] (feet) Low Estimate	Best Estimate	High Estimate	Net-to-Gross Ratio (decimal) Low Estimate	Best Estimate	High Estimate
A Sand	10,003,045	10,894,258	11,680,583	74,393	78,924	83,215	134	138	140	0.75	0.81	0.84
B Sand	2,618,134	2,899,455	3,180,676	36,647	40,183	44,953	71	72	71	0.37	0.42	0.48
BC Sand	1,550,119	1,727,208	1,937,410	24,268	27,048	30,079	64	64	64	0.13	0.14	0.15
C Sand	1,826,280	2,151,885	2,718,411	18,438	21,086	24,602	99	102	110	0.71	0.75	0.78

Reservoir	Porosity[3] (decimal) Low Estimate	Best Estimate	High Estimate	Gas Saturation (decimal) Low Estimate	Best Estimate	High Estimate	Gas Formation Volume Factor (SCF/RCF)[4] Low Estimate	Best Estimate	High Estimate	Gas Recovery Factor (decimal) Low Estimate	Best Estimate	High Estimate
A Sand	0.24	0.23	0.23	0.73	0.76	0.79	374	374	374	0.63	0.66	0.67
B Sand	0.24	0.23	0.23	0.68	0.70	0.72	374	374	374	0.63	0.66	0.67
BC Sand	0.24	0.24	0.23	0.66	0.68	0.71	374	374	374	0.63	0.66	0.67
C Sand	0.23	0.23	0.23	0.74	0.77	0.81	374	374	374	0.63	0.66	0.67

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

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